GENERATION INTERCONNECTION HANDBOOK

April 24, 2023

This Interconnection Handbook is provided by San Diego Gas & Electric Company (SDG&E) for Generators interconnecting to SDG&E-owned Transmission system.

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1. INTRODUCTION AND SUMMARY

1.1 PURPOSE

This Interconnection Handbook is written to provide information, guidance, and requirements for Generating Facilities ("GF" s) connecting to SDG&E's electric transmission system.

SDG&E has transferred operational control of its electric transmission system to California Independent System Operator ("CAISO") (Transmission Control Agreement [1]) and therefore conforms to CAISO's FERC-approved Tariff for the governance of interconnecting new generation resources, specifically Appendix DD - Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Any entity proposing to interconnect its GF to SDG&E's transmission system must also adhere to CAISO's tariff for Interconnection of Generating Units and Facilities.

1.2 APPLICABILITY

This Interconnection Handbook applies to any new or materially modified GF. SDG&E's electric transmission system, under CAISO operational control includes all network lines and buses at transmission voltage levels (for SDG&E: 69 kV, 138 kV, 230 kV, 500 kV). Certain sections of the Handbook have equipment requirements for system interoperability that are part of the Interconnection Customer's ("IC's") Interconnection Facilities ("IC's IF") or the GF. The IC's IF and GF will be collectively referred to as the ("Project"). Other requirements herein apply to equipment and configuration at the Point of Interconnection ("POI") as part of the SDG&E Participating Transmission Owner ("PTO" or "TO") Interconnection Facilities ("PTO IF") or for Network Upgrades that will ultimately be owned and operated by SDG&E. For instances where a new switchyard or substation is required to interconnect a new GF, additional requirements will be specified by the SDG&E project team(s).

Upon execution of the Generator Interconnection Agreement ("GIA") and subsequent Written Authorization to Proceed, SDG&E may provide additional requirements specific to the interconnection. The requirements specified by the SDG&E project team(s) may be in addition to requirements set forth in this Handbook, and the IC will be responsible to comply with other requirements provided in accordance with Good Utility Practice.

1.3 ROLES AND RESPONSIBILITIES

1.3.1 Interconnection Customer

The IC is responsible for meeting the requirements set forth in this Handbook and other requirements specified by the project team(s). The IC will be responsible to design, install, operate, own and maintain the Project, unless otherwise specified in the GIA. The IC shall provide timely information regarding equipment, specifications or other interdependent activities required for the construction, commissioning, and operations. Failure to provide information or schedules for interdependent activities could result in IC driven delays to the construction or commissioning of the Project.

[1] https://www.caiso.com/Documents/TransmissionControlAgreement.pdf

1.3.2 SDG&E

SDG&E as a Transmission Planner and Transmission Owner, is responsible for the data validation, studies, reports, and providing cost estimates for the PTO IF and Network Upgrades of the interconnection in coordination with the CAISO. SDG&E is provides interconnection related information including its standards and specifications needed for the interconnection of the Project. SDG&E is responsible for design, engineering, installation, maintenance, etc. of PTO IF and the work inside the substation/switchyard, unless otherwise specified in the GIA.

1.3.3 CAISO

The CAISO is responsible for processing interconnection requests and administering the GIDAP to move interconnections from request to commercial operation.

1.4 COMPLIANCE WITH NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ("NERC") RELIABILITY STANDARD, FAC-001

R1.1.
This Interconnection Handbook provides requirements for generation Facilities seeking to interconnect to SDG&E's electric transmission system. The current version is published on SDG&E's public website.

R3.1.
Section 2.1 of this Interconnection Handbook provides procedures for coordinated studies of new or materially modified existing interconnections.

R3.2 & R3.3.
Section 2.1.7 describes CAISO's role in the coordination and notification for affected systems.

2. PROCESS

2.1 STUDY PROCESS

The study process described in this section primarily refers to the cluster study process under CAISO GIDAP. Projects that seek interconnection to SDG&E's transmission system must also comply with requirements set forth in this Interconnection Handbook. Refer to CAISO's GIDAP and procedures for additional details regarding the cluster study processes and other interconnection study processes.

2.1.1 Interconnection Request ("IR")

ICs seeking to connect to SDG&E's transmission system will request interconnection pursuant to CAISO GIDAP. The IR is submitted to CAISO during the Cluster Application Window, typically between April 1 – April 15. CAISO reviews the IR for completeness, verifies documentation for site exclusivity and IC company state of incorporation documentation, and receives necessary deposits. For more information visit CAISO webpage for Generation Interconnection (http://www.caiso.com/planning/Pages/GeneratorInterconnection/). All data the IC submits, required to properly study the interconnection, are specified in the Interconnection Study Agreement.

2.1.2 IR Validation and Scoping Meetings

SDG&E reviews the technical data submitted and validates consistency between all documents and details provided as part of the IR package. Any inconsistencies or deficiencies identified are then returned to the IC for updates and corrections. To avoid lengthy delays in processing the IR, it is important to ensure any changes made in the preparation of the documents are reflected in all documents where the data resides.

During the validation of technical data, SDG&E also reviews requested Point of Interconnection to determine availability. POIs are either a bay position at an existing substation or switchyard, or at a future loop-in switchyard of an existing Transmission Line ("TL") segment.

During the Scoping Meeting, coordinated by CAISO, SDG&E will inform the IC the results of scoping bay positions. Additionally, general information from past studies regarding system conditions and upgrades will be provided, as available.

2.1.3 Studies

SDG&E studies the reliability impacts of interconnecting new GFs and materially modifying interconnections of GFs and identify Reliability Network Upgrades.

CAISO performs deliverability studies during the phases of the cluster study process which determine Area and Local Delivery Network Upgrades ("ADNU", and "LDNU").

Reports showing the results of the studies will be provided to the IC.

2.1.4 Cost and Time to Construct Estimates

SDG&E determines costs and time to construct estimates for PTO's IF. The PTO's IF are the portion of the gen-tie and facilities required to physically interconnect the project to SDG&E's transmission system between the expected Point of Change of Ownership ("POCO") and the POI.

All Network Upgrades costs are estimated by SDG&E during the cluster study process, and the Per Unit Cost Guide is used during Phase I, with more detailed cost estimate provided during Phase II. The Per Unit Cost Guide is posted annually by CAISO for each PTO. The Factors and Assumptions tab of the guide provides the reason for differences between the study reports and the guide. GIDAP specifies how each type of upgrade is allocated to projects within the cluster, then establishes the cost responsibility and cost exposure for the project.

The upgrade or facilities with the longest time-to-construct estimates are used to determine if the IC's requested In-Service Date ("ISD") and Commercial Operation Date ("COD") are achievable. Construction Activities begin after the execution of the Generator Interconnection Agreement ("GIA"), Written Authorization to Proceed ("WATP") and the required Interconnection Financial Security ("IFS") postings are received.

2.1.5 Results Meetings

After each Phase of the study process, SDG&E and CAISO meet with each IC to discuss the cluster study results as provided in the Appendix A (individual report) and Area Report. SDG&E staff from Generation Interconnection, Engineering and other departments, as requested, will

answer questions about the results provided in the report or discuss details about the interconnection.

IC seeking to enter in an Engineering and Procurement (“E&P”) Agreement must indicate so after Phase I and execute the optional 2-party agreement no later than the date the Phase II reports are issued. The scope of the E&P agreement typically involves engineering and procurement of long-lead equipment. After Phase II, the 2-party voluntary E&P agreements between the PTO and the IC are not available; instead, the IC, PTO and CAISO will work towards GIA execution.

2.1.6 Modifications

SDG&E follows GIDAP Section 6.7.2 for Material Modification Assessments (“MMA”). The process is managed by CAISO’s Queue Management team, with assessment of material impact being performed by SDG&E.

2.1.7 Affected Systems

CAISO coordinates the notification and maintains the system of record of potential or identified Affected Systems. CAISO notifies and invites Affected Systems to Scoping and Results Meetings during the Study Process. The IC is required to coordinate with Affected Systems and CAISO provides instructions and details in the associated meeting minutes. CAISO follows Sections 3.7, 6.7 and 8.7 of GIDAP, notifies Affected Systems following the completion of any modification requests and confirms Balancing Authority Area.

2.2 INTERCONNECTION AGREEMENTS

Generator Interconnection Agreements for projects connecting to SDG&E’s transmission system are typically 3-party agreements between the IC, CAISO and SDG&E. SDG&E tenders the draft GIA to the IC and CAISO following the Phase II results meetings, and after IC’s selection of option for the Project subsequent to receipt of its CAISO-issued Transmission Plan Deliverability ("TPD") allocation. ICs, after the Phase II results meeting, can request early tendering of the GIA, but should note that a GIA cannot be executed for parked projects.

2.3 PRE-CONSTRUCTION

Once the GIA is executed, WATP and IFS postings are provided, the project is ‘handed off’ to SDG&E’s project team(s). The assigned Project Manager will be the primary point of contact for the IC as the project proceeds through the design, engineering, and construction process. Typically, the SDG&E project team(s) will meet with the IC during a reoccurring meeting. SDG&E maintains the minutes and agenda for the meeting which serves as documentation for communication between the parties.

2.4 PROJECT SCHEDULES

IC is required to provide timely and detailed schedules to the SDG&E project team(s) throughout the design and construction phase. ICs will be notified of deficient schedule information during project meetings or otherwise. It is important ICs provide timely and detailed schedules to avoid milestone delays.

2.5 COMMISSIONING

Section 7 provides information for testing and procedures required prior to commissioning.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO's Interconnection Facilities to obtain back feed power. The gen-tie receives back-feed (i.e., energization) once the construction of PTO IF and Interconnection Reliability Network Upgrades are complete. After ISD, the IC is responsible for getting synchronization approval from the CAISO. The IC is responsible for completing all requirements through the CAISO New Resource Implementation ("NRI") process. http://www.caiso.com/participate/Pages/NewResourceImplementation/

2.6 OPERATIONS

Sections 8 and 9 provide information about operating requirements for GFs.

Upon synchronization to SDG&E's transmission system, the GF will be subjected to operating requirements by both SDG&E and CAISO.

3. METERING REQUIREMENTS

3.1 GENERAL

3.1.1 Purpose

This section specifies the metering requirements for GFs interconnecting to SDG&E's transmission system.

3.1.2 Applicability

All wholesale GFs (GFs who make sales for resale) connected to SDG&E's transmission system must meet both SDG&E and CAISO metering requirements. SDG&E metering is also required for retail standby service, such as auxiliary loads. All other GFs (not providing wholesale service) must meet SDG&E's retail metering requirements. Furthermore, all GFs 1 MW and above must meet all applicable Western Electricity Coordinating Council (WECC) metering standards.

GFs that fall under CAISO requirements but are outside of SDG&E service territory are not covered in this Section. IC to reach out to SDG&E for additional information.

3.2 BASIC METERING REQUIREMENTS

SDG&E meter(s) shall be installed to measure auxiliary load per SDG&E metering standards and requirements.

- SDGE METERING REQ 1001

CAISO meter(s) shall be installed to measure net generation, and any additional required CAISO meter(s), shall meet CAISO metering standards and requirements. The CAISO meter type(s) shall be specified by the CAISO and shall meet CAISO metering standards and requirements.

3.2.1 Non-Battery Energy Storage System Metering

Auxiliary loads associated with non-battery energy storage GFs are considered retail loads.

If auxiliary loads associated with non-battery energy storage GFs are located behind the meter, additional metering is not required. IC to refer to service standards for additional information.

3.2.2 Battery Energy Storage System Metering

Battery Energy Storage System (BESS) metering shall adhere to separate metering requirements as outlined in Schedule SPES (Station Power – Energy Storage).

Auxiliary loads associated with battery energy storage GFs are considered wholesale loads when the BESS is in operation (charging or discharging). When BESS is idle (not charging or discharging), the auxiliary power is considered retail loads.

3.3 METERING ROLES AND RESPONSIBILITIES

3.3.1 Customer's Role and Responsibilities

The IC shall provide to SDG&E, in writing, projected load and generation information including projected maximum and minimum current levels, in-rush current, harmonic content level, load/generation profile and any other pertinent data.

The IC shall provide to SDG&E all preliminary meter related electrical and structural design drawings.

The IC shall provide 3FT x 3FT footprint for metering cabinet (to be furnished by SDG&E). IC shall provide SDG&E all drawings, documentations, specifications, etc. for final review and approval.

The IC shall provide to SDG&E all preliminary metering equipment specifications and attributes (i.e., Current Transformer ("CT") secondary wire sizes, lengths, and calculated burden). If the metering Potential Transformer ("PT") has a second set of coils that will be used for protection, monitoring, and/or synching purposes, the IC shall provide SDG&E applicable specifications, drawings, and wiring diagrams for verification that the second set of PT voltage coils will not draw any appreciable load.

The IC shall provide to SDG&E two copies each of the final design drawings, CT/PT test reports, other meter related equipment test reports/specifications, the main transformer test report (if applicable), and all other metering related information.

The IC shall notify SDG&E of any proposed upgrades or changes to the SDG&E meter or metering scheme, and SDG&E Meter Engineering shall be responsible for approval of any aforementioned upgrades or changes.

The IC shall provide an uninterruptable 120VAC or 125VDC power supply (UPS) with 24-hour minimum runtime to power SDG&E meters, wireless communications module, and other auxiliary devices as required.

The IC is responsible for mounting the wireless communication module (as required and as provided by SDG&E) in a suitable location for normal operation. In areas with low cellular coverage and/or strength issues, additional signal boosting equipment shall be furnished and installed at the expense of the IC.

The IC shall accommodate and ensure that SDG&E meter personnel have unrestricted 24hr/7day access to the SDG&E meters, metering PTs/CTs, and associated wiring/terminations/enclosures. Locked doors and gates (which SDG&E personnel must pass through to access the SDG&E metering and associated equipment) shall be keyed with Schlage restricted VTQP Quad section keyway. A list of locksmiths that provide these cylinders for door locks, padlocks, and gate controllers is available upon request and is shown in SDG&E's Service Standards and Guide.

The IC shall provide physical shade for outdoor metering installations. IC shall construct physical shade in compliance with clearance requirements as indicated in SDG&E Service Standards and Guide.

The IC shall provide a 120VAC or 125VDC source for strip heaters for outdoor installations as required.

The IC shall procure the primary CAISO meter and manage/implement all aspects to program and install the CAISO primary meter per CAISO requirements and practices.

3.3.2 SDG&E Roles and Responsibilities

Only upon SDG&E's approval of preliminary drawings and metering equipment specifications may final design drawings be issued for construction and metering equipment purchased by the IC.

SDG&E Meter Electricians shall procure, wire, and install the SDG&E meter(s), meter test switches, A-base adapters, and all equipment beyond a termination block located in or near the metering cabinet (or wall plate).

If a wireless communication module antenna is required for SDG&E meter, SDG&E shall provide the wireless communication module antenna to the IC for installation. Refer to previous section detailing IC requirements.

SDG&E shall survey the site for cellular coverage and shall determine the required signal boosting equipment to be furnished and installed at a suitable location.

Prior to initial generation testing, SDG&E must inspect, verify, and test all SDG&E meter-related wiring, connections, terminations, and metering PTs/CTs. The GF may not be energized until SDG&E has provided written notice that all metering components and wiring have been checked and verified as being acceptable by SDG&E.

SDG&E is not responsible for installation or other related activities for CAISO meters. The IC is responsible to adhere to CAISO meter requirements as it applies to them.

3.4 LOCATION OF METERING

The auxiliary load metering instrument transformers shall be located on the transmission side of the facility. The IC can, as an alternative, place the auxiliary load metering instrument transformers on the low voltage side of the main GF transformer bank.
If located on the low voltage side of the main GF transformer bank, the IC shall provide certified transformer test reports that indicate transformer losses, used to program the meter(s) to account for transformer losses. No metering instrument transformers (used for SDG&E metering purposes) shall be located behind any other transformers other than the main GF transformer bank.

If the distance between the point of connection and location of the meter exceeds one (1) mile, the IC shall provide the transmission line section parameters that will be required and used to program the meter(s) to account for losses associated with the Interconnection Customer's (IC) transmission line.

The preferred and typically most cost-effective method of metering the GF is to utilize one set of instrument transformers for both the CAISO meter and SDG&E meter where the SDG&E meter also serves to measure auxiliary load, i.e., bi-directional metering. Specialized extended range CTs are required for this type of installation. Refer to Section 3.7, Instrument Transformers, for extended range CT requirements. If the high voltage facility circuit breaker is located on the SDG&E transmission side, and upstream of the meter's CTs and PTs, a separate set of dry

contacts must be provided to each SDG&E meter whose open/close status indicates whether the facility is energized. See Figure 3.1 for a typical layout utilizing this arrangement type.

The alternative method of metering the GF is to utilize one set of instrument transformers for the CAISO meter and SDG&E meter and one, or up to a maximum of two, SDG&E metering points to measure auxiliary load. At each auxiliary load metering point the CT/PT enclosure, meter panel, pull section, disconnect switches, etc. shall meet all SDG&E service standards and requirements.

If the high voltage side facility circuit breaker is on the SDG&E service side of the metering CTs/PTs used for net generation metering, a set of dry contacts must be provided to each auxiliary load meter whose open/close status indicates if the facility is energized. In addition, a set of dry contacts must be supplied to each SDG&E auxiliary load meter indicating whether the generator output breaker is in the closed or open position. Given this metering configuration, the meter assumes that when the generator output breaker is closed, the generator is operating, and auxiliary load is being provided to the GF. See Figure 3.2 for a typical layout utilizing this arrangement type. The IC may elect to furnish their own metering cabinet but must coordinate with SDG&E for parts lists and requirements. The IC shall provide SDG&E all drawings, documentations, specifications, etc. for final review and approval.

3.5 METERING SPECIFICS

SDG&E meters will be form 9, class 20 meters per American National Standards Institute (ANSI) C12 standards. The CAISO meters shall meet all CAISO standards and requirements.

Each meter shall utilize its own dedicated test switch. SDG&E will supply a test switch for each SDG&E meter. The IC shall adhere to metering requirements, work clearances, as stated in SDG&E service standard requirements.

The metering cabinet shall be provided by SDG&E. The IC may elect to furnish their own metering cabinet, but design and documentation must be reviewed and approved by SDG&E.

The IC shall provide 3FT x 3FT footprint for metering cabinet (to be furnished by SDG&E). IC shall provide SDG&E all drawings, documentations, specifications, etc. for final review and approval.

National Electrical Manufacturer Association (NEMA) 3R type (or a higher rated NEMA water-tightness rating) enclosures shall be used for outside metering installations. Physical shade shall be provided for outdoor metering installations. The IC shall also provide a 120VAC or 125VDC source for strip heater for outdoor metering installations.

All SDG&E-owned meters shall require an uninterruptible 120VAC or 125VDC power supply (UPS) source with 24-hour minimum runtime to keep them energized in the event the facility has an outage. A separately fused position or breaker position from the uninterruptible power supply shall be provided to each SDG&E meter.

Each SDG&E meter shall be provided a separate set of dry A-finger contacts that indicate the open/close status of the main facility circuit breaker.

The uninterruptible power supply wiring shall terminate to a terminal strip in the metering cabinet or on the wall plate. This terminal strip may be the same as that used for the PT and CT secondary leads. A separate terminal strip shall be installed to accommodate the main breaker A-finger contact wires.

3.6 METER COMMUNICATIONS

SDG&E shall supply a wireless communications module, as required, which will be used to support data transfer from the SDG&E meter to SDG&E's meter data storage center. SDG&E shall also supply the associated wireless module antenna that will be mounted outside with a clear line of sight to receive/transmit a cellular signal. In areas with low cellular coverage and/or strength issues, additional signal boosting equipment shall be furnished and installed at the expense of the IC. For areas with poor cellular coverage, IC may request for IP connection for meter communications.

The IC shall provide an open area close to the meter for the wireless communications module to be mounted and a path to route communication wiring between the wireless communications module and the SDG&E meter. The IC shall consult with SDG&E to determine the most suitable location for the wireless communications module.

The IC may split the 120VAC or 125VDC UPS source into two (2) fused disconnects to supply power to the SDG&E meter and wireless communications module as required. With outdoor metering cabinets, the 120VAC receptacle can be used to power the wireless communications module as long as it meets these two requirements: 1) powered by the supplied UPS source with 24-hour minimum runtime, and 2) installed with a separate fuse or breaker from the metering equipment.

The IC shall be responsible for mounting the wireless communications module antenna in a suitable location (typically on the roof of a control house) and routing the antenna cord between the wireless communication module and the antenna. The IC shall consult with SDG&E to determine the most suitable location for the antenna.

3.7 INSTRUMENT TRANSFORMERS

The metering PTs and CTs shall be 0.3% ANSI accuracy class, or higher, metering devices. If the instrument transformers used for auxiliary load metering are located on the transmission side of the facility, special extended range CTs are required, i.e., guaranteed and tested to accurately measure current down to at least 0.5% of CT rating.

Wire size utilized for PTs and CTs shall be sized accordingly to not compromise accuracy. When the wiring exceeds 1ohm between the PTs and metering cabinet, IC shall upsize wire size to improve PT accuracy. The CT wiring shall not exceed 1/2 burden of the CT rating.

Metering accuracy requirements for PTs and CTs are listed below.

3.7.1 PT Requirements

The PT voltage coils shall be utilized for revenue metering, which includes SDG&E meter(s) and CAISO meter(s). If the metering PT has a second set of coils, it may be used for protection, monitoring, and/or synching purposes with the condition that no appreciable load will be drawn from it. The IC will provide SDG&E applicable specifications, drawings, and wiring diagrams for verification that the second set of PT voltage coils will not draw any appreciable load.

PT secondary fused disconnect switches must be installed in close proximity to the metering PTs. Each SDG&E meter shall have a dedicated fused disconnect switch that is readily accessible (i.e., no ladder required to access) and clearly labeled.

No unmetered auxiliary load is permissible on the source side of the SDG&E metering. PTs (or Coupling Capacitor Voltage Transformers ("CCVT")) used for protection, monitoring and/or synching purposes may be located upstream of the SDG&E metering with the condition that no appreciable load will be drawn from it. Under this circumstance, the IC will provide SDG&E applicable specifications, drawings, and wiring diagrams for verification that the PT's (or CCVTs) will not draw any appreciable load.

All PT secondary non-polarity leads shall be tied together and grounded as close to the PTs as practical. One common wire shall emerge from this point which extends to the appropriate position on the metering connection terminal strip. This is in addition to the 3 PT secondary polarity leads that also extend to the appropriate positions on the metering connection terminal strip.

PTs shall have a minimum Z rated ANSI burden rating and a minimum 0.3% ANSI accuracy class.

3.7.2 CT Requirements

The metering CTs shall be sized in accordance with good metering practices and shall always be within meter accuracy class range during generation cycles and/or auxiliary load cycles.

Metering CTs shall be guaranteed and tested to be 0.3% ANSI accuracy class and accurately measure current down to at least 0.5% of rating.

There should be no means or possibility of by-passing metering CTs except by use of temporary high voltage jumpers.

All metering CTs shall be utilized for revenue metering, which includes SDG&E meter(s) and CAISO meter(s).

CT shorting blocks must be installed in close proximity to the metering CT's switch that is readily accessible (i.e., no ladder required to access) and clearly labeled. They will be available to isolate the CTs from all load-side (downstream) metering.

All CT secondary non-polarity leads shall be tied together and grounded as close to the CTs as practical. One common wire shall emerge from this point which extends to the appropriate position on the metering connection terminal strip. This is in addition to the three CT secondary polarity leads that also extend to the appropriate positions on the metering connection terminal strip next to each SDG&E meter.

The metering unit CTs shall have a minimum B-1.8 ANSI burden rating and at minimum 0.3% ANSI accuracy class.

3.7.3 General PT & CT Requirements

All transmission voltage-level metering CTs and PTs shall be freestanding. Any exceptions must be reviewed and approved by SDG&E.

The metering PTs and CTs shall be 0.3% ANSI accuracy class, or higher, metering devices.

Wire size utilized for PTs and CTs shall be sized accordingly to not compromise accuracy. When the wiring exceeds 1ohm between the PTs and metering cabinet, IC shall upsize wire size to improve PT accuracy. The CT wiring shall not exceed 1/2 burden of the CT rating.

If the alternative method of metering auxiliary power is approved (i.e. metering auxiliary load on the low voltage side of the main GF transformer bank in addition to metering at the net-generation point), the CT/PT enclosure, meter panel, pull section, disconnect switches, etc. at each auxiliary load metering point shall meet all SDG&E service standards and requirements. These standards and requirements are referenced in SDG&E's Service Standards and Guide (Sections 603 and 604) and are available upon request.

Associated CTs and PTs shall be located electrically at the same location. No appreciable capacitance, inductance, or resistance shall be located between the devices.

Disconnect switches shall be located on both sides of transmission level metering CTs and PTs. It is permissible to locate the main breaker between one of these disconnect switches and the metering CTs and PTs.

The primary side of the metering units upstream of the CTs and PTs shall not be fused and shall not have any sort of switch or disconnect capable of de-energizing the metering units without de-energizing the circuit being metered.

The metering unit CTs and PTs shall be inductive type. CCVT types can only be used if SDG&E Meter Engineering reviews and approves the specific model and type.

Spare metering CTs and PTs shall either be stored on site or be installed redundantly.

All CT's and PT's secondary leads shall be terminated to a termination strip located in or near the metering cabinet. This may be the same terminal strip required to terminate the UPS wires. A separate terminal strip is required for the main breaker status and/or generator output breaker leads if there is a breaker status going to the metering, breaker is located upstream from CTs and PTs.

There shall only be one grounding point for the PT secondary neutral and CT secondary non-polarity wires. The PT secondary neutral and CT secondary non-polarity leads can connect to separate grounding points or a common grounding point.

CT and PT neutral common wires shall not be shared.

