

# Distribution Interconnection Handbook

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## 1 General Information

### 1.1 Purpose

The purpose of this manual is to provide information on how to interconnect generating facilities or distributed generation (DG) to Pacific Gas and Electric Company's (PG&E's) electrical distribution system. This information is presented by PG&E in an effort to maintain safe, uniform, and reliable service to generating facilities and customers.

This manual is based on the applicable Federal Energy Regulatory Commission (FERC) and California Public Utilities Commission (CPUC) rules and tariffs (e.g., Electric Rules 2, 21, and 22), as well as accepted industry practices and standards.

To find out more about interconnecting generating system to PG&E's electric distribution or transmission systems visit <http://www.pge.com/gen>.

There are two categories listed below for interconnection to the PG&E distribution system.

### 1.2 Retail (Under CPUC Jurisdiction)

Retail interconnection occurs when there is no export of power sales to the California Independent System Operator (CAISO)-controlled system grid. [Electric Rule 21](#) is a tariff (or set of regulations) that describes the interconnection, operation and metering requirements for distributed generators that will be connected to a utility's electric system to supply local load. The California Public Utilities Commission (CPUC) has jurisdiction over the [Electric Rule 21](#) tariff.

### 1.3 Wholesale (Under FERC Jurisdiction)

A Wholesale interconnection occurs when power is exported to the distribution system under PG&E's [Wholesale Distribution Tariff](#) (WDT). Wholesale interconnections are governed by the [Federal Energy Regulatory Commission](#) (FERC). For more information click [here](#) or email PG&E at: [wholesalegen@pge.com](mailto:wholesalegen@pge.com).

### 1.4 Single Point of Contact

PG&E's Electric Generation Interconnection (EGI) department is the single point of contact for processing all Distributed Generation (DG) interconnections to PG&E's distribution lines. Contact us by email at [Rule21gen@pge.com](mailto:Rule21gen@pge.com) or [wholesalegen@pge.com](mailto:wholesalegen@pge.com).

### 1.5 Application Submittal

Customers who want to apply for interconnection, must submit an online application in one of the following ways:

1. For Standard NEM (PV and Wind less than or equal to 30 kW), the online application must be submitted in the PG&E Interconnection Portal - [yourprojects.pge.com](http://yourprojects.pge.com) .
2. For Wholesale Distribution Tariff or Rule 21 Export projects, the online application must be submitted through Customer Connections Online (CCO), [www.pge.com/cco](http://www.pge.com/cco). Additional information about these project types is available at, [www.pge.com/wholesale](http://www.pge.com/wholesale).

## 1.6 Electronic File Format

In the interest of assisting PG&E in its goal to deliver safe, uniform service, all electronic document files should be transmitted in Adobe PDF format. This includes drawing files for architectural, mechanical, and civil site plans. AutoCAD or other file formats are no longer accepted.

## 1.7 Interconnection Forms

Forms associated with [Electric Rule 21](#) projects are listed in Appendix A of the Rule 21 tariff at, [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf).

Forms associated with [Wholesale Distribution Tariff](#) (WDT) projects are provided within the tariff at: [http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE\\_Wholesale\\_Distribution\\_Tariff.pdf](http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf)

## 1.8 Application Completeness

Before proceeding with technical evaluation, PG&E shall provide notification within 10 business days of receipt of the application indicating whether the application is deemed administratively complete and valid.

For all interconnection projects except NEM, a complete and valid application must include the following items:

1. Single line diagram
2. Site plans and diagrams
3. Site control/exclusivity, if applicable
4. Disconnect switch specification sheet, if applicable
5. Transformer nameplate information, if applicable
6. Transfer switch/scheme, if applicable
7. Protective relay information, if applicable
8. Any applicable fees

Please note that a submitted online application is **not** complete until PG&E receives the review fee, if applicable. As required, an invoice will be provided within 10 business days of application receipt.

## 1.9 Glossary of Terms

The links below provide commonly used electrical and distributed generation terms for your reference.

[Interconnection Glossary \(https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/glossary/glossary.page\)](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/glossary/glossary.page)

[Electric Distribution Glossary \(http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/glossary.pdf\)](http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/glossary.pdf)

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## 2 Interconnection Processes

### 2.1 Overview

This section describes the basic process requirements and programs for generators that are requesting to interconnect to PG&E's electrical distribution system. The specific interconnection criteria set forth by PG&E is applicable to all retail generators.

The Net Energy Metering (NEM) and other [Electric Rule 21](#) programs allow PG&E customers to reduce their monthly electric bill with the energy generated by their own generating facilities and/or export power for sale under a PURPA PPA.

PG&E allows interconnection of generating facilities with its distribution system if the customer meets all the requirements set forth by PG&E and the requirements described in Electric Rule 21. The cost of interconnecting a generating facility with PG&E's system can be affected by variables such as the circuit capacity and loading, the location, and the size and type of the generating facility as well as other factors.

### 2.2 Introduction

There are various programs offered for customers connecting generators under Rule 21. [Electric Rule 21](#), including Net Energy Metering (NEM) qualified programs allow customers to install their own generators, which are interconnected to and operate in parallel with PG&E's electric grid. The interconnection processes described below is dependent on the program selected by the applicant. Interconnection requirements also depend on whether the generator will export energy to the grid or not.

### 2.3 Interconnection Programs

#### 1. [Rule 21 Non-Export](#)

- a. All types of customer generators.
- b. Parallel generation solely for a customer's site use. This could include neighbors site use under Public Utilities Code (PUC) 218.
- c. No export of power to PG&E distribution lines.
- d. Rule 21 specifies certain requirements to assure a generator will not export to the grid.
- e. Grid impacts are determined via interconnection studies that are specified in Rule 21.

#### 2. [Rule 21 Export](#)

- a. Generating system sizes can be limited based on the capabilities of distribution circuits.
- b. Types of customer generators depends on the program selected below.
- c. Parallel generation for a customer's site use. This could include neighbors site use under Public Utilities Code (PUC) 218 and is dependent on any program restrictions below.
- d. Grid impacts are determined via interconnection studies that are specified in Rule 21.

The following PG&E programs all fall under “[Electric Rule 21](#) Export” applications.

a. [Renewable Energy Self-Generation Bill Credit Transfer \(RES-BCT\)](#)

Eligible renewable generators include solar, wind, hydro, biogas, biomass, wave, tidal, fuel cells running on biogas, and others. For more information about renewable generators, visit the California Energy Commission website: <http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf>

- (1) All accounts located within the geographic boundaries of the Local Government
- (2) Generating Facility no more than 5 megawatts (MW) owned, operated or on property leased by or under the control of the same Local Government
- (3) Takes service on a bundled, time-of-use rate schedule
- (4) Generating Facility sized to offset part or all of the electricity load (kWh) of the customer’s site use and Benefitting Accounts belonging to the same Local Government.

e. Power Purchase Agreement (PPA):

- (1) Applies to customers who install qualifying generators to reduce the amount of power they purchase from the utility and who enter into a Public Utility Regulatory Policy Act (PURPA) PPA for the exported power.
- (2) These generators may be powered by wind, hydroelectric, biomass, waste, cogeneration or geothermal energy. Visit PG&E’s website for more information regarding available PPA contracts: [https://www.pge.com/en\\_US/for-our-business-partners/floating-pages/renewable-feed-in-tariffs/renewable-feed-in-tariffs.page?WT.mc\\_id=Vanity\\_feedintariffs](https://www.pge.com/en_US/for-our-business-partners/floating-pages/renewable-feed-in-tariffs/renewable-feed-in-tariffs.page?WT.mc_id=Vanity_feedintariffs)

f. [Net Energy Metering \(PG&E Schedule NEM\)](#)

NEM is a type of distributed generation program that allows customers with eligible renewable generation systems to offset the cost of their electric usage with energy they export to the grid.

Eligible renewable generators include solar, wind, hydro, biogas, biomass, wave, tidal, fuel cells running on biogas, and others. For more information about renewable generators, visit the California Energy Commission website: <http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf>

The NEM programs detailed below allow customers to reduce their monthly electric bill with the energy generated by their own solar or renewable generators. A programmed net meter measures the difference between the amount of electricity generated at the home or business that is exported to the grid, and the amount of electricity supplied by PG&E to the property over the course of the month. The process of calculating customers’ bill using this difference is called “net energy metering.”

Click on the programs links for more information.

- (1) [Standard NEM](#): A solar and wind energy program for residential and non-residential customers whose generator size is 30 kilowatts or less.

To apply for a Standard NEM interconnection, all of the following conditions must apply:

- Generating systems that are 30 kilowatts (kW) or less.
- Residential and non-residential customers.
- Photovoltaic (PV) systems or wind systems or a hybrid of both.

- (2) [Expanded NEM](#): Expanded Net Energy Metering is a solar and wind energy program for non-residential customers whose generator system is over 30 kilowatts and up to 1 megawatt (MW).

To apply for Expanded NEM interconnection, all of the following conditions must apply for:

- Generating systems that are greater than 30 kW and up to 1 megawatt (MW).
- Residential, and non-residential (commercial, industrial, and agricultural) customer generators.
- Renewable Electrical Generation Facility as defined in the latest version of the California Energy Commission's (CEC's) Renewables Portfolio Standard (RPS) Eligibility Guidebook

- (3) [NEM Aggregation](#): Net Energy Metering Aggregation (NEMA) is a sub program of the Standard and Expanded NEM Programs available to customers with multiple electric accounts or meters on the same property as the renewable generator or on adjacent and contiguous parcels. All NEMA meters must be located on properties that are solely owned, leased or rented by the same PG&E customer-of-record. NEMA allows customers to allocate generation among all of the eligible, participating accounts monthly.

- (4) [Virtual Net Energy Metering \(PG&E Schedule NEMV\)](#): a program for customers in multi-unit housing or commercial property with a common renewable generating system.

- (5) [Net Energy Metering Multifamily Affordable Solar Housing \(PG&E Schedule NEMVMASH\)](#): A solar energy program for customers living in low income, multifamily affordable housing.

- (6) [Net Energy Metering for Fuel Cells \(PG&E Schedule NEMFC\)](#): For customers with eligible fuel cell generators.

- (7) NEMBIO: For customers with eligible bio-gas digester

- (8) NEMMT (NEM Multi-Tariff): Combination of two types of NEM, or NEM and non-NEM

(9) NEM Successor Program (NEM 2.0)

The NEM Successor program is under development by the California Public Utilities Commission (CPUC). NEM applicants take service from this program when PG&E reaches the NEM program cap. The [NEM Program Cap Tracking](#) webpage provides the progress toward the NEM program limit.

For additional information regarding these programs, please see the electric schedule on the [Tariff Book](#) webpage.

2.4 Inadvertent Export (Per Rule 21, Section M):

For incidental export of power to PG&E's distribution lines the following minimum requirements apply.

1. Any generating technology applies.
2. Generator is optimally sized to meet customer's load.
3. Customer installs a control system to limit export to within the limits specified in Electric Rule 21.
4. Limited grid impact results in expedited interconnection process.

For more information on [Electric Rule 21](#) generators and the interconnection process, please refer to PG&E's website, [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf).

Note: For the installation of standby, emergency, or backup generators refer to Section 5 Temporary and Momentary Use Generator Interconnections.

2.5 Timelines

From the beginning to the end of a generation project there are several phases of review and approval that take place before the entire interconnection process is completed. Each phase of the process is allotted a set range of days that it may take to complete. The timeframes for each of these phases can be found in the following table, [Generation Interconnection Process & Timeline](#). This table also includes information on required documentation that is needed.

**Note:** In a few cases, PG&E's engineering review of the distribution system may determine that additional system upgrades are necessary to support the generation interconnection. These upgrades may incur a cost and add additional time to the project timeline.

2.6 Fees, Deposits and Exemptions

[Electric Rule 21](#) Section E Table E-1, "Summary of Interconnection Request Fees, Deposits and Exemptions", provides the information and costs for NEM and Non-NEM interconnections.

2.7 Single Line Diagram and Project Details

A Single Line Diagram (SLD) must accompany the application. This drawing must meet National Electric Code (NEC) or have a drawing with a Professional Engineering Stamp or C10 license. The diagram or drawing must show the major electric switchgear, protective function devices (including relays, current transformer and potential transformer configurations/wiring in addition to circuit breakers/fuses), wires, generators, transformers, meters and other devices, providing relevant

details to communicate to a qualified engineer the essential design and safety of the system being considered.

