SECTION G3
OPERATING REQUIREMENTS
FOR GENERATION ENTITIES
PG&E GENERATION INTERCONNECTION HANDBOOK

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 ISO 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 ISO Controlled Grid. 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 ISO 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 ISO Tariff and operating requirements established by PG&E. If conflicts arise between the PG&E’s operating requirements and the ISO Tariff or Protocols, the ISO 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 at the Generation Entity’s expense or make other arrangements with PG&E. For Generation Facilities larger than 20 MW, this provision is pursuant to Large Generator Interconnection Agreement (LGIA) Articles 9.3 and 9.6.1 and 10.5.

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 reactive support from the interconnected system, unless they have installed corrective equipment.

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 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 Designated PG&E Electric Control Center will specify the required voltage schedule. 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 Designated PG&E Electric 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.

G3.1.1.3 Power System Stabilizer Operating Requirements For Generators

PG&E and the California ISO are responsible for the safe and reliable operation of the electric system. 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 for approval to PG&E’s Director, Electric T&D Engineering.

G3.1.1.4 Power Factor Control

A power factor controller is generally only applicable to units connected to the distribution system. It shall maintain a constant power factor on a synchronous generator by controlling the voltage regulator. The controller must be capable of maintaining a power factor within ± 1 percent at full load.
at any set point within the capability of the generator. However, in no case shall control limits be greater than (closer to 100%) between 90 percent lagging (producing Vars) and 95 percent leading (absorbing Vars). In addition, all power factor controllers for synchronous generators larger than 1,000 kW must have programmable capability to vary hourly settings.

The Designated PG&E Electric Control Center shall specify required settings for voltage or power factor. Generally, a power factor of 1.0 is preferred on distribution level systems.

The programmable controller for units larger than 1,000 kW is normally obtained by combining a non-programmable controller and a general purpose programmable device.

Control over the Var production associated with the delivery of power to PG&E falls under the following general classifications, depending upon the contractual arrangements:

- **Surplus-Sale Operation:** When a Generation Entity dedicates its generator to serve plant needs first, selling only the surplus to PG&E under a Standard Offer contract, treatment differs depending on whether excess power is being sold to PG&E or supplemental power (no-sale mode) is being purchased from PG&E. In a no-sale mode, the Generation Entity has sole control over Var production; however, the customer shall meet the power factor requirements for its overall facility as described by the applicable tariff(s). When surplus power is being sold, PG&E has operational control of the power factor at which the power is delivered.

- **Net-Sale Operation:** All electricity produced, excluding station load, is sold to PG&E under a Standard Offer contract. PG&E therefore has operational control of Var production within the generator operating range described in Sections G3.1.1.2 and G3.1.1.4.

- **No-Sale Operation:** When a Generation Entity uses generation exclusively to offset load, the customer has sole control of the generator power factor; however, the customer shall meet the power factor requirements for its overall facility as described by the applicable tariff(s).

- **Generation Directly Connected to the ISO Controlled Grid:** Selling Into the California Energy and Ancillary Service Markets or Wheeling Power out of the ISO Controlled Grid: The California ISO has operational control of Var production within generator operating range described in Section 5 of the ISO Tariff and applicable ISO protocols.

- **Generation Connected to the PG&E UDC Power System (Less than 10 MW and Total Output Sold to PG&E UDC):** All electricity produced, excluding station load, is sold to PG&E under a Standard Offer Contract. PG&E therefore has operational control of Var production within the generator operating range described in Sections G3.1.1.2 and G3.1.1.3.
G3.1.2 Non-Synchronous Generator Control (without Var Control)

Induction generators or other generators without Var control absorb Vars and therefore require reactive power support from PG&E’s system. All facilities require power factor correction. Power factor correction or capacitors must be installed either by the Generation Entity or as part of the special facilities installed by PG&E at customer expense. For Generation Facilities larger than 20 MW, this provision is pursuant to LGIA Articles 9.3 and 9.6.1 and 10.5. Care must be exercised by the Generation Entity in connecting capacitors directly to the generator terminals to avoid self-excitation. Switched capacitors supplied by the Generation Entity shall be switched on and off at the request of PG&E.

G3.1.2.2 Induction Generators Larger Than 40 kW:

Under Electric Rule 21, the Generation Entity must provide reactive supply equivalent to operating at 95 percent leading power factor (absorbing Vars). PG&E may further require the provision of reactive support equivalent to that provided by operating a synchronous generator anywhere within the range from 95 percent leading power factor (absorbing Vars) to 90 percent lagging power factor (producing Vars) within an operating range of ±5 percent of rated generator terminal voltage and full load. (This is typical, if the induction project is greater than 1,000 kW.)

When PG&E determines that it is not practical for the Generation Entity to provide this level of support, the customer shall be charged the cost to install capacitors on the PG&E system as special facilities to correct to either 95 percent leading power factor (absorbing Vars) or to 90 percent lagging power factor (producing Vars). For Generation Facilities larger than 20 MW, this provision is pursuant to LGIA Articles 9.3 and 9.6.1 and 10.5.

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 (generator operating at 90 percent lagging power factor) and,
- Absorb maximum reactive power from PG&E’s system (generator operating at 95 percent leading power factor).

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 geographic location.
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.2.

G3.3.2 Harmonic Limits

All generators shall comply with the voltage and current harmonic limits specified in IEEE Standard 519-1992, “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.2). 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. For Generation Facilities larger than 20 MW, this provision is pursuant to LGIA Articles 9.3 and 9.7.6 and 10.5.

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.