Section G3: OPERATING REQUIREMENTS FOR TRANSMISSION GENERATING ENTITIES

PURPOSE

The purpose of this section is to help all generators satisfy applicable PG&E operating requirements. In addition to the operating requirements in this handbook, a more detailed description may be found in the CAISO Tariff and Protocols, which may be obtained from the ISO. See Appendix A for the ISO’s address or visit the ISO website.

Applicability

The operating requirements of this section apply to all generators interconnecting with the Transmission System. All generators must meet applicable Western Electric Coordinating Council (WECC) standards.

Participating Generators shall operate, or cause their facilities to be operated, in accordance with the CAISO Tariff and Protocols, and are required to have signed applicable Agreements with the ISO. Participating Generators, connected to the ISO Controlled Grid, are required to schedule energy or Ancillary Services through a designated Scheduling Coordinator. Furthermore, Participating Generators greater than 10 MW (and their active Scheduling Coordinator) electing to provide Ancillary Services must possess and maintain a valid ISO certification to provide such Ancillary Services.

In the absence of specific ISO Protocols, the Participating Generator shall abide by the CAISO Tariff and operating requirements established by PG&E. If conflicts arise between the PG&E’s operating requirements and the CAISO Tariff or Protocols, the CAISO Tariff and Protocols shall take precedent subject to resolution through the TAC or ADR processes.

G3.1. REACTIVE AND VOLTAGE CONTROL REQUIREMENTS FOR GENERATORS

Reactive power (Var) and voltage control are vital components of safe and reliable system operation. It is essential that PG&E receive both real and reactive power from interconnected generators. Where a Generator is unable to furnish reactive power support, due to interconnection limitations, type of generator, the generator loading or other reasons, the Generation Entity shall install equivalent reactive support or power factor correction at the Generation Entity’s expense or make other arrangements with PG&E.

How a generator meets PG&E’s reactive requirements depends on its type and size. Synchronous generators have an inherent reactive flexibility that allows them to operate within a range to either produce or absorb Vars. Induction generators operate at a power factor absorbing Vars and require power factor corrective equipment such as capacitors. Inverters, such as those used to connect Photo-voltaic (PV) generating facilities to AC systems, are also subject to reactive and voltage control requirements.
G3.1.1. Synchronous Generator Control

G3.1.1.1. Frequency/Speed Control
To enhance system stability, a governor is required on the prime mover, set to provide a 5 percent droop characteristic. Exceptions must be approved in writing by PG&E. Governors shall be operated unrestrained to regulate system frequency.

G3.1.1.2. Voltage Control
Voltage regulators are required for all synchronous generators larger than 100 kW. All synchronous generators connected to PG&E's transmission system shall operate the units using the voltage regulators for voltage control. The PG&E Grid Control Center will specify the required voltage schedule that will be used to determine the set point of the automatic voltage regulator. Generators connected to the distribution system in most cases will also require a power factor controller. Generators connected to the transmission system that have both voltage and power factor modes available on the controller system, shall be set on voltage control mode. In rare exceptions the PG&E Grid Control Center may direct a specific generator(s) to operate on power factor control mode.

Voltage regulators must be capable of maintaining the generator voltage under steady-state conditions without hunting and within ± 0.5 percent of any voltage level between 95 percent and 105 percent of the rated generator voltage. The generator must be capable of operating at 90 percent lagging power factor and at 95 percent leading power factor at rated output measured at the generator terminals.

G3.1.1.3. Power System Stabilizer Operating Requirements for Generators
Synchronous generators larger than 30 MVA or part of a complex that has an aggregate capacity larger than 75 MVA are required to have power system stabilizers (PSS). Generators with properly tuned and calibrated PSS provide damping to electric power oscillations. Such damping improves stability in the electrical system and may also prevent an individual generator from unnecessary tripping.

The PSS must be calibrated and operated in accordance with the latest standard procedures for calibration, testing and operation of such equipment. See Appendix H for WECC tuning guidelines. Recalibration and testing of the PSS is required at least every five years; data must be submitted to PG&E’s Electric Asset Management, Transmission Planning Department via an email to GenModel@pge.com.

G3.1.1.4. Power Factor Control
Power factor control is not allowed.
G3.1.2. Non-synchronous Generator Control

As of June 16, 2016, approval of FERC Order 827 changed the power factor requirements for non-synchronous generators.

**Before:** Non-synchronous generating projects with Interconnection Agreements prior to June 16th, 2016 must follow power factor requirements as identified for safety and/or reliability reasons in the Phase II study.

**After:** Non-synchronous generators with Facilities Study Agreement executed after June, 16, 2016 must provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation while operating at full nameplate output. The power factor range must be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. All non-synchronous generating facilities will operate the plant in voltage control mode according to the voltage schedule as directed by the PG&E Grid Control Center.

G3.1.4 Interconnections Following [Rule 21 Tariff](#)

1. **General Requirements**
   1. According to Rule 21 Tariff Section H.2.i, Producer must provide adequate reactive power compensation on site to maintain the Generating Facility power factor near unity at rated output or a Distribution Provider specified power factor within a range from 0.90 leading to 0.90 lagging, based on local system conditions. While not required, for generators that do not have inherent reactive power control capability, the Distribution Provider at its option may offer reactive power support in the form of power factor correction capacitors on its Distribution or Transmission System, under a Generator Interconnection Agreement of an Added Facilities or Special Facilities agreement, as described in Rule 2.H, as applicable.

2. **Requirements for Inverter Based Technologies**
   1. After September 8, 2017, interconnections of inverter-based technologies through the Rule 21 Tariff must meet the smart inverter requirements specified in Rule 21 Tariff Section Hh. According to Section Hh.2.i, the Producer must provide adequate reactive power compensation on site to maintain the Smart Inverter power factor near unity at rated output or
a Distribution Provider specified power factor in accordance with the following requirements:

2. Default Power Factor setting: Absorbing reactive power at 0.95 lagging power factor.

3. Aggregate generating facility is greater than 15 kW: 1.0 +/- 0.15 (0.85 Lagging to 0.85 Leading) down to 20% rated power based on available reactive power.

4. Aggregate generating facility is less than or equal to 15 kW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% rated power based on available reactive power.

Refer to Rule 21 Tariff Section Hh.2.j for Dynamic Volt/VAR Operations.

3. Behind the Meter Transmission Rule 21 Generation

If a Rule 21 generator is to be added behind the meter of a transmission load, the reactive flow at the point of interconnection must be maintained within a specified power band of 0.97 lag and 0.99 lead per the CAISO Tariff, or a power factor range specified by PG&E if the POI is not on the CAISO Controlled Grid.

G3.2. GENERATOR STEP-UP TRANSFORMER

The available voltage taps of a Generation Entity’s step-up transformer must be reviewed by PG&E for their suitability with PG&E’s system. The Generation Entity is expected to request this review before acquiring the transformer.

PG&E shall determine which voltage taps would be suitable for a step-up transformer for the Generation Entity’s proposed project. Suitable taps are required to give the transformer the essential capacity for the generator to:

- Deliver maximum reactive power to PG&E’s system at the point of interconnection (per generators lagging power factor requirements) and,
- Absorb maximum reactive power from PG&E’s system at the point of interconnection (per generators leading power factor requirements).

The Generation Entity’s transformer, with correct voltage taps, helps maintain a specified voltage profile on PG&E’s system for varying operating conditions. Actual voltage tap settings can be different for transformers connected at the same voltage level, depending upon their electric connection point to the grid.

G3.3. POWER QUALITY REQUIREMENTS

G3.3.1. Voltage Fluctuation Limits

A generator connected to the PG&E system must not cause harmful voltage fluctuations or interference with service and communication facilities. Any
generation facility that does so is subject to being disconnected from the PG&E system until the condition has been corrected. Refer to Electric Rule 21, Section D.9.

G3.3.2. Harmonic Limits

All generators shall comply with the voltage and current harmonic limits specified in IEEE Standard 519-2014, “Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems”.

The harmonic content of the voltage and current waveforms in the PG&E system must be restricted to levels which do not cause interference or equipment operating problems for PG&E or its customers.

Any harmonic problems shall be handled on a case-by-case basis. A generation facility causing harmonic interference is considered by PG&E as a serious interference with service and is subject to being disconnected from the PG&E system until the condition has been corrected. (Refer to Electric Rule 21, Section D.9). If the cause of the problem is traceable to the Generation Entity’s facilities, all costs associated with determining and correcting problems shall be at the customer’s expense.

Many methods may be used to restrict harmonics. The preferred method is to install a transformer with at least one delta connection between the generator and the PG&E system. This method significantly limits the amount of voltage and current harmonics entering the PG&E system. Generation system configuration with a star-grounded generator and a two-winding (both star-grounded) transformer shall not be allowed.

G3.4. VOLTAGE & FREQUENCY RIDE-THROUGH REQUIREMENTS

All generating facilities interconnecting must ride through abnormal frequency and voltage events and not disconnect during such events per FERC Order 828, issued July 21, 2016.

PG&E currently follows the Voltage and Frequency Ride-Through Criteria that WECC has adopted to ensure continued reliable service.

The interconnection customer must ensure all generator protection is compliant with those set forth in NERC standard PRC-024.

More information on voltage ride-through issues associated with alternative technologies can be found on the FERC website:
G3.4.2 Interconnections Following Rule 21 Tariff

All Rule 21 non-synchronous generators are required to follow smart inverter requirements Rule 21 Section Hh for voltage and frequency ride-through and trip settings.