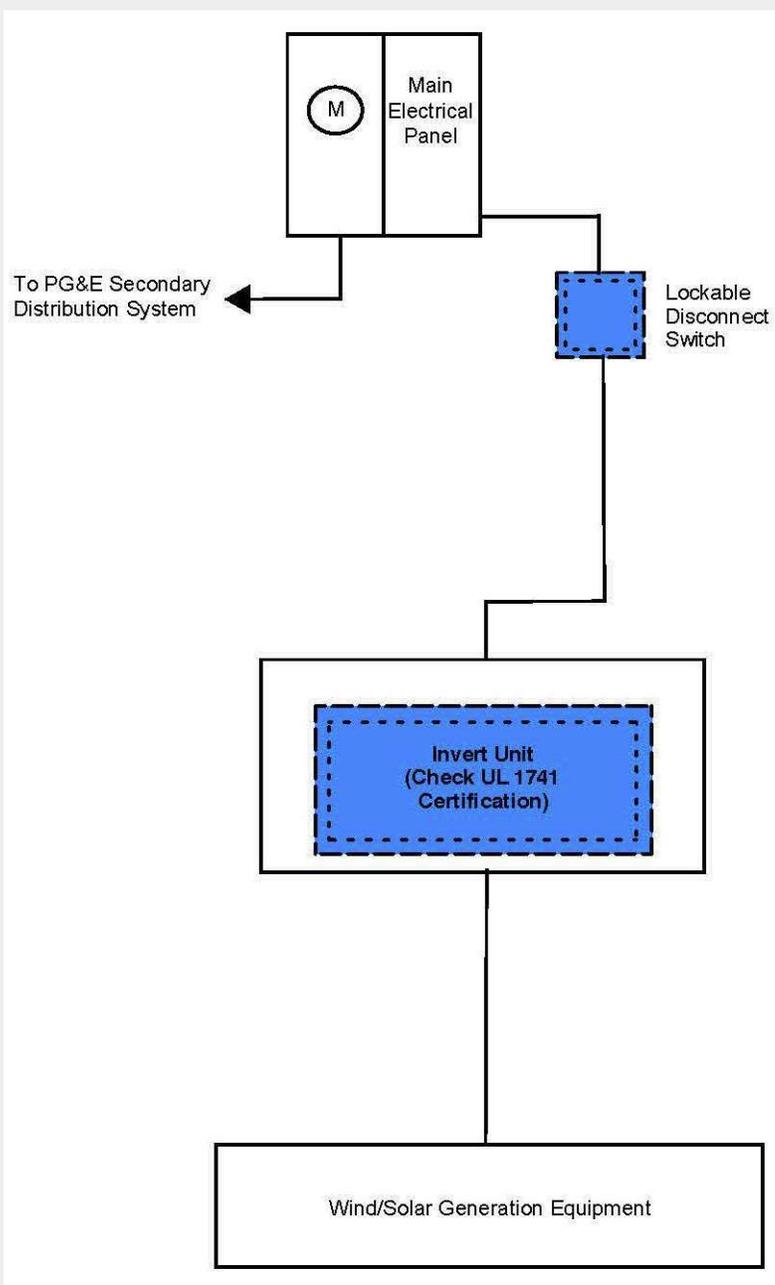
If an existing generating facility is already interconnected at the location then the existing equipment also needs to be identified on the new SLD.

Project related drawing files may also need to be submitted. This could include schematic drawings, such as 3-line alternating current (ac), and tripping schemes (direct current [dc]) for all PG&E-required relays. The impedances for machine based generators will also need to be reviewed.

All drawings must include a legend and notes describing the abbreviations and symbols used to communicate and detail the characteristics on the drawing.

Note: Standard NEM customers are required to submit a SLD as described above except the drawing does **not** have to have a Professional Engineering Stamp or C10 license.

An example of a simple single line diagram is shown in Figure 2-1 on the next page.



**Figure 2-1 Simple Single Line Drawing**

## 2.8 Signed Agreement

Interconnection Agreements associated with Rule 21 projects are listed in Appendix A of the Rule 21 tariff at: [http://www.pge.com/tariffs/tm2/pdf/elec\\_rules\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/elec_rules_21.pdf)

Interconnection Agreements associated with Wholesale Distribution Tariff projects are provided within the tariff at: [http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE\\_Wholesale\\_Distribution\\_Tariff.pdf](http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf).

## 2.9 Proof of Insurance Coverage

Please refer to your applicable Interconnection Agreement for information regarding the insurance requirements.

## 2.10 Approved Building Permit

Before PG&E performs an inspection of the generation system, proof is required that the installation has passed a building and electrical inspection by the local authorities.

**Note:** The customer's generation system **must not be operated in parallel with PG&E's distribution system** until the customer has received a **written approval** from PG&E.

## 2.11 Review and Study Requirements

PG&E must review all generating-facility applications for interconnection, under either the [Wholesale Distribution Tariff \(WDT\)](#) or Rule 21 process. After an interconnection request is deemed complete, PG&E will perform either a Fast Track or a Detailed Study evaluation. For additional information on the review and processes described below, see the applicable sections of [Electric Rule 21, Generating Facility Interconnections](#).

## 2.12 Fast Track

### 1. Initial Review

If PG&E deems that the application is complete, PG&E has 15 business days to perform the initial review.

If the project passes initial review, and does **not** require distribution upgrades, PG&E will provide an interconnection agreement within 15 business days of providing notice of the initial review results.

If the project passes initial review, and does require distribution upgrades, PG&E will provide a non-binding cost estimate for the distribution upgrades within 15 business days.

### 2. Supplemental Review

If the project does not pass Initial Review, PG&E will perform a supplemental review. A supplemental review determines if the project qualifies for a fast track interconnection, or if the project requires a detailed study. PG&E must complete the supplemental review within 20 business days after receiving the supplemental review fee of \$2,500, if applicable.

PG&E will provide one of the following items after the supplemental review:

- a. If the project passes supplemental review, and does **not** require distribution upgrades, PG&E will provide an interconnection agreement within 15 business days of providing notice of the review results.
- b. If the project passes supplemental review, and does require distribution upgrades, PG&E will provide a non-binding cost estimate for the distribution upgrades within 15 business days of providing notice of the review results..
- c. If the project does not pass the supplemental review then further study is required under the Detailed Study process. Review results of the failed supplemental review will be provided.

### 2.13 Detailed Study

If the customer applies directly for a detailed study or the project does not pass the fast track review process then a detailed study will be performed. PG&E will provide an invoice for the detailed study refundable deposit as described in Rule 21 Section E.3.

Upon receipt of payment, the project will proceed to the Electrical Independence Test (Rule 21 Screens Q and R) to determine the applicable detailed study track. The detailed study tracks are:

1. Independent Study
2. Distribution Group Study
3. Transmission Cluster Study

Based on the applicable Detailed Study track, PG&E will offer an agreement that sets forth the following:

- The nature and scope of the studies.
- The facility design and engineering work to be performed.

### 2.14 Inspections

To ensure that the system has been installed in accordance with all PG&E requirements and the originally submitted specifications, PG&E must perform a final inspection of the system before operation begins.

Please refer to subsection 4.14, [Preparallel Inspections \(PPI\)](#), for the types of inspections and for additional information located on PG&E's [DIH](#) internet webpage.

**Note:** The system **must not be operated** until the customer has received a **written approval** from PG&E.

### 2.15 NEM and Rule 21 Agreements

Generator interconnection projects under the provisions of NEM's and Rule 21 require one or more agreements. Copies of these forms can be found on PG&E's Tariff Book ([Electric Forms](#)) webpage.

### 3 Protection and Technical Requirements

#### 3.1 Introduction

This section describes the specific requirements that may be applicable, on a case-by-case basis, to any retail generators that may or may not meet one or more of the simplified interconnection criteria set by the CPUC's, "[Electric Rule 21-Generating Facility Interconnections](#)" requirements.

For the complete text of Rule 21 please see:  
[http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf)

#### 3.2 General Interconnection Requirements

This information is provided in an effort to ensure interconnections to the PG&E system will be made in a safe and reliable manner for the interconnection and customer.

The customer must install, at a minimum, an approved disconnecting device or switch with load- and/or fault-interrupting capability, as needed, at the point of interconnection. See section [4.3 Manual Disconnect Switch](#).

After a generator is interconnected to the local distribution system it is still expected to operate within the parameters specified in CPUC Rule 2. Please refer to the CPUC [Electric Rule 2](#) Description of Service at: [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_2.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf).

The interconnection of a new facility to the PG&E distribution system must not degrade any of the existing PG&E protection and control schemes nor lower the existing levels of safety and reliability to other customers.

Also, as a general rule, neither PG&E nor the customer should depend on the other for detection of abnormal conditions (known as faults) or protection of their respective equipment against such conditions. Each entity is required to independently detect faults and initiate action to interrupt its contribution to the fault. Sequential Fault Detection is not allowed.

Sequential Fault Detection is when an entity can only detect a fault after detection and separation has been completed by the other entity.

Certified anti-islanding generation is exempted from the Sequential Fault Detection requirement since the generator needs to be separated from the system for the anti-islanding detection to operate properly.

**Note:** As specified in Electric Rule 21, PG&E's minimum protection requirements are designed and intended to protect the PG&E power system only. The customer is responsible for the costs of PG&E's installation of any protective equipment necessary to ensure safe and reliable operation of both PG&E's and the customer's facilities. The need for protective equipment will vary, depending on the type, and the size of generation and the facility's location within a PG&E circuit.

#### 3.3 Dedicated Transformers

A dedicated transformer may be required to step-up the generator voltage to the interconnection level and isolate the Generation Entity from other customers.

The impedance of a dedicated transformer limits fault currents on the generator bus from the PG&E Power System and also limits fault currents on the PG&E Power System from the generator. Hence, it reduces the potential damage to both parties due to faults. It also must have a delta winding to reduce the generator harmonics entering the PG&E Power System. The delta winding will also reduce the PG&E Power System harmonics entering the generation facility.

A high-side fault-interrupting device is required for transformer protection. A three-phase circuit breaker is recommended, but fuses are acceptable for generation facilities of less than 1,000 kW, providing that coordination can be obtained with the existing PG&E protection equipment. If fuses are used, it is recommended that the Generation Entity install single-phase protection for its equipment.

Lightning arrestors, if the Generation Entity chooses to install them, must be installed between the transformer and the fault-interrupting devices and be encompassed by the generator's relay protection zone.

### 3.4 Protection and Control Requirements

PG&E's protection requirements are designed and intended to protect the PG&E electric system only.

In view of this objective, PG&E requires that all protective equipment be able to automatically detect and rapidly isolate faulty equipment. It is also important that the protective equipment limit interruptions only to the faulty equipment or section, so that a minimum number of customers are affected by any outage.

The specific protection requirements for interconnection depend on the following factors:

1. The generating facility's size and type.
2. The number of generating facilities.
3. Distribution Feeder configuration and characteristics (i.e., 3 or 4 wire, voltage, impedance, and ampacity).
4. Location of the proposed generating facility and point of interconnection.
5. The ability of the existing protective equipment at the local PG&E distribution system to function adequately with the proposed interconnection facility.

Identical generator projects connected at different locations in the PG&E system can have widely varying protection requirements and associated costs. These differences are due to different feeder configurations, system impedance at the point of interconnection, fault duties, the existing protection schemes, and the generator type and size.

For small NEM customers that meet specified criteria an exception to the disconnect switch requirement may be allowed where the PG&E meter may serve as the disconnect device. See section 5.10.1. in the PG&E Electric and Gas Service Requirements ([Greenbook](#)) manual for these requirements.

Depending on the interconnection factors mentioned above customers may need to install additional protective relays to adequately protect the generator's facility. Customers are responsible for protecting their own systems and equipment from faults or interruptions originating on either PG&E's side or customer's side of the interconnection.

All additionally required system-protection facilities are at the customer's expense. Facilities must be installed, operated, and maintained in accordance with all applicable regulatory requirements as well as the design and application requirements of this handbook.

The protective devices and/or equipment such as relays, breakers, reclosers, etc., used in isolating the generator from the PG&E electric system at the point of interconnection must meet the following requirements:

- The devices must be approved by PG&E.
- The devices must be set to coordinate with the PG&E protective relays or devices for the system to which the generator is connected.

Based on PG&E's station configuration or the type of interrupting devices on the main path between the substation to the Point of Interconnection (POI), PG&E may specify additional protective devices to be installed by the customer. Specific types and styles of the protective devices will be determined by PG&E on a case-by-case basis.

**Note:** PG&E will work with the customer about installation of any additional protective equipment that may be required. The customer will be responsible for the costs of the additional protective equipment.

To ensure that the customer's facility is adequately protected and that the PG&E requirements are met by the proposed design, PG&E recommends that the customer acquire the services of a qualified registered electrical engineer to review the electrical design of the proposed generation facility.

### 3.5 Types of Generation

For a description of the terms "Certified" and "Non-Certified" see [Electric Rule 21, Generating Facility Interconnections](#).

#### 1. Generators with Inverter-Based Interface

PG&E recommends that "Inverters" of all generators with inverter-based interface be certified to Underwriters Laboratories (UL) Standard UL 1741 and be on the California Energy Commissioner's (CEC) [list of eligible inverters](#). Non-Certified inverters will be subject to additional protection requirements.

For more information, please refer to the following link: <http://www.gosolarcalifornia.ca.gov/equipment/index.php>

In addition to having an Underwriters Laboratories Standard UL 1741 certification, an inverter-based generating facility must meet the "non-islanding" criteria specified in the CPUC's "Rule 21- Generating Facility Interconnections,".

PG&E approved single inverters must meet the following criteria:

- a. Have an Underwriters Laboratories Standard UL 1741 certification.
- b. Be on the California Energy Commission (CEC) [eligible list](#).
- c. If the inverter is not UL 1741 certified, it must meet all the criteria set by the [Electric Rule 21](#), Section “J,” and be tested by a Nationally Recognized Testing Laboratory (NRTL) acceptable to PG&E. The test reports must be approved by PG&E prior to scheduling the interconnection.

PG&E may require additional testing for multiple units unless the customer has received an earlier approval.

Single or multiple-unit inverters that are not in compliance with Underwriters Laboratories Standard UL1741 and have not been tested by a NRTL with acceptable results, will be denied for interconnection and commercial operation.

PG&E reserves the right to disconnect previously certified interconnected units when Underwriters Laboratories (UL) decertifies the units. PG&E may implement an acceptable mitigation procedure for recertification at customer’s expense.

Therefore, it is critical that the interconnecting applicant understands all of PG&E’s technical requirements before conducting any engineering design or material procurement.

Note: Until September 8th, 2017, at PG&E’s discretion, non-certified inverters may be interconnected if the applicant meets the requirements as specified in [Electric Rule 21](#) as well as any additional requirements determined by PG&E. The additional requirements may include, but are not limited to, those listed in [Table 3-2 Generator Protection Devices](#).

After September 8th, 2017 all new Inverters are required to be Smart Inverters and Certified to UL-1741 SA (Supplement A).

## 2. Generators with Smart Inverter Interface

Smart Inverter (SI) characteristics described below are currently optional with a mutual agreement by PG&E. After September 8<sup>th</sup>, 2017 these Smart Inverter functions will be mandatory for all new inverter installation.

SI’s are a new generation of inverters with additional functionalities. SI is capable of communication with the utilities smart grid system that may minimize potential grid impact and enable operating flexibility.

The SI requirements are expected to comply with the full revision of the ANSI/IEEE 1547 known as the full revision Standard for Interconnecting Distributed Generation sources”. The full version of ANSI/IEEE 1547 is scheduled to be completed and issued in 2017. The Protective Functions and requirements are designed to protect the utilities distribution system and not the generating facility.

For additional requirements please refer to [Electric Rule 21](#) section Hh., “Smart Inverter Generating Facility Design And Operating Requirements”.

## a. Power Factor

PG&E's default Power Factor (PF) setting for SI's are described below. SI's should be factory programmed to the default settings. Modifications to these settings are not allowed unless required by PG&E..

The producer shall provide adequate reactive power to maintain near unity power factor at the rated output of the SI, or as specified by the Distribution Provider in accordance with the following requirements.

- (1) Default Power Factor setting: 1.0 +/- 0.01 (0.99 Lagging to 0.99 Leading).
- (2) For aggregate generating facilities greater than 15 kW: 1.0 +/- 0.15 (0.85 Lagging to 0.85 Leading) down to 20% of rated power.
- (3) For aggregate generating facilities less than or equal to 15 kW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% of rated power.

## b. Dynamic Volt/VAR Operations

The SI's shall have the ability of operating dynamically within a power factor range of;

+/- 0.85 PF for generating facilities with aggregate capacities larger than 15 kW, down to 20% of rated power,

+/- 0.9 PF for generating facilities with aggregate capacities equal to or smaller than 15 kW, down to 20% of rated power.

This dynamic Volt/VAR ability shall be capable of being activated or deactivated in accordance with Distribution Provider requirements.

The Distribution Provider may permit or require the SI systems to operate in wider power factor ranges. The wider range includes operations in all 4-quadrants with presences of storage systems. Additional anti-islanding protection as determined by the Distribution Provider may be required.

The SI shall be capable of providing dynamic reactive power compensation (dynamic Volt/VAR operation) within the following constraints:

- (1) The SI shall not cause the line voltage at the point of interconnection to go outside the requirements of the latest version of ANSI C84.1, Range A.
- (2) The SI shall be able to consume reactive power in response to an increase in line voltage, and produce reactive power in response to a decrease in line voltage.
- (3) The reactive power provided (or consumed) by the SI shall be based on the Distribution Provider's need (or availability) of reactive power. The maximum reactive power provided to (or consumed from) the system shall be as directed by the Distribution Provider.

Note: SI's with inadequate available reactive power at maximum real power output are incapable of voltage correction applications. Other mitigation measures may be required.

c. Volt/Var Curve

SI are capable of operating dynamically within a power factor range. PG&E may require the power factor settings on a smart inverter be changed as determined by the available reactive power on the distribution system. To make this determination based on the make and model of the installed SI(s). The Volt/Var curve(s) of the unit(s) must be set in the “On” position with the default settings shown below.

Table 3-1 – Voltage and Reactive default settings

Voltage Setpoint	Voltage Value	Reactive Setpoint	Reactive Value	Operation
V1	92.0%	Q1	30%	Reactive Power Injection
V2	96.7%	Q2	0	Unity Power Factor
V3	103.3%	Q3	0	Unity Power Factor
V4	107.0%	Q4	30%	Reactive Power Absorption

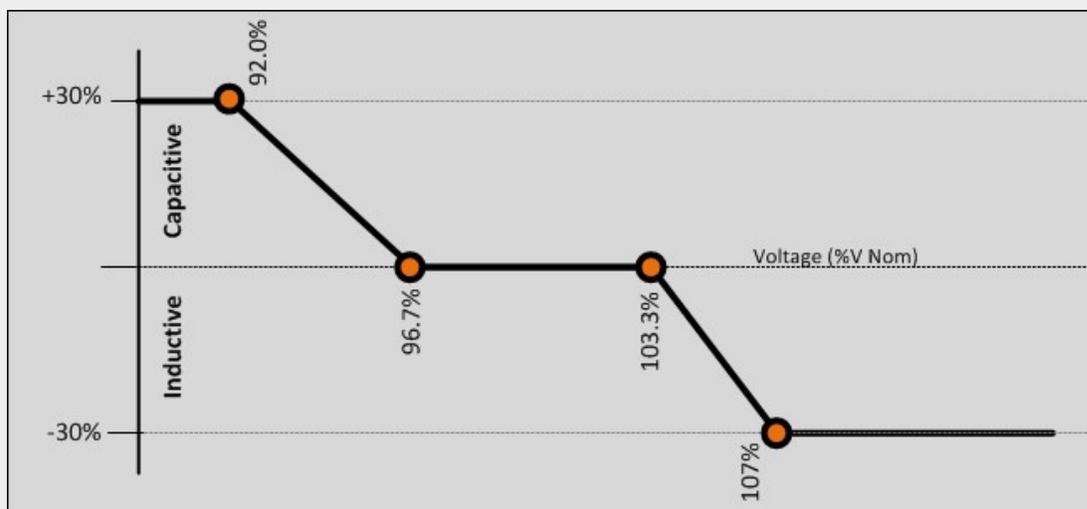


Figure 3-1 Voltage and Reactive default settings

- (1) Small Inverters (< 100 kW) will be set to Figure 3-1.
- (2) Large Inverters (> 100 kW) will be set as specified by PG&E.

d. Communications - Common Smart Inverter Profile (CSIP)

Communications between the utility and DG systems are one of the essential functions for SI’s. CSIP was developed to create a common communication profile for inverter communications that could be relied on by all parties to enable communications-level interoperability between the utilities and SI’s or the systems managing those inverters.

The CSIP covers the complete set of communications as defined by the Smart Inverter Functionality requirements and serves as a guide to assist manufacturers, DER operators, system integrators and DER aggregators to implement the CSIP for California.

The [IEEE 2030.5 Common California IOU Rule 21 Implementation Guide for Smart Inverters](#) (CSIP) can be found on the [DIH](#) webpage.

- (1) Conditions for Mandatory Communications.
  - Required for all generators 1 MW or greater.

### 3. Battery Energy Storage Systems (BESS)

Energy storage is considered a generator under Electric Rule 21 and is subject to interconnection procedures to ensure the safety and reliability of the electric system. Battery energy storage systems are typically one part of a customer Distributed Generation (DG) project and consist of batteries, inverter(s), and an associated control system. All BESS interconnected directly to the PG&E distribution system must be connected using an approved inverter interface. BESS connections will be reviewed as part of the customer's generation system or facility and will be required to meet the technical and operational requirements of this manual. For additional information and qualifications please visit PG&E's webpage on [energy storage](#) at, [https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/export-power/distributed-generation-handbook/net-energy-metering/energy-storage/energy-storage.page](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/export-power/distributed-generation-handbook/net-energy-metering/energy-storage/energy-storage.page).

PG&E has provided a guide to aid customers in the PG&E interconnection process for energy storage devices applying under Electric Rule 21. This guide provides clarity and sets expectations for how PG&E implements the applicable electric rules governing utility service to retail customers deploying energy storage devices. The document can be found at the following link, "[Guide to Energy Storage Charging Issues For Rule 21 Generator Interconnection](#)".

### 4. Machine-Based Generation without Inverter-Based interface

In addition to the standard generator protection (such as voltage and frequency relays), the following equipment may be required for machine-based generating facilities.

- a. Phase and ground fault-detection schemes to detect faults on the PG&E system. See [Notes 1 and 2](#) below [Table 3-2 Generator Protection Devices](#).
- b. An anti-islanding scheme to inhibit formation of or to de-energize "Unintentional Islanding" conditions, (rarely available on machine-based units).
- c. A reclose-blocking scheme.
- d. A transfer-trip scheme.
- e. The power quality requirements described in [Electric Rule 2](#) may also apply to machine-based generating facilities.

## Notes:

- (1) “Reverse-power” relays are acceptable as a substitute for fault detection provided the reverse power elements on each phase can operate due to abnormal voltages caused by faulted conditions. Reverse power relays on the PG&E approved relay list meet this criteria.
- (2) An “under-power” function may be a viable substitute for some fault-detection schemes.
- (3) An “under-power” function is not a suitable substitute when “inadvertent export” is a possibility.
- (4) A utility-grade device with three, independent, current-measuring elements may be required for the generator.

### 3.6 Reliability and Redundancy

The customer’s design must include a protection system with adequate redundancy. Adequate redundancy means that despite failure of any one component, the customer’s facility will still have the capability to be isolated from the PG&E electric system during a fault condition.

Multifunction, three-phase protective relays must have a redundant back-up relay(s). The circuit breakers must be trip-tested by the customer at least once a year. The redundant relay may be of the same manufacturer and model.

### 3.7 Relay Grades

Utility Grade relays are required for interconnection applications. Utility-grade relays, have high reliability and accuracy. They are constructed robustly to operate in a high voltage, high energy environment.

These devices typically have indicating targets with manual reset capabilities. In addition, to facilitating testing and troubleshooting, they are equipped with superior recording capability.

PG&E requires that utility grade relays be installed as described below.

#### 1. Utility-Grade Relays

All utility-grade relays must be equipped with relay targets that can be reset manually.

All utility-grade relays must have DC power supplies powered by a station-battery and charging system. A station battery system must be equipped with a DC-undervoltage detection alarm.

Note: Monitoring of the DC battery voltage by a separate voltage relay or through a charger that provides a critical alarm to a 24/7/365 monitoring system is required. A critical alarm may also be annunciated by a strobe light with audible alarm system that can be detected or other alarm notification methods that have been reviewed and approved by PG&E.

Fuses are not allowed in the dc trip circuitry (dc breakers or slugs are acceptable).

Utility-grade relays are required for interconnections to PG&E's Distribution Grid in the following circumstances:

- a. In all generation facilities with aggregate nameplate ratings in excess of 1,000 kW.
  - b. On all generation facilities using non-certified inverter-based interface systems.
  - c. On all generation facilities that require fault detection as specified in Electric Rule 21.
  - d. When the relays are used in ground-fault-detection schemes for detection of faults on PG&E system as required.
  - e. For all cases requiring a voltage-restraint or a voltage-controlled overcurrent relay.
  - f. When auxiliary relays and timers are used in the tripping circuits of PG&E-required protection schemes, they must be utility grade.
  - g. When additional protection is required as determined by PG&E.
2. Relays Approved by PG&E

The customer must submit all proposed relay specifications to PG&E for approval before ordering the relays. The line-protection and Generation-protection relays must be listed on PG&E's approved list. The tables below list the types of relays approved for the PG&E distribution and transmission systems.

PG&E approved relays are listed in Tables G2-4 and G2-5 located in [Section G2, "Protection and Control Requirements."](#) of the [Transmission Interconnection Handbook](#) (TIH).

PG&E required protective relays must meet either of the following conditions:

- a. Be on the PG&E-approved list.
- b. Be tested and approved according to [the](#) requirements in the [Transmission Interconnection Handbook's Appendix R - "Generator Protective Relay Requirements."](#)

The customer is responsible for the costs of any required, qualified tests performed on the relays. All tests must be completed prior to PG&E's approval of the relay for interconnection use.

PG&E's approval does not imply any endorsements or warranties for the quality or reliability of any products or services. Customers proposing to use relay's that are not on the PG&E approved list, must be aware of the additional time that maybe required for testing and PG&E's review and approval.

### 3.8 System Fault Detection and Protection

The customer's equipment must be able to independently detect phase and ground faults on the PG&E system, as specified by [Electric Rule 21](#) (i.e., For Machine-based generation without Inverter-based interfaces, "sequential fault detection," where the equipment is unable to detect the fault until after the PG&E system has been isolated, is unacceptable). All required fault-detection relays must coordinate with PG&E's devices, as necessary.

The line-protection schemes must be able to distinguish between generation, inrush, and fault current.

PG&E's existing relaying schemes may have to be reset, replaced, or augmented with additional relays for proper protection and coordination due to the interconnection of the customer's new facility. All associated costs to accomplish required modifications/additions will be at customer's expense.

For communication aided protection schemes (typically high speed protection or DTT) PG&E determines the appropriate communication type to be used on a case-by-case basis.

The leased telephone line or dedicated communication network must have high-voltage protection equipment on the entrance cable so the communication assisted scheme (such as DTT) can operate properly during fault conditions. For a more detailed description of the protection requirements and the associated DTT equipment and communications circuit monitoring, refer to, "[Telemetry and Transfer Trip](#)", located on the [DIH](#) webpage.

PG&E's distribution network is designed for high reliability. Certain load centers and customers may have multiple and/or redundant supply sources. When there are multiple sources and paths, PG&E may require more complex protection schemes to properly detect and isolate faults.

Interconnection of any new generation facility to the PG&E electric system must not degrade the existing protection and control schemes or lower the levels of safety and/or reliability for existing PG&E customers. For more information, please refer to "[Electric Rule 2 Description of Service](#)" at: [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_2.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf).

Many parts of the PG&E electric system have provisions for an alternate feed when the normal feeder is out of service. However, due to protection concerns with the existing schemes, there are cases where PG&E is unable to allow generation to be online while being fed from an alternate source. For some of these cases, it may be possible to upgrade the existing protective schemes to allow operation of the generation on the alternate feed.

Upon customer's request, PG&E can provide the estimated cost of upgrades needed for customer's generator to stay online while being served from an alternate source. After completion of the required upgrades, which will be at customer's expense, the generation facility may stay online while being transferred to the alternate source. However, if the required upgrades are not completed, PG&E will require that the facility stay off line while the line section with other customers is being served from the alternate source.

1. Direct Transfer Trip (DTT)

DTT is required if PG&E determines that a generation facility cannot detect and trip for PG&E's end-of-line faults within an acceptable time frame. DTT is also required when PG&E determines that the generation facility is capable of sustaining a section of the distribution system energized (form unintentional island) when separated from PG&E. Before a new Generation Facility may be connected to the PG&E distribution System, additional protection and telecommunications systems may be required. When required, these protection and telecommunications systems must be satisfactorily commission tested and in-service prior to parallel operation. If PG&E requires DTT protection, then all required communication circuits and equipment as determined by protection studies, must be provided by the customer at customer's expense. The customer must have a telephone communication line in service for the DTT at least three weeks before the facility is energized.

Please refer to, "[Telemetry and Transfer Trip](#)", located on the [DIH](#) webpage for the current telecommunication options. This document also provides the requirements for communication assisted protection, including the associated DTT equipment, communication circuit monitoring, and the commissioning test. Radio based communication may also be available for some DTT applications. Refer to [TD-1013B-001 Direct Transfer Trip 900 MHz Radio Scheme](#).

The number of required DTT's will be determined by PG&E's protection study. If PG&E determines that DTT is necessary, the customer will have to install a DTT to the generator circuit breaker or the interconnection substation circuit breaker from one or all of the following devices.

- a. Transmission remote end terminal.
- b. High-side circuit breaker/circuit switcher on the transmission side of the substation transformer.
- c. Distribution feeder circuit breaker.
- d. Any distribution line reclosers.

Note: DTT is more likely to be required for non-certified inverter and/or machine based systems than for generation with certified inverter based interfaces. Each facility is reviewed on an individual basis and the requirements will depend on variables influencing protection including: type, size, and location of the generator and the existing protective equipment on PG&E's system. Please refer to section 3.7.2. below for further details.

2. Alternate Protection to DTT

Depending on the type of new Distributed Generation, protection requirements for interconnecting have been modified to reduce the need for DTT schemes. These requirements can be found on the [DIH](#) webpage in document, "[TD-2306B-002 Distributed Generation Protection Requirements](#)".

3. Reclose Blocking

Automatic restoration or testing of PG&E's facilities is normally performed by PG&E's reclosing devices such as circuit breakers or line reclosers. The restoration of power by automatically re-energizing PG&E's facilities may cause generator damage and system disturbances. PG&E's automatic restoration scheme may need to be modified to inhibit "out-of-phase" reclosers on energized generators to prevent generator damage and/or a system disturbance. This may be accomplished by delaying of the automatic reclosers until after the affected line voltage as measured by PG&E's equipment falls below 10% of the nominal voltage. This is typically known as Reclose Blocking. PG&E requires this modification when it determines that the generator(s) has (have) the capability of keeping a section of PG&E system energized as an unintentional island for longer than 2 seconds when separated from the PG&E system.

Reclose blocking is required on the substation breaker or at the line recloser if the aggregate generation exceeds 50% of minimum annual line section load. If minimum load is unavailable, then 15% of line section annual peak is used for this purpose. Each facility is reviewed on an individual basis and in conjunction with other generation sources on the distribution feeder. In general, reclose blocking is required if formation of an unintentional island lasting longer than 2 seconds is possible.

Exceptions may apply as specified in [TD-2306B-002 Distributed Generation Protection Requirements](#).

For synchronous generation units, please refer to Engineering Document 053826, "[Requirements For Distribution Feeder with Synchronous Generating Equipment](#)", located on the [DIH](#) webpage.

### 3.9 Protection and Control for Generating Facilities

The customer is responsible for providing all of the necessary protection for its own generator. All protective equipment required by PG&E are intended solely for the protection of the utility and its customers.

Multiple single-phase generator units must be connected in a balanced fashion. This is to ensure that an equal amount of generation output is supplied to each phase of a three-phase circuit. Also see section 4.10 Limits Specific to Single-Phase Generating Facilities.

All generating facilities must comply with the latest, applicable regulatory standards for:

1. Waveform and power quality.
2. Telephone interference.
3. DC current injection and AC harmonic current injection limits, etc., as specified in Electric Rule 21.

Synchronous generators, regardless of the generating capacity, must be equipped with an acceptable synchronization method, as specified in subsequent sections of this document. Synchronous generators may be subjected to [Reclose Blocking](#) schemes on one or more of PG&E's automatic reclosing devices.

Please see Table 3-1. "Generator Protection Devices" for the protection equipment that is required to operate a generator safely and reliably in parallel with PG&E's electric system.

PG&E will determine any additional generator-protection requirements on a case-by-case basis.

**Table 3-2 Generator Protection Devices**

<b>Generator Protection Device</b>	<b>Device Number<sup>1</sup></b>	<b>40 kW or Less</b>	<b>41 kW to 400 kW</b>	<b>401 kW and Larger</b>
Phase Overcurrent	50/51	X <sup>2</sup>	X <sup>2</sup>	
Overvoltage	59	X	X	X
Undervoltage	27	X <sup>3</sup>	X	X
Overfrequency	81O	X	X	X
Underfrequency	81U	X	X	X
Ground-Fault-Sensing Scheme (Utility Grade)	51N		X <sup>4</sup>	X
Overcurrent with Voltage Restraint (51V) or Overcurrent with Voltage Control (51C)	51V 51C		X <sup>5</sup>	X
Reverse-Power Relay	32	X <sup>6</sup>	X <sup>6</sup>	X <sup>6</sup>
Direct-Transfer Trip	TT	X <sup>7</sup>	X <sup>7</sup>	X <sup>7</sup>

**Notes:**

- 1) Please refer to [Table 3-7 Standard Device Numbers](#) for device numbers, definitions, and functions.
- 2) When fault-detection is required, overcurrent protection must be able to detect phase fault condition at the end of protection zone. 50/51 devices are not required by PG&E if a 51V or 51C relay is used.
- 3) For generators 40 kW or less, the undervoltage requirement can be met by the contactor undervoltage release.
- 4) If fault detection is required per CPUC Rule 21, then phase and ground-fault detection schemes are required for all, induction, synchronous, or all generating facilities with non-certified inverter based interfaces.

Synchronous generators with an aggregate generation over 40 kW and induction generators with an aggregate generation over 100 kW require ground-fault detection.

- 5) If fault detection is required then, a group of generators, each less than 400 kW but whose aggregate capacity is 400 kW or greater, must have an overcurrent-relay with voltage restraint (known as 51V) or voltage control (known as 51C) as determined by PG&E. This relay is installed for each generator rated greater than 100 kW. Generation units using certified inverter based interfaces are excluded from this requirement. Induction generators will be reviewed on a case-by-case basis.

- 6) "Non-export" generating facilities with a dedicated transformer, having a finite "minimum power import" (without any possibility of an "incidental" or an "inadvertent" export), may use a set of three single-phase, very sensitive reverse-power relays in lieu of phase and ground-fault protection.

PG&E prefers that the relay be set as an "under-power" element. As specified by CPUC Rule 21, the relay should be set at 5% of the customer's minimum import power (despite the generator's maximum output) for each phase, to trip the main circuit breaker with a maximum time delay of 2 seconds.

As a "reverse-power" element, the relay must be set for 0.1% of the transformer rating with a maximum time delay of 2 seconds.

- 7) PG&E determines, based on PG&E's circuit configuration and loading, if the distribution-level interconnections require DTT protection. Refer to Direct Transfer Trip (DTT) requirements. For exemptions to DTT see [TD-2306B-002 Distributed Generation Protection Requirements](#).

Note: For primary service, load only (no generation), facilities, please see the PG&E approved protective devices listed in Table L2-1 located in [Section L2](#) on the [Transmission Interconnection Handbook](#) (TIH).

The following items describe typical protection and control functions that may be required for generators:

1. Phase Overcurrent

Please see [Table 3-7 Standard Device Numbers](#) (Device 50/51) for the definition and function of the phase-overcurrent relays.

2. Over/Undervoltage

The over/undervoltage relay is used to trip the interrupting device when the voltage is above (in case of overvoltage) or below (in case of undervoltage) PG&E's operating voltage levels..

For all distribution interconnections, the undervoltage relay is set for 88% of the nominal voltage (106 V on the 120 V base) unless system conditions require otherwise.

The overvoltage relay is set for 110% of the nominal voltage (132 V on the 120 V base).

The voltage trip settings below, for inverter and Smart inverter based interfaces, can be found in Sections H and HH of Electric Rule 21, [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf).

**Table 3-3 General Voltage Trip Settings for Generating Facilities<sup>1, 2</sup>**

<b>Voltage at Point of Common Coupling</b> (the ranges below are used to trip the generator during abnormal distribution system conditions)		<b>Maximum Trip Time<sup>3</sup></b>	
Assuming 120 Volt Base	% of Nominal Voltage	# of Cycles (Assuming 60 Hz Nominal)	Seconds
Less than 60 volts	Less than 50%	10 Cycles	0.16 Seconds
Greater than or equal to 60 volts but less than 106 volts	Greater than or equal to 50% but less than 88%	120 Cycles	2 Seconds
Greater than 132 volts but less than or equal to 144 volts	Greater than 110% but less than or equal to 120%	60 Cycles	1 Second
Greater than 144 volts	Greater than 120%	10 Cycles	0.16 Seconds

**Notes:**

- 1) For Generating Facilities with a Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table 3-2 may be negotiated with Distribution Provider.
- 2) After September 8th, 2017 all new Inverters are required to be Smart Inverters and Certified to UL-1741 SA (Supplement A).
- 3) "Maximum Trip Time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize Distribution Provider's Distribution System. Protective Function equipment and circuits may remain connected to Distribution Provider's Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow for a Generating Facility to minimize tripping during short term system disturbances. Set points shall not be user adjustable for generating facilities less than 30 kW.

**Table 3-4 Smart Inverter Voltage Ride-Through and Trip Table<sup>1</sup>**

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	$V > 120$			0.16 seconds
High Voltage 1 (HV1)	$110 < V < 120$	12 seconds	Momentary Cessation	13 seconds
Near Nominal (NN)	$88 < V < 110$	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	$70 \leq V < 88$	20 seconds	Mandatory Operation	21 seconds
Low Voltage 2 (LV2)	$50 \leq V < 70$	10 seconds	Mandatory Operation	11 seconds
Low Voltage 3 (LV3)	$V < 50$	1 seconds	Momentary Cessation	1.5 seconds

**Notes:**

- 1) After September 8th, 2017 all new Inverters are required to be Smart Inverters and Certified to UL-1741 SA (Supplement A).

## 3. Over/Underfrequency

For non-smart inverters and machine based distribution generator interconnections, the underfrequency function and the overfrequency function should be set to the values in Electric Rule 21 or as specified by PG&E.

The over/underfrequency function is used to trip the interrupting device when the frequency is above or below PG&E's normal operating level. It is used for generator or turbine protection and as a backup protection.

To maintain generation online during system disturbances, the customer may need to coordinate the generator's underfrequency settings with those of other utilities in the [Western Electric Coordinating Council \(WECC\)](#). [PG&E will notify the customer if different settings are needed](#). For more information about the WECC, please refer to <https://www.wecc.biz/Pages/home.aspx>

For smart inverters, voltage and frequency setting should conform to Electric Rule 21 Smart Inverter requirements in Section Hh.

For non-smart inverters and machine based distribution generator interconnections, the underfrequency function and the overfrequency function should be set to the values in Electric Rule 21 or as specified by PG&E.

**Table 3-5 Frequency Trip Settings**

<b>Generating Facility Rating</b>	<b>Frequency Range (Assuming 60Hz Nominal)</b>	<b>Maximum Trip Time<sup>1</sup> (Assuming 60 Cycles per Second)</b>
Less or equal to 30kW	Less than 59.3 Hz	10 Cycles
	Greater than 60.5 Hz	10 Cycles
Greater than 30 kW	Less than 57.0 Hz	10 Cycles
	Less than an adjustable value	Adjustable between 10 and 18,000
	between 59.8 Hz and 57 Hz but	Cycles <sup>2, 3</sup>
	greater than 57 Hz. [2]	Cycles <sup>2, 3</sup>
	Greater than 60.5 Hz.	10 Cycles

**Notes:**

- 1) "Maximum Trip time" refers to the time between the onset of the abnormal condition and the Generating Facility ceasing to energize Distribution Provider's Distribution or Transmission System. Protective Function sensing equipment and circuits may remain connected to Distribution Provider's Distribution or Transmission System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow a Generating Facility to "ride through" short-term disturbances to avoid nuisance tripping. Set points shall not be user adjustable (though they may be field adjustable by qualified personnel). For Generating Facilities with a Gross Rating greater than 30 kVA, set points shall be field adjustable and different voltage set points and trip times from those in Table 3-4 may be negotiated with Distribution Provider.
- 2) Unless otherwise required by Distribution Provider, a trip frequency of 59.3Hz and a maximum trip time of 10 cycles shall be used.
- 3) When a 10 cycle Maximum trip time is used, a second under frequency trip setting is not required.

**Table 3-6 Frequency Ride-Through and Trip Settings Table**

<b>System Frequency Default Settings (Hz)</b>	<b>Minimum Range of Adjustability (Hz)</b>	<b>Ride-Through Until</b>	<b>Ride-Through Operational Mode</b>	<b>Maximum Trip Time</b>
$f > 62$	62 - 64	No Ride Through	Not Applicable	0.16 seconds
$60.5 < f \leq 62$	60.1 - 62	299 seconds	Mandatory Operation	300 seconds
$58.5 \leq f \leq 60.5$	Not Applicable	Indefinite	Continuous Operation	Not Applicable
$57.0 \leq f < 58.5$	57 - 59.9	299 seconds	Mandatory Operation	300 seconds
$f < 57.0$	53 - 57	No Ride Through	Not Applicable	0.16 seconds

#### 4. Ground-Fault-Sensing Scheme

##### a. General

When ground fault detection is required, as determined by PG&E, the following will apply.

PG&E requires a delta winding in the generator step-up transformer. See section [3.3 Dedicated Transformers](#).

The ground-fault-sensing scheme detects ground faults on PG&E's power-system and trips the circuit breaker at the generator or the main circuit breaker at the PCC, preventing the generator from continuously contributing to a ground fault.

The ground-fault-sensing scheme must be able to detect faults between the PG&E system's side of the dedicated transformer and the end of PG&E's distribution circuit.

Ground fault detection is influenced by the configuration of the system and step-up transformer configuration interconnection transformer. Ground Fault Detection Schemes for Distribution Interconnections.