Figure 3.1
Typical Generation Metering Layout
(Preferred Method)

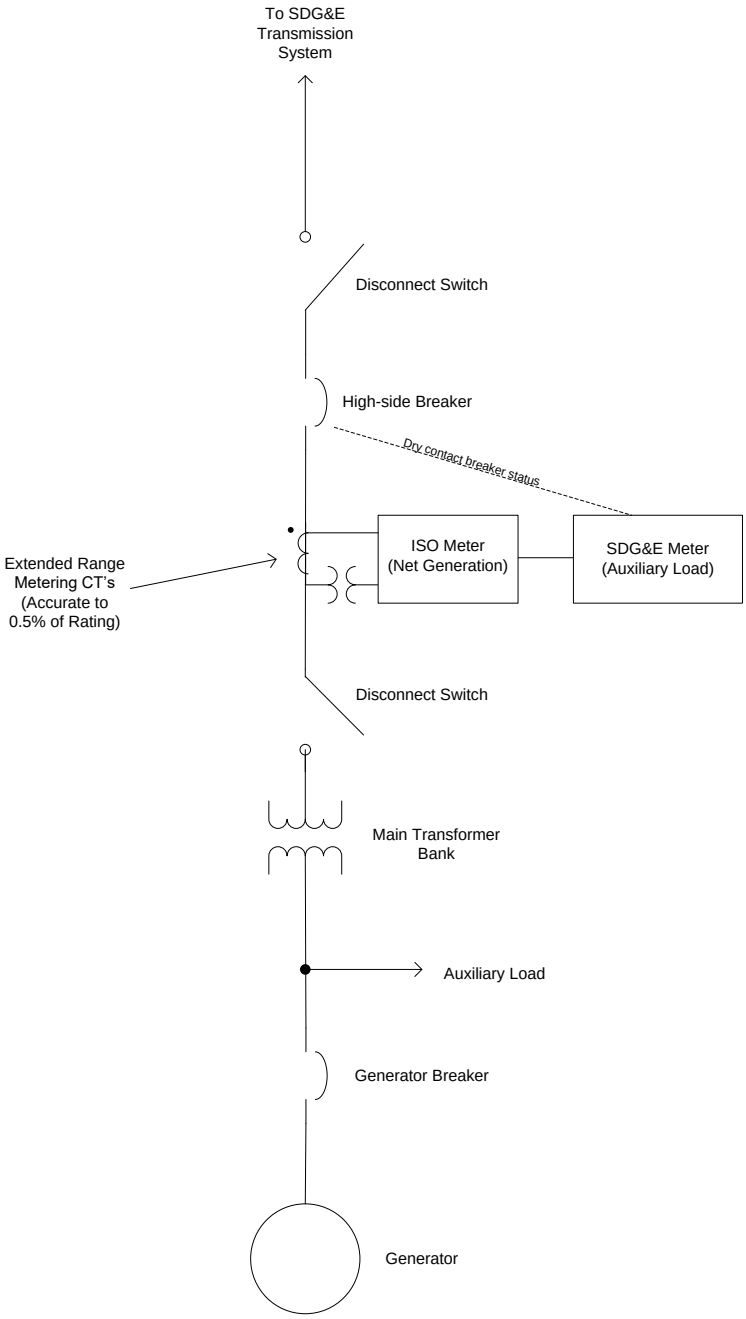
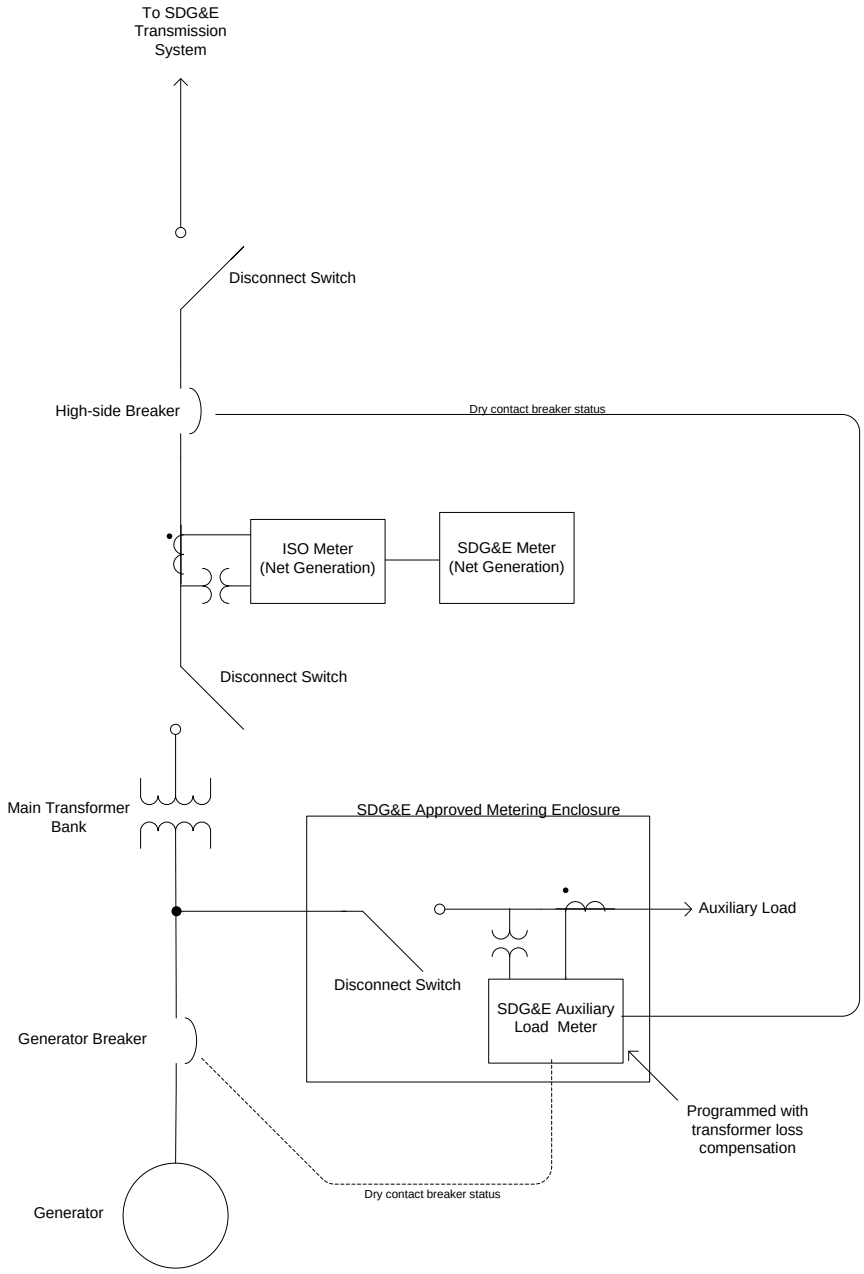


Figure 3.2
Typical Generation Metering Layout
(Alternate Method)



4. PROTECTION AND CONTROL REQUIREMENTS

4.1 PURPOSE

This section specifies the requirements for protective relays, control devices and telemetry for GFs interconnecting to SDG&E's electric transmission system.

4.2 APPLICABILITY

The applicable protective standards of this section apply to all GFs interconnecting to any portion of SDG&E's transmission system. These standards, which govern the design, construction, inspection and testing of protective devices, have been developed by SDG&E to be consistent with applicable regional reliability criteria and to include appropriate CAISO consultation. The CAISO, in consultation with SDG&E, may designate certain new or existing protective devices as CAISO Controlled Grid Critical Protective Systems. Such systems have special CAISO requirements, e.g., for installation and maintenance, as described in the CAISO Tariff Section 4 and the Transmission Control Agreement ("TCA") Section 8.

In addition, for GFs connecting directly to a non SDG&E owned-transmission facility: The non-SDG&E-owned entity must coordinate with the CAISO, SDG&E (as the Transmission Owner), and the GF, as needed, to ensure that any CAISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the protective systems of the GF and the SDG&E power system in accordance with the CAISO Tariff Section 4 and the CAISO-UDC Agreement, both available on the CAISO website (www.caiso.com).

4.3 PROTECTIVE RELAY REQUIREMENTS

An important objective in the interconnection of facilities to the SDG&E system is minimizing the potential hazard to life and property. The primary safety requirement is the ability to disconnect immediately when a fault is detected.

The protection equipment for a GF must protect against faults within that facility, faults on the SDG&E Power System and on any nearby or intervening systems. A GF must also trip off-line (disconnect automatically) when power is disconnected from the line into which the unit generates.

Due to the high energy capacity of the transmission system, high-speed fault clearing is required to minimize equipment damage and potential impact to system stability. Some protection requirements can be standardized; however, most line relaying depends on GF size and type, number of generators, line characteristics (i.e. voltage, impedance, and ampacity), and the existing protection equipment connected to the SDG&E System.

SDG&E protection requirements are designed and intended to protect the SDG&E Power System only but is also intended to coordinate with the customer-owned protection system. As a general rule, neither party should depend on the other for the protection of its own equipment.

The IC shall install between the Point of Interconnection and the GF, at a minimum, a disconnecting device or switch with generation interrupting capability. Additional protective relays are typically needed to protect IC's facility adequately. It is the IC's responsibility to protect its own system and equipment from faults or interruptions originating on both SDG&E's side and the GF's side of the Interconnection. The GF's system protection facilities shall be designed, operated, and maintained to isolate any fault or abnormality that would adversely affect the SDG&E system or the systems of other entities connected to the SDG&E system. The GF shall, at its expense, install, operate, and maintain system protection facilities in accordance with applicable CAISO, WECC and NERC requirements and in accordance with design and application requirements of this Generation Interconnection Handbook.

The protective relays used in isolating the GF from the SDG&E system between the Point of Interconnection and the GF must be set to coordinate with the protective relays at the SDG&E line breaker terminals for the line on which the GF is connected. Additional requirements, as to the exact type and style of the protective devices, may be imposed on the IC based on the proposed station configuration or the type of interrupting device closest to the point of common coupling to SDG&E's facility. **Note:** *There may be additional protective equipment requirements, at the GF's cost, which SDG&E will coordinate with the GF or its representatives.*

SDG&E recommends that the IC acquire the services of a qualified electrical engineer to review the electrical design of the proposed GF and ensure that it will be adequately protected.

Generally, fault-interrupting equipment should be located as close to the interconnection point as possible – typically within one span of overhead line or 200 feet of non-spliced underground cable.

The GF should provide SDG&E with electrical drawings for review prior to equipment procurement. The drawings provided should consist of Single Line Meter and Relay Diagrams, schematic drawings detailing connectivity (3-Line AC (Alternating Current)) and tripping schemes (Direct Current (DC)) for all SDG&E required relays. The Single Line Meter and Relay Diagrams listing the major protective equipment should be provided for review prior to ordering relays. The 3-Line AC and the DC schematics should be provided before fabricating relay panels. The following documents must be submitted by the IC for review by SDG&E's Systems Protection and Control Engineering Department (SPACE) before equipment is procured: Single Line Diagram, Single Line Meter and Relay Diagrams.

On-site power (typically 120 volts) is required for the test equipment. Circuit breakers must be tested on a schedule consistent with the equipment manufacturer's instruction manual or Good Utility Practice after the pre-back-feed inspection. It is also in the IC's best interest to make sure all of its protective equipment is operating properly, since significant equipment damage and liability can result from failures of the IC's protective equipment.

4.4 RELIABILITY AND REDUNDANCY

The IC shall design the protection system with sufficient redundancy that the failure of any one component will still permit the GF to be isolated in the required clearing time from the SDG&E system under a fault condition. Multi-function three-phase protective relays used for line protection must have redundant relay(s) for backup. The required breakers must be trip tested by the GF at least once a year.

The addition of any new GF to the SDG&E's transmission system facilities must not degrade the existing protection and control schemes, create safety concerns or cause service reliability to drop to levels that violate minimum reliability standards.

4.5 RELAY GRADES

Only utility grade relays can be used for interconnection protection, and must meet the following specifications:

- The minimum and maximum operating temperatures are the range of -40^{o} to 70^{O} C.
- Must be certified to meet ANSI/IEEE (Institute of Electrical and Electronics Engineers, Inc.) C37.90 dielectric testing requirements.
- Must be certified to meet ANSI/IEEE 37.90.1 Surge Withstand Capability (SWC) and Fast Transient testing.
- Must be certified to meet Radio Frequency Interference (RFI) with stand capability in accordance with ANSI/IEEE C37.90.2.
- Must meet Power Frequency Magnetic Field Immunity (ANSI/IEEE 1308-1994 (R2001) and International Electrotechnical Commission (IEC) 61000-4-8).
- Must meet Underwriters Laboratory (UL) and Federal Communications Commission (FCC) test requirements, as necessary.
- Must be certified for output contact Load Break Capability tests- through an inductive network (UL-1054, ANSI C37.90).
- Airborne Arcing Noise susceptibility (IEEE C62.41.2, C62.45 and IEEE 896.5).
- Must be certified for DC Hi-pot Test or Megger with no leakage or breakdown of the components (IEC 61000-4-11 and 60255-11).
- Electrostatic Discharge Immunity (ANSI/IEEE C37.90).
- Must be certified to meet IEC 60255-21-1 Class 1 Vibration test (sinusoidal) or equivalent tests and IEC 60255-21-2 Class 1 Shock and bump or equivalent tests.

4.6 LINE PROTECTION

Line protection relays must coordinate with the protective relays at the SDG&E breakers for the line on which the GF is connected. The typical protective zone is a two-terminal line section with a breaker on each end. Line protection must be directional. Also, the complexity and the required number of protective devices increase dramatically with increase in the number of terminals in each protective zone.

The SDG&E-required relays must be located so that a fault on any phase of the SDG&E's Electric transmission facility shall be detected. If transfer trip protection is required by SDG&E, the IC shall provide all required communication circuits at its expense. A communication circuit may be a leased line from the telephone company, a dedicated cable, microwave, or a fiber optic circuit and shall be designed with sufficient levels of monitoring of critical communication channels and associated equipment. SDG&E will determine the appropriate communication medium to be used on a case-by-case basis. The leased phone line or dedicated communication network must have high-voltage protection equipment on the entering cable so the transfer trip equipment will operate properly during fault conditions.

4.6.1 Methods of Generation Transmission Line Protection

SDG&E commonly uses the following methods to protect its generation interconnecting transmission lines. These methods, or protection elements, are enabled within the microprocessor multi-functional relays protecting the generation interconnecting transmission line.

1. Line differential protection (87L)
   a. Phase differential
   b. Ground differential
   c. Negative-sequence differential
2. Line distance protection
   a. Phase distance (21P)
   b. Ground distance (21G)
3. Pilot protection
   a. Permissive overreaching transfer trip (POTT)
   b. Permissive underreaching transfer trip (PUTT)
4. Overcurrent protection
   a. Directional phase/ground instantaneous overcurrent (67P/67G)
   b. Non-directional phase time-overcurrent (51P) used with loss-of-potential
   c. Directional ground time-overcurrent (51G)
5. Overvoltage/undervoltage (59/27) for Anti-Islanding
6. Overfrequency/Underfrequency (81O/81U) for Anti-Islanding
7. Open Breaker Keying
8. Breaker Failure (50BF)
   a. 50BF will utilize voltage supervision at the GF end of lines interconnecting with SDG&E.
   b. GF will coordinate with SDG&E System Protection on voltage supervision requirements for 50BF schemes.

4.6.2 No Tapped Transmission Lines

SDG&E does not allow GFs to tap existing transmission lines. SDG&E requires a loop-in switchyard to be constructed to accommodate any TL POIs. Loop-In Switchyards are considered Network Upgrades which will be owned and operated by SDG&E.

Tapped transmission lines increase the number of terminals in each protective zone and are subject to the strictures of the following language:

SDG&E's position is founded on prudent practice. SDG&E's practice is not strictly associated with protection concerns; it is also based on the ability to reliably restore the line/system following a protection event. SDG&E's practice of connecting a GF to an SDG&E substation bus via a radial

line allows for straightforward line protection and assurance that 1) only SDG&E can re-energize a transmission line following a line trip, and 2) a generator closure out-of-synchronism cannot occur.

Additionally, connecting a GF to SDG&E facilities via a tapped line increases the consequences of outages since a fault on any of the tapped line segments will remove all line segments from service. In contrast, a fault on the radial line connecting a GF to an SDG&E substation or switching station bus will remove only the radial line from service; and a fault on any other transmission line will not remove the radial line from service.

For non-SDG&E owned gen-ties the maximum allowable number of terminals is three (3).

4.7 GENERATOR PROTECTION AND CONTROL

GF protection shall, at a minimum, include:

4.7.1 Over/Under-Voltage Relay

This protection is used to trip the circuit breaker(s) when the voltage is above or below an acceptable operating range, specified by SDG&E. It is used for generator protection and backup protection in the event that the generator is carrying load that has become isolated from the SDG&E transmission system and for anti-islanding.

4.7.2 Over/Under-Frequency Relay

This protection is used to trip the circuit breaker(s) when the frequency is above or below an acceptable frequency range as specified by SDG&E. It is used for generator and/or turbine protection and back-up protection and for anti-islanding.

4.7.3 Low/High Voltage and Frequency Ride Through

Generator relay settings (for voltage and frequency) are coordinated with other utilities in the Western Electricity Coordinating Council (WECC) and the CAISO to maintain generation on-line during system disturbances (also known as “ride through”). Relay settings should not be set for a higher frequency/voltage or shorter time delay than specified in the NERC standard PRC-024 without prior written approval by SDG&E and the CAISO.

4.7.4 Ground Fault Sensing Scheme

The ground fault sensing scheme detects ground faults on SDG&E’s transmission system facilities and trips the generator breaker or the GF’s main circuit breaker(s), thus preventing the GF from contributing to a ground fault. This scheme must be able to detect faults between SDG&E’s side of the dedicated transformer and the end of SDG&E’s line segment.

The following generator step up (GSU) transformer connections, along with appropriate relaying equipment, are commonly used to detect system ground faults. One of these two types of GSUs shall be specified for the Generating Facility:

- SDG&E System side (primary) – grounded wye: tertiary winding – delta; generator side (secondary) – wye;

- SDG&E System side (primary) – grounded wye: generator side (secondary) – delta; The customer must also be able to sense ground faults on the delta side of the transformer, so a grounding transformer may need to be installed on the secondary system.

4.7.5 Inverter-Based Resource ("IBR") Controller Characteristic

In addition to the requirements of Section 4.6, IBRs are subject to additional requirements to ensure the safety and reliability of the transmission system as specified in IEEE 2800 and provided below for specific applicability.

Abnormal conditions can arise on the transmission system to which the IBR plant shall appropriately respond. This response contributes to the stability of the system, as well as the avoidance of damage to connected equipment, including the IBR plant.

- Voltage disturbance ride-through
- Fault ride-through
- Frequency disturbance ride-through

Any applied IBR voltage protection shall allow the IBR plant to meet its ride-through requirements. The transmission system owner and the IBR owner shall coordinate the IBR plant voltage protection with the transmission system's voltage protection, if present, and the undervoltage load shedding (UVLS) scheme in the area.
All instantaneous overvoltage protection used within the IBR plant shall use filtered quantities to minimize the possibility of misoperation while providing protection to the desired equipment and system. Any instantaneous overvoltage protection(s) that uses input from one voltage transducer and has the possibility of disrupting the power output of the entire plant shall use at least one cycle (of fundamental frequency) measurement window to minimize such possibility and the related impact on the transmission system. Protection margin shall be coordinated with the Towner, wherever applicable.

Where instantaneous overvoltage protection is applied on IBR unit(s), it shall:

- be coordinated with transient overvoltage capability of IBR units
- be coordinated with any surge protection implemented within the IBR plant and at the POI
- allow the IBR plant to meet its transient over voltage ride-through requirements

4.7.5.1 Voltage disturbance ride-through requirements

The voltage disturbance ride-through requirements specified in this clause do not apply when applicable frequency is outside of the continuous operation region and the frequency ride-through mandatory operation region.

The IBR plant shall be designed to provide the voltage disturbance ride-through capability specified in this clause. Any tripping of the IBR plant, or other failure to provide the specified ride-through capability, due to IBR plant self-protection as a direct or indirect result of a voltage disturbance within a ride-through region, shall constitute non-compliance with this standard.
Exception: An IBR plant shall be considered compliant with this standard if the failure to provide the specified ride-through capability does not result in a reduction of the apparent current of the IBR plant by more than 10% of the pre-disturbance apparent current; and the failure occurs due to a voltage disturbance that reduces the applicable voltage at the connection point to less than 50% of nominal.

***Note**: Tables below are from IEEE Std2800-2022. See full standard for more details.*

Table 13—Voltage ride-through requirements at POM for IBR plants with Auxiliary Equipment Limitations[84]

Voltage (p.u.) at POM	Operating mode/response	Minimum ride-through time (s) (design criteria)
V > 1.20	Mandatory Operation or May Trip	NA
V > 1.10	Mandatory Operation	1.0
V > 1.05	Continuous Operation[85]	1800
V < 0.90	Mandatory Operation	3.00
V < 0.70	Mandatory Operation	2.50
V < 0.50	Mandatory Operation	1.20
V < 0.25	Mandatory Operation	0.16
V < 0.10	Permissive Operation[86]	0.16

For interconnection at 500 kV nominal system voltage, the minimum ride-through time is infinite when applicable voltage is > 1.05 per unit and ≤ 1.10 per unit at 500 kV base.

Table 14—Voltage ride-through requirements at POM for IBR plants without Auxiliary Equipment Limitations[87]

Voltage (p.u.) at POM	Operating mode/response	Minimum ride-through time (s) (design criteria)
V > 1.20	Mandatory Operation or May Trip	NA
V > 1.10	Mandatory Operation	1.0
V > 1.05	Continuous Operation[85]	1800
V < 0.90	Mandatory Operation	6.00
V < 0.70	Mandatory Operation	3.00
V < 0.50	Mandatory Operation	1.20
V < 0.25	Mandatory Operation	0.32
V < 0.10	Permissive Operation[86]	0.32

For isolated IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility, the voltage ride-through requirements specified in Table 14 applies.

During low voltage disturbances, including faults on the transmission system, for which the applicable voltage with the lowest voltage magnitude is within the permissive operation region, the IBR plant:

- Shall not trip
- May continue to exchange current with the transmission system or may operate in current blocking mode. Active and reactive current oscillations that are positively damped are permitted during the disturbance and post-disturbance period.
- If operates in current blocking mode, shall restart current exchange in less than or equal to 5 cycles of applicable voltage returning to continuous operation region or mandatory operation region. The restart of current exchange is performed by IBR units, when applicable voltage at the RPA (as interpreted at the IBR unit terminals) returns to continuous operation region or mandatory operation region.

4.7.5.2 Voltage disturbances within continuous operation region

Voltage disturbances of any duration, for which the applicable voltage remains within the continuous operation region, shall not cause the IBR plant to trip from the transmission system. The IBR plant shall remain in operation during any such disturbance and shall continue to deliver pre-disturbance level of active power or available active power, whichever is less. Temporary

deviations of active power output may be permitted as agreed upon between the IBR owner and the Transmission Operator.
If the IBR plant cannot deliver both active and reactive power due to its current limit (or apparent power limit), when the applicable voltage is below 95%, then preference shall be given to active or reactive power according to requirements specified by the Transmission Operator.

Exception: If required for self-protection,

- The IBR plant may trip if Vneg> 3% of the nominal voltage for greater than 10 seconds, OR Vneg>2% of the nominal voltage for 300 seconds, provided that the voltage imbalance is neither caused nor aggravated by unbalanced currents of the IBR plant.
- The IBR plant may also trip for Vneg> 6.7% of the nominal voltage for a duration determined by the transmission system owner based on feasible shunt or series fault scenarios, provided that the voltage imbalance is neither caused nor aggravated by unbalanced currents of the IBR plant.

4.7.5.3 Low and High voltage ride-through capability

The ride-through mode is also widely referred to as fault ride-through mode. The IBR unit shall have capability to select operation in either active current priority mode or reactive current priority mode during a high or low voltage ride-through events. By default, the IBR unit shall operate in reactive current priority mode during high and low voltage ride-through events. If requested by the transmission system owner, and mutually agreed with the IBR owner, the IBR unit may operate in active current priority mode for both the high and low voltage ride-through events.

For unbalanced faults, in addition to increased positive sequence reactive current, IBR unit shall inject negative sequence current:

- Dependent on IBR unit terminal negative sequence voltage and
- Leads the IBR unit terminal negative sequence voltage by an allowable range as specified below.
- 90-100 degrees, for full converter-based IBR units
- 90-150 degrees, for type III WTGs.
- Assuming pre-fault negative sequence current output is zero or negligible, the negative sequence reactive current injection during a fault is an incremental negative sequence reactive current (ΔIR-2).
- If IBR unit's total current limit is reached, either ΔIR-1, or ΔIR-2, or both may be reduced with a preference of equal reduction in both currents.
- Additionally, the incremental positive sequence reactive current (ΔIR-1) injection shall not be reduced below incremental negative sequence reactive current (ΔIR-2).

4.7.5.4 Ground Grid Requirements

Transformers connected to the transmission system at 69 kV and higher must have a grounded wye connection on the system side, and a ground current sensing scheme must be used to detect ground faults on the SDG&E Power System as stated above.

For any substations and/or GF built by other entities but subsequently owned and/or operated by SDG&E, the ground grid must meet the minimum design and safety requirements used in SDG&E substations and meet IEEE Std. 80.

Additionally, when GFs (operated by GF personnel) need to be connected to the ground grid of an existing or new SDG&E substation (i.e. when they are located inside or immediately adjacent to SDG&E substation or switching stations OR when system protection requires solid ground interconnection for relay operation), the ground grid must meet the minimum design and safety requirements used in SDG&E substations and meet IEEE Std. 80.

When GFs are not in any way connected to the SDG&E ground grid or neutral system, the GF will be solely responsible for establishing design and safety limits for their grounding system.

4.8 MANUAL DISCONNECT SWITCH

An SDG&E-operated disconnect device must be provided as a means of electrically isolating the SDG&E Power System from the GF. This device shall be used to establish visually open working clearance for maintenance and repair work in accordance with SDG&E safety rules and practices. A disconnect device must be located at all points of interconnection with SDG&E. This disconnect switch should be a gang-operated, three-pole lockable switch. No equipment that can back feed into the gen-tie shall be installed on the line side of the disconnect.

All switch installations must be approved by SDG&E. SDG&E personnel shall inspect and approve the installation before parallel operation is permitted.

4.9 FAULT-INTERRUPTING DEVICES

The fault-interrupting device selected by the GF must be reviewed and approved by SDG&E for each particular application.

There are two basic types of fault-interrupting devices:

- Circuit Breakers
- Circuit Switchers

SDG&E will determine the type of fault-interrupting device required for a GF based on the size and type of generation, the available fault duty, the local circuit configuration, and the existing SDG&E protection equipment.

4.9.1 Circuit Breakers

A three-phase circuit breaker at the GF automatically separates the GF from the SDG&E Power System upon detection of a fault. Additional breakers and protective relays may be installed in the GF for ease in operating and protecting the facility, but they are not required for the purpose of interconnection. The interconnection breaker must have sufficient capacity to interrupt maximum available fault current at its location and be equipped with accessories to:

- Trip the breaker with an external trip signal supplied through a battery (shunt trip)
- Telemeter the breaker status when it is required
- Lock-out if operated by protective relays required for interconnection

Generally, a three-phase circuit breaker is the required fault-interruption device at the GF, due to its simultaneous three-phase operation and ability to coordinate with SDG&E line-side devices.

4.9.2 Circuit Switchers

A circuit switcher is a three-phase fault-interrupter with limited fault interrupting capability. These devices may substitute for circuit breakers when the fault duty is within the interrupting rating of the circuit switcher. With SDG&E approval, some circuit switchers with blades can double as the visual open disconnect switch between the metering transformers and the main transformer. Since circuit switchers do not have integral current transformers, they must be installed within 30 feet of the associated current transformers to minimize the length of the unprotected line/ bus disturbance.

4.10 GENERATORS

The GF must meet all applicable ANSI and IEEE standards. The prime mover and the GF should also be able to operate within the full range of voltage and frequency excursions that may exist on the SDG&E Power System without damage to the prime mover or GF. The GF must be able to operate through the specified frequency ranges for the time durations listed in the WECC Off-Frequency standard (PRC-006-WECC-CRT-2) to enhance system stability during a system disturbance.

4.10.1 Synchronizing Relays

The application of synchronizing devices attempts to assure that a synchronous generator will parallel with the utility electric system without causing an unacceptable disturbance to other customers and facilities (present and in the future) connected to the same system. It also attempts to assure that the GF itself will not be damaged due to an improper parallel action.

Synchronous generators and other generators with stand-alone capability must use one of the following methods to synchronize with the SDG&E Power System:

4.10.1.1 Automatic Synchronizer

Automatic synchronization with automatic synchronizer **(**ANSI Device 15/25) to synchronize with the SDG&E Power System:

The automatic synchronizer must be approved by SDG&E and have all of the following characteristics:

- Slip frequency matching window of 0.1 Hz or less
- Voltage matching window of + 3 percent or less
- Phase angle acceptance window of + 10 degrees or less
- Breaker closure time compensation. For an automatic synchronizer that does not have this feature, a tighter phase angle window (+ 5 degrees) with one second time acceptance window shall be used to achieve synchronization with + 10-degree phase angle

Note: *The automatic synchronizer has the ability to adjust generator voltage and frequency automatically to match system voltage and frequency, in addition to having the above characteristics.*

4.10.1.2 Manual Synchronization Supervised by a Synchronizing Relay

Manual synchronization with supervision from a synchronizing relay (ANSI Device 25) to synchronize with the SDG&E Power System:

The synchronizing relay must have all of the following characteristics:

- Slip frequency matching window of 0.1 Hz or less
- Voltage matching window of + 3 percent or less
- Phase angle acceptance window of + 10 degrees or less
- Breaker closure time compensation

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

4.10.1.3 Frequency/Speed Control

Please refer to Section 8

4.10.1.4 Excitation System Requirements

An excitation system is required to regulate generator output voltage.

Excitation systems shall have a minimum ceiling voltage of 150 percent of rated full load field voltage and be classified as a high response excitation system as defined in IEEE 421.1. Static Systems shall meet these criteria with 70 percent of GF terminal voltage. The offline GF terminal voltage response shall have an overshoot limited to 20 percent and a band width of at least 0.1 to 4 hertz. However, in no case shall the bandwidth upper limit be less than local mode frequency. All systems shall be suitable to utilize a Power Stabilizer as described in Section 4.10.1.5

Ceiling current shall have a transient time capability equal to or greater than the short time overload capability of the generator. See ANSI C50.12, 13, or 14.

A means shall be provided to quickly remove excitation from the generator field to minimize contributions to faults. The preferred method is to reverse generator field voltage to drive the current to zero.

Excitation system shall respond to system disturbances equally in both the buck and boost directions. All bridges that govern excitation responses shall be full wave type. Bridges feeding a pilot exciter shall have negative forcing capability.

4.10.1.5 Voltage Regulator

Voltage control is required for all GFs interconnected at transmission level voltages.

The unit should be able to operate in Automatic Voltage Control Mode with its automatic voltage regulator (AVR) in service and controlling voltage continuously; except when instructed otherwise by the Transmission Operator (TOP), or it is in starting, shutting down or testing mode. If the Voltage Control equipment is out of service, the GF operator shall have an alternative method to control GF voltage and reactive output to meet the voltage or reactive power schedule directed by the SDG&E Designated Control Center (per applicable NERC Reliability Standard: NERC

Reliability Standard VAR-002-4 or any future revisions) and as directed by the CAISO. The regulator must be acting continuously and be able to maintain the specified voltage or reactive power schedule at the interconnection point under steady-state and contingency conditions without hunting and within ± 0.5 percent of any voltage level between 95 percent and 105 percent of the nominal voltage at the point of interconnection.

Voltage regulators for synchronous generators shall have a minimum of the following signal modifiers:

- Reactive current compensator capable of line drop or droop characteristic
- Minimum and maximum excitation limiter
- Volts per Hertz limiter
- Two levels of over-excitation protection. The first level should provide a forcing alarm and trip the voltage regulator after a time delay. The second level shall have an inverse time characteristic such that the time-current relationship may be coordinated with the generator short time thermal requirements (ANSI C50.13 or C50.14).
- A two input Power System Stabilizer (PSS) utilizing Integral of Accelerating Power to produce a stabilizing signal to modify regulator output. The PSS shall be an integral part of the voltage regulator and be incorporated into the excitation system for all generation units greater than 30 MVA and connected to the transmission system at 69 kV and greater. The PSS shall provide a positive contribution to damping for a frequency range from 0.1 hertz through local mode frequency.

4.10.1.6 Power Factor Controller

The controller must be able to maintain a power factor setting within ±1 percent of the setting at full load at any set point within the capability of GF. However, in no case shall control limits be greater than the following: Between 90 percent lagging and 95 percent leading. Per CAISO tariff, the GF will maintain a composite power delivery at continuous rated power output at the terminals of the GF at a power factor within the range of 0.95 leading to 0.90 lagging, unless the CAISO has established different requirements that apply to all GFs in the Control Area on a comparable basis.

Wind GFs and other GFs of the induction type must install enough equipment to maintain at least unity power factor and the voltage within criteria at the point of interconnection, under normal and extreme system conditions. This compensating equipment must have dynamic characteristics as determined by the interconnection studies.

4.10.1.7 Inverter-based Generators (Solar, Wind, Battery and others)

Inverter based generation must comply and meet the latest applicable IEEE 1547, and UL 1741 standards, and must meet the latest applicable requirements of IEEE Std 2800 (2022) – IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems. Many definitions in IEEE 2800 are taken directly from IEEE 1547, but 2800 should be used over IEEE 1547 for issues particularly governing the design and operation of IBR-based generator applications. The harmonics generated by these inverters must be limited according to the latest revision of IEEE 519. At SDG&E's request, all voltages, frequencies, and set points must be verified by providing calibration test reports showing pass/fail indication.

4.11 REMEDIAL ACTION SCHEMES

As stated in the NERC and WECC Planning Standards, the function of a Remedial Action Scheme (RAS) is to “detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance.” In the context of new generation projects, the primary action of a RAS would be to detect a transmission facility outage or an overloaded transmission facility and then trip or run back (reduce) generation output to prevent damage to the overloaded facilities, protect against potential overloads, and/or avoid other criteria violations.

The output of GFs will flow over the entire interconnected transmission system. A GF is therefore required to participate, at any point in time, in a RAS(s) to protect local transmission facilities and the entire system as SDG&E and the CAISO determines necessary.

A typical disturbance, as it is considered in the planning and design of the transmission system, is the sudden loss of one or more critical transmission lines or transformers. A widely applied corrective measure is to instantaneously drop a sufficient amount of generation on the sending end of the lost transmission facility. This is known as *generation dropping*, and a GF may be disconnected from the transmission system by the automatic RAS controller, in much the same way as by a transfer-trip scheme. A GF should therefore have full load-rejection capability as needed both for local line protection and RAS.

The RAS design must be such that any single-point failure will not prevent the effective operation of the scheme.

Whether RAS shall be required will depend on the overall location and size of the generator and load, the nature, consequences and expected frequency of disturbances and the nature of potential transmission reinforcements. Interconnection customers may be required to implement new or expanded RASs at any time.

Any RAS proposal must be approved by both SDG&E and CAISO and must comply with the applicable CAISO Planning Standards and Good Utility Practice.

4.12 PERMISSIVE CLOSE FOR INTERRUPTING DEVICE AT POINT OF INTERCONNECTION

SDG&E may provide a Permissive Close Control Signal to enable closing of the Generation Entity’s interrupting device at or near the Point of Interconnection, which is typically the circuit breaker(s) at the SDG&E bus position. The intent of this control is to ensure that SDG&E is ready for the GF to be energized from the SDG&E power system, and to prevent the closing of the GF’s interrupting device when the SDG&E facility is de-energized. The GF must incorporate the interface to SDG&E’s Permissive Close Control Signal communication interface in the design of the associated interrupting device close circuit(s). In addition, the GF must provide status of the interrupting device (open or closed) to SDG&E via the communication control interface.

4.13 SYSTEM MEASUREMENT DATA

For inverter-based resources, the requirements for system measurement data are specified in IEEE Std 2800 – IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems,

Chapter 11. The data types 4.13.1 through 4.13.5 listed below are specified in Table 19 of Std 2800.

4.13.1 SCADA DATA

Measurements

- Point of Measurement voltage and medium-voltage collector system voltages
- Point of Measurement frequency
- IBR plant active and reactive power output
- IBR units active and reactive power output of individual
- Shunt dynamic device reactive power output

Signals

- External control signals from RC
- External automatic control signals
- Active and reactive power commands sent to IBR units

4.13.2 SEQUENCE OF EVENTS RECORDING (SER) DATA

- Event/date/time synchronized to UTC
- Event type (status changes, synchronization status, configuration change, etc.)
- Sequence number (for potential overwriting)

4.13.3 DIGITAL FAULT RECORDING (DFR) DATA

- Time stamp
- Phase-to-ground voltage for each phase
- Bus frequency (as measured/calculated by the recording device)
- Each phase current and residual or neutral current
- Calculated active and reactive power output
- If applicable, dynamic reactive device voltage, frequency, current, and power output
- Applicable binary status

4.13.4 DYNAMIC DISTURBANCE RECORDER (DDR) DATA

- Time stamp
- Bus voltage phasor (phase quantities and positive-sequence)
- Bus frequency
- Current phasor (phase quantities and positive-sequence)
- Calculated active and reactive power output

4.13.5 POWER QUALITY DATA

- Power quality – flicker (PQDIF format)
- Plant-level RVC (PQ DIF format)
- Power quality – Very short-term harmonics (COMTRADE or PQDIF format)
- Power quality - Short-term harmonics (COMTRADE or PQDIF format)
- Power quality - Long-term harmonics (COMTRADE or PQDIF format)

NOTE: The following is required for all GFs

4.13.6 PHASOR MEASUREMENT UNIT

4.13.6.1 Standards and Requirements

As a Balancing Authority under NERC reliability standards, the CAISO has an obligation to match (i) the actual dynamic response of the system to disturbances, to (ii) the simulated dynamic response of the system to the same disturbances under similar system conditions. To allow the CAISO to match actual and simulated performance, individual generators larger than 10 MVA[2], and GFs with a maximum facility output equal to or greater than 20 MVA[2] are required to provide Transmission Providers with dynamic models that simulate the GF's dynamic response to disturbances on the system.

Under NERC reliability standards, SDG&E is a Transmission Planner within the CAISO Balancing Authority. SDG&E thereby has an obligation to provide to the CAISO dynamic models that will allow the CAISO to demonstrate a match between actual and simulated dynamic performance. Accordingly, each individual generator that is larger than 10 MVA[2], or GF that has a maximum facility output equal to or greater than 20 MVA[2], shall install and maintain, at its expense, phasor measurement units (PMUs).

These PMUs must be capable of capturing real-time data sufficient to allow SDG&E to either (i) validate, or (ii) identify errors or inaccuracies in, the dynamic models provided by the IC to SDG&E[3].

4.13.6.2 Installation Location

PMUs shall be installed on the Customer Facility low side of the GF step-up transformer, unless it is a non-synchronous generation facility, in which case the PMUs shall be installed on the Customer Facility side of the Point of Interconnection.

4.13.6.3 Sampling Rate

Installed PMU must be capable of a minimum of 30 samples per second and synchronized via a high-accuracy satellite clock.

4.13.6.4 Phasor Data Concentrator (PDC) Requirements

PMU equipment which includes the communication circuit should be capable of carrying the PMU data to a local data concentrator, and then transporting the information continuously to SDG&E, as well as storing the PMU data locally for thirty days.

4.13.6.5 Network Requirements

SDG&E will install and provide for ongoing support and maintenance of the network communications linking the data concentrator to SDG&E.

4.13.6.6 Data Exchange and Management Requirements

Interconnection Customer shall provide to SDG&E all necessary and requested information through the SDG&E synchro-phasor system, including:

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[2] http://www.caiso.com/Documents/ISO-SDGEMOD-032-01Requirements.pdf

[3] http://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf (R3)

- Gross MW and MVAR measured at the Customer Facility side of the generator step-up transformer (or, for a non-synchronous generation facility, to be measured at the Customer Facility side of the Point of Interconnection)
- Generator terminal voltage
- Generator terminal frequency
- Generator field voltage and current, where available.

5. SUBSTATION REQUIREMENTS

5.1 PURPOSE

The purpose of this section is to help all ICs satisfy applicable SDG&E substation requirements. In addition to the operating requirements in this handbook, a more detailed description may be found in the Conformed CAISO Tariff, which may be obtained from the CAISO website.

This document provides guidelines for:

- The determination of breaker duty and surge protection for GFs connecting to SDG&E's transmission system.
- Engineering and design of grounding systems for GFs connecting to SDG&E's transmission system.
- Establishing the methodology used by SDG&E to determine equipment ratings. These equipment ratings will be used in determining ratings of SDG&E's transmission system facilities. Conductors, equipment, and material should be selected to prevent substation elements from being the most limiting element of a facility.
- The selection of substation insulation and contamination levels for generation, transmission or end-user electric facilities connecting to SDG&E's transmission system facilities.

5.2 APPLICABILITY

The substation requirements of this section apply to all GFs interconnecting with SDG&E's transmission system facilities. All GFs must meet applicable WECC and NERC standards.

5.2.1 Standards and References

- San Diego Gas & Electric Company FERC Electric Tariff
- SES-3801 – Substation Arrestor Selection Requirements
- SES-1301 – Substation and Transmission Equipment Rating Methodology
- SES-1302 – Substation Conductor Rating Methodology
- IEEE C62.22 Guide to the Application of Metal-Oxide Surge Arrestors for Alternation Current Systems
- IEEE 80 Guide for Safety in AC Substation Grounding
- IEEE Std C62.82.1, IEEE Standard insulation Coordination-Definitions, Principles and Rules
- IEEE 1313.2, IEEE Guide for the Application of Insulation Coordination

5.2.2 Definitions

- Surge – A transient wave of current, potential or power in an electric circuit.
- Breaker Fault Duty – The highest value of the symmetrical component of the three-phase, short-circuit current in RMS amperes measured from the envelope of the current wave at the instant of primary arcing contact separation that the circuit breaker shall be required to interrupt at rated maximum voltage and on the standard operating duty.

- Grounding Study – A study to determine the long-term performance of differing types of commonly used grounding electrodes in diverse geographical locations and soil types.
- Basic Lightning Impulse Insulation Level (BIL) – The electrical strength of insulation expressed in terms of the crest value of a standard lightning impulse under standard atmospheric conditions. BIL may be expressed as either statistical or conventional.
- Crest Value – The maximum absolute value of a function when such a maximum exists.
- Insulation Coordination – The selection of insulation strength consistent with expected over-voltages to obtain an acceptable risk of failure.

5.3 BREAKER DUTY AND SURGE PROTECTION

5.3.1 Breaker Duty

The breaker duty for facilities connecting to SDG&E's transmission system facilities should meet the requirements stated in section 4.9.1 or 4.9.2 of this handbook depending on which device will be used. The fault duty for the device used depends on the physical connection to the system. A study will be needed in order to determine fault duty and the results will be used to determine the specified circuit breaker fault duty rating.

5.3.2 Surge Protection

Facilities connecting to the SDG&E's transmission system facilities will require surge protection. This applies to all transmission voltage levels 69 kV and above. Furthermore, any new transmission-level transformer connecting to an SDG&E facility will require surge protection.

The minimum surge protection varies depending on the voltage level of the third party's connecting facility. San Diego Gas & Electric has opted to use metal oxide type surge arrestors for substation surge protection. Third-party owned facilities connecting to an SDG&E-owned substation are required to use the latest revision of IEEE C62.22, Guide to the Application of Metal-Oxide Surge Arrestors for Alternation Current Systems, in order to determine the appropriate surge protection. In addition to using IEEE C62.22 for the application of surge arresters, any new connecting facility must meet the equipment requirements for surge arrester as dictated in Substation Engineering Standard SES-3801. SES-3801 describes and quantifies standard station class, metal oxide surge arrestors for 69 kV to 500 kV

5.4 GROUNDING AND SAFETY

5.4.1 Grounding

Any new facility connecting to the SDG&E's transmission system, regardless of its business functionality, will require an independent grounding study. That study will require the modeling and engineering of the grounding system based on the latest revision of IEEE 80, "Guide for Safety in AC Substation Grounding". The grounding study will be required to use the CDEGS software.

5.5 EQUIPMENT RATING

The ratings of Electric Facilities on SDG&E's transmission system are derived from the individual ratings of the equipment, or elements, which comprise that electric facility. Specifically, a Facility Rating will be equal to the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

Substation Equipment Rating Methodology are in accordance with:

- SES-1301 Sections 6.2 – 6.12
- SES-1302 Section 4

5.6 INSULATION AND INSULATION COORDINATION

5.6.1 Insulation and Insulation Coordination

Third-party owned facilities connecting to SDG&E's transmission system facilities will be required to coordinate with the insulation strength of the facility to which interconnection is made. A system transient analysis will be performed to determine the amplitude, waveform and duration of the over-stress voltages and generally done using software such as Electromagnetic Transient Program (EMTP). The insulation level will be in accordance with the latest revision of IEEE Std C62.82.1, "IEEE Standard insulation Coordination-Definitions, Principles and Rules" and IEEE 1313.2, "IEEE Guide for the Application of Insulation Coordination".

All equipment will adhere to the chosen basic lightning impulse insulation level.

6. TRANSMISSION LINE REQUIREMENTS

6.1 APPLICABILITY

The following section applies to the PTO IF portion of the gen-tie. In situations where the IC is responsible for any portion of the PTO IF, or otherwise required for interoperability, these requirements and standards apply.

Although IC is not required to follow SDG&E standards for IC's IF, SDG&E recommends using consistent and standard conductor size. In cases of outages due to cable/conductor failure, mutual assistance opportunities may be available for faster restoration time should standard conductor/cable sizes be used.

6.2 TRANSITION FROM IC IF to PTO IF

The PTO's scope of work and IC's scope of work for transitions between PTO's Interconnection Facilities and IC's Interconnection Facilities are outlined in the GIA. IC's should refer to their executed GIA for details.

6.3 OVERHEAD ELECTRIC TRANSMISSION

Interconnection Customers shall adhere to the following SDG&E's Electric transmission specifications:

- TE-0042: Technical Specification for Welded Tubular Steel Transmission and Distribution Pole Structures
- TE-0100: Construction Specification General Requirements
- TE-0105: Construction Specification for Drilled Pier and Direct Bury Foundations for Lattice Towers and Tubular Steel Poles
- TE-0106: Construction Specification for Conductors, Overhead Ground Wire, Optical Ground Wires, and Accessories
- TE-0144: Technical Specification for Calculating Overhead Conductor Ratings

6.3.1 SDG&E Standard Overhead Conductor Sizing

All voltages: 636 ACSR/AW, 636 ACSS/AW, 900 ACSS/AW, 1033.5 ACSR AW

6.4 UNDERGROUND ELECTRIC TRANSMISSION

Interconnection Customers shall adhere to the following electric transmission specifications:

- TE-0100: Construction Specification General Requirements
- TE-0107: Construction Specification for Underground Cable and Accessories, Conduits and Ducts, and Subsurface Structures
- TE-0141: Technical Specification for Transmission Underground Cable Rated 69kV, 138kV, and 230kV XLPE Extruded Dielectric Insulation
- TE-0145: Technical Specification for Calculating Underground Cable Ratings

6.4.1 SDG&E Standard Underground Cable Sizing Underground cable

- 69kV: 1750kCMIL AL, 1750kCMIL CU, 3000kCMIL CU
- 138kV: 1750kCMIL AL, 1750kCMIL CU, 2500kCMIL CU, 3000kCMIL CU
- 230kV: 3500kCMIL CU, 4000kCMIL CU, 5000kCMIL CU

7. ENERGIZATION AND SYNCHRONIZATION REQUIREMENTS

The following is SDG&E's procedure for performing inspections and testing prior to energization and synchronization of the GF to SDG&E's transmission system. All time requirements must be met for SDG&E to provide the GFs with timely service.

Any inspections required by local government agencies must be completed and permits signed off prior to the back-feed/ISD. Failure to meet the requirements within the periods specified may delay of successful synchronization of the Project to the SDG&E system.

The Interconnection Customer (IC) must comply with the CAISO's NRI process before the GF can synchronize to the SDG&E system.

The Generator System Operating Procedure must be drafted, reviewed (SOP page turn), revised and approved prior to back-feed. See timeline in section 7.1.5 below.

7.1 REQUIREMENTS PRIOR TO BACK-FEED/ISD

***Note**: The SDG&E system has A-B-C clockwise rotation.*

7.1.1 Relay Testing

The IC must provide SDG&E with test reports for the particular types of protection devices, including verification of all protective functionality, before SDG&E will allow the facility to parallel. Where tele-protection is utilized, the communication circuits must be tested, and the scheme operation functionally verified prior to back-feed. The Generator must submit written test reports for qualified testing to SDG&E upon request by SDG&E, which demonstrate the relays are operable and within calibration. SDG&E will not test the IC's equipment but may witness the testing performed by a qualified testing firm retained by the IC or its contractor.

7.1.2 RTU Point-to-Point Testing

The IC must provide a points list including system measurement data as specified in section 4, and additional data points upon request.

SDG&E Operations must verify the following:

- Communications circuits meet SDG&E's telecommunication specifications and are functioning properly
- RTU data is mapped correctly to SDG&E EMS and SCADA systems
    - Scaling on all analog data points is correct
    - Point-to-Point check on all status points is verified at SDG&E designated control centers

7.1.3 Remedial Actions Scheme Testing

SDG&E Construction and Operations must verify the operation of all RAS the GF participates and is subject to tripping from. The IC must confirm the feeder breakers used to trip the generator

during RAS operation are operational for testing, required communication between equipment is operational and provide test reports for protection devices 60-90 days, prior to field testing.

7.1.4 Metering

Subsequent to SDG&E Engineering approval of the metering design and receipt/approval of applicable equipment test reports and documentation, SDG&E shall be provided at least thirty (30) business days' notice to perform an inspection of the facility. This inspection includes, but is not limited to, verifying wire impedances, ratio checking of CTs, and inspecting the metering cabinet and associated hardware.

Upon a satisfactory inspection by SDG&E of the facility, the SDG&E meters and ancillary equipment shall be installed by SDG&E. The facility may not be energized before the installation of the SDG&E meters.

7.1.5 Generator System Operating Procedure

A Generator-specific System Operating Procedure must be drafted, reviewed (SOP page turn), revised and approved prior to back-feed. The following timeline applies:

- SDG&E Grid Operations Department obtains Single Line Drawing and Generator Operator information from IC 60-90 days prior to back-feed date
- SDG&E schedules SOP Page turn meeting 30 – 45 days prior to back-feed
- SDG&E issues SOP Draft (95% complete with minimal edits and/or pending items) 1 week prior to the SOP Page turn meeting.
- Hold SOP Page Turn meeting to discuss pending (5%) items to finalize draft.
- Upon SOP Page Turn meeting (Same day or next), the IC / Generator Operator to make contact with MC Training to schedule and complete Hold Authorization before back-feed.
- Shortly after SOP Page Turn meeting (1-week time-frame) apply all resolved pending items to draft and send out for review.
- Issue 100% finalized draft SOP for a two-week review (includes IC and a variety of departments within SDG&E)
- Upon the two-week review completion (Draft with no major revisions), obtain internal approval from Grid Control manager and compliance review (typically 3–4-day turnaround time)
- Publish final SOP upon back-feed completion.

Note: Back-feed CANNOT be achieved without final SOP and a Hold Authorization.

7.1.6 Permission to Synchronize

Upon completion of all requirements, SDG&E will provide a letter with PTO approval of initial synchronization.

7.1.7 Model Testing and Validation Report

Following NERC MOD requirements and WECC data preparation guidelines applicable to Generator Operators/Owners, generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. However, in the absence of verified test data that are preferred for commissioning, the generator shall successfully demonstrate generator gross

and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed and/or load governor controls, and PSS system, prior to COD.

7.2 SUBSYNCHRONOUS INTERACTION (SSI) EVALUATIONS

Wind turbine and inverter-based GFs using power-electronic devices installed near series compensated lines may be exposed to Subsynchronous Interaction (SSI) conditions. Subsynchronous Interaction includes Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter-based GFs using power electronic devices. Table 1 indicates applicability of SSI to different generation types.

