Community Microgrid Technical Best Practices Guide

For Multi-Customer Distribution Microgrids

Inclusive of projects utilizing PG&E's Community Microgrid Enablement Tariff (CMET), Community Microgrid Enablement Program (CMEP), Microgrid Incentive Program (MIP), and other distribution microgrids

Document History

Revision	Date	Notes
1.0	12/22/20	Initial Version Issued
2.0	5/15/23	2023 major revision

Table of Contents

Tables

Figures

Acknowledgements

Schatz Energy Research Center (SERC):

PG&E would like to acknowledge the Schatz Energy Research Center at Cal Poly Humboldt for their extensive contributions to this guide. Specifically, David Carter, Jim Zoellick, Steve Richards, Marc Marshall, Kristen Radecsky, and Peter Lehman contributed. Their partnership and deep expertise in the development of cutting-edge microgrids has been invaluable. More information about SERC can be found at https://schatzcenter.org/.

Electric Power Research Institute (EPRI):

PG&E would like to thank EPRI for their review and inputs to this document, especially insights related to grid forming inverter requirements for islanded systems. Specific thanks to Jackie Baum, Wenzong Wang, Deepak Ramasubramanian, and Ajit Renjit for their extensive comments, consideration, and coordination on this effort. More information about EPRI can be found at https://www.epri.com/.

MPR Associates:

PG&E would like to thank Paul Duncan and John Schroeder for their helpful detailed review comments. More information about MPR can be found at https://www.mpr.com/.

1 Introduction

The purpose of this Community Microgrid Technical Best Practices Guide (Guide) is to provide information to help development teams understand the key technical concepts and approved means and methods for deploying multi-customer Community Microgrids (CMGs) on Pacific Gas & Electric's (PG&E) electric distribution grid. These projects may utilize PG&E's Community Microgrid Enablement Tariff (CMET), Community Microgrid Enablement Program (CMEP), and/or the Microgrid Incentive Program (MIP).[1] For single-customer microgrids or other grid-hardening resources, please visit www.pge.com/resilience for additional information.

The content is geared towards practicing professionals with some experience implementing renewable energy projects, and the intent is to use language to make the content accessible to a relatively broad audience. Capitalized terms and acronyms used in this document are defined in the Glossary at the end of this Guide.

This Guide is not intended to describe PG&E's programs, such as CMEP or MIP, or interconnection processes and tariffs. PG&E's Resilience Representatives, Resilience Solution Integrators, Distribution Engineers, Grid Innovation Engineers, and existing standards are the primary resources for project development teams. This Guide provides supplemental and supportive information and in cases where information presented here is contradictory, the information provided by those primary resources takes precedence. An overview of the 5-stage Community Microgrid process is provided in **Appendix A - Community Microgrid 5-Stage Process** Workflow.

Multi-Customer Community Microgrids represent a nascent approach to providing resiliency for communities within the PG&E service territory. The content of this Guide is intended to represent Good Utility Practice and as more Community Microgrids are deployed on the PG&E system, this Guide will be updated to reflect new information, opportunities, and requirements.

The current version of this Guide is based largely on the Redwood Coast Airport Microgrid in McKinleyville, California, because that is the first multi-customer Community Microgrid that has been deployed and is functional and operating on PG&E's Distribution System.

2 Community Microgrid Architecture

Microgrids come in many shapes and sizes. Community Microgrids are characterized by having multiple PG&E customers that are included inside the Microgrid Boundary. PG&E is responsible for providing safe and reliable electricity to these customers during both Grid-Connected and Islanded Operations. For that standard to be met, deploying a Community Microgrid on PG&E's Distribution System is a rigorous process. The degree of rigor depends on the specifics of the Community Microgrid being deployed.

[1] Please contact communitymicrogrids@pge.com for more information. CMET: ELEC_SCHEDS_E-CMET.pdf (pge.com), CMEP: www.pge.com/cmep. MIP to be launched in Q4 2023.

2.1 Bright Clean Line Principle

For a Community Microgrid to be successful, a close partnership between the CMG Aggregator and PG&E is required, and the roles and responsibilities of each partner must be carefully delineated. To separate those roles and responsibilities, the guiding principle used for the partnership can be represented as a "Bright Clean Line" between the Distribution System Operator (DSO) and the Generation System Operator (GSO). The DSO (PG&E) is responsible for the safe and reliable operation of the distribution circuit that hosts the Community Microgrid. The GSO (CMG Aggregator or authorized agent) is responsible for operating the grid forming generation source(s) that enable Islanded Operations within the constraints of the Interconnection Agreement(s) and Microgrid Operating Agreement.

2.2 Reference Architecture

Implementing Community Microgrids that follow an architecture that has previously been implemented by PG&E should be less difficult than other Community Microgrids with a more complex design. At this time, PG&E has approved the Redwood Coast Airport Microgrid (RCAM), which is a multi-customer Community Microgrid located in Humboldt County, CA. The reference architecture presented in this Section is based on the RCAM with minor design variations accommodated. Note that this reference architecture may be updated as more Community Microgrids are accepted and deployed on the PG&E system. A Single Line Diagram (SLD) with the Reference Architecture is provided in **Appendix C – Reference SLD for Reference Architecture CMET Projects**. In general, CMG Aggregators who desire to follow a streamlined path are encouraged to plan for a relatively simple microgrid design consisting of one dominant Grid-Forming Generator, one Microgrid Islanding Point, and the typical characteristics described in this Section.

2.2.1 Primary Grid Forming Generator

Community Microgrids with the Reference Architecture will have a dominant or Primary Grid-Forming Generator because they are the most straightforward to deploy and operate at this time. This Primary Grid Forming Generator may be rotating mass or inverter-based, however PG&E expects the predominance of these generators to be inverter-based. Some of the best practices below may not be applicable for machine based Primary Grid Forming Generators.

As described by EPRI in its 2021 technical brief "Performance Requirements for Grid Forming Inverter Based Power Plant in Microgrid Applications"[2], the following are best practice requirements for grid-forming inverter-based resources:

1. Ability to create an open circuit voltage at the point of interconnection of the inverter plant. Note that this characteristic is defined at the plant point of interconnection and not at the terminal of an individual inverter within the plant. This implicitly assumes that the inverter plant is capable of,
    a. serving its own auxiliary load, and

[2] *Performance Requirements for Grid Forming Inverter Based Power Plant in Microgrid Applications: First Edition.* EPRI, Palo Alto, CA: 2021. 3002020571

   b. operating in the absence of a synchronous machine.
2. Ability to synchronize and operate in conjunction with other sources of energy in the grid. These other sources can include conventional rotating machines as well as other forms of inverter plant control methods. This also includes different types of controllable loads.
3. Upon the occurrence of a large load/generation event, to have the ability to contribute towards arresting the increase/decline of frequency and also contribute towards the subsequent return of frequency to the nominal value.
   a. The contribution of the inverter should share the burden with other participating resources.
4. Contribute towards the provision of reactive power support and voltage regulation within the continuous operation region. For abnormal grid conditions, contribute towards aiding fast and stable voltage recovery.
   a. Regulate Voltage to meet Rule 2
5. If required by protection relay algorithms, contribute the requisite level and type of fault current. The implicit acknowledgment here is the understanding that the provision of fault current above a certain threshold might require changes/upgrades in the inverter hardware.
   a. Including the ability to provide negative sequence current during unbalanced fault
6. Contribute towards maintaining sufficient damping of naturally occurring oscillations in the power system following major disturbances.
7. Contribute towards minimization of unbalanced operation (within the continuous region of operation) and improvement of power quality of the network.

When a grid-forming plant is the only grid-forming generation source inside a microgrid, it should:

1. Regulate the steady state voltage at the point of interconnection to be within Rule 2 (or other ranges specified by the microgrid operator), when the grid-forming plant output is within its continuous power and current capability.
2. Maintain balanced voltage at its point of interconnection when it operates within the negative sequence current capability and total current (phase current) capability. The negative sequence current capability should be greater than x pu.
3. Maintain voltage total harmonic distortion (THD) at its point of interconnection to be below y% when operating within its physical limits. And its output current should support a crest factor higher than z.

The values x, y, and z depend on particular microgrid characteristics and should be determined based on analysis of the particular microgrid.

Both the PG&E Circuit and the Primary Grid-Forming Generator must be able to energize the microgrid from a fully de-energized state. This is commonly referred to as a “Blackstart.” Blackstart capability should be designed such that the Primary Grid-Forming Generation is sized to support the microgrid load plus the inrush current required during a Blackstart. It may be possible to reduce Blackstart load by excluding disputable load and adding it to the microgrid load after inrush current has stabilized. This would require advanced coordinated controls and testing.

2.2.1.1 Blackstart

Blackstart is an important aspect of microgrid operation. In the scope of this architecture where there is only one grid-forming resource, it should have the ability to Blackstart itself (without any external power supply) including the local auxiliary load and establish an open circuit voltage at the plant point of interconnection. To achieve this, the grid-forming plant is required to have its own power supply (e.g., an uninterruptible power supply (UPS)) that can boot the control circuits and communication modules inside the plant. Subsequently, the grid-forming plant needs to crank start the whole microgrid following a predetermined Blackstart sequence. During Blackstart, voltage and frequency must be maintained within acceptable limits following the ITIC (CBEMA) curve or other trip/ride through settings such as established in IEEE 1547-2018 or the forthcoming IEEE 2800.

While a large Community Microgrid could be Blackstarted in sections using a series of smaller Grid-Forming Generators, each sized for their respective section of the microgrid, this would require a more complicated architecture. Therefore, the study and approval process are likely to take significantly longer.

2.2.1.2 Battery Energy Storage Systems

Battery Energy Storage Systems (BESS) are good candidates for the Primary Grid-Forming Generators in Community Microgrids. PG&E's Reference Architecture includes a BESS with the following characteristics:

- The BESS inverter Nameplate Rating (MVA not MWh) is at least three times greater than the aggregated PG&E-owned distribution transformer capacity inside the electrical boundary of the microgrid. This rule-of-thumb provides a reasonable starting place for sizing the Primary Grid-Forming Inverter. During the Community Microgrid Technical Consultation a PG&E Engineer will evaluate the proposed size of the Primary Grid-Forming Inverter relative to the peak loads within the Microgrid Boundary. This evaluation may identify an opportunity for the CMG Aggregator to adjust the size of the Primary Grid-Forming Inverter.
- The manufacturer verifies that the BESS is capable of Blackstarting the entire Community Microgrid circuit with no help from other sources.

2.2.1.3 Synchronous Generators

In some cases, Synchronous Generators are allowed to operate in parallel with the Distribution Grid, when additional protective features are included, which may include Direct Transfer Trip (DTT). A Synchronous Generator can act as the Primary Grid-Forming Generator for the Community Microgrid with the Reference Architecture if it meets the requirements in Section 2.2.3. Please refer to PG&E Distribution or Transmission Interconnection Handbook for interconnection and protection requirements for Synchronous Generators. Synchronous Generators may also be limited under CMEP or MIP eligibility guidelines; be sure to discuss with PG&E. PG&E recommends that CMG Aggregators considering deployment of synchronous generators in Community Microgrids review appropriate program or tariff eligibility standards and discuss permitting pathways with the local Air Quality Management District early in the planning process.

2.2.2 Additional Requirements for All Grid-Forming Generators

Any Grid-Forming Generator in a Community Microgrid, whether it fits within the Reference Architecture or not, will be required to have the following characteristics:

- The DER controller can be interfaced to a PG&E Owned Microgrid Controller
- The DER controller can regulate frequency and voltage in Grid-Forming mode, share loads with other grid-forming generators, and regulate over-generation during Islanded Operations.
    - These frequency and voltage settings should be real-time settable to enable coordinated centralized control for load sharing and DER curtailment when islanded.
- The DER control should comply with the standard interconnection agreements within 2 seconds of the Microgrid Islanding Point (MIP) breaker closing during a retransfer to grid-connected state. *If* the inverter changes modes while islanded, it should automatically change within 2 seconds of MIP closure to comply with grid codes.
- If the DER controller loses communication with the MIP Recloser Control and therefore cannot determine the position of the MIP recloser or Circuit Breaker it will remain in grid-connected compliance mode and adhere to existing interconnection agreements.
- Its PCC circuit breaker must be supervised by redundant protection relays that can operate with one settings group for Grid-Connected Operations and one settings group for Islanded Operations.
    - The protection relays at its PCC must have telemetry to the PG&E Microgrid Controller and be able to switch from a grid-connected protection settings group to an islanded settings group within two seconds of the MIP recloser or circuit breaker opening during a transition from Grid-Connected to Islanded State and vice versa.
- The DER will provide telemetry to PG&E on status, output, and other attributes as needed

Note that Isochronous Control can also be used when there is only one Grid-Forming Generator planned for the Community Microgrid. However, Compared with Droop Control, Isochronous Control is less able to support because it does not allow load sharing between multiple GFM sources during Islanded Operations. Additional technical studies may be required.

2.2.3 Points of Isolation from Distribution System

The majority of PG&E's distribution system is based on hub and spoke architecture, with the substations as hubs and the distribution circuits as spokes. Community Microgrids adopting the Reference Architecture can either have a single Microgrid islanding Point (MIP) or have multiple Microgrid Islanding points (MIPs). If the microgrid is located at the end of the distribution circuit we call this an "End-of-line" microgrid and will require a single MIP. Microgrids in the middle of a feeder are called "Mid-Feeder Microgrids" and will require multiple MIPs. Currently, for Mid-Feeder Community Microgrids that are seeking a streamlined deployment path, PG&E recommends that Break-Before-Make Transitions be used for transitions from Grid-Connected to Islanded State. However, using Seamless Retransfers from Islanded to Grid-Connected State in Mid-Feeder Microgrids are not likely to slow the deployment process significantly for reasons described below.

2.3 Alternate Architecture

Alternate Architecture generally includes anything not described above.

If a given Community Microgrid location requires multiple MIPs, the design will be more complex due to the need to coordinate more devices when transitioning between Blue Sky and Islanded Operations. In any case, there will be one MIP that is closest to the substation, or upstream of all the other MIPs. This MIP and its Recloser Control or Protect Relays will become the Primary MIP and other MIPs will be Secondary MIPs.

For Mid-Feeder Microgrids, seamless Transitions from Blue Sky to Islanded State will typically have to be tested with Control Hardware-in-the-Loop (CHIL) and potentially Power Hardware-in-the-Loop (PHIL) in a Real-Time Simulation (RTS) environment and will be more challenging to accomplish. Operationalizing seamless transitions of mid-feeder microgrids is an area of on-going research. Additional equipment, communication pathways, and best practices not discussed in this document may be required.

The Primary Grid-Forming generator's controller will need confirmation that all MIPs have tripped within two seconds of detecting a fault, which may be difficult depending on the geographic spread of the various MIPs and associated communication latencies. When performing a seamless transition, two seconds is the maximum time a Grid-Forming inverter can remain in Grid-Forming (or a "hybrid" mode if applicable) while awaiting confirmation that all POIs are open before the inverter must revert to Grid-Following mode as required by IEEE 1547 and UL 1741. This reflects PG&E's anti-islanding limits and prevents an inverter from backfeeding into a fault condition.

For Mid-Feeder Community Microgrid designs using Break-Before-Make Transitions from Grid-Connected to Islanded State, the need for RTS based testing will be evaluated on a case-by-case basis. For these types of microgrids, Seamless Transitions from Islanded to Blue Sky State are slightly more challenging than for End-of-Line Microgrids, but may be achievable for most major manufacturers of Grid-Forming Generators.

In principle, a Seamless Retransfer sequence for Mid-Feeder Community Microgrids could follow this general form:

- PG&E personnel repair the cause of the fault between Primary MIP and Substation.
- The Primary MIP Recloser Control or Protection Relay detects that the Distribution System is energized from the Substation.
- If no alarms are pending, the PG&E Microgrid Controller issues a Retransfer command.
- The Generation Controller and Primary Grid-Forming Generator synchronize the Microgrid to the Distribution System across the Primary MIP.
- The Recloser Control or Protection Relay at the Primary MIP closes the Line Recloser or Circuit Breaker after confirming synchronization requirements are met.

- After the Primary MIP is closed, the Recloser Controls or Protection Relays at the Secondary MIPs close the Line Reclosers or Circuit Breakers that they supervise in a pre-defined sequence to re-energize customers on the Load-Side of each MIP.

In general, Mid-Feeder Microgrids will not begin Islanded Operations unless there is a fault between the Substation and the Primary MIP. Any fault on the Load-Side of a Secondary MIP will be isolated by the Recloser Control or Protection Relay supervising that MIP and the Primary MIP will remain closed keeping the microgrid powered by the substation. PG&E personnel will repair the cause of the Load-Side fault and then clear the associated alarm in the PG&E Microgrid Controller. Then a PG&E Operator will use the PG&E Microgrid Controller to manually close the applicable Secondary MIP to re-energize those customers.

3 Microgrid Operational Modes

The basic operational modes for Community Microgrids are Blue Sky, Islanded, and Microgrid Disabled.

3.1 Blue Sky

Blue Sky Mode refers to normal grid-connected operations. The Distribution Feeder hosting the Community Microgrid is healthy and all DERs, especially those capable of Grid-Forming operation, are in interconnection compliance mode and operate in conformance with their standard interconnection agreements, including any flow constraints on resources for producing/generating or charging/consuming. The protection relays located at the MIPs and PCCs in the microgrids are in their Blue-Sky settings group and monitoring for signs of electrical faults on the feeder.

3.2 Islanded

Islanded Mode becomes active when the MIP(s) open and the DERs that are capable of Grid-Forming operation are in Grid-Forming Mode. The loads inside the Electrical Boundary are being met precisely by real-time adjustments in real and reactive power injection or absorption by the Grid-Forming Generators[3]. While islanded, the protection relays located at the MIPs and PCCs operate in their Islanded Mode settings group and monitor for signs of electrical faults within the microgrid Electrical Boundary. Some interconnection settings may also be changed as necessary to support the microgrid provided those settings revert to their original state during grid-connected Blue-Sky operations.

3.2.1 Voltage and Frequency Regulation

Voltage and frequency must remain within the limits specified in PG&E Electric Rule 2 during Islanded Operations. The Primary Grid-Forming Generator will use one of two control modes to accomplish this; Isochronous Control or Droop Control.

Isochronous Control is applicable to Synchronous Generators where the rotational speed of the generator is managed to maintain constant speed corresponding to 60 Hz. Changes in Real Power load results in more or less energy needed to keep the rotational speed constant. Islanded voltage is

[3] There may be other resources within the microgrid (grid-following) that also contribute to the support of microgrid needs through injection of real and reactive power including fixed output, freq-watt, volt-watt, or volt-var control modes

regulated by managing the field excitation voltage in the Synchronous Generator, which provides all the reactive power needed to maintain stable system voltage.

Isochronous Control is recommended for Community Microgrids using a Synchronous Generator for the Grid-Forming Generator. Note that in this case managing Over-Generation and load sharing with other Grid-Forming Generators will be more difficult as compared to using an inverter using a Droop Control scheme as the Primary Grid-Forming Generator.

Droop Control uses proportional control to react to a given deviation from the desired voltage or frequency (nominal setpoint) by either injecting or absorbing real power (frequency droop) or reactive power (voltage droop). Voltage regulation during Islanded Operation is done using two voltage droop settings: 1) the nominal voltage setpoint, and 2) a percentage of Nameplate Reactive Power capacity that will be dispatched in response to a given change in system voltage. Reactive power is injected into the microgrid circuit if the voltage is below the nominal setpoint and absorbed from the microgrid circuit if the voltage is above the setpoint.

Similarly, microgrid frequency is regulated using two frequency droop settings: 1) a nominal frequency setpoint (60Hz), and 2) a percentage of Nameplate Real Power capacity that will be dispatched in response to a deviation from the nominal setpoint. Real Power is injected if the frequency is below the nominal setpoint and reduced or absorbed if the frequency is above the setpoint.

For Reference Architecture projects with a Primary Grid-Forming Generator consisting of a BESS Inverter (no other Grid-Forming Generators), the voltage and frequency droop settings should be set to maximum available settings in the device to provide a “stiff” islanded microgrid. The resulting voltage and frequency will fluctuate within very narrow bands around the nominal setpoints as the Grid-Forming inverter responds aggressively to changes in islanded voltage and frequency resulting from Reactive and Real power load fluctuations inside the Microgrid Boundary.

Droop control can also be used to load-share between multiple Grid-Forming Generators in a Community Microgrid. In this case the voltage and frequency droop settings are set the same in each Grid-Forming Generator controller so that the load is assigned proportionally to the Nameplate capacities. Droop control can also be used to allow a Grid-Forming inverter to load share with an Isochronous Synchronous Generator, however this requires more advanced generation control scheme.

Whether Droop Control or Isochronous Control is implemented, the goal is to provide a “stiff” grid when islanded. This means that the frequency and voltage are both very stable in response to step changes [4]in Real and Reactive Power loads while islanded, with only minor deviation from the values found in Electric Rule 2.

3.2.2 Load Shedding

Load shedding may be necessary if the Project Resource(s) lack necessary energy reserves or energy inputs such as state of energy (SOE) drops below a low setpoint during Islanded Operations. Some or all

[4] Currently PG&E is unable to define a specific expectation that the system will be stable for a XX% step change in real power and will be evaluated on a case-by-case basis.

the microgrid loads can be shed at various SOE setpoints in order to prioritize critical loads. PG&E reserves the right to prioritize these loads as necessary. Typically load shedding is accomplished by tripping a motorized circuit breaker that has telemetry to the Generation Controller. Other forms of load shedding include cloud-based signals to distributed loads such as heat pump water heaters, EV chargers, or HVAC systems, for example. During extended outages loads can be restored as the SOE of the Grid-Forming BESS rises due to increased output from generation on the microgrid circuit. Typically, the last level of load shed is the entire microgrid falling back to the most critical load, which is the Station Battery charger. If the Station Battery charger becomes de-energized, then the microgrid control system will need to continue running on the Station Battery for a period of time. PG&E recommends at least 8 hours before shutting down. PG&E recommends that design teams prioritize keeping the Station Battery charger energized under all but the most extreme conditions because restarting the controls from a powered-down state could be quite involved, depending on the design specifics. Station Battery design is standardized under IEEE 485 and further information is available in Appendix T of PG&E's Transmission Interconnection Handbook.

Another type of load shedding is fast load shedding in response to decreasing frequency. If the Grid-Forming Generation in the microgrid is beginning to exceed its steady state current production the frequency will begin to decrease. In this case it may be possible, with appropriate controls, to shed non-critical loads fast enough to avoid tripping the Grid-Forming Generation offline and de-energizing the entire microgrid.

3.2.3 Over-Generation Mitigation

During Islanded Operations it is possible that the net load could become negative if there is a significant amount of Behind-the-Meter (BTM) solar installed inside the Electrical Boundary. Even if this does not seem likely when the project is initially designed, PG&E recommends that CMG Aggregators design Over-Generation mitigation into the microgrid design to account for future DER growth inside the microgrid. DER growth that exceeds the design mitigations for Over-Generation in the microgrid may require a re-study of the microgrid islanding operations.

Depending on the type of Grid-Forming Generators in the islanded microgrid, a variety of failures can occur if Over-Generation is not properly mitigated. For a Grid-Forming BESS, the excess current can be absorbed by the BESS until the SOE reaches its maximum capacity. If no Over-Generation mitigations are in place, the frequency would start to rise because there is more real power being generated than consumed in the microgrid. For Synchronous Grid-Forming Generators, Over-Generation mitigations are needed to prevent a reverse power condition at the generator's PCC and tripping of the Circuit Breakers, causing the microgrid to become de-energized.

Over-Generation mitigations typically include one or more of the following strategies:

- A motor operated circuit breaker at the PCC for the Grid-Following inverters controlled by the Generation Controller, allowing it to trip the circuit breaker.

- Telemetry between the Generation Controller and the Grid-Following Inverter controllers, allowing the Generation Controller to cause the Grid-Following Inverters to curtail when necessary.
- In the case of a synchronous generator-based DER, load sharing through Droop Control and anti-motoring generator protections can be employed.

Of the methods described above, tripping the DERs PCC circuit breaker is the most certain but least elegant approach, and is primarily applicable to large DERs (as a percentage of peak load inside the Electrical Boundary).

Using direct telemetry connections to DER inverters that are near the Generation Control Rack is a robust approach. If the DER inverters are distributed and remote, cloud or radio-based telemetry may be possible to be used. Note that interfacing the Generation Controller to multiple DER inverters can be time consuming during design and commissioning.

An emerging approach to mitigating over-generation during Islanded Operations is to take advantage of the Smart Inverter frequency-watt curves to cause distributed Smart Inverters to curtail by slightly raising the nominal frequency of the microgrid. For smart inverters installed after February 2019, carefully coordinated frequency-watt curtailment curves could be used in coordination with minor, intentionally controlled increases in islanded frequency (often referred to as “frequency shift”) to cause the inverters to automatically curtail when the frequency on the islanded microgrid reaches a predetermined value (60.5 Hz for example). This approach likely requires settings changes on the grid following inverters located within the microgrid boundary. Since this method has not yet been implemented on PG&E’s system, additional coordination with PG&E from the early stages of the project and RTS testing may be required.

3.2.4 Duration

The duration of Islanded Operation is a function of the amount of energy available to generate electricity and the net aggregated load within the Electrical Boundary. Available energy sources could include stored energy (kilowatt hours) in a BESS, solar radiation, wind, fossil fuels[5] such as diesel or natural gas, biofuels, or stored hydrogen. The net aggregated load is the real-time difference between energy consumed by customer loads and energy produced by variable Grid-Following energy resources like rooftop solar inside the Electrical Boundary.

PG&E has no minimum duration requirement for Community Microgrids deployed on its system under the CMEP program. The Microgrid Incentive Program requires that projects have a minimum island duration of 24 hours. Please check with your PG&E representative. PG&E’s interest is in supporting community-led resilience projects, while ensuring that the level of service provided under post-project

[5] Note that to be eligible for the Community Microgrid Enablement Program (CMEP), the grid-forming generation technologies must comply with the emission standards adopted by the State Air Resources Board pursuant to the distributed generation certification requirements of Section 94203 of Title 17 of the California Code of Regulations

conditions is equal to or better than under pre-project conditions for all customers in and adjacent to the microgrid.

Since Community Microgrids are complex, time consuming, and expensive to deploy, CMG Aggregators are encouraged to plan for Islanded Operations that can support critical loads for as long as five days. This target should result in meaningful resilience services for host communities in light of continuing risks of seasonal wildfires or other emergencies. Sizing the DERs in the microgrid to achieve the community's desired duration can be accomplished using computer modelling tools, including tools such as HOMER or DER-CAM.

3.3 Microgrid Disabled Mode

Microgrid Disabled Mode is the Failsafe State for Community Microgrids with the Reference Architecture installed on PG&E's Distribution System. In this mode the microgrid circuit will operate the same as a standard PG&E distribution circuit without a microgrid.

- The MIP Line Reclosers will remain closed if a fault occurs between the Substation and the Primary MIP so that, if the Feeder is de-energized at the substation, the microgrid circuit becomes de-energized. When the Feeder is re-energized the microgrid circuit also becomes re-energized.
- The Primary MIP Line Recloser will open and lockout if a fault is detected within its zone of protection downstream of its position on the Distribution System.
- The Primary Grid-Forming Generator is only allowed to operate in grid interconnected compliance mode.

This mode can be automatically asserted by the MIP Recloser Control or PG&E Microgrid Controller in response to Priority Alarms or manually by PG&E operators if an emergency operational need arises, such as switching the feeder to another substation bank.

4 Transitions

PG&E controls all transitions between Grid-Connected and Islanded states for Community Microgrids installed on its system. The PG&E MIP Control Relay will lead transfers from Grid-Connected to Islanded state and supervise synchronization and closing of the MIP Line Recloser or Circuit Breaker during transitions from Islanded to Grid-Connected states.

Transitions between Grid-Connected and Islanded states can either be Seamless or Break-Before-Make. However, Community Microgrids that plan to use Seamless transitions must also provide Break-Before-Make transitions and provisions for PG&E operators to select between the two in the PG&E Microgrid Controller. This is because Seamless transitions are relatively uncommon at the utility level and their efficacy must be ensured by the manufacturer of the Primary Grid-Forming Generator and proven in the field before they are used routinely. Example control sequences for transitions are shown in the 7.2.1 Sequence Diagrams Section of this Guide.

4.1 Seamless

Seamless transitions are preferred as they provide for a better customer experience. However seamless transitions cannot be guaranteed and break-before-make transitions may be preferred based on feasibility and operational simplicity in some situations. All Community Microgrids must be able to perform Break-before-make transitions.

4.1.1 Grid-Connected to Islanded

In a seamless transition from Grid-Connected to Islanded state, the Grid-Forming Generator must be paralleled with the Distribution System and operating in Grid-Following mode at the time the transition occurs, and then rapidly switch between Islanding and grid-connected compliant modes while supporting the aggregated loads within the Microgrid Boundary without interruption. Therefore, inverters wishing to perform seamless transitions must have the ability to transition from grid-connected compliant operations to island GFM operation without disrupting local power.

As noted previously in this Guide, a Synchronous Generator may be used as the Primary Grid Forming Generation, with the proper protection equipment. CMG Aggregator teams should reference PG&E Distribution Interconnection Handbook (DIH) and Transmission Interconnection Handbook (TIH) for technical requirement information. If the Synchronous Generator is permitted to operate in parallel with the Distribution Grid in Blue Sky Mode, seamless transitions to islanded state may also be possible with careful review and coordination with the generator manufacturer and PG&E engineers.

Even if Seamless Transitions are used by PG&E routinely for Blue Sky Mode, their performance is a function of the type of external fault that causes the MIP Line Recloser or Circuit Breaker to open. Under certain fault conditions (typically low impedance faults that may occur outside the microgrid boundaries) the seamless transition may fail, in which case the Primary Grid-Forming Generator should Blackstart the Community Microgrid automatically within a couple of seconds.

4.1.2 Islanded to Grid-Connected (Retransfer)

For Retransfers, the PG&E MIP Control Relay will monitor the Distribution System to determine when the Retransfer should occur. The PG&E Microgrid Controller will then command the Generation Controller to execute the Retransfer sequence. The Generation Controller and Grid-Forming Generator's embedded Controller will coordinate to synchronize the Community Microgrid to the Distribution System and issue a close command to the MIP Control Relay. The MIP Control Relay will then verify that synchronization conditions are met and close the MIP Line Recloser or Circuit Breaker. The state of the Recloser will be visible at all times to the PG&E Distribution Control Center.

If a Synchronous Generator is used as the Primary Grid-Forming Generator, a Seamless Retransfer can be used only when the proper protection is in place and settings are approved by PG&E.

4.2 Break-Before-Make

Break-Before-Make transitions involve completely disconnecting one electrical Distribution source from the Community Microgrid loads, resulting in a momentary loss of power (generally a few seconds), and then immediately connecting the other source. The MIP Control Relay and the Grid-Forming Generators PCC Protection Relays ensure that the Community Microgrid circuit is de-energized and no electrical faults are present before either source, the Distribution System or the Grid-Forming Generator, is connected to the Community Microgrid circuit.

The length of time it takes to switch between sources varies from around 2 to 15 seconds for transfers from Grid-Connected to Islanded State, depending on whether the Primary Grid-Forming Generator is inverter based or a Synchronous Generator that has to start an engine before it can generate power. For Retransfers, the Break-Before-Make transition typically takes a second or two because it is a relatively simple matter, following synchronization, of opening the PCC Circuit Breakers for the Grid-Forming Generators and then closing the MIP Line Recloser or Circuit Breaker.

For Mid-Feeder Microgrids with multiple MIPs, the Primary MIP should close first to energize the Community Microgrid Circuit and then the Secondary MIPs should be closed with a delay of 5 seconds or greater between each closure event.

5 Sizing Grid-Forming Generation

As part of the consultation stage of the 5-stage process workflow (see **Appendix A - Community Microgrid 5-Stage Process** Workflow), PG&E will help the CMG Aggregator define the Microgrid Boundary so that the process of determining how much generation will be needed to support islanded operations can begin. The PG&E Resilience Solution Engineer will gather information on the Distribution System within the Microgrid Boundary such as a complete list of distribution transformers and a Pocket Load Analysis, which will contain the coincident peak loads within the Microgrid Boundary as well as daily and seasonal load profiles. This information will be critical for sizing the Grid-Forming Generation.

For Community Microgrids with Reference Architecture that are using an inverter-based resource as the Primary Grid-Forming Generator, PG&E currently requires the Project Resource to perform Blackstart and meet fault duty requirements. Therefore, PG&E recommends sizing the inverter Nameplate Apparent Power of the Primary Grid Forming Resource rating to be at least three times the sum of the nameplate ratings of the PG&E distribution transformers inside the Microgrid Boundary.

The following points are provided to further enumerate the rationale and need for oversizing of inverter-based resource only microgrids:

Regarding the need for a resource to be oversized for a microgrid there are two primary reasons, both of which could be characterized as abnormal/transient conditions:
Protection Needs:

- It is critical that any faulted conditions be detected and isolated for public safety as well as equipment safety and health
- Historically over current detection methods have been used to detect and isolate faults on the system
    - To correctly distinguish between a faulted condition and other short term transient conditions of load changes (AC, motor starts, etc) industry has relied on two factors; magnitude and duration
        - To confidently identify a fault a magnitude of 2-3 times the normal rated current is sufficient to make a determination.

        - Additionally duration above a pre-determined threshold can help with this determination, though again for the sake of safety it is desirable to limit this duration to as short as possible

Blackstart (cold-load-pickup, in-rush):

- PG&E is requiring all microgrids to be capable of starting from a de-energized state (blackstart, break-before-make, drop and pickup) as seamless transitions cannot be guaranteed.
- During these initial starting conditions it is expected that there will be an increased current demand exceeding the steady state normal operations peak demand. This is driven by several factors:
    - Transformer magnetizing current needs
    - In-rush currents for motor starts (A/C and other motors)
    - Simultaneous load energization
        - Many loads go through cycles of higher and lower demand (refrigerator kicks on and off as needed). However during this blackstart condition all loads may initiate and begin their higher demand phase at the same time which is not typically seen under normal conditions given the diversity of loads and their operations.

For the above detailed reasons, current best practice for inverter based resources (e.g. BESS) is to size the resource 2-3X the normally expected peak load of the microgrid or the aggregate nameplate of the service transformers.

This is a guideline and other technical solutions may be considered provided the Project Resource meets Blackstart and fault duty requirements. As mentioned previously in this Guide, during the Community Microgrid Technical Consultation the Islanding Study Engineer will evaluate the proposed size of the Primary Grid-Forming Inverter relative to the peak loads within the Microgrid Boundary and this may result in an opportunity for the CMG Aggregator to adjust the size of the Primary Grid-Forming Inverter.

For Reference Architecture projects using Synchronous Generators as the Primary Grid-Forming Generator, industry-standard sizing recommendations for standby generators suggest that peak load should be no greater than 80% of rated generator output, leaving a minimum 20% safety margin to account for future requirements and unforeseen load peaks and inrush conditions. The generator must also have the ability to generate three-phase fault current of at least 250% of its Nameplate Apparent Power rating.

In addition to the size requirements, the Primary Grid-Forming Generation must also meet requirements as set forth in 2.2.1 Primary Grid Forming Generator:

6 Interconnection Processes

The installation of a microgrid will typically require the interconnection of distributed energy resources to PG&E's Distribution System (e.g., solar PV, fuel cell generator, Li-ion battery energy storage, or motor generation). Interconnection of these distributed resources will require the completion of a standard interconnection process with PG&E.[6] These interconnections will fall under one of two processes. Distributed energy resources being connected behind a retail electric meter will follow the Rule 21 interconnection process. Resources not being connected behind a retail meter, typically referred to as Front-of-the-Meter systems, will follow the wholesale distribution interconnection process. These wholesale systems are still connected behind a meter, but it is a wholesale meter rather than a retail meter. This Section of the Guide briefly describes these two interconnection processes and highlights key aspects. Additional resources regarding interconnection to PG&E's system can be found on the Interconnection and Renewables web page.

6.1 Deciding Which Interconnection Path to Take

The first decision to be made with regard to interconnection is to decide which path should be taken for a particular distributed energy resource. This decision is primarily based on how the resource will be operated during "Blue Sky" grid-connected mode. If the goal is self-generation to offset electric bills for a single electric account or a group of immediately adjacent accounts that all belong to one customer, then the Rule 21 path can enable this.

If the generator is sized larger than the net annual load [Confirm w/ Tariff language], then it will not be eligible for net metering[7]. Larger generators can be interconnected as wholesale generators and can sell power directly to PG&E, sell power through bilateral contracts, or participate in the California Independent System Operator (CAISO) wholesale electricity market. Wholesale generators can be interconnected under the CPUC-regulated Rule 21 tariff, as a Rule 21 Export project, or the FERC-regulated Wholesale Distribution Tariff. Rule 21 Export projects are required to obtain Qualifying Facility status and will sell all exported power to PG&E under a power purchase agreement entered into pursuant to the Public Utility Regulatory Policies Act of 1987 (PURPA).

6.2 Rule 21 Interconnections

Electric Rule No. 21 describes in detail the requirements for a Rule 21 interconnection. The Rule 21 interconnections process applies to all distributed energy resources being connected behind a retail electric meter, including net metered generation and energy storage facilities and generators and storage facilities that do not sell exported power to the grid.

The net metering tariff - Electric Schedule NEM2, Net Energy Metering Service - includes a number of sub-schedules that cover various types of NEM interconnections. These include:

- NEM2S (standard net energy metering) – Applies to solar and/or wind generating systems ≤ 30 kW.

[6] Note that the standard interconnection process will occur in parallel with the Microgrid Islanding Study process, and the completion of both of these processes will be required as inputs to the Microgrid Operating Agreement.
[7] Note that in order to be eligible for net metering, the generating resource must be sized no-greater than to offset part or all of the customer's own annual electrical requirements.

- NEM2EXP (expanded net energy metering) – Applies to solar and/or wind generating systems and other eligible Renewable Electrical Generation Facilities > 30 kW .
- NEM2MT (net energy metering multiple tariff) – Applies to facilities that include both NEM-eligible and non-NEM-eligible generators. These facilities require special metering, non-export relays, a certified power-control configuration, or a functionally equivalent non-export configuration to ensure that only the NEM-eligible generation is credited under the NEM2 tariff. A NEM2MT interconnection can often be applicable for larger battery storage systems that do not meet NEM-paired storage requirements.
- NEM2A (net energy metering aggregation) – Applies to aggregate net metering arrangements where load aggregation is available to an eligible customer-generator that has load served by multiple meters located on a property where an eligible generator is located and on adjacent or contiguous property if those properties are solely owned, leased, or rented by the eligible customer-generator.

In addition to these NEM2 sub-schedules, there are additional NEM tariffs that cover other configurations, including:

- NEM2V (virtual net energy metering) – Applies to multi-meter and/or multi-tenant properties where a NEM-eligible generator provides service to individually metered electric account(s) serving tenants and/or common areas.
- NEMFC (net energy metering for fuel cell customer-generator) – Applies to facilities that install an eligible fuel cell electric generator[8].
- RES-BCT (Schedule for Local Government Renewable Energy Self-Generation Bill Credit Transfer) – Applies to local government facilities only. Allows an eligible renewable generation facility to be installed at one location and energy generated to be credited to multiple government accounts at other locations.

All of these NEM interconnections go through the Rule 21 interconnection process. Prior to engaging in this process, it is recommended that key information be compiled regarding the proposed generating facility. Required information includes: interconnection location, interconnection voltage, export capacity, equipment specifications, single line diagram and site plan. A sample Rule 21 Interconnection Application form is filed with the CPUC as form 79-1174-02.

If the interconnection application is submitted under the Fast Track Review Process, a preliminary screening will be performed, and if needed, a supplemental review. If the project does not meet the Fast Track criteria, a detailed study process will be required to ensure a safe and reliable interconnection. The detailed study process could include an Independent Study Process, a Distribution Group Study Process, or a Transmission Cluster Study Process. A customer may also opt to apply directly for the Detailed Study Interconnection Review Process.

[8] This tariff is only eligible for fuel cell generators that commence operation before Dec. 31, 2021.

The results of the screening and detailed study process will include a determination of what transmission and distribution system upgrades and special facilities will be required to accommodate the proposed generator interconnection. These results will be provided to the applicant along with a non-binding cost estimate for the upgrades and facilities.

Once the required upgrades and facilities are agreed upon, an interconnection agreement can be drafted and executed. After the generator is installed, it will be tested and inspected during PG&E required commissioning tests (Pre-Commissioning). Any required metering will then be installed, and when all required milestones are satisfied, PG&E will issue full permission to operate.

Note that as part of the Detailed Interconnection Study Process, there is a System Impact Study and an optional Facilities Study. The second step, the Facilities Study, allows for a more reliable cost estimate, primarily for Network Upgrades. The Detailed Interconnection Review Process allows for an iteration in the process where the import and export capacity can be refined to potentially mitigate system upgrade costs, if desired.

6.3 Wholesale Interconnections

The wholesale interconnection process is for generators that will sell excess power directly to PG&E or on the open market through PG&E's distribution or transmission network. These interconnections can occur either at the distribution level (generally below 60 kV and governed by FERC or the CPUC), or at the transmission level (greater than 60 kV) and governed by the CAISO tariff.

6.3.1 Distribution Level Interconnections

The FERC wholesale generator interconnection at the distribution system level is similar to the Rule 21 interconnection process in many ways. It includes a PG&E online application process followed by a Fast Track, Independent Study, or Cluster Study review process. However, rather than this process being dictated by the CPUC regulated Rule 21, this distribution level wholesale interconnection process is dictated by the FERC regulated Wholesale Distribution Tariff, or WDT. Also, analogous to the Rule 21 interconnection process, there is a System Impact Study and then an optional Facilities Study as part of the process.

6.3.2 Transmission Level Interconnections

Projects that choose to interconnect at the transmission level will generally interconnect at line voltages greater than 60 kV and will be governed by the CAISO Open Access Transmission Tariff. This process is facilitated entirely by the CAISO, nonetheless, it is similar in many ways to both the Rule 21 and the WDT interconnection processes. It also includes a Fast Track, Independent Study, or Cluster Study review process, as well as a System Impact Study and Facilities Study. Transmission level microgrids are atypical and require additional coordination with PG&E.

6.4 Energy Storage

It is expected that most front of the meter (FTM) resources will utilize the wholesale distribution tariff (WDT). Rule 21 information is provided for completeness as some supplementary resources may help support from behind the meter but are not expected to perform significant grid forming functions.

6.4.1 Rule 21

Energy storage is not a renewable resource, and therefore is not necessarily eligible under the NEM2 tariff. Special Condition 9 of the NEM2 tariff describes the treatment of energy storage under the tariff. If the storage system meets certain requirements it can be treated as NEM paired storage, where it receives some of the benefits of being considered a NEM eligible generator. Requirements for qualifying as NEM paired storage include criteria such as the storage device only being capable of storing power from the eligible renewable generator, not being able to export power to the grid, or being metered in such a way as to determine exactly where power is coming from (i.e., from the storage system or from the eligible renewable generator). Details for treatment of energy storage can be found in the NEM2 tariff under Special Condition 9, on the PG&E Energy Storage web page, and in the PG&E Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection. One common way for energy storage to be interconnected is via use of the NEM2 multiple tariff.

6.4.2 WDT

Under the CAISO wholesale distribution interconnection process, energy storage can be treated in various fashions as well. For CAISO market participation it can be treated as 1) a separate, non-generating resource, 2) a non-generating resource co-located with a variable renewable energy resource (i.e., if paired with a solar or wind generator), or 3) a hybrid resource paired with a variable renewable energy resource. These wholesale interconnection and market participation choices should be explored and understood before choosing the CAISO interconnection pathway. Information about the CAISO interconnection process can be found on the CAISO interconnection web page.

6.5 Energy Only vs. Full Deliverability

One important decision that needs to be made when interconnecting a distributed energy resource is whether to choose Energy Only or Full Deliverability for the resource. This applies to both Rule 21 and WDT interconnections, though in Rule 21 interconnections Energy Only deliverability is assumed unless the applicant requests a Full Deliverability interconnection.

Under the Energy-Only deliverability status the Interconnection Customer is responsible only for the costs of Reliability Network Upgrades and is not responsible for the costs of Delivery Network Upgrades. However, the Generating Facility will be deemed to have a Net Qualifying Capacity, as defined in the CAISO Tariff, of zero. This means the generator will not qualify for Resource Adequacy. Therefore, the interconnection customer must weigh these tradeoffs. While an Energy Only interconnection can mitigate the need for system upgrades and associated costs, it also can hamper revenue opportunities.

7 Controls Development

Community Microgrid controls must strike a careful balance between safety, cybersecurity, capability, and resilience in the event of control component or communication failures.

The architecture previously described under Reference Architecture can meet all of these requirements through careful design using a layered control framework and carrying the Bright Clean Line design principle through to the microgrid controllers. A diagram showing a simplified control architecture based on these principles can be found in Error! Reference source not found..

Close technical and operational coordination between PG&E and the CMG Aggregator when developing the control scheme is vital to the success of a Community Microgrid.

7.1 Layered Controls

In order to provide the highest level of service while maintaining fallback and fail-safe functionality, it is recommended that a Community Microgrid use multiple independent controllers organized in a layered control concept. Lower layer controllers operate with low Latency and interact more directly with hardware, while higher layer controllers operate with higher Latency and at a more abstract level.

A fundamental advantage to the layered controls architecture is that controllers in each layer degrade in a safe manner in the event the higher-level controls become unavailable due to communication or hardware failure. Additionally, if designed carefully, lower layers of control can continue to operate at a reduced level of functionality when higher-level controls are not functioning, providing the highest level of service possible to the Community Microgrid customers while in a communications or hardware failure state.

In a microgrid with the Reference Architecture, such as RCAM, the controls can be broadly categorized into three layers:

- **Foundational Controls**, which are implemented with Protection Relays. Integrated DER controllers also broadly fall into this low-level category. These devices will generally accept commands from and provide telemetry to higher-level controllers, and should include basic safety and simple fallback functionality.
- **Advanced Controls**, consisting of advanced microgrid controllers that receive telemetry from sensors and low-level controllers, send commands to low-level controllers, feature more advanced control logic, interact with high-level optimizers, and have advanced remote or local HMI screens.
- **Optimization Controls**, which will be used by the CMG Aggregator to participate in energy markets with generation or storage resources.

The layered design also facilitates cybersecurity and the Bright Clean Line Principle. By splitting control responsibilities between controllers that are exclusively controlled by the GSO and DSO, respectively, interaction between the controllers can be precisely defined based on contractual responsibilities, and routable data links between controllers and networks can be eliminated.

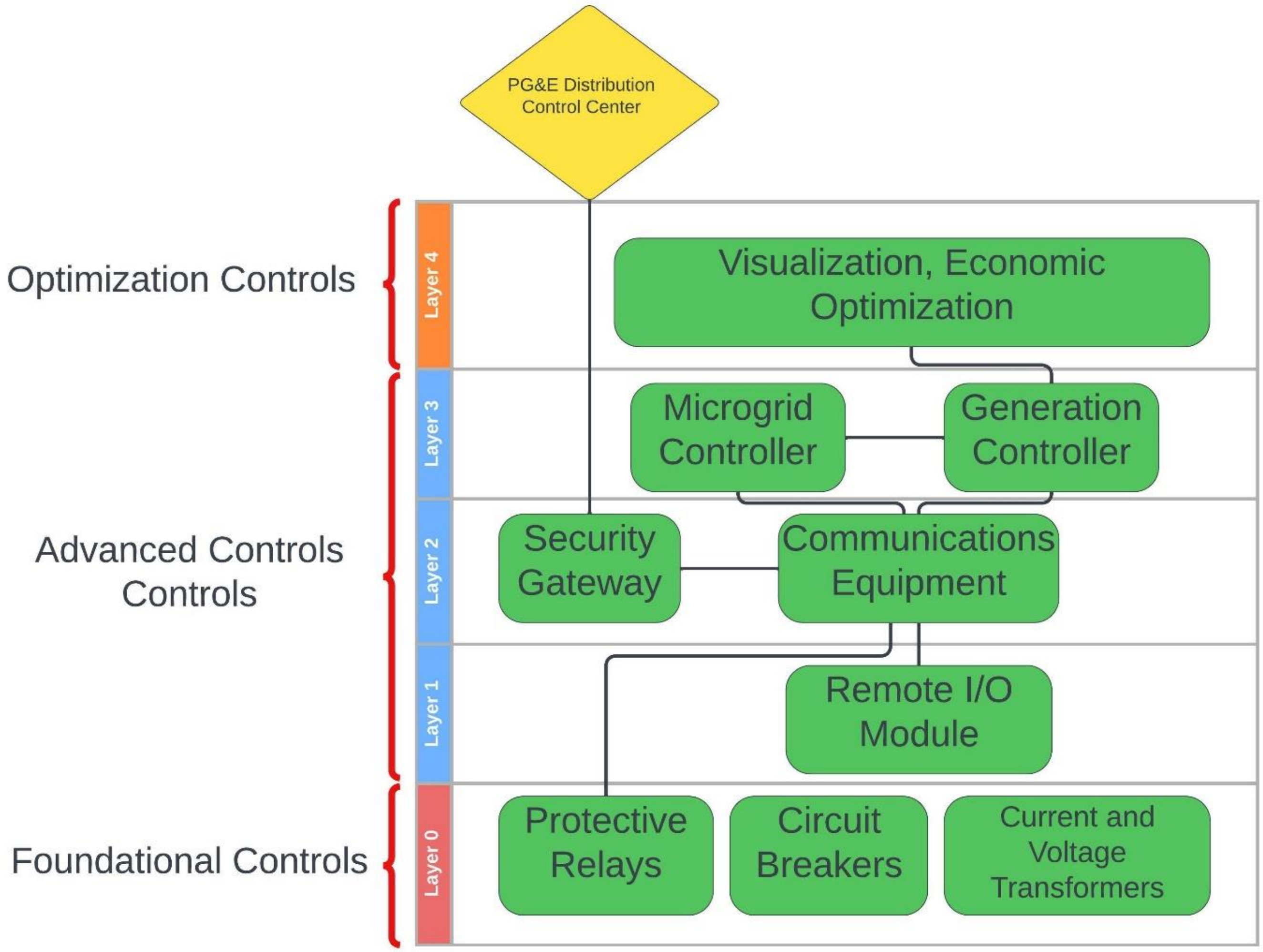


Figure 1: Simplified Layered Control Scheme

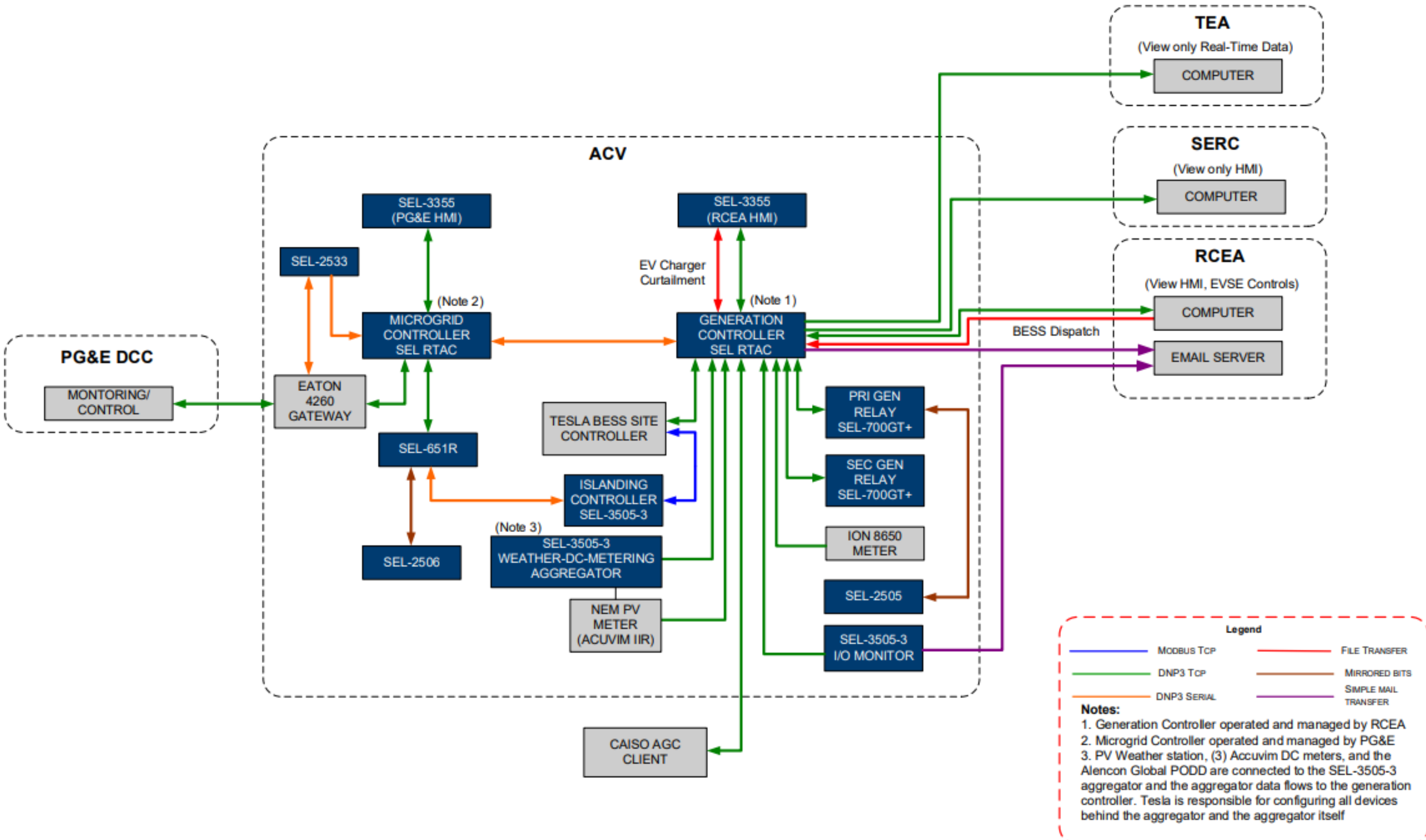


Figure 2 Data Flow and Control Architecture for the RCAM Reference Architecture

7.1.1 Foundational Protection and Control in Protection Relays

The lowest level of Community Microgrid control is provided by the Protection Relays. In the case of the Reference Architecture, these Relays monitor and operate the Line Recloser at the Microgrid Islanding Point(s) and the Primary Grid-Forming Generator's PCC Circuit Breaker. Each generation source shall also have its own independent on-board protection appropriate for the type of generator; this may include over/under voltage/frequency, fault detection, and active anti-islanding. Microgrids using Alternate Architectures may include additional Protection Relays.