Please see the examples in the following drawings:

Figure 3-2, “Recommended Ground Detection Schemes 12 kV Distribution Circuits,”.

Figure 3-3, “Recommend Ground Detection Schemes 21 kV Distribution Circuits,”.

This is known as “Voltage Sensing” ground fault detection scheme and it is used strictly on 3-wire systems without any back ties to a 4 wire system. Voltage sensing schemes are used for 4 wire distribution systems or any 3 wire system with a back tie to a 4 wire system.

Please see [“TD-2306B-002 Distributed Generation Protection Requirements”](#) for when ground fault sensing is required.

b. Substation Interconnections

For any substation or generation facility built by other entities but subsequently owned, maintained, and/or operated by PG&E, the facility’s ground grid must meet the minimum design and safety requirements used in PG&E’s substations. The ground-grid design must comply with the criteria set by document, [067910](#), [“Grounding Requirements for Outdoor Electrical Substations”](#) and documented according to the “PG&E Analysis Specification”.

The ground grid must meet the minimum design and safety requirements used in PG&E substations when the customer connects the generating facilities (operated by the customer) to the ground grid of an existing or a new PG&E substation when one of the following situations occur:

- (1) The generator is located within or immediately adjacent to a PG&E’s substation or switching station.
- (1) The system protection requires solidly grounded connections for relaying operations.

When the customer’s facilities are not connected to PG&E’s ground grid or neutral system, the customer is solely responsible for establishing design and safety limits for the ground grid system that comply with all applicable industry standards.

Please see subsection 4.9 [Ground Potential Rise](#)

5. Overcurrent Relay with Voltage Restraint or Voltage Control

An overcurrent relay with voltage restraint or voltage control is used to detect phase faults and initiate tripping of the generator or the main circuit breaker at the PCC.

All generators rated at 400 kW or larger must be equipped by a voltage restraint or a voltage control over current relay as determined by PG&E.

A group of generators with an aggregate rating equal to or larger than 400 kW must be equipped with an overcurrent relay with voltage restraint or voltage control (as determined by PG&E) installed on each generator with a rating of 100 kW or larger. Generators rated at, or greater than, 400 kW must be equipped with an overcurrent relay with voltage restraint or voltage control.

PG&E will determine the suitability of a voltage restraint (device 51V) or a voltage control (device 51C) relay on a case-by-cases basis and depending on the system characteristics for the specific interconnecting project.

Note: Generation units using certified inverter based interfaces are excluded from this requirement..

The selected relay should have the capability to correct the phase-shift produced by the wye-delta or delta-wye transformer. If the relay does not, the potential circuits to an overcurrent relay with voltage restraint or voltage control must have a delta-wye or wye-delta auxiliary potential transformer (also know as a Y-T bank). Proper connection of this auxiliary transformer, will depend on the relay design.

A Y-T bank will be required when electro-mechanical and solid-state relays are installed. Depending on the micro-processor relays capabilities a Y-T bank may not be required.

Please contact the applicable PG&E representative to find out the proper connection of the auxiliary transformers if needed. These connections are shown in Hydro document 4003756 “Electrical Elementary Diagram Connections Of Voltage Restraint Overcurrent And Voltage Control Overcurrent Relays”.

#### 6. Reverse-Power Relay

Please see [Table 3-7 Standard Device Numbers](#) (Device #32) for the definition and function of a reverse-power relay.

#### 7. Fault-Interrupting Devices

PG&E must review and approve all customer-selected fault-interrupting devices. PG&E will determine the type of fault-interrupting device that a customer needs based on the following conditions:

- a. The size and type of generator.
- b. The available fault duty at the location of the generating facility.
- c. The local distribution feeder configuration.

There are three basic types of fault-interrupting devices for distribution interconnections:

#### d. Circuit Breakers

A three-phase circuit breaker with sufficient fault interrupting capability is required at the PCC or point of interconnection (POI). This is also known as the “Main” or the “Interconnection” circuit breaker. The three-phase circuit breaker is required to automatically separate the generating facility from PG&E’s electric system upon detection of circuit faults on the distribution feeder or customer’s equipment. For faults on the PG&E distribution system either the main breaker or the generator breaker can be tripped. For faults on the customers side the main breaker must be tripped.

The customer may install additional circuit breakers and protective relays, which are not required for interconnection, in the generation facilities.

The circuit breaker tripped by PG&E required relays must be DC controlled with “shunt trip” capability. See exception below for AC tripping schemes that may be acceptable on a case by case basis. The breaker must also be equipped with accessories to perform the following functions:

- (1) Trip the circuit breaker via external trip contacts activated by relays or remote signals. This is known as “shunt trip” capability.
- (2) Telemeter the circuit breaker status, if required by PG&E.
- (3) Capacitive tripping is unacceptable.

Note: See Tripping Schemes section for detailed requirements on lock out relays and AC tripping schemes and remote reclosing options.

Note: Certified inverter-based generation with adequate internal inverter protection may not require breakers with a dedicated relay tripping scheme as described above.

e. Reclosers

Customer owned reclosers and controls that are PG&E approved can be used as the customer’s main interrupting device.

f. Fuses

Fuses are single-phase, direct-acting sacrificial links that melt to interrupt fault current and protect the equipment.

The customer must replace their blown fuses by trained personnel after each fault before the facility may be returned to service.

Fuses cannot be used as the primary protection for three-phase generation facilities because fuses:

- (1) Are single-phase devices.
- (2) May not completely melt during some remote faults on the PG&E system.
- (3) May not fully separate the generation facility from PG&E’s electric system.
- (4) Cannot be operated by the protective relays.

However, PG&E may allow customers to use fuses as high-side protection for the dedicated transformers at generation facilities rated below 1,000 kW. Fuses must be coordinated with the existing PG&E phase and ground fault detecting devices.

If fuses are used, the customer should consider installing a negative-sequence relay and/or other devices to protect the facility against single-phase conditions. If fuses are used for high-side transformer protection, the generator must have a separate generator circuit breaker to isolate the facility from PG&E electric system during a fault or abnormal system conditions.

Note: Certified inverter-based generation with adequate internal inverter protection may not require breakers with a dedicated relay tripping scheme.

PG&E does not allow the customer to use large primary fuses that do not coordinate with the circuit breaker or recloser ground relays on PG&E's system. This is because a lack of coordination may cause unnecessary outages to other customers due to a fault inside the generating facility. Relay Tripping and Control Schemes

g. Tripping Schemes < 1,000 kW

In order to ensure reliable tripping, as a general rule, PG&E uses and recommends DC shunt tripping via a battery equipped with a charging system. Other methods are acceptable with the stipulation the tripping source is, reliable, independent from the Power System AC source, and fail safe in that a loss of the tripping source trips the main generator breaker (or the main breaker at the PCC, or any other breaker intended for isolation of the unit).

An example of such a system would be an "AC Holding Coil" powered from a UPS. The scheme and associated drawings will be subject to review and approval by PG&E and limited to installations with an aggregate nameplate capacity of less than 1,000 kW.

h. Local Manually Resettable Lock-Out Device

For generation projects requiring a primary service, the phase, ground, and instantaneous relaying elements at the main breaker are required to pick up a manually resettable lock out device. Generation projects that require a 51V/51C, Direct Transfer Trip, and ground fault sensing scheme must also pick up a local manually resettable lock out device.

Exceptions:

- (1) Reclosers and Interrupters that are set with one shot to lockout and have no remote reclosing.
- (2) Certified inverters and customer secondary breakers may be exempt.

8. Synchronous Generators

The customer must ensure that the generating unit meets all the applicable standards of the:

- a. American National Standards Institute (ANSI) (please refer to: [www.ansi.org](http://www.ansi.org)).
- b. Institute of Electrical and Electronic Engineers (IEEE) (please refer to: [www.standards.ieee.org](http://www.standards.ieee.org)).

The prime mover and the generator must be able to operate within the full range of voltage and frequency excursions that may exist on PG&E's electric system without damaging the generator. For system disturbances causing excursions outside of [Electric Rule 2](#) limits the customer is responsible for protection of their own equipment.

9. Induction Generators

Induction generators and other generators with no inherent var (reactive power) control capability must be able to provide an amount of reactive power equivalent to that required for a synchronous generator.

Induction machines can be self-excited by nearby distribution capacitors or as a result of the capacitive voltage on the distribution grid.

Induction generators may be subjected to the same protection and control requirements as synchronous generators.

## 10. Synchronizing Devices

The purpose of synchronizing devices is to ensure that a generator parallels with PG&E's electric system without causing disturbance to other customers and facilities (present and in the future) that are connected to the same system.

Synchronizing devices also ensure that the generator will not be damaged due to an improper parallel action. Please refer to document, "[Generator Automatic Synchronizers for Generation Entities](#)" for additional information and requirements.

Synchronous generators and other generators with stand-alone capability, including micro-grids, must use one of the methods in the following sections to synchronize with PG&E's electric system.

A generator that has a greater than 1,000 kW aggregate nameplate rating must have a synchronizing relay or an automatic synchronizer.

### a. PG&E-Approved Automatic Synchronizers

The PG&E-approved automatic synchronizer (Device 15/25) must have all of the following characteristics:

- (1) A slip-frequency matching window of 0.1 Hz or less.
- (2) A voltage-matching window of  $\pm 10\%$  or less.
- (3) A phase-angle acceptance window of  $\pm 10^\circ$  or less.
- (4) Breaker-closure time compensation.

For an automatic synchronizer that does not have the "breaker-closure time compensation" feature, the generator must use a tighter phase-angle window ( $\pm 5^\circ$ ) with a 1-second time-acceptance window to achieve synchronization within a  $\pm 10^\circ$  phase angle.

Note: In addition to the above characteristics, the automatic synchronizer must also be able to automatically adjust the generator voltage and frequency to match the system voltage and frequency.

### b. Automatic Synchronizers Not Approved by PG&E but Supervised by a PG&E-Approved Synchronizing Relay

An automatic synchronizing device that is not PG&E-approved but is supervised by a PG&E-approved synchronizing relay (Device 25) must have all of the following characteristics:

- (1) A slip-frequency matching window of 0.1 Hz or less.

- (2) A voltage-matching window of  $\pm 10\%$  or less.
- (3) A phase-angle acceptance window of  $\pm 10^\circ$  or less.
- (4) Breaker-closure time compensation.

**Note:** The synchronizing relay closes a supervisory contact after the above conditions are met, allowing the non-approved automatic synchronizer to close the circuit breaker.

c. Manual Synchronization Supervised by a Synchronizing Relay

Manual synchronization with supervision from a synchronizing relay (Device 25) functions to synchronize the customer's facility with PG&E's electric system.

The synchronizing relay must have all of the following characteristics:

- (1) A slip-frequency matching window of 0.1 Hz or less.
- (2) A voltage-matching window of  $\pm 10\%$  or less.
- (3) A phase-angle acceptance window of  $\pm 10^\circ$  or less.
- (4) Breaker-closure time compensation.

Note: The synchronizing relay closes a supervisory contact, after the above conditions are met, allowing the circuit breaker to close.

d. Manual Synchronization With a Synch-Check Relay

Manual synchronization with a synchroscope and a synch-check (Device 25) relay with supervisory control is allowed only for generators with a less than 1,000 kW aggregate nameplate rating.

The synch-check relay must have the following characteristics:

- (1) A voltage-matching window of  $\pm 10\%$  or less.
- (2) A phase-angle acceptance window of  $\pm 10^\circ$  or less.

11. Frequency or Speed Control

Unless otherwise specified by PG&E, a governor is required on the prime mover to enhance the system stability.

The customer must set the governor characteristics to provide;

- a. A 5% droop (i.e., a 0.15-Hz change in the generator speed must cause a 5% change in the generator output), and
- b. To help regulate PG&E's system frequency, the governors on the prime mover must be able to operate freely.

## 12. Excitation System Requirements

The excitation system must be capable of regulating the generator-output voltage and power factor for the full range of the limits specified by the CPUC Electric Rule 21 or PG&E's [Wholesale Distribution Tariff](#) (WDT).

## 13. Voltage Regulation and Power Factor Control

CPUC Rule 21 requires that the power-factor control shall be capable of maintaining a power factor between 90% lagging and 90% leading (within a PG&E-acceptable tolerance) except for smart inverters greater than 30 kW.

For smart inverters greater than 30 kW the power-factor control shall be capable of maintaining a power factor between 85% lagging and 85% leading.

Distribution generator interconnections typically require power-factor control (i.e., the generator is put on a power-factor control, rather than on a voltage control).

Distribution generator interconnections with smart inverters may be put on a volt/var curve (i.e., the generator is put on volt/var default settings). See the [Volt/Var Curve](#) section .

## 14. Event Recording Capability

Event recording capability is required for all generation facilities with a capacity greater than 400kW and/or with automatic or remotely initiated paralleling capability.

The event recording device must provide PG&E with sufficient information to determine the status of the generation facility during system disturbances. This information must be provided to PG&E when requested. The device must provide a record of the following items at a minimum rate of 16 samples per cycle.

- a. Oscillography (current and voltage wave forms).
- b. Sequence of events.

Note: PG&E services between 0-600 volts may be exempt from these requirements as determined by PG&E.

### 3.10 PG&E Protection and Control-System Modifications

At the customer's expense, PG&E performs a detailed interconnection study to identify the cost of any required modifications to PG&E's protection and control systems before interconnecting the new generator. These modifications are in addition to any distribution-system upgrades that PG&E identifies in the system-impact or facilities studies.

To recover the costs to PG&E for any protection and control-system modifications that are directly assigned to the generator, retail generation customers will execute a "Generation Special Facilities Agreement"

The following are some of the protection-system modifications that PG&E may require:

1. Reclose Blocking – refer to the [Reclose Blocking](#) section.

2. Line Fuses - For generation facilities with a greater than 1,000 kW aggregate nameplate rating, the customer must replace all the existing, single-phase, fault-interrupting devices (fuses) located in series between the generator and PG&E's next three-phase interrupting device. This replacement is to prevent possible single-phasing of other customers. Also fuses may be replaced with three-phase devices, for generators less than 1,000 kW, to achieve coordination.
3. Substation Fused Bank - When the generator is on a distribution circuit fed from a fused PG&E substation transformer bank, and the bank's minimum load is equal to or less than 200% of the generator's nameplate rating, the customer may be required to replace the PG&E substation transformer's high-side fuses with a three-phase interrupting device. This is subject to evaluation by the System Protection department.
4. Substation Transformer High Voltage Winding Configuration - For substation transformers with high voltage configuration in delta or ungrounded wye, the generator can cause high voltage on PG&E's transmission equipment. For generators where the bank's minimum load is equal to or less than 200% of the generator's nameplate rating, further study is required to determine any mitigation needed to eliminate possible high voltage.

### 3.11 Non-Export Interconnections

[Non-Export](#) generators that operate in parallel with PG&E have the same requirements as that of any other standard generator interconnection. When the facility is served by a dedicated transformer, PG&E may, at its discretion, allow the installation of sensitive, reverse-power relays, as an alternative to the normally required phase and ground fault detecting relays. Also, when there is no possibility of "inadvertent" export of power, PG&E may allow installation of "under-power" relays as a viable substitute for the required fault-detection schemes.

Please see the PG&E approved relay list for distribution and transmission interconnections located in Table G2-4 of the, "[Protection And Control Requirements](#)", section of the [TIH](#).

The reverse-power relays must be installed on the secondary (low voltage) side of the transformer and set to pick up on transformer-magnetizing current with a time delay not to exceed 2 seconds. This option may not be feasible on generating systems with a slow load-rejection response, as these generating systems may be tripped off-line frequently for in-plant disturbances.

The under-power relays should be set at 5% of the customer's minimum import power (despite the generator's maximum output) for each phase, to trip the main circuit breaker at with a maximum time delay not to exceed 2 seconds. The under power relay can be installed on the primary (high voltage) side or secondary (low voltage) side of the transformer.

The customer must execute a non-export operating agreement with PG&E before operating the generation facility.

### 3.12 Inadvertent Export

When a Generating Facility exports unscheduled and uncompensated power for a limited duration this is referred to as inadvertent export.

Note: Inadvertent export is not available for interconnections to networked secondary distribution system.

The following are the minimum requirements for inadvertent export systems.

1. Inadvertent Export should be limited to the following minimum values:
  - a. 50% of the Generating Facility Capacity, or
  - b. 10% of the continuous conductor rating in watts at 0.9 power factor for the lowest rated feeder conductor upstream of the generating facility (i.e. 200kW @ 12kV), or
  - c. 110% of the largest load block in the facility, or
  - d. 500kW or some other maximum level indicated by Distribution Provider
2. In addition to the limits above, the following are required:
  - a. A reverse power protective function will be provided to trip the connected generator(s) within two seconds if the proposed amount of inadvertent export is exceeded.
  - b. The frequency of inadvertent export occurrences should be less than two occurrences per 24-hour period.
  - c. A separate reverse power or underpower protective function will be required (in addition to the reverse power protective function described in 2a. Above) to trip the connected generator(s) if the duration of reverse power or underpower (i.e. any export) exceeds 60 seconds.

The following are the additional minimum requirements for inadvertent export systems with Smart inverter interfaces.

3. The certified control functions internal to the inverter control or external control system may be used to replace the discrete reverse/under power relay functions described above provided the requirements outlined below are met.

All of the following requirements must be met by the Generating Facility to qualify for Inadvertent Export.

- a. The Generating Facility must utilize only UL-1741 certified or UL- 1741 SA listed grid support non-islanding inverters; and,
  - b. The Generating Facility must have an aggregate maximum nameplate capacity of 500 kVA or less; and,
  - c. The Generating Facility's total energy export must not exceed its nameplate rating (kVA-gross) multiplied by 0.1 hours per day over a rolling 30-day period (e.g., for a 100 kVA-gross nameplate Generating Facility, the maximum energy allowed to be exported for a 30-day period is 300 kWh) ; and,
  - d. Export from the Generating Facility across the PCC to the Distribution System is less than 100 kVA.
4. To govern the level of Inadvertent Export allowable under this Section, the Generating Facility must utilize a NRTL-certified control system or NRTL-certified inverter system that meets all of the following requirements.

- a. Must result in the Generating Facility disconnecting from the Distribution System, ceasing to energize the Distribution System or halting energy production within two (2) seconds after either: The period of continuous export exceeds 30 seconds; or, the level of export exceeds 100 kVA.
- b. Must monitor that the total energy export is maintained within the allowable energy export outlined above and provide an indication or notification (e.g., electronic, alarm) if that energy export limit is exceeded.
- c. Failure of the of the control or inverter system for more than thirty (30) seconds, resulting from loss of control signal, loss of control power or a single component failure or related control sensing of the control circuitry, must result in the Generating Facility entering Non-Export operation where no energy is exported across to the PCC to the Distribution System.

For complete details see sections M and Mm in [Electric Rule 21](#).

### 3.13 PG&E’s Network System

The PG&E distribution network system is complex and designed to be highly reliable. Therefore distributed generation sources are only allowed to parallel with the network but may **not** export generation back into it. Network customers installing generation sources may be required to install more complex protection schemes to properly detect and isolate faults. Non-export interconnections that utilize non-export relays will require a pre-parallel inspection as required for most types of interconnections.

Network customers requesting to export generation sources may be required to interconnect to a PG&E radial distribution system.

Information on, 2004PGM-10 “[Secondary Spot Network System Requirements for Distributed Generation Interconnection](#)”, can be found on the [DIH](#) webpage.

### 3.14 Standard Device Numbers

**Table 3-7 Standard Device Numbers**

Device Number	Device Name, Definition and Function
15	<b>Speed or Frequency Matching Device.</b> A device that functions to match and hold the speed or frequency of a machine or a system equal to, or approximately equal to, that of another machine, source, or system.
21	<b>Distance Relay.</b> A relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.
25	<b>Synchronizing or Synchronism-Check Device.</b> A device that operates when two ac circuits are within the desired limits of frequency, phase angle, and voltage to permit or cause the paralleling of these two circuits. A <b>Synch-Check relay</b> only has voltage and frequency matching.

**Table 3-7 Standard Device Numbers**

<b>Device Number</b>	<b>Device Name, Definition and Function</b>
27	<b>Undervoltage Relay.</b> A relay that operates when its input voltage is less than a predetermined value.
32	<b>Directional Power Relay.</b> A relay that operates on a predetermined value of power flow in a given direction or upon reverse power flow such as that resulting from the motoring of a generator upon loss of its prime mover.
46	<b>Reverse-Phase or Phase-Balance Current Relay.</b> A relay that functions when the polyphase currents are of reverse-phase sequence, or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.
47	<b>Phase-Sequence or Phase-Balance Voltage Relay.</b> A relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence, when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a given amount.
50	<b>Instantaneous Overcurrent Relay.</b> A relay that functions instantaneously on an excessive value of current.
51	<b>AC Time Overcurrent Relay.</b> A relay that functions when the ac input current exceeds a predetermined value, in which the input current and operating time are inversely related through a substantial portion of the performance range.
52	<b>AC Circuit Breaker.</b> A device that is used to close and interrupt an ac power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.
59	<b>Overvoltage Relay.</b> A relay that operates when its input voltage is more than a predetermined value.
60	<b>Voltage or Current Balance Relay.</b> A relay that operates on a given difference in voltage, or current input or output, of two circuits.
61	<b>Density Switch or Sensor.</b> A device that operates on a given value, or a given rate of change, of gas density.
62	<b>Time-Delay Stopping or Opening Relay.</b> A time-delay relay that serves in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.
67	<b>AC Directional Overcurrent Relay.</b> A relay that functions on a desired value of ac overcurrent flowing in a predetermined direction.
79	<b>AC Reclosing Relay.</b> A relay that controls the automatic reclosing and locking out of an ac circuit interrupter.

**Table 3-7 Standard Device Numbers**

<b>Device Number</b>	<b>Device Name, Definition and Function</b>
81	<b>Frequency Relay.</b> A relay that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds or is less than a predetermined value.
87	<b>Differential Protective Relay.</b> A protective relay that functions on a percentage, phase angle, or other quantitative difference between two currents or some other electrical quantities.
90	<b>Regulating Device.</b> A device that functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.
94	<b>Tripping or Trip-Free Relay.</b> A relay that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.

### 3-Wire Systems, Service Transformer Connected Wye on 12 kV Side:

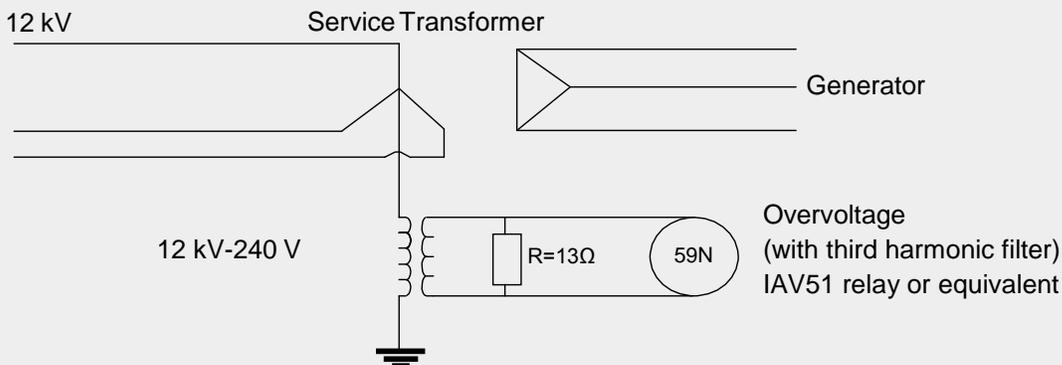
Connect a 12 kV-240 V distribution transformer (or a 12 kV-120 V potential transformer [PT]) between the neutral and ground; load the secondary with a 13 Ω (Ohms) resistor, and an overvoltage relay.

For 12 kV- 240 V:

$$\text{Turns ratio, } N = \frac{12,000}{240} = 50$$

$$\text{Maximum secondary voltage, } V = \frac{12000}{\sqrt{3} (50)} = 138.5 \text{ V}$$

$$\text{Short time ratings for resistor and transformer: } \frac{V^2}{R} = \frac{138.5^2}{13} = 1,477 \text{ W (or VA)}$$



### 3-Wire Systems, Service Transformer Connected Delta on 12 kV Side:

Install 3 PTs or distribution transformers, 12 kV-240 V, 1.0 kVA or larger, on 12 kV side as shown below. Connect a 13 Ω (Ohms) resistor across the broken delta.

For 12 kV-120 V:

$$\text{Turns ratio, } N = \frac{12,000}{120} = 100$$

$$\text{Normal secondary voltage, } V_n = \frac{12,000}{\sqrt{3} (100)} = 69.3 \text{ V}$$

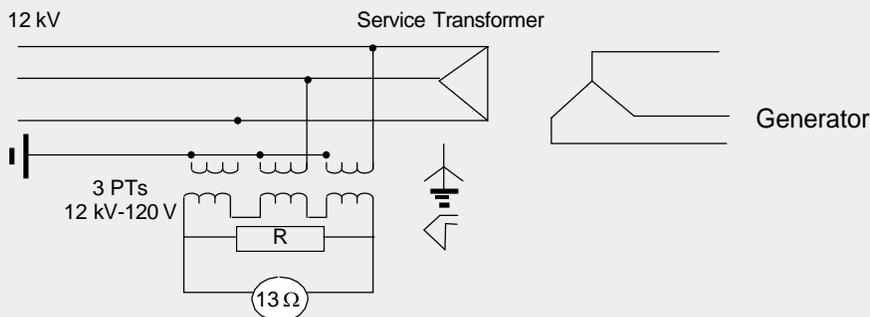
Maximum voltage across delta,  $V_d = 3 \times 69.3 = 208 \text{ V}$  (minimum relay voltage rating)

Short time ratings for resistor and transformer:

$$\text{Resistor } W = \frac{V^2}{R} = \frac{208^2}{13} = 3,328 \text{ W} (*)$$

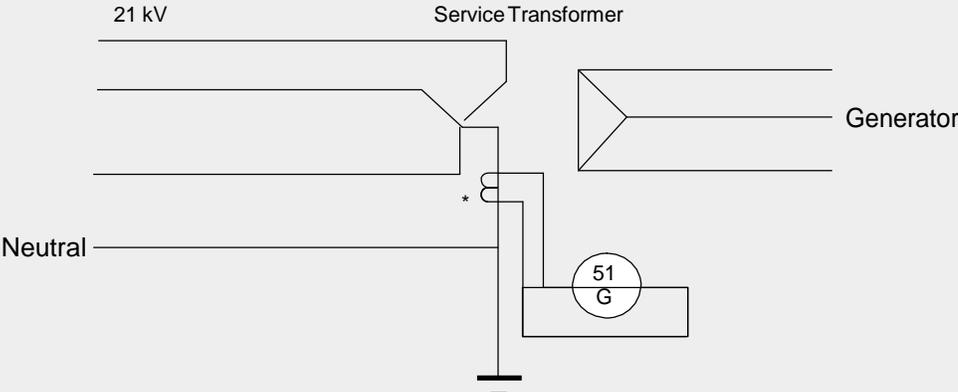
$$\text{Transformer VA} = 120 \times \frac{208}{13} = 1920 \text{ VA (each)} (*)$$

(\*)1,000 W continuous rated resistor and 1.0 kVA transformer will be adequate.



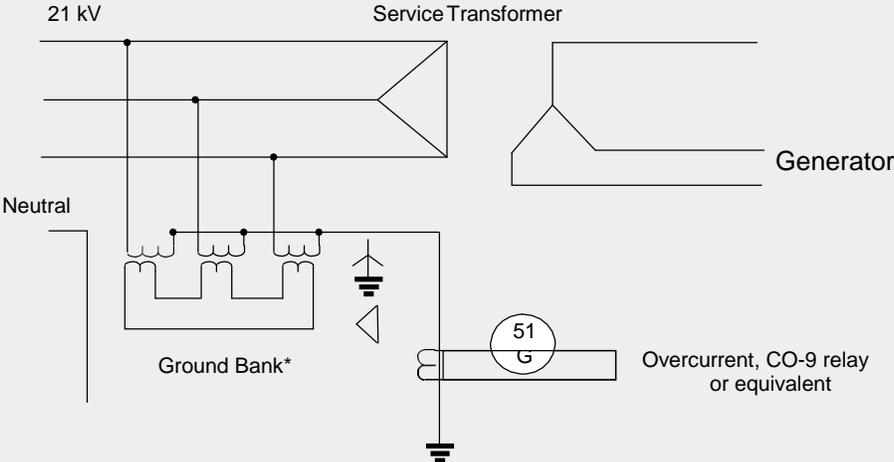
**Figure 3-2**  
Recommended Ground Detection Schemes 12 kV Distribution Circuits

**4-Wire System, Service Transformer Connected Ground Wye on 21 kV Side:**



\* CT ratio to be selected according to ground fault currents for the location.

**4-Wire System, Service Transformer Connected Delta on 21 kV Side:**



\* Ground bank to be sized to limit overvoltages to 1.15 of normal.

**Figure 3-3**  
**Recommended Ground Detection Schemes 21 kV Distribution Circuits**

## 4 Operational Requirements

### 4.1 Introduction

This section describes the specific operational requirements that may be applicable, on a case-by-case basis, to any retail generators that may or may not meet one or more of the operational interconnection criteria set forth by PG&E and CPUC's "Rule 21-Generating Facility Interconnections." For the complete text of Rule 21 please see, [http://www.pge.com/tariffs/tm2/pdf/ELEC\\_RULES\\_21.pdf](http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf).

### 4.2 Maintenance Requirements

Since significant equipment damage and liability can result from failures of the customer's protective equipment, the customer must ensure that all of the facility's protective equipment is operating properly. Failure of customer's equipment due to lack of maintenance that results in an outage to other customers may make the initiating customer liable for damages. The customer must also perform scheduled maintenance and testing according to the manufacturers recommended instructions as described in the manuals and documentation for the equipment installed.

PG&E requires a maintenance schedule for the PG&E required equipment including relays, batteries, telecommunication, and any additional equipment installed.

After the initial testing, the customer must have a qualified testing firm perform retesting of the equipment according to manufacturer recommendations and not to exceed 6 years, or when requested by PG&E. Testing should verify that all equipment is operable and within calibration. PG&E does not test the customer's equipment, but may witness testing performed by the qualified testing firm retained by the customer. At PG&E's request the customer must provide the test reports for the particular types of protective devices installed. The test reports must be received by PG&E within 10 business days of the requested date.

Testing must also be performed if any modifications or replacement of the existing equipment that was required on, or associated with, the original PS-1 and/or G5 forms and any subsequent PS-1 and/or G5 forms.

Test reports should include all documents (1 line, 3-line, meter relay, DC schematic, etc.) submitted in the original interconnection package to PG&E. All testing must follow the procedures specified in "[Pre-Parallel Inspection](#)", located in Section G5 on the [Transmission Interconnection Handbook](#) (TIH) webpage.

For PG&E's detailed requirements for battery types and required maintenance refer to Section 11 in document, [TD-2999B-030 Technical Requirements for Electric Service Interconnection at Primary Distribution Voltages](#). Section 11 specifies the technical requirements for all load and generation customers where batteries and charging systems are installed for the protective equipment.

## 4.3 Manual Disconnect Switch

### 1. General

As specified in Electric Rule 21, “Generating Facility Interconnections,” and as required by PG&E, the generating facility must have an ac disconnect switch that meets the requirements described by PG&E. The customer must use only PG&E-approved devices.

As a means of electrically isolating PG&E’s electric system from the customer’s systems, the customer must provide a PG&E-operated disconnect device. To establish a visually open working clearance, in accordance with PG&E’s safety rules and practices, the manual disconnect may be opened during all maintenance and repair work.

PG&E must inspect and approve the installation before parallel operation is allowed. The switch must be accessible to PG&E employees. When maintenance or other work procedures are scheduled, this disconnect switch will be opened and locked for the safety of PG&E employees and others.

The disconnect switch must not be used for “make” or “break” parallel operations between PG&E’s electric system and the customer’s power system.

The disconnect switch must be visible and easily accessible to PG&E employees. When installed on the customer’s side of the point of interconnection (POI), the switch must be installed close to the metering.

Some disconnect switches may have an interlock feature that allows the customer to open a locked, fused disconnect switch, but not to close it, so that the customer’s system can be isolated for maintenance without PG&E’s assistance. A fused disconnect switch with an interlock must be unlocked by PG&E before it can be closed.

Note: A fusible ac disconnect switch is required for interconnections to the line (supply) side of the main breaker. See [TD-6999B-048 Requirements for Line Side Tap Interconnections for Distributed Generation](#).

Also see PG&E’s Electric and Gas Service Requirements ([Greenbook](#)) manual for electric meter equipment requirements.

### 2. Specifications

The manual disconnect switch must meet the following minimum set of requirements specified below. Refer to the referenced documents throughout this, “Manual Disconnect Switch”, section for additional requirements.

- a. Be rated for the voltage and current requirements of the particular installation.
- b. Adequately sized to handle maximum continuous loading and transient fault conditions..
- c. Be designed to withstand exposure to weather.
- d. Manually operated: Operated by a person ( not electronically).
- e. Gang-operated: One switch handle opens and closes all phases simultaneously.

- f. Allows visible verification that an air-gap of separation has occurred between the blades and contact points.
  - g. Includes PG&E approved markings on the switch that clearly indicates the open (off) and closed (on) positions.
  - h. Lockable in both the open (off) and closed (on) positions with a standard (5/16 shaft) PG&E lock. See [060559 Disconnect Switch Requirements For Distributed Generation Customers](#)
  - i. Easily accessible by PG&E, when requested.
  - j. Installed in a safe and acceptable location that meets all PG&E working space requirements. For working space requirements see section 4.4.3. in the PG&E Electric and Gas Service Requirements ([Greenbook](#)) manual.
  - k. Located 10 feet or less from PG&E's electric meter at the point of interconnection (POI) and is seen easily from the panel.
  - l. Includes signage and a map showing the location of the ac disconnect switch if more than 10 feet away from the point of interconnection (POI). The map must include the following:
    - (1) Direction indicator – show the north direction with an arrow
    - (2) Plan view of the site
    - (3) Generator's AC disconnect and PG&E electric meter locations
3. Low Voltage Disconnects (0 to 600 Volts)

As specified the generating facility must have an ac disconnect switch that meets PG&E approval. All of the specific requirements for low voltage disconnects are identified in [Numbered Document 060559, "Disconnect Switch Requirements For Distributed Generation Customers"](#). This document is also located in Appendix C of the PG&E Electric and Gas Service Requirements ([Greenbook](#)) manual.

The disconnect switches listed in items a. and b. below meet the basic and functional requirements described in Document [060559](#). All three of these documents are on the [Distribution Interconnection Handbook](#) website.

- a. [Cross Reference for Safety Switches - Eaton](#)
- b. [Cross Reference for Safety Switches - Siemens](#)

Low-voltage disconnect switches are rated as general or light duty (240 V) and heavy duty (600 V).

### Exception to AC Disconnect Switch Requirement

For small inverter-based generators that meet specified criteria, an exception to the disconnect switch requirement may be allowed where the PG&E meter may serve as the disconnect device. See section 5.10.1. in the PG&E Electric and Gas Service Requirements ([Greenbook](#)) manual for these requirements.

#### 4. Primary (Medium) Voltage Disconnects (601 Volts to 25 kV)

For interconnections of 2.4 kV and above, the PG&E approved disconnect switch must be located at the point of interconnection (POI) with PG&E. It must be identified with a PG&E-designated switch-number plate. The device's enclosure and operating handle must be locked at all times, using PG&E's padlocks.

If the disconnect switch will be located on PG&E's side of the point of interconnection, then the device will be installed by, PG&E at the customer's expense.

If the disconnect switch will be located on the customer's side, it must be furnished and installed by the customer. The installation must meet all PG&E requirements

If the disconnect switch is pad-mounted it must have a minimum distance from other structures of 8 feet in front, 8 feet in back, and 3 feet on each side. This provides adequate space for using hot tools and portable grounds.

If the disconnect device is in the customer's substation, it must be located on the substation's dead-end structure and have a PG&E-approved operating platform.

The link in item "a" provides the list of PG&E approved disconnect switches for the voltage range of 2,400 V - 25,000 V). The linked engineering documents in items "b" and "c" provide specifications, installation, and associated information for the approved switches.

- a. List of approved [Primary Voltage Disconnect Switches](#).
- b. Numbered Document [066195 "25 kV Underarm Sidebreak Switch, Manual and Automated."](#)
- c. Numbered Document [053318, "Pad-Mounted, Load-Break Switches And Fuses"](#).

#### 4.4 Metering Requirements

See PG&E's Electric and Gas Service Requirements ([Greenbook](#)) manual for electric meter equipment requirements. The customer is responsible for ensuring that the metering panels meet PG&E's installation and revenue-metering requirements.

Rule 21 installations are generally designed to operate in parallel with the PG&E system.

PG&E's revenue grade meters used for Rule 21 interconnections are solid-state programmable SmartMeters.

#### 4.5 Telemetry Requirements

For Generating Facilities with aggregate (gross nameplate rating) generation 1,000 kW or greater, real-time data (MW, MVAR, Volt, Amps) must be telemetered to PG&E's Control Centers. On a case-by-case basis, PG&E may require telemetering for generators of less than 1,000 kW. For additional information on these requirements refer to section G1.3. Telemetry Requirements For Generator Monitoring, in the document titled, "[Metering Requirements For Transmission Generation Entities](#)". This document is located on the [TIH](#) website. The requirements also apply to generation facilities connected to the distribution system.

If the meter is read via a telephone line, the customer is responsible for installing the conduit, phone line, and establishing service. If a land line is unavailable, and cellular signals are acceptable, a cellular phone-based meter may be used. See the *Electric and Gas Service Requirements (Greenbook)* [section 5.2.3. Applicant Responsibilities](#), for these specific requirements. Including on how to request a field review to determine if a cellular meter is adequate for the location and an exemption to the phone line requirements.

A line sharing switch or Voice over Internet Protocol (VoIP) system will not be allowed.

The telephone-line termination installed in switchboards, panels, pole-mounted meters, and pedestals must meet the following requirements:

1. For switchboards see [Greenbook Figure 5-5](#), Detail A, and Figure note 2.
2. Be located within 5 circuit-feet from the centerline of the meter.
3. Have a height between a minimum of 18 inches and a maximum of 72 inches above the finished grade.

When cellular telephones are used, the same location requirements apply to the power supply when measured from the load side of the meter and located outside PG&E's sealable section.

#### 4.6 Communication

PG&E may require the installation of communication circuits for System Protection, Energy Management Systems (EMS), Supervisory Control & Data Acquisition (SCADA), as well as voice communication between PG&E and the customer's generation facilities.

Note: For communication requirements refer to [TIH Appendix F](#).

If a System Protection communication circuit is required, it must be provided between PG&E's determined transmitting point (substation or recloser) and the generator's receiving equipment. When "communication assisted protection" scheme such as DTT is required, the customer must ensure that the communication circuits are tested and approved by PG&E. The customer must also verify that the scheme is operating properly before a generating facility may be released for commercial operation. Testing for communication-assisted protection includes end-to-end functional testing and verifying the communication between the interconnected terminals.

When an Energy Management System (EMS) or Supervisory Control and Data Acquisition (SCADA) is required, a telemetering circuit must be provided between the generator's site and the designated PG&E electric control center.

A direct, customer supplied, voice communication service may be required for reception of operating instructions by PG&E.

The customer is responsible for the installation and monthly costs of all communication facilities. The customer is also responsible for the costs incurred by PG&E personnel while assisting the telephone company personnel during installation or repairs of the leased circuits.

It is customer's responsibility to ensure that external communication circuits meet all applicable High Voltage Protection (HVP) standards.

#### 4.7 Ground Potential Rise

The customer is responsible for calculation of the Ground Potential Rise (GPR) value during a line to ground fault condition at the service point. The GPR value determines the grade of the required high-voltage protection equipment for the telephone cable, as well as the minimum, dielectric strength of the cable's insulating jacket.

To calculate the GPR, the customer needs to have the highest calculated fault current (provided by PG&E), X/R ratio, and the ground resistance (evaluated and provided by the customer).

When the customer's generation units increase in aggregate nameplate rating, the customer must recalculate the GPR value. For specific information, consult the responsible telecommunications engineer.

Note: See 3.9.4.b, [Substation Interconnections](#), for information on the ground grids installed within (or near) PG&E substations.

#### 4.8 Normal Voltage Operating Range and Voltage Flicker limits

PG&E may have specific operating-voltage ranges for designated generating facilities which will be determined on a case-by-case basis and may require adjustable operating-voltage settings.

As a general rule, PG&E's normal operating voltage range, at the PCC, must follow Electric Rule 2. As an example the normal voltage range on a 120 V base are between 114 volts and 126 volts. For a complete description see Electric Rule 2.

To minimize the adverse voltage effects experienced by other customers on PG&E's electric system, any voltage flicker at the point of common coupling (PCC) caused by the generating facility must comply with the limits as specified by PG&E.

Voltage fluctuation limits apply to all new and existing interconnections.

#### 4.9 Limits Specific to Single-Phase Generating Facilities

The maximum aggregated Gross Ratings for all the Generating Facilities connected to a secondary distribution transformer must not exceed the transformer rating or secondary conductor rating. If the transformer or secondary conductor rating are exceeded the facilities will be upgraded as needed at customer's expense.

Generating Facilities connected to a single-phase transformer with 120/240 V secondary voltage must be installed such that the aggregated gross output is as balanced as practicable between the two phases of the 240 volt service as described in [Electric Rule 21](#). The difference in amperes between any two phases at the customer's peak load (or generation output) should not be greater than 10 percent or 50 amperes at the service delivery voltage (120 V), whichever is greater as described in [Electric Rule 2](#). It will be the responsibility of the customer to keep facility's load demand (or generation output) balanced within these limits.

#### 4.10 System Upgrades and Modifications

Based on the results from an engineering review, PG&E may require distribution system upgrades to accommodate the interconnection of the DG facility.

Please refer to [Electric Rule 21](#) section E.4., "Interconnection Cost Responsibility", for the cost allocation responsibilities of system upgrades for the installation of NEM and Non-NEM interconnection facilities .

If the generating facility's output exceeds the operating capabilities of existing distribution equipment , PG&E will evaluate the application based on Rule 21 criteria to determine any system modifications that may be required for parallel operation of the facility.

The following general criteria is usually applied along with other location specific criteria in determination of system modifications.

1. No degradation or mis-operation of existing protection and control devices due to interconnection of customer's facility.
2. Overloading – PG&E's equipment and line rating are not overloaded by the applicant's generating system.
3. Voltage operating levels – the applicant's generating system does not cause a voltage drop or a voltage rise outside the allowable operating-voltage bandwidths specified in [Electric Rule 2](#).
4. Transmission Grounding bank for delta connected transformer. Some distribution interconnections can trigger required upgrades at the transmission voltage level.

#### 4.11 Primary Electric Service

For customers requesting a primary service from PG&E, the detailed requirements are in document, "[TD-2999B-030 Technical Requirements for Electric Service Interconnection at Primary Distribution Voltages](#)". This document specifies the technical requirements for all customers requesting electric service at any of PG&E's primary distribution voltage levels. The generation facility may or may not include any load.

For primary services the PG&E approved protective devices are listed in Table L2-1 located in [Section L2](#) on the [Transmission Interconnection Handbook](#) (TIH).

When a new or upgraded primary service is installed a pre-energization inspection is required. The inspection procedures for connecting the primary service to PG&E's distribution system can be found in, "[Pre-Energization Test Procedures](#)", located in [Section L5](#) on the Transmission Interconnection Handbook (TIH) webpage. The same inspection requirements are also applicable for load only primary service customers connecting to the PG&E distribution system.

Primary service customers, with or without load, interconnecting generation sources will also require a preparallel inspection of the facility. For these requirements see the Preparallel Inspections (PPI) section located below.

#### 4.12 Preparallel Inspections (PPI)

To ensure that the generation system has been installed in accordance with all PG&E's requirements and the customers submitted specifications, as specified in "[Pre-Parallel Inspection](#)", located in TIH Section G5. PG&E must perform a final inspection of the system before approving parallel operation. This is also known as Pre-Parallel Inspection (PPI).

In order for PG&E to provide a timely PPI, the customer must provide all required documents and meet all the required deadlines. Documents that must be completed and submitted include test reports (Form G2-2, "Relay Test Report,") for the required types of protective devices as outlined in [Table 3-2 Generator Protection Devices](#) before PG&E will allow the facility to parallel. On-site power (typically 120 V) is required for the test equipment during the PPI.

It is the customer's responsibility to ensure that any inspections required by local governmental and regulatory agencies are complete and any applicable permits are obtained before the scheduled date of PPI.

Depending on the required protective devices for the generating facility, one of the following two types of inspections will be performed.

1. Field Metering Inspection

When required this inspection will verify that UL 1741 certified generation equipment and the approved a/c disconnect switch are installed and interconnected according to PG&E requirements. Functional and operational tests on the inverter and a/c disconnect switch are also part of this inspection.

2. Substation Test Group Inspection

Generating systems or facilities where protective devices and changes to protective device settings are required will need to have specialized testing performed. These inspections are for generating systems where the functional and operational testing of the transformers, data telemetry & communications, relay systems, and other protective devices are required.

The PPI procedures for generation entities interconnecting to the PG&E distribution and transmission systems can be found in, "[Pre-Parallel Inspection](#)", located in Section G5 on the [Transmission Interconnection Handbook](#) (TIH) webpage. The PPI requirements apply to both distribution and transmission interconnections.

After a satisfactory inspection, the customer will receive a written approval from PG&E to operate the system in parallel with PG&E's grid. This approval is commonly known as the, Permission To Operate (PTO). Parallel operation of the customer's equipment is only allowed after receipt of a **written approval** from PG&E.

## 5 Temporary and Momentary Generator Interconnections and Automatic Transfer Switches

### 5.1 Introduction

This section describes the specific requirements for interconnecting a portable or permanently installed temporary generator for emergency, standby, backup, or for momentary paralleling purposes.

During a power outage, customers can use a temporary electric generator as a standby system to keep lights and appliances running until service is restored.

A generator can power the refrigerators, freezers and other essential equipment during a prolonged outage. However, generators are expensive and noisy, and can pose serious safety hazards. Therefore, customers must follow all the manufacturer's safety instructions.

By state regulations and local jurisdiction, customers are prohibited to connect any generator to PG&E without prior PG&E approval.

Owners and operators of generators are responsible for ensuring that the generators are used properly, and that the electricity from the unit does not "back-feed," i.e., flow into PG&E's power lines. Improper utilizations of generators can be hazardous and may endanger lives or damage property.

### 5.2 Portable Generators

Please visit "Electric Generator Safety" (<http://www.pge.com/generator/>) for more information. (From PG&E's home page, click "For My Home," then from the "Education & Safety" drop-down box, click on "Gas & Electric Safety." On the left side of the page, click "Electric Generator Safety.")

Find more information on how to stay safe with your generator. Download the [Electric Generator Safety](https://www.pge.com/includes/docs/pdfs/shared/edusafety/gaselectric/electricgenerator/generator_safety.pdf) brochure at, [https://www.pge.com/includes/docs/pdfs/shared/edusafety/gaselectric/electricgenerator/generator\\_safety.pdf](https://www.pge.com/includes/docs/pdfs/shared/edusafety/gaselectric/electricgenerator/generator_safety.pdf).

### 5.3 Permanent (Standby/Emergency) Generators

Only a qualified professional, such as a licensed electric contractor, may install a permanent standby/emergency generator.

When a generator is permanently connected to a customer's electric system, it energizes the building's wiring with a potential to be in parallel with PG&E. This type of installation requires a device that prevents the generator from operating in parallel with PG&E for longer than 60 cycles (1 second).

#### 1. Safety Requirements

Below are some safety requirements for the installation of permanent generators.

- a. All additions, modifications, or re-configurations to the facility's wiring for installation of the generator must be performed by a licensed contractor and inspected by the local regulating agency having jurisdiction for the location.
- b. Completion of the generator installation must be reported to PG&E. In some cases, PG&E's field personnel may need to examine/witness the operation of the electric generator's transfer switch to ensure safety of its operation.

Note: The Generator owner is responsible for any injuries to personnel and/or any damages to the property of PG&E or other customers resulting from improper installation or operation of the generator.

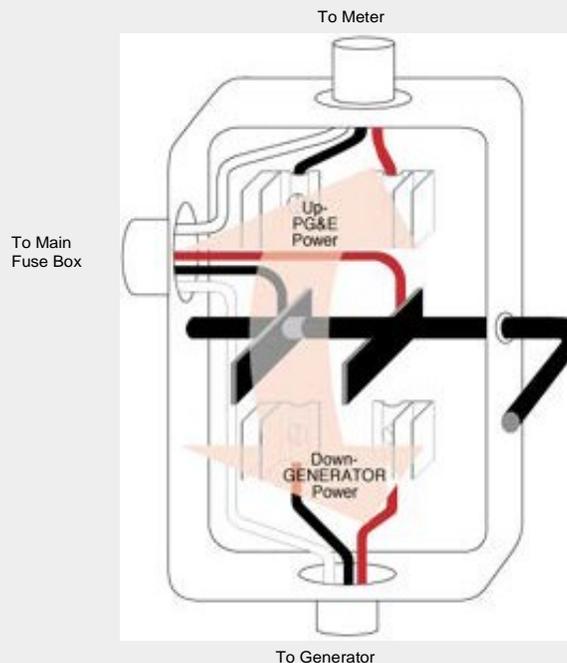
There are two methods for safe transferring an electric load between the PG&E source and the emergency generator system. The methods are known as: Open Transition (Break Before Make) and Closed Transition (Make Before Break).

1. Open Transition - Break Before Make (PG&E's preferred method)

Customers may transfer loads using the "break-before-make" method via a double-throw transfer switch or an interlock scheme that prevents the two systems from operating in parallel.

In this method, the circuit breaker that supplies power from PG&E to the customer must open before the customer's generator breaker closes. This method does not require any additional protective equipment. However, it causes the customer's load to experience a short outage while transferring back to PG&E. The outage duration depends on the transfer equipment.

To see a diagram of a transfer switch, please see Figure 5-1 below or at <http://www.pge.com/myhome/edusafety/gaselectricsafety/electricgenerator/>.



**Figure 5-1 Manual Transfer Switch**

PG&E recommends using a open transition (break before make) transfer method. This method prevents PG&E's power from re-energizing the building's wiring while the generator is energized and serving the load. This protects the generator, wiring, and appliances from potential damage when the power is restored.

## 2. Closed Transition - Make Before Break

The "make-before-break" method is used to eliminate the power outage or disturbance to the electric load during a scheduled system outage or the load transfer back to the PG&E source .

With the "make-before-break" method, the customer's generator and PG&E's electric system will be in a parallel operation for the very short interval during which the customer's load is being transferred between the PG&E source and the standby/emergency generator.

The transfer of load from PG&E to the standby/emergency source and back to PG&E can be done without causing the customer to experience an outage.

The transient "switch-onto-fault" rating of the transfer switch must be adequate for the highest fault current level through the switch.

The switch must be equipped with "failure-safe" interlock system to prevent parallel operation of the generator with PG&E system during any switch failure. The controls for the transfer switch must prevent parallel operation of the customer's generator and PG&E's electric system for a period no longer than one second (60 cycles).

## 5.4 Interconnection Requirements

The list below gives the requirements for interconnecting standby/emergency generators that use open or closed transition transfer schemes.

### 1. Transfer Switch

The transfer switch must be capable of the following:

- a. Rated for the maximum possible load current.
- b. Rated for the maximum available fault duty in the event that the transfer switch closes into a fault condition.
- c. The automatic transfer switch control, when applicable, must meet the industry certification requirements list in [TIH Appendix R](#).

### 2. Notification and Documentation

The customer must notify PG&E in writing regarding all emergency generator installations, regardless of the method of interconnection or transfer.

The customer must submit completed documentation that includes, but is not limited to, the following information:

- a. A description of the generator and its control-system.
- b. Single-line diagrams of the system.

- c. Identification of all interlocks.
- d. A description of the sequence of events for transfer operation and the specifications for any PG&E-required protective devices.

All PG&E required relays and protective schemes must be verified and tested by a licensed contractor and the test reports be supplied to PG&E.

PG&E will review and approve the relay test reports at least 15 days before scheduling the preparallel inspection.

### 3. Operation/Clearance

For the purposes of any clearance or line work, the customer must consider the emergency generator as a power source.

Before performing any planned load transfers using the “make-before-break” transfer method, the customer must notify PG&E’s designated operation center. This notification is not required for load transfers using a “break-before-make” transfer method.

#### a. Manual Disconnect

A PG&E approved manually operated disconnect switch located at the point of interconnection is required. This is to establish a visually open safety clearance point for protection of PG&E’s employees working on the electric system. For the disconnect switch requirements see section 4.3 [Manual Disconnect Switch](#).

#### b. Synchronizing Function for close transition operation

To ensure that the load is transferred safely, reliably, and smoothly, the transfer scheme must have the following capabilities:

- (1) Be equipped with adequate controls and protective devices.
- (2) Use an automatic synchronizer or a synchronizing relay for proper synchronization to ensure that the customer’s electric system can properly synchronize with PG&E’s system before the two systems are paralleled.

The automatic synchronizer or synchronizing relay must meet have the following criteria or be supervised by a PG&E approved sync-check relay:

- (1) Slip frequency matching of 0.1 Hz or less.
- (3) Voltage matching of  $\pm 10\%$  or less.
- (4) A phase-angle acceptance of  $\pm 10^\circ$  or less.
- (5) A circuit breaker closure-time compensation.

## c. Protection

“Make Before Break” transfer schemes - The emergency generators are paralleled with PG&E’s electric system. In the event of a fault on the PG&E system during a load transition, the customer must have adequate protective devices to detect the fault and separate the customer’s generator from PG&E’s electric system. This is to prevent damage to the customer’s equipment, PG&E’s electric system, and other PG&E customers’ equipment.

For most installations, the customer may install a sensitive reverse-power relay or an approved timing relay to meet this protection requirement.

## (1) Timing Relay:

The timing relay must meet the following requirements:

- There must be an interlock that will trip the main beaker or generator in the event of a failure of the transfer switch so that the unit will not remain paralleled to the PG&E Power System. This can be accomplished via an approved timing relay. See Table G2-4 located in TIH [Section G2, “Protection and Control Requirements.”](#)
- The controls for the transfer switch must prevent a parallel condition of the customer generator and the PG&E Power System from existing for longer than 1 second. Any system that allows a parallel to exist for greater than 1 second (60 cycles) on the distribution system will be subjected additional requirements.
- Be able to trip the customer’s Generator breaker or the main circuit breaker.

## (2) Reverse Power Relay:

The reverse power relay will be installed on the customer’s side of the service transformer and must meet the following requirements:

- Be able to trip the customer’s Generator breaker or the main circuit breaker.
- Be able to detect the dedicated transformer core’s magnetizing power.

To ensure that the relay meets the requirements, the customer must set the relay pickup value to 60 % of the dedicated transformer bank’s magnetizing current. Because this current value will be small, the current transformers and the relay must be capable of detecting low values of current.