Table 1: SSI Applicability

Category	Generation Type
SSR	Conventional Wind Turbine (Type 3)
SSTI	Conventional
SSCI	Inverter (Wind type 4, PV, BESS)

Screening Criteria

A susceptible electrical network may exist if any combination of up to five transmission facility contingencies would result in the GF being radially connected to a transmission line with series-compensation. Note that this is not meant to imply that a GF has to be radially connected with series compensation for there to be unacceptable SSR/SSCI; the five-contingency test is solely for the purpose of identifying which portions of electrical may be susceptible.

- Identify which N-1, N-2, N-3, N-4 or N-5 contingency conditions could result in a GF being radially connected to a transmission line with series compensation, in which case the GF is deemed to be connected to a susceptible network and could be subject to unacceptable SSR/SSCI.
- If connected to a susceptible network, a Full SSI study is required based on resource type as specified in Table 1.

SSI Study Requirements

The IC must finalize the inverter selection, perform the required PSCAD studies, and subsequently submit a report along with the PSCAD models, OEM black boxes, and completed CAISO IBR checklist for SDG&E and CAISO review, at least 6 months before the ISD.

In addition, SDG&E highly recommends that the IC consults with SDC&E when finalizing the scope of the studies and required deliverables with their consultant who is going to perform the studies.

SDG&E requires a series of PSCAD studies are performed for two operating conditions Heavy Summer (HS) and Light load (LL), for a list of contingencies, based on the Screening Criteria. Additional project specific sensitivity studies may be performed by the IC based on the conditions of each case.

For validation of the final report, all studies and relevant graphs/tables must be reproducible by SDG&E engineers. It is required that all setup and configurations relevant to each study must be shared with SDG&E, and upon request, the IC will provide detailed instructions on how to reproduce the graphs/tables that are included in the final report.

SDG&E will provide the PSCAD 500 kV backbone, to explain the scope of the network to be studied. The system may be extended/enhanced, as necessary. However, it may not be reduced, unless approved by SDG&E.

To add the project model, the IC should update the enhanced backbone with sub-pages or sub-modules, similar to the external equivalences that are shown on the main module.

The IC will coordinate with the Original Equipment Manufacturer (“OEM”) to utilize the “black box” for the plant inverter/controller. See CAISO Electromagnetic Transient Modeling Requirements for further information. Please include sufficient documentation on how the OEM .dll may be installed for SDG&E’s testing.

The model should utilize scaling, preinstalled switches, and graphs, so that the validation of different studies and reports could be facilitated and streamlined.

After building your first draft of the model and sharing it with SDG&E, please do not start your studies before receiving SDG&E’s confirmation email, regarding the acceptance of your proposed models and list of contingencies for the SSI studies.

8. OPERATING REQUIREMENTS

8.1 PURPOSE

This section highlights applicable NERC Standards and WECC Regional Criteria to the generator owner/operator (GO/GOP) and to the transmission operator (TOP). Highlighting the operating requirements helps with the coordination activities between these two operating entities (GOP/TOP) to ensure safe and reliable operation of the transmission system.

Excerpts of the currently applicable NERC and WECC criteria/standards are cited in this section. Interconnection Customers should refer to the latest applicable versions of the NERC and WECC Criteria.

In addition to the operating requirements in this handbook, the CAISO Tariff, Protocols and Business Practices Manual may set forth additional operating requirements. The CAISO website is at *www.caiso.com*.

8.2 APPLICABILITY

The operating requirements of this section apply to all GFs interconnecting to SDG&E's transmission system.

8.3 VOLTAGE SCHEDULE, AND VOLTAGE SUPPORT/CONTROL

GF voltage regulators must be capable of maintaining the voltage schedule at POI under steady-state and contingency conditions. Typically, the schedule or target voltage is within 5% of nominal voltage, in some cases a tolerance band for NERC reporting purposes is also specified. This tolerance band will typically be ±5 percent of the nominal voltage at the point of interconnection. See Section 4.10.1.5 for Voltage Regulator requirements and refer to NERC/WECC Reliability Standards VAR-001 and VAR-002.

8.3.1 Voltage Schedule

Excerpts from NERC Standard VAR-001-5 (Voltage and Reactive Control) and applicable WECC Variance:

> *Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.*
>
> *E.A.13. Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area*
>
> *E.A.14. Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator….*
>
> - *The generator terminals.*
> - *The high side of the generator step-up transformer.*
> - *The point of interconnection.*

- *A location designated by mutual agreement between the Transmission Operator and Generator Operator.*

Per the Coordinated Functional Registration (CFR) Agreement[4], SDG&E is the TOP designated for complying with Requirement E.A.13 and provides the voltage schedule to the generator operators in the form of Standard Operating Procedure (SOP). SDG&E's practice is to provide the voltage schedule prior to the generator operator energizing their gen-tie for back-feed. SDG&E annually sends out SOP to review voltage schedule information to all GFs in its TOP footprint.

8.3.2 Voltage Control and Support

Excerpt from NERC Standard VAR-002-4.1 (Generator Operation for Maintaining Network Voltage Schedules):

> *Purpose: To ensure generators provide reactive support and voltage control, within GF capabilities, to protect equipment and maintain reliable operation of the Interconnection.*
>
> *R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator…*
>
> *R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[5] (within each GF's capabilities[6]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations…*
>
> *2.2 When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.*

Note Requirement R2.2 and two other requirements not shown (R3 on status change and R4 on capability change) require notification to transmission operator in the control room.

SDG&E annually sends out SOP to review reactive power capability and AVR information to all GFs in its TOP footprint.

8.3.3 Power System Stabilizer (PSS)

GFs with 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.

Excerpt from VAR-501-WECC-3.1 (Power System Stabilizer):

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[4] In the CFR Agreement, the California Independent System Operator Corporation (CAISO) and SDG&E specify their respective compliance responsibilities as both the ISO and SDG&E are both NERC-registered TOP.

[5] The voltage or Reactive Power schedule is a target value with a tolerance band, or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[6] Generating Facility capability may be established by test or other means and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, Reactive Power capability may change based on stability considerations.

Purpose: To ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions by establishing the performance criteria for WECC power system stabilizers. This standard applies to synchronous generators, connected to the Bulk Electric System.

R1. Each Generator Owner shall provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days…

This standard applies to synchronous generators, connected to the Bulk Electric System. SDG&E annually sends out SOP to review PSS information to all GFs in its TOP footprint.

8.3.4 Voltage Control/Support Non-Synchronous Generator

As of June 16, 2016, approval of FERC Order 827 changed the power factor requirements for non-synchronous generators. 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 satisfied 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 GFs will operate the plant in voltage control mode according to the voltage schedule as indicated in Section 8.3.1.

8.4 GENERATOR STEP-UP TRANSFORMER

The available voltage taps of a GF's step-up transformer must be reviewed by SDG&E for their suitability with SDG&E's transmission system. The GF is to request this review before acquiring the transformer.

8.4.1 Transmission Equipment and Operating Data

Excerpt from NERC Standard VAR-001-5 (Voltage and Reactive Power Control) and applicable WECC Variance:

E.*A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology.*

Contact the SDG&E Procedure Desk for this request.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

8.4.2 Transformer Equipment and Nameplate Data

Excerpt from NERC Standard VAR-002-4.1 (Generator Operation for Maintaining Network Voltage Schedules):

> *R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.*
>
> *5.1. For generator step-up and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:*
> *5.1.1. Tap settings.*
> *5.1.2. Available fixed tap ranges.*
> *5.1.3. Impedance data.*
> *R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement…*

8.4.3 Voltage Flicker Criteria

Random voltage fluctuations (flicker) occurring at the POI directly attributable to the GF shall remain within the limits specified in latest revision of IEEE Std 2800-2022 “IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.”

Interconnecting generators shall be operated and monitored pursuant to the requirements of IEEE P2800, ANSI/IEEE 1547, and IEEE 519, as applicable. Post commissioning power quality monitoring shall be provided by the IBR Operator per IEEE P2800 Table 20 Clause 8 Power Quality.

8.5 VOLTAGE AND FREQUENCY RIDE-THROUGH REQUIREMENTS

In addition to the requirements set forth in sections 4.7.3 and 4.7.5, the GF will be required to adhere to the following section. All GFs interconnecting must ride through frequency and voltage excursion and not disconnect during such events per FERC Order 828, issued July 21, 2016.

8.5.1 Frequency and Voltage Ride-Through Requirements

Excerpt from NERC Standard PRC-024-3 (Frequency and Voltage Protection Settings for Generating Resources):

> *Purpose: To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).*
>
> *R1. Each Generator Owner shall set its applicable frequency protection in accordance with PRC-024 Attachment 1 for Western Interconnection such that the applicable protection does not cause the generating resource to trip or cease injecting current within the “no trip zone” during a frequency excursion…*

R2. Each Generator Owner shall set its applicable voltage protection in accordance with PRC-024 Attachment 2 (see Figure 1 and Table 1 for generating resources in the Western Interconnection), such that the applicable protection does not cause the generating resource to trip or cease injecting current within the "no trip zone" during a voltage excursion at the high side of the GSU or MPT…

WECC Criterion PRC-006-WECC-CRT-3.1 (Underfrequency Load Shedding)
Purpose: To document the WECC Off-Nominal Frequency Load Shedding Plan (Coordinated Plan), or its successor, and to assure consistent and coordinated requirements for the Coordinated Plan among all WECC applicable entities
WR8. Each Generator Owner shall implement the Coordinated Plan
WR9. Each Generator Owner shall annually compile and submit to the UFLSRG, no later than June 1, its respective Coordinated Plan data and dynamics file for its generation, in the format defined in Attachment A of this document.

8.5.2 Provision to Trip Load

Excerpt from WECC Off-Nominal Frequency Load Shedding Plan (Coordinated Plan):

Purpose: recognize the need for a common plan for underfrequency load shedding
Section 3. Requirement 13. Generator Owners that have generators that do not meet the requirements in Item 12 (or refer to R1 above) must either (a) automatically trip load (in addition to the amounts required by Item 1a, 1b, 1c, or combinations thereof of this Section E) to match the anticipated generation loss at comparable frequency levels, or (b) have contractual relationships providing for automatic load shedding.

Both the frequency and voltage ride through settings are documented in SDG&E SOPs and are annually shared with the GF owners/operators for their review. Any setting changes are also forwarded to SDG&E Transmission Planner for updating the WECC low/high frequency and voltage ride-through relay models in dynamic data file.

9. OPERATING PROCEDURES

9.1 GENERAL

9.1.1 PURPOSE

The purpose of this section is to provide GFs with a general understanding of applicable SDG&E and CAISO operating procedures.

9.1.2 APPLICABILITY

The operating procedures of this section apply to all GFs interconnecting with the SDG&E's transmission system. For all other GFs, including Participating GFs, the SDG&E Large Generation Interconnection Agreement (LGIA) may not include certain provisions of this section, such as energy reporting, paralleling and/or separating, and Ancillary Services (handled by Scheduling Coordinators), and maintenance scheduling (handled by the CAISO). Such provisions, which are described in the CAISO Tariff, will be covered under separate agreements. In the future, and subject to appropriate regulatory approval, the CAISO may develop revised or new operating procedures applicable to the interconnection of certain GFs. If conflicts arise between SDG&E's operating procedures and the CAISO's procedures, then SDG&E and the CAISO shall negotiate the difference(s) and use the applicable CAISO tariff process. If the conflict requires a resolution during real-time operations, the most conservative parameters shall be used.

9.2 JURISDICTION OF THE CAISO AND THE SDG&E DESIGNATED CONTROL CENTER

On March 31, 1998, the CAISO assumed operational control over most of SDG&E's 69 kV and above electric transmission system. Notwithstanding the operational jurisdiction of the CAISO over most of SDG&E's electric transmission system, the CAISO Protocols delegate certain operational activities to SDG&E on selected parts of the CAISO Controlled Grid. Under the CAISO's control and instruction, SDG&E performs all physical switching operations, including de-energization and restoration of SDG&E-owned facilities.

Both SDG&E and the CAISO serve as points of contact for GFs that are connected to SDG&E's electric transmission system that are part of the CAISO Controlled Grid. These GFs will communicate and coordinate with the CAISO and SDG&E as specified in the CAISO's Protocols, Operating Procedures, and tariffs.

The GF, while operating its facility interconnected with the CAISO Controlled Grid or with SDG&E's electric transmission system, shall at all times follow the operating instructions of the CAISO and SDG&E. The SDG&E Designated Control Center shall be responsible for implementing the CAISO's orders, protocols, and operating procedures.

9.3 COMMUNICATIONS

The GF operator shall maintain telephone service at the GF. If the facility is remote or unattended, telephone service shall be provided to the nearest location normally occupied by the responsible GF (acting on its own behalf or through its designated GF operator). SDG&E and the GF operator shall maintain operating communications through the SDG&E Designated Control Center. The Generation Facility operator shall be accessible at all times and shall provide to the SDG&E Designated Control Center a 24-hour phone number where the facility operator may be reached.

For each GF, 20 MW or greater, an operating agreement shall be mutually developed (between the GF, CAISO and SDG&E) to facilitate scheduled and forced operating activities.

Any changes to SDG&E-required protection equipment or major equipment (e.g., transformers and breakers) at a GF must be submitted to SDG&E for review by the appropriate SDG&E engineer prior to the changes being made.

9.3.1 Daily Capacity and Energy Reports

A GF whose facilities may produce 1 MW or more, must provide data via telemetry to the CAISO according to the requirements of the CAISO Tariff. SDG&E may also require telemetry of data depending on the number of generators and the complexity of the transmission configuration. The GF operator shall provide and maintain the data circuits required to telemeter the GF. When such telemetering is inoperative, the GF operator shall report to the SDG&E Designated Control Center on an hourly basis the voltage reading and the real and reactive power flows at the GF terminal.

9.3.2 Voltage Control Operation and Other Service Requirements

The Generation Facility operator shall operate any voltage control (i.e., generator controls, shunt capacitors) at the direction of the SDG&E Designated Control Center and in accordance with provisions of applicable agreements and tariff(s), CAISO requirements, and other electric service schedules. The facility operator shall ensure the orders are understood and passed on to subsequent shift operator as appropriate to ensure that any relief or backup operator is aware of the current voltage instruction. The GF is responsible for the safe operation and interruption and de-energization of the customer-owned voltage control devices.

SDG&E's voltage schedules and power factor schedules shall treat all sources of reactive power in the service area in an equitable and non-discriminatory manner. The SDG&E Designated Control Center shall endeavor to provide the GF with voltage schedules and power factor (reactive power) schedules, if possible, at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the SDG&E transmission system. The GF shall operate their GF to maintain the specified voltage set-point (or power factor). If the GF is unable to maintain the specified voltage set point (or power factor), it shall promptly notify the SDG&E Designated Control Center. If the GF's voltage or power factors, at the point of interconnection, are outside of the specified values, SDG&E shall have the right to order a reduction or increase in output, or to disconnect the GF from the transmission system, if the plant's operation is adversely affecting the SDG&E transmission system.

Prime movers for GFs with power system stabilizers shall be operated on unrestrained governor control unless the Generation Facility operator and the CAISO system dispatcher otherwise agree for a temporary period. The standard governor droop setting shall meet WECC requirement PRC-001-WECC-CRT-1.2.

Whenever primary relays or protective devices are out of service, backup or secondary relays must be available to clear faults. When restoring any relays that have been out of service, the GF's designated representative shall verify that the contacts of any such relays, which are normally open, are in fact open. The GF must ensure that relays do not have standing trip output. **Note: The CAISO may have additional requirements for systems designated as CAISO Controlled Grid Critical Protective Systems. Refer to the CAISO Tariff available on the CAISO website (www.caiso.com).**

9.3.3 Paralleling To and Separating From SDG&E

The GF's designated representative shall notify the SDG&E Designated Control Center prior to paralleling or separating from the SDG&E system. For unexpected separations, the GF's designated representative will inform the SDG&E Designated Control Center of the nature of the problem (e.g., over-voltage, under-frequency, ground fault, remedial action) and report on any relay target operations. For safety and reliability, a mutually developed set of operating procedures between SDG&E and the IC must be documented prior to paralleling and before the facilities connecting the GF to SDG&E's transmission system are energized.

9.3.4 Work Authorizations and Switching Requests

The GF operator must request a work authorization from SDG&E a minimum of ten calendar days in advance of commencement of the requested work. SDG&E shall notify the GF at least three (3) business days in advance of any plans by SDG&E to take a clearance, which affects the GF.

Each interconnected facility shall have installed an approved disconnect or other switching device for operation by the GF as an isolating point. The disconnect must be capable of being locked open and accessible to SDG&E personnel.

9.3.5 Unusual or System Emergency Conditions

For all System Emergencies, the CAISO is responsible for managing the emergency and for restoration as specified in the CAISO Tariff. All GFs and System Resources that are owned or controlled by a Participating GF are (without limitation to the CAISO's other rights under the CAISO Tariff) subject to control by the CAISO during a System Emergency and in circumstances in which the CAISO considers that a System Emergency is imminent or a threat. The CAISO shall, subject to applicable CAISO Tariff provisions, have the authority to instruct a Participating GF to bring its GF on-line, off-line, or increase or curtail the output of the GF and to alter scheduled deliveries of Energy and Ancillary Services into or out of the CAISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

SDG&E is responsible for complying with all directions from the CAISO regarding management and alleviation of the System Emergency unless such compliance would impair the Health and Safety of personnel or the general public. As directed by the CAISO, SDG&E will be responsible for communicating with GFs regarding emergencies. Unusual operating conditions or other factors that have affected or may affect the CAISO Controlled Grid or SDG&E's transmission system (e.g., abnormal voltages or loading or unbalanced loading) must be reported to the SDG&E Designated Control Center as soon as possible. Conditions imperiling life or property shall be reported to the SDG&E Designated Control Center immediately. The SDG&E Designated Control Center shall be notified of any forced outage. The SDG&E Designated Control Center shall notify the GF of any unusual CAISO Controlled Grid or SDG&E conditions that may affect the GF. During any emergency, the facility operator shall follow the instructions of the SDG&E Designated Control Center

9.4 OTHER REQUIREMENTS

The GF operator shall notify the SDG&E Designated Control Center of any replacement, modification or removal of any interconnection facilities (e.g., transformer, breaker), changes in EMS/SCADA, (Emergency Management System/Supervisory Control and Data Acquisition), disconnects, relays, special protection equipment).

Note: Regardless of generator size, protective equipment designated as CAISO Controlled Grid Critical Protective devices utilize special CAISO procedures, as specified in the CAISO Tariff.

For the Interconnection Facilities listed above, the GF operator shall follow the manufacturer's minimum maintenance requirements on file for audit by the SDG&E Designated Substation Maintenance Supervisor.

- Results of four-year bench tests on all SDG&E-required relays (see SECTION 4).
- Results of recommended maintenance tests on interconnection circuit breakers and transformers.

The GF operator shall notify the SDG&E Designated Control Center:

- The time of any relay operations and targets of the relay that caused the GF to separate, if applicable.
- The time of any paralleling with and separations from the SDG&E system.
- The time of the change in voltage-control device set points (if applicable) and the time of change in the operating status (i.e., opened or closed) of any other voltage-control device (i.e., shunt capacitors or reactors).

9.4.1 Event Recorder

All generation facilities connecting to SDG&E's transmission system must have an event recorder that will enable SDG&E to make an after-the-fact determination of the status of the GF at the time of a system disturbance, should such a determination be required. The events should be recorded to sub-cycle resolution. The GF shall ensure the time reading is correct and synchronized via a high accuracy satellite clock.

9.4.2 Remedial Action Schemes

Where identified in the interconnection study and/or interconnection agreement, the GF may be required to participate in a RAS to maintain the reliable operation and performance of the SDG&E transmission system. The GF operator will be responsible to maintain the associated equipment and communications required for the reliable operation of the RAS at its own expense. The GF operator is also responsible for NERC compliance associated with the RAS equipment including maintenance and testing based on the latest version of PRC-012. The GF operator will be required to coordinate with SDG&E to perform scheduled testing of RAS including review of testing procedures, providing access and personnel to support testing activities, and scheduled outages to perform functional tests.

ATTACHMENT A. CONTROL AND PROTECTION CHECKLIST

Substation or Switchyard at which Generator is Interconnecting to SDG&E-Owned Transmission System_____

A. Site Drawings

1. Relay Functional 1-line
2. 3-line AC Schematic
3. Circuit breaker control schematic
4. Transformer protection schematic
5. Generator protection schematic(s)
6. Generator breaker control schematic(s)
7. Site Plan

B. Relay Settings

1. Transmission interconnection line relay settings (SDG&E must approve)
2. Step-up Transformer relay settings (SDG&E must approve over-current settings)
3. Generator relay settings (review only)

C. Apparatus Testing (In accordance with Manufacturer's Instructions or Good Utility Practice which may include but not be limited to the following:)

1. Transmission voltage circuit breaker(s)
    a. Power factor
    b. Contact resistance
    c. Timing
    d. Gas pressure switches
2. Relay circuit CTs
    a. Ratio
    b. Polarity
    c. Saturation
3. Transformer(s)
    a. Test report
    b. Power factor test (Doble)
    c. Insulation test (Megger)
    d. Transformer Turns Ratio test (TTR)
    e. Oil Quality/DGA
    f. Oil Fill Results (log, dewpoint etc.)
4. Generating Unit(s)
    a. Test Reports
    b. Neutral resistor rating (if used)

D. Control & Protection Testing

1. Protective relays
    a. Calibration reports
    b. Verify as-left settings
2. Protection trip test
    a. Transmission voltage Circuit Breaker(s)
    b. Generating Unit Circuit Breaker(s)
3. Verify close circuit controls, including synchronizing controls

E. In-service Testing

1. High voltage interconnection relays
2. Backup interconnection relays

F. Security

Substation fence installed and locked.

ATTACHMENT B. DEFINITIONS

AC	Alternating Current
ACSR/AW	Aluminum Conductors-Aluminum Clad Steel Reinforced
ACSS/AW	Aluminum Conductors-Aluminum Clad Steel Supported
ADR	Alternative Dispute Resolution
AL	Aluminum
ANSI	American National Standards Institute
AVR	Automatic Voltage Regulator
BESS	Battery Energy Storage System
BIL	Basic Lightning Impulse Insulation Level
CAISO	California Independent System Operator
CCVT	Coupling Capacitor Voltage Transformers
CDEGS	Current Distribution, Electromagnetic Fields, Grounding and Soil Structure Analysis
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
CRT	Criterion
CT	Current Transformer
CU	Copper
DC	Direct Current
DDR	Dynamic Disturbance Recorder
DFR	Digital Fault Recorder
DNU	Delivery Network Upgrade
DPG	Data Processing Gateway
DVAR	Dynamic VAR
EMS	Energy Management System
EMTP	Electromagnetic Transient Program
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
GF	Generating Facility
GIA	Generator Interconnection Agreement
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
IBR	Inverter-Based Resource
IC	Interconnection Customer
IC's IF	Interconnection Facilities owned and operated by the IC
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IF	Interconnection Facility
IFS	Interconnection Financial Security
IR	Interconnection Request
ISD	In-Service Date
kCMIL	thousand circular mils
kV	kilovolt
LGIA	Large Generator Interconnection Agreement
MC	Mission Control

MMA	Material Modification Assessment
MTA	Maximum Torque Angle
MVA	megavolt-ampere
MW	megawatt
NEMA	National Electrical Manufacturer Association
NERC	North American Electric Reliability Corporation
NLTC	No-Load Tap Changer
NRI	New Resource Implementation
OEM	Original Equipment Manufacturer
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
POCO	Point of Change of Ownership
POI	Point of Interconnection
POTT	Permissive overreaching transfer trip
PRC	Protection and Control
PSCAD	Power Systems Computer Aided Design
PSLF	Positive Sequence Load Flow
PSS	Power System Stabilizer
PT	Potential Transformer
PTO	Participating Transmission Owner
PTO's IF	Interconnection Facilities owned and operated by the PTO
PUTT	Permissive underreaching transfer trip
RAS	Remedial Action Scheme
RC	Reliability Coordinator
RFI	Radio Frequency Interference
RIG	Remote Intelligent Gateway
RMS	Root-Mean-Square
RNU	Reliability Network Upgrade
RTU	Remote Terminal Unit
RVC	Rapid Voltage Change
SDG&E	San Diego Gas & Electric Company
SER	Sequence of Events Recorder
SES	Substation Engineering Standards
SGIA	Small Generator Interconnection Agreement
SOP	System Operating Procedure
SPACE	Systems Protection and Control Engineering Department
SPES	Station Power - Energy Storage
SPS	Special Protection System
SSCI	Subsynchronous Control Instability
SSI	Subsynchronous Interaction
SSR	Subsynchronous Resonance
SSTI	Subsynchronous Torsional Interactions
SWC	Surge Withstand Capability
TCUL	Tap Change Under Load

TE	Transmission Engineering
TL	Transmission Line
TO	Transmission Owner
TPD	Transmission Plan Deliverability
UDC	Utility Distribution Company
UL	Underwriters Laboratory
UPS	Uninterruptible Power Supply
UTC	Universal Time Coordinated
UVLS	undervoltage load shedding
VAR	Voltage and Reactive Control (NERC)
VAR	volt-ampere
VSC-HVDC	Voltage Source Converters - High Voltage DC
WATP	Written Authorization to Proceed
WECC	Western Electricity Coordinating Council
XLPE	Cross-Linked Polyethylene

ATTACHMENT C. VERSION HISTORY

Update	Section(s)	Date
Original		July 2000
Updated and reformatted the entire handbook	All	August 21, 2008
• Inserted reference that optical metering unit CT's and PT's can be used under special circumstances • Inserted web- link to California Public Utility Commission (CPUC) Electric Rule 2 • Inserted reference to reactive power support and voltage control requirements for Small Generator	1.4 2.4 3.1	August 24, 2010
Deleted reference to California Public Utilities Commission (CPUC) Rule 21 interconnection requirements	3.5.2	June 22, 2011
• Updated Section 2.4.1 to include the SDG&E Addendum for the "no taps practice" • Updated the applicability portion of Section 4 • Added version history • Formatting Changes	2.4.1 4 All	January 22, 2016
• Added a new Section 3 titled "Substation Requirements" • Updated Sections 1, 2, 4, 5 and 6	All	November 30, 2016
• Updated Section 2.5.3 • Changed terminology from "SPS" to "RAS" when applicable	All	December 18, 2017
Updated and reformatted the entire handbook	All	April 24, 2023