The foundational control provided by these devices acts as a failsafe and fallback layer of the controls, so that even if the higher-level controls fail the microgrid will still have protections necessary for safety, simple control necessary for repair work, and will provide service to customers at a limited level if possible.

These Protection Relays serve three critical functions in the microgrid:

- **Protection**: The protection settings required for safe operation of the microgrid, as described in Electrical Design, Grounding, and Protection Scheme, which will continue to function even if communication links or advanced controls fail.
- **Point of control**: Each Protection Relay provides telemetry to the higher-level controllers and accepts commands from those controllers to actuate the associated Line Recloser or Circuit Breaker.
- **Fallback control**: In the event that the advanced controllers or their communication links fail, the Protection Relays should be programmed to automatically enter a fallback state to safely provide a level of service to the customers on the feeder that is equivalent to pre-project conditions. This is described further under Fail Safe Operation.

7.1.2 DER Controllers

DERs on the Community Microgrid will normally each have their own controller, which can be considered part of the low-level control layer. Common controllers will include a controller for grid-forming BESS resources, the controls inherent in smart PV inverters, Synchronous Generator controllers, and ATS controllers associated with standby generators.

Depending on the resource, these controllers may operate completely independently, such as in the case of an ATS and Standby Generator or distributed BTM PV inverters, or receive commands from the GSO Microgrid Controller, such as with a BESS or Synchronous Generator. These controllers should be configured to operate as independently as possible to simplify communication architecture and control algorithms. To address failure conditions safely, they must operate cooperatively or fail-safe in the event of an advanced control loss.

One concrete example of this is to configure the Time Delay Engine Start (TDES) timers on any standby generators to at least 5 seconds to give sufficient time for the Community Microgrid to complete a transition to island mode before the standby generator starts. Another example is to configure Droop

Control settings on the Primary Grid-Forming Generator relative to other DERs on the microgrid (such as BTM PV inverters operating under standard Rule 21 settings) to generate stable voltage and frequency when islanded. Ideally, Droop Control on DERs will be configured to appropriately balance load and generation when the Community Microgrid is islanded without active input from the advanced controls.

7.1.3 DSO Microgrid Controller

The Distribution System Operator (DSO) Microgrid Controller has the responsibility of gathering telemetry from DSO owned devices and from the GSO Generation Controller, and providing telemetry to the PG&E DCC. It will receive settings and control commands from the DCC or an onsite HMI, perform internal logic based on settings and commands, and transmit commands to DSO owned devices or the Generation Controller, as appropriate.

The Microgrid Controller will connect to the Generation Controller using only a Non-Routable Data Link (such as DNP3 transmitted over a serial connection) in order to maintain the Bright Line between the two entities and their respective networks. This link will include agreed-upon commands from the Microgrid Controller, which will prepare the microgrid to respond in the event of a Distribution System disruption that de-energizes the Community Microgrid.

Under most circumstances, the PG&E Microgrid Controller should be able to automatically manage transition of the microgrid to an islanded state. If the Primary Grid-Forming Generator is a BESS capable of seamless transition, the PG&E Microgrid Controller should proactively send commands to the Generation Controller and Microgrid Islanding Point Protection Relay to prepare the microgrid to react to a Distribution System outage by transitioning automatically, in conjunction with the BESS controller. If break-before-make operation is desired, an automated sequence of events may be executed by the Microgrid Controller to achieve this.

In the event of communication loss or other failure, the Microgrid Controller will respond accordingly to put the assets it is still able to control into a safe state.

7.1.4 GSO Generation Controller

The Generation System Owner/Operator (GSO) Generation Controller has the responsibility of controlling the GSO's generation and storage assets and interacting with GSO-owned devices. This includes both market-participation dispatch of FTM assets during Blue Sky operation, and management of the Primary Grid-Forming Generator during islanded operation of the Community Microgrid.

For Blue Sky market participation, the Generation Controller may receive dispatch commands directly from CAISO and/or from an offsite optimization and dispatch service via the internet, depending on the markets that the generation assets are participating in. It will collect telemetry from DER controllers and other monitoring devices, perform control logic based on any constraints that have been set for the system (e.g. limiting discharge when a BESS has reached a minimum SOE or implementing generation constraints sent from the Microgrid Controller), and send commands to the DER controllers.

For transitions to island mode, the Generation Controller will receive an islanding preparation configuration from the PG&E Microgrid Controller and will prepare the Primary Grid-Forming Generator to seamlessly transition to island if possible. The Generation Controller will then be expected to manage the generation assets and SOE of storage assets to energize the Community Microgrid for as long as possible. If the Primary Grid-Forming Generator is a BESS and other generation is present, this will involve control algorithms to manage the BESS SOE, de-energize when storage is depleted, and potentially re-energize and resume Islanded Operation when sufficient generation is available.

In the event of communication loss or other failure, the Generation Controller will respond accordingly to put the assets it is still able to control into a safe state.

7.2 Concept of Operations

Careful development of a Concept of Operations (CONOPS) document, with input from the GSO, DSO, and any other stakeholders, is the first and most important step in developing a successful microgrid control scheme. The CONOPs document is the conceptual foundation for the Community Microgrid control system, explaining with as much specific detail as possible how it is intended to work. Involving all stakeholders at as early a stage as possible is critical, as coordinated development and review of the CONOPS will allow all parties to ensure that the proposed control scheme meets their needs.

PG&E recommends that CMG Aggregator teams develop an initial draft of the Concept of Operations (CONOPS) document during the Application stage of the 5-stage process workflow. This will allow the PG&E Islanding Study Engineer to review the operational concept in advance, gather related information, and provide feedback. The CMG Aggregator team should then revise the CONOPS and include it in the CMET Application.

The document should not specify implementation details unless they are known with certainty, such as specific hardware devices, programming methods, or protocols to be used. It should instead describe the conceptual logic of each function of the microgrid and how the functions interact. Flow charts and diagrams can be useful in helping other groups to understand desired behavior; add them whenever it might improve clarity or ease of understanding. An example CONOPS Table of Contents is included as **Appendix D - Sample CONOPs Table of Contents**.

Note the following relationship between the CONOPS document and the PG&E Description of Operations, as well as the role that the CONOPS document plays in hiring the Controls Vendor:

- The CONOPS should include a Draft Description of Operations (DOO), which after multiple revisions during design development, will become an official PG&E document that is finalized by PG&E Automation and SCADA engineers and ultimately used by PG&E operators. The DOO is focused specifically on the functionality PG&E will need as the DSO, whereas the CONOPS as a whole will also cover the functionality required by the GSO.
- PG&E recommends that the CONOPS be used to define the scope of work for the Controls Vendor hired by the CMG Aggregator team. From reading the CONOPS, the Controls Vendor should be able to understand the intent of the controls design for both DSO and GSO functionality and develop a scope of work to implement and test the controls.

7.2.1 Sequence Diagrams

A useful feature of a CONOPS document is sequence diagrams, which provide a visual representation of the series of events during an operation involving multiple devices acting in parallel and/or tandem.

They are read from top to bottom, with each device represented by a bar and signals between devices represented by arrows between the bars. Reading from the top, each signal shown must be completed before the one below it can occur.

A selection of highly simplified example diagrams for the four major states of a Community Microgrid using a BESS as the Primary Grid-Forming Generator are shown here.

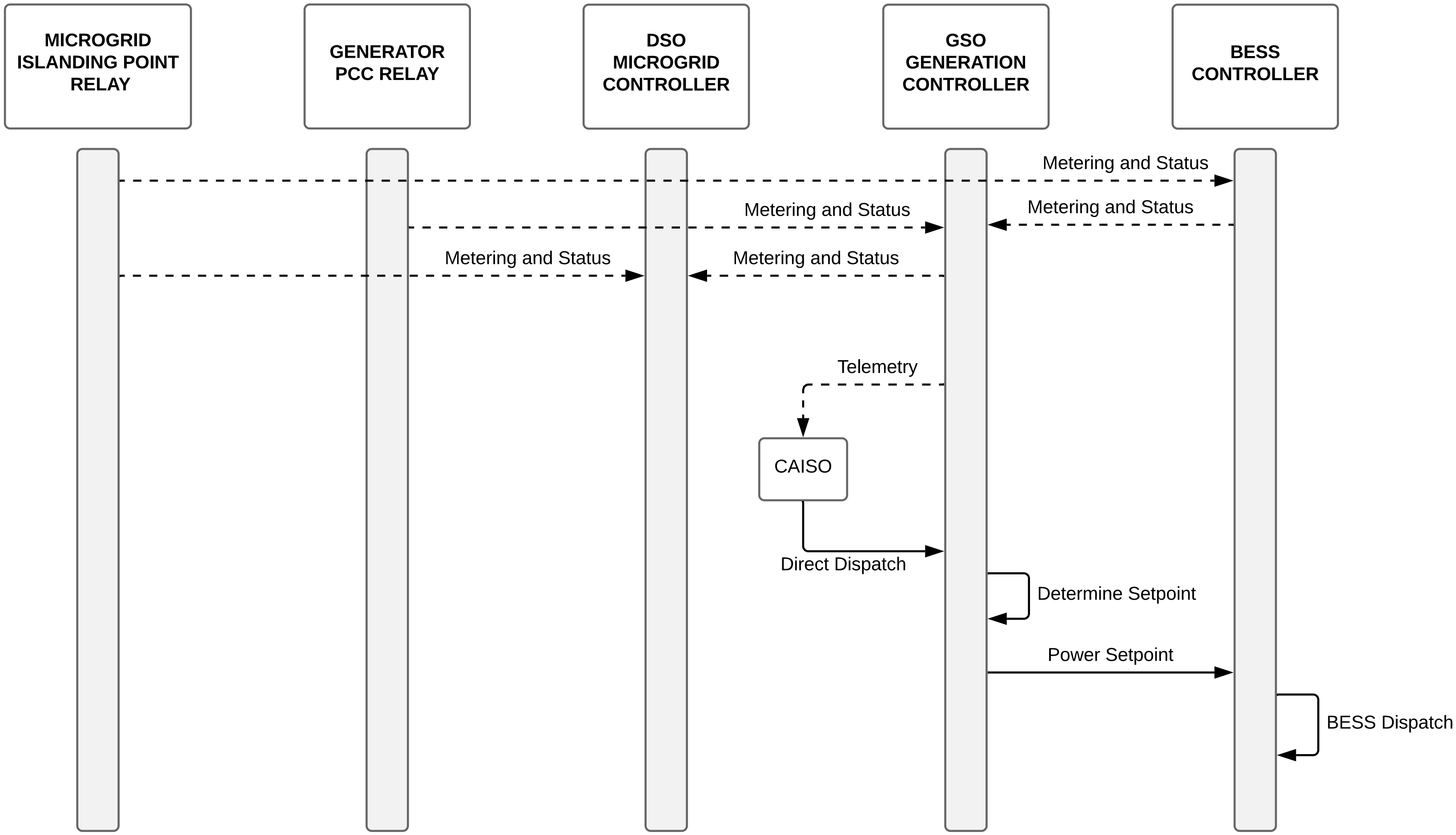


Figure 3: Blue Sky Mode simplified sequence diagram

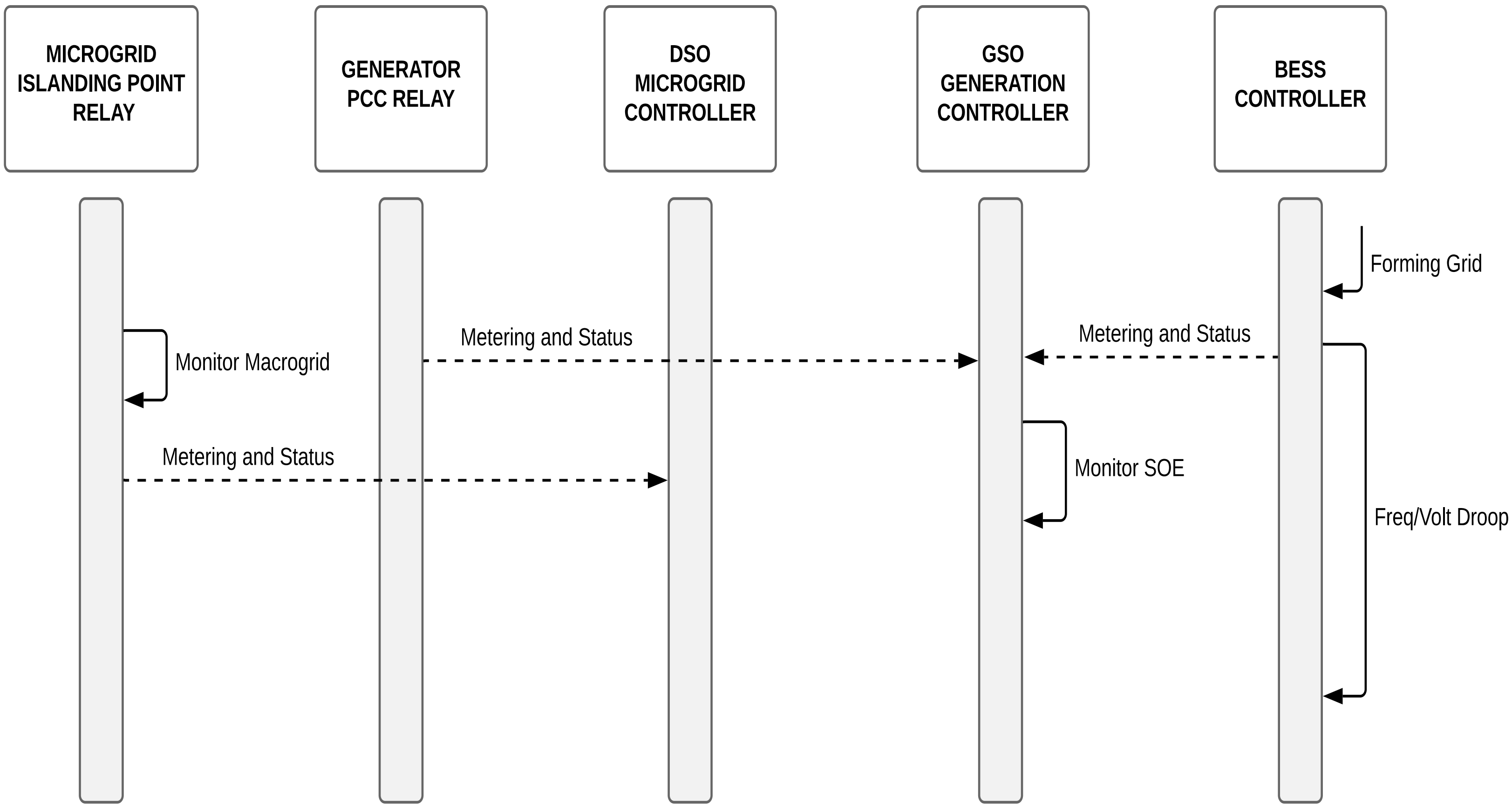


Figure 4: Islanded Mode simplified sequence diagram

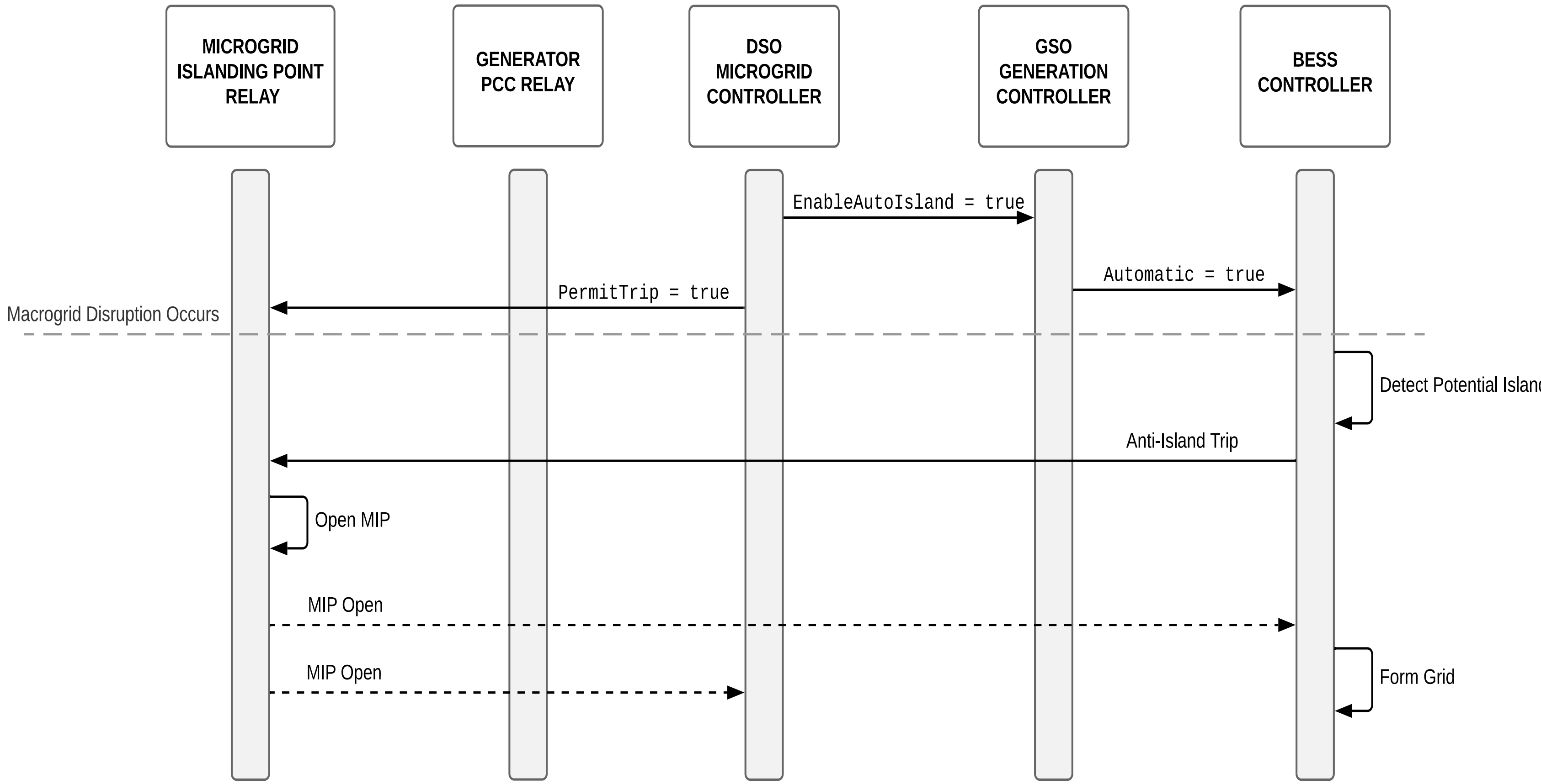


Figure 5: Transition - Blue Sky to Islanded Mode simplified sequence diagram

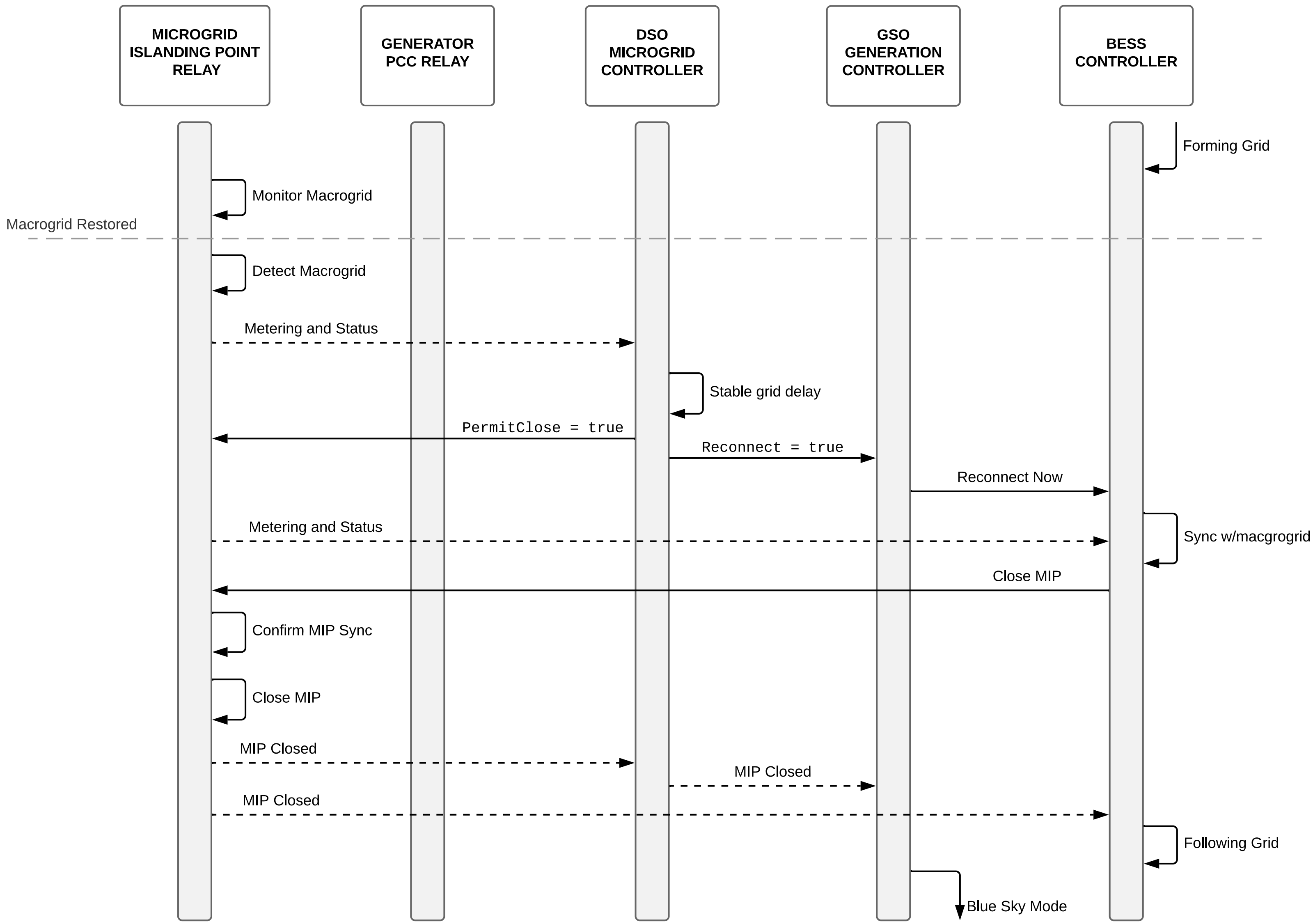


Figure 6: Transition - Islanded Mode to Blue Sky simplified sequence diagram

7.3 Functional Design Specification

Once the project partners have agreed on a controls scheme and documented it in a CONOPS document, the scheme must be implemented by a Controls Vendor. The Controls Vendor will generate a Functional Design Specification (FDS) based on the CONOPS document. The FDS can be thought of as translating the conceptual descriptions of a CONOPS document into the concrete language of controls hardware and programming to produce a buildable implementation scheme. The FDS will therefore include implementation details that a CONOPS might not, such as variable names, specific hardware, control points, programming methods, and communication protocols.

The controls vendor will develop the controls system exactly as specified in the FDS, so the document should be carefully reviewed by all stakeholders and iterated as necessary until all details meet the exact intent of the design. Once the system is complete, it will be subjected to Factory Acceptance Testing (FAT). The FAT will confirm that the hardware and software behave exactly as specified in the FDS, which increases the importance of its accuracy.

7.4 Points Lists

An important aspect of the controls development for a Community Microgrid is defining Points Lists that meet the needs of PG&E, the GSO, and any other parties (such as CAISO or an optimization vendor) that require telemetry or control capability. The Points Lists will define the specific data points and control points that will be telemetered between the Microgrid Controller or Generation Controller and each HMI or other external controller or interface. These interfaces may include local HMI consoles, remote HMI (such as at the PG&E DCC or GSO control center), CAISO, or an entity providing optimization services.

The necessary points will vary depending on the microgrid architecture, but will generally consist of analog and digital inputs and outputs. Inputs will reflect telemetry read from low-level devices on the microgrid by a Controller and read by an interface. Outputs will reflect commands generated by an interface and sent to a Controller, which will in turn send commands to low-level devices.

For example, the Analog Inputs Points List for the PG&E Remote HMI will include all values necessary for DCC visibility into the microgrid. These will be collected either directly from PG&E-controlled devices, or from the Generation Controller, which will in turn collect them from GSO-controlled devices. Some sample points lists are provided in **Appendix E - Reference Points Lists**.

7.5 Priority Alarms

Priority Alarms indicate a failure that cannot be recovered from automatically or by PG&E action alone, and will require collaborative action between PG&E and the GSO to restore the microgrid to a normal operating state. These alarms must be telemetered between the Microgrid Controller and Generation Controller, and appropriate responses and procedures for each agreed upon between PG&E and the GSO. The alarms falling into this category will vary depending on both the architecture of the project and the design specifics of the controls; the greater the level of automation, the shorter the list of alarms that will require Priority Alarm status. A sample list of Priority Alarms can be found in **Appendix F**

- Reference Priority Alarms List. Note that local Authorities Having Jurisdiction (AHJs) over the microgrid may have additional alarm requirements.

7.6 Fail Safe States

As described previously, each layer of the control scheme and/or individual hardware controller must include failsafe functionality such that if a communication or device failure occurs the system will enter a safe state in response. In failure conditions where it is safe and possible to do so, these failsafe states should continue to energize the Community Microgrid.

The GSO controls must include a failsafe means to allow PG&E to prohibit grid-forming inverters from entering or remaining in island forming control mode. The implementation method will depend on the type of grid-forming inverter, but the signal should come from the Microgrid Islanding Point Relay via a Non-Routable Data Link, such as a serial link or hardwired output, and should be automatically initiated if the Microgrid Islanding Point Relay enters the non-microgrid-operation fallback mode described under the Foundational Protection and Control in Protection Relays Section of this Guide.

Combined, these failsafes will create a “non-microgrid-operation” fallback mode that is an important feature. If while in Blue Sky Mode the utility wishes to disable microgrid functionality, or there is a controls failure, the foundational controls should fall back to a mode similar to a standard non-microgrid recloser, allowing business-as-usual operation of the feeder while repairs are undertaken. In this state, in the absence of a fault within the microgrid, the Microgrid Islanding Point Line Recloser will remain closed to continue providing service to the microgrid, and will remain closed in the event of a Distribution System disruption of the upstream feeder, while the Primary Grid-Forming Generation asset will be prevented from energizing the microgrid. Customers would experience an outage of equivalent duration to pre-project conditions and Grid-Following DERs would shut because there is no grid to follow. When the Distribution System is restored, microgrid customers will be re-energized as with a normal feeder outage and all DERs inside the Electrical Boundary can begin operating in Grid-Following Mode again.

Conversely, if a failure occurs during islanding that prevents the microgrid from reconnecting to the Distribution System, the microgrid should remain energized if safe to do so until PG&E and the GSO can coordinate a manual retransfer to Grid-Connected state.

7.7 Factory Acceptance Testing

Upon completion of the controls racks and programming, the controls vendor shall perform a complete Factory Acceptance Test (FAT) on the racks and associated hardware and software using a Real Time Digital Simulator to verify and demonstrate that the integrated controls package meets all specifications described in the FDS.

8 Network Communications and Cybersecurity

In the modern world, cybersecurity is one of the most important aspects of any networked system, and is of particularly critical importance for a Community Microgrid. Adding to the complexity is the need to segregate the PG&E owned and operated controls, equipment, and wide-area network from the GSO and CMG Aggregator owned and operated controls, equipment, and wide-area network, while still allowing the two systems to interact with each other.

Central to the Bright Clean Line between PG&E and customer-owned control systems, PG&E does not allow any routable network (TCP/IP) connections between their systems and customer-owned systems. Only Non-Routable Data Links, such as serial or hardwired I/O connections (dry or wetted contacts), are allowed. This can be accommodated through the use of an appropriate protocol transmitted over a serial connection between the Microgrid Controller and the Generation Controller, and using either serial or hardwired I/O to communicate with other devices requiring independent communication, such as telemetering the island state from the Microgrid Islanding Point Relay to the Generation Relay or island status to the Primary Grid-Forming Generator Controller. Currently the preferred protocol is DNP3.

A communication network is also required between the microgrid network and PG&E SCADA network. This pathway may be MPLS Fiber, PG&E owned Field Access Network (FAN), point-to-point radio network, or a third party cellular network.

Broadly speaking, it is important to treat cybersecurity as an integral part of the design from the start rather than as something to be dealt with later in the design process. Indeed, security best-practices should be employed as part of the design phase itself; sloppy communication during the design phase can expose a project to outside bad actors before anything is constructed.

A non-exhaustive list of cybersecurity considerations includes but is not limited to:

- Plan for security from as early in the design phase as possible, and consider security implications of decisions as the design progresses. Particularly with networked devices, design from the start to limit communication links and data paths to just those necessary to make the microgrid function.
- During the project design phase, limit the exposure of sensitive information, such as IP addresses and firewall configurations, which an attacker could collect and save for later use in attacking the completed system. Use secure file transfers for documents containing sensitive information rather than email. Segregate IP addresses and similar sensitive information that is only relevant at the final implementation stage from other design documents, to limit unnecessary exposure to team members.
- Employ a third-party cybersecurity expert to do an analysis of the design before it has reached a finished state and while there is still ample time to address identified concerns. Be aware that these concerns may require restructuring of network connections or additional hardware (firewalls or network switches) which can both require additional rack space in the Control Racks and increase power requirements, impacting Station Battery size.
- Remember that cybersecurity is not limited to remote attacks over the internet; an attacker with physical access to the site is perhaps the greatest risk. Employ physical security to mitigate this risk, such as cameras, locked metal enclosures, deactivating unused network ports, and not leaving data cables exposed.

- Include penetration testing during the FAT and/or system commissioning to confirm that security measures used are effective.
- Use access control wherever practical to limit the impact of compromised user credentials and future employee turnover. Use good password hygiene and security best-practices on all devices.
- Make sure that a means to apply patches for vulnerabilities is built into the operating budget for the life of the project.
- Remember that cybersecurity does not stop when the project goes online. Continue cybersecurity coordination between PG&E and the CMG Aggregator throughout the project's life.

9 Electrical Design

The purpose of this Section is to provide information to help development teams understand the key technical concepts and recommended means and methods for deploying Community Microgrids.

9.1 Generator Selection

Once the single dominant Grid Forming Generator has been sized, the generator must be selected based on the need for a power source that is reliable and cost-effective with a preference for renewable sources where possible. Additionally, the generator controls should have the ability to:

- Integrate with multiple smart grid technologies furthering federal SMART Grid initiatives
- Integrate with other distributed and renewable energy systems
- Integrate with the Microgrid control system.

As noted earlier, a Synchronous Generator may be used as the microgrid Grid-Forming Generator; however, a Seamless Transition may be challenging due to the ramp time of a rotating machine. Battery energy storage systems make Seamless transitions to the island mode feasible. In addition to the Grid-Forming Generator, any number of Grid-Following DERs allowed by the DSO may be connected to the microgrid presuming they can either curtail power output in response to a shift in frequency or have a generation controller that can be networked with the microgrid controls to avoid Over-Generation within the microgrid. Over-generation within the microgrid would lead to unacceptable frequency excursions and grid shutdown. All inverter-based DERs requesting interconnection with the Distribution System must be listed to UL 1741 Supplement SA, ensuring that they implement the anti-islanding protection scheme that enables frequency shift curtailment as per Electric Rule 21 Smart Inverter requirements.

9.2 Electrical System Design

The electrical system supporting the power flow between the PCC and the Grid-Forming Generator terminals must be designed to be safe and reliable. Design of the Distribution System itself, including the microgrid circuit between the PCC and POI, is the responsibility of PG&E.

9.2.1 Interconnection Configuration

The first step to designing a safe and reliable electrical system is to determine the constraints placed on the system by the utility interconnection. This must be done in close coordination with PG&E and in compliance with PG&E's Electric Generation Interconnection procedures. Customers considering a Primary Service (PS) should contact PG&E early in the design process. PG&E's online documentation describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. Rule 21 or the WDT in combination with PG&E's Distribution and Transmission Interconnection Handbooks and the PG&E Greenbook contain most of the information required for a system designer to prepare the preliminary design information necessary to submit a Generator Interconnection Request. This preliminary design information will guide the detailed system design moving forward. It is important to note, however, that the utility interconnection studies could impact the DER size, capability, and design. See the Section on Interconnection Processes in this Guide for more information.

9.2.2 Transformers

System design begins with the DER facility step-up transformer. PG&E should be consulted early in the project to determine PG&E's service wire configuration and the transformer primary winding configuration. See PG&E's Technical Requirements for Electric Service Interconnection at Primary Voltages for more information. PG&E's distribution system is typically fed from substation transformers with a Wye -Grounded secondary winding. For three wire distribution service , the primary windings of a DER facility step-up transformer is typically ungrounded (i.e. Floating Delta) for interconnection to the PG&E distribution system. In these cases, a supplemental grounding and/or ground fault detection system will be required. In the case of four wire configurations the transformer should be grounded wye on the primary side or have supplemental grounding, such as grounding transformer, to prevent overvoltage on the isolated system during microgrid operations. See grounding considerations below for more information.

The generator/inverter technical literature should be consulted for allowable secondary winding configurations and connections. The transformer should be sized to carry rated generator Apparent Power output including harmonic currents without overheating under worst-case for the greater of 24hr or the designed islanding duration for average loading and peak temperature conditions for the design life of the facility.

9.2.3 Grounding Considerations

For three wire systems, the system ground is typically at the PG&E distribution substation. Therefore when disconnected from the PG&E sources, such as during Islanded Operations, effective grounding and ground fault detection must be maintained. For three wire systems, a supplemental grounding bank should be installed. Ground overcurrent detection will be used to detect ground faults. If the study concludes that grounding bank is not needed, then ground fault protection via Zero Sequence Voltage can be installed. This can be accomplished either by including a separate set of broken-delta PTs and an overvoltage relay, or by using a microprocessor-controlled relay capable of detecting a Zero Sequence overvoltage from a set of wye-connected PTs. Four wire systems may require supplemental grounding to prevent overvoltages. This could include installing a wye/closed delta transformer with ground overcurrent protection that could be switched in for micro operations, or having a main generator transformer primary winding configuration of wye grounded, which will provide a ground reference. Reference the IEEE C62.92 set of standards for further reading regarding neutral grounding of three phase electric utility systems.

The primary interconnection equipment for the generation facility must include a circuit breaker supervised by redundant protection relays. For underground services this will typically include PCC Switchgear, which must be designed for the conditions of operation. The equipment must be designed to carry full transformer Apparent Power output and the insulation ratings of all interconnection equipment must be rated to withstand overvoltages due to lightning strikes, switching surges, and ground faults. Careful consideration of the insulation systems is required to ensure surge protection devices are installed and to properly specify the insulation ratings of all electrical equipment and cable systems.

A Grounding Study for the vicinity around the Medium Voltage PCC is recommended to calculate the resulting step and touch potentials during a system ground fault and to design a grounding electrode system capable of carrying the rated fault current safely into the ground without the development of unsafe step and touch potentials. Step potentials are the voltage differences between the feet of a person and touch potentials are voltage differences between a person and a piece of conductive equipment.

During a ground fault, the ground potential itself is raised; therefore, communications circuits entering and leaving the generating station should be fiber optic in order to avoid raising the potential of the ground reference at remote communications equipment and creating unsafe working conditions.

9.2.4 Metering

In accordance with PG&E guidelines, a Gang-Operated Circuit Breaker or Recloser is required at the PCC as well as an Electric Utility Service Equipment Requirements Committee (EUSERC)-compliant metering cabinet for utility metering. This metering cabinet must contain provisions for PG&E-provided metering CTs, PTs, and bi-directional energy meter(s) in accordance with the PG&E Greenbook. In the case where a DER is required to have a circuit breaker at the PCC, PG&E also requires a visible, lockable Gang-Operated AC Disconnect switch between the generator output and the metering cabinet to enable PG&E personnel to visually verify isolation of the metering section from all electrical sources for the safety of PG&E personnel. See **Appendix C – Reference SLD for Reference Architecture CMET Projects** for an example.

For participation in the wholesale energy markets, a California Independent Systems Operator (CAISO) meter will also be required. This meter may share the PG&E utility meter CT's and PT's in which case meter provisions, such as a socket in the metering section, will be required. See CAISOs Business Practice Manual for Metering for more information. The data from this meter may also be utilized for generation control system feedback. PG&E must approve the system Single and Three Line Diagrams at the time of electric service application (for new Service Drop) and utility metering cabinet drawings prior to manufacture. PG&E must also approve of the DC Schematic for the PCC Switchgear prior to manufacture.

9.2.5 Protections Considerations and Protective Devices

Protective device coordination is critical for proper microgrid operation. Typical objectives for protective device coordination in an electric power system are to prevent injury to personnel, to minimize damage to the system components, and to limit the extent and duration of service interruption. In a microgrid, these objectives are no different, but with the added requirement of coordination with the disconnect at the Microgrid Islanding Point (MIP) to safely transfer the microgrid from grid-connected to Islanded Operations and back.

In order to properly size the primary interconnection equipment and set the Protection Relays, a Short Circuit and Coordination Study should be conducted to determine the required ampacity and short circuit capacity under all fault conditions. The results of the study will enable specification of equipment with adequate short circuit withstand and interrupting capabilities, enable protective device coordination, and determine maximum fault current levels. PG&E should be consulted early in the project to obtain:

- System fault duty at the MIP and PCC
- Settings for PG&E Line-Side protective devices and their require clearance time to comply with PG&E protection standards
- Relay curves for PG&E Line-Side protective devices.

A Community Microgrid distribution circuit is part of the PG&E Distribution System. Existing DERs connected to the Distribution System are all required to adhere to the same interconnection procedures; therefore, in the case of a microgrid with a Reference Architecture, existing power system protection facilities between the MIP and the PCC will remain; however, their protection settings will be reviewed under the Microgrid Islanding Study.

For responding to faults external to the microgrid, the Protection Relay at the MIP should open a circuit breaker or a Recloser and then signal the microgrid to start Grid-Forming mode. For all downstream faults (i.e. within the microgrid) the Protection Relay at the MIP should trip and lock out both itself and the Grid-Forming generator switch or circuit breaker (for faults internal to microgrid) to cease energization of the microgrid. A Priority Alarm should assert and the PG&E trouble team should be dispatched to the site to repair the fault. Coordinated action between PG&E and the GSO will be required to return the Community Microgrid back to a normal operating state.

The Protection Relay at the Grid-Forming Generator PCC must be able to not only isolate a fault within the GSO facility from the Distribution System before the relay at the MIP opens the MIP switching device, but it also must communicate to the generation controller(s) and ultimately the DCC that microgrid is disabled from operating in the Islanded Configuration. Additionally, when islanded, the Grid-Forming Generator must assume the responsibility of protection of the Distribution System by providing End-of-Line Fault Detection.

Because an inverter-based Grid-Forming Generator supplies limited Fault Current, a voltage-restrained or voltage-controlled overcurrent protection scheme is recommended. Inverter based generation may also be required to inject unbalanced current, also called negative sequence current, to allow overcurrent protection to operate correctly for all types of faults (line to line, line to ground, and line-line-ground). A Synchronous Condenser may be recommended to support fault current during islanded operations depending on the size of the Grid-Forming Generator and the results of the Microgrid Islanding Study.

Additionally, voltage and frequency protections must be included for islanded operation in order to ensure Power Quality for the microgrid customers. Rule 21 required voltage and frequency trip and Ride-Through Settings should be coordinated between the MIP relay and the PCC relays so that the MIP breaker trips first for faults outside of the microgrid, with back up protection provided by the voltage and frequency settings at the Grid-Forming Generator PCC.

All inverter-based DERs requesting interconnection with the Distribution System must be listed to UL 1741 or UL 1741-SA ensuring that they implement the voltage, frequency and anti-islanding protections outlined in IEEE 1547 and included in Electric Rule 21 section Hh. For Grid-Forming inverters, those settings may be changed to support the microgrid .

Fault study will be conducted in PSCAD and will use the inverter models provided by the manufacturer.

The additional requirements of the microgrid protection system can be implemented through microprocessor-controlled Protection Relays with multiple Settings Groups (for Grid-Connected and Islanded operations) networked with a DSO Controller, GSO Controller(s), and DER Controller(s) as discussed in the Controls Development Section of this Guide. Protection Relay and controller settings must be reviewed and approved by PG&E. It is recommended to apply PG&E approved relays.

9.3 Microgrid Islanding Study

The Microgrid Islanding Study (MIS) is a collection of studies required to ensure the operational safety and stability of the Community Microgrid during Islanded Operations. The study relies on detailed information about the Grid-Forming Generator(s), its interconnection to the grid, transition from grid tied to islanded and back to grid tied, and the microgrid circuit itself.

The Microgrid Island Study is segmented into six electrical study elements:

9.3.1 Electrical Study #1: Base Model Development and Validation

The first electrical study is the Base Model Development and Validation. PG&E will develop a PSCAD model of the Community Microgrid circuit and microgrid electrical boundary. This model covers the detailed circuit sections, distributed loads, main equipment on the feeder such as line reclosers, sectionalizers, large three-phase service transformers, and includes representation of the main single-phase laterals in the microgrid boundary to have the full feeder coverage. This model will then be validated according to PG&E error criteria.

After the development of this model, the Applicant's vendors will provide the PG&E the DER model(s) to be added to the base system/model. For DERs that no vendor-specific model is available, the data provided by DER vendor can be used to develop proper steady-state and dynamic models[9]. Such data includes, but not limited to, short circuit test, load rejection test, and load acceptance test, voltage recovery. Power flow studies will then be performed by PG&E to E to evaluate system voltage level and equipment thermal loading under different microgrid configurations, microgrid loading conditions, and generation dispatch scenarios. This validated model with the DERs will be used throughout the duration of the MIS.

9.3.2 Electrical Study #2: Power Flow and Voltage Analysis

The second electrical study is Power Flow and Voltage Analysis. This study will be performed by PG&E to evaluate system voltage level and equipment thermal loading under different microgrid configurations, microgrid loading conditions, and generation dispatch scenarios. The current flows are compared with the nominal and emergency ratings of equipment to ensure no thermal violation is observed when the microgrid operates under different configuration and loading/generation conditions. Further, the steady-state voltage values and imbalance levels are compared with the system normal and emergency ranges to ensure compliance. In case the microgrid includes BESS, different scenarios with various BESS charging/discharging levels shall also be considered for both maximum and minimum loading conditions. However, to manage the level of effort, the study will focus on worst-case scenarios.

The following system conditions are considered for the power-flow study:

- Different microgrid loading conditions (minimum daytime and maximum)
- Grid-following DERs being in service or out of service
- Charging and discharging conditions for grid-following battery energy storage systems (BESS)
- Various system reconfiguration in the islanded mode, if allowed

Future operation scenarios such as load growth

9.3.3 Electrical Study #3: Microgrid Protection Studies

Following the Power Flow and Voltage Analysis, PG&E will perform the Microgrid Protection Studies. The protection system study investigates reliability of the designed protection settings. The study results provide information required for evaluating the effectiveness of the microgrid protection schemes including initial protection settings and fault clearing times for various protection devices and/or elements. Further, the study identifies any required changes/improvements that should be made to the protection schemes and/or settings to provide adequate coordination in all microgrid operating conditions. In some cases, the modifications to the existing relay schemes or changes in relay settings may not be sufficient to satisfy the protection coordination requirements, and consequently the replacement of existing relays, breakers or scheme may be necessary.

The Microgrid Protection Studies will comprise of five study elements including:

1) Effective Grounding Analysis
2) Short Circuit & Equipment Duty

[9] Most vendors have already developed these Electromagnetic Time-Domain (EMTD) modeled. However, it is recommended that vendor should be required to provide these models.

3) Overcurrent Protection Coordination
4) Arc Flash Study and Labels and;
5) Ride Through Protection Analysis

At the completion of the Protection Studies, PG&E will be able to determine the settings for the MIP relay and the PCC relays for any new Grid-Forming DERs. PG&E will also review the protection settings for any existing FTM or BTM protection relays inside the electrical boundary of the microgrid and determine if modifications to those settings are required.

9.3.4 Electrical Study #4: Power Quality and Harmonics

Power Quality and Harmonics studies will be performed by PG&E to evaluate power quality and harmonic contents when the community microgrid is islanded. The targeted power quality criteria should be maintained within their acceptable range during the islanded operation of the microgrid. Typical areas of concern include large voltage excursions due to inadequate load pick up or excessive generation, harmonic content of the microgrid due to the presence of inverter-based resources and non-linear loads, and potential voltage flicker due to fluctuations in PV generation.

The results of the power quality study are dependent on the assumptions made for the types of microgrid loads, operating conditions of the DERs, and level of harmonic background in the microgrid which can vary by time and is highly dependent on microgrid components. Hence, it is important that power quality tests, measurements, and verifications be carried out during the microgrid commissioning and spot checks be performed during island operation of the microgrid.

9.3.5 Electrical Study #5: Microgrid Transitions

Following the Power Quality and Harmonics study, PG&E will need to evaluate transition of the microgrid from one operational state to another (i.e., from grid-connected state to the island state and vice versa). If the operational design of the microgrid is to perform automated seamless (make-before-break) transitions, these transitions should function such that minimal disturbance and no interruption affects the microgrid loads. This study will focus on the demonstrating the ability of the microgrid to complete a seamless islanding transition as well as identifying the necessary conditions for a smooth transition with minimal voltage and frequency disturbances under various scenarios.

These transition studies will also include Blackstart and load restoration studies to ensure that if, in the event the microgrid fully de-energizes, the microgrid is capable of black-starting from a de-energized state by utilizing its grid forming resource(s). The grid-forming resource(s) can be brought online first, then the load can be energized in steps or all at once—depending on the capabilities of the grid-forming resource(s) and the load characteristics—while maintaining voltage and frequency of the microgrid within acceptable levels.

9.3.6 Electrical Study #6: Transient Stability Studies

The sixth and final set of studies are the Transient Stability Studies. These studies are required to evaluate the transient stability of the islanded microgrid in response to different transient events that can expose the microgrid to sudden changes in voltage and frequency. This will also include Energization studies to evaluate system performance during the energization of microgrid assets, Load Variation studies to evaluate microgrid system performance during and subsequent to sudden changes in the microgrid load while in island mode, Ramping Studies, and Response to Fault Clearance Studies to evaluate the transient response of the microgrid system to a short-circuit fault incident within the islanded boundary.

Once the electrical studies have been completed, PG&E will work with the CMG Aggregator to develop the following documentation:

1. Draft Description of Operations
2. Draft Project Operational Protocols & Procedures
3. List of Equipment to be included in the Microgrid Special Facilities Agreement

9.4 Controls Testing

Prior to onsite commissioning, CHIL Testing may be required for Community Microgrids deployed on PG&E's system. The purpose of CHIL Testing is to prove that the control logic of the various controllers and equipment operates in accordance with the approved FDS. Typically, CHIL Testing is completed by the controls vendor during FAT, either at their own facility or at a third-party facility. In either case, PG&E recommends that the controls vendor scope of work include CHIL testing so that the control logic can be proven by the same company responsible for configuring the devices in the Control Racks and associated peripherals. This will lead to better outcomes during onsite commissioning of the controls. The controls vendor scope of work should also include support for onsite commissioning activities.

All control devices shown on the Network Diagram need to be included in the CHIL Testing with the exception of embedded DER controllers, since those may not be portable and can be simulated. The controls vendor should prepare a FAT Test Plan for review and approval by both PG&E and the CMG Aggregator well in advance of the FAT date.

In preparation for FAT, the Control Racks and peripherals should be installed in the test environment and networked together as they would be in the field. Three-phase power supplies may be used to generate the voltage, frequency, and secondary current needed to simulate the Distribution System and Grid-Forming Generation in the test environment. Note that the voltage, frequency, and current provided are only used to indicate the presence or absence of the electrical sources in the Community Microgrid so that the control logic can be observed responding to the expected steady-state operating conditions. Circuit breakers and Line Recloser positions can be simulated using contacts on the power flow simulator or Remote I/O units.

First the controls vendor will complete the FAT Test Plan with their internal engineering team and work through any issues that are uncovered. Next they will invite stakeholders to witness the FAT. Engineers from PG&E, the CMG Aggregator, and the controls vendor will travel to the FAT facility for the witness testing to ensure consensus on the passing results. Once FAT is complete and documented, the control hardware can be shipped to the project site or, if RTS Testing is required by PG&E, the hardware can be shipped to the RTS Testing facility.

9.5 Real-Time Simulation Testing

In the case where PG&E determines that RTS Testing is required for the Community Microgrid, the components tested under FAT (or a clone setup) will be set up at an RTS Test Facility. In the RTS Facility the control hardware will be connected to an RTS that has a digital model of the distribution feeder that hosts the Community Microgrid. The Grid-Forming and Grid-Following generators will be simulated using dynamic models, and some manufacturer support will typically be needed to configure the dynamic models. During RTS Testing the focus is on observing how the system responds to electrical transients caused by instability and certain fault conditions.

If RTS Testing is required, an additional RFI will be issued to obtain additional information. Table 1 below shows the types of information would be included in that additional RFI.

Table 1: Example of information needed for RTS Testing

PHIL Testing RFI Item	Responsible Party	
	PG&E	Applicant
Microgrid Drawing package	-	Including the one-line diagram, three-line diagram, wiring diagrams of the P&C
Length and type of each conductor	From the MIP to the Service Drop	From the Service Drop to the Generating Facility output terminals.
Protection relay and/or recloser control data (Manufacturer, model, and part number)	To be installed on the utility side of the DER PCC	To be installed on the customer side of the DER PCC
List of DERs, nameplate rating, vendor datasheets	Existing Grid-Following inverter inside the microgrid	New Grid-Forming and Grid-Following inverter inside the microgrid
Operating time (open/close) and trip setting for Circuit Breakers/reclosers	For MIP Recloser/Circuit Breaker.	PCC recloser/CB connecting Grid-Forming and Grid-Following Generators to the Distribution System
CT /PT Ratios for Protection Relays	To be installed on the PG&E side of the DER PCC	To be installed on the customer side of the DER PCC
Transformer nameplate rating, vendor data sheets, test Reports	Any new or existing distribution transformers inside the Electrical Boundary	Connecting Grid-Forming and Grid-Following Generators that are on the customer side of the PCC
Controller Firmware and Settings	PG&E Microgrid Controller	Applicant Generation Controller Islanding Controller (if applicable) DER controller and site EMS
Protective relay settings	To be installed on the PG&E side	To be installed on the customer side
Load Profile	Existing Load Profile within microgrid electrical boundary	Applicant's Type of load, Load profile (Peak load, average load, min load)

PHIL Testing RFI Item	Responsible Party	
	PG&E	Applicant
Grounding methods	Substation and Feeder grounding configuration	Applicant's DER and Transformer grounding configuration
Network devices	Network switches, gateways, HMIs, etc. at the PG&E control panel	Network switches, gateways, HMIs, etc. at the Applicant control panel

10 Construction

Construction of a Community Microgrid is similar to a typical large electrical project with significant Medium Voltage work items. The CMG Aggregator can elect to hire a contractor to install the underground conduit and vaults, concrete pads, and bollards needed for new PG&E facilities such as conductors, switches, junctions, and transformers. In this case, the engineering plans should be developed using PG&E's Greenbook and a PG&E Trench Inspection will be required before any customer-installed conduits are backfilled. PG&E will then send a construction crew to the site to pull the conductors and install other PG&E owned and operated electrical equipment. Note that PG&E will require that the customer's contractor pull a mandrel through each conduit to prove that there are not obstructions prior to pulling wires. Alternatively, the CMG Aggregator can elect to pay PG&E to install the underground and above ground components.

11 Pre-Commissioning

Pre-Commissioning Activities consist of Pre-energization Testing (PET) and Pre-Parallel Inspection (PPI), which are two onsite witness tests that PG&E inspectors must complete before Permission to Operate (PTO) can be granted to the CMG Aggregator. Additionally, electrical testing on CMG Aggregator owned switchgear, medium voltage cables, junctions, transformers and the like should also be tested during Pre-Commissioning and before the Cutover.

11.1 Pre-Energization Testing

Pre-Energization Testing (PET) is a PG&E witness test that occurs after the Medium Voltage PCC Switchgear for a Grid-Forming Generator has been installed. In order for PG&E to schedule the PET the CMG Aggregator must hire a third-party electrical testing company to come to the site to perform electrical tests on the Medium Voltage PCC Switchgear and generate relay test reports.

Once PG&E has approved the relay test reports they will schedule the PET. During the PET the electrical testing company will come to the site again and re-test the relay settings with the PG&E inspector witnessing the test. After passing the PET PG&E will schedule its construction crew to come to the site and do the Cutover to connect the PCC switchgear to the Distribution System and energize it.

The Cutover is typically one of the last construction items completed before commissioning begins because backfeed power is typically needed for commissioning. Note that if the PET is not passed the first time, PG&E may charge a fee for sending an inspector out for a re-test.

11.2 Pre-Parallel Inspection

After construction is completed, PG&E receives and approves all required PPI documents specified in Section G5 of the PG&E Transmission Interconnection Handbook, and when the Grid-Forming Generator manufacturer is ready to commission their system, PG&E will schedule the PPI.

During the PPI, PG&E will send an inspector to the site to witness the testing of any generator required relay settings, which will require another visit from the electrical testing company. However, at this point in many microgrid designs, PG&E will be unable to witness the microgrid's anti-islanding functions during the PPI because additional commissioning of the system is needed that could not have been performed before backfeed power was provided to the Grid-Forming Generator. Therefore, at this point PG&E can provide *Permission to Parallel for Test Purposes* (PtP for Testing).

With PtP for Testing, the Grid-Forming Generator and subsystems can be energized, and the necessary additional commissioning can be performed. PG&E will then return to the site to witness the anti-islanding testing once all commissioning is complete. Upon approval, PG&E will grant the system Permission To Operate (PTO).

11.3 Detailed Steps & Tips

The chronological outline below provides more detailed descriptions for each step involved in testing the microgrid's protection settings, along with notes of lessons learned to assist in a smoother process.

1. Benchtop test protection settings prior to sharing with PG&E, if possible, to confirm proposed settings perform as intended.
   Tips:
   - Include functionality tests, e.g. breaker(s) open and close as expected during simulated scenarios
   - Available testing equipment may be limited; test as much as possible.
2. Request PG&E's confirmation on the protection settings. Submit PG&E's G5-1 form, which includes a table to specify the protection settings for the project's protection device(s).
   Tips:
   - Request confirmation from PG&E on these settings prior to mobilization of the electrical testing company to ensure the settings tested by the testing company are approved by PG&E.
   - If the project uses multiple protection devices, e.g. the SEL 700GT+ includes two protection relays, PG&E requests a copy of the table be filled out for each protection device, even if the protection device does not control the PCC CB.
3. Complete first mobilization of the electrical testing company; company will provide a Relay Test Report to verify the protection settings.
   Tip:
   - Typically the electrical testing company hired to test the protection settings also completes additional PCC Switchgear acceptance testing during the first mobilization. Hiring one company to do all required testing can save on costs.

4. Submit Transmission Interconnection Handbook Appendix T required station battery documentation to PG&E. This submission proves to PG&E that the relay controls have a robust, appropriately-sized back-up power system.
5. Submit the final G5-1 form, Relay Test Report, and Appendix T station battery documentation to PG&E. PG&E requests these three items, along with the additional PPI paperwork, 30-60 days before scheduling the project's PPI.
   Tip:
   - Suggest a window of potential PPI dates to PG&E early so they can schedule the PG&E representative (Substation Test) in advance.
6. Complete PPI. During the PPI, a PG&E representative (Substation Test) witnesses the electrical testing company perform the protection settings testing (second mobilization of the electrical testing company). The electrical testing company sends the PG&E representative the second Relay Test Report, as well as the as-left protection relay settings file, e.g. .rdb file.
   Tips:
   - Depending on the system, it may take more than one day to test all relay settings. Testing companies generally send a tester on site for at least two days to ensure testing is completed during the mobilization.
   - Depending on the system, PG&E may not be able to witness anti-islanding during this step. For example, the system may need to be energized before all commissioning can be completed.
7. Receive PtP for Testing from PG&E. This step is required if the commissioning plan makes it impossible for the PG&E representative to witness anti-islanding during the initial PPI visit.
8. Energize the system for testing purposes only. Complete final commissioning if unable to do so before PPI.
9. Complete anti-islanding testing. This testing may be completed during the PPI if all system commissioning is able to be completed before the PPI. This testing does not require another mobilization by the electrical testing company. The PG&E representative collects the final protection relay file, e.g. .rdb file, from the protective relays[10].
   Anti-islanding testing includes:
   - Opening the system's visible, lockable AC disconnect to confirm that the PCC CB opens and the system islands with the BESS becoming grid-forming.
   - Closing the system's visible, lockable AC disconnect and see the system transition back to the PG&E grid and the BESS switch back to grid-following mode.
10. If approved, obtain PTO from PG&E.

[10] Note that ".rdb file" refers to the settings file for Schweitzer Engineering Laboratories Protection Relays.

Figure 7: Pre-commissioning steps

As described above, the third-party electrical testing company will typically have three mobilizations to the project site:

1. The first visit is to generate the relay test reports and complete electrical testing on the PCC switchgear.
2. The second visit is to perform witness testing of the protection settings in the relays during the PET.
3. The third visit is to perform witness testing of the protection settings again during the PPI.

During one of these visits, depending on construction sequence for the project, it is recommended that the electrical testing company test any new medium voltage cables that have been installed on CMG Aggregator owned equipment, as well as perform tests on any other new circuit breakers, switchgear, non-PCC related protection relays, and transformers. Much of the cost to hire these firms is in the mobilization and these electrical tests on newly manufactured electrical components are generally considered cheap insurance. A sample scope of work for a third-party testing firm is included in **Appendix G - Sample Scope of Work for Third-Party Electrical Testing Company.**

Note that for Low Voltage PCC Switchgear installations PG&E may allow the PET and PPI relay witness testing to be combined, which could reduce the number of mobilizations required by the electrical testing company from three to two for some projects.

12 Commissioning

The CMG Aggregator is required to submit a Draft Commissioning Plan and Schedule to PG&E 120 days prior to the planned Commercial Operation Date. The plan will include a schedule of activities that will be completed along with a list of the responsible party for each step and the test reports to be submitted to PG&E. The Pre-Commissioning activities described above and associated test reports should be included in the Commissioning Plan. A sample commissioning test plan for an automatic and seamless transitions community microgrid is available in **Appendix J – Sample Commissioning Test Plan**

In general terms, once the PtP for Testing has been issued by PG&E as described in the Pre-Commissioning Section of this Guide, the rest of the commissioning activities may proceed. The Grid-Forming Generator manufacturer will have an onsite commissioning plan that will be followed by the contractor installing that system. This typically involves the following types of activities:

- Completing inspection checklist confirming the physical installation meets manufacturer’s specifications
- Checking torques on field installed wiring, confirming required labeling and signage is installed correctly
- Checking coolant and oil levels
- Checking insulation with a megger tester
- Checking for correct phase rotation
- Checking polarity of CTs

- Verify customer low voltage control and network connections are per plan
- Confirming control power meets requirements
- Conducting point to point testing for each control interface

PG&E will be responsible for any pre-energization testing activities associated with the MIP control relay or MIP Circuit Breaker Protection Relay, whichever the case may be.

The controller logic will have been tested previously by the CMG Aggregator's control vendor during Factory Acceptance Testing, which will be witnessed by PG&E as described above.

Once the commissioning of each subsystem is completed with test reports reviewed and approved by PG&E, the manufacturer of the Grid Forming Generator will run a series of tests to verify that the unit is responding to setpoint commands with expected ramp rates and closed-loop setpoint feedback is performing within specifications. A typical next step would be to push and pull power at maximum for the site for a period of 30 minutes to an hour to test cooling system operation. Once the Manufacturer has completed their commissioning process and PG&E has approved of the results, onsite commissioning of the microgrid system may begin.

Commissioning of the microgrid begins with Blue Sky Operations following the approved Description of Operations, which is described below. For Grid-Forming Generators connected under PG&E's WDT, CAISO will have a series of tests that they will perform at this point under what is called the Sync Test. This involves point to point testing, ramp rate testing, and setpoint response time testing with the CAISO Energy Management System team. Representatives from all vendors should be on-site during commissioning to troubleshoot any issues that arise.

Once the Grid-Forming Generator has been commissioned and is considered operational for Blue Sky Mode, then commissioning for transitions and Islanded Mode can begin. This should start with the simplest test and work up to the hardest test. The simplest test is typically a break-before-make manual islanding event followed by islanding for some brief period on the order of an hour or two followed by a manual break-before-make retransfer back to grid connected state. From there the next test would be the same sequence of events, but using seamless transitions instead (if applicable).

After those tests are completed the controls can be tested in automatic mode by simulating an outage at the POI. This can be done by manually opening the MIP recloser under load using the pushbuttons on the recloser control HMI. The controls should respond as if the upstream Distribution System became de-energized and should automatically transition the microgrid to Island Mode. Then a short time later the system should automatically retransfer back to a grid-connected state since the Distribution System is present and stable and the controls should be configured to remain connected to the Distribution System when possible.

With the Final Commissioning Plan successfully completed and the results properly documented, the commissioning can be considered complete. Note that for any planned outages during commissioning PG&E will notify customers in advance to provide the anticipated timing and expected duration of the outage(s).

13 Operating the Microgrid

The Microgrid Operating Agreement, Description of Operations, and Operational Protocols and Procedures Documents will be the governing documents for operating the Community Microgrid.

13.1 Microgrid Operating Agreement

A standardized Pro Forma Microgrid Operating Agreement (MOA) will be provided by PG&E during the Community Microgrid Technical Consultation so that the CMG Aggregator can know the operational requirements relatively early in the process. For example, the CMG Aggregator is responsible for controlling DERs within the Microgrid Electrical Boundary during Islanded Operations to comply with relevant provisions of Electric Rule 2, PG&E's WDT, and Electric Rule 21, including frequency and voltage and other power quality requirements. The CMG Aggregator will also be required to retain operational coordination with PG&E operators at all times and be responsible for maintenance of the Generation Facilities and associated Balance of Systems and conduct periodic testing to demonstrate availability and capability of the Primary Generating Facility at their own cost. Once the system is operational, the CMG Aggregator will be committed under the Microgrid Operating Agreement (MOA) to maintain all controller and protection settings as recorded during commissioning. Proposed controller and protection settings must be submitted in writing to PG&E for approval.

13.2 Description of Operations

The Description of Operations (DOO) is a critical section of the CONOPS for the Community Microgrid Project that is specific to PG&E's role as DSO operating the Community Microgrid circuit. PG&E recommends that the initial version of the DOO be included in the CONOPS document, which is described in the Controls Development Section of this Guide. After multiple revisions during design development, the DOO will become an official PG&E document that is finalized by PG&E Automation and SCADA engineers and reviewed by PG&E Protection Engineers and Distribution Engineers and ultimately used by PG&E operators.

The PG&E Islanding Study Engineer will require a draft DOO at the beginning of the MIS. The PG&E Distribution Engineer will also require the draft DOO at the beginning of the Rule 21 Interconnection Review or the WDT System Impact Study (SIS) for Community Microgrid Projects. PG&E recommends that the CMG Aggregator's technical integrator, who should be experienced in both power systems engineering and control systems engineering, develop the initial draft of the DOO early enough so that it can be vetted during the Consultation stage of the 5-stage process workflow.

After the Community Microgrid Technical Consultation, the DOO should be revised again before being submitted as part of the CMEP Application. Note that the DOO will typically be revised/updated several times over the course of project development as new information becomes known and decisions are made.

Once the MIS and Rule 21 and WDT interconnection studies are completed, PG&E Distribution, Protection, and Automation Engineers will meet with the CMG Aggregator team to review the study results and jointly finalize the DOO outline and list of outstanding items that need to be covered in the DOO. From there the CMG Aggregator's Controls Engineer will develop the Draft Final DOO and submit to PG&E. From here PG&E Automation Engineers will take responsibility for finalizing the DOO for the project.

Once the Draft Final DOO is approved by PG&E, the CMG Aggregator’s Controls Vendor can finalize the FDS. As stated in the Controls Development Section of this Guide, the FDS will include all of the necessary implementation details needed to design, test, and commission the control systems for the project. The FDS must be consistent with the approved Draft Final DOO and the FAT Plan must document that consistency.

After FAT the DOO may be revised again by PG&E to account for any changes resulting from FAT. The result will be the Final DOO for the Community Microgrid project, which will be used by PG&E Automation Engineers to develop the SCADA HMI screens for the PG&E Distribution System Operators. The process of developing the PG&E operator HMI screens may require some input from the CMG Aggregator’s Controls Vendor so some follow up should be included in the Control Vendor’s scope of work.

In the end, the DOO must be consistent with the FDS and presented in a way that is functional for PG&E operators, who interact with many Distribution System control nodes throughout the course of their workday and therefore need straightforward and clear and concise documentation on how to operate the Community Microgrid. In general, the most important sections of the DOO will be the general description of the microgrid control system, the description of control modes with references back to the SCADA HMI screens, and the Priority Alarm protocols and procedures.

The Priority Alarms list is especially important because it will provide instructions on how to respond to any alarm that requires a coordinated response from both the GSO and the DSO, such as a fault inside the electrical boundary of the microgrid or a communication or hardware failure that causes Microgrid Disabled Mode to become active (See the Microgrid Operational Modes Section of this Guide) . A reference Priority Alarms List is included in **Appendix F - Reference Priority Alarms List**.

13.3 Project Operational Protocols & Procedures

The Project Operational Protocols & Procedures (POPP) will be drafted by Applicant at the end of the MIS process and finalized prior to signing the MOA. The POPP will identify and describe the operational roles and responsibilities of PG&E and the CMG Aggregator during Blue Sky and Islanded Operational Modes. Responsible entities and key contacts will be identified, along with any communications requirements for operational notification and coordination. This will cover emergency situations, Priority Alarms, and requests that PG&E de-energize a section of the Distribution System with the Electrical Boundary. Either party is required to report changes in the mechanical or electrical equipment that may affect operations immediately upon discovery. Any planned islanding event must be controlled by PG&E and coordinated with the CMG Aggregator. Requirements around coordination for periodic capability and functionality testing will also be included. Under normal conditions PG&E will give advance notice of plans to conduct work that may affect the CMG Aggregator’s operations. However, under emergency circumstances PG&E may disconnect Grid-Forming Generators inside the electrical boundary without advanced notice if a situation exists which may adversely affect the PG&E electric system integrity. In addition to the Project Operational Protocols and Procedures, PG&E will develop internal Protocols and Procedures for use by the Distribution Control Center. These Protocols and Procedures will be memorialized in a Jurisdictional Boundaries Letter of Agreement jointly executed by PG&E and the CMG Aggregator and attached to the MOA.

14 Change Management

When managing a highly complex technical project such as a Community Microgrid, it is important to start building consensus around the technical design early in the development process and work diligently to maintain and document that consensus through the design, permitting, testing, construction, and commissioning processes. That consensus can become the basis for a successful partnership between PG&E and the CMG Aggregator once the project becomes operational.

To accomplish this, PG&E recommends that CMG Aggregators employ a technical integrator that can be responsible for carefully documenting the evolving consensus and frequently back-checking to ensure that as more implementation details are worked out, the consensus remains intact or is updated with consent from key stakeholders. With this approach the technical integrator needs to be engaged with all of the technical work streams associated with the project. This will lead to a more efficient development process and will minimize errors. Below are three key recommendations that have proven helpful with change management during microgrid project development.

14.1 Tracking Key Correspondence

Microgrid projects often involve multiple partners and technical design communications often involve information, decisions, and files being shared over email. It is very helpful to keep track of the multiple emails and meeting outcomes in a consistent, organized manner. One successful method is for the technical integrator to archive each attachment received or sent via email and save them in an organized folder structure, e.g. organized by sent/received, year, partner, and subject. In cases where the email text itself contains a record of decision or key design information, the email can be printed to PDF and put into the archive. An example format for folders in the archive is:

- //Correspondence//Received//PG&E//201209_From(Name)-PTOApproval/
- //Correspondence//Sent//PG&E//190101_To(Name)-PPIPaperwork/
- //Correspondence//Received//ControlsVendor//201202_From(Name)FDS_Rev2/

Using the numeric Year, Month, Day code at the beginning of the folder name as shown will result in the folders being automatically sorted in chronological order.

14.1.1 Document Version Tracking

As the team builds upon the system design and the consensus evolves, key documents such as the DOO, the Project Operational Protocols and Procedures, or the Project Implementation Plan will be continually updated. It is important to be able to easily identify the most recent version, as well as the sequential changes to the document. Adding revision blocks to a document is recommended to establish and maintain consistent version control. Below is an example revision block that could be added to the beginning of every key document.

Revision	Date	Notes
1	8/01/2020	Initial version, John Doe
2	9/01/2020	Reviewed by Jane Doe
3.1	10/01/2020	Revised based on PG&E comments, Jane Doe
3.2	11/01/2020	Revised based on Controls Vendor comments, John Doe
4	12/01/2020	Release to Controls Vendor and PG&E

14.1.2 Recommended Plan Set Etiquette

The construction plan set(s) are a key part of the microgrid design. Projects will typically have multiple plan sets from different partners, as well as multiple plan set versions. When building a plan set, the designer(s) generally start drawing sheets as “concept development” or “initial release” versions. As the project engineers and partners review and improve the design, the designer revises the drawings and adds sheets as needed. With each release of the drawings to project partners, the designer increments the revision: 50% design, 75% design, 90% design, etc., and records the increment in the revision block of each drawing. The percentage designation represents the team’s estimate for how far along the design is and can be helpful for managing partner expectations during review.

Once the plan set reaches the 100% design stage it is ready for permitting. Through the permitting process, bidding, and/or during construction, the designer may need to modify the plan set. These revised versions should be referred to as Rev 1, Rev2, etc. When changes are made after the 100% design, revision clouds are used to identify changes. If a plan set has multiple versions after the 100% design, the revision clouds are identified with the drawing sheet’s revision number (Figure 8). Once construction is complete, the designer generates an “as-built” version of the plan set using notes recorded during construction observations, as well as notes the contractor records on their hard copy of the plan set, if available. Revision clouds are typically removed in the as-built version.

Below is a revision block example for a drawing sheet of a construction plan set; it is standard to embed the revision block within the title block for the plan set. Each drawing sheet will have its own revision block.

7	12/1/2020	AS-BUILT DESIGN
6	9/1/2020	REV 2
5	7/1/2020	REV 1
4	6/1/2020	100 PERCENT DESIGN
3	5/1/2020	90 PERCENT DESIGN
2	2/1/2020	50 PERCENT DESIGN
1	1/1/2020	CONCEPT DEVELOPMENT
REV	DATE	DESCRIPTION

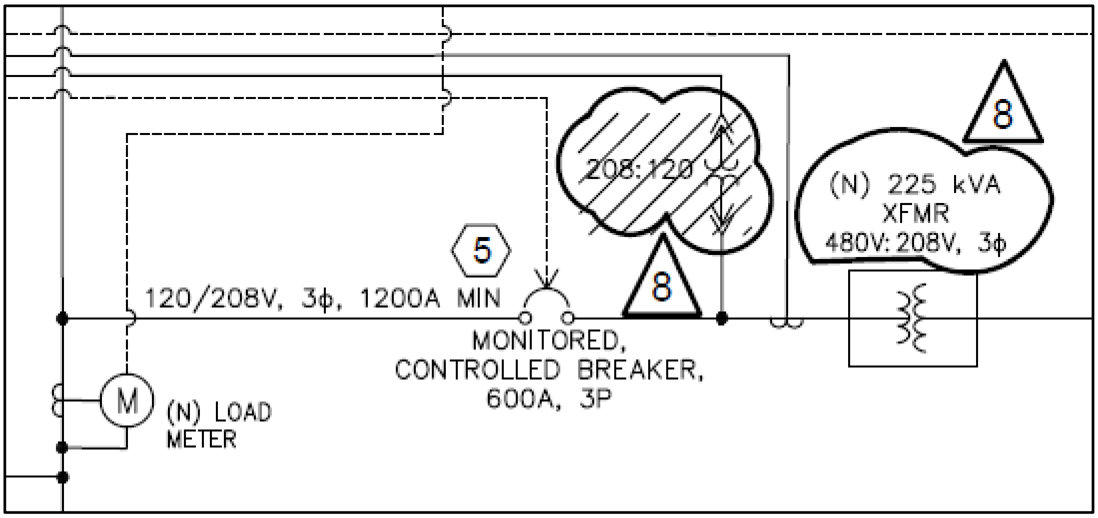


Figure 8: Revision cloud example in construction plan set drawing

15 Glossary

The following definitions apply only to the content presented in this Guide. While the intent is to use industry standard terms and definitions, these terms may be defined more formally in tariffs and contracts. The terms used herein do not replace terms, definitions, or usage in these primary sources such as tariffs and contracts. Please refer to these other sources for formal terms and definitions and where there is ambiguity or conflict, those documents take precedence. Capitalized terms and acronyms are defined elsewhere in the Glossary.

AC Disconnect:, A visible, lockable disconnect switch is required between the generating facilities and the PG&E system for the safety of PG&E personnel. The switch must be gang operated and have a visible open point (air gap, visible either through a viewing window or an operable door). PG&E operating personnel must be able to independently operate the switch and lock it in the open position. This switch will be the PG&E operable disconnect point for the Generating Facility. PG&E currently requires a S&C PMH-3 pad mounted disconnect for Primary Service Customers that are served by an underground service. For overhead Primary Services PG&E currently requires pole mounted load break switch. Information on approved Medium Voltage AC Disconnects is included in **Appendix H- Currently Approved Primary Disconnect Switches .**

Aggregated Net Metering: A tariff structure whereby a customer who has facilities on contiguous properties can generate electricity on one parcel and credit the export to accounts located at other facilities on contiguous properties.

See (https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/net-energy-metering/nem-aggregation.page?) for more information.

Applied Technology Services: A division of PG&E that tests devices that are installed on PG&E's grid. The facility includes a microgrid testing laboratory with RTS, CHIL, and PHIL capabilities.

Air Switch: A Gang-Operated pole-mounted switch that is manually operated by PG&E line workers that provides a visible open position for isolating sections of the distribution grid.

Anti-Islanding: Required functionality built into inverters that are connected to the distribution grid that causes the inverter to continually attempt to perturb the frequency on the Distribution System. When the Distribution System is healthy, the frequency cannot be perturbed by small inverters. When a fault occurs that causes a section of the Distribution System to form an unintentional island, any inverters connected inside that island will be able to perturb the frequency, which will cause them to trip offline for the safety of PG&E personnel, the public, and customer/utility equipment

Apparent Power: The square root of the sum of the squares of the Real Power and Reactive Power. The Apparent Power is used to size Transformers and Grid Forming Generators in Community Microgrids to account for both Real Power and Reactive Power demands. The proportion of Reactive Power (kVAR) and Real Power (KW) demands in an electrical system at a given time determine the apparent power (kVA) that a Grid-Forming Generator needs to provide to maintain stable voltage and frequency.

Arc Flash: An electrical hazard where a flashover of electric current leaves its intended path and travels through the air to another conductor path or to ground.

Automatic Transfer Switch (ATS): A common electrical device used to connect backup Generators to facilities such that two sources are available to serve the load; the switching between the two sources is automatic. The Normal Source is the Distribution System and the Emergency Source is a Synchronous Generator or another source such as a PG&E Service Drop from a separate feeder.

Battery Energy Storage System (BESS): An integrated system that includes batteries to store electrical energy, a battery management system, and inverters to convert direct current from the batteries into alternating current (AC) that can be used to power AC loads and/or Export to the Distribution System.

Behind-the-Meter (BTM): A type of generator interconnection where the generator injects power into the customer's electrical system on the Load-Side of the electricity meter. If the generator's output exceeds the loads in the customer's electrical system, then power Export to the Distribution System may occur within the constraints of the Interconnection Agreement.

Blackstart: The act of energizing the Community Microgrid circuit from a completely de-energized state. The primary Grid-Forming Generator must be able to Blackstart the Community Microgrid and the manufacturer should be made aware of this.

Blue Sky Operations: An operational state for Community Microgrids where all conditions are normal; the microgrid is connected to the Distribution System and all connected generators inside the microgrid are operating in grid-following mode.

Break-Before-Make Transition: When the Community Microgrid circuit is being energized by one source (Normal or Emergency Source) and then transitions to the other source, either a Break-Before-Make or Seamless Transition can be used. In a Break-Before-Make Transition, the Community Microgrid circuit is de-energized for a few seconds during the transition as the switches connecting the two sources actuate. One switch opens to disconnect the source being transitioned from, then after the Community Microgrid is confirmed by the Protection Relay to be de-energized, the other switch closes to connect the circuit to the source being transitioned to. This description applies to Break-Before-Make transitions from grid-connected to islanded state and vice versa. See below for a description of Make-Before-Break (Seamless) Transition.

Circuit Breaker (CB): A device that can open automatically to stop current from flowing into a fault. Circuit Breakers are controlled by either an internal trip unit or a Protection Relay and can be opened and closed using a remote control signal, if so equipped. Circuit Breakers that are suitable for bi-directional power flow are marked as such.

Community Microgrid (CMG): A section of PG&E's distribution grid that includes multiple retail customers and that can be isolated from the rest of the distribution circuit and safely energized by a local grid-forming generator or generators. The PG&E substation bank that normally energizes the feeder is considered the "normal" electricity source for the microgrid and the local grid-forming generator is considered the "emergency" electricity source. The primary purpose of the community microgrid is to provide resiliency services for the customers inside the electrical boundary of the microgrid. Depending on where the community microgrid is located on the distribution grid, it may or may not also provide grid services to PG&E while operating in grid connected mode.

Community Microgrid Aggregator (CMG Aggregator): The contracted counter-party who provides the microgrid forming service to PG&E under the Community Microgrid Enablement Program.

Community Microgrid Enablement Program (CMEP): A PG&E program to provide technical and financial support for community-requested microgrids designed to provide resilience during natural or human caused emergencies and to mitigate power loss from Public Safety Power Shutoffs. The purpose of the Community Microgrid Enablement Program (CMEP) is to empower local stakeholders to initiate and install critical facility community microgrid solutions. The CMEP provides a framework in which communities bring their innovative ideas and local expertise to the table and PG&E provides utility technical and, as appropriate, financial support for projects that are designed to provide resilience and mitigate PSPS impacts, focusing on the most critical and vulnerable customer groups. There are four main components to CMEP:

1) Web-based tools and information;
2) Enhanced Technical Support
3) Community Microgrid Enablement Tariff
4) Cost offsets for certain distribution upgrades

Community Microgrid Enablement Tariff (CMET): Guidelines and regulation which implements multi-customer Community Microgrids on PG&E's distribution system pursuant to Public Utilities Commission Decision D.20-06-017.

Commercial Operation Date: The date on which a wholesale generator has received final written Permission to Operate from PG&E for operating in parallel with the Distribution System.

Concept of Operations (CONOPs): A document that explains the detailed operational strategy for the Community Microgrid. Typically this document includes a controls narrative, description of the microgrid electrical boundary, description of communications network, description of the actors (hardware, software algorithms, and people) in the microgrid, and associated diagrams, etc. An example CONOPs table of contents is included as **Appendix D - Sample CONOPs Table of Contents** in this Guide. This document is typically developed by the CMG Aggregator's team in collaboration with PG&E. The final version of the CONOPs represents consensus on basic operations and typically used as a specification for a controls contractor, who will add all the necessary implementation details and create the Functional Design Specification. The CONOPS should include a Description of Operations (DOO), which is focused specifically on the functionality PG&E will need as the DSO, whereas the CONOPs as a whole will also cover the functionality required by the GSO.

Control Hardware in-the-Loop (CHIL): A type of electrical testing where the actual control hardware that will be used in the Community Microgrid is connected to a power flow simulator and tested to confirm that all of the control logic operates as described in the approved Functional Design

Specification. CHIL is often combined with PHIL but can also be used without PHIL on Community Microgrids with relatively simple circuit design, at PG&E's discretion.

Control Rack: A rack system where the devices that make up the control system are mounted. For Community Microgrids there are typically at least two Control Racks onsite: one for the DSO Microgrid Controller and associated devices, and one for the GSO Generation Controller and associated devices. PG&E allows one Non-Routable serial connection between its microgrid controller and the GSO's Generation Controller for visibility and control coordination purposes. Each Control Rack will typically have devices to allow the controller to communicate with offsite (remote) networks for visibility and control purposes. Typically those connections are via fiber optic cable, point-to-point radio, cellular connection, or coaxial cable. The Control Racks are part of the CMG SCADA system.

Controls Vendor: A company hired the CMG Aggregator to implement the microgrid control system, including drafting of the Functional Design Specification, Points Lists, configuring/programming the devices in the Controls Rack, hosting Factory Acceptance Testing, and providing commissioning support. PG&E recommends that CMG Aggregators select a Controls Vendor with experience in both power systems engineering and controls engineering as well as CHIL, PHIL, and FAT Testing, and onsite commissioning of Distribution System protection and control hardware and software.

CT Ratio: The ratio between the number of wire loops (turns) on the primary and secondary sides of a Current Transformer.

Customer Edge Node: A device or devices that the communication service provider will install in a Control Rack to transition from fiber optic service to Ethernet and route traffic. Data encryption can be supported by Customer Edge Node devices if needed. Typically six rack units are needed at the top of the control rack for the Customer Edge Node devices.

Current Transformer: A sensor used to measure current flowing in an electrical circuit. The Current Transformer generates a small secondary current in proportion to the larger primary current that is flowing to loads on the electrical circuit. The secondary current is passed through input contacts on electrical meters, Protection Relays and Recloser Controllers, which then measure the primary current using the CT Ratio.

Cutover: After Pre-Energization Testing and Trench Inspection have been completed, the CGM Aggregator and PG&E will coordinate a time for a PG&E crew to install the Service Drop and connect the PCC Switchgear to PG&E's distribution feeder. This is commonly referred to as a Cutover. PG&E will typically require that the CMG Aggregator's contractor pull a mandrel through the customer-installed conduit to ensure there are no obstructions before PG&E pulls its conductors through the raceway.

Cyber Security: The means and methods used to protect SCADA systems associated with PG&E, the CMG Aggregator, or CASIO from being accessed by unauthorized entities.

DC Schematic: A schematic drawing created by the manufacturer of any PCC Switchgear where Protection Relays are supervising the PCC Circuit Breaker. The DC Schematic shows how the DC control power is routed through the test switches, the Protection Relay contacts, and the Circuit Breaker control and auxiliary contacts.

Deliverability Status: A term applicable to WDT interconnected generators that indicates whether or not the facility has been determined through study to be able to deliver its nameplate capacity to the Transmission Grid under coincident peak demand and a variety of stressed system conditions. Applicants under PG&E's WDT must specify desired deliverability status. The choices are Energy-Only, Full, or Partial Deliverability. Under CPUC rules, only Generating Facilities that obtain Full or Partial Deliverability Status can provide Resource Adequacy and be compensated accordingly.

Description of Operations (DOO): The Description of Operations (DOO) is a critical section of the CONOPs for the Community Microgrid Project that is specific to PG&E's role as DSO operating the Community Microgrid circuit. After multiple revisions during design development, the DOO will become an official PG&E document that is finalized by PG&E Automation and SCADA engineers and ultimately used by PG&E operators. A detailed description of the DOO is included in the Description of Operations Section of this Guide.

Direct Transfer Trip (DTT): A protection function used to disconnect a generator from the Distribution Grid when a severe event occurs. DTT schemes are typically used when the generator is located remotely and cannot be physically wired to allow a substation controller to trip it offline if needed. If a Synchronous Generator is used as the Primary-Grid Forming Generator in a Community Microgrid and if it is approved to operate in parallel with the Distribution Grid during Blue Sky Operations, then PG&E may require that a DTT scheme be installed.

Distributed Energy Resources (DERs): Sources of electrical energy (generators) which are distributed throughout the electrical grid as opposed to being centralized in large generating stations. DERs also include controllable loads such as EV chargers, batteries, and heat pumps, for example, that can be used to help manage power flow within Community Microgrids.

Distribution System: The portion of PG&E's electrical grid that is fed by the secondary side of substation transformers and operates at less than 60,000 Volts. PG&E Distribution voltage is defined in Electric Rule No. 2. The portion of the grid on the primary side of the substation transformer is transmission system.

Distribution System Operator (DSO): The entity responsible for the safe and reliable operation of the Distribution System, including the section used for the Community Microgrid. This is PG&E in northern and central California.

Distribution Control Center (DCC): PG&E's operations center for monitoring and controlling its electrical distribution system.

Distributed Network Protocol 3 (DNP3): A SCADA protocol commonly used by electric utilities including PG&E. It can be used over both TCP/IP networks and point-to-point serial connections, and includes features to accommodate slow or unreliable communication links and accurate time-stamping of data and events.

<u>Distribution System Upgrades:</u> The additions, modifications, and upgrades to PG&E's Distribution System at or beyond the PCC that are necessary to interconnect a Generating Facility (within the microgrid). Distribution Upgrades do not include Network Upgrades. Distribution Upgrades are to be expected when interconnecting large Generating Facilities.

<u>Droop Control:</u> A closed loop proportional control system to achieve droop characteristics between active power and frequency, and between reactive power and voltage. For Grid-Forming BESS Inverters, a nominal frequency setpoint is tracked by the controller and any deviation of system frequency from the nominal setpoint causes a corresponding real power injection (low system frequency) or absorption (high system frequency). The response is configurable and proportional to total nameplate real power capacity (kW). For Grid-Forming Synchronous Generators, governor output power is increased if system frequency is low and decreased if system frequency is high. For maintaining system voltage, a nominal voltage setpoint is tracked by the controller and if the system voltage is low the Grid-Forming Generator injects reactive power. Likewise, if the system voltage is high, the Grid-Forming Generator absorbs reactive power. Again the response is configurable and proportional to nameplate reactive power capacity (kVAR). Note for inverter-based Grid-Forming Generators, Droop Control can be any type of Grid-Forming control that can achieve the abovementioned droop characteristics, not limited to the particular control method commonly known as "droop control".

<u>Electrical Boundary (Microgrid Boundary):</u> An electrically contiguous area beyond a Microgrid Islanding Point on the Distribution System that defines a microgrid as a single controllable entity. The Electrical Boundary is defined by the point(s) of isolation on the Line-Side and the PG&E customer metering on the Load-Side for each customer service drop within the isolated portion of the circuit.

<u>Emergency Source:</u> The Grid Forming Generator(s) inside the Electrical Boundary of the Community Microgrid that provides electricity to customers during Islanded Operations.

<u>End-of-Line Fault Detection:</u> Required functionality provided Protection Relays supervising the PCC Circuit Breaker on the Primary Grid-Forming Generator in a Community Microgrid that allows the relays to detect faults that occur between the PCC and the ends of the islanded microgrid circuit.

<u>Export:</u> Power flowing out to the Distribution System from a generator at the Point of Common Coupling or out of the Community Microgrid from the Microgrid Islanding Point.

<u>Factory Acceptance Test (FAT):</u> A series of hardware and/or software tests hosted by the manufacturer or vendor of a custom integrated component(s) that is to be deployed for use on a project. The purchaser and their authorized agents are invited to witness the test at the factory or other facility operated by the manufacturer or vendor. The test proves that the manufacturer or vendor has met the customer's specifications. Examples of components where FAT is typically conducted include custom Switchgear and Control Racks. After a successful FAT, the component(s) are ready for PHIL and/or CHIL testing (if applicable) or installation at the project site.

<u>Failsafe State:</u> A safe state that occurs when a critical communication loss or a critical hardware failure occurs. For Community Microgrids there are typically two failsafe states depending on how critical the failure is. For the most critical failure type, such as the recloser control hardware-failure contact closing, the Grid-Forming Generator's PCC Circuit Breaker will be tripped by PG&E and locked out until the failed hardware is replaced. For less critical failures, such as the PG&E Microgrid Controller losing communication with the CMG Aggregator's Generation Controller, the Microgrid will be "Disabled," which means that the CMG Aggregator's generation system can continue to operate in Grid-Following mode only. The CMG Aggregator must allow PG&E to remotely disable the Grid-Forming capabilities of its generator temporarily while the issue is being resolved. If the manufacturer of the Grid-Forming generator cannot provide a means for the Grid-Forming capability to be turned off by PG&E, then the Grid-Forming Generator's PCC Circuit Breaker will likely have to be tripped for all critical communication loss or critical hardware failure cases. PG&E will make every effort to repair its equipment in a timely manner and would prefer that the customer be able to continue Grid-Following operations while the repair is in process; however, Islanded operations must be suspended until the critical failure is resolved.

Fault Current: An abnormal electrical current flowing through an unintended path between multiple phases or between one or more phases and ground in a three phase electrical system. When a fault occurs, current will flow into the fault from the substation and any generators connected to the circuit. Fault Current sourced from small inverters operating in parallel with the grid is of less concern than fault current provided by large generators like a Grid-Forming Generation Source in a Community Microgrid that operates in Parallel Grid-Following mode during Blue Sky Operations. In any case, each generator that operates in Parallel with the grid must detect the fault and disconnect on its own, and the PCC for Grid-Forming Generators must be supervised by two redundant Protection Relays that can operate a circuit breaker to do that.

During Islanded Operations, a Community Microgrid will have different Fault Current availability as compared to Blue Sky Operations. This requires special attention to the Protection Scheme design as described in the Electrical Design Section of this Guide

Feeder: Another name for a Distribution Circuit.

Field Area Network (FAN): PG&E uses a variety of hardware devices on its Distribution System, mostly to regulate voltage and to detect and isolate faults. These devices typically require a communication path to PG&E's Operational Data Network. For Community Microgrids, PG&E also requires a communication path for remote visibility and control. This communication path can be via a fiber optic connection or a point-to-point radio, which requires line-of-sight with an existing radio device within its local Field Area Network. The type of communication path will depend on the existing infrastructure in the project area.

Firewall Appliance: A hardware component that monitors and controls routable network traffic into a trusted, secure network from an untrusted network. The Firewall is configured to filter any packets that do not meet specific rules set up during configuration. In this way, unauthorized traffic is not allowed through the Firewall into the secure network.

Floating Delta System: An ungrounded three phase system connected in delta as opposed to a Wye configuration. PG&E's distribution circuits are typically fed from center-grounded delta transformer windings at the substation. On this type of distribution circuit, when a Community Microgrid operates in islanded mode it becomes a Floating or Ungrounded Delta System. Ground fault current is typically small and can be detected using a ground fault detection bank and overvoltage relay or similar element in a multi-function micro-processor controlled protection relay. Transient overvoltages due to intermittent ground faults on ungrounded systems need to be accounted for when specifying insulation requirements. Additional information is provided in Electrical Design Section of this Guide.

Functional Design Specification (FDS): A detailed and comprehensive document that contains all of the implementation details for the microgrid SCADA system. This document is typically developed by a controls vendor and is based on the Description of Operations (DOO). All the necessary implementation details are included for configuring the hardware in the Control Racks, networking that hardware to remote telemetry points in a cyber-secure fashion, and programming the control logic. Protection relay and Recloser Control settings are included as appendices and these settings will typically include protection settings, analog quantities and binary status variables for visibility, as well as control logic.

Front-of-the-Meter (FTM): A front-of-the-meter generator connection means that the generator connects directly to the Distribution System and delivers electricity to or can charge from the grid in the case of a BESS. FTM resources typically participate in CAISO wholesale markets.

Gang Operated: A characteristic of a multi-pole switch where all poles are opened or closed together, not individually.

Generation System Owner/Operator (GSO): A partner in the Community Microgrid who is responsible for operating a grid-forming generator that supports islanded operations. Typically the GSO will be the CMG Aggregator in a CMET project. However, a Community Microgrid may have more than one GSO aggregated under the umbrella of a third-party CMG Aggregator.

Generation Controller: An automation controller that is located at the project site, owned and operated by the GSO, and used to control the Grid-Forming Generation in Community Microgrids. The Generation Controller is interfaced to the PG&E Microgrid Controller with a Non-Routable Data Link. See the Controls Development Section of this Guide for more details.

Generating Facility: A facility that generates electricity and operates in parallel with the Distribution System.

Good Utility Practice: From PG&E Wholesale Distribution Tariff Glossary: Practices, methods, and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts know at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Greenbook: PG&E’s comprehensive guide to Electric and Gas Service Requirements. This comprehensive guide will help CMG Aggregator teams to understand the specific requirements PG&E has for installing new electric services as well as the safety considerations behind those requirements. It is important that teams consult the Greenbook as design plans are being developed.

End-of-Line Microgrid: A microgrid that has a MIP located on the grid such that when the MIP is open, a line segment from the MIP to the end of the distribution line is isolated from the Distribution System. Only a single MIP is needed to isolate an End-of-Line Microgrid as opposed to a Mid-Feeder Microgrid.

Grid-Forming Generator: A generator that is capable of acting as a voltage source and a current source. It regulates voltage and frequency within its ratings, and can therefore energize an appropriately sized electrical circuit independent of any other electrical source. If generator is an Inverter Based Resource (IBR) it possesses Grid Forming IBR Controls.

Grid Forming IBR Controls: "GFM IBR controls maintain an internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame. This allows the IBR to immediately respond to changes in the external system and maintain IBR control stability during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices in the grid and must also regulate active and reactive power appropriately to support the grid." [11]

Grid-Following Generator: A generator that acts primarily as a current source and that will not operate unless it is connected to an electrical circuit with a stable voltage and frequency generated by a grid-forming generator. Many Grid-Following Generators have voltage and frequency support capabilities that can be enabled if needed depending on their location on the grid. Conventional GFL IBR controls contrast with Grid Forming IBR Controls wherein immediately after a disturbance (0-5 cycles), within the normal operating range of voltage, the output current phasor magnitude and angle remain unchanged, and the current phasor begins changing only within the transient time frame (tens of cycles) to strictly control the active and reactive power being injected into the network. This change in current is the result of the action of outer loop controls. [12] Grid-Following inverter generators installed on PG&E's system after February 22, 2019 are required to provide voltage and frequency support as specified in Electric Rule No. 21.

Ground Fault: An electrical fault where current flows from one or more phase conductors to the earth (ground) using an unintended path.

Grounding Study: An electrical study that checks for hazardous voltage differences between the earth (ground) and metallic structures in a Medium or High Voltage switchyard that could develop in the event of a ground fault. The study results inform the quantity and location of grounding electrodes that are installed in the switchyard to ensure that for the maximum available fault current at the site, no hazardous voltages would be developed.

High Voltage: Greater than 35,000 Volts

---

[11] B. Kroposki *et. al*, "UNIFI Specifications for Grid-forming Inverter-based Resources—Version 1," *UNIFI-2022-2-1*, December 2022.

Hosting Capacity: The ability of a distribution circuit to accept additional DER generator connections. The more DER generators installed on a circuit whose output is intermittent, such as wind and solar, the harder it is to maintain stable voltage and frequency on the circuit without upgrades to the circuit.

Human Machine Interface (HMI): A computer terminal with or without mouse, keyboard, and monitor that allows human operators to monitor and control the microgrid. For Community Microgrids on PG&E's system, PG&E will have a local and a remote HMI. The GSO will typically have both local and remote HMIs. In some cases, third parties that provide operational support to the GSO may have a remote HMI as well. Local HMIs will have both read and write capabilities. Remote HMIs may also have read and write capabilities or read-only capabilities, as deemed appropriate by the GSO.

Inrush Current: The maximum instantaneous input current drawn by the electrical loads and equipment within the microgrid when they are first energized. Inrush current is an important factor in calculating protection settings for the microgrid to ensure that overcurrent elements in protection relays do not inadvertently operate. The CMG Aggregator team should consider the inrush current when sizing the Grid-Forming Generation in order to ensure that the Community Microgrid can be Blackstarted.

current drawn by the electrical loads and equipment within the microgrid when they are first energized. Inrush current is an important factor in calculating protection settings for the microgrid to ensure that overcurrent elements in protection relays do not inadvertently operate. The CMG Aggregator team should consider the inrush current when sizing the Grid-Forming Generation in order to ensure that the Community Microgrid can be Blackstarted.

Import: Power flowing towards a generator at the Point of Common Coupling or into the Community Microgrid from the Microgrid Islanding Point.

Instrument Transformer: See Potential Transformer and Current Transformer.

Interconnection Agreement: A legally binding agreement between PG&E and the owner of a Generating Facility that specifies the conditions under which the Generator will operate when paralleled to PG&E's Distribution System. This agreement includes certain rights and obligations to effect or end interconnections.

Islanding Study Engineer (ISE): A PG&E Distribution Planning Engineer (or third-party consultant hired by PG&E) that is responsible for evaluating the information compiled and prepared by the CMG Aggregator and the PG&E Resilience Solution Engineer and leading the Community Microgrid Technical Consultation. The ISE will evaluate the system design, protection, equipment, and communications aspects of the proposed project and provide feedback and recommendations to the CMG Aggregator team to support their formal application to PG&E's CMET, CMEP, or MIP.

Isochronous Control: A control mode for Synchronous Generators whereby the voltage and frequency output are held constant and are not expected to change in response to changes in Real and Reactive loads that are connected to its output. Frequency is controlled by the rotational speed of the generator rotor and voltage is controlled by the generator's excitation system. From the perspective of loads connected to it, a properly sized Synchronous Generator using Isochronous Control will appear to be essentially the same as the Distribution Grid, in that the voltage and frequency will remain constant and be very stable. For Community Microgrid applications, Isochronous Control has advantages and disadvantages, as discussed further in this Guide.

Islanded Operations: An operational state for Community Microgrids where the Microgrid Islanding Point is open and the microgrid customers are being provided power from a Grid Forming Generator(s)

Latency: A time elapsed between when a change in state occurs in a networked device on the microgrid and when that change in state is recognized by another device on the same network. Latency should be considered when designing communication architecture and control sequences for Community Microgrids.

Line Recloser (Recloser): A switching device, typically pole mounted but also available in pad-mounted form, that is used on the distribution system to isolate sections that have experienced a fault. Reclosers are the preferred Microgrid Islanding Point switching devices for community microgrids. PG&E specifies and installs the reclosers on their distribution circuits. G&W Viper-ST and Cooper Nova are two types of reclosers used by PG&E.

Line-Side: The side of an electrical device that is facing towards the substation that acts as the Normal Source for the Community Microgrid.

Load-Side: The side of an electrical device that is facing away from the substation that acts as the Normal Source for the Community Microgrid. Even though the normal power flow from a given generator may be Export onto the Distribution System, the side of a given device facing away from the substation is still considered the Load-Side.

Load Flow Study: A steady state analysis of an electrical power system. The study determines the operating state of the system and typically various scenarios are evaluated. For Community Microgrids, the Microgrid Islanding Study will include a Load Flow Study for various islanded states that are likely to occur such as high-load, generation mix scenario 1 (night, no solar, battery only with high SOE, for example), low-load, generation scenario 2, and so on. Load Flow Studies will determine if all voltages and thermal loadings are within normal operating ranges for the scenarios modelled. The Load Flow Study can include a stability analysis to look at the effects of large load steps, Blackstarting, or loss of generation units on voltage and frequency stability in the islanded microgrid.

Low Voltage: Less than 600 Volts. Refer to the National Electric Code for further clarification.

Make-Before-Break (Seamless) Transition: When the Community Microgrid circuit is being energized by one source (Normal or Emergency Source) and then transitions to the other source, either a Break-Before-Make or Make-Before-Break Transition can be used. The term Seamless Transition is also used to refer to Make-Before Break Transitions. In a Seamless Transition from grid-connected to islanded state, the Microgrid Islanding Point Recloser opens and within some tens of milliseconds (typical) the Grid-Forming Generator changes from Grid-Following to Grid-Forming mode to keep the Community Microgrid circuit energized without dropping any loads. Depending on the type of fault that caused the Recloser Control to open the Recloser, the transition could be imperceptible to customers or in the other extreme, the loads may be dropped, which would necessitate a Blackstart to complete the transition to islanded state.

In a Seamless Transition from islanded to grid-connected state, the Community Microgrid circuit is synchronized to the Distribution System by the Grid-Forming Generator(s). The Microgrid Islanding Point Recloser Control supervises the synchronization and the recloser control closes when the synchronization conditions are met. The Grid-Forming Generator must change from grid-forming to grid-following mode within two seconds of the recloser closing. See above for a description of Break-Before-Make Transitions.

Medium Voltage: Greater than 600V and less than 35,000 Volts.

Microgrid Controller: The PG&E automation controller that is installed at the project site that communicates with PG&E's Distribution Control Center and that controls the Community Microgrid circuit. The Microgrid Controller is interfaced to the Generation Controller using a Non-Routable Data Link. See the Controls Development Section of this Guide for more information.

Microgrid Islanding Point: (MIP): The point(s) on PG&E's Distribution System that establishes the microgrid interface consistent with applicable standards including IEEE 1547-2018. The Microgrid Islanding Point is the location(s) where the microgrid circuit can be separated, disconnected, or isolated from the rest of the distribution circuit in order to facilitate islanded operations. The Microgrid Electrical Boundary is in part defined by the Microgrid Islanding Point. This point may or may not be coincident with the Point of Common Coupling.

Microgrid Special Facilities Agreement (Microgrid SFA): The agreement that describes the upgrades on the Distribution System, and at the project site to be installed under the terms and conditions regarding Special Facilities (or added facilities) on file with the Commission, pursuant to Electric Rule 2, and incorporated in the MOA.

Mid-Feeder Microgrid: A microgrid that requires opening two or more MIPs in order to begin Islanded Operations.

Modbus: A communications protocol developed by Modicon systems that is used by many manufacturers of embedded systems. Modbus should only be used in the microgrid control system if no other protocols are available. This is because there are more robust options such as DNP3 that are readily available for most devices.

Nameplate Rating: The range of (and typically the maximum) electrical, mechanical, and environmental operating characteristics in which a piece of equipment is designed to operate. These are referenced by the identification label of the equipment. The Nameplate Rating is used by PG&E during the interconnection studies and the Microgrid Islanding Study to characterize the worst-case power flow dynamics between the proposed generation sources and the grid. The Nameplate Rating declared on DER interconnection applications is strictly enforced. If the Nameplate Rating increases after the interconnection application has been submitted, then the application will have to be withdrawn and a new interconnection application must be submitted.

Network Diagram: A drawing that shows all of the devices in the SCADA system for the Community Microgrid and the wired connections between those devices. The types of devices shown include real time automation controllers, HMI computers, alarm annunciators, network switches, Firewall Appliances, Ethernet routers, remote input/output devices, protection relays, recloser controls, and the like. Each wired connection should show the type of cable and communication protocol used over that signal path. The purpose of the Network Diagram is to show the communication interfaces between devices in the SCADA system. This supports controls design, cybersecurity review, device configuration, telemetry and interface development.

Network Upgrades: Additions, modifications, and upgrades to PG&E's Transmission System required at or beyond the Substation to accommodate the interconnection of the Generating Facility and includes Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distribution Upgrades.

For Community Microgrids connecting under a Wholesale Distribution Tariff, Network Upgrades may be identified during the system impact study. Network upgrades are typically more expensive than Distribution System Upgrades.

Net Energy Metering: A scheme which utilizes an energy meter to measure the difference between the energy exported versus the energy imported over a period of time. The customer pays only for the net energy imported (used); thus the energy generated is credited at the tariff specified rate. Net Energy Metering is used for most small generator interconnections such as rooftop solar.

Non-Routable Data Link: A non-network signal path between two devices that is configured such that IP packets cannot be transmitted between devices through the signal path. Non-routable links can be used for peer-to-peer connections between devices in distribution automation and protection systems such as microgrid control systems. For cybersecurity reasons, PG&E only allows non-routable links between CMG Aggregator owned and operated devices and PG&E owned and operated devices. Examples of non-routable links include dry-contact I/O and RS-232 serial. Examples of protocols that can be transmitted over a non-routable serial link are DNP3, Modbus RTU, and SEL Mirrored Bits.

Normal Source: The Distribution System that provides electricity to community microgrid customers during Blue Sky (normal) Operations.

Over-Generation: A condition wherein Grid-Following DERs within a microgrid (e.g., roof-top solar) generate more power than is necessary to supply the loads within an islanded microgrid. Thus, the net-load on the microgrid becomes negative. Depending on the type of Grid-Forming Generators in the islanded microgrid, a variety of failures can occur if Over-Generation is not properly managed.

Parallel Operation: A common electrical state whereby a Generating Facility and the Distribution System or two or more Generating Facilities in a Microgrid operate simultaneously and in concert with each other. In the former case, the Generating Facility matches the voltage and frequency of the Distribution System and acts as a current source or sink. In the latter case, multiple Grid-Forming Generators inject or absorb real and reactive power to support frequency and voltage in the microgrid thereby matching real-time loads exactly. This is typically done using Droop Control. Any Grid-Following Generators inside the Microgrid operate in parallel with the Grid-Forming Generators as described for the former case.

Phase Imbalance: Any condition other than the normal balanced operation of all phases of a multi-phase system in which the voltages and currents are the same across all phases. In Community Microgrids, if the loads are not distributed evenly across the three phases inside the Electrical Boundary, the ability of the grid-forming generator to Blackstart the microgrid circuit could be affected. Phase imbalance should be checked through PG&E when sizing grid-forming generation.

Phase Fault: A system fault involving two or more phases of a multi-phase system. See Fault Current.

Permission to Operate: Express written permission from PG&E that the Generating Facility is permitted to operate in parallel with the Distribution System within the constraints of the applicable Interconnection Agreement.

Permission to Parallel for Test Purposes (PtP for Testing): Authorization granted by PG&E to operate in parallel with the distribution system for testing purposes only. This permission is granted after the initial pre-parallel inspection and testing solely for the purpose of providing time for the customer to complete commissioning and testing of its generating facilities. This permission is limited in time and scope, with notice requirements. This testing time period then is followed by a final pre-parallel inspection before a permission to operate letter is issued.

Pocket Load Analysis: A load study conducted by PG&E on a specific section of its Distribution System. All the electrical accounts in the study area are included to develop an aggregated load profile for the section. PG&E will work with the CMG Aggregator during the Technical Consultation Phase to determine the study area and will then generate the Pocket Load Analysis for the Community Microgrid project.

Point of Common Coupling (PCC): The transfer point for electricity between the DSO's equipment and the GSO's equipment. A typical PCC location would be in the metering section of the GSO's Switchgear. This point may or may not be coincident with the Microgrid Islanding Point.

Potential Transformer (PT): A voltage (potential) measuring device that has primary and secondary windings. The primary winding is connected to the line voltage source and the secondary winding is connected to a control or monitoring device. The PT Ratio defines the degree to which the primary voltage is scaled (reduced) to the secondary output of the PT. Distribution circuit voltages are typically too high for a direct connection to a meter or protection relay so a PT is used to reduce the voltage by a defined amount for use in metering, protection, and control applications.

Power Factor: The Power Factor is defined as the ratio of the Real Power flow to Reactive Power flow at a given point in an alternating current electrical system. A lagging power factor occurs when the current waveform lags behind the voltage waveform and a leading power factor occurs when the opposite is true. Purely resistive loads have a power factor of 1. Lagging power factor is typical of net inductive loads such as motors and coils while leading power factor is typical of net capacitive loads such as long transmission lines. Grid-following Generators should operate with a power factor of 1 (unity power factor) at their PCC unless otherwise specified by PG&E.

Power Hardware in-the-Loop Testing (PHIL): A type of testing where the same make and model Grid-Forming and/or Grid-Following inverters that will be used in the microgrid are connected to a grid emulator and an RTS in a laboratory environment to test system response under extreme conditions that cannot be tested during onsite commissioning. Examples are three phase faults, ground faults, overloading, etc. PHIL is usually conducted with CHIL as well. This is the most comprehensive type of testing that may be required for Community Microgrids deployed on PG&E's Distribution System.

Primary Customer: A customer that receives electrical service from PG&E at Medium Voltage.

Primary Grid-Forming Generator: The dominant Grid-Forming Generator in a Community Microgrid with Standard Architecture. The generator must be large enough to blackstart the Community Microgrid on its own. See further information in Community Microgrid Architecture Section of this Guide.

Pre-Energization Testing (PET): A predetermined set of tests to be performed prior to primary voltage electric service energization. For a generation entity, the interconnection switchgear containing the hardware at the PCC must pass testing, including insulation testing, circuit breaker testing, station battery charge verification, Instrument Transformer circuitry and ratio verification. The relay settings must also be tested by an International Electrical Testing Association (NETA)-certified testing agency prior to being energized. In order to schedule Pre-Energization Testing, PG&E Distribution Engineers will need to have reviewed the switchgear drawings (which should be done prior to manufacturing, to allow any necessary changes to be picked up) as well as Relay Test Reports for the settings shown on the G5-1 form.

Pre-Parallel Inspection (PPI): An inspection scheduled by PG&E prior to issuing Permission to Operate, to ensure that generator required relays, data telemetry and other protective devices are set and functioning as approved by PG&E, proper signage is installed, approved station battery DC voltage equipment is installed, and DC undervoltage detection device and alarm are functioning per PG&E's Transmission Interconnection Handbook Sections G2, G5, and Appendix T. The relay settings must also be tested by an International Electrical Testing Association (NETA)-certified testing agency and witnessed by PG&E prior to being authorized to operate in parallel with the distribution system. PG&E's Energization and Synchronization Requirements are described in Section G5 of the PG&E Transmission Interconnection Handbook.

Priority Alarm: A fault or communication loss or hardware failure alarm that necessitates collaborative action by PG&E and the GSO. Some examples include an electrical fault in the Community Microgrid circuit, a loss of communication between the Microgrid Controller and the Generation Controller, hardware failure of a Recloser Control or Protection Relay. Priority Alarms result in a deviation from the normal operating state of the Community Microgrid and coordination involving human intervention is required to return to a normal operating state.

Protection Relay: A device that sends control signals to a circuit breaker in response to measured system parameters. This is a specialized microprocessor-controlled device with a Human Machine Interface, communication capabilities, voltage, frequency, and current sensing capabilities, and multiple hardware input and output contacts that are used to control circuit breakers or Line Reclosers. The primary purpose of the Protection Relay is to provide fault detection and to operate a circuit breaker to interrupt current flowing into a fault. Modern microprocessor-controlled Protection Relays include logic capabilities that can be used as part of a microgrid control scheme.

Protection Settings Group: Modern microprocessor-controlled Protection Relays have the capability of being programmed with multiple Protection Settings Groups which can be toggled for different system operating states such as when a community microgrid is grid-connected or islanded. GSO owned and operated Protection Relays in Community Microgrids will have one group of protection settings for grid-connected operations and one for islanded operations and PG&E requires visibility into which settings group is active at any given time. PG&E's Recloser Control will typically use one settings group for normal operation and another settings group for a Failsafe State where islanding functionality is disabled.

PT Ratio: The ratio of the number of turns of electrical wire between the primary winding and secondary windings of a PT. A PT used to transform 12,000 Volts on the primary winding to 120 Volts on the secondary winding would have a PT ratio of 100:1.

RTS Testing: Advanced testing using a Real-Time Simulator with Control Power In-the-Loop and sometimes Power Hardware In-the-Loop in order to study the response of the generation, protection, and control systems in Community Microgrids to transient electrical phenomena. See the Controls Testing Section of this Guide for more details.

Reactive Power: Reactive Power is a component of electrical power that is needed to establish the electromagnetic fields present in conductors and equipment powered by alternating current. In order to maintain nominal system voltage, grid operators inject Reactive Power to raise system voltage and absorb Reactive Power to lower system voltage. Reactive power is not consumed by loads but nonetheless must be provided in order for anything but a purely resistive load to operate.

Real Power: Real Power is a component of electrical power that is used to do work by electrical devices (loads) connected to the electrical power system. Grid operators use system frequency as a measure of how well they are matching Real Power demands in the system. If the frequency is low (grid is decelerating) then grid operators inject more real power to bring the frequency up. If the frequency is high (grid is accelerating), grid operators reduce the amount of real power they are injecting into the grid.

Real Time Digital Simulator (RTS): A power system simulation program run on a super computer that is used to study complex power systems.

Recloser Control: A specialized Protection Relay that is used to control Line Reclosers. The primary purpose of the Recloser Control is to provide fault detection and to operate a recloser to interrupt current flowing into a fault and reclose when the fault has been cleared. Modern Recloser Controls include logic capabilities that can be used as part of a microgrid control scheme.

Remote Input/Output (Remote I/O): Devices located throughout a facility that accept inputs from and provide corresponding outputs to other devices as part of the facility SCADA system. One application in

Community Microgrids is cybersecurity, robust passing of binary values between GSO and DSO Control Racks and Protection Relays for Priority Alarms, protection, and control.

Relay Test Report: Customer protection relays that supervise the PCC for grid forming generators must be tested after the associated Switchgear is installed at the project site. The protection settings that PG&E has agreed to, as specified on the G5-1 form, are tested by an electrical testing company using specialized test equipment that can simulate voltages, currents, and frequency on both sides of the Circuit Breaker being supervised. The test equipment will generate a report that shows how the relay responded to each setting shown on the G5-1 form. PG&E Distribution Engineers will use the Relay Test Report to verify that the protection relays have been configured correctly for the site.

Resilience Solution Engineer (RSE): A PG&E engineer who works with the CMG Aggregator during the Consultation stage of the process to evaluate the Community's resilience needs and help craft potential solutions. If a Community Microgrid is the preferred approach, the RSE will gather the necessary information and prepare a Resilience Solution Evaluation Report, in consultation with the CMG Aggregator that will be discussed during the Consultation stage of the process.

Resource Adequacy (RA): Resource Adequacy is the ability to provide an agreed upon amount of power when directed to do so by CAISO. The CPUC adopted a Resource Adequacy Policy in 2004 to ensure that there are enough interconnected energy resources to provide reliable electricity service in California (https://www.cpuc.ca.gov/ra/) Under this complex policy, a Generating Facility that has been awarded Deliverability Status and is participating in the CAISO wholesale markets will be compensated for providing Resource Adequacy. Resource Adequacy is considered an important revenue source for Generating Facilities operating in the CAISO wholesale markets. Obtaining Deliverability Status is non-trivial and needs to be considered carefully at the beginning of the project.

Retransfer: A transition from Islanded to Grid-Connected Operational State.

Ride-Through Settings: These are system protection settings that are set to ignore minor system disturbances and support grid voltage and frequency while still protecting the system from rapid system voltage and frequency excursions. Ride-through settings are prescribed through the IEEE 1547 standards and are implemented in Grid-Following inverter generators installed on PG&E's system as specified in Electric Rule No. 21.

Rule 21 Interconnection: a DER generator interconnection that falls under PG&E's Electric Rule 21, over which the California Public Utilities Commission (CPUC) has jurisdiction. This is in contrast to PG&E's Wholesale Distribution Tariff, which is overseen by the Federal Energy Regulatory Commission (FERC). According the California Public Utilities Commission:

> Rule 21 governs CPUC-jurisdictional interconnections, which include the interconnection of all net energy metering (NEM) facilities, "Non-Export" facilities, and qualifying facilities intending to sell power at avoided cost to the host utility. Rule 21 does not apply to the interconnection of generating or storage facilities intending to participate in wholesale markets overseen by the Federal Energy Regulatory Commission (FERC). These facilities must typically apply for interconnection under the FERC-jurisdictional "Wholesale Distribution Access Tariff" (when

connecting to the distribution system) or "CAISO Tariff" (when connecting to the transmission system).

SCADA: Supervisory Control and Data Acquisition System.

Seamless Transition: See Make-Before-Break.

Secondary Customer: A customer that receives electrical service from PG&E at Low Voltage.

Secondary Grid-Forming Generator: A generator that is capable of grid-forming operation and load sharing using Droop Control during Islanded Operations, but is not capable of forming the islanded microgrid on its own.

Service Drop: Conduits, wires, and sometimes new utility poles and transformers that are installed, owned, and operated by PG&E to serve a new electrical account in PG&E territory. A Primary Service Drop serves Primary Customers. A Secondary Service Drop serves Secondary Customers.

Short Circuit and Coordination Study: An electrical study performed to determine the short circuit currents and the system performance under all fault conditions. The Short Circuit and Coordination study results will prove the adequacy of the equipment to withstand all fault conditions as well as determine and report the ability of the protective device settings to isolate a fault in a coordinated manner. This ensures that the device closest to the fault opens first to minimize the impact to the system.

Single Line Diagram (SLD): An electrical diagram representing an electrical power system in which the circuit components are represented by symbols and the cables and buses that interconnect them are represented by single lines. The single-line diagram should contain all of the pertinent distribution and protection equipment technical specifics such as CT and PT locations and ratios, and Protection Relay elements, as well as clearly identify system points of demarcation such as the PCC and MIP. See **Appendix C – Reference SLD for Reference Architecture CMET Projects** for an example.

Smart Inverter: An advanced inverter that meets the requirements of UL 1741-SA and Electric Rule 21 Section Hh.

Station Battery: The flooded lead-acid battery bank and associated charger that is relied on to keep a grid-interconnected facility's control, protection, telemetry, and security systems active in the case of a grid outage for a predetermined amount of time (8 hours minimum). The station battery must be sized to operate the protection and control system during a standard cycle and still be able to open the circuit breaker at the end of the cycle. The station battery sizing follows the IEEE-485 method. PG&E's specific requirements are located in Appendix T of the Transmission Interconnection Handbook.

State of Energy (SOE): The amount of electrical energy stored at any given time in a BESS, typically reported in kilowatt-hours (kWh). The ability of a BESS to power a given load or absorb energy is dependent on its SOE.

Switchgear: Metal-enclosed equipment that typically contains the Circuit Breaker(s), electricity meters, Protection Relays, Instrument Transformers, and other components necessary to distribute power from the utility to the loads or from generators to the utility. The Distribution System is connected on the Line-Side and Generation and/or loads are connected on the Load-Side. Switchgear often demarks the PCC between the DSO and the GSO in Community Microgrids.

Substation: A facility that contains the equipment necessary for the transformation and distribution of power from the utility transmission grid to the Distribution System or between the Distribution System and load and generation facilities. A substation typically contains the protection, control and networking equipment through which the utility can protect, monitor and control its transmission and Distribution Systems. When a Generating Facility is being studied for interconnection, any impacts on the High Voltage components of the substation are considered Network Upgrades and any impacts on the Medium Voltage components of the substation are considered Distribution Upgrades.

Synchronous Condenser: An alternating current electric machine without a prime mover that spins freely at a speed in sync with the system frequency, but can supply varying magnitudes of reactive power to the electrical system by the management of its internal magnetic fields. Synchronous Condensers can be used to increase fault current availability in Community Microgrids during Islanded Operations when inverters are used as the grid-forming source.

Synchronous Generator: An alternating current electrical machine that converts the mechanical power of a prime mover to electrical power at a particular voltage and frequency. A synchronous generator can supply or absorb varying magnitudes of real power by varying the amount of mechanical power connected to its rotor and can exchange varying magnitudes of reactive power with the electrical system by the management of its internal magnetic fields through the adjustment of the current through its rotor windings. The rotor current is adjusted by means of a closed loop excitation control system to maintain grid stability. Synchronous Generators are not intended to absorb significant quantities of real or reactive power and caution should be exercised to avoid violating manufacturer's reverse real and reactive power limits.

Three Line Diagram: An electrical diagram representing an electrical power system in which the circuit components are represented by symbols, and the cables and busses that interconnect them are represented by three (or more) lines to include phase, neutral, and ground wires.

Time Delay Engine Start Timer (TDES): A setting on conventional ATS that determines the delay time that will elapse before the engine on a generator set will start up after the utility source is lost. Once the engine starts and the generator voltage is acceptable, the ATS will transfer the connected loads to the generator set. For Community Microgrids there may be non-paralleling generator sets connected by ATSs within the Electrical Boundary. The TDES settings can be set to 5 seconds to prevent the engines from starting unnecessarily during transitions from grid-connected to islanded states.

Transformer: An alternating current electrical device that converts electrical power from one voltage to another. For a Community Microgrid, power is typically generated at low voltage which must be transformed to Distribution System voltage for interconnection with the utility.

Trench Inspection: The CMG Aggregator's contractor will typically install the underground conduit or vaults needed to connect their Grid-Forming Generator to the Distribution System. PG&E's design requirements are included in the Green Book. Before a trench containing PG&E conduit is backfilled, a PG&E inspector will typically visit the site and verify that the proper size conduit is installed at the proper depth with the proper bedding material. The PG&E inspector will also verify the backfill is per PG&E specifications. If the CMG Aggregator elects to have PG&E install the underground conduit and vaults, then Trench Inspection is not applicable.

Ungrounded Substation: A substation wherein the substation transformer is ungrounded. If the Community Microgrid is hosted from an Ungrounded Substation, then PG&E will evaluate whether or not a grounding transformer or an overvoltage tripping scheme is required to prevent overvoltage conditions on the High Voltage side of the Substation Transformer. These Network Upgrades can be expensive and CMG Aggregators should determine whether or not the substation feeding the microgrid circuit is ungrounded early on in the process.

Wholesale Distribution Tariff (WDT): The regulations under which a DER generator within a microgrid operates if it is to sell power on the wholesale market. Such a DER generator interconnection is overseen by the Federal Energy Regulatory Commission (FERC) in contrast to those systems which fall under PG&E's Electric Rule 21, which is overseen by the California Public Utilities Commission. There are three paths for WDT Interconnections: Fast Track, Independent Study, and Cluster Study. CMG projects that are connecting generators under the WDT should consider whether or not they intend to provide Resource Adequacy when determining which path to use and be sure to apply for Full or Partial Deliverability as applicable. Further information is included in the Wholesale Interconnections Section of this Guide.

Zero-Sequence Voltage: The potential developed across a resistor connected across a set of broken-delta potential transformers or calculated by a microprocessor-controlled Protection Relay as a result of Line to Ground Faults. Zero-Sequence Voltage is used to detect ground faults on an ungrounded delta system, such as a Community Microgrid during Islanded Operations.

16 Appendix A - Community Microgrid 5-Stage Process Workflow

The creation of a multi-customer Community Microgrid is a complex endeavor involving the distribution system owner and operator (PG&E in this case) and the Community Microgrid Aggregator (CMG Aggregator). Project developers wishing to serve as a third-party CMG Aggregator on PG&E's system must follow the eligibility requirements and procedures in the Community Microgrid Enablement Tariff (CMET). Additionally, if certain financial incentives – such as those available via the Community Microgrid Enablement Program (CMEP)[12] or Microgrid Incentive Program (MIP)[13] – are sought, additional criteria will apply. In all cases, projects will progress through a 5-stage process, described at a high level below. *The entire process from initial consultation through Islanding Operation Date may take approximately 3-5 years.* For more detailed information, please consult with your PG&E representative, or contact communitymicrogrids@pge.com.

1. CONSULT

In this stage, the potential CMG Aggregator and PG&E discuss resilience needs for a specific community. PG&E will help the CMG Aggregator understand the available options and will share basic grid characteristics in the area that may impact the extent of likely upgrades needed under different scenarios.

Objective(s): Help the CMG Aggregator discern which resilience approach may best meet the stated needs of the community. If applicable, prepare the CMG Aggregator to apply for CMET, CMEP, or MIP.

Key documents: Non-disclosure agreement (NDA)

2. APPLY

In this stage, the potential CMG Aggregator will apply for a provisional eligibility review under CMET. If applying for CMEP or MIP, different procedures will apply, and demonstrated partnership with the local community leadership will be required.

[12] www.pge.com/cmep
[13] At the time of this writing, the Microgrid Incentive Program remains under review by the California Public Utilities Commission.

Objective(s): Determine provisional eligibility status for CMET, or funding award for CMEP or MIP.

Key documents: Application for CMET, CMEP, or MIP

3. STUDY

In this stage, two critical sets of studies are undertaken. The Interconnection Study process determines the necessary upgrades and requirements to safely interconnect any new Distributed Energy Resources deployed as part of the microgrid. Separately, the Microgrid Island Study (MIS) is required to ensure the operational safety and stability of the Community Microgrid during Islanded Operations.

Objective(s): Determine the time and cost required for any necessary distribution upgrades for DERs within the microgrid, and identify requirements to ensure the operational safety and stability of the Community Microgrid during Islanded Operations.

Key documents (Interconnection Related): Application for interconnection study (Rule 21 or Wholesale Distribution Tariff (WDT)), Interconnection Agreement

Key documents (MIS Related): Application for Microgrid Islanding Study, Functional Design Specification, Project Operational Protocols & Procedures (POPP), Microgrid Special Facilities Agreement

4. DEVELOP

In this stage, the CMG Aggregator and PG&E develop a Project Implementation Plan, execute the Microgrid Operating Agreement (MOA), and develop their respective parts of the project. The Utility constructs any necessary interconnection special facilities, distribution upgrades, and Microgrid Special Facilities. The CMG Aggregator constructs its elements of the microgrid. Finally, the project goes through pre-commissioning tests and inspections towards achievement of final project commissioning.

Objective(s): Finalize agreement between the parties about roles and responsibilities in the MOA, construct the microgrid including any necessary interconnection special facilities, distribution upgrades, and Microgrid Special Facilities, perform pre-commissioning tests and inspections, and achieve final commissioning of the project.

Key documents: Project Implementation Plan, Project Safety Plan, Microgrid Operating Agreement (MOA), Commissioning Test Plan

5. OPERATE

In this stage, operation of the Community Microgrid is governed by the MOA, the Concept of Operations document, and the Project Operational Protocols & Procedures.

Objective(s): Operate safely and effectively during Blue Sky and Islanded Operations.

Key documents: Change management documentation

17 Appendix B – PG&E Reference Hardware List

The following equipment has been previously deployed by PG&E for use in Community Microgrids hosted on its Distribution System.

Control Rack Components (Listed by location from top of rack down)

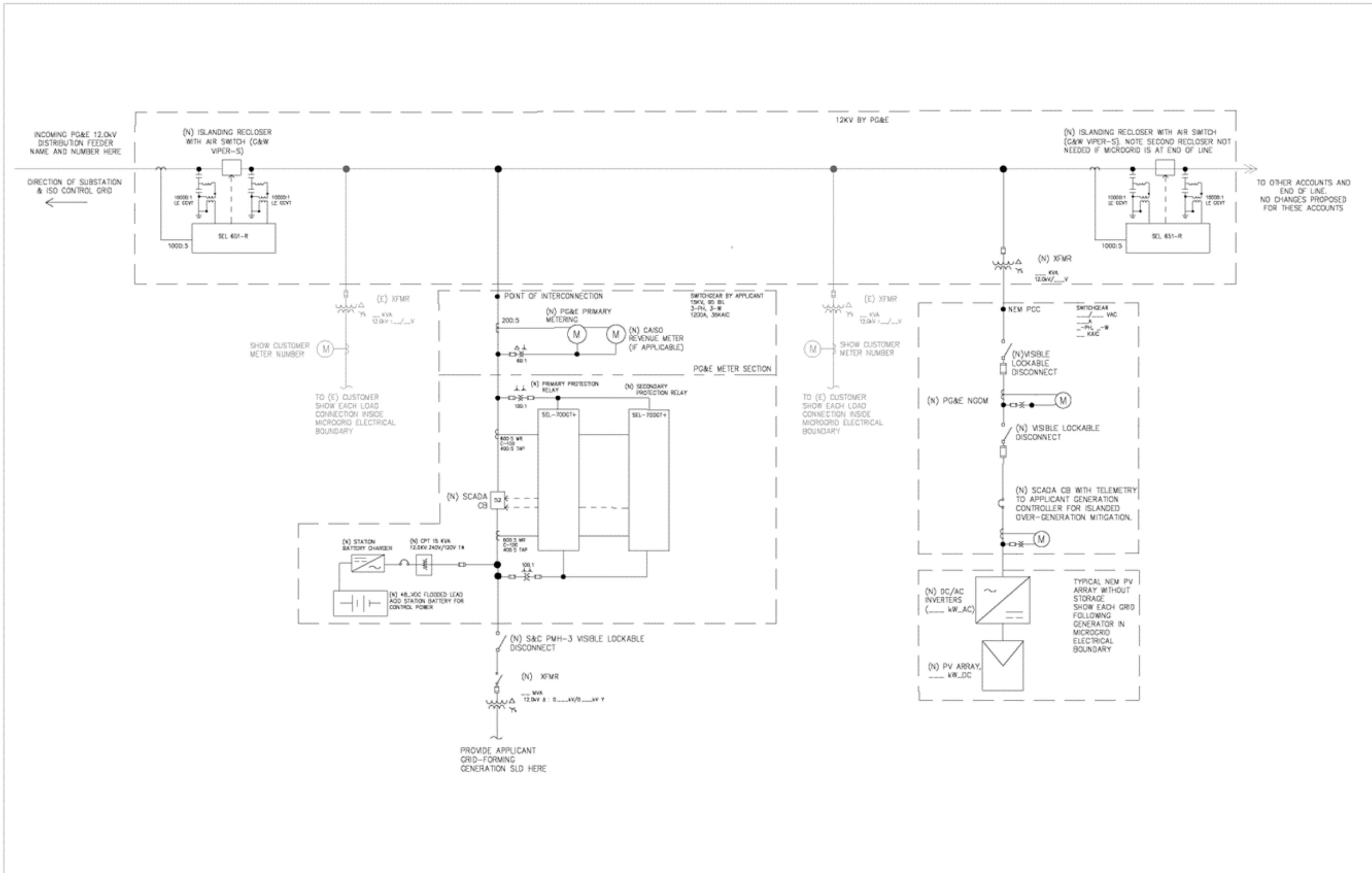
Component	**Power Supply**
Wilmore 1766-48-120-60 U Inverter	48 VDC in, 120 VAC out
Ciena 3930 Service Delivery Switch[14]	120 VAC
SEL 2488 Satellite Synchronized Clock	48 VDC
CISCO 4451 Customer Edge Node Router[5]	120 VAC
Palo Alto Networks PA-850 Firewall	120 VAC
CISCO CGS-2520 Rugged Ethernet Switch	120 VAC
Eaton 4260 Substation Gateway Controller	48 VDC
SEL-2533 Annunciator	48 VDC
SEL-3555 Real Time Automation Controller	48 VDC
SEL-2506 Remote I/O Module	48 VDC

MIP Recloser

Component	**Specification**
Recloser	G&W Viper-ST, 3 single pole LR – 27 kV Kit, six LEA outputs, 2-40 foot power cables.
Recloser Control Relay	SEL-651R with 40 AH battery

[14] Provided by AT&T for sites with fiber optic connections to DCC

18 Appendix C – Reference SLD for Reference Architecture CMET Projects



19 Appendix D - Sample CONOPs Table of Contents

The following CONOPs table of contents is adapted from the Redwood Coast Airport Microgrid (RCAM) project, on which the Reference Architecture is based.

20 Appendix E - Reference Points Lists

The following points lists are an example of the minimum points the PG&E local and remote HMIs might require for a microgrid designed with the Reference Architecture. The lists are not exhaustive, and will vary depending on the microgrid architecture.

Analog Inputs

These values are read by the DSO Microgrid Controller PG&E local and remote HMIs from the source devices and transmitted to the PG&E local and remote HMIs.

Analog Value	Source
Distribution System Frequency at Microgrid Islanding Point	MIP Relay
Microgrid Frequency at Microgrid Islanding Point	MIP Relay
Distribution System Voltage at Microgrid Islanding Point, Phase A, B, C	MIP Relay
Microgrid Voltage at Microgrid Islanding Point, Phase A, B, C	MIP Relay
Current through Microgrid Islanding Point, Phase A, B, C	MIP Relay
Real Power through Microgrid Islanding Point	MIP Relay
Reactive Power through Microgrid Islanding Point	MIP Relay
Microgrid Voltage at PCC, Phase A, B, C	Via Generation Controller
Current through PCC, Phase A, B, C	Via Generation Controller
Real Power through PCC	Via Generation Controller
Reactive Power through PCC	Via Generation Controller

Binary Inputs

These values are read by the DSO Microgrid Controller PG&E local and remote HMIs from the source devices and transmitted to the PG&E local and remote HMIs.

Binary Value	Source
Microgrid Islanding Point Line Recloser Position	MIP Relay
PCC CB Position	Via Generation Controller
Position of other CBs and LRs within microgrid, if extant	Via Generation Controller
Primary Grid-Forming Generator Online State	Via Generation Controller
Primary Grid-Forming Generator Available to island microgrid State	Via Generation Controller

Binary Outputs

These values are sent by the PG&E local or remote HMI to the DSO Microgrid controller, which in turn sends them to the target device.

Binary Output	Target
Trip MIP Line Recloser	MIP Relay
Close MIP Line Recloser	MIP Relay
Trip Generation Offline Command	MIP Relay
PCC CB Close Permissive Command	MIP Relay
Permit MIP Line Recloser Customer Trip	MIP Relay
Permit MIP Line Recloser Customer Close	MIP Relay
MIP Line Recloser Target Reset Command	MIP Relay
MIP Line Recloser Fault Alarm Clear Command	MIP Relay
Microgrid Disabled Mode Initiate Command	MIP Relay
Microgrid Disabled Mode Clear Command	MIP Relay
PG&E Discharge Limit Selected	Microgrid Controller
PG&E Charge Limit Selected	Microgrid Controller
Blackstart Microgrid Command	Microgrid Controller
Generation CB Close	Microgrid Controller
PG&E Auto/Manual Mode Command	Microgrid Controller
Grid-Connect To Islanded Transition Type Command	Microgrid Controller
Islanded To Grid-Connect Transition Type Command	Microgrid Controller
Force Island Command	Microgrid Controller
Seamless Transition To Island Auto Seq Selected	Microgrid Controller
Break-Before-Make Transition To Island Auto Sequence Selected	Microgrid Controller
Seamless Transition From Island Auto Sequence Selected	Microgrid Controller
Break-Before-Make Transition From Island Auto Sequence Selected	Microgrid Controller
Transition To Utility From De-Energized State Auto Sequence Selected	Microgrid Controller
Manual Mode Retransfer Command	Microgrid Controller

21 Appendix F - Reference Priority Alarms List

Priority Alarms indicate a failure that cannot be recovered from automatically or by PG&E action alone, and will require collaborative action between PG&E and the GSO to restore the microgrid to a normal operating state. This reference list of Priority Alarms is based on the Recommended Microgrid Architecture. It is not definitive or exhaustive; some Priority Alarms may not be necessary and others may be required in some microgrid configurations.

Priority Alarm	**Source**
MIP Tripped On Internal Fault	MIPI Relay
Microgrid Internal Fault Alarm	MIP Relay
MIP Line Recloser Failure	MIP Relay
Grid-Forming Generator Failure When Islanded	Via Generation Controller
Microgrid Internal Fault Alarm While Islanded	Via Generation Controller
Fault Within Customer Generation (upstream of PCC) While Islanded	Via Generation Controller
Grid-Forming Generator Internal Fault While Islanded	Via Generation Controller
Grid-Forming Generator Communication Loss While Islanded	Via Generation Controller
PCC CB Tripped on Customer Side Fault While Islanded	Via Generation Controller
PCC CB Failure Status	Via Generation Controller
Generation Controller Communication Problem While Islanded	Via Generation Controller
Generation Controller Hardware Alarm While Islanded	Via Generation Controller
PG&E Gateway Hardware Alarm	PG&E Annunciator Device
Microgrid Controller Hardware Alarm	PG&E Annunciator Device
MIP Relay Hardware Alarm	PG&E Annunciator Device
PG&E Gateway Comm Loss While Grid Connected	Microgrid Controller
PG&E Annunciator Device Hardware Alarm	Microgrid Controller
MIP Relay Remote I/O Comm Loss	MIP Relay
MIP Relay Comm Loss with Grid-Forming Generator Controller	MIP Relay
Generation Controller Comm Loss with Grid-Forming Generator Controller While Islanded	Via Generation Controller
PG&E Gateway Hardware Alarm	PG&E Annunciator Device
Microgrid Controller Hardware Alarm While Islanded	PG&E Annunciator Device
PG&E Gateway Comm Loss While Islanded	Microgrid Controller
PG&E Annunciator Device Hardware Alarm While Islanded	Microgrid Controller
Failed Transition to Island	Microgrid Controller
Failed Transition to Grid	Microgrid Controller

22 Appendix G - Sample Scope of Work for Third-Party Electrical Testing Company

Scope of Work - Example Microgrid Project

The work requires three mobilizations by the testing engineer. All work will be performed during the first visit except for the second relay test that must be witnessed by PG&E approximately 60 days later during the PPI. Reporting is required for each test.

Acceptance Testing to Support PG&E G5 Compliance, Mobilization 1

Component Level Acceptance Testing to include the following equipment:

- 1 x Medium Voltage Switchgear Lineup, Rating 15KV Main 15kV Switchgear Lineup
- 2 x Potential Transformer 12kV-120V 15kV Class
- 3 x Current Transformer, Rating 150/5 15kV Class
- 1 x Main Circuit Breaker, Rating: 1200A 52M
- 2 x Schweitzer SEL 700G Generator Protection Relay 700 GT: 27, 59, 81O/U, 25, 32, 50/51
- 86 - Lockout Relay
- 2 x Accuenergy Acuvim II Meters
- Ground Testing

Function/Witness Testing to Support PG&E Pre-Energization Test of Medium Voltage PCC Switchgear, Mobilization 2

Witness Testing, Function Testing of 700 GT Relays and Equipment, to include;

- 2 x Schweitzer SEL-700G Generator Protection Relay Witness Proof Testing: 27, 59, 81O/U, 25, 32, 50/51

Cable Testing and Onsite Assistance, to include;

- VLF Test one set of Medium Voltage cables
- After cable testing is complete, assist with energization. Switching by others.

Function/Witness Testing to Support Generator Pre-Parallel Inspection, Mobilization 3

Witness Testing, Function Testing of 700 GT Relays and Equipment, to include;

- 2 x Schweitzer SEL-700G Generator Protection Relay Witness Proof Testing, 27, 59, 81O/U, 25, 32, 50/51

23 Appendix H- Currently Approved Primary Disconnect Switches

Each project will be evaluated on a case by case basis but it is expected that the majority of projects will use Overhead Line Reclosers and/or Pad Mounted Interrupters in line with existing PG&E distribution standards utilized for typical interconnections which usually will be sufficient for microgrid designs

24 Appendix I- CMET Project Resources and CMET Project Balance of System Facilities

CMET PROJECT RESOURCES				
Location	Description	Mfg	Model Number	Owner
TESLA FIELD ENCLOSURE	BESS INVERTERS	TESLA	1462965-4X-B (QTY 3)	RCEA
TESLA FIELD ENCLOSURE	2.198 MW PV ARRAY	LONGI SOLAR	LR4-72HIBD-430M	RCEA
TESLA FIELD ENCLOSURE	8.874 MWH LI-ION BATTERY	TESLA	MEGAPACK (QTY 11 @70KVA EACH)	RCEA
TESLA FIELD ENCLOSURE	TESLA BESS SITE MASTER CONTROLLER	TESLA	TESLA	RCEA
TESLA FIELD ENCLOSURE	TESLA INTERNAL FIELD SWITCH	HIRSCHMANN	RSP20	RCEA
TESLA FIELD ENCLOSURE	BATTERY METER	ACCUENERGY	ACUDC 243 (QTY 3)	RCEA
TESLA FIELD ENCLOSURE	SURGE ARRESTER	COOPER	3238018C15M	RCEA
TESLA FIELD ENCLOSURE	REMOTE I/O UNIT	SEL	SEL-2505	RCEA
TESLA FIELD ENCLOSURE	STEP UP TRANSFORMER (PAD MOUNT)	COOPER	12KV/480v DELTA-WYE	RCEA

CMET PROJECT BALANCE OF SYSTEM				
Location	Description	Mfg	Model Number	Owner
FTM RCEA SWITCHGEAR	PRIMARY PROTECTIVE RELAY	SEL	SEL-700GT+	RCEA
FTM RCEA SWITCHGEAR	SECONDARY PROTECTIVE RELAY	SEL	SEL-700GT+	RCEA
FTM RCEA SWITCHGEAR	LOCAL HMI	SEL	SEL-3355	RCEA
FTM RCEA SWITCHGEAR	HMI MONITOR AND KEYBOARD	CYBERVIEW	RKP119	RCEA
FTM RCEA SWITCHGEAR	SATELLITE CLOCK	SEL	SEL-2488	RCEA
FTM RCEA SWITCHGEAR	GENERATION CONTROLLER	SEL	SEL-3555	RCEA
FTM RCEA SWITCHGEAR	ANNUNCIATOR	SEL	SEL-3505-3	RCEA
FTM RCEA SWITCHGEAR	SECURITY GATEWAY	SEL	SEL-3620	RCEA
FTM RCEA SWITCHGEAR	INTERNAL NETWORK SWITCH	SEL	SEL-2730M	RCEA
FTM RCEA SWITCHGEAR	CAISO METER	SEL	SEL-735	RCEA
FTM RCEA SWITCHGEAR	ETHERNET TRANSCEIVER	SEL	SEL-2890	RCEA
FTM RCEA SWITCHGEAR	BESS METER	ACCUENERGY	ACUVIM-IIR	RCEA

CMET PROJECT SPECIAL FACILITIES				
Location	Description	Mfg	Model Number	Owner
PG&E MICROGRID CONTROL CABINET	SATELLITE CLOCK	SEL	SEL-2488	PG&E
PG&E MICROGRID CONTROL CABINET	MICROGRID CONTROLLER	SEL	SEL-3555	PG&E
PG&E MICROGRID CONTROL CABINET	SUBSTATION GATEWAY	EATON	SG-4260	PG&E
PG&E MICROGRID CONTROL CABINET	MPLS ROUTER (FIBER)	CISCO	4451 CISCO MVRF	PG&E
PG&E MICROGRID CONTROL CABINET	NETWORK SWITCH	CISCO	CGS-2520-16S8PC	PG&E
PG&E MICROGRID CONTROL CABINET	NETWORK SWITCH (ATT FIBER)	CIENA	3930	PG&E
PG&E MICROGRID CONTROL CABINET	INVERTER	WILMORE	WILMORE 1766-48-120-60-U	PG&E
PG&E MICROGRID CONTROL CABINET	POWER DISTRIBUTION UNIT	TRIPP LITE	RS-0615-R PDU	PG&E
PG&E MICROGRID CONTROL CABINET	POWER DISTRIBUTION UNIT	TRIPP LITE	RS-0615-R PDU	PG&E
PG&E MICROGRID CONTROL CABINET	KVM SWITCH	IO GEAR	GCS1108KIT2	PG&E
PG&E MICROGRID CONTROL CABINET	HMI MONITOR AND KEYBOARD	CYBERVIEW	RKP119	PG&E
PG&E MICROGRID CONTROL CABINET	PALO ALTO FIREWALL	PAN	PA-850	PG&E
PG&E MICROGRID CONTROL CABINET	LOCAL HMI	SEL	SEL-3355	PG&E
PG&E MICROGRID CONTROL CABINET	REMOTE I/O MODULE	SEL	SEL-2506	PG&E
PG&E MICROGRID CONTROL CABINET	ALARM ANNUNCIATOR	SEL	SEL-2533	PG&E
FIELD - PG&E POLE	FIBER OPTIC TRANCEIVER	SEL	SEL-2815	PG&E
FIELD - PG&E POLE	FIBER OPTIC TRANCEIVER	SEL	SEL-2812	PG&E
FIELD - PG&E POLE	ISLANDING RECLOSER RELAY	SEL	SEL-651R	PG&E
FIELD - PG&E POLE	ISLANDING RECLOSER	G&W	VIPER-ST	PG&E

25 Appendix J – Sample Commissioning Test Plan

Date:						
		Island Function Test #1				
Description:		**Manual planned Seamless Islanding Event initiated from onsite Eaton 4260 HMI, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions		Unbypass LR 136680 for the duration of commissioning				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
		LR closed with source and load side voltage good				
		Generation CB closed				
		BESS Available				
		System Operative				
		Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1		**Enable the Microgrid**	**Planned Time**	**Actual Time**	**Result**	
	a	Enable Microgrid from onsite Eaton 4260 HMI				
	b	Check that Microgrid = Enabled on DC SCADA Main Overview Screen				DCC OPERATOR NEEDED
	c	Check that Microgrid Disabled Mode light is OFF in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
	d	Check that Microgrid Disbled Mode light is OFF in the Eaton 4260 LR Faceplate Screen				
Step 2		**Set the transition type for Grid-Connected to Islanded Transition**	**Planned Time**	**Time**	**Result**	
	a	Navigate to "Grid Connected to Islanded" screen on Eaton 4260 HMI and select seamless transition type				
	b	Check that the transition type on the "Grid Connected to Islanded" screen in DC SCADA also shows "Seamless"				DCC OPERATOR NEEDED
Step 3		**Execute a manual seamless transition to islanded state**	**Planned Time**	**Time**	**Result**	
	a	On "Grid Connected to Islanded" screen in the Eaton 4260 HMI click the Start Seamless button and then execute.				
	b	Check that LR Opens and source and load side voltages remain nominal				
Step 4		**Prepare for manual seamless retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
	a	After 15 minutes have passed since the LR opened, Navigate to "Islanded to Grid Connected" screen on Eaton 4260 HMI and select seamless transition type.				
	b	Check that the transition type on the "Islanded to Grid Connected" screen in the DC SCADA HMI also shows "Seamless"				DCC OPERATOR NEEDED
	c	Using the SEL-3355, Connect to the SEL-651R using accelerator quickset and open the HMI				
Step 5		**Execute a manual seamless transition to Grid Connected state**	**Planned Time**	**Time**	**Result**	
	a	On the "Islanded to Grid Connected" screen on the Eaton 4260 HMI click the Start Seamless button and then execute				
	b	Toggle to the SEL-3355 using the KVM switch and observe synchroscope and confirm that the LR closes				
Step 6		**Wrap up.**	**Planned Time**	**Time**	**Result**	
	a	Set Microgrid Mode = Disabled from Main Overview Screen on the Eaton 4260 HMI				
	b	Check that Microgrid = Disabled on DC SCADA HMI Main Overview Screen				DCC OPERATOR NEEDED
	c	Check that Microgrid Disbled Mode light is ON in the Eaton 4260 HMI LR Faceplate Screen				
	d	Download Event Reports from the SEL-651R				

		Island Function Test #2				
Description:		**Manual planned Seamless Islanding Event initiated from DC SCADA HMI, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions		LR closed with source and load side voltage good				
		Generation CB closed				
		BESS Available				
		System Operative				
		Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1		**Enable the Microgrid**	**Planned Time**	**Actual Time**	**Result**	
	a	Enable Microgrid from DC SCADA Main Overview Screen				DCC OPERATOR NEEDED
	b	Check that Microgrid = Enabled on onsite Eaton 4260 Main Overview Screen				
	c	Check that Microgrid Disabled Mode light is OFF in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
	d	Check that Microgrid Disbled Mode light is OFF in the Eaton 4260 LR Faceplate Screen				
Step 2		**Set the transition type for Grid-Connected to Islanded Transition**	**Planned Time**	**Time**	**Result**	
	a	Navigate to "Grid Connected to Islanded" screen on DC SCADA HMI and select seamless transition type				DCC OPERATOR NEEDED
	b	Check that the transition type on the "Grid Connected to Islanded" screen in Eaton 4260 also shows "Seamless"				
Step 3		**Execute a manual seamless transition to islanded state**	**Planned Time**	**Time**	**Result**	
	a	On "Grid Connected to Islanded" screen in the DC SCADA HMI click the "Start Seamless" button and then execute.				DCC OPERATOR NEEDED
	b	Check that LR opens and source and load side voltages are nominal				
Step 4		**Prepare for manual seamless retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
	a	After 15 minutes have passed since the LR opened, Navigate to "Islanded to Grid Connected" screen on DC SCADA HMI and select seamless transition type.				DCC OPERATOR NEEDED
	b	Check that the transition type on the "Islanded to Grid Connected" screen in Eaton 4260 HMI also shows "Seamless"				
	c	Connect to the SEL-651R using accelerator quickset and open the HMI synchroscope				
Step 5		**Execute a manual seamless transition to Grid Connected state**	**Planned Time**	**Time**	**Result**	
	a	On the "Islanded to Grid Connected" screen on the DC SCADA HMI click the Start Seamless button and then execute				DCC OPERATOR NEEDED
	b	Observe synchroscope and confirm that the LR closes				
Step 6		**Wrap up.**	**Planned Time**	**Time**	**Result**	
	a	Set Microgrid Mode = Disabled from Main Overview Screen in DC SCADA				
	b	Check that Microgrid = Disabled on Eaton 4260 HMI Main Overview Screen				
	c	Check that Microgrid Disbled Mode light is ON in the DC SCADA LR Faceplate Screen				
	d	Download Event Reports from the SEL-651R				

Island Function Test #3

Description:		**Manual planned Break-Before-Make Islanding Event initiated from onsite Eaton 4260 HMI, followed by islanding for 20 minutes, followed by manual Break-Before-Make retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions		LR closed with source and load side voltage good				
		Generation CB closed				
		BESS Available				
		System Operative				
		Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1		**Enable the Microgrid**	**Planned Time**	**Actual Time**	**Result**	
	a	Enable Microgrid from onsite Eaton 4260 HMI				
	b	Check that Microgrid = Enabled on DC SCADA Main Overview Screen				DCC OPERATOR NEEDED
	c	Check that Microgrid Disabled Mode light is OFF in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
	d	Check that Microgrid Disbled Mode light is OFF in the Eaton 4260 LR Faceplate Screen				
Step 2		**Set the transition type for Grid-Connected to Islanded Transition**	**Planned Time**	**Time**	**Result**	
	a	Navigate to "Grid Connected to Islanded" screen on Eaton 4260 HMI and select Break-Before-Make transition type				
	b	Check that the transition type on the "Grid Connected to Islanded" screen in DC SCADA also shows "Break-Before-Make"				DCC OPERATOR NEEDED
Step 3		**Execute a manual break-before-make transition to islanded state**	**Planned Time**	**Time**	**Result**	
	a	On "Grid Connected to Islanded" screen in the Eaton 4260 HMI click the Start Break Before Make button and then execute.				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
	b	Check that LR Opens and after a momentary outage, the source and load side voltages are nominal				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 4		**Prepare for manual break-before-make retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
	a	After 15 minutes have passed since the LR opened, Navigate to "Islanded to Grid Connected" screen on Eaton 4260 HMI and select Break-Before-Make transition type.				
	b	Check that the transition type on the "Islanded to Grid Connected" screen in the DC SCADA HMI also shows "Break-Before-Make"				DCC OPERATOR NEEDED
Step 5		**Execute a manual break-before-make transition to Grid Connected state**	**Planned Time**	**Time**	**Result**	
	a	On the "Islanded to Grid Connected" screen on the Eaton 4260 HMI click the Start Break-Before-Make button and then execute				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
	b	Confirm that the LR closes after a momentary outage on the microgrid				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 6		**Wrap up.**	**Planned Time**	**Time**	**Result**	
	a	Set Microgrid Mode = Disabled from Main Overview Screen on the Eaton 4260 HMI				
	b	Check that Microgrid = Disabled on DC SCADA HMI Main Overview Screen				DCC OPERATOR NEEDED
	c	Check that Microgrid Disbled Mode light is ON in the Eaton 4260 HMI LR Faceplate Screen				
	d	Download Event Reports from the SEL-651R				

Island Function Test #4

Description:		**Manual planned Break-Before-Make Islanding Event initiated from onsite DC SCADA HMI, followed by islanding for 20 minutes, followed by manual Break-Before-Make retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions		LR closed with source and load side voltage good				
		Generation CB closed				
		BESS Available				
		System Operative				
		Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
		Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1		**Enable the Microgrid**	**Planned Time**	**Actual Time**	**Result**	
	a	Enable Microgrid from DC SCADA HMI				DCC OPERATOR NEEDED
	b	Check that Microgrid = Enabled on onsite Eaton 4260 HMI Main Overview Screen				
	c	Check that Microgrid Disabled Mode light is OFF in the DC SCADA HMI LR Faceplate Screen				DCC OPERATOR NEEDED
	d	Check that Microgrid Disbled Mode light is OFF in the Eaton 4260 LR Faceplate Screen				
Step 2		**Set the transition type for Grid-Connected to Islanded Transition**	**Planned Time**	**Time**	**Result**	
	a	Navigate to "Grid Connected to Islanded" screen on the DC SCADA HMI and select Break-Before-Make transition type				DCC OPERATOR NEEDED
	b	Check that the transition type on the "Grid Connected to Islanded" screen in the onsite Eaton 4260 HMI also shows "Break-Before-Make"				
Step 3		**Execute a manual break-before-make transition to islanded state**	**Planned Time**	**Time**	**Result**	
	a	On "Grid Connected to Islanded" screen in the DC SCADA HMI click the Start Break Before Make button and then execute.				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
	b	Check that LR Opens and after a momentary outage, the source and load side voltages are nominal				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 4		**Prepare for manual break-before-make retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
	a	After 15 minutes have passed since the LR opened, Navigate to "Islanded to Grid Connected" screen on DC SCADA HMI and select Break-Before-Make transition type.				DCC OPERATOR NEEDED
	b	Check that the transition type on the "Islanded to Grid Connected" screen in the onsite Eaton 4260 HMI also shows "Break-Before-Make"				
Step 5		**Execute a manual break-before-make transition to Grid Connected state**	**Planned Time**	**Time**	**Result**	
	a	On the "Islanded to Grid Connected" screen on the DC SCADA HMI click the Start Break-Before-Make button and then execute				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
	b	Confirm that the LR closes after a momentary outage on the microgrid				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 6		**Wrap up.**	**Planned Time**	**Time**	**Result**	
	a	Set Microgrid Mode = Disabled from Main Overview Screen on the DC SCADAHMI				DCC OPERATOR NEEDED
	b	Check that Microgrid = Disabled on onsite Eaton 4260 HMI Main Overview Screen				
	c	Check that Microgrid Disbled Mode light is ON in the DC SCADA HMI LR Faceplate Screen				DCC OPERATOR NEEDED
	d	Download Event Reports from the SEL-651R				
	e	Bypass 136680				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED

Island Function Test #5

Description:	**Automatic unplanned Seamless Islanding Event , followed by islanding for 20 minutes, followed by automatic seamless retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions	Unbypass LR 136680 for the duration of commissioning				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
	LR closed with source and load side voltage good				
	Generation CB closed				
	BESS Available				
	System Operative				
	Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1	**Enable the Microgrid and set to Auto**	**Planned Time**	**Actual Time**	**Result**	
a	Enable Microgrid from the DC SCADA HMI				DCC OPERATOR NEEDED
b	Check that Microgrid Disabled Mode light is OFF in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
c	Set Microgrid Control Mode to Auto on main overview screen in DC SCADA HMI				DCC OPERATOR NEEDED
d	Check that Microgrid Auto indicator light is on in LR Faceplate Screen in DC SCADA HMI				DCC OPERATOR NEEDED
Step 2	**Set the transition types**	**Planned Time**	**Time**	**Result**	
a	Navigate to "Grid Connected to Islanded" screen on DC SCADA HMI and select seamless transition type				DCC OPERATOR NEEDED
b	Navigate to "Islanded to Grid Connected" screen on the DC SCADA HMI and select seamless transition type.				DCC OPERATOR NEEDED
Step 3	**Trigger an automatic seamless transition to islanded state**	**Planned Time**	**Time**	**Result**	
a	Open at least one phase on the source side of LR 136680				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
b	Check that LR Opens and source and load side voltages remain nominal				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 4	**Trigger an automatic seamless retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
a	Close source side device used to trigger				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
b	Connect to the SEL-651R using accelerator quickset and open the HMI synchroscope				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED
Step 5	**Observe a automatic seamless transition to grid connected state**	**Planned Time**	**Time**	**Result**	
a	15 minutes after source side voltage is restored, observe synchroscope and confirm that the LR closes automatically				
Step 6	**Wrap up.**	**Planned Time**	**Time**	**Result**	
a	Set Microgrid Mode = Disabled from Main Overview Screen on the Eaton 4260 HMI				
b	Check that Microgrid = Disabled on DC SCADA HMI Main Overview Screen				DCC OPERATOR NEEDED
c	Check that Microgrid Disbled Mode light is ON in the Eaton 4260 HMI LR Faceplate Screen				
d	Download Event Reports from the SEL-651R				

Island Function Test #6

Description:	**Automatic unplanned internal fault Event , followed by manual restoration to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions	LR closed with source and load side voltage good				
	Generation CB closed				
	BESS Available				
	System Operative				
	Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
Step 1	**Enable the Microgrid and set to Auto**	**Planned Time**	**Actual Time**	**Result**	
a	Enable Microgrid from the DC SCADA HMI				DCC OPERATOR NEEDED
b	Check that Microgrid Disabled Mode light is OFF in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
c	Set Microgrid Control Mode to Auto on main overview screen in DC SCADA HMI				DCC OPERATOR NEEDED
d	Check that Microgrid Auto indicator light is on in LR Faceplate Screen in DC SCADA HMI				DCC OPERATOR NEEDED
Step 2	**Set the transition types**	**Planned Time**	**Time**	**Result**	
a	Navigate to "Grid Connected to Islanded" screen on DC SCADA HMI and select seamless transition type				DCC OPERATOR NEEDED
Step 3	**Trigger a Zone 1 Primary Fault**	**Planned Time**	**Time**	**Result**	
a	Temporarily change phase time overcurrent element 51AJP pickup in Group 6 of the SEL-651R settings to a value around 25 amps (pri). This value needs to be above the peak load inside the microgrid with some headroom.				PG&E to verify appropriate trip setting
b	RCEA operator will send a charge command to the battery to cause the 51P element to pick up and cause a trip of LR 136680.				Customers will loose power at this point.
c	Verify that LR 136680 trips.				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED/MONENTARY OUTAGE
d	Verify that the Generation CB trips and is locked out immediately after LR 136680 trips.				Verify that internal fault alarm asserts on RCEA HMI
e	Verify that RCEA operators cannot close the Generation CB with PG&E lockout asserted				
Step 4	**Manually restore power to the customers in the microgrid.**	**Planned Time**	**Time**	**Result**	
a	Reset targets on the faceplate of LR 136680 (either from actual LR faceplate or from LR faceplate screen in DC SCADA)				DCC OPERATOR NEEDED
b	Confirm source side voltage is good.				
c	Close LR 136680 using the close button on the faceplate of LR (actual LR faceplate)				Customers will be reenergized at this point.
Step 5	**Close Generation CB**	**Planned Time**	**Time**	**Result**	Check that internal fault alarm can be cleared in RCEA HMI (Generation Screen)
a	From Main Overview SCADA Screen, reset Generation CB Lockout				DCC OPERATOR NEEDED
b	From Main Overview Screen, Force Generation CB Close				DCC OPERATOR NEEDED
c	Verify Generation CB Closes				
Step 6	**Wrap up.**	**Planned Time**	**Time**	**Result**	
a	Set Microgrid Mode = Disabled from Main Overview Screen on the Eaton 4260 HMI				
b	Check that Microgrid = Disabled on DC SCADA HMI Main Overview Screen				DCC OPERATOR NEEDED
c	Check that Microgrid Disbled Mode light is ON in the Eaton 4260 HMI LR Faceplate Screen				
d	Download Event Reports from the SEL-651R and SEL-700GT+ Primary				

Island Function Test #7					
Description:	**Manual planned Seamless Islanding Event initiated from DC SCADA HMI, followed by load shed testing, followed by manual seamless retransfer to grid-connected state.**	**Initial Conditions Confirmed?**			**Notes**
Initial Conditions	LR closed with source and load side voltage good				
	Generation CB closed				
	BESS Available				
	System Operative				
	Microgrid Mode = Disabled (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Control Mode = Manual (Check both DC SCADA and Eaton 4260)				DCC OPERATOR NEEDED
	Clear SERs in SEL-651R, SEL-3555 MGC, SEL-3555 GC, and SEL-3505 ISLC, and SEL-700GT+ primary				
	Confirm that BESS SOC is greater than 30%				
Step 1	**Enable the Microgrid**	**Planned Time**	**Actual Time**	**Result**	
a	Enable Microgrid from DC SCADA Main Overview Screen				DCC OPERATOR NEEDED
Step 2	**Set the transition type for Grid-Connected to Islanded Transition**	**Planned Time**	**Time**	**Result**	
a	Navigate to "Grid Connected to Islanded" screen on DC SCADA HMI and select seamless transition type				DCC OPERATOR NEEDED
Step 3	**Execute a manual seamless transition to islanded state**	**Planned Time**	**Time**	**Result**	
a	On "Grid Connected to Islanded" screen in the DC SCADA HMI click the Start Seamless button and then execute.				DCC OPERATOR NEEDED
b	Check that LR opens and source and load side voltages are nominal				
Step 4	**Check automatic load shedding and Generation Limp**	**Planned Time**	**Time**	**Result**	
a	Force BESS SOC to 19% and verify that EV load shed flag is set in Generation Controller				
b	Force BESS SOC to 4% and verify that Generation CB trips				
c	Force BESS SOC to 11% and verify that Generation CB Closes				
d	Unforce BESS SOC and verify that EV load shed flag is deasserted in Generation Controller				
e	Force BESS SOC to 96% and verify that NEM PV CB trips				
f	Force BESS SOC to 79% and verify that NEM PV CB closes				
Step 5	**Prepare for manual seamless retransfer to grid-connected state**	**Planned Time**	**Time**	**Result**	
a	After at least 15 minutes have passed since the LR opened, Navigate to "Islanded to Grid Connected" screen on DC SCADA HMI and select seamless transition type.				DCC OPERATOR NEEDED
b	Connect to the SEL-651R using accelerator quickset and open the HMI synchroscope				
Step 6	**Execute a manual seamless transition to islanded state**	**Planned Time**	**Time**	**Result**	
a	On the "Islanded to Grid Connected" screen on the DC SCADA HMI click the Start Seamless button and then execute				DCC OPERATOR NEEDED
b	Observe synchroscope and confirm that the LR closes				
Step 7	**Wrap up.**	**Planned Time**	**Time**	**Result**	
a	Set Microgrid Mode = Disabled from Main Overview Screen in DC SCADA				DCC OPERATOR NEEDED
b	Check that Microgrid = Disabled on Eaton 4260 HMI Main Overview Screen				
c	Check that Microgrid Disbled Mode light is ON in the DC SCADA LR Faceplate Screen				DCC OPERATOR NEEDED
d	Download Event Reports from the SEL-651R				
e	Bypass 136680				DCC OPERATOR NEEDED/FIELD SWITCHING NEEDED