Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC 3.11 – Location-Specific Options for Reliability and/or Resilience Upgrades***
Reference Name	***EPIC 3.11 Redwood Coast Airport Microgrid (RCAM)***
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1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for EPIC Project 3.11 – Location-Specific Options for Reliability and/or Resilience Upgrades, also referred to as the Redwood Coast Airport Microgrid (RCAM), as listed in the EPIC Annual Report. The project was authorized in June 2019 and concluded in July 2023.

1.1 RCAM Project Context

Over the past 10 years, the United States, and California in particular, have experienced an increased frequency of climate change related natural disasters which have led to longer and more frequent disruptions of power. In the face of these new challenges, utilities, communities, and individual customers are seeking to enhance resiliency of the energy system including through the development and deployment of microgrids. Microgrids can be a useful tool in providing energy resilience during broader grid disruptions.

The demand for this functionality is increasing, particularly at critical facilities that are prone to natural disasters and/or de-energization due to Public Safety Power Shutoff (PSPS) events. Behind-the-Meter (BTM) Microgrids have long been a viable solution to serve this resilience need for individual customers or private campuses using customer-owned generation. However, there was neither a regulatory pathway nor the technical understanding within the industry to create "Community Microgrids" which could leverage third-party owned generators to provide this same support to multiple customers across utility-owned distribution assets.

To bridge this gap between the needs of California communities and the industry's capabilities, the EPIC 3.11 project "Location-Specific Options for Reliability and/or Resilience Upgrades" henceforth referred to as the "Redwood Coast Airport Microgrid (RCAM)" project was developed with the primary goals to:

a. Solve the regulatory, technical, and operational challenges required to integrate Community Microgrids within PG&E's distribution system.
b. Establish a replicable model to deploy similar projects across PG&E's territory.

The RCAM project was developed in partnership with the local Community Choice Aggregator (CCA), the Redwood Coast Energy Authority (RCEA) who owns and operates the generation resources, and the Schatz Energy Research Center (Schatz Center) of Cal Poly Humboldt who provided the engineering, procurement, and construction management services. The project was funded through a California Energy Commission (CEC) EPIC grant to the Schatz Center and a loan from United States Department of Agriculture (USDA) to RCEA, in collaboration with PG&E's EPIC 3.11 RCAM Project. PG&E's budget for the project was $3.1MM while the total project budget for all project partners was around $15MM.

1.2 RCAM Project Overview

RCAM is California's first 100% renewable multi-customer Community Microgrid. It is the culmination of five years of research and innovation across a dozen PG&E teams and external partners including the keystone partners of the Schatz Center and RCEA. The project features a 2.3 MW DC-coupled Battery and PV generator owned by RCEA at the Redwood Coast-Humboldt County Airport in

McKinleyville, CA that uses PG&E's distribution infrastructure to provide energy resilience for Humboldt County's geographically isolated regional airport[1] and the neighboring U.S. Coast Guard - Sector Humboldt Bay[2] which maintains search and rescue missions for 250 miles of remote, rugged coastline.

RCAM is the joint responsibility of both PG&E and RCEA (Figure 1). While PG&E maintains primary control over the microgrid and owns and operates the distribution circuit, RCEA owns and operates the front-of-the-meter (FTM) DC-coupled 2.2MW PV and 2.3MW/8.8MWh Battery Electric Storage System (BESS) that participates in the wholesale market during blue sky days. In addition, RCEA owns and operates a separate 300kW PV system participating under the Net Electric Metering (NEM) tariff. At installation, the microgrid served 19 customers with an average load of 175kW and a maximum load of 360kW.

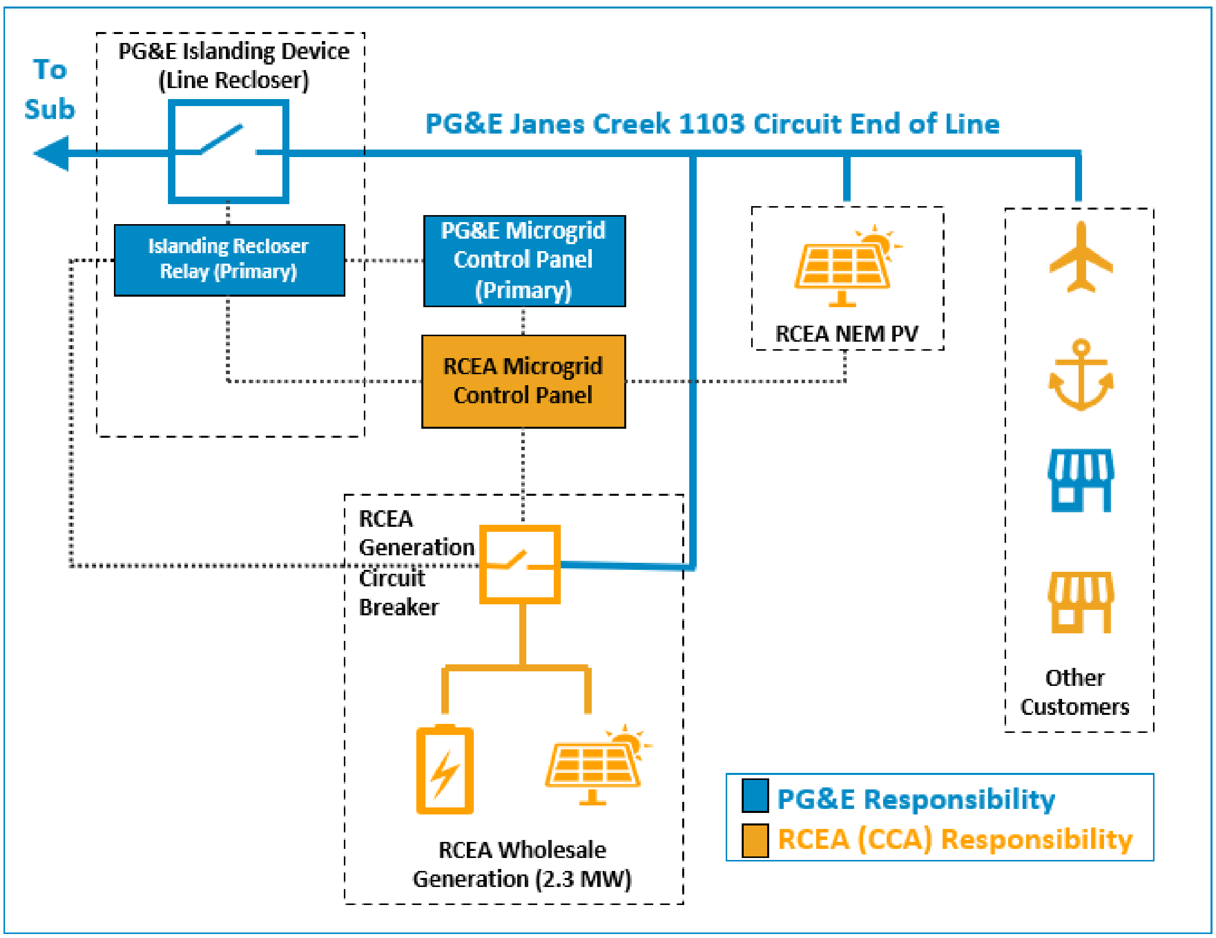

Figure 1: RCAM Overview

Under normal conditions RCEA operates the FTM BESS in the wholesale market and reserves a defined capacity to provide resilience in case of an unplanned grid outage. If an outage occurs on the PG&E source side of the PG&E islanding device the microgrid will seamlessly island and support all assets

[1] Humboldt County Airport, CA | Official Website (flyacv.com)

[2] Sector / Air Station Humboldt Bay (uscg.mil)

within the microgrid with power from the BESS. Once grid power is restored, RCAM will seamlessly transfer back to a grid-connected mode automatically after a defined period.

Settlement for market and NEM participating assets within the microgrid was unchanged even when islanded. This proved beneficial in reducing the complexity of the tariff by keeping the roles and responsibilities unambiguous, preventing cost shifts to non-participating PG&E customers, and protecting the revenue streams of the participating assets.

1.3 Key Objectives and Accomplishments

RCAM was a seminal project in the deployment of community microgrids in California. It not only provided a blueprint for technical implementations of community microgrids but also laid the groundwork for the Community Microgrid Enablement Tariff (CMET)[3], the corresponding Community Microgrid Enablement Program (CMEP)[4], and California's Microgrid Incentive Program (MIP) [5] which will provide $200M statewide for Community Microgrid development.

The following outlines the key objectives and accomplishments by PG&E in support of the goal of developing scalable and replicable approaches to planning, designing, deploying, and operating multi-customer microgrids in California.

Objective 1: Support the technical design and deployment of a Community Microgrid.

Accomplishments:

- PG&E, the Schatz Center, and vendor partners developed a novel microgrid design implementation that shared control between PG&E with primary oversight of the system, and RCEA with control over the generation assets.
- PG&E's Real-Time Digital Simulation (RTDS) testing and Power-Hardware-in-Loop (PHIL) testing identified multiple issues that were then resolved to confirm proper operation of the microgrid under various abnormal conditions prior to field deployment.
- PG&E developed and installed new distribution equipment necessary to island the microgrid in coordination with RCEA's microgrid equipment.
- RCAM was placed in service as a Community Microgrid on May 26, 2022, after passing all commissioning tests.

Objective 2: Demonstrate how microgrids can increase resiliency and reduce the customer impacts of extended outages from natural disasters, including Public Safety Power Shutoffs (PSPS) during severe wildfire weather conditions.

Accomplishments:

- RCAM has thus far provided over 51 hours of incremental resilience to critical infrastructure within the microgrid.

[3] www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CMET.pdf

[4] www.pge.com/en/save-energy-and-money/rebates-and-incentives/community-microgrids.html?vnt=mip

[5] www.pge.com/assets/pge/docs/save-energy-and-money/rebate-and-incentives/PGE-MIP-Handbook.pdf

- RCAM provided resilience through 12 grid events, including a 6.4 earthquake and multiple atmospheric river conditions that caused long-duration outages on the PG&E assets that normally serve the customers within the microgrid footprint.
- RCAM was able to automatically and seamlessly island and return to normal for a majority of the outage events.

Objective 3: Develop advanced testing capabilities at PG&E's Applied Technology Services (ATS) labs to configure and validate future third party microgrid equipment.

Accomplishments:

- ATS developed a state-of-the-art Microgrid Testbed and demonstrated that it could provide microgrid controller and DER integration, control, and stability testing via a RTDS and PHIL testing platform.
- ATS testing identified and troubleshot multiple issues that needed to be resolved, highlighting the nascency of the market, and the need for more standardized processes.
- The testing by ATS informed the novel Microgrid Islanding Study (MIS), a valuable output of the EPIC 3.11 project for future Community Microgrids.
- ATS testing informed the standardization of microgrid equipment and configurations approved for use on PG&E's distribution grid.

Objective 4: Develop scalable approaches for future Community Microgrids.

Accomplishments:

- PG&E developed, and the California Public Utilities Commission (CPUC) approved, CMET, CMEP, and MIP to support statewide Community Microgrid efforts.
- PG&E developed the Microgrid Operating Agreement (MOA) under which RCAM and its successor Community Microgrids will operate, and established roles within PG&E to support the development lifecycle of Community Microgrids.
- PG&E developed an industry first formalized study process dedicated to the evaluation and operational performance of Community Microgrids in the MIS.
- Lessons learned from deploying RCAM were published in the Community Microgrid Technical Best Practices Guide[6] defining reference architectures and design standards for future Community Microgrids.

1.4 Key Takeaways and Recommendations

The following provides a summary of PG&E's key takeaways and recommendations in deploying RCAM in both policy and technical areas.

Policy Takeaway 1: Independent evaluation of Community Microgrid operational modes streamlines the implementation of new processes and tariffs.

To scale microgrid development, it was critical that the tariff and associated development processes did not conflict with or unduly impact any existing rules, processes, and standards for grid-connected

[6] Community Microgrid Technical Best Practices Guide (pge.com)

interconnection and operation (e.g., Rule 21, Wholesale Distribution Tariff, etc.). The CMET accomplishes this by restricting its governance to islanded mode only and leverages existing relevant rules and tariffs wherever possible, as when grid-connected.

Additionally, by establishing an independent Microgrid Islanding Study as a counterpart to the System Impact Study and Facility Studies required for the grid-connected interconnection process, PG&E engineers were able fully study the Community Microgrid without impacting the strict timelines under the Wholesale Distribution Tariff (WDT)[7].

Recommendations:

- Preserve the grid-connected interconnection rules and processes to the greatest extent possible. Programmatic components such as the CMET and the MOA must be consistent with existent interconnection rules and processes.
- Establish an independent MIS process to evaluate the novel technical and operational elements of community microgrids separate from the established study for generation grid-connected operational modes.

Policy Takeaway 2: Establish clear roles and responsibilities.

Community Microgrids introduce potential ambiguity related to operational responsibilities and liability in that they rely on both third-party owned and operated project resources (i.e., generation) and utility-owned distribution grid assets to energize critical facilities when the broader grid is down.

A “clear bright line” needed to be established for microgrid asset ownership and control to ensure no third-party or their equipment had operational control of PG&E assets without PG&E permission. This allows PG&E to remain as the distribution grid owner and operator during grid-connected and islanded scenarios. The CMET, MOA, and Jurisdictional Boundaries Letter of Agreement were three critical documents used to define and enforce these roles and responsibilities.

Recommendations:

- When updating tariffs or agreements, ensure the roles and responsibilities are unambiguous and, to the greatest extent possible, consistent with the typical roles, responsibilities, and obligations established under existing interconnection agreements.
- Maintain a “clear bright line” in terms of community microgrid ownership and control
- Have a single third-party countersigner (e.g., a CCA) to all agreements with the utility to ensure continuity and clarity of responsibilities.

Policy Takeaway 3: Preserve energy settlements during island mode.

Energy settlements must maintain compatibility with FERC jurisdictional compensation for community microgrid resources that participate in wholesale markets under the existing established tariffs. Through the process of identifying possible compensation mechanisms for the energy provided to customers when a community microgrid is islanded, PG&E found that the energy settlement provisions under a project resource’s Wholesale Distribution Tariff or Rule 21 Tariff will continue to be enforced even when the microgrid is disconnected from the bulk grid. Integrating existing settlement

[7] Understand PG&E distribution qualifications (pge.com)

mechanisms is a tremendously practical approach as it reduced the complexity of the tariff by keeping the roles and responsibilities unambiguous, preventing cost shifts to non-participating PG&E customers, and protecting the project resource's revenue streams. Therefore, CMET points to the existing rules (i.e., Wholesale Distribution and Rule 21 tariffs) and processes that are necessary for settling energy transactions during island mode and no separate energy settlement provisions were required in the tariff.

Recommendations:

- Use existing settlement mechanisms even when community microgrids are islanded.
- Maintain CAISO's prevailing energy settlement policy.
- Allow existing Energy Only facilities to re-enter the interconnection queue and apply for Full Capacity Deliverability Status to help support the economics of smaller generating resources interconnected specifically to support community microgrids.

Technical Takeaway 1: Community Microgrids are nascent technology and standardization is critical to scaling.

Community Microgrids are complex and still a nascent technology. Needing to develop, study, and test each individual community microgrid is a barrier to scaling. Therefore, standardization will play an important role in managing the complexity and costs of future Community Microgrid projects. The lack of standardization and certifications in the Community Microgrid space meant PG&E had to perform significant testing and troubleshooting even after the vendors had completed their factory acceptance testing. PG&E has begun the process of documenting lessons learned and standardization suggestions and published the Community Microgrid Technical Best Practice Guide[8] which will be periodically updated as the state-of-the-art matures.

Recommendations:

- Standards should be developed for microgrid controllers, grid-forming inverter requirements, control logic and testing, and operational protocols and procedures.
- Additional research is required to develop standards around microgrid configurations not studied under EPIC 3.11.
- Until better standardization, certifications, and testing protocols are implemented, utilities will have to take a significant role in testing and verifying that Community Microgrid products function as intended.
- Proper failsafe design is very important to ensure the safe operation of the system across a variety of abnormal conditions including edge cases.

Technical Takeaway 2: Experienced Project Partners Matter

Because of the nascency of the technology and complexity of Community Microgrids, the project greatly benefited from having experienced partners in terms of the technology and control integrations. In addition, the 24/7 support and technical capabilities of the third-party support team have been instrumental in ensuring the continuing success of the project post commissioning.

[8] Community Microgrid Technical Best Practices Guide (pge.com)

Recommendations:

- Future projects should emphasize the importance of skilled and experienced control integrators and operational support capabilities.
- Based on this learning, CMEP and MIP programs were implemented to provide increased technical support for community microgrid projects.

Technical Takeaway 3: There is a tradeoff between seamless transitions and nuisance islands.

To support seamless transitions there is a bias to transitioning very quickly which can increase the number of “nuisance” islands where the microgrid transitions to island mode when the grid experiences a transient event that would not have resulted in an outage. While generally not a problem for customers because the transitions were seamless, there were certain cases when a nuisance trip also resulted in an outage due to initial issues within the RCAM controls that were later corrected.

Recommendations:

- Considerations should be made to optimize protection settings and control schemes to prevent unneeded impacts to customers. This will become more important for mid-feeder microgrids, where the transitions of the microgrid can also affect non-microgrid customers.

1.5 Further Exploration

In addition to the challenges and learnings discussed above, the EPIC 3.11 project also identified gaps in PG&E’s understanding of Community Microgrids and where further exploration is required.

One example is to better understand mid-feeder microgrids. RCAM is an end-of-the-line microgrid, which means there is only one islanding device to separate it from the PG&E system. This simplified the implementation because it did not require coordination during transitions among multiple islanding devices (as would be needed for a mid-feeder microgrid). Mid-feeder microgrids may not be able to have seamless transitions, and their operations will also affect customers outside of the microgrid boundary.

PG&E is also further evaluating ways to scale Community Microgrids. This involves evaluating methods to improve the ability to model and effectively coordinate multiple resources within the Community Microgrid’s boundary, including how to coordinate inverter-based and traditional machine generation effectively potentially through modifying frequency within the microgrid. In addition, there is continuing research into the best method of control architecture, protection, coordination, and fault detection within the microgrid under various scenarios including the ability to handle load growth and increased penetration of behind the meter DERs within the microgrid boundary while also balancing implementation costs.

Additionally, PG&E is exploring the concept of Flexible Interconnections to potentially provide cost savings to interconnecting generation assets that may be oversized to support microgrid resilience. For example, the RCAM generation is sized larger than the PG&E conductor ratings and existing loads can withstand at peak conditions. To save costs for the generation interconnection, RCAM chose to have a limited interconnection to avoid needing to reconductor a portion of the PG&E circuit feeding RCAM. While this limit is fixed today based on worst case scenarios, a flexible interconnection could potentially allow for more capacity based on near-real time loading conditions vs planned peak conditions.

1.6 Conclusion

The EPIC 3.11 Project is the culmination of five years of research and innovation across a dozen PG&E teams and in close partnership with Schatz Energy Research Center at Cal-Poly Humboldt and the Redwood Coast Energy Authority. It has already proved its ability to provide resilience to critical infrastructure in the community through various storms and even a large earthquake.

The project successfully met its objectives by dramatically improving PG&E's technical and operational capabilities and developing a scalable production path to integrate additional community microgrids onto PG&E's system. Meeting these objectives required meaningful innovations in both the policy and technical domains.

PG&E developed a coherent framework to deploy community microgrids which included the Community Microgrid Enablement Tariff and the contractual arrangements such as the Microgrid Operating Agreement between PG&E and the operator of the Grid-Forming DER. Nothing like this structure existed in the US or elsewhere prior to this project.

The project team also had to solve for the novel technical challenges of using third-party inverter-based resources to maintain power quality and ensure safe operations of the system during islanded operations. Key technical challenges included modeling the behavior of the inverters, developing protection schemes, and testing control logic and operational coordination between PG&E and third-party devices. To support this work, PG&E built a world class microgrid test bed to support further microgrid research.

This ground-breaking engineering work led to the industry-first Microgrid Islanding Study which is designed to solve for the novel control methodologies, protection schemes, and operational coordination required for DERs acting as grid-forming generators.

As a result of these policy and technical innovations, EPIC 3.11 has delivered a replicable and scalable model to implement community microgrids across PG&E's service territory.

However, for all its success, the EPIC 3.11 project has shown that Community Microgrids require unique and complex solutions. There is still significant work to be accomplished to standardize these systems and incorporate new functionalities such as mid-feeder configurations with seamless and automatic transitions.

2 Introduction

This report documents the EPIC 3.11 – RCAM project achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E and the broader industry to leverage the learnings from this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[9], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*[10], which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[11]

The decision also required the EPIC Program Administrators[12] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[13] On April 28, 2017, in A.17-04-028, PG&E filed its third triennial EPIC Application at the CPUC, requesting authorization for its for 43 Technology Demonstration and Deployment Projects. CPUC approved this plan through D.18-10-052 on October 25, 2018, and D.20-02-003 on February 10, 2020, and authorized $49,771,845 for the 43 TD&D projects.

Pursuant to PG&E's approved 2018-2020 EPIC triennial plan, PG&E initiated, planned and implemented the following project: EPIC 3.11 – Location-Specific Options for Reliability and/or Resilience Upgrades. Through the annual reporting process, PG&E kept CPUC staff and stakeholders informed on the progress of the project. The following is PG&E's final report on this project.

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9 http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF
10 http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF
11 Decision 12-05-037 pg. 37
12 Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)
13 In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

2.1 Project Background

PG&E is working to transition to the sustainable grid of the future by updating interconnection processes, developing new tariff structures, and grappling with the effects of more intermittent renewable energy on the grid. Meanwhile, climate change has increased the frequency and severity of natural disasters, highlighting the importance of keeping critical facilities operating to provide emergency services in times of dire need.

Microgrids can be a useful resilience tool during broader grid disruptions. A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. It can connect and disconnect from the grid to operate in grid-connected or islanded mode[14].

The demand for this functionality is increasing, particularly at critical facilities that are prone to natural disasters and/or de-energization due to Public Safety Power Shutoff (PSPS) events. Behind-the-Meter (BTM) Microgrids have long been a viable solution to serve this resilience need for individual customers or private campuses using customer-owned generation. However, there was neither a regulatory pathway nor the technical understanding within the industry to create "Community Microgrids" which could leverage third-party owned generators to provide this same support to multiple customers across utility-owned distribution assets.

To bridge this gap between the needs of California communities and the industry's capabilities, the EPIC 3.11 project was developed with the primary goals to:

1. Solve the regulatory, technical, and operational challenges required to integrate Community Microgrids within PG&E's distribution system.
2. Establish a replicable model to deploy similar projects across PG&E's territory.

The RCAM project was funded and developed in partnership with the local Community Choice Aggregator (CCA), the Redwood Coast Energy Authority (RCEA) who owns and operates the generation resources, and the Schatz Energy Research Center (Schatz Center) of Cal Poly Humboldt who provided the engineering, procurement, and construction management services. RCAM was co-funded between PG&E's EPIC 3.11 project ($3.1M), a California Energy Commission EPIC Grant led by RCEA and the Schatz Center ($5M), and a USDA loan secured by RCEA ($6.6M). These sources dovetailed to support the unified objective of developing scalable and replicable approaches to planning, designing, deploying, and operating multi-customer microgrids in California.

[14] DOE Definition developed by the Microgrid Exchange Group, which is comprised of an ad hoc group of individuals working on microgrid deployment and research: doi:10.1016/j.tej.2012.09.013 (energy.gov)

3 RCAM Overview

RCAM is California's first 100% renewable multi-customer Community Microgrid. The project features PV solar generation and battery storage owned by RCEA that uses PG&E's distribution infrastructure to provide energy resilience to the California Redwood Coast Humboldt County Airport and the U.S. Coast Guard Air Station, which are among the most critical facilities in the host community. At installation, the microgrid served 19 customers with an average load of 175kW and a maximum load of 360kW.

Figure 2: Map of the RCAM project at the California Redwood Coast - Humboldt County Airport

3.1 RCAM Equipment

RCAM has a 2.3 MW hybrid generation resource acting as the primary grid-forming resource. This resource is comprised of a 2.2 MW DC Photovoltaic array DC-coupled to an 8,874 kWh lithium-ion Battery Energy Storage System with a 2.3 MVA grid-forming inverter along with supporting equipment and infrastructure to complete the system. This system is connected at the end-of-line of the Janes Creek 1103 distribution circuit and is interconnected under the FERC-approved PG&E Wholesale Distribution Tariff (WDT) and participates in the CAISO wholesale market under the FERC-approved CAISO Tariff.

RCAM is the joint responsibility of both PG&E and RCEA. While PG&E maintains DSO control[15] over the microgrid and owns and operates the distribution circuit, RCEA owns and operates the FTM generation and storage assets. Figure 3 provides a detailed look at the different equipment installed at RCAM with the ownership highlighted by color.

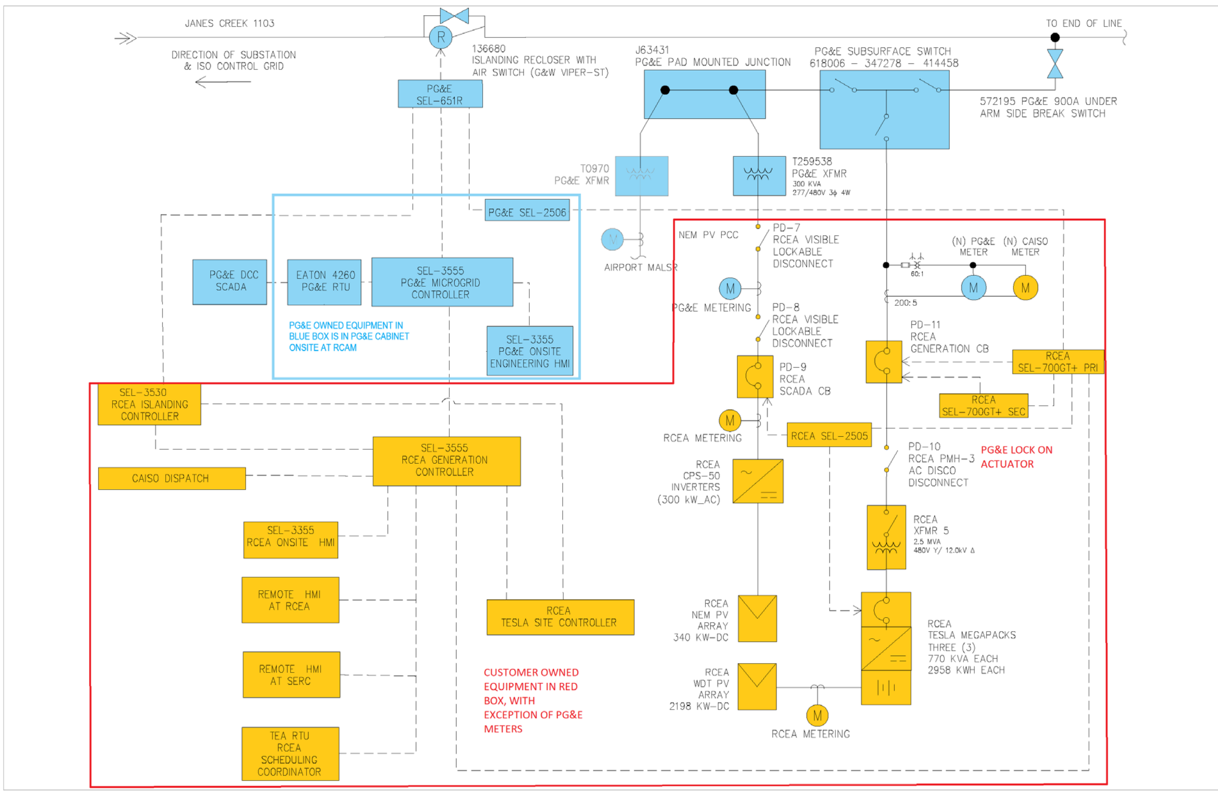

Figure 3: RCAM Equipment Ownership (PG&E-Blue, RCEA-Yellow)

PG&E maintains DSO control over the microgrid through the PG&E-owned line recloser and the PG&E-owned microgrid controller. The line recloser acts as the islanding device to separate or connect the microgrid from the broader PG&E grid. The microgrid controller allows PG&E to have control over the operating modes and settings of the microgrid. PG&E's microgrid controller is cyber-securely connected to RCEA's microgrid controller. RCEA's microgrid controller takes commands from PG&E and ensures PG&E's controls are passed appropriately to the other local controllers including the BESS site controller and RCEA islanding controller. RCEA also manages market integration with CASIO to participate in the wholesale market during blue-sky conditions.

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[15] DSO Control refers to PG&E's ability to enable / disable the microgrid functionality and set limits on the system based on DSO needs like safety and reliability. DSO control does not include the asset owner's local site control or market participation control of the asset.

3.2 RCAM Operational States

Under normal conditions RCEA operates the FTM BESS in the wholesale market and reserves a defined capacity to provide resilience in case of an unplanned grid outage. If an outage occurs on the PG&E source side of the PG&E islanding device the microgrid will seamlessly island and support all assets within the microgrid with power from the BESS. Once grid power is restored, RCAM will seamlessly transfer back to a grid-connected state after a defined period. An overview of each of these microgrid states is provided in Figure 4.

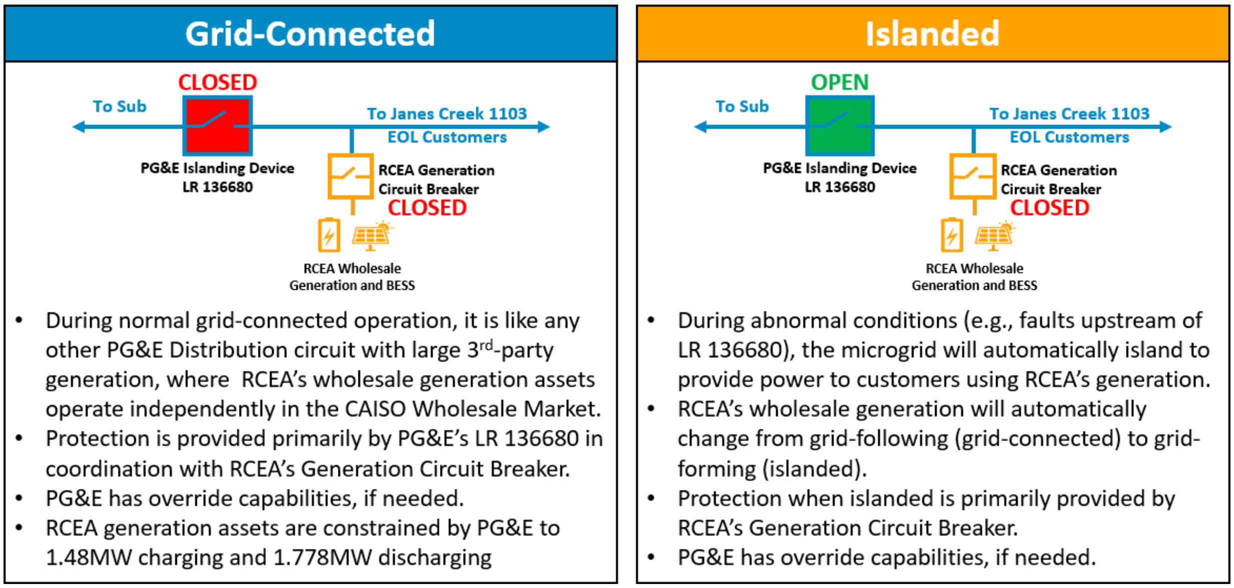

Figure 4: Overview of Grid-Connected and Islanded Microgrid States

Settlement for market and NEM participating assets within the microgrid was preserved even when islanded. This reduced the complexity of the tariff by keeping the roles and responsibilities unambiguous, preventing cost shifts to PG&E customers, and protecting the revenue streams of the participating assets.

3.3 RCAM Modes of Operation

RCAM has three modes of operation: Microgrid Enabled Mode, Microgrid Disabled Mode, and a Non-Operative State. PG&E controls the enabled/disabled mode of operation of the microgrid, with the non-operative state being a failsafe if certain issues are detected.

Microgrid Enabled Mode (Normal Operation)

Microgrid Enabled Mode is the setting for normal operation of the system. It allows both grid-connected operation when there are no issues on the PG&E system and islanded operation in the event of a disturbance on the PG&E system. It enables the line recloser Settings Group for everyday operation in Grid-connected or Islanded state. RCAM will island automatically if there is a PG&E grid disturbance on the source side of LR 136680 and will automatically return to PG&E grid-connected power when PG&E power at the source side of LR 136680 is stable for 15 minutes. The RCEA Generation Circuit Breaker relay settings group will automatically change if transitioning to an islanded or grid-connected state. LR 136680 functions as both an islanding device and a protective device in this mode, with no reclosing (one shot to lockout) and no sensitive ground fault detection.

Microgrid Disabled Mode

Microgrid Disabled Mode may be selected by a PG&E Distribution Operator (DO) during abnormal/maintenance conditions or may assert automatically due to a communication failure, which will be indicated by an alarm. Microgrid Disabled Mode enables the line recloser Settings Group to prevent islanding. RCEA generation remains grid-connected and can participate in the wholesale market; however, Disabled Mode will not allow the microgrid to island. If already islanded when this mode is activated, generation will shut down. If a fault is detected while in this mode LR 136680 will function like a normal protective device by only tripping on overcurrent elements but with no reclosing (one shot to lockout) and no sensitive ground fault detection. Disabled Mode may be selected by PG&E Distribution Operators (DOs) or may assert automatically due to a communication failure, which will be indicated by an alarm.

Non-Operative Mode

The Non-Operative Mode is a failsafe where the RCEA wholesale generation is automatically turned off to avoid mis-operation in the event that changes are made to the internal configuration of the microgrid or if communications fail between critical controllers.

If the cause was a configuration change, the DO cannot change the system back to Operative mode remotely to prevent unauthorized changes without PG&E's consent. To return to Operative mode, PG&E must enable it via the PG&E onsite engineering Human Machine Interface (HMI).

If the cause was a communication failure, an alarm will identify the issue and the system will return to Operative mode automatically when communication is restored. The communication failures that trigger the Non-Operative mode are:

- PG&E SEL-3555 Microgrid Controller to RCEA SEL-3555 Generation Controller
- PG&E SEL-3555 Microgrid Controller to PG&E SEL-651R Islanding Recloser Control
- RCEA SEL-3555 Generation Controller to RCEA SEL-700GT+ Primary Generation Relay
- RCEA SEL-3555 Generation Controller to RCEA BESS Site Controller

3.4 PG&E Operator Controls

PG&E Operators and Field Personnel have DSO control of RCAM to maintain the safety and reliability of the grid. The following settings are controlled by PG&E.

Automatic / Manual Control

RCAM is designed to operate in Automatic Control under normal conditions. This feature allows the microgrid to transition automatically based on the settings and conditions in the field. The normal setup for the microgrid is to be in Microgrid Enabled Mode under Automatic Control.

The DO must transition to Manual Control if changes are required to the configurable operator inputs (e.g., manual transitions, changing from seamless to break-before-make transitions, etc.). Manual mode may assert automatically for communication failures indicated by an alarm. After the alarm is resolved, the control mode can be returned to Automatic Control.

Enable / Disable Microgrid Mode

PG&E can enable or disable the microgrid mode as described in Section 3.3. RCAM is normally in Microgrid Enabled Mode.

Modify Charge / Discharge Limits

PG&E has control over the maximum charge and discharge limits of the DC-coupled BESS and PV system when grid-connected. This is needed because the RCAM generation is sized larger than the PG&E conductor ratings. To save costs for the generation interconnection, RCAM chose to have a limited interconnection to avoid needing to reconductor a portion of the PG&E circuit feeding RCAM. RCAM is limited to 1.45MW charging and 1.75MW discharging while grid-connected. In addition, DOs can update these limits under certain conditions where RCAM may be fed abnormally. For example, the DO will limit RCAM charging to zero during certain abnormal switching scenarios.

Transitions between Grid-Connected and Islanded Operation

PG&E can set the type of transition to be either a seamless transition or a break-before-make transition. The default is set to seamless transitions to avoid any outage for the customer as much as possible. PG&E DOs can also manually transition the microgrid between grid-connected and islanded states if needed.

PG&E Line Recloser Control

The PG&E line recloser is the islanding device for the microgrid that connects it to the PG&E larger grid. PG&E can manually open or close this line recloser as needed. It also has particular Settings Groups specific to operating RCAM that are set by choosing the Microgrid Enabled or Microgrid Disabled modes.

RCEA Generation Circuit Breaker Control

The RCEA Generation Circuit Breaker provides protective functions for the microgrid when islanded. Therefore, PG&E reviewed and approved the settings on this device and maintains control over this device if needed. For example, RCEA can reset the lockout if there is a fault on their side of the breaker (generation side), once they have resolved the issue. However, if the breaker trips and locks out due to an issue on the PG&E primary within the microgrid, only PG&E has the ability to reset the lockout, not RCEA, to ensure the line is not energized during fault or maintenance conditions.

3.5 Community Microgrid Aggregator Operator Controls

While PG&E Operators and field personnel have DSO control of RCAM to maintain the safety and reliability of the grid, the asset owner has control over the asset for normal and maintenance operations of the asset within the limits prescribed by the utility. This includes dispatches and market participation when grid-connected, and any required controls for maintenance activities of the asset and facility. PG&E Operations and RCAM Operational Support have available 24/7 communications if any coordination is required between the two entities.

4 Community Microgrid Policy and Process

A Community Microgrid, like the Redwood Coast Airport Microgrid, consists of a group of interconnected customers and distributed energy resources within clearly defined electrical boundaries that can disconnect from and reconnect to the grid. These microgrids are typically designed to serve a community's critical facilities, such as hospitals, police and fire stations, gas stations, and grocery stores. Each community microgrid is unique and is designed by the community to address their specific goals and needs for the project. A range of variables will dictate the size of the microgrid, what community services are served and what elements are included in the design.
In the case of RCAM, the project serves the Arcata regional airport and the neighboring Coast Guard Air Station. Figure 5 represents an example layout of a community microgrid.

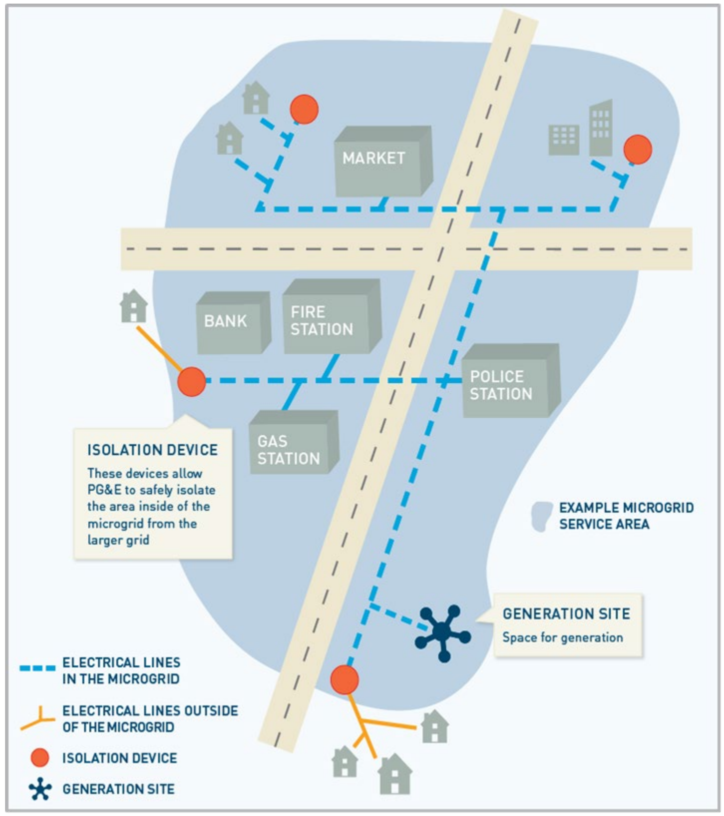

Figure 5: Illustrative Community Microgrid

To enable community microgrids like RCAM on PG&E's distribution system, new rules and agreements needed to be developed. A key objective of this project was to use RCAM as a model to develop experimental agreements and tariffs that govern various aspects of the relationship between PG&E and the generating resource such as the operational roles and responsibilities, service obligations, compensation for energy provided during island mode, and commercial terms and conditions. RCAM was an essential project to help consider the relevant issues necessary to enable multi-customer microgrids, and RCEA, as the local CCA, was an ideal partner to deepen PG&E's understanding of the relationship of the counterparty to these agreements. This ability to partner and create a mutually agreeable strategy between two disparate organizations was a key accomplishment and paved the way for the successful technical implementation of RCAM.

The intention of a community microgrid tariff and the associated agreements were to support the commercialization of multi-customer microgrids in PG&E's service territory that could be replicated in other service territories. Three standardized documents were created based on learnings from the RCAM project:

- **The Community Microgrid Enablement Tariff (CMET)** was an experimental tariff that enabled third-party owned DERs to operate on PG&E's distribution grid in an islanded configuration. The tariff governed the eligibility, engineering studies, development, and island and transitional operation of community microgrids. CMET was filed with the Commission on

August 17, 2020[16] and has been updated several times to expand the eligibility requirements for community microgrids and improve clarity. On October 9, 2023[17], PG&E, SCE, and SD&GE separately filed proposals for a permanent Multi-Customer Microgrid Tariff that closely align with PG&E's original CMET proposal, which were approved on November 7th, 2024. As such, CMET has transitioned from an experimental PG&E tariff to the permanent statewide standard, marking a major win for the EPIC 3.11 project.

- **The Microgrid Operating Agreement (MOA)** is necessary to allow the full deployment of a microgrid project on PG&E's system by establishing operational roles and responsibilities (e.g., modes of operation and operational coordination), performance requirements, interconnection agreements, project safety plan, commissioning plan, data security requirements, and non-disclosure agreements. The intention of a pro forma MOA is to standardize the body of the MOA and use appendices to make necessary adjustments based on the unique qualities of each community microgrid project. The pro forma MOA was submitted to the commission as a Tier 1 Advice Letter (AL) and was approved July 12, 2021[18].

- **The Microgrid Special Facilities Agreement (Microgrid SFA)** allows PG&E to recover infrastructure investments and incremental distribution services to support the islanding capabilities of a microgrid on PG&E's distribution system (e.g., reclosers, controls). It was determined PG&E's existing Rule 2 Special Facility Agreement (SFA; Electric Form 79-255)[19] could be slightly modified to handle microgrid infrastructure cost recovery.

4.1 The Community Microgrid Enablement Tariff (CMET)

PG&E's Track 1 OIR testimony[20], which was supported by the commission's decision[21], noted that the tariffs necessary to support community microgrids do not exist. In that testimony, PG&E committed to submit an experimental tariff to address this gap. PG&E submitted that experimental tariff, named the Community Microgrid Enablement Tariff (CMET)[22], to the commission on August 12, 2020. The CMET Tariff governs the eligibility, technical studies, development, energy settlements and microgrid operations during islanded mode.

There were six guiding principles in developing a tariff that would enable this arrangement between PG&E and a third party:

1. Safety above all else.
2. Respond to customer needs.
3. Leverage existing tariffs and processes to the greatest extent possible and, when necessary, establish new microgrid specific processes which align with existing processes.
4. Maintain rate integrity and minimize cost shifts.

[16] ELEC_5918-E.pdf (pge.com)
[17] ELEC_7042-E.pdf (pge.com)
[18] Resolution E-5127 (ca.gov)
[19] ELEC_FORMS_79-255.pdf (pge.com)
[20] PG&E Track 1 Proposal (ca.gov)
[21] Resolution E-5127 (ca.gov)
[22] ELEC_5918-E.pdf (pge.com)

5. Establish a "Clear Bright Line" which means that operational control over any device is the sole responsibility of the device owner. No third parties or third-party equipment should have operational control over PG&E assets.
6. Operational State Independence. Separate the study and evaluation process of the islanding operational state from the grid-connected operational state.

These six principles informed PG&E's decision making while tackling difficult questions with little precedence such as jurisdiction, roles and responsibilities, development lifecycle and process, and defining technical requirements for the project. Not only were these complex issues, but these elements had to remain logically and functionally coherent with existing utility rules, standards, and processes.

In addition to the six principles, the development of CMET was directly informed by the work done for RCAM. RCAM was a catalyst for tariff development by being a real-world project with an engaged counterparty (RCEA) and an experienced research center (Schatz Center), that allowed for workshopping policy and approaches in real-time. It provided important context to be able to craft a functionally complete tariff that addressed the complexities of a real-world community microgrid. This informed the overall structure of CMET (Figure 6), with key elements and decisions described in the sections below.

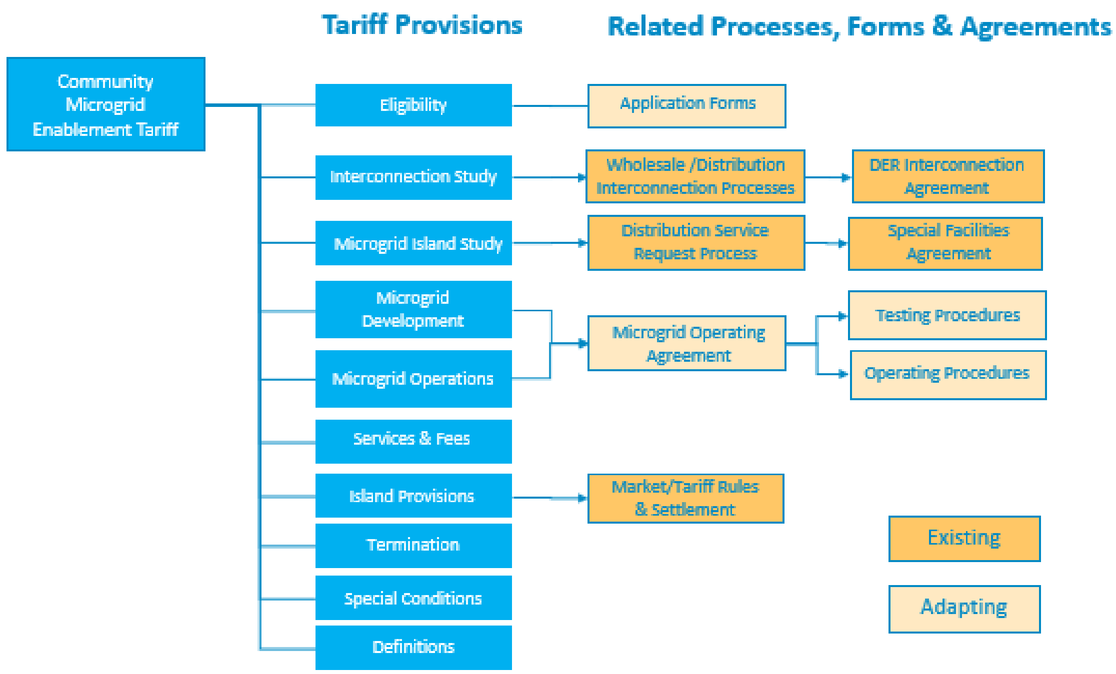

Figure 6: CMET Structure

4.1.1 Interconnection and Operational State Independence

One of the first and most significant decisions PG&E made during the tariff development process was to isolate the evaluation and study of the net new abnormal "Islanded" operational state from the normal grid-connected operational state (often informally referred to as the "Blue-Sky" state). By isolating these two states and treating them independently, PG&E was able to firewall the complexities of the abnormal island conditions and leverage the existing interconnection rules and procedures of traditional grid-connected generation. Each Project Resource in the microgrid needs to have its own interconnection agreement governed by the existing interconnection rules (e.g., Rule 21, WDT) as defined in Section 5.1 of the Tariff[23]. In this way, it greatly simplified the process, and this decision had many positive knock-on effects in the Microgrid Operating Agreement and technical domains as will be discussed later.

Before establishing this framework for operational state independence, PG&E explored integrating the microgrid development process into the existing interconnection process. However, it was quickly discovered that the more the team tried to prescribe a universal process to integrate microgrids into the established interconnection processes, the more they conflicted with existing programs and mandates. This was particularly true when trying to establish new timelines and obligations to the FERC Wholesale Distribution Tariff (WDT) and Rule 21 Interconnection processes. In separating the grid-connected state from the Islanded states, these pathways could be performed in parallel and leverage the existing studies and processes used for the existing WDT and Rule 21 interconnection process.

4.1.2 Microgrid Islanding Study

The concept of independence led to the second key decision to introduce a new study focused on safety and operational performance of the microgrid during islanded operations and transitions to/from grid-connected mode. CMET introduced a new technical study, called the Microgrid Islanding Study (MIS), to evaluate the safety and operational integrity of the system during islanding. This study evaluates elements such as:

- The microgrid electrical boundary (e.g., location of recloser/breaker & distribution upgrades)
- Simulation model development and validation
- Power flow and voltage analysis
- Protection requirements (e.g., fault current & protection coordination)
- Power quality and harmonics
- Transitions to/from grid-connected operations
- Transient stability
- Controls requirements such as PG&E's microgrid controller and Community Microgrid (CMG) Aggregator controller parameters
- Telemetry & Cybersecurity requirements
- Required electrical system upgrades (Special Facilities) to establish the microgrid electrical boundary (e.g., recloser) and microgrid operational controls

To ensure safety, the Community Microgrid Aggregator must agree to actively coordinate with PG&E's Distribution Operations Team and submit to additional technical studies to ensure the safe performance of the generator during islanding operations.

The independence of the MIS is important because it allows PG&E to study the complex novelties of the islanded state without encumbering the statutory deadlines imposed under the WDT and Rule 21 processes.

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[23] *Each Project Resource is required to be interconnected to PG&E's Distribution System under PG&E's WDT GIP or Electric Rule 21, according to the applicability of each of those tariffs.*

The MIS can be seen as the functional equivalent to the System Impact Study process of the normal generation interconnection pathway. Whereas the System Impact Study is focused on the generators impacts during grid-connected operations, the MIS is an independent study focused on the generators impacts during Islanded mode and transitions to/from islanded mode. The union of the two studies gives a comprehensive study of safe operations under all operational conditions: grid-connected, islanded, and the transition between these states.

4.1.3 CMET Section 7 – Community Microgrid Development and Operation

Section 7 of CMET governs the Community Microgrid Development and Operation. In concert with the set of guiding principles noted above, it was essential that the roles and responsibilities of each counterparty to the tariff be unambiguous. PG&E explored several ownership and operational models, many of which were proposed during the public workshops and reviewed during the Microgrid OIR proceeding[24]. Community Microgrids often include multiple parties in the design, development, and operation of a microgrid, which complicated assigning roles and responsibilities when designing RCAM. In working through the various proposals, PG&E found that the modifications clashed with the guiding principles in some way, such as violating the Clear Bright Line principle, or allowing rate arbitrage that would impact the Rate Integrity principle. After exploring the various options, it was clear that CMET should not change the existing roles and responsibilities between PG&E, generators, or the relationship with customers:

- **PG&E remains the Distribution System Operator (DSO) at all times.** PG&E, as the utility distribution owner and operator, is responsible for distribution service[25] under both grid-connected and islanded modes including the sole determination of emergency events.
- **PG&E provides Distribution Service at all times.** PG&E will provide distribution service for the resources and customers within the microgrid electrical boundary during grid-connected and islanded modes pursuant to all applicable rules (e.g. Rule 2).
- **There will only be one single operational counterparty to the agreement called the Community Microgrid Aggregator[26] ("CMG Aggregator").** The CMG Aggregator is a third-party that coordinates control of distributed resources within the microgrid electrical boundary, and any demand side management resources, to operate the Project Resources within PG&E parameters to enable the CMET Project to operate in Island Mode. The CMG Aggregator is also responsible for making necessary upgrades to the microgrid when it becomes unsafe to operate in island mode due to load growth or other factors.

The roles and responsibilities of the Community Microgrid Aggregator were thoughtfully chosen. One unexpected outcome of the tariff development process is that the CMG Aggregator need not be the same party as the owner of the grid-forming assets. Although this is the most likely outcome, the safety and coordination responsibilities enumerated in the Tariff are independent of facility ownership. This independence holds through the Microgrid Operating Agreement (MOA) as discussed

[24] Resiliency and Microgrids Events and Materials (ca.gov)

[25] PUC Section 218 and Rule 2. CA Electric Rule 218 is what defines an Electrical Corporation for the purposes of regulation. Embedded in this definition is all the roles and responsibilities of Utilities. Rule 2 is the description of service.

[26] Defined in Sec. 7.1c of CMET

later. For RCAM specifically, RCEA is the Community Microgrid Aggregator and project resource owner, the Schatz Center designed and engineered the microgrid and is the subcontracted entity that is helping to fulfill the Operating Procedures and Protocols outlined in the MOA, and there is a separate third-party entity acting as the scheduling coordinator to manage bidding and dispatching of the project resources for market participation.

4.1.4 Clear Bright Line Principle

The division of responsibility can get complex with third-party CMG Aggregators leveraging project resources and utility-owned assets to energize islanded customers. PG&E maintains responsibility for the safe operation and maintenance of its assets (i.e., the distribution grid). Because of this responsibility, any third-party such as RCEA, may not control PG&E assets directly. This includes the line recloser that acts as the islanding device for the microgrid, therefore PG&E retains control and ownership of that device which is consistent with existing PG&E processes and standards. While the islanding device is able to act on a signal from RCEA's generation assets to island the microgrid to enable seamless transitions, PG&E controls a permissive signal to enable the line recloser to accept (or ignore) this specific signal from RCEA. PG&E also maintains full control over the operational settings of the microgrid as described in Section 3.4, determining when the microgrid can be islanded for emergency events (the default objective of PG&E), or disabling the microgrid for safety or maintenance issues. The MIS study not only verifies these types of functionalities, but it also creates the mechanism for PG&E to review and approve settings with the CMG Aggregator's generator control logic under islanded conditions.

While PG&E retains control over the islanded state of the microgrid, the Community Microgrid Aggregator maintains operational control over their generator when grid-connected for things such as dispatch and maintenance of the facility defined under their interconnection agreement. Having the separate Community Microgrid and Interconnection Processes allows for responsibilities to be clearly defined for both situations.

4.1.5 CMET Sections 8, 9, 10, and 11 – CMET Services and Energy Settlements

Another challenge was to define the services provided by the Project Resource and address energy settlements during islanded operation. PG&E explored multiple types of service and fee models including compensating Project Resources for an abstract "Value of Resiliency" and settling exported energy while islanded at higher rates. PG&E evaluated these different models in relation to the guiding principles of leveraging existing tariffs, maintaining rate integrity, and minimizing cost shifts.

In terms of services, it followed that PG&E would maintain its role as Distribution Operator and Distribution Service Provider under all operating conditions. As such, no additional microgrid service needed to be defined under CMET for the Community Microgrid Aggregator. It is worth noting however, that in islanded mode, PG&E remains bound to maintain power quality to its customers consistent with Rule 2. Therefore, a key objective of the Microgrid Island Study is to ensure the Project resource can meet these power quality requirements.

Regarding settlement, PG&E found that the energy settlement provisions under a Project Resource's Wholesale Distribution Tariff or Rule 21 tariff will continue to be enforced even when the microgrid is disconnected from the bulk grid. Through the process of identifying possible compensation mechanisms for the energy provided to customers when a microgrid is islanded, CAISO confirmed that all meters in the wholesale market continue to spin during islanded mode and any energy generated by project resources within the microgrid will be settled by the CAISO in the imbalance market based on the nearest CAISO pricing node. This was fortunate because it meant that the tariff did not need to define a separate settlement mechanism for islanded operations. CMET therefore can point to the existing settlement rules and processes defined under the generators existing Wholesale Distribution or Rule 21 tariffs. This arrangement with CAISO is a key outcome that simplified the tariff. This arrangement should be protected due to its cohesion with existing tariffs and policies. With respect to the value of resiliency, after careful consideration, PG&E determined that providing compensation to community microgrids would result in a cost shift, which is prohibited by Senate Bill 1339 and at odds with PG&E's policy of promoting ratemaking based on cost causation. The logic is as follows:

1. A microgrid is a premium non-standard service that benefits a specific community;
2. Community microgrids governed by the CMET are constructed at the request of the benefitting community or a party working on their behalf;
3. Thus, providing payment for resiliency services would effectively result in paying a community to provide a benefit to itself at the expense of PG&E's broader customer base that would bear the cost, thereby resulting in a cost shift.

There are additional CAISO operational procedures that the generator must observe while in Islanded mode. Specifically, when a microgrid is islanded, the microgrid aggregator's scheduling coordinator will submit an outage card to CAISO. During islanded operations the generator's sole responsibility is to the loads within the microgrid electrical footprint which is segmented from the broader grid. Therefore, the generation facility is unable to respond to dispatch signals from CAISO. Failing to respond to these CAISO dispatch signals could result in financial penalties. By submitting an outage card during islanding events, the generator avoids possible penalties should CAISO call on their resource. However, the outage card still allows the resource to obtain market revenue. Any energy generated to meet the load within the microgrid will still be settled in the energy imbalance market based on the real-time price at the nearest CAISO pricing node.

In addition, this arrangement preserves the continuity of retail settlements of Behind-the-Meter resources such as net energy metered resources. Net energy metered resources which generate during islanded mode, will continue to accrue electric bill savings when operating as part of an islanded microgrid.

Integrating existing settlement mechanisms is a tremendously practical approach as it reduced the complexity of the tariff by keeping the roles and responsibilities unambiguous, preventing cost shifts to customers, and protecting the Project Resources' revenue streams, which must be adequate to support CMG operations. This is a key element in scaling and integrating community microgrids onto the PG&E system.

4.1.6 FERC and CPUC Jurisdictional Considerations

For RCAM, the project resource is interconnected under the FERC jurisdictional Wholesale Distribution Tariff. Both during islanded and non-islanded conditions, the project resource is settled financially pursuant to the mechanisms in the CAISO's tariff, which is approved by FERC. Thus, while the CMET is a CPUC-approved tariff that describes the roles and responsibilities of the utility and microgrid operator, the CMET defers for financial settlement purposes to FERC-approved CAISO tariff provisions. The project participants and consulted parties preferred this approach because it avoided the need for either the CPUC or FERC to approve a separate rate for wholesale transactions occurring during islanded conditions. This simplifies contracting and reduces regulatory risk and ambiguity.

4.1.7 Deviations from Initial Expectations

It's worth noting where the Tariff defied RCAM stakeholders' initial expectations and the expectations of public stakeholders at large. This is important because there were certain expectations the PG&E Tariff development team, the RCAM project Team, and the public stakeholders at large, had at the beginning of the tariff development process that ultimately were rejected because they were not consistent with the guiding principles outlined above.

Initial Expectation	End Result
Microgrids should apply for interconnection as a single controllable entity	Keep the existing interconnection process for the grid-connected state and have an additional separate islanded state process.
New processes and billing schemes should be developed for compensation during outages	New billing schemes can be avoided and instead leverage existing tariffs for Wholesale Generation and Rule 21 resources for compensation of generation when the microgrid is islanded.

4.1.8 Managing for Edge Cases

PG&E evaluated a number of rare but possible edge cases (Figure 7) to test the Tariff framework for coherence against the core principles. The Tariff contemplates and manages for future load growth within the microgrid, interconnections of additional generators related, and modifications to the Project resource during the operational term.

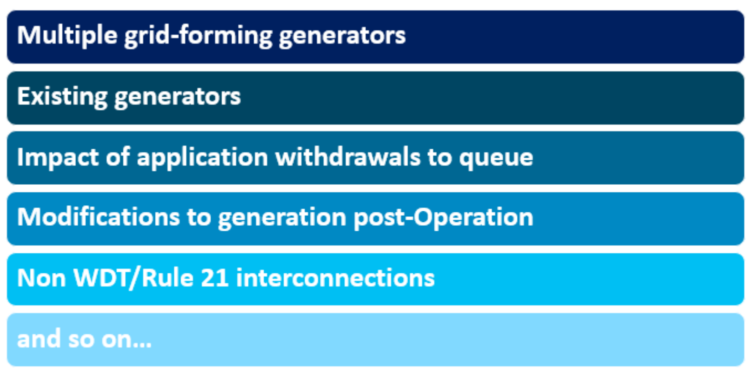

Figure 7: Edge Cases Evaluated for CMET

One of CMET's greatest accomplishment is that it leads to coherent conclusions for these edge cases. The successful testing of CMET across multiple edge cases gives confidence that the Tariff's framework can manage many of the unexpected situations and outcomes in the future.

4.2 The Microgrid Operating Agreement (MOA)

Along with CMET, a Microgrid Operating Agreement (MOA)[27] is the second document required to fulfil RCAM's objective of developing a scalable model to integrate community microgrids onto PG&E's system. Whereas CMET governs how microgrids fit into existing rules and regulations and defines important programmatic components such as eligibility requirements and participant roles, the MOA governs how the project gets developed and ultimately the roles and responsibilities of operating the microgrid in island mode and transitions to/from grid-connected mode. Additionally, the MOA is the mechanism by which the electrical integrity of the system is ensured and describes the parties' obligations to maintain safety and service quality.

When viewed together, the relationship between the CMET and the MOA is functionally similar to the existing interconnection process. Where the Community Microgrid Enablement Tariff mirrors the function of the WDT and Rule 21 tariffs, the Microgrid Operating Agreement is functionally similar to the Interconnection Agreement but designed specifically for islanded operations (Figure 8).

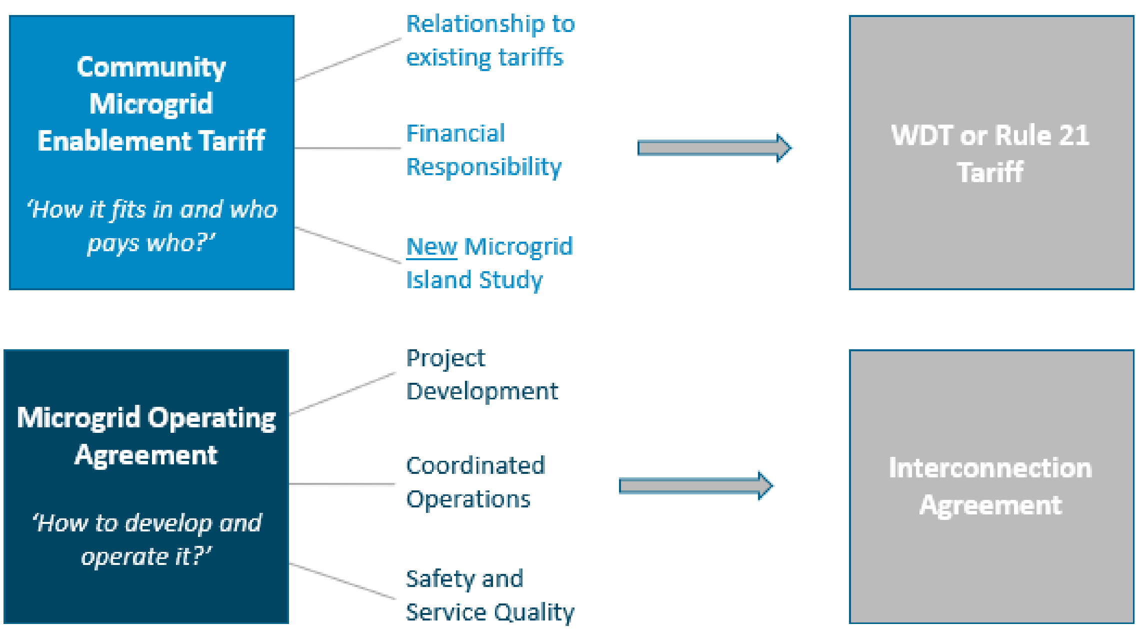

Figure 8: CMET and MOA Comparison to Existing Documents

4.2.1 MOA Principles, Structure, and Strategic Choices

The MOA also needed to be coherent with the guiding principles discussed above. The RCAM MOA overcame a number of challenges throughout its development with the majority of the complexity landing in one of four areas:

- Agreement structure
- Development coordination

[27] ELEC_7042-E.pdf (pge.com)

- Applicant representations & warranties
- Managing for change

Regarding the structure of the Agreement itself, it is notable that this is a new class of asset on PG&E's system. There were few existing agreements on which to predicate the MOA. The MOA was developed with considerable contracted support using PG&E's Technology Neutral Pro-Forma (TNPF) and the Small Generator Interconnection Agreement (SGIA) as the primary references.

The body of the MOA has five components: Recitals, Term & Termination, Development & Commissioning, Operations, and Contract Conditions (Figure 9). The Recitals, Term, and Contract Conditions which bookend the agreement are mostly legal constructs ported over from existing agreements such as the Technology Neutral Pro Forma and Small Generator Interconnection Agreement. As such, the following will focus on select Articles of the Microgrid Operating Agreement (Development & Commissioning and Operations) which are the "Operational Heart" of the MOA.

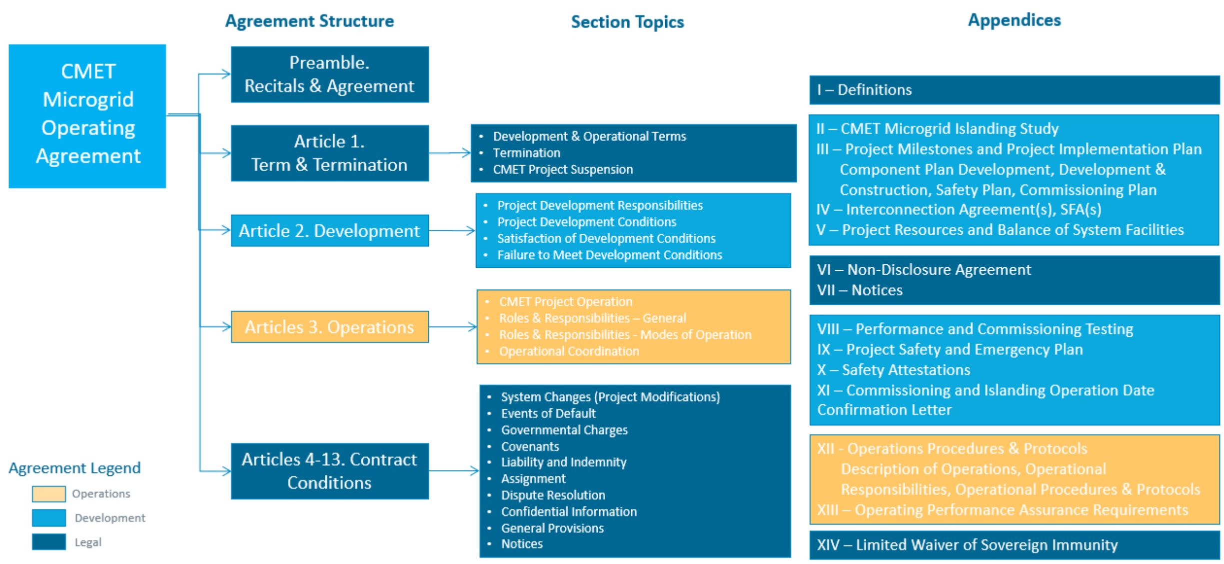

Figure 9: MOA Agreement Structure

One distinguishing feature of the Microgrid Operating Agreement is that it had to be highly flexible yet complete. The novelty of RCAM meant that there were technical and operational challenges that needed to be solved during the development term of the project. Moreover, community microgrids are each unique and the solutions found for RCAM may not always apply to future community microgrids. Therefore, flexibility and completeness were achieved through the extensive use of Appendices. A combined fourteen appendices allow the project to continue its development under an executed agreement while the project specifics are being developed. The metaphor most often used to describe the body of the MOA itself is like scaffolding on which the various contractual elements could be hung as they were developed. This flexibility proved important for RCAM and will prove important when managing for the unknown unique characteristics of each future community microgrid.

4.2.2 Terms

The MOA defines two separate terms: the Development Term and the Operational Term. Each of these terms have their own requirements and obligations. The Development Term starts on the signing of the MOA and ends on the Project Online Date whereas the Operational Term covers everything after the Project Online Date.

4.2.3 Article 2 – CMET Project Development

Article 2 of the MOA describes the development conditions required to achieve commissioning. The CMG Aggregator is responsible for developing the Operating Protocols and Procedures as well as meeting any requirements contained in the Interconnection Agreement, the Microgrid Islanding Study, and Special Facilities Agreements.

Another key responsibility of the CMG Aggregator during the Development Term is to develop a Project Implementation Plan (PIP) which includes deliverables such as:

- Key Workstreams & Project Milestones
- Identify Responsible Parties and Agents
- Project Management Details
- Project Description of Operations to identify scenarios in planed/unplanned outage events and failsafes
- The Commissioning Test Plan

Article 2 also defines the Operational Testing Requirements needed to meet PG&E's standard of care as the Distribution grid operator.

4.2.4 Article 3 – CMET Project Operation

Article 3 of the MOA governs everything after Permission to Island is granted, whereas Article 2 governs the requirements to get the Permission to Island. Article 3 covers four key areas:

1. Responsibilities of CMG Aggregator
    a. Maintain voltage and frequency support
    b. Retain operational coordination with PG&E
    c. Maintain the Project Resources
    d. Liability for operational and maintenance costs, and damages.
2. Project Modifications:
    a. Modifications are allowed provided they do not represent a Material Modification and are in accordance with other CMET provisions and existing tariffs.
    b. PG&E is required to notify CMG Aggregator when load conditions represent a Material Modification.
    c. PG&E will notify CMG Aggregator of any third-party interconnection requests.
    d. A new Microgrid Islanding Study will be required for any Material Modification within the microgrid boundary.
    e. CMG Aggregator will notify PG&E of any modification.
    f. PG&E reserves the right to suspend and change as necessary.
3. Project Operations:
    a. Maintain 24/7/365 readiness for operating communications
    b. Notifications of emergency CMET Islanding
    c. Special operations and clearance requests

    d. Work performance notifications
    e. Notification and operation requirements and responsibilities under both planned and unplanned outages
    f. Maintenance and testing requirements
4. Settlement: CAISO "In-Market"

4.2.5 Article 4 – System Change

Article 4 addresses managing for system changes, which was one of the more challenging aspects when developing the agreement. Community Microgrids are naturally dynamic systems. Over time, there will be changes in loads within the electrical boundary of the microgrid (e.g., due to electrification) and a likely increase in penetration of DERs. On one hand, PG&E must maintain the responsibility to allow interconnections and load growth on the system. On the other hand, PG&E committed significant resources to specifying the islanding protection schemes and controls at the Commercial Operation Date. PG&E studies these schemes as a part of the MIS but this study is a snapshot frozen in time. These schemes may need to be revised if the load/generation balance changes. The project team explored defining a specific trigger as one solution, but this was problematic given the complexity of the analysis. Instead, PG&E landed on a scheduled bi-annual review cycle with the ongoing right for PG&E to review the microgrid at any time. This aligns with PG&E's existing right to evaluate the conditions of the system at its discretion.

There is the additional question of associated costs. If PG&E determines an MIS re-study is required based on system changes, it was unclear who should bear the cost responsibilities of that study. PG&E determined the most equitable approach was to tie the cost responsibility of the restudy to the entity driving the system change. For example, if the change is driven by the CMG Aggregator or another customer within or outside the microgrid, then the CMG Aggregator should pay for the study and the associated microgrid upgrade costs. However, if the system change that led to the restudy is driven by PG&E to support its role as distribution system operator, then PG&E pays for the re-study and associated microgrid upgrades. These conditions are all outlined in Article 4, including a table summarizing cost responsibility scenarios (Table 1).

System Change Category	System Change Scenario	MOA Section Referenced	MIS Cost Responsibility	Microgrid Upgrade Cost Responsibility
Load	Customer within microgrid changes panel sizing	4.1 or 4.3	CMG Aggregator	CMG Aggregator
	New customer load application for interconnection within the Microgrid Boundary	4.1 or 4.3	CMG Aggregator	CMG Aggregator
	Customer outside microgrid requests to be included	4.3	CMG Aggregator	CMG Aggregator
	Customer within microgrid requests to be removed from microgrid	4.3	CMG Aggregator	CMG Aggregator
Generation	Non-Project Resources added (BTM or FTM generation)	4.1 or 4.3	CMG Aggregator	CMG Aggregator
	Project Resource modification or addition	4.2	CMG Aggregator	CMG Aggregator

	CMG Aggregator proposed load management solutions (e.g., demand response)	4.2	CMG Aggregator	CMG Aggregator
Operational changes	Changes at PG&E's discretion to support DSO role	4.1	Utility	Utility

Table 1: System Change Cost Responsibilities Outlined in MOA

4.2.6 Article 5 – Events of Default, Remedies and Default

The Events of Default, Remedies and Default in Article 5 provide an interesting conclusion although it has not been the subject of much public inquiry. Careful consideration was given to what performance obligations PG&E should enforce on the CMG Aggregator under various conditions like failure to energize during a Public Safety Power Shutoff (PSPS) event. There was a question if there would be any PG&E claw backs, penalties, or liquidated damages, however all these remedies seemed punitive.

Because these Community Microgrids are developed at the pleasure of the Community and the majority of development costs are borne by the generation owner, it didn’t seem justified for PG&E to impose strict default or performance obligations on the system. So, while PG&E requires the resource to meet PG&E power quality standards when the resource is operating, the MOA does not impose any operational requirements to keep an island energized for any set duration and no penalties are assessed. If the project fails to energize the grid during PSPS, the community is in no worse off of a state than they would be without that resource. However, if PG&E is funding the project through a program such as the Microgrid Incentive Program, there are additional performance expectations given ratepayer dollars were invested in the project. Those additional operating term performance assurances are specified in Attachment XIII, Operating Term Performance Assurance Requirements.

Lastly, prolonged and detailed conversations regarding liabilities of the microgrid occurred. As the Distribution Operator, PG&E bears the liability of damages caused by the failure of PG&E assets or operations of those assets. PG&E must protect the safety of its communities and takes this responsibility very seriously. PG&E manages this liability through rigorous evaluation during the Microgrid Island Study, Operator training, and extraordinary operational coordination between the CMG Aggregator and PG&E. PG&E also requires the Project Resource to carry general liability insurance to indemnify the community for damage that is caused by the generating resource itself.

4.3 Interconnection and the Microgrid Special Facilities Agreement

A primary objective of the EPIC 3.11 project was to create a scalable model for integrating Community Microgrids onto PG&E's system. To achieve this, the grid-forming generator which provides the frequency and voltage support functions required for Community Microgrids must be interconnected to PG&E’s distribution grid. There are multiple types of interconnection processes, with Rule 21 and the FERC Wholesale Distribution Tariff (WDT) interconnections being the most likely for grid-forming generators within Community Microgrids. While there are important distinctions between these two interconnection arrangements, these considerations lie outside the scope of this report. For simplicity, this report collectively refers to these arrangements as the "interconnection process."

The interconnection process has three key functions that are useful for integrating Community Microgrids.

First, it ensures that the interconnection will not impact the stability of the grid. This is accomplished through a series of technical studies, such as an Electrical Independence Test, a System Impact Study, and a Facility Study. These studies are conducted to safeguard the integrity of PG&E's distribution system.

Second, the interconnection process identifies the necessary upgrades and special facilities needed to integrate the generator into the system, ensuring reliability. The process provides transparency and cost certainty around these upgrades.

Third, the interconnection process verifies that the generator and its equipment meet PG&E's standards for safety. The standard interconnection model follows a strict choreography of events and statutory timelines as determined by FERC and CPUC jurisdictional agreements. Figure 10 provides a sample of milestones in this process.

Milestones

In-Service Date: October 23, 2020

Critical milestones and responsibility as agreed to by the Parties:

	Milestone	Date	Responsible Party
1	Financial Security Posting Due Date	February 14, 2020	Interconnection Customer
2	Submit electronic initial design package *(including but not limited to equipment list, 70% final SLD, site map and site plan)*	February 28, 2020	Interconnection Customer
3	On-site project kick-off meeting	March 6 2020	Distribution Provider & Interconnection Customer
4	Completion of the Interconnection Facilities, Distribution Upgrades, and Network Upgrade facilities	October 23, 2020	Distribution Provider & Interconnection Customer
5	In-Service Date (back-feed power)	October 23, 2020	Distribution Provider & Interconnection Customer
6	Pre-parallel Inspection and Testing	November 6, 2020	Distribution Provider & Interconnection Customer
8	Provide written approval to Interconnection Customer for the operation of the facilities (PTO) and Commercial Operation Date (COD)	November 6, 2020	Distribution Provider

Note 1 – Ability to Meet Milestone Dates
The ability to meet these Milestone dates requires that all tasks, including tasks preceding the milestones listed above, to be completed in a timely fashion and does not account for unanticipated delays, including but not limited to delays caused by: emergency response due to wildfires or storms; time to complete environmental studies; availability of needed resources (e.g., materials or crews); difficulties securing necessary permits, easements, right of ways, licenses or other approvals; construction additional information needed to complete the project implementation process; or delays scheduling clearances to complete the interconnection of this project to the PG&E system.

Figure 10: Sample Interconnection Milestone Table

4.3.1 Challenges with the Existing Interconnection Process for Microgrids

Initially, it was believed that the existing interconnection process would be sufficient to manage the interconnection of a microgrid as a single controllable entity. However, as discussed in the Tariff section above, the existing interconnection process only evaluates for grid-connected operations and does not contemplate the unique technical and operational requirements for microgrids during islanded mode. Therefore, the existing interconnection process was necessary but not sufficient to fully evaluate the performance and safe operations of Community Microgrids under all conditions.

The first challenge with the existing interconnection process is the timing of the technical studies. The timelines for traditional generation interconnections are well defined and understood, so utilities are comfortable committing to them. However, generators interconnected to microgrids require a new and unique set of studies to evaluate the safety and performance of the system while the microgrid is islanded. This new type of evaluation does not lend itself to clear timelines and makes it difficult for PG&E to meet the statutory timelines required by the interconnection process.

The second challenge is that microgrids have Special Facilities unique to their operation. These "Microgrid Special Facilities" go beyond those identified in typical Interconnection Technical Studies. Because these Microgrid Special Facilities are directly required to interconnect under the WDT or Rule 21, there was a jurisdiction and scoping challenge. For example, if the non-required Microgrid Special Facilities were included in the WDT and the project abandoned their intentions of a microgrid, the WDT is simply not set up to cover what may be considered superfluous equipment.

Finally, Community Microgrids do not yet have a robust set of standards and reference architectures. As a result, the facilities and equipment used in these systems need to go through an additional level of design review and approvals, impacting interconnection timelines. The existing interconnection process is ill-equipped to manage for these unknows.

4.3.2 The Microgrid Special Facilities Agreement

To address these challenges, the EGI and RCAM project teams decided to develop a supplemental and independent process called the Microgrid Special Facilities Agreement[Attachment IV-B in the MOA] that isolates the unique technical studies, special facilities, and standards required of the primary grid-forming generator in microgrid mode. This new process focuses on evaluating just the problem-set that exists in the islanded state, while maintaining the existing interconnection process for grid-connected generators. The newly developed Microgrid Operating Agreement (MOA) captures the roles and responsibilities for this new independent process.

Isolating the islanding operations and technical challenges from the standard interconnection process allows for flexibility and adaptability. One key benefit of this approach is that a generator can progress through the standard interconnection process, get online, and then the community can evaluate whether they want the generation to act as the grid-forming generator.

4.3.3 Interconnection Process Results and Findings

4.3.3.1 Technical Assistance with Interconnection

Proper technical assistance significantly increases the chances of a successful interconnection application. Understanding potential distribution upgrade requirements early in the process is critical to assess the business case. Additionally, engaging PG&E's Distribution Planning Engineers early in the design phase can streamline the interconnection process by pre-empting many of the typical issues that arise when interconnection mistakes are discovered later in the design cycle.

Based on the lessons learned, the CMEP and MIP programs provide increased technical support for community microgrid projects as a foundational pillar of these programs. Both RCEA and the Schatz Center have noted that increased technical assistance to the microgrid applicant significantly increases chances of a successful interconnection application. This was evident for example when the initial system impact study identified the incremental distribution upgrade costs (including cost of ownership) to RCEA would be $2.2MM. These costs significantly exceeded the project budget and would have killed the project. After some conversation with Distribution Planning, at the request of the customer, the issue was resolved by changing the import/export limits on the battery. This simple change brought the interconnection costs down to around $200K which substantially increased the economic viability of the project. While this technical review is available to any interconnection customer, this example demonstrates how technical support can make or break a project.

PG&E's Distribution Planning Engineers were key stakeholders in this project and were engaged early and often in the design phase. This engagement streamlined the interconnection process by pre-empting many of the typical issues which arise when interconnection mistakes are discovered later in the design cycle. This includes, most importantly, early review of the projects inverter's capabilities prior to submitting the interconnection application.

In addition to increased technical support from PG&E, it is equally important for applicants to understand the utility interconnection process. Experience with interconnecting projects matters. Case in point, another microgrid project entered the interconnection process around the same time as RCAM. The project team lacked the interconnection experience of RCAM's project partners the Schatz Center and RCEA. The project with a less experienced team ran into significant project delays forced by redesign and interconnection agreement negotiations. In contrast, the RCAM project team with a more complicated interconnection was able to meet all key interconnection milestones and successfully interconnect. Where interconnection experience is lacking, microgrid developers need additional technical assistance to navigate the interconnection process. Therefore, PG&E's Community Microgrid Enablement Tariff requires the technical partner to demonstrate previous development experience.

A full accounting of the technical lessons learned during the interconnection process can be found in the Community Microgrid Technical Best Practices Guide[28].

4.3.3.2 Implications on Deliverability

RCAM was interconnected under the WDT which provides three pathways for interconnection[29]:

1. Cluster Study Process
2. Fast Track Process
3. Independent Study Process

The Cluster Study Process has an "interconnection request" window open once per year between April 1st and April 30th and takes approximately two years to complete. This timeline did not work with the

[28] Community Microgrid Technical Best Practices Guide (pge.com)
[29] Distribution Interconnection Handbook (pge.com)

RCAM project schedule. Additionally, the project was not eligible for the PG&E DER fast-track process. Therefore, RCEA applied through the WDT Independent Study Process.

When RCEA first applied for the interconnection in March of 2019, they needed to decide whether to connect as an Energy Only or as a Full-Capacity Deliverability resource (FCD). The ability to obtain FCD is important to enable these resources to claim Resource Adequacy (RA) credit. The value of RA can be an important component to the economic viability of a project. However, the FCD requires a network-wide engineering analysis to mitigate any potential impact on transmission level voltage facilities. This analysis is costly and can take up to two years to complete. As with the Cluster Study Process, the RCAM project schedule could not accommodate this schedule impact.

By choosing the Energy Only Delivery, RCEA is able to participate in the CAISO market operations, but cannot deliver its full output to the aggregate of load on the grid[30].

While RCEA understood the implications of these tradeoffs, they did not realize that this decision was final and could not be changed during the interconnection process and there were very limited options for seeking FCD as an existing interconnected resource.

That limited option for seeking deliverability as an existing interconnected resource is called the Distributed Generation Deliverability (DGD) Study Process which is run by CAISO. This DGD process theoretically allows generators that are either in the interconnection queue or are already interconnected as Energy Only assets to receive FCD and thus Resource Adequacy credit. However, as a practical matter, this is not an option. The DGD process is run by CAISO on an annual basis and is only available to generators on highly constrained circuits identified by CAISO. As it happened, Janes Creek 1103 was not selected as one of these constrained circuits and therefore the RCAM generator is not eligible. When looking at the economic viability of these project resources, this is not a reliable pathway to obtain RA credit.

There has been some discussion of changing this policy to allow existing Energy Only facilities to re-enter the interconnection queue and apply for Full Capacity Deliverability Status (FCDS). Changing this policy would help support the economics of smaller generating resources interconnected specifically to support community microgrids.

4.3.3.3 Interaction between PG&E Interconnection and CAISO

While RCEA and the Schatz Center were able to effectively navigate the WDT Interconnection Process and CAISO New Resource Implementation Process without PG&E and work directly with CAISO to establish RCAM as a wholesale generation resource, it is worth mentioning a few areas where PG&E has been informed of some possible roadblocks for future projects.

CAISO typically requires 100% of the generator's deliverable capacity to be available for the market at any given time. However, for Community Microgrids with batteries, it is best practice to keep some percentage of the battery's capacity in reserve to be able to respond to emergency events. Therefore, if the Community Microgrid requires a WDT interconnected battery, it is important for the Applicant to

[30] Wholesale Generation Interconnection Services Wholesale Distribution Independent Study and Cluster Study Interconnection Processes Interconnecting Your Generating Facility with PG&E's Electric Grid (pge.com)

work with CAISO to ensure the project can maintain reserve capacity while also participating in wholesale markets. The RCAM project was able to accomplish this and typically leaves 25% of battery capacity in reserve for resiliency purposes.

Secondly, CAISO is indifferent whether the generator is grid-connected and exporting to the bulk electrical system, or whether the microgrid is islanded. The generator receives CAISO market revenue in either scenario. However, in an islanded state, the generator's sole responsibility is to support the load in the microgrid and is unavailable to respond to market signals. The failure to respond to CAISO dispatch signals by the generator will result in financial penalties. Therefore, an outage card must be issued during islanding events so that the generator is not called by CAISO. It is important for generators to manage these outage cards.

4.4 Community Microgrid Policy and Process Key Takeaways

- **Preserve Grid-Connected Rules and Processes.** In creating a community microgrid tariff, it was critical that it not conflict with or impact any existing rules and processes. This was accomplished by restricting CMET applicability to islanding and transitional conditions only and pointing to relevant rules and tariffs. Otherwise, when the microgrid is in standard grid-connected conditions, all other rules and tariffs apply. This includes maintaining the standard interconnection process required for any and all project resources within the microgrid. All timelines for the system impact study, facilities study, etc. are unchanged and remain separate from CMET.

- **Clear Equipment Ownership.** One of the more contentious challenges with Community Microgrids is allowing a third-party (i.e., Community Microgrid Aggregator) to leverage front-of-the meter project resources and utility-owned assets to energize critical facilities when the broader grid is down. This safety and liability concern was solved for by creating a clear bright line of microgrid asset ownership and ensuring no third-party equipment nor third-party operational control of PG&E assets. While this solution is clean, it does increase the cost and complexity of a project by requiring two microgrid controllers (one owned by each party). This solution allows PG&E to remain the utility distribution owner and operator during both grid-connected and Islanded modes, including determining when the microgrid can be islanded for emergency events (the default objective of PG&E), or disabling the microgrid for safety or maintenance issues.

- **Clear Roles and Responsibilities.** Community Microgrids often include multiple parties in the design, development, and operation of a microgrid, which can complicate the assignment of roles and responsibilities. The CMET, Microgrid Operating Agreement (MOA), and the Jurisdictional Boundaries Letter of Agreement are three critical documents used for defining roles and responsibilities of parties involved (Section 8.2). When designing these agreements, it was essential that PG&E maintain the utility role as the grid operator and provide distribution services to customers at all times and that there be a single third-party countersigner to the agreements (i.e., the Community Microgrid Aggregator). The Community Microgrid Aggregator is the party responsible for coordinating the grid forming generator(s) and making necessary upgrades to the microgrid when it becomes unsafe to operate in island mode. The Community Microgrid Aggregator is not necessarily the generation owner, which was an unexpected outcome when initially drafting the tariff and MOA. For RCAM specifically, RCEA is the Community Microgrid Aggregator and project resource owner, the Schatz Center designed and engineered the microgrid and is the entity that helped fulfill the Operating Procedures and Protocols outlined in the MOA, and there is a separate scheduling coordinator that operates and maintains the dispatch of the project resources to provide frequency and voltage support when the microgrid is islanded.

- **Energy Settlements during Island Mode.** Through the process of identifying possible compensation mechanisms for the energy provided to customers when a microgrid is islanded, PG&E found that the energy settlement provisions under a Project Resource's Wholesale Distribution Tariff or Rule 21 tariff will continue to be enforced even when the microgrid is disconnected from the bulk grid. CAISO confirmed that all meters in the wholesale market continue to spin during island mode and any energy generated by project resources within the microgrid will be settled by the CAISO in the imbalance market based on the nearest CAISO pricing node. When a microgrid is islanded, the microgrid aggregator's scheduling coordinator must submit an outage card to the CAISO because the grid-forming generator must meet the loads of the islanded microgrid and cannot respond to CAISO dispatch instructions. Any energy generated to meet the load within the microgrid will be settled in the energy imbalance market based on the real-time price at the nearest CAISO pricing node. In addition, net metered resources will continue to accrue electric bill savings when operating as part of an islanded microgrid. The RCAM wholesale and retail generators will therefore be compensated in this way during islanded operation. PG&E developed the Community Microgrid Enablement Tariff (CMET) that will be used to govern the operational and financial aspects of a multi-customer microgrid. The CMET points to the existing rules (i.e., Wholesale Distribution, Rule 21, CAISO tariffs) and processes that are necessary for settling energy transactions during island mode.

- **Capturing Resource Adequacy and Interconnection Timelines.** RCEA originally intended for their FTM solar and battery project resources to qualify for Resource Adequacy (RA) credit as another revenue stream to further justify the economic viability of the project. Unfortunately, given the complexity of attaining Full Capacity Deliverability Status (FCDS) for RA credit and the time and cost it would take to participate in the required cluster study (a few years), RCEA chose to interconnect as an Energy Only resource (instead of a FCDS resource), hoping they would have the opportunity to later make a request to change their interconnection status from Energy Only to FCDS. Unknowingly, this early decision to interconnect as an Energy Only resource restricted the project resource from later going through the cluster study to apply for FCDS. One of the policy recommendations from this experience is to allow re-entry into the interconnection process for Energy Only resources that are already operational so they can engage in the cluster study process and obtain FCDS if they desire to do so. Another recommendation is to enhance the support provided to DG owners/operators/developers through the interconnection process (e.g., better educational and awareness information, better publicity, a more transparent process, etc.).

- **Relying on the MOA Appendices for Flexibility.** When developing the Microgrid Operating Agreement for RCAM, one of the key intents was to create a replicable agreement for other community microgrid projects. One of the challenges in doing so is that each microgrid is unique (e.g., microgrid configurations, required equipment, development timelines, microgrid islanding study etc.) which needs to be documented and addressed in the MOA. At the same time, PG&E also needs to avoid re-negotiating contractual terms in the MOA that are nonnegotiable. To balance these requirements, the MOA was structured such that the terms in the body of the MOA are fixed and appendices are used to provide flexibility for unique characteristics for each microgrid. Many of the MOA appendices developed for RCAM were also drafted with the intention of re-use for other Community Microgrid projects with minor modifications.

- **Modification of PG&E's Special Facility Agreement.** When RCAM was originally proposed, it was thought that a new agreement or tariff would need to be developed to appropriately handle cost recovery of equipment required for islanding. It was later determined that PG&E's existing Special Facilities Agreement could be slightly modified for a Community Microgrid use-case.

- **No Performance Requirements.** It was ultimately determined that when the Community Microgrid Aggregator is responsible to pay for maintenance and upgrades of the microgrid to ensure the microgrid can island safely (as described in Section 4.2.5), PG&E does not obligate the Community Microgrid Aggregator to pay for those upgrades if they decide they do not want to make those investments to enable island mode. If the Community Microgrid Aggregator chooses not to pay for upgrades, the microgrid will be restricted from islanding until required upgrades are met. However, this approach is not applied for projects that are provided incentive funding through PG&E's Microgrid Incentive Program which do have performance obligations.

- **Generation Reserve for Islanding.** The resilience provided by a microgrid is inextricably linked to the ability to hold a portion of stored energy in reserve at all times. CAISO requires full participation from energy storage market participants however a microgrid aggregator also needs to maintain a reserve capacity of the project resources for islanding needs (i.e., battery energy system). RCEA set a minimum state of charge parameter on the battery to 25%, which was acceptable to CAISO, that serves as the reserve state of charge to respond to emergencies.

4.5 Gaps and Recommendations

4.5.1 Challenges with the Siting and Study Processes

Siting a generator is highly dependent on the location having available hosting capacity. Given the capacity issues throughout PG&E's territory, it is important to provide potential microgrid developers visibility into the current available capacity on the system. The ICA maps are a tool in service to this goal, but they are often too coarse for final site selection. Improving the granularity of this data would help with future microgrid siting activities.

One of the key gaps that needs to be addressed is to simplify the Microgrid Island Study. For example, Real-Time Digital Simulation and Power-Hardware-in-Loop testing were critical tools to evaluate Community Microgrid generators at this stage in the Community Microgrid maturity. However, this testing is expensive and raises questions about the long-term sustainability of this approach. Development is needed to find ways to standardize studies, develop less intensive processes to model Community Microgrids more efficiently, reduce costs, and shorten implementation times.

4.5.2 Managing Change within the Community Microgrid

It is unclear how PG&E will accommodate load growth within the microgrid. The microgrid islanding studies and operational components were studied as a static microgrid footprint. However, microgrids are dynamic. While PG&E has the right to re-study the microgrid if there are material changes such as load growth, PG&E will need to establish a load growth doctrine consistent with the principles of how it manages load growth within the larger distribution network.

4.5.3 Additional Value from Community Microgrid Resources

Community microgrids backed by batteries may provide an opportunity to provide additional services beyond the resiliency afforded by microgrids. The Interconnection Technical Studies view batteries as a standard generation source whereas batteries can provide a host of grid support functions which standard generators cannot. As feeders get more dynamic with the addition of electric vehicles, PG&E may want to revisit this conservative approach and employ these batteries for additional uses. This may also open additional revenue opportunities battery-based generators for microgrids.

5 RCAM Protection and Design

The RCAM protection system is a combination of PG&E-owned and RCEA-owned protective devices. The protection system is designed to successfully isolate faults experienced during both grid-connected and grid-forming microgrid operations.

Developing an effective protection scheme is particularly challenging for microgrids with only inverter-based resources, such as RCAM, due to the reduced fault current contribution. The protection scheme was made even more challenging given this is an ungrounded system when islanded, and the desire for seamless transitions between grid-connected and grid-forming modes. Successful development, commissioning, and real-world performance are key project achievements and represent noteworthy advancements to the current state-of-the-art.

5.1 RCAM Protective and Control Devices

PG&E and RCEA needed to add specific equipment and settings to enable the Community Microgrid beyond what is needed for a normal large generation interconnection. Below is a description of the protective and control devices that support the microgrid and the interconnected system with a diagram of the connections (Figure 11).

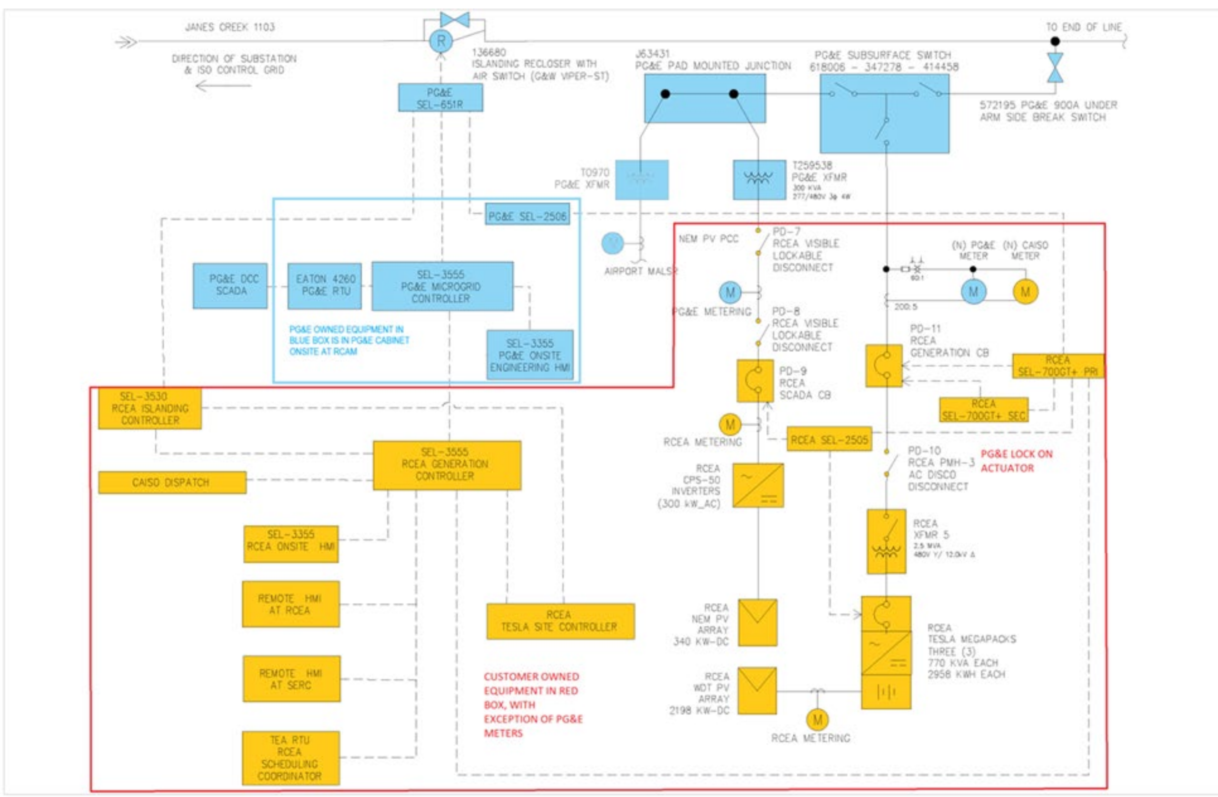

Figure 11: RCAM Protective and Control Devices

PG&E Facilities:

a. The PG&E owned G&W Viper ST Line Recloser LR 136680 located on Janes Creek 1103 circuit is the RCAM Microgrid Islanding Point and is the islanding recloser.

b. The PG&E owned SEL-651R Advanced Recloser Control relay is used to supervise and control the line recloser LR 136680. The protective settings are set to coordinate with the RCEA-owned RCAM SEL-700GT+ relays and upstream PG&E Line Recloser LR 7588, and to protect the remaining 12kV line section up to the end of the line.
c. The PG&E owned SEL-2506 Remote I/O unit provides hardwired control outputs and status inputs between the SEL-651R and the RCEA owned SEL-700GT+ relays.
d. The PG&E owned SEL-3555 microgrid controller provides control and integration with the RCEA generation controller.

RCEA facilities:

a. The RCEA owned Generation Circuit Breaker is the point of interconnection between RCEA's grid forming generation and the PG&E distribution Janes Creek 1103 circuit.
b. The RCEA owned, two SEL-700GT+ Intertie Protection relays are used to supervise and control the RCEA medium voltage Generation Circuit Breaker. The primary SEL-700GT+ relay provides protection and control. The secondary SEL-700GT+ relay provides redundancy for protection related functions and elements, but there are no control functions.
c. The RCEA Islanding Controller (SEL-3530) can trip the PG&E Recloser LR 136680, when PG&E permits "customer trips", for instances where the RCEA BESS Site Controller detects a potential islanding condition. This provides a more sensitive island detection than using the PG&E recloser alone.
d. The RCEA Multi-Mode Grid Forming Generation - 2.3 MVA / 8.8 MWh Battery System and 2.2 MW of DC-coupled photovoltaic (PV) panels, also referred to as the BESS can operate in "Grid Following" or "Grid Forming" modes.
    - Grid Following mode – Inverter is configured per WDT UL-1741 requirements, including Voltage, Frequency, Active Anti-Islanding, and Volt/Var.
    - Grid Forming mode - Inverter is configured to support the microgrid load. Voltage and Frequency elements are configured accordingly. Active Anti-islanding is disabled.
e. The SCADA operated 480VAC RCEA SCADA Circuit Breaker, is controlled by the SEL- 3555 RCAM Generation Controller as over-generation mitigation during islanded operations for the 300 kW Net Energy Metered (NEM) PV system.
f. The SEL-2505 Remote I/O unit is used for monitoring and controlling the NEM PV RCEA SCADA Circuit Breaker and the Battery AC circuit breakers. The SEL-2505 communicates with the Primary SEL-700GT relay and has hardwired connections to the customer I/O sections in the Battery and NEM PV SCADA Circuit Breaker.
g. The RCEA owned S&C PMH-3 12kV AC disconnect for the BESS.
h. The RCEA owned SEL-3530 islanding controller is connected to PG&E's line recloser to support islanding with the BESS.

5.2 State-Based Protection Settings

Protection settings automatically change at the PG&E-owned line recloser (islanding device) depending on if RCAM is in Microgrid Enabled Mode or Microgrid Disabled Mode (Section 3.3). The settings for the RCEA-owned Generation Circuit Breaker will change automatically depending on if the Community Microgrid is grid-connected or islanded. Figure 12 provides an overview of the protective device group settings for the line recloser and Generation Circuit Breaker, with more detailed descriptions in the following sections.

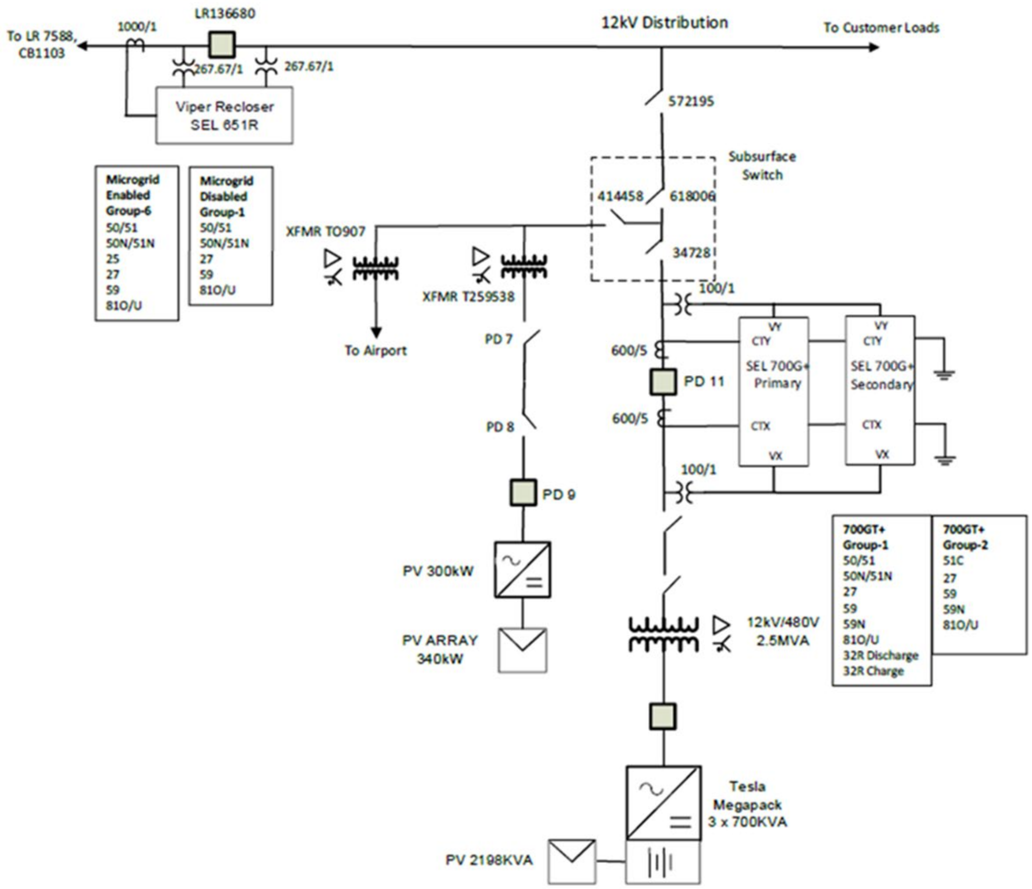

Figure 12: RCAM Protective Device Configuration

Microgrid Enabled Mode:

The Microgrid Enabled Mode setting allows grid-connected or islanded operation of the microgrid.

- RCAM will island automatically if there is a PG&E grid disturbance on the source side of LR 136680 and will automatically reconnect to the grid when PG&E power source-side of LR 136680 is stable for 15 minutes.
- PG&E's LR 136680 will function as both an islanding device and a protective device in this mode, with no reclosing enabled (1 shot to lockout) and no Sensitive Ground Fault features.
- RCEA's SEL 700GT+ relay setting group will automatically change for the RCEA Generation Circuit breaker if transitioning to an islanded or grid-connected state based on the status change of LR 136680.
- Trip/Close signals from the RCEA BESS are allowed in Microgrid Enabled Mode.
- PG&E's SEL 651R relay is set on Group-6 - Microgrid "Enabled" for both Grid-Connected and Islanded operation. The SEL-651R is coordinated with the RCEA Generation System. The following protective elements are enabled:
    - 50/51 Phase Instantaneous/Time Overcurrent
    - 50/51G Ground Instantaneous/Time Overcurrent
    - 27 Undervoltage (Supervised with ground and phase overcurrent)
    - 59 Overvoltage (Supervised with ground and phase overcurrent)

  - 81 Over / Under Frequency
  - 25 Synchronism Check
  - Direct-Transfer-Trip to RCEA 12kV Generation Circuit Breaker
  - The 27 and 59 elements are supervised with the phase and ground time overcurrent element pick-up elements in Group-6. This supervision will prevent the 27 and 59 elements from operating for in-section faults.

Microgrid Disabled Mode:
The Microgrid Disabled Mode setting allows grid-connected operation of the RCEA generation; however, it will not allow the microgrid to island.

- Islanding and transitioning are not allowed.
- If already islanded when this mode is activated, the generation will shut down.
- LR 136680 will function like a normal protective device by only tripping on overcurrent elements, with no reclosing enabled ("One shot to lockout") and no Sensitive Ground Fault features.
- This mode may be selected by Operators or may assert automatically due to an alarmed communication failure.
- Redundant SEL-700GT+ relays controlling the RCEA Generation CB are in Settings Group 1 for Grid-Connected Operation.
- RCAM BESS is in "Grid Following" mode.
- The SEL-651R Recloser Control Relay that controls LR 136680 will be in Setting Group 1 when in Microgrid Disabled mode for Grid-Connection operation.
- The SEL-651R relay is coordinated with the RCEA Generation System.
- Trip/Close signals from the RCEA BESS are inhibited in Microgrid Disabled Mode.
- SEL-651R Setting Group 1 (Microgrid Disabled Mode) has the following protective elements active:
  - 50/51 Phase Overcurrent
  - 50/51G Ground Overcurrent
  - 27 Undervoltage (Supervised with ground and phase overcurrent)
  - 59 Overvoltage (Supervised with ground and phase overcurrent)
  - 81 Over / Under Frequency
  - Direct Transfer-Trip to RCEA 12kV Generation Circuit Breaker
  - Close supervision over LR 136680

Grid-Connected State:
Under blue-sky conditions, the microgrid is connected to the PG&E grid and RCEA's wholesale generation assets operate independently in the CAISO wholesale market. This state can occur when RCAM is in Microgrid Enabled Mode or Microgrid Disabled Mode.

- Protection is provided by LR 136680 in coordination with RCEA generation circuit breaker.
- RCAM BESS is in "Grid-Following" mode.
- PG&E has override capabilities if needed.
- RCEA generation assets are constrained by PG&E to between 1.45MW charging and 1.75MW discharging.
- Redundant SEL-700GT+ relays controlling the RCEA Generation CB are in Settings Group 1 (Grid-Connected Operation) with the following protective elements:
  - Over/undervoltage (27/59) - Settings per Rule 21
  - Over/underfrequency (81O/U) - Settings per Rule 21

- Ground overvoltage (59N): RCAM transformer high side (12kV) is delta connected winding leaving the microgrid 12kV portion ungrounded, hence the 59N element will be used for ground protection and a sensitive 59 element is used for phase overvoltage protection.
- Phase Instantaneous/Time overcurrent (50/51) - Settings coordinated with LR 136680.
- Ground Instantaneous/Time overcurrent (50N/51N) - Settings coordinated with LR 136680.
- Discharge (Generation) Restriction (32R discharge) 1750kW and Charge Restriction (32R charge) 1450kW.

Islanded State:
If there is a PG&E grid disturbance on the source side of LR 136680, the RCAM system will island, and RCEA's BESS system will support the load under the islanded condition. This state can only occur when RCAM is in Microgrid Enabled Mode.

- The RCAM BESS will transition from "grid-following" mode to "grid-forming" mode.
- Protection when islanded is provided primarily by RCEA's generation circuit breaker.
- PG&E has override capabilities if needed.
- Redundant SEL-700GT+ relays controlling the RCEA Generation circuit breaker are in Settings Group 2 (Islanding Operation) with the following protective elements:
    - Over/undervoltage (27/59) Overvoltage is set to trip in 0.16 seconds at 115% phase-ground overvoltage.
    - Over/underfrequency (81O/U)
    - Ground overvoltage (59N) – Detects 12kV line to ground faults.
    - Voltage Controlled phase overcurrent (51C).
    - Overcurrent protection is supervised by a phase-phase undervoltage element set at 80% that measures the 12kV BESS fault current contribution.

5.3 Microgrid Fault Responses

The microgrid protection and control system operation is designed based on short circuit analysis for line to ground and three phase faults in the below mentioned scenarios for the grid-connected and islanded system, respectively. The different fault zones are represented in Figure 13 below.

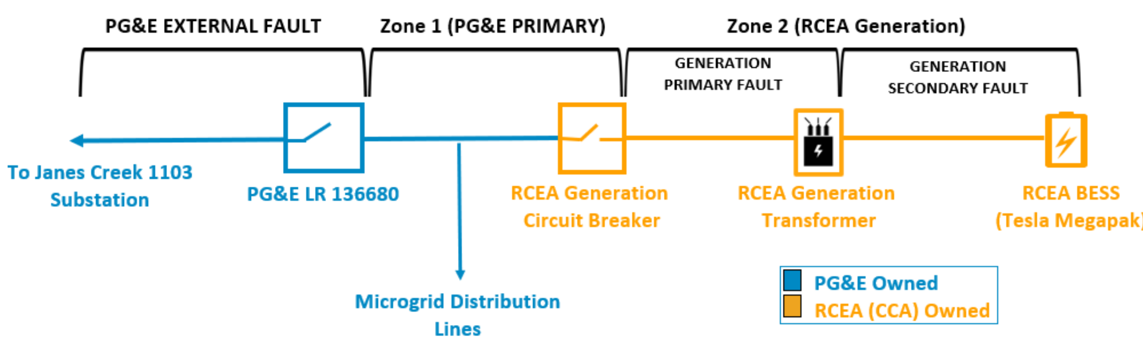

Figure 13: RCAM Fault Zones

5.3.1 Grid-Connected Fault Response in Microgrid Enabled Mode:

PG&E External Fault:

- The PG&E microgrid controller auto-transfer scheme is activated.

- LR 136680 is tripped open by either the LR SEL-651R voltage or frequency elements, or tripped from the RCAM BESS via the inverter island detection function.
- SEL-651R transmits the open status to the RCAM SEL 700GT+ relays to change the relay setting group to Group-2 for the RCEA Generation Circuit Breaker.
- The RCAM SEL 700GT+ relay settings shift to Group-2.
- RCAM BESS inverters shift to "Grid Forming" mode to supply customer load.

Zone 1 (PG&E Primary Grid with in the RCAM Boundary) Fault:

- SEL-651R relay phase or ground protective elements will detect the fault and trip open LR 136680.
- SEL-651R sends a trip command to the RCAM SEL 700GT+ relays which in turn trips the RCEA Generation circuit breaker and drives to lockout.
- The RCEA 300 kW PV system inverters will shut down on anti-islanding.

Zone 2 (RCEA-owned Wholesale Generation Equipment) Fault:

- SEL-700GT+ relays will detect the fault and trip the RCEA Generation Circuit Breaker to lockout.
- BESS internal circuit breakers will also trip.

5.3.2 Islanded Fault Response in Microgrid Enabled Mode:

Zone 1 (PG&E Grid with in the RCAM Boundary) Fault:

- SEL-700GT+ relays detect the fault and trips RCEA Generation circuit breaker to lockout, and a lockout signal will be sent to LR 136680.
- The SEL 700GT+ settings do not coordinate with the tap fuses when the BESS is supplying the island.
- Faults must be observed and investigated beyond fuses as they may not trip during a fault while islanded due to lower generator fault duty.
- The RCEA 300 kW PV system inverters will shut down on anti-islanding.

Zone 2 (RCEA Wholesale Generation) Fault:

- SEL-700GT+ relays detect the fault and trip the RCEA Generation Circuit Breaker.
- The BESS internal circuit breakers will also trip.
- Microgrid Disabled Mode is automatically triggered.
- The RCEA 300 kW PV system inverters will shut down on anti-islanding.

5.3.3 Fault Response in Microgrid Disabled Mode:

PG&E External Fault:

- Since the fault or outage is on the grid side of the line recloser, LR 136680 will remain closed and source side protection devices will coordinate and operate.
- The SEL-651R voltage and frequency elements are disabled in this mode.
- The RCAM SEL 700GT+ relay settings will remain in Group-1.
- RCAM BESS remains in "Grid Following" mode.
- RCAM BESS inverter trips on Active Anti-islanding or voltage/frequency elements.
- The RCEA 300 kW PV system inverters will shut down on anti-islanding.

Zone 1 (PG&E Grid with in the RCAM Boundary) Fault:

- The SEL-651R phase or ground overcurrent protective elements will detect the fault.
- LR 136680 will open and lockout.
- The SEL-700GT+ automatically trips and lockouts the RCEA generation circuit breaker.
- The RCAM BESS remains in “Grid Following” mode.
- The RCAM BESS inverter trips on Active Anti-islanding or voltage/frequency elements.
- The RCEA 300 kW PV system inverters will shut down on anti-islanding.
- LR 136680 does not auto-reclose, a manual test may be performed via SCADA.

Zone 2 (RCEA Wholesale Generation) Fault:

- LR 136680 will remain closed.
- The RCEA Generation CB will trip and lockout.

5.4 RCAM Protection and Design Key Takeaways

Need for New PG&E Microgrid Protection Device:
PG&E did not have a standard device for microgrid protection. PG&E introduced SEL-651R relays for protection at the microgrid point of interconnection based on design analysis and evaluation. To support this new device PG&E had to create new setting files, testing, commissioning, documentation, and maintenance processes.

Need for Overcurrent Supervision of Voltage Elements:
The SEL-651R was initially tripping on voltage-based protection for internal faults in the microgrid while the microgrid was grid-connected and allowed the BESS to island into a fault in PHIL testing. This caused the device to not send a signal to the SEL-700GT+ to trip the Generation CB since the condition to send this signal was an overcurrent trip. This was later addressed with an overcurrent supervision to the under-voltage element in SEL-651R. Overcurrent supervision allowed discriminating between faults internal and external to the microgrid and did not allow the BESS to form the microgrid during internal faults.

Faults During Islanded Operation May Not Trip Fuses:
For the microgrid internal faults under islanded operation, faults must be observed and investigated beyond fuses as fuses may not trip during a fault while islanded due to lower generator fault duty.

Sufficient Short Circuit Current Required:
When in an islanded condition, the inverter introduced short circuit current should be significant enough to contribute to the microgrid internal fault detection and protection coordination. The fault contribution should be tested to confirm fault detection. Testing for RCAM found the BESS did not generate sufficient fault current levels as specified in the product documentation. This issue led to faults being undetected during islanded condition in PHIL testing at the ATS (Applied Technology Services) Microgrid Testbed. This issue was resolved by updating the firmware in the inverter to increase the fault current.

Grounding Bank for Improved Fault Response:
During a ground fault, a ground reference helps to mitigate potential overvoltage conditions due to a neutral shift and provides a path for ground fault current to enable traditional protection methods to detect the ground fault. RCAM is normally connected to the PG&E 12kV, 3-wire, uni-grounded (neutral

is grounded only at the substation and the distribution transformers) distribution system. When RCAM islands there is no longer a grounding reference because the RCAM BESS and loads have delta-wye grounded transformers (delta on the high side and wye grounded on the low side). Although ground faults are detected by a ground overvoltage element (59G) there can be issues with overvoltage. To help mitigate this issue in the future for similar scenarios, the following actions are suggested to help with the successful detection of ground faults:

- High side (12KV side with delta winding) should not be grounded in grid-connected mode
- High Side (12KV side with delta winding) should be grounded in island mode (using a switched in grounding bank)

6 Hardware and Controls Testing

The objective of the hardware and controls testing scope was to support the successful deployment of RCAM by providing a means of validating the microgrid control logic and protection scheme settings to be deployed in the field. PG&E took a three-stage approach to testing consisting of FAT, ATS Testing, and Field commissioning as described in Figure 14.

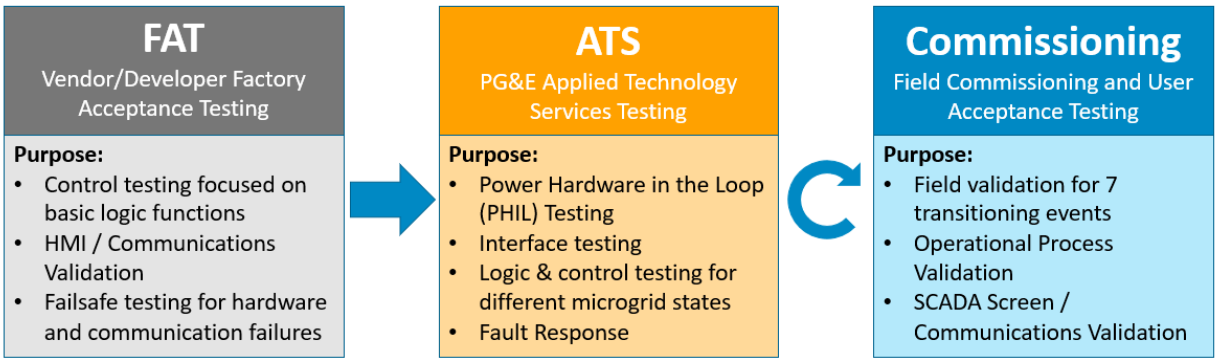

Figure 14: PG&E RCAM Test Strategy

6.1 Factory Acceptance Testing (FAT)

FAT was performed by the vendor and RCAM developer. While the FAT test plan was reviewed by PG&E, PG&E did not have a major role in this testing. FAT only provided a basic level of testing as it used emulated relays and power hardware. This was adequate for hardware and communications failsafe logic testing as well as providing confidence in basic capabilities of the system. However, significant updates were still required after passing the basic tests in FAT. It highlighted the technology was not mature enough to be "off the shelf", and provided insight that FAT alone was inadequate to let a system go directly to the field.

6.2 PG&E Applied Technology Services (ATS) Testing

PG&E internal testing was performed at PG&E's ATS laboratory in San Ramon, CA. PG&E's approach was to develop a Power Hardware-in-the-Loop testbed that would allow the execution of various control sequences and the application of power system faults in a controlled laboratory environment. The testbed included the same microgrid controllers, protective relays, and DERs that would be active in the field, but in contrast to pure hardware testing, the equipment was interfaced with a real-time simulation model of the microgrid. This allowed ATS to evaluate the protection and control devices under a wide range of conditions, including edge cases, that would be difficult or impossible to test in the field. Whenever a performance issue was found, either at the testbed or in the field, logic changes could be readily implemented and re-tested as necessary in a safe and efficient manner. This ability to rapidly iterate and deploy fixes was a key contributor to the success of the RCAM project.

Figure 15: ATS Testbed for RCAM

A test plan was designed to test the core functions of the microgrid and the protection functions in grid-connected and islanded modes. This test plan was developed and based on IEEE 2030.8[31] Standard for the Testing of Microgrid Controllers and IEEE 2030.7[32] Standard for the Specification of Microgrid Controllers. The ATS test plan covered three major areas and is provided in

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[31] IEEE SA - IEEE 2030.8-2018
[32] IEEE SA - IEEE 2030.7-2017

Appendix 3 – ATS RCAM Test Plan:

1. **Confirmed the correct execution of microgrid control sequences:**
    - Microgrid dispatches are limited by PG&E provided constraint limits (Figure 16)
    - Automatic and Manual transitions between grid-connected and islanded states
    - BESS State of Charge related functions

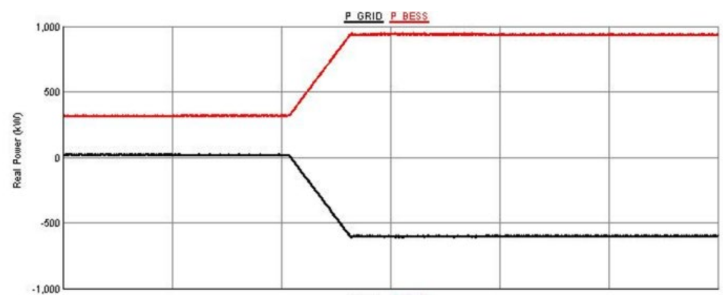

Figure 16: Confirming BESS Dispatches are Constrained by PG&E Provided Limits during Testing

2. **Evaluated the stability of the microgrid for various modes of operation:**
    - Microgrid voltage and frequency regulation
    - Seamless and break-before-make transitions

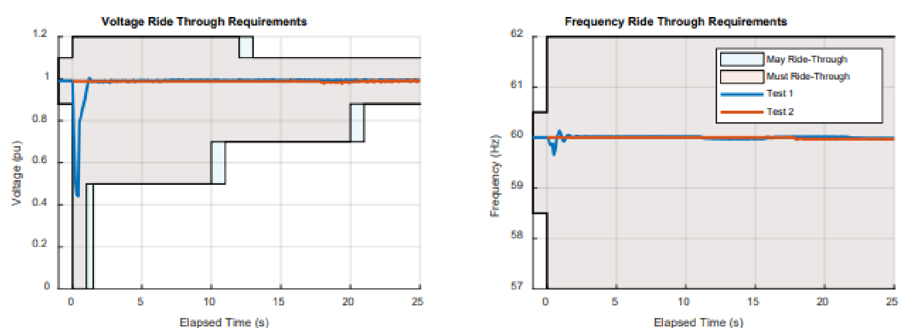

Figure 17: Voltage / Frequency Profiles from Seamless Transition to Island Tests

3. **Validated relay protection settings:**
    - Grid Voltage and Frequency Fluctuations
    - Line-to-ground (LG), three-phase (3P), line-to-line (LL), and line-to-line-to-ground (LLG) faults
        - External to the Microgrid Faults
        - PG&E Microgrid Primary Faults
        - Customer Generation Zone Faults

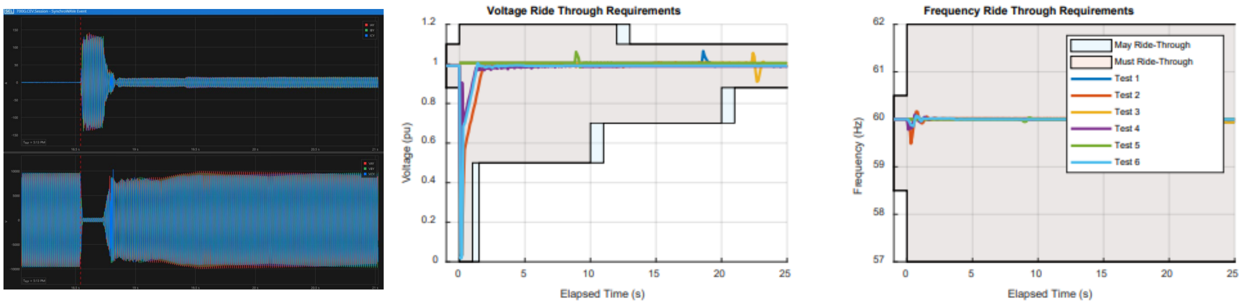

Figure 18: External Fault Testing Results

The testing plan was executed over the course of 10 months between June 2021 and April 2022. Three rounds of tests were performed including a final “regression test” which resolved all remaining issues identified during initial testing and field commissioning. A large part of commissioning time at ATS was spent developing and testing the islanding controller logic in the SEL-3505-3 and its interaction with the BESS Site Controller. ATS supported the Schatz Energy Research Center (Schatz Center), Schweitzer Engineering Laboratories (SEL), and the battery vendor throughout this development process and subsequent testing.

6.2.1 ATS Testing Findings

FAT Inadequate:

Issues were initially found with post-Factory Acceptance Testing (FAT) controller programming when the controllers were tasked to interoperate with real (non-emulated) relays and power hardware, including:

- Communication issues
- Grid-connected real/reactive power dispatch issues based on the configuration of weak-grid detection algorithms of the BESS.
- Issues for both seamless and break-before-make transitions.

It was also found that the processing power of the SEL-3505-3 was not enough to allow consistent operation of the microgrid controls. This led to sporadic issues that occurred when the processor usage spiked up to 100%. The issue was resolved by replacing the SEL-3505-3 with the more powerful SEL-3530-4. Grid-connected Fault Detection and Islanded Fault Detection functions were then tested with the upgraded hardware and BESS firmware to complete the testing scope.

BESS Not Performing to Specifications:

Another finding of the PHIL Testing was that the Battery Energy Storage System (BESS) did not initially generate the fault current levels as specified. This issue was discovered by ATS and reported to our project partners. This issue was resolved with firmware changes to the inverter.

Need for Lab Testing:

Because the testbed included the physical protection, control, and power hardware devices used at RCAM, ATS was able to identify hardware-specific configuration errors, communication issues, and validate performance specifications in advance of field testing and deployment. As a result of this thorough lab testing, the field tests only identified minor issues and resolving these issues did not significantly delay deployment.

Need for Regression Testing:
In cases where field testing uncovered issues not identified during ATS testing, the ability to replicate the problem in the testbed and compare results between the two environments proved to be an invaluable learning and development tool.

Protection Setting Updates:
ATS testing allowed PG&E to test a wide variety of fault and abnormal conditions that would not have been possible in the field. Based on these findings, protection settings of the system were updated to provide the proper fault response when insufficient. For example, it was found that overcurrent supervision was required for the voltage-based protection of the PG&E recloser when grid-connected to allow the Generation Circuit Breaker to trip and isolate faults within the RCEA Generation Zone.

ATS Testing Not Scalable:
ATS testing lasted 10 months and had four rounds of testing. This is not easily replicable and scalable. A need for more standardization is required in the future to reduce the testing burden.

6.3 Commissioning Testing

Commissioning testing was done in the field prior to operation and consisted of seven tests (Appendix 4 – RCAM Commissioning Test Plan Summary). Testing was done in coordination with all project and vendor partners and late at night so as not to impact airport operations. Field testing highlighted that even with all the testing done through FAT and ATS, there were still issues that needed to be resolved. However, the extensive failsafe planning and lab testing provided a safety net for the unknowns, where even though there were issues, they did not impact the safety of the system. Also, because of the ATS testbed, issues found in the field could be easily retested prior to restarting commissioning testing. Still, it took 6 sessions to complete the commissioning testing for RCAM to be ready for operation.

6.3.1 Commissioning Testing Findings

There were two key issues from the commissioning test process that led to changes in the controls, hardware, and future design thinking. It is recommended that all project vendors and sub-vendors participate in the project commissioning. Commissioning is resource intensive, and the complexity of these projects mean that unforeseen challenges are the rule rather than the exception. Having all relevant vendors on-site during commissioning helped identify and troubleshoot problems in real-time.

Cold Load Pickup Did Not Work in Field:
The first issue was the failure of the microgrid to execute a cold-load pickup, where the microgrid generation was up to voltage and needed to energize the microgrid island by closing the generation breaker. This is different than a black start, which had passed commissioning, where the generation ramped up power and voltage while connected to the microgrid. During the cold-load pickup the voltages were unable to stabilize within the required protection settings time window, and the system would trip offline due to phase overvoltage on the ungrounded delta microgrid circuit. This led to a change in the control logic to use a black-start vs a cold-load pickup for any conditions requiring the generator to pick up the unpowered island. It also highlighted future design thinking around the need for a grounding bank in future 3-wire installations. Currently RCAM relies on overvoltage protection for the ungrounded system.

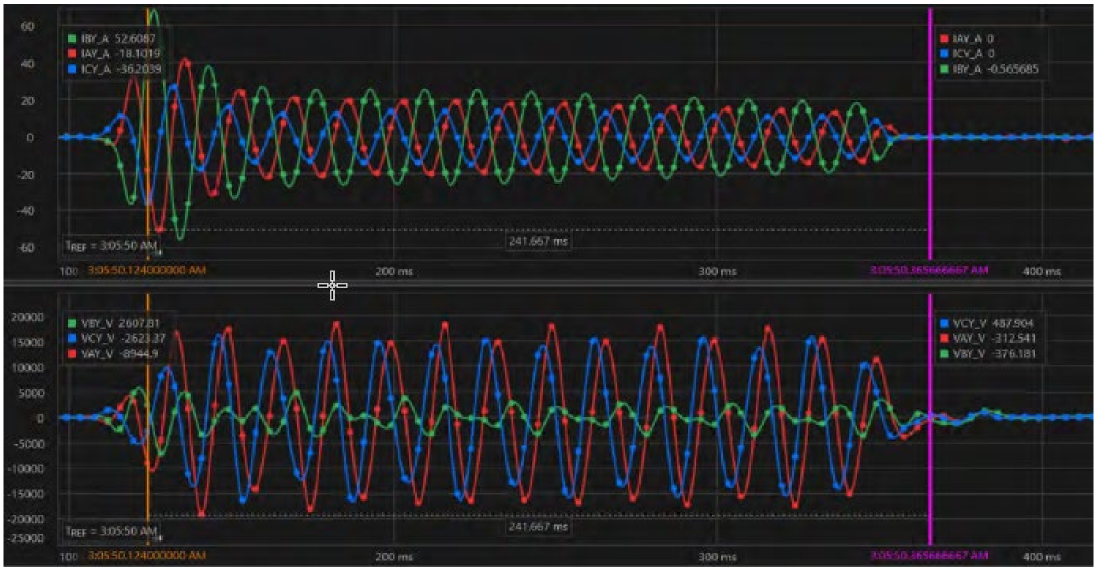

Figure 19: Waveform Capture of Failed Cold-Load Pickup Test during Field Commissioning

Over-Burdened Processor
As described earlier in the ATS testing section, the processing power of the SEL-3505-3 was not enough to allow consistent operation of the microgrid controls. During some of the commissioning tests this led to unexpected outcomes because the signal processing delays caused associated systems to not react within their prescribed timeframe causing the protective elements of the microgrid to trip the system offline. The issue was resolved by replacing the SEL-3505-3 with the more powerful SEL-3530-4. Grid-connected Fault Detection and Islanded Fault Detection functions were then retested at ATS before retrying commissioning testing in the field.

6.4 Hardware and Controls Testing Key Takeaways

Improve FAT:
There is an opportunity to clarify and improve on the expectations of the Factory Acceptance Test Procedure. More thorough and robust testing initially by the vendors should reduce the burden on PG&E testing resources and requirements.

Proper Failsafe Design:
PG&E and RCAM partners spent many weeks to define and implement the failsafes across a multitude of potential hardware, communications, and logic failure scenarios. This provided a layer of safety in that even though testing could not identify all issues before going to the field, none of the field issues resulted in any safety or equipment failures due to the robustness of the failsafes implemented.

Value of a Comprehensive Test Environment:
Community Microgrids are still at an early development stage. Having the flexibility to troubleshoot, adjust controls, and repeat tests as required in advance of field work without the risk on equipment, field personnel, or customers was a great advantage. This testing also increased the level of confidence on the protection scheme for the aspects that could not be tested in the field such as those associated with PG&E distribution system faults, internal faults along the microgrid circuit, and the short-circuit

current contribution of the BESS. Strong collaboration among all the project partners was an important factor to the success of lab testing. The testing also highlighted potential gaps and risks in relying on vendor provided specifications and factory acceptance testing that does not include the depth of testing provided by the PG&E PHIL testbed.

Need for Reduction in Testing and Development Cycles:
While RCAM would not be as successful as it is without the testing done, particularly at ATS, the resources and time required to get RCAM successfully through testing is not scalable in its current form. Standardization, improved FAT, and the maturity of vendors will help improve this in the future, but the nascency of the market will keep this as a risk in the near-term.

Experienced Partners Matter:
The project greatly benefitted from the deep experience and engagement of the Schatz Center and SEL acting as the control’s integrator. One of the biggest risks identified was that PG&E cannot expect to have this high level of expertise on future projects. PG&E should emphasize the importance of the Controls Integrator role in future projects, either by tariff, contracts, or programmatically.

7 IT Communication and Cybersecurity

7.1 Overview of Activities

Resiliency in communications networks was a key design priority. The scope of the IT Communication and Cybersecurity workstream was to integrate the microgrid into PG&E's distribution network, enable visibility and control of the microgrid at the Distribution Control Center (DCC), establish the communications infrastructure, and ensure the solution complied with existing cybersecurity protocols.

Two core documents were developed to support these objectives: the Solution Blueprint and the System Security Plan. The Solution Blueprint supported the IT requirements by outlining the infrastructure and recommendations required for monitoring and controlling the microgrid controller and devices. This includes specific recommendations for the communication network, the local area network, the local firewall solution, and PG&E's microgrid controller.

The second document the Project Team developed was the System Security Plan (SSP). This plan was developed by PG&E's Cybersecurity Solutions team and contains all information necessary to make objective security and risk management decisions regarding the operation of a specific technology asset at PG&E. The SSP documents the security requirements and conditions necessary for RCAM to operate in PG&E's production environment in compliance with Cybersecurity policies and standards.

RCAM demonstrated that real-time SCADA could be safely integrated to the Distribution Control Center to enable visibility and allow for grid-level control during both grid-connected and islanded modes. Furthermore, after implementing initial security mitigations, the residual cybersecurity risk was evaluated to be low and no additional cybersecurity action was needed for the scope of this project. The IT Communications and Cybersecurity solution developed for RCAM is a viable, scalable, and replicable approach for future community microgrid deployments.

7.2 The Communication Network

A communication network is required between the RCAM local network and PG&E's SCADA Network. The requirements of this network are that it must be a high speed and secure connection. PG&E explored four options that met these requirements.

- PG&E owned FAN (Field Area Network) wireless mesh network
- PG&E owned PTP (Point-to-Point) Radio network
- MPLS (Multiprotocol Label Switching) Connection (Leased line)
- Third-party cellular network

Option	Pros	Cons
(Option #1) **PG&E ODN-FAN Network**	• PG&E owned • Powered during an islanding event with battery backup • Higher availability and reliability than others (Wireless Mesh Network) • Highly secure communication network	• Not feasible at RCAM Site due to terrain and tree density.

	• Low-cost solution	
(Option #2) **PG&E PTP Radio**	• PG&E owned • Secure communications	• Tree heights created issues • 35 ft Pole installation issues near Airport
(Option #3) **MPLS connection (Leased line)**	• Available Solution • High speed and secure connection • Leverage with RCEA fiber connection • Will be higher availability than cellular network in case of a PSPS or islanding events	• Cannot guarantee third-party connectivity in the event of a PSPS or outage event • More expensive
(Option #4) **Third Party Cellular communication network**	• Available solution • Provides higher speed bandwidth than PG&E FAN • Short deployment timeframe • Lower cost than leased line (fiber).	• Cannot guarantee the Cell Site will remain powered during an islanding event or PSPS • High-cost solution long-term

Table 2: Communication Network Options

The PG&E ODN-FAN Network was originally chosen as the recommended option. However, after a pre-construction site walk it was determined that this option was infeasible. With an existing third-party Fiber line passing within 200-300ft of the proposed location, the Solution Architect recommended the third-party MPLS option, also known as a "leased line."

While the cost of this solution was high, the MPLS solution offered several advantages. Chief among these advantages was a reliable and fast communication pathway that did not rely on maintaining power to an external cellular site to maintain the communications pathway. This was an important consideration given that RCAM is designed to respond to emergency outages which could impact local and regional communication towers. While the MPLS option is still dependent on a third party, it was determined this pathway would have higher availability than a cellular network in case of PSPS or islanding events.

7.3 General Security Principles and Governance

The primary principle driving network security was to have no routable network connections between PG&E devices and third-party owned devices. For example, PG&E's microgrid controller communicates with the Generation Controller through a serial connection. Along with this principle, the PG&E project team followed existing PG&E network security and cybersecurity standards. Key elements of these governance documents are summarized in Table 3:

Boundary Protection	All systems must have defined network boundaries and protections in place for any external interfaces.
Information System Monitoring	All systems must be monitored to detect unauthorized use including network connections, process behavior, and others. Alerts are sent to the appropriate incident response personnel.
Wireless Access	PG&E publishes security guidance for remote network access and only authorized connections are allowed.
Least Functionality	PG&E Security policies govern which ports and protocols are allowed on internal networks.
Information System Component Inventory	All systems must have a documented inventory including hostname, IP address, physical/virtual, location, software/firmware, and network ports and protocols.
Device Identification and Authentication	All systems must have unique hostnames and IP addresses prior to connecting to PG&E's network to ensure the ability to identify resources.

Table 3: Key Elements of Network and Cybersecurity Standards

Pursuant to PG&E’s Physical Security Program Standard, it was determined that the RCAM project was not a North American Electric Reliability Corporation (NERC) classified site. Physical controls are still in place with only PG&E having access to the networking equipment cabinet and the broader RCAM site footprint being fenced in and secured by a lock with PG&E and RCEA each having access.

7.4 System Security Plan and Cybersecurity Risk Review

The System Security Plan (SSP) summarizes the process and results of PG&E’s Cybersecurity Risk Review and documents all information necessary to make objective security and risk management decisions regarding the operation of the asset at PG&E. This includes documenting the security requirements and conditions necessary for RCAM to operate in PG&E’s production environment in compliance with Cybersecurity policies and standards as well as Critical Infrastructure Protection (CIP) and NERC standards.

The development of the SSP was led by the PG&E IT Solutions Analyst and reviewed a wide array of risks.

1. The **RCAM System Architecture & Design** was reviewed to confirm it was in accordance with CIP 02 and CIP 05 R1, and CIP 10R2. To ensure this, the SSP reviewed the RCAM Topology and Dataflow diagrams as implemented in the field.

2. **Interconnectivity Risks** were also studied to evaluate what happens when you connect the defined system architecture to PG&E’s Operational Data Network (ODN).

3. **Data Flow Risks** were evaluated to make sure the data is properly encrypted and appropriately handled at endpoints. This included confirming the following were in accordance with the relevant CIP standards:

   1) Ports, Protocols, and Services (CIP 07 R1.1) listing all ports that are used by RCAM system components and the associated protocol and service it corresponds to including origin/destination and why.
   2) Firewall Exception Requests (CIP 05 R1.3)

4. The SSP also evaluated **Vulnerabilities Associated with Onboarded Assets** through an Asset Inventory to document all physical and virtual assets associated with the system. A software inventory was also performed to document and review all applications/software associated with RCAM including **Risk associated with the relay programming software**.

5. Finally, there were a number of third-party vendors associated with this project. The SSP evaluated **Risks associated with Third Party Implementation** through
   1) A Third-Party Services Inventory which lists all third-party vendors that are being provided information from, performing a service for, or have an interconnection with the system.
   2) A Third-Party Services Review.

The Cybersecurity review identified several initial vulnerabilities on the assets prompting the cybersecurity team to add additional controls. After these controls and remediation efforts, a final vulnerability scan was done in January 2022 and no vulnerabilities were found on non-OT assets. The System Security Plan was completed in February 2022 and the Cybersecurity team authorized the Release to Operation (RTO) soon after.

7.5 IT Communication and Cybersecurity Key Takeaways Lessons Learned

There were four important key takeaways from the IT workstream:

1) Determine the communications network early in the design process and conduct a pre-construction site walk to confirm viability of the proposed solution
2) Separating the PG&E and RCEA control cabinets simplified cyber security and improved replicability
3) Firmware update process must be clear and defined in the Microgrid Operating Agreement
4) The project needed additional IT resources and skill sets than estimated in the initial scope to meet the project needs and timeline

8 Operations Integration

To ensure the safe and reliable operation of RCAM at PG&E, it was essential that RCAM was integrated into the normal PG&E processes and tools for Operators and field personnel. Additionally, full documentation and training were required for all Operators and field personnel prior to allowing RCAM to go into service as a community microgrid. The RCAM team engaged early and often with different members of the Operations team to ensure that the systems, processes, and integrations aligned with standard operating principals as much as possible. After RCAM was commissioned, updates were made to the training and documentation to ensure lessons learned were transferred appropriately to the managing teams. These operational lessons shaped the development of the Microgrid Operating Agreement and actively informed the programmatic structure of PG&E's Community Microgrid Enablement Program (CMEP) and Microgrid Incentive Programs (MIP). Development of the Operational Integration workstream centered around 3 major areas:

- Controls, Failsafes, and User Interface Development and Verification
- Process, Roles, and Responsibilities Development
- Documentation and Training

8.1 Controls, Failsafes, and User Interface Development and Verification

The development of a community microgrid is unique in that responsibilities are shared among two parties: the utility and a third-party CMG Aggregator. The CMG Aggregator for RCAM was RCEA who was the generation owner and operator, and the prime developer of the system. PG&E was responsible for approving the designs and integrations to ensure the safe operation of the system and alignment with existing utility procedures and processes, where applicable. With RCAM being the first fully renewable community microgrid, there was significant care taken to ensure that the controls proposed by the vendor met the operational needs of PG&E while still providing all the functions required by the community.

For RCAM, there was a progression of three main documents that were reviewed and refined over time to develop the control functions of the community microgrid in increasing detail. These documents were:

- Concept of Operations (CONOPs)
- Functional Design Specification (FDS)
- Description of Operations (DOO)

8.1.1 Concept of Operations (CONOPs)

The CONOPs was the first document created by the Schatz Center with input from the generation system operator, PG&E, and other stakeholders. This is the conceptual foundation of the community microgrid control system, explaining how it is intended to work. Stakeholders were involved as early as possible to ensure the control scheme met the needs of all the involved parties. While the CONOPs does not need to specify specific hardware, programming, or protocols, it should describe the conceptual logic of each function of the microgrid and interactions among devices. It should have enough detail for a controls vendor to be able to understand the controls design and integrations with the generator, wholesale markets, and the distribution utility, and develop a scope of work to implement and test these controls. The CONOPs includes sequence diagrams to help visualize the interactions of multiple devices for a particular operation or mode (Figure 20). Additionally, it includes a preliminary description of operations for the utility to verify their perceived role in the operation of the microgrid.

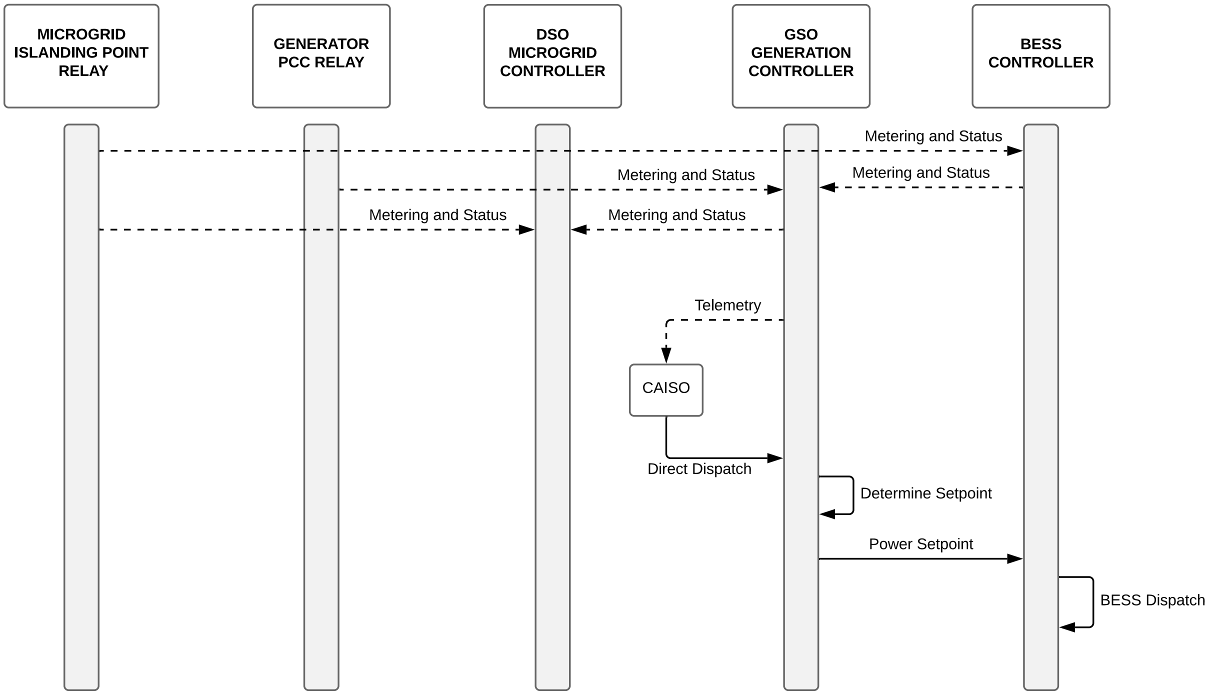

Figure 20: Typical Sequence Diagram in the CONOPs for Grid-Connected Market Participation

8.1.2 Functional Design Specification (FDS)

The FDS was then subsequently created by the controls vendor after stakeholders had agreed on the control schemes and updated the CONOPs appropriately. The FDS was based on the CONOPs but had specific implementation details including names of variables, specific hardware makes/models, control points, programming methods, and communication protocols.

The FDS was carefully reviewed and iterated on by all stakeholders as it provided the blueprint for exactly what the controls vendor would develop. Verification of the control functionality was done through the testing processes described earlier.

8.1.2.1 Failsafe Analysis:

As part of the FDS there was also significant collaboration between the generation owner and the utility on the failsafe states, not only for abnormal grid conditions, but for any issues with microgrid hardware or communications. It required a detailed analysis of each scenario if any one piece of hardware failed, or communications between any two pieces of hardware failed, to ensure that the system would provide actionable alarms at the right priority level, and either continue operating or safely disable the system. For each scenario the following 10 questions were answered to ensure the programming, point lists, and redundancy within the microgrid system was developed appropriately:

1. Was PG&E protection (i.e., safety) impacted?
2. Was PG&E visibility impacted?
3. Was PG&E control impacted?
4. Could the BESS still support grid-connected operation?
5. Should the BESS be allowed to operate in grid-connected mode?

6. Could the BESS still support islanding?
7. Should the BESS be allowed to island?
8. What is the failsafe state of the microgrid under this condition (i.e., Microgrid Disabled, Force Generation Offline (Trip Generation Circuit Breaker), or Alarm Only)?
9. Does the generation need to be forced offline?
10. What is the alarm priority of this scenario?

Not all failsafe conditions required the microgrid to be disabled. A balance was necessary to ensure that the system would be safe but still provide resilience for the customer under likely extreme circumstances of wide-spread electrical and communication outages during large natural disasters.

8.1.3 Description of Operations (DOO)

Based on the information in the CONOPs and FDS, PG&E created a DOO which is primarily geared toward the PG&E Operators and Engineers in the day-to-day operation of the community microgrid. The DOO is simplified to focus on the need-to-know items for Operators of the system including a high-level description of the different modes of the community microgrid, responses to abnormal situations, instructions for operating under different scenarios, and information on how to respond to various alarms. For completeness, PG&E also required RCEA to develop a Description of Operations for their own operations which PG&E reviewed for conformity.

PG&E worked with Operators and Engineers to design specific Supervisory Control and Data Acquisition (SCADA) user interface screens that would be used in the PG&E Distribution Control Center to operate the microgrid. The display and priority of alarms through SCADA was also designed and based on the information from the FDS. Various screen shots and instructions for how to operate the system remotely via SCADA (Figure 21) were included for reference.

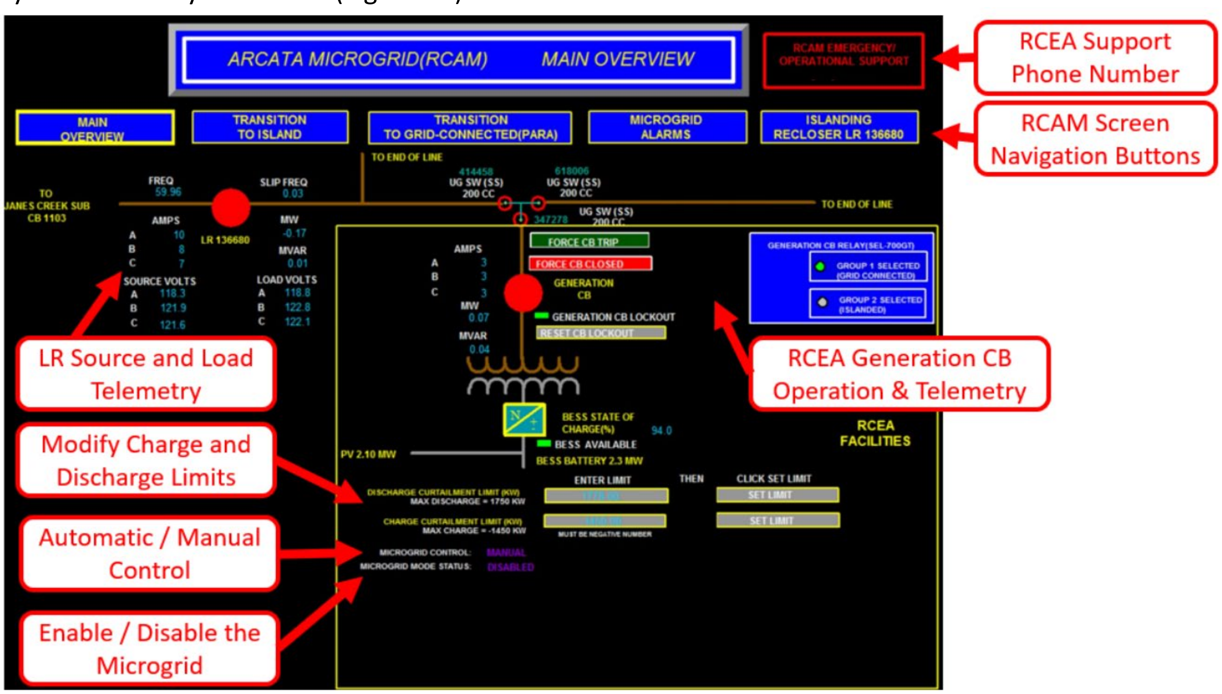

Figure 21: RCAM Main Overview SCADA Screen with Annotations from the DOO

8.2 Process, Roles, and Responsibilities Development

The RCAM team met with multiple internal and external stakeholders to determine the roles and responsibilities for the different portions of this new system. RCAM had two unique characteristics that made the allocation of responsibility challenging:

- Interdependency of PG&E and RCEA for operations, control, and protection of the system
- Use of new hardware and protection schemes

The interdependency of PG&E and RCEA for operating the system was new for PG&E. PG&E needed to maintain overall control of the system, but it was operating devices that were the responsibility of a third-party. Being reliant on third-party equipment, particularly the customer generation breaker that served as the main protective device for the PG&E circuit when islanded, was a significant shift in normal operating practices. While PG&E did not design the system, it had the authority to approve important aspects of the project that interfaced with or impacted the PG&E system. This included the control design as discussed before in the CONOPs and FDS development, but also the particulars of the protection design and settings. PG&E engineers helped develop and approve the protection settings for the system, including the customer's generation breaker as it served as the primary protection device of RCAM when the system was islanded.

To ensure these responsibilities were properly documented, PG&E and RCEA developed a series of documents formalizing the operational responsibilities between the RECA and PG&E. PG&E and RCEA each created a Description of Operations for their respective equipment and a Jurisdictional Boundaries Letter of Agreement was signed by both parties describing how the intersection of those responsibilities would be managed. Specifically, this Jurisdictional Boundaries Letter of Agreement highlighted that while PG&E has operational jurisdiction over the 12kV system, RCEA has responsibilities to maintain their equipment and has jurisdiction over the dispatch of its generation assets within the prescribed limits set by PG&E. This letter also describes the communications required between the parties, access rules, and general operating procedures and protocols. These three documents are combined to form the Operating Procedures and Protocols which is a key Appendix to the Microgrid Operating Agreement.

The use of new hardware and protection schemes created internal challenges for PG&E regarding standardization, asset ownership, and knowledge of the system. Because RCAM and other microgrids rely on programmable devices, it does not fit nicely into the utility's traditional systems for approval of devices. For example, the same SEL Real-Time Automation Controller (RTAC) can act very differently depending on how it's programmed. Therefore, standardizing to a particular model of RTAC for microgrids doesn't necessarily accomplish the goal of having a standardized microgrid controller, because logic within the RTAC can differ depending on the unique microgrid it is controlling. Similarly, for the recloser controller (SEL-651R), it is programmed in a particular way to be integrated with the community microgrid. So, although the PG&E Standards team has approved the SEL-651R for use on PG&E's distribution system, they only approved it as a templated recloser controller, and were not well positioned to take initial ownership of the RCAM islanding recloser relay, because it was programmed differently than the PG&E standard recloser setup.

The protection scheme was also unique in that it relied on both utility and third-party devices for protection of the system. While grid-connected, PG&E's SEL-651R could island the system, but it also got direct inputs from the third-party BESS system to potentially identify islanding events faster than the protection settings in the SEL-651R. In addition, while islanded, PG&E was entirely relying on the third-party generation breaker to protect the microgrid and the attached PG&E equipment. Therefore, PG&E oversight was needed to ensure the third-party set these devices correctly, and that there was a prescribed maintenance plan to ensure these devices would continue to operate effectively even though they would not fall under PG&E's normal maintenance and asset management practices.

8.3 Documentation and Training

There were two main sets of internal PG&E documentation for the operation of RCAM, Operator/Engineer centric documentation and those focused on Field Personnel. These documents and training were also updated post commissioning, incorporating the lessons learned from actual field experience.

8.3.1 Operator / Engineer Documentation

The Operator / Engineer focused documentation was primarily based on the DOO described above and published on PG&E's internal Technical Information Library. There were multiple stakeholders involved in the development of this documentation across the PG&E business and with the microgrid developer. The documents were composed and refined over the course of the project and updated appropriately based on the lessons learned from field experience. It was packaged into a single procedure that included:

1. RCAM Operating Procedures
2. RCAM Description of Operations
3. Single Line Diagrams and Device Descriptions
4. Alarm Descriptions and Responses
5. Quick Reference Guide

In-person and web-based training was also developed and used to train PG&E Operators and Engineers based on the RCAM documentation. Operations required that all documentation and training was complete prior to allowing RCAM to go live in the field to ensure proper operation and safety of the microgrid. A guiding principle of RCAM was to try and reduce the impact to normal Operations as much as possible. This was made evident through the amount of automation, failsafes, and seamless transitions provided in the final product.

PG&E also worked with RCEA and local agencies to create an Emergency Response Plan in the event of fire or other emergency at the generation site. This provided information regarding emergency contacts, emergency response procedures, site hazards, site layout, site equipment, and site access.

8.3.2 Field Personnel Documentation

The Field Personnel documentation and training was mainly centered on the new PG&E recloser relay used for the microgrid islanding point, the SEL-651R. The faceplate and logic were modified from the standard relay setup for PG&E to implement the requirements of the microgrid. This was also the first installation of this relay in the field. Therefore, significant documentation was necessary for field personnel to be able to program, maintain, and operate the equipment safely and knowledgeably.

Seventeen separate job aids were created to ensure sufficient documentation was available for field personnel to operate the RCAM recloser and relay package under different field scenarios. These job aids are posted to PG&E's internal Technical Information Library.

8.4 Operations Integration Key Takeaways

PG&E successfully integrated RCAM into PG&E's operational ecosystem both in terms of technology and process. Being the first community microgrid in PG&E's service territory, the overall development spanned multiple years of collaboration between RCEA, the Schatz Center, and multiple PG&E internal teams. To shorten this development period for future community microgrids, PG&E is working to standardize as much as possible, as well as providing information upfront to customers via the Community Microgrid Technical Best Practices Guide to steer their development based on the learnings from RCAM.

The following are some of the key takeaways from the Operations integration experience:

- Community microgrids create a unique sharing of responsibilities between the owner and the utility that must be fully documented and trained on prior to operation.
- Control logic and architectures for community microgrids are still relatively bespoke and require significant review and collaboration at this stage in the maturity of the technology.
- Failsafe development with the Operations and Protection teams was a fundamental step to ensure system safety under various abnormal conditions.
- RCAM was designed to require minimal interaction with PG&E Operations for normal operation and transition events while still providing Operations with visibility of the system and overriding control of the system if needed.
- Early engagement with Operations and Field Personnel helped ensure better integrations with PG&E processes and technology.

9 Field Experience

RCAM has been in service for over 2 years and has supported the community through a large earthquake and several significant winter storms[33]. RCAM has proven to be a valuable asset for the community, providing over 43 hours of additional resilience in just the first 12 months of operation in response to 7 unplanned outages. However, although RCAM went through extensive lab testing both by the vendor and by PG&E, there were still some challenges in the field that required updates to the controls and operational procedures and PG&E continues to work closely with RCEA to improve the performance of the system over time.

9.1 RCAM Field Performance Overview

RCAM was released into service on May 26, 2022, with a public go-live event on June 22, 2022. Figure 22 shows a summary of RCAM operations from June 2022 until August 2024. The summary not only shows the benefits that RCAM provided, but also highlights some of the issues with RCAM performance, and islanding events not due to outages on the grid (i.e., nuisance events).

RCAM Summary for 6/1/2022-8/1/2024	
Total Outage / Voltage Events:	12
Islanded Time for Outage / Voltage Events (HH:MM):	51:51
Additional Outages due to RCAM Issues (HH:MM):	2:20
Total Nuisance Events:	36
Islanded Time for Non-Outage Events (HH:MM):	8:54

Figure 22: RCAM Performance Summary

In green is the total amount of time RCAM needed to island for an outage or abnormal voltage event. RCAM was able to provide almost 52 hours of additional resilience over 12 events for customers within the microgrid, including the Coast Guard and airport. Triggering events included outages due to the large earthquake in the Humboldt area and severe winter storms.

In red is the total amount of time RCAM customers experienced an outage not due to a PG&E event, but due to issues with the microgrid. There were 8 events that led to outages for RCAM customers, with 3 lasting just 11-15 seconds for a break-before-make transition to occur, and 5 lasting between 6 minutes to around an hour. While these events were initially triggered by small transient events on the system, the failure to seamlessly or black-start transitions to an islanded state was found to be a combination of firmware issues and the mis-coordination of various timers used for failsafe conditions. RCEA has resolved the firmware issue and is in the process of updating the timer settings.

The gray section of the table provides the total amount of nuisance islands experienced by RCAM. RCAM experienced multiple “nuisance” islands, where a transient event on the grid was not large enough to cause an outage but was enough for the microgrid to detect a disturbance and try to island. In general, because the system is designed to have seamless transitions, most of the nuisance events

[33] Clean Energy Microgrid Keeps Arcata Airport and U.S. Coast Guard Station Powered Following Humboldt Quake and Winter Storms - PGE Currents

are inconsequential to the microgrid customers. However, these 36 nuisance events also include the 8 described above that led to outages for RCAM customers shown in the red section of the table.

9.2 RCAM Challenges in the Field

9.2.1 DC-Coupled Solar and Storage Issues

RCAM had initial issues with the DC-DC converters for the DC-coupled PV and battery system. These continuous issues were due to a design flaw inside the DC-DC converters which created repeated ground faults and resulted in RCEA needing to replace all the DC-DC converters equipment over the course of multiple months. This severely limited the amount of PV available and created issues with providing solar support for the BESS charging, especially during long duration outage events. When the 6.4 Magnitude earthquake hit at 2:34 AM on December 20, 2022, the state of charge (SoC) of the BESS was only at 34% because RCEA had just completed a market dispatch (Figure 23).

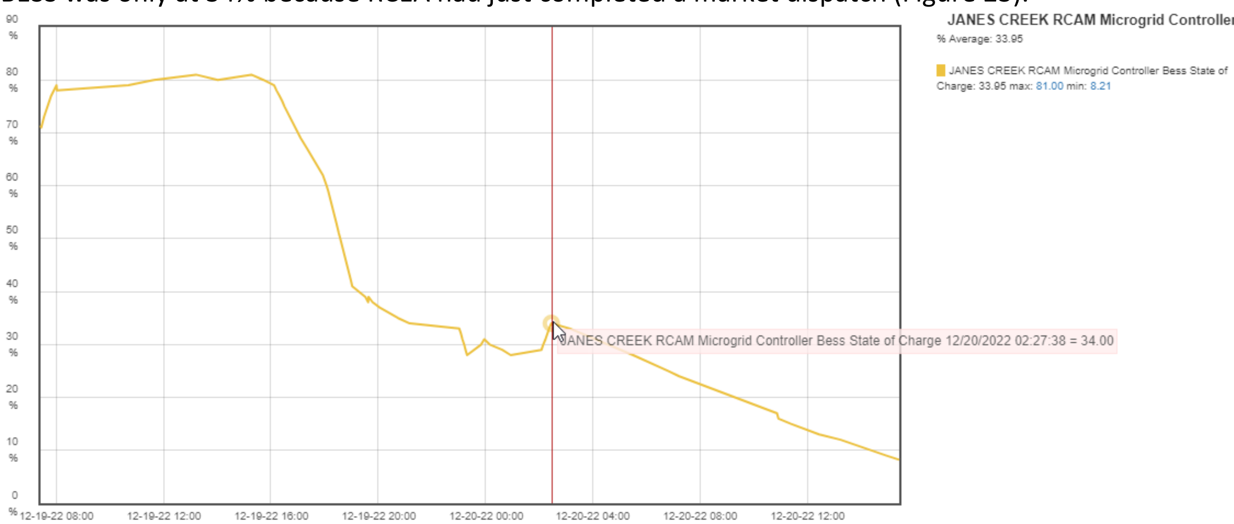

Figure 23: RCAM BESS State of Charge at Time of Earthquake and Beginning of Island

Even at that low state of charge, the island was supported by the BESS for almost 15 hours, with almost no contribution from the solar system because of the DC-DC converter issue. Unfortunately, without the PV support, after 15 hours, the battery reached its minimum allowed state of charge (5%) (Figure 24) and needed to disable the microgrid, causing customers within the microgrid to lose power until PG&E was able to restore power to the area about an hour later. The earthquake outage also provided lessons learned for RCEA regarding their procedures for charging manually during emergencies to ensure the BESS can charge more quickly following a significant islanding event in the future.

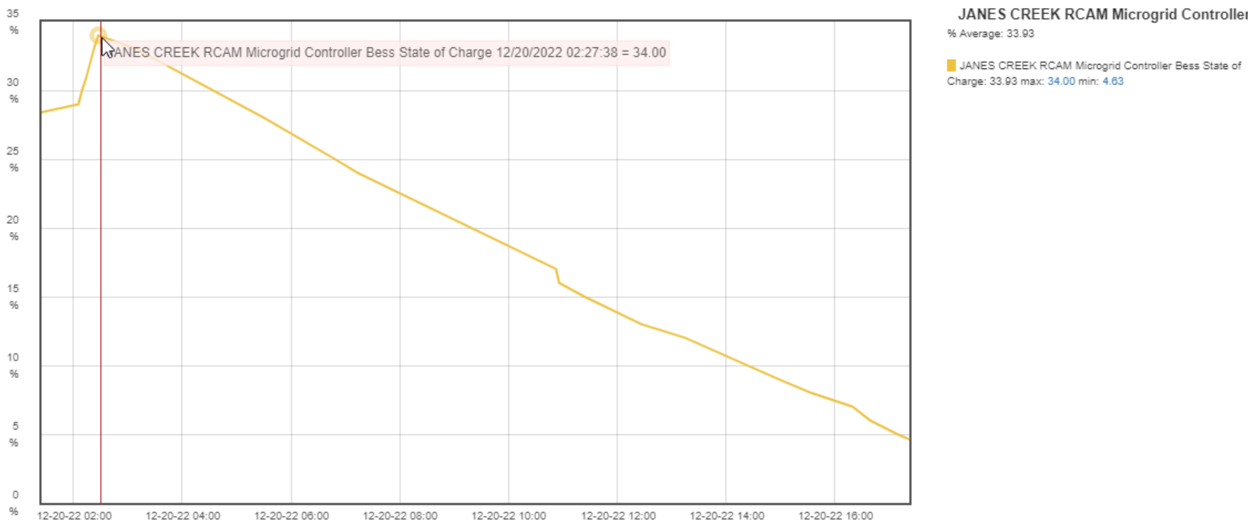

Figure 24: RCAM BESS State of Charge Reduced to Minimum of 5% to Support Island without PV Support

To compensate for the lack of solar generation, RCEA raised their minimum state of charge for market dispatches from the default of 25% in advance of known potential outage conditions, particularly the winter storms. These changes plus the replacement of some of the DC-DC converters allowed RCAM to then ride-through all the remaining outages it experienced, including a 16-hour storm related outage on 2/23/23 where solar was able to contribute to the SoC during the outage (Figure 25).

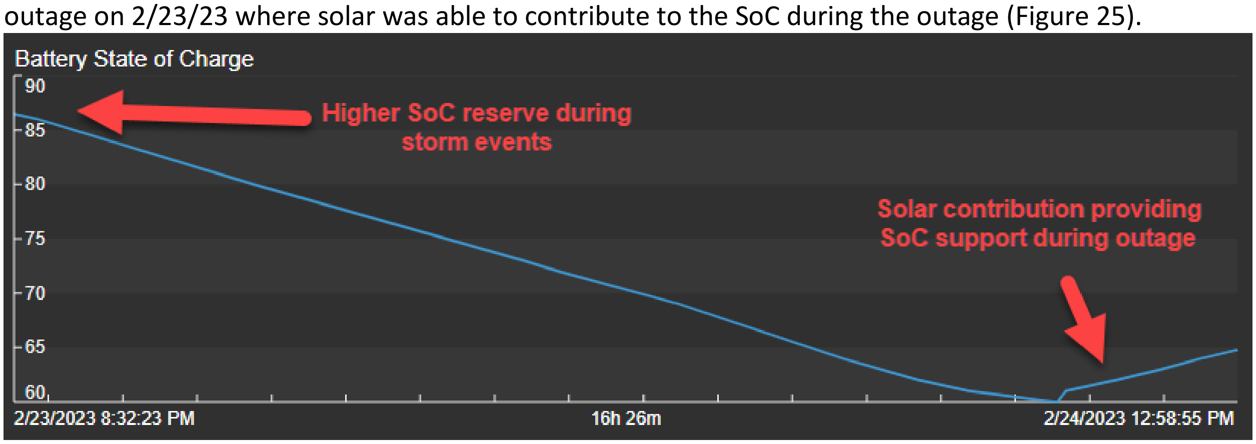

Figure 25: RCEA Raises SoC in Anticipation of Storm Events and DC-DC Converter Fixes Allow PV to Provide Support During Outages

In addition to the DC-DC converter issue, there were also issues with the frequency shift algorithm used by the DC-coupled system. This led to a very high BESS state of charge during an islanded condition because the solar contribution was not being adequately controlled. In cases of very high BESS state of charge, the vendor had implemented a frequency shift algorithm to raise the frequency to 63Hz to trip any connected generation through that generation's local frequency trip settings, a requirement of interconnection. However, this was not coordinated with frequency protection settings of the microgrid and resulted in the island being de-energized as it exceeded the protection limits for more than 2 seconds. This was later resolved by coordinating the frequency-shift algorithm settings with the existing protection settings, as well as resolving the issues with the DC-coupled solar system.

9.2.2 Charge and Discharge Limit Sensitivity

The initial charge/discharge limits for RCAM were based on the results of the interconnection study for the site and are codified within the Small Generator Interconnection Agreement of the generation owner. The full 2.3 MW system could not safely be interconnected without limits due to generation and load capacity constraints on the line feeding the system. Any upgrades to the PG&E facilities to supply the full rating of the generation system would have been borne by the customer. As a result of the large expense needed for upgrades, RCEA opted for a constrained interconnection. The initial constraints were 1,480 kW for charging and 1,778 kW for discharging.

There are two levels of protection to ensure the BESS does not exceed its given limits. The first is soft control via communications to PG&E's Distribution Control Center where PG&E Operators can change the settings via their Supervisory Control and Data Acquisition (SCADA) system that causes the RCEA generation controller to only send setpoints to the BESS that are within the limits set by PG&E. The second is a physical control on site within the RCAM SEL 700GT+ relay settings.

The BESS at RCAM normally participates in the wholesale market via CAISO. RCEA found that although the dispatches were set to the maximum settings (1,480 kW / 1,778 kW) the BESS would actually slightly overshoot those values for over 2 seconds when set to dispatch to those levels. This in turn caused the generation circuit breaker to open, thus disconnecting the generator from the system. RCEA analyzed the events and asked PG&E to change the default soft control settings to allow a buffer for the known overshoot so as not to create nuisance trips for their generation circuit breaker. PG&E updated the settings and related Operator training documentation to accommodate the change to 1,450 kW charging and 1,750 kW discharging.

Although the system had gone through limited testing in the PG&E lab, there was no certification of the output control based on standards like the upcoming UL 3141 and Power Control Systems (PCS). In RCAM's case, there was redundancy via the required protection settings in the customer breaker, but for sites without this type of physical redundancy, this finding further supports the value of PCS type certification of equipment required to perform strict control limits for constrained interconnections.

9.3 Managing Abnormal Switching in Operations

In order to ensure the safe operation of RCAM with PG&E's Operations team, formal documentation was developed, and training was conducted prior to allowing RCAM to energize as a microgrid. In addition, PG&E Operators were provided with RCEA's 24/7 operational contact information so Operators can coordinate any updates or actions required.

As part of this training and documentation, certain sections describe the process for abnormal switching conditions that may require RCAM to be curtailed beyond the initial charge/discharge limits established during the interconnection process and delineated in the interconnection agreement.

Guidelines to manage and analyze the impact of planned or unplanned work are provided with instructions to notify RCEA in advance of any planned shutdowns or curtailments, if possible.

PG&E engineers have also identified known alternate grid configurations impacting RCAM including when the Humboldt Bay Transmission Source is islanded during emergency conditions[34]. PG&E's current policy prohibits large generating facilities (>1MW nameplate) from discharging into the Humboldt Bay Regional Island. The 1MW curtailment threshold considers the capacity of the PG&E Grid Operations team to manage complex curtailment calculations and rules during emergency conditions.

The strict limit on generation is enforced to maintain stability of the Humboldt Bay Regional Island. PG&E sought to leverage the BESS's unique capabilities for visibility and constraint controls to allow for more operational flexibility of the BESS during this type of emergency grid configuration. PG&E performed a study and considered modified import/export settings that varied based on time of day, ensuring exports were limited during non-peak periods. However, operationalizing this proposal was infeasible due to the added manual complexity to monitor and manage constraints by the Grid Operations Team which would have detracted from their primary responsibilities when responding to the emergency events that created the abnormal grid configuration.

The RCAM system has not been proven out as a model for scaling curtailment controls to large numbers of DER customers. The process for coordinating with RCEA and the BESS is still very manual in terms of needing to apply specific settings for each abnormal condition, creating the proper switch logs, having engineering review of planned work, and anticipating the curtailment limits required. Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) functionality is required to be built out and verified before a more scaled approach can take hold. Moreover, the 24/7 support PG&E required of RCEA could be difficult to scale but is important in ensuring the proper operation of these new systems.

9.3.1 Field Experience Changing Charge and Discharge Limits

There was a total of 12 unplanned and planned events since RCAM became operational that required PG&E Operators to modify the charge and/or discharge limits. For these events, PG&E was able to coordinate with RCEA and remotely update the limits appropriately using the PG&E SCADA system. If there were any issues via SCADA, PG&E would work with the local RCEA staff to update the limits. For example, during the first event on 8/8/22 there were issues changing the limit from the PG&E SCADA Screens. PG&E Operators worked with the 24/7 RCEA support staff to update the settings locally and uncovered a gap in the process. Operator training and documentation were updated accordingly.

In addition to changing the limits, PG&E also worked with RCEA on two occasions to support load during abnormal situations by requesting RCAM to discharge during certain hours while work was being performed on the PG&E system.

A summary of the limit changes is below for reference.

[34] PG&E Corporation - Humboldt Bay Generating Station Ready to Serve as a Direct Local Power Source During Emergencies, Reducing Impact of PSPS Events (pgecorp.com)

#	Date	Duration (H:M)	Limit Change	Summary
1	8/8/22	5:13	Charge Limit Reduced to 0	An unplanned transmission event created outages for neighboring substations. Asked RCEA to reduce charging to 0 to be able to pick up additional load.
2	10/11/22	11:23	Charge and Discharge Limits Reduced to 0	Planned work to replace a recloser on the Janes Creek circuit required RCEA to limit charging and discharging.
3	11/10/22	208:41	Charge Limit Reduced to 0	Planned work for the substation needed abnormal switching, which required RCEA to limit charging.
4	11/21/22	13:10	Charge Limit Reduced to 0	Planned work for the substation needed abnormal switching, which required RCEA to limit charging.
5	1/1/23	8:24	Charge and Discharge Limits Reduced to 0	Unplanned event where a car hit a PG&E pole on the RCAM Janes Creek circuit, requiring switching to do repairs.
6	4/19/23	2:43	Charge Limit Reduced to 0	Planned work for the substation needed abnormal switching, which required RCEA to limit charging.
7	7/11/23	4:34	Charge and Discharge Limits Reduced to 0	Clearance on Janes Creek 1103 to replace a pole.
8	7/17/23	50:05	Charge Limit Reduced to 0	Equipment issues at RCAM required changing the limits while being fixed.
9	11/5/23	13:36	Charge Limit Reduced to 0	Offloading an adjacent substation required RCEA to limit charging and requested a discharge to support the work.
10	11/7/23	0:04	Charge Limit Reduced to 0	Test of Limit Change
11	3/1/24	91:14	Charge Limit Reduced to 0	In response to Humboldt Bay Transmission Islanding activities.
12	5/8/24	9:26	Charge Limit Reduced to 0	Line work replacing a switch and pole required RCEA to limit charging and requested a discharge to support the work.

Figure 26: Summary of Limit Change Events

In addition to the approximately 418 hours of limit changes from the PG&E Distribution Operations team, there were also curtailments or non-dispatches done via CAISO for events on the Transmission system, specifically related to the Humboldt Bay Transmission Island. PG&E does not have direct information regarding CAISO related curtailments and durations, but Transmission related events can have a significant effect on the operations for RCAM as discussed above.

9.4 Field Experience Key Takeaways

As the first 100% renewable multi-customer microgrid in PG&E's territory, RCAM required significant development and testing prior to going live in the field. Introducing new hardware, controls, user interfaces, and processes to PG&E while ensuring the safety of the systems was a significant accomplishment. While it is impractical to test every possible permutation of events that may be seen in the field, the work done by PG&E, RCEA, and the vendors regarding testing, protection, and incorporated failsafes did ensure that under the various unexpected conditions that were experienced in the field the system always maintained a safe operating condition. PG&E and the customer were successfully able to quickly address new challenges in the field via the commissioning process and post-commissioning support.

While RCAM is designed to be mostly automated, the 24/7 support provided by RCEA, and their agents, was instrumental in coordination and troubleshooting of the system to ensure any planned or unplanned events were properly administered. The operational coordination process for the BESS is still very manual, particularly for the setting of constraints during abnormal switching scenarios, and would be difficult to scale until new and more automated tools like ADMS and DERMS are available for PG&E Operators.

The following summarizes the key takeaways from RCAM's field experience thus far:

- RCAM was able to safely provide valuable resiliency to the community through an earthquake and multiple significant storms.
- Robust failsafe development and PG&E lab testing was successful in ensuring safety under unexpected conditions found in the field.
- The 24/7 support provided by RCEA, and their agents, was instrumental in coordination and troubleshooting of the system to ensure limits were properly administered.
- PG&E and the customer were successfully able to quickly address new challenges in the field via the commissioning process and post-commissioning support.
- Supporting seamless transitions introduces a bias to transitioning very quickly which can increase the number of "nuisance" islands.
- The operational coordination process for the BESS is still very manual and would be difficult to scale until new and more automated tools like ADMS and DERMS are available for PG&E Operators.
- Based on the issues seen with potential overshoot, it is recommended the systems using constraints be certified to upcoming UL 3141 as applicable or a similar PCS standard to avoid potential issues with compliance or protection when no other physical assurance is in place

10 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC Project 3.11 – RCAM has demonstrated that PG&E and third parties can work together to create a new paradigm in multi-customer microgrids that provide communities safe, clean, and reliable power to support reliability and resiliency for communities. This work has not only resulted in California’s first 100% renewable multi-customer microgrid at RCAM, but it has set up the framework for future microgrids through the pioneering work of CMEP, CMET, and MIP.

10.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- Greater reliability: RCAM is a model for the development of community microgrids to provide higher reliability and resiliency to communities to support critical infrastructure during grid outages.
- Lower costs: RCAM provided a model for future community microgrids in California with project documentation, processes, and lessons learned that will be used to reduce the costs of future community microgrids through standardization and implementation of best practices.
- Increased safety: Not only did RCAM provide reliable power to critical facilities in the Humboldt region through earthquakes and storms, the failsafes developed through the RCAM project allowed safe operation of the community microgrid even under unexpected conditions in the field. These same failsafe principles will be used in future community microgrids to ensure the safety of these new systems.

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following secondary principles: societal benefits, greenhouse gas (GHG) emissions reduction, the loading order, economic development, and efficient use of ratepayer funds.

- Societal benefits: RCAM provides a model for how communities can partner with utilities to deliver reliable and resilient power during larger grid outages to support critical infrastructure in those communities.
- Greenhouse gas (GHG) emissions reduction: RCAM was able to prove out the ability to create a 100% renewable microgrid with no fossil-fuel redundancy, aside from three pre-existing diesel generators, which are now relegated to deep-backup duty. It not only provides resiliency during outages but provides clean and renewable power for RCEA and the Humboldt area during normal operation.
- The loading order: As stated earlier, RCAM provides 100% clean and renewable energy for the area.

- Economic development: RCAM provide reliability to an economic hub of the area in the terms of the regional airport. Additionally, the programs inspired through the work at RCAM in terms of CMEP, CMET, and MIP are providing a path for potentially funding economic development through reliable and resilient power for tribal and disadvantaged communities that are particularly affected by these types of disruptions.
- Efficient use of ratepayer funds: Through the RCAM project PG&E set the stage for enabling more standardized community microgrids and programs state-wide.

10.2 Benefits Quantification

RCAM had significant impact on the development of microgrid programs such as CMEP and MIP. The most straightforward customer benefit to calculate, and the only one which will be attempted in this benefits analysis, is quantifying the reduction in customer minutes of interruption and the resulting decrease in economic impact. This is a future-looking (prospective) benefits calculation, so reasonable projections and assumptions from subject matter experts are used. What follows are the assumptions and calculation methodology used to determine the benefits attributable to the EPIC 3.11 project.

CMEP and MIP microgrid projects are currently being awarded in early 2025 from the first MIP application tranche. PG&E anticipates holding at least 2 additional tranches or as many tranches are needed until the full $79.2M allotted to this program as disseminated. It is assumed that these microgrids will take 3-5 years to become operational, which would make the first tranche of CMEP and MIP microgrids operational starting in 2027-2029. Starting at this time, it is estimated that 1-2 microgrids per year (average of 1.5 per year) will be connected to the PG&E system and start providing benefits to customers in the form of increased electric reliability.

Based on the CMEP applications PG&E received, it is clear that the number of customers on a microgrid can vary significantly. When looking at the 22 applicants who applied to MIP in the first application tranche (minus three exceptionally large projects that were outliers), those microgrids on average served 121 customers per microgrid. Of the 9 projects that are likely to be awarded from the first application tranche (minus the three exceptionally large projects that were outliers), 17.9% of the customers identified in the microgrids are commercial customers while the remaining 82.1% are assumed to be residential customers. The estimated annual number of customers added to microgrids is described by these equations:

$$\#\,\textit{non-residential customers/year} = \#\,\frac{microgrids}{year} \times \#\,\frac{customers}{microgrid} \times \%\ \textit{non-res customers}$$
$$\#\,\textit{non-residential customers/year} = 1.5\,\frac{microgrids}{year} \times 121\,\frac{customers}{microgrid} \times 17.9\%$$
$$\#\,\textit{non-residential customers/year} = 32\ \textit{non-residential customers/year}$$

$$\#\,\textit{residential customers/year} = \#\,\frac{microgrids}{year} \times \#\,\frac{customers}{microgrid} \times \%\ \textit{res customers}$$
$$\#\,\textit{residential customers/year} = 1.5\,\frac{microgrids}{year} \times 121\,\frac{customers}{microgrid} \times 82.1\%$$
$$\#\,\textit{residential customers/year} = 149\ \textit{residential customers/year}$$

It is estimated that 32 non-residential and 149 residential customers per year will benefit from the increased reliability of microgrids enabled by this project.

These values were used with the Interruption Cost Estimate (ICE) Calculator tool which was developed by Lawrence Berkeley National Laboratory (LBNL) to estimate the value of interruption costs. The ICE calculator needs reliability data in the form of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), or Customer Average Interruption Duration Index (CAIDI). One of the MIP and CMEP requirements is for applicants to be "prone to outages". This could mean the microgrid area is located in (a) a Tier 2 or 3 High Fire-Threat District, (b) area that experienced prior PSPS outage(s), (c) elevated earthquake risk zone, (d) locations with lower historical reliability, or (e) local or tribal government leadership may justify other forms of vulnerability. Locations with lower historical reliability is defined as the top 1% Worst Performing Circuits (excluding Major Event Days), as shown in the annual Electric Reliability Report, either in the AIDI or AIFI category. For the purpose of using AIFI and AIDI values with the ICE Calculator, PG&E used the Electric Reliability Report for 3 of the 9 microgrid projects that are on a 1% worst performing circuit (i.e., Hoopa 1101 circuit) and likely to be awarded from Tranche 1. In 2023, the Hoopa 1101 circuit had an AIFI of 5.6 and an AIDI of 2,447. Note that the other 6 projects likely to proceed with funding in Tranche 1 are not on a worst performing circuit and PG&E did not have reliable AIDI and AIFI values to use. This means the outage estimates used as part of this benefit assessment are likely overestimated since PG&E is applying values for the microgrids with the highest AIDI and AIFI values. Nevertheless, using the Hoopa 1101 AIDI and AIFI values, the ICE Calculator returned the cost of interruption to be $1,663,486 per year. This value will be further modified below with discount factors.

A discount factor is needed to account for outages which cannot be mitigated by the microgrid. It is estimated that a microgrid can avoid 62% of total outages based on a historical analysis of outage types for CMEP and MIP applications. This value was based on reviewing all 22 projects that applied to MIP in Tranche 1 and averaging the number of outages the project with the most potential uptime (i.e., 100%) and the worst potential uptime (i.e., 25%) using 5 years of historical data.

Additionally, since this project was a partnership among many entities, EPIC funding and the EPIC program cannot claim all the credit, so a benefits attribution of 50% is used to account for non-EPIC contributions. Because attribution is a subjective and difficult-to-quantify metric, and it is hard to justify a precise value, so the attribution value is purposely made in increments of 25%.

The final step is to apply the discount factors to the result from the ICE calculator to find the final estimated benefits:

$$EPIC\ 3.11\ benefits = ICE\ calc\ savings\ \frac{\$}{year} \times EPIC\ attribution\ \% \times microgrid\ uptime\ \%$$

$$EPIC\ 3.11\ benefits = 1{,}663{,}486\ \frac{\$}{year} \times 50\ \% \times 62\ \%$$

$$EPIC\ 3.11\ benefits = 515{,}681 \frac{\$}{year}$$

The result is a total estimated customer benefit of $515,681 per year, which should be realized starting in 2027-2029 when the first CMEP and MIP microgrids become active. Once deployed, microgrids will continue to provide benefits for 10 years, which is assumed to be a conservative expected useful life for the microgrid. Every year, as more microgrids become operational, the annual benefits rate will increase with the number of microgrids until year 10 where there will be 15 operational microgrids. At this point it is assumed that an equal number of microgrids come online as go offline due to the expected end of life. This will result in a steady state of annual estimated benefits of $5,156,807 per year starting around year 10 (2037-2039). It is important to note that the benefits of the projects must be weighed against the total cost to build the projects. While the cost of the MIP projects are subject to non-disclosure agreements and are therefore confidential, PG&E does note that the costs are many times the benefits estimated here.

10.3 Key Accomplishments

RCAM was a seminal project in the deployment of community microgrids in California. It not only provided a blueprint for technical implementations of community microgrids but also laid the groundwork for the Community Microgrid Enablement Tariff (CMET), the corresponding Community Microgrid Enablement Program (CMEP), and the Microgrid Incentive Program (MIP) which will provide $200M statewide for Community Microgrid development. The following summarize some of the key accomplishments of the project over its duration:

- Established California’s first 100% renewable community microgrid
- Provided over 51 hours of islanded energy during emergency events to support critical infrastructure in the region through 12 grid events including a 6.4 earthquake and multiple atmospheric river conditions.
- Provided seamless transitions between grid-connected and islanded operation to not impact customers during outages.
- PG&E, the Schatz Center, and vendor partners developed a novel microgrid design implementation that shared control between PG&E with primary oversight of the system, and RCEA with control over the generation assets.
- PG&E’s ATS department developed a state-of-the-art Microgrid Testbed using Real-Time Digital Simulation (RTDS) testing and Power-Hardware-in-Loop (PHIL) testing which identified multiple issues that were then resolved to enable proper operation of the microgrid under various abnormal conditions prior to field deployment.
- PG&E developed and installed new distribution equipment necessary to island the microgrid in coordination with RCEA’s microgrid equipment.
- The testing by ATS informed the novel Microgrid Islanding Study (MIS), a valuable output of the EPIC 3.11 project for future Community Microgrids.
- PG&E developed, and the California Public Utilities Commission (CPUC) approved, CMET, CMEP, and MIP to support statewide Community Microgrid efforts.
- PG&E developed the Microgrid Operating Agreement (MOA) under which RCAM and its successor Community Microgrids will operate, and established roles within PG&E to support the development lifecycle of Community Microgrids.
- PG&E developed an industry first formalized study process dedicated to the evaluation and operational performance of Community Microgrids in the MIS.
- Lessons learned from deploying RCAM were published in the Community Microgrid Technical Best Practices Guide.

10.4 Key Recommendations

The following provides a summary of PG&E's key takeaways and recommendations in deploying RCAM in both the policy and technical fields.

- **Policy Takeaway 1: Independent evaluation of Community Microgrid operational modes streamlines the implementation of new processes and tariffs.**
    - Preserve the grid-connected interconnection rules and processes to the greatest extent possible. Programmatic components such as the CMET and the MOA must be consistent with existent rules and processes.
    - Establish an independent MIS process to evaluate the novel technical and operational elements of community microgrids separate from the established study for generation grid-connected operational modes.
- **Policy Takeaway 2: Establish clear roles and responsibilities**
    - When updating tariffs or agreements, ensure the roles and responsibilities are unambiguous and, to the greatest extent possible, consistent with the typical roles and responsibilities established under the interconnection agreements.
    - Maintain a "clear bright line" in terms of community microgrid ownership and control
    - Try to have a single third-party countersigner (e.g., the CCA) to all agreements with the utility to ensure continuity and clarity of responsibilities.
- **Policy Takeaway 3: Preserve energy settlements during island mode.**
    - Use prevailing CAISO market settlement mechanisms even when community microgrids are islanded.
    - Maintain CAISO's current energy settlement policy.
- **Technical Takeaway 1: Standardization is critical to scaling.**
    - ATS testing identified and troubleshot multiple issues that needed to be resolved, highlighting the nascency of the market, and the need for more standardized processes.
    - Standards should be developed for microgrid controllers, grid-forming inverter requirements, control logic and testing, and operational protocols and procedures.
    - Additional research is required to develop standards around microgrid configurations not studied under EPIC 3.11.
    - Until better standardization, certifications, and testing protocols are implemented, utilities will have to take a significant role in testing and verifying that Community Microgrid products function as intended.
- **Technical Takeaway 2: Experienced Project Partners Matter.**
    - Future projects should emphasize the importance of skilled and experienced microgrid developers and control integrators, and operational support capabilities.
- **Technical Takeaway 3: There is a tradeoff between seamless transitions and nuisance islands.**
    - Considerations should be made to optimize protection settings and control schemes to prevent unneeded impacts to customers. This will become more important for mid-feeder microgrids, where the transitions of the microgrid can also affect non-microgrid customers.

11 Technology Transfer Plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC, and the industry. In order to facilitate this knowledge sharing, PG&E will share the results of this project on its public web site (www.pge.com/epic) and in public workshops as applicable.

Specifically, below is information sharing forums where the results and lessons learned from this EPIC project were presented:

- *Distributech 2020 1/29/20*
- *Grid FWD 2020 10/9/20*
- *EPIC Virtual Symposium 10/20/20*
- *EPRI Conference 10/21/20*
- *EPRI Advisory and Sector Council Meeting 2/23/21*
- *UC Berkeley Energy Resources Collaborative (BERC) Conference 9/11/21*
- *Distributech 2022 5/25/22*
- *EPRI Field Engineering Interest Group 7/13/22*
- *CPUC ATS RCAM Tour 4/29/22*
- *Microgrid Conference 5/16/23*

11.1 Adaptability to other Utilities and Industry

As a result of the EPIC 3.11 project, there were three notable documents that support the technology transfer of the lessons learned from this project that are available to the industry:

- The Microgrid Islanding Study
- The Microgrid Technical Best Practices Guide
- The Community Resilience Guide

These documents are designed to inform both technical and non-technical audiences on the performance requirements and expectations of a Community Microgrid. In addition to these core documents, PG&E formed an internal Microgrid Technical Working Group to investigate the many outstanding technical challenges with microgrids as well as update the technical documentation as necessary.

11.1.1 The Microgrid Islanding Study

The Microgrid Islanding Study (MIS) is the key technical study required to implement Community Microgrids onto PG&E's system as described in Section 4.1.2. The MIS is a first-of-its kind industry study which was formalized pursuant to the core EPIC 3.11 goal of developing a scalable and replicable model. The MIS has four major elements as shown in Figure 27.

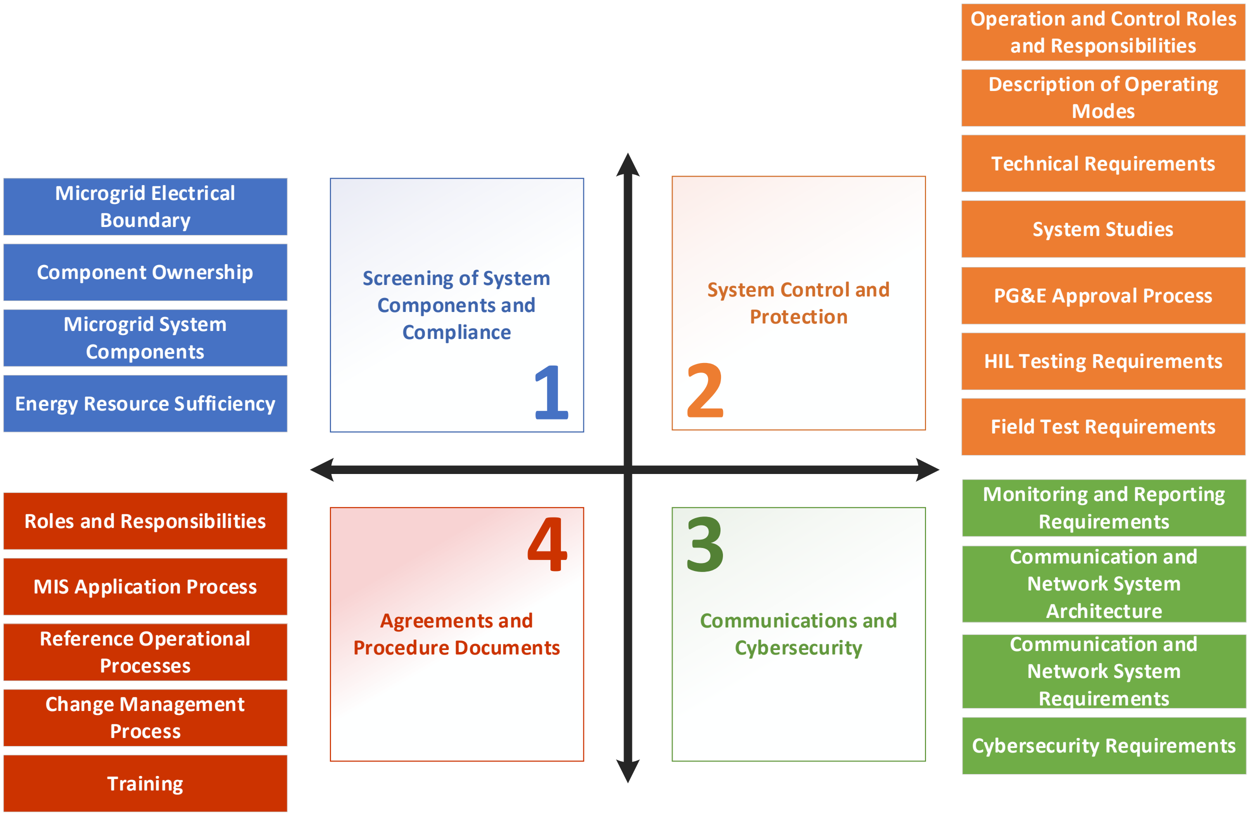

Figure 27: Major Elements of the Microgrid Islanding Study

The MIS focuses only on islanded mode and is the counterpart to the interconnection studies such as the System Impact Study and Facility Studies required during the interconnection process for Grid-Connected operation. When reviewed in conjunction with the Independent Study Process, PG&E engineers will have a complete technical picture of the Community Microgrid in all operational states. A high-level graphical representation of study chapters and elements within the MIS is shown in Figure 28.

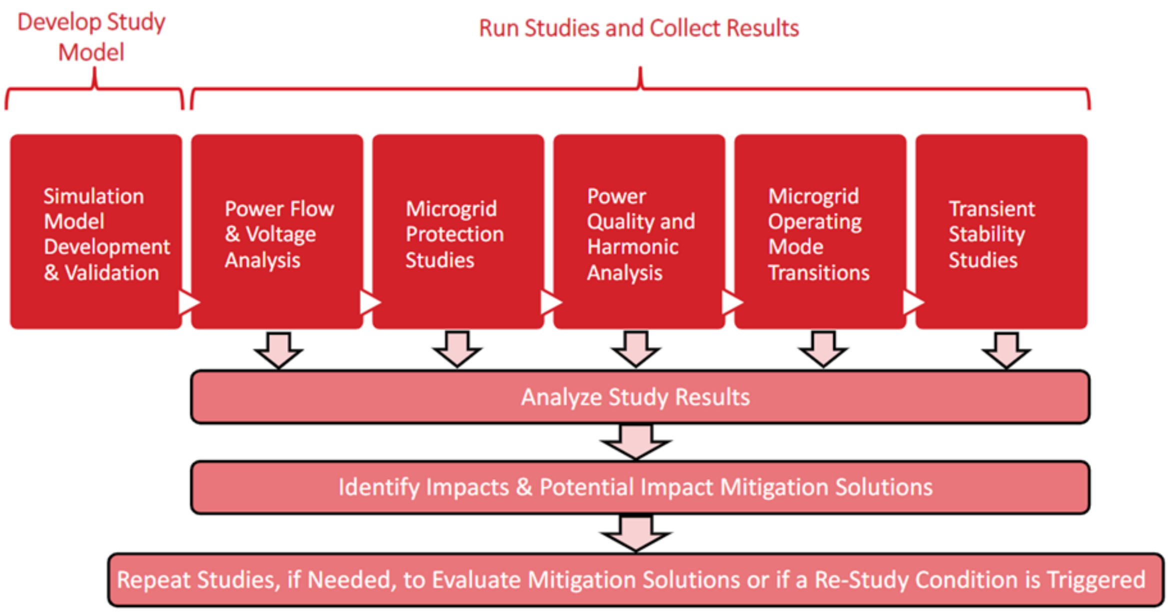

Figure 28: Microgrid Islanding Study Process Overview

11.1.2 The Community Microgrid Technical Best Practices Guide

The first public document is the Community Microgrid Technical Best Practices Guide[35]. The purpose of the Community Microgrid Technical Best Practices 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 on PG&E's electric distribution grid. 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.

The Technical Best Practices Guide covers the following topics:

a. Microgrid Reference Architectures
b. Microgrid Operational Modes
c. Transitions
d. Sizing Grid-Forming Generators
e. Interconnection Processes
f. Controls Development
g. Network Communications and Cybersecurity
h. Electrical Design
i. Construction
j. Pre-Commissioning
k. Commissioning
l. Operating the Microgrid
m. Change Management

[35] Community Microgrid Technical Best Practices Guide (pge.com)

While this document is constantly maturing, the intent of this guide is to develop into an analogue of the Distribution Interconnection Handbook for Community Microgrids which developers use to design Community Microgrids against PG&E standards and good utility practice. As more Community Microgrids are deployed on the PG&E system and the state-of-the-art matures, this guide will be updated to reflect new information, opportunities, and requirements.

11.2 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

12 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[36] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
a. Outage number, frequency and duration reductions	Section 0
d. Public safety improvement and hazard exposure reduction	Section 0
9. Adoption of EPIC technology, strategy, and research data/results by others	
a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for widespread deployment or technologies included in adopted building standards	Section 4

[36] 2020 PG&E EPIC Annual Report. March 1, 2021. Pacific Gas and Electric Company Electric Program Investment Charge (EPIC) 2020 Annual Report (pge.com)

13 Conclusion

The Redwood Coast Airport Microgrid (RCAM) introduced a new class of microgrids called "Community Microgrids" to the state of California. These Community Microgrids leverage third-party owned generation and utility distribution grid infrastructure to keep critical community facilities energized during broader grid outages. RCAM also holds the distinction of being California's first 100% renewable multi-customer microgrid. This project is the culmination of five years of research and innovation across a dozen PG&E teams and in close partnership with Schatz Energy Research Center at Cal-Poly Humboldt and the Redwood Coast Energy Authority. The project was funded through a California Energy Commission EPIC grant to the Schatz Energy Center and loan from the United States Department of Agriculture, Rural Utility Service to the Redwood Coast Energy Authority, in collaboration with PG&E's EPIC 3.11 RCAM Project. PG&E's budget for the project was $3.1MM while the total project budget for all project partners was around $15MM.

The RCAM project features a 2.3MW hybrid Battery and PV generator providing energy resilience for Humboldt County's geographically isolated regional airport and neighboring U.S. Coast Guard Air Station which maintains search and rescue missions for 250 miles of remote, rugged coastline. In its first twelve months of operation, RCAM has already responded to 12 grid events including a 6.4 earthquake and a parade of atmospheric rivers – automatically and seamlessly islanding without human intervention. To date, RCAM has provided over 51 hours of incremental resilience to critical infrastructure.

RCAM's operational success notwithstanding, developing RCAM and the Community Microgrid model required meaningful innovations in both the policy and technical domains.

Prior to RCAM, there was not a pathway to integrate Community Microgrids onto PG&E's distribution system. As such, PG&E needed to develop a coherent framework to enable these types of microgrids. Key pieces of this framework included a Tariff and the contractual arrangement between PG&E and the operator of the grid-forming DER. To PG&E's knowledge, nothing similar to this structure existed in the US or elsewhere.

The project team developed a regulatory framework that aligned PG&E's strategic goals with California's resilience objectives. The resulting Community Microgrid Enablement Tariff (CMET) and a pro-forma Microgrid Operating Agreement were approved by the CPUC and received strong stakeholder support. The framework is notable for several reasons but chief among them is its simplicity. Both the tariff and agreement are highly compatible with existing utility standards, rules, and processes such as those defined in the interconnection process and Distribution Operations. Moreover, the roles and responsibilities are clear and unambiguous. The Utility always remains the Distribution System Operator and Distribution Service Provider independent of whether the microgrid is islanded or grid-connected. This framework provides a viable and compelling approach to keep the utility in the center of grid planning enabling resilience.

The project team also had to solve the technical challenges of using third-party inverter-based resources to maintain power quality and ensure safe operations of the system during islanded operations. Key technical challenges included modeling the behavior of the inverters, developing protection schemes, and testing control logic and operational coordination between PG&E and RCEA devices.

RCAM's technical development culminated in the industry-first Microgrid Island Study designed to solve for the novel control methodologies, protection schemes, and operational coordination required for DERs acting as grid-forming generators. Additionally, PG&E built a world class microgrid test bed to support further microgrid research.

The result of these policy and technical innovations is a replicable and scalable model to implement community microgrids across PG&E's service territory.

In fact, the impact of RCAM is already evident. As a companion to CMET, PG&E launched a $90MM program called the Community Microgrid Enablement Program (CMEP) to develop Community Microgrids in communities with a high risk of outages. This then had impact well beyond PG&E's service territory as CMEP served as the model for California's recently approved Microgrid Incentive Program (MIP). In April 2023, the CPUC approved $200MM among the three IOUs to support community-driven microgrid projects, similar to RCAM, throughout California. MIP is a competitive grant program that funds up to $14MM to cover eligible project resources, engineering and development costs in Disadvantaged and Vulnerable Communities that have a high outage risk.

PG&E has received a lot of interest in both community microgrid programs. Since CMEP launched in 2021, the PG&E team met with roughly 100 communities and/or technical developers, and of those interested parties, 40 projects advanced through the initial stages of CMEP. It should be noted that most CMEP projects did not move forward due to the following reasons: 1) because another solution such as a Behind-the-Meter microgrid was a better fit, 2) the community didn't meet the eligibility requirements of CMEP or 3) there was a lack of additional funding needed from the community to procure the project resources. However, four CMEP projects remain in an early stage of development. Since MIP officially launched in October 2023 and could cover a significant portion of eligible project costs, 11 communities that initially came through CMEP have applied to this grant program with a total of 22 communities and/or tribes submitting applications to the first MIP application tranche.

Furthermore, the success of RCAM and these innovative programs have led utilities in several US states and internationally to seek out PG&E's advice and have considered RCAM as a model for structuring their own microgrid policy.

However, for all its success, RCAM has shown that Community Microgrids are unique and complex solutions. There is still significant work to be accomplished to increase scalability and manage more complicated microgrid configurations.

14 Appendix 1 – List of Figures and Tables

14.1 Figures:

14.2 Tables:

15 Appendix 2 – Definition of Terms and Abbreviations

3P	3-Phase
ADMS	Advanced Distribution Management System
AL	Advice Letter
ATS	Applied Technology Services
BESS	Battery Electric Storage System
BTM	Behind-the-Meter
CAIDI	Customer Average Interruption Duration Index
CCA	Community Choice Aggregator
CEC	California Energy Commission
CIP	Critical Infrastructure Protection
CMEP	Community Microgrid Enablement Program
CMET	Community Microgrid Incentive Program (MIP)
CMG	Community Microgrid
COD	Commercial Operation Date
CONOPS	Concept of Operations
CPUC	California Public Utilities Commission
DC	Direct Current
DCC	Distribution Control Center
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DGD	Distributed Generation Deliverability
DO	Distribution Operator
DOO	Description of Operations
DSO	Distribution System Operator
EPIC	Electric Program Investment Charge
FAN	Field Area Network
FAT	Factory Acceptance Testing
FCD	Full-Capacity Deliverability
FCDS	Full-Capacity Deliverability Status
FDS	Functional Design Specification
FTM	Front-of-the-meter
GHG	Greenhouse Gas
HMI	Human Machine Interface
LG	Line-to-Ground
LL	Line-to-Line
LLG	Line-to-Line-to-Ground
LR	Line Recloser
MIP	Microgrid Incentive Program

MIS	Microgrid Islanding Study
MOA	Microgrid Operating Agreement
MPLS	Multiprotocol Label Switching
NEM	Net Electric Metering
NERC	North American Electric Reliability Corporation
ODN	Operational Data Network
OIR	Order Instituting Rulemaking
PCS	Power Control System
PG&E	Pacific Gas & Electric
PHIL	Power Hardware in the Loop
PIP	Project Implementation Plan
PSPS	Public Safety Power Shutoff
PTP	Point-to-Point
PV	Photovoltaic
RA	Resource Adequacy
RCAM	Redwood Coast Airport Microgrid
RCEA	Redwood Coast Energy Authority
RTAC	Real-time Automation Controller
RTDS	Real-Time Digital Simulator
RTO	Release to Operation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Site Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SEL	Schweitzer Engineering Labs
Schatz Center	Schatz Energy Research Center of Cal Poly Humboldt
SFA	Special Facilities Agreement
SGIA	Small Generator Interconnection Agreement
SoC	State of Charge
SSP	System Security Plan
TD&D	Technology Demonstration and Deployment
TNPF	Technology Neutral Pro-Forma
USDA	The United States Department of Agriculture
WDT	Wholesale Distribution Tariff

16 Appendix 3 – ATS RCAM Test Plan

The test plan presented here was designed to test the microgrid protection and control functions described in the Arcata-Eureka Airport Microgrid Functional Design Specification document (FDS Rev. 5). The test plan adhered to the testing requirements presented in IEEE Std 2030.8 Standard for the Testing of Microgrid Controllers, which is designed to meet the objectives described in IEEE Std 2030.7 Standard for the Specification of Microgrid Controllers.

The test plan covered the following functions:

1) **Grid-connected functions:** Blue-Sky BESS Dispatch and Grid-Connected Fault Detection
2) **Islanded functions:** Islanding with BESS and Islanded Fault Detection
3) **Islanding transition functions:** Seamless and Break-Before-Make Transition to Island
4) **Reconnection functions:** Seamless and Break-Before-Make Reconnection to grid

Failsafe tests were not part of the test plan except for those that were difficult to evaluate in the field:

1) Zone 1 Primary Fault
2) Failed Retransfer to Grid

The remaining failsafe tests which evaluated alarms and recovery actions in response to events such as communications loss or hardware failure have been successfully completed in the field and in the FAT. Tests were classified per function where each test consisted of multiple scenarios with a set of initiating conditions and events. The objectives of this test plan were the following:

a) Confirm the correct execution of microgrid control sequences
b) Evaluate the stability of the microgrid for various modes of operation
c) Validate relay protection settings

To validate relay protection settings, line-to-ground (LG), three-phase (3P), line-to-line (LL), and line-to-line-to-ground (LLG) faults were applied at different points on the system. Points P1-P5 in Figure 29 show the fault location for internal fault testing in the Microgrid Zone of Protection. Points P6 and P7 in Figure 30 show the internal fault location in the Customer Generation Zone of Protection and points P8-P10 in Figure 31 show the fault location in the External Protection Zone.

The fault points given in Figure 29 for the Microgrid Zone of Protection were placed on the 12-kV side of the step-down transformer serving each load as shown in Figure 32 for the case of P5.

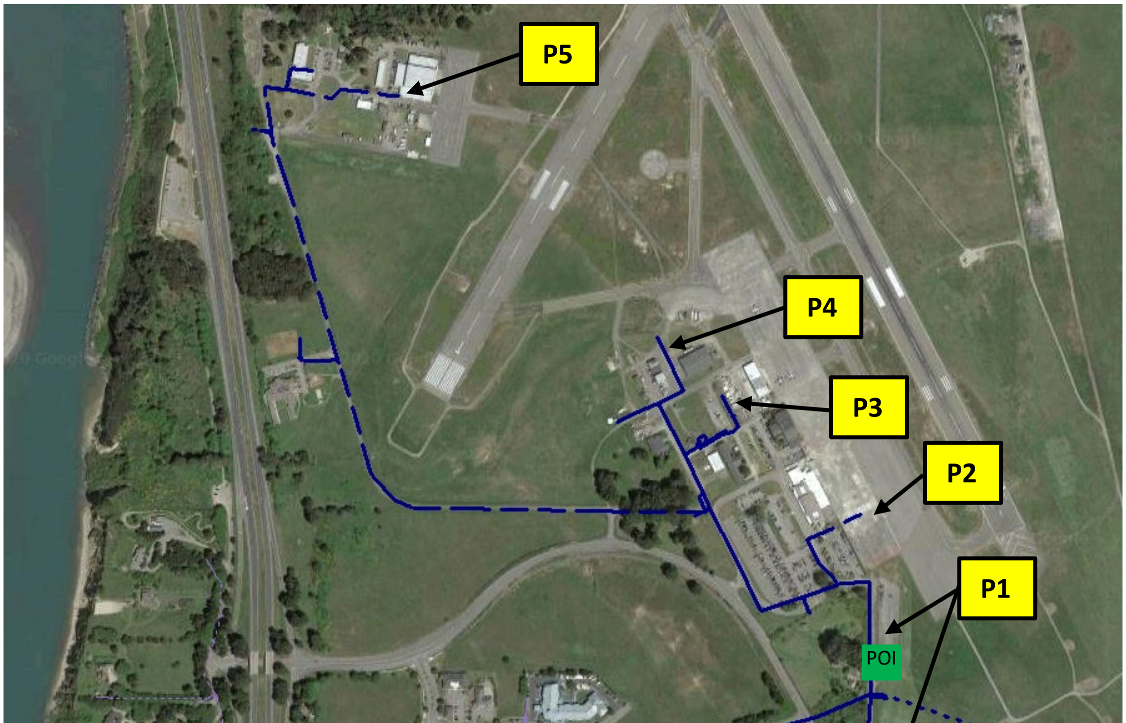

Figure 29 Janes Creek 1103 Internal Protection Zone fault location.

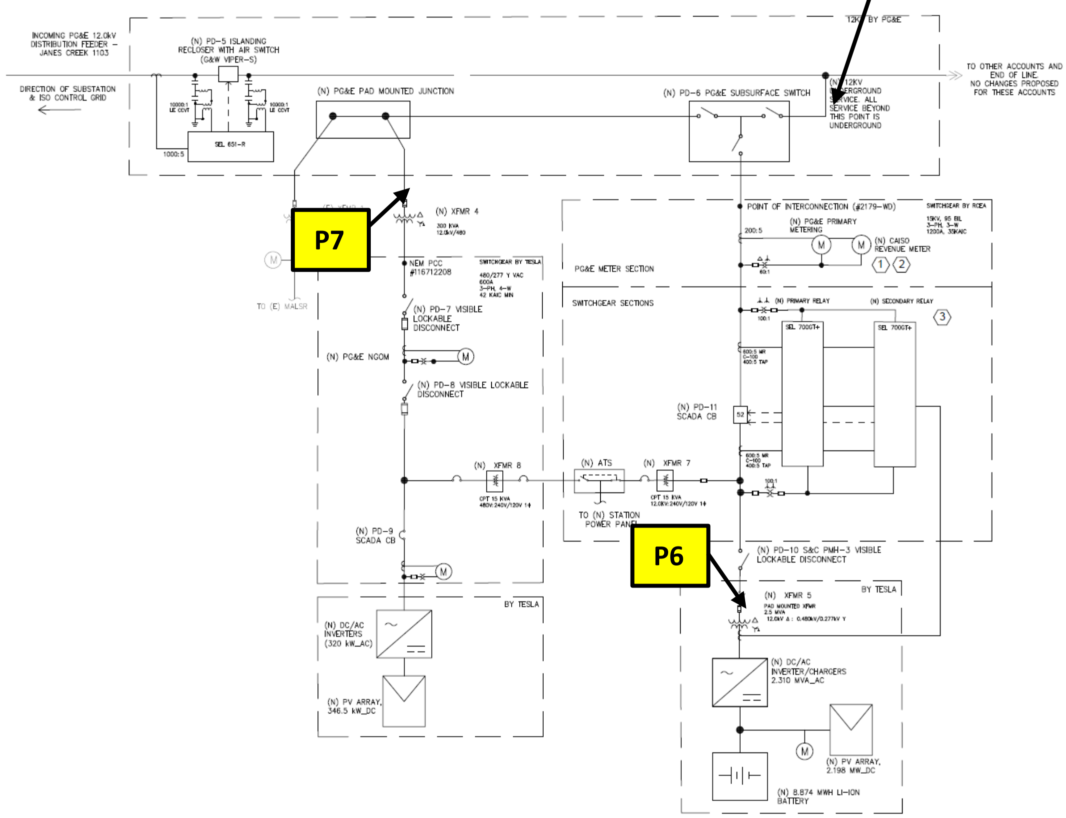

Figure 30 Customer Generation Protection Zone fault location.

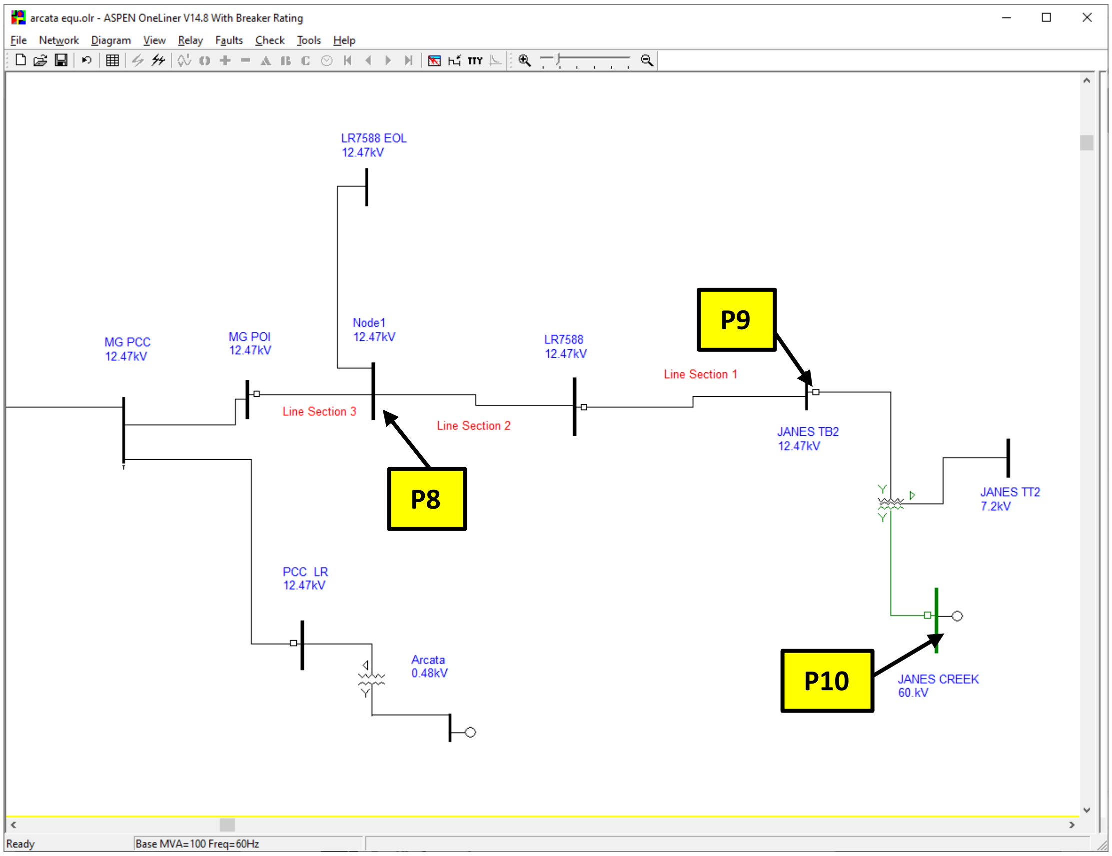

Figure 31 Janes Creek 1103 out-of-section fault location.

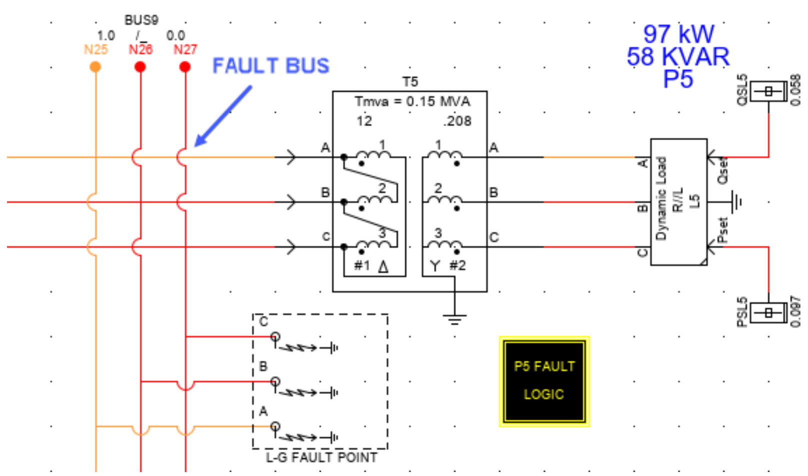

Figure 32 Microgrid fault location in RSCAD model.

16.1 Grid-Connected Function Tests

No.	Function	Testing Scenarios	Expected Operation
1	**Blue-Sky BESS Dispatch**	**1)** BESS Direct Dispatch a) Real/Reactive power setpoint within PG&E limits b) Real/Reactive power setpoint outside PG&E limits	BESS execution of real power setpoints while maintaining the microgrid within PG&E import and export curtailment limits.
2	**Grid-Connected Fault Detection**	**1)** Fault on External Protection Zone a) Abnormal grid operation - Voltage sag/rise - Frequency drop/rise b) LG, 3P faults at points: - Node 1 (P8) - 12 kV J. Creek substation bus (P9) - 60 kV J. Creek substation bus (P10)	BESS or SEL-651R detects fault or abnormal condition and trips the Islanding Recloser.
		2) Fault on Internal Protection Zone a) LG, 3P, LL, LLG faults at points P1-P5	SEL-651R detects fault and trips Islanding Recloser while simultaneously issuing a signal to the SEL-700GT+ to trip the Generation CB. Protection coordination with fuses will also be evaluated.
		3) Fault on Customer Generation Protection Zone a) LG, 3P, LL, LLG faults at points P6-P7	SEL-700GT+ Generation Relay detects fault and trips Generation CB followed by BESS entering Complete System Shutdown operating mode.

16.2 Islanded Function Tests

No.	Function	Testing Scenarios	Expected Operation
1	**Islanding with BESS**	**1) Voltage and frequency regulation** a) BESS SOC > Islanded BTM PV Curtail SOC value b) BESS SOC < Islanded BTM PV Curtail SOC value	BESS maintains stable voltage and frequency on the microgrid while Generation Controller trips or closes NEM PV CB at maximum PV generation output. When a) is true, NEM PV CB will trip. When b) is true, NEM PV CB will close.
2	**Islanded Fault Detection**	**1)** Fault on Internal Protection Zone a) LG, 3P, LL, LLG faults at P1-P5	SEL-700GT+ Generation Relay trips Generation CB and SEL-651R goes into lockout. BESS maintains power up to the open Generation CB. Protection coordination with fuses will also be evaluated.
		2) Fault on Customer Generation Protection Zone a) LG, 3P, LL, LLG faults at P6-P7	SEL-700GT+ Generation Relay detects fault and trips Generation CB followed by BESS entering Complete System Shutdown operating mode.
3	**BESS Depleted while Islanded**	**1)** Generation Limp a) BESS SOC < IslandedMinSOC b) BESS SOC > IslandedMinSOC	Generation Controller trips/closes Gen CB based on BESS SOC. When a) is true, Gen CB will trip. When b) is true, Gen CB closes and re-energizes the islanded microgrid.

16.3 Transition Function Tests

No.	Function	Testing Scenarios	Expected Operation
1	**Seamless Transition to Island**	**1) Automatic Transition (Unplanned Islanding)** a) Grid voltage sag	BESS enters VF (grid-forming) mode following operation of SEL-651R for fault on external protection zone. The microgrid becomes islanded and automatic retransfers are inhibited until the grid voltage is nominal for 15 minutes.
		2) Manual Transition (Planned Islanding) a) Planned islanding request from Eaton 4260 PG&E HMI	Upon reception of open command, BESS balances power at Islanding Recloser, switches to VF (grid-forming) mode, and opens Islanding Recloser via SEL-3530-4. The microgrid becomes islanded and automatic retransfers are inhibited.
2	**Break-Before-Make Transition to Island**	1) **Automatic Transition (Unplanned Islanding)** a) Grid voltage sag	BESS switches to standby mode following operation of SEL-651R for fault on external protection zone. BESS switches to VF (grid-forming) mode and black-starts the microgrid once Islanding Recloser opens. Automatic retransfers become inhibited until the grid voltage is nominal for 15 minutes.
		2) Manual Transition (Planned Islanding) a) Planned islanding request from Eaton 4260 PG&E HMI	BESS enters standby mode upon reception of open command. BESS switches to VF (grid-forming) mode and black-starts the microgrid once Islanding Recloser opens. Automatic retransfers are inhibited.
3	**Seamless Reconnect**	**1) Automatic transition** a) Grid restoration	Once grid voltage and frequency return to expected range for 15 min, BESS synchronizes microgrid to main grid and SEL-3530-4 issues close command to SEL-651R. SEL-651R confirms synchronization and closes Islanding Recloser followed by BESS switching from VF (grid-forming) to PQ (grid-following) mode enabling Blue Sky BESS Dispatch Function.
		2) Manual transition a) Reconnect request from Eaton 4260 PG&E HMI	Once reconnect request is issued, BESS synchronizes microgrid to main grid and SEL-3530-4 issues close command to SEL-651R. SEL-651R confirms synchronization and closes Islanding Recloser followed by BESS switching from VF (grid-forming) to PQ (grid-following) mode enabling Blue Sky BESS Dispatch Function.
4	**Break-Before-Make Reconnect**	**1) Automatic transition** a) Grid restoration	Once grid voltage and frequency return to expected range for 15 min, BESS enters standby mode de-energizing the microgrid. SEL-3530-4 issues close command to SEL-651R to black-start the microgrid and BESS switches from VF (grid-forming) to PQ (grid-following) mode enabling Blue Sky BESS Dispatch Function.

		2) Manual transition a) Reconnect request from Eaton 4260 PG&E HMI	Once reconnect request is issued, BESS enters standby mode de-energizing the microgrid. SEL-3530-4 issues close command to SEL-651R to black-start the microgrid and BESS switches from VF (grid-forming) to PQ (grid-following) mode enabling Blue Sky BESS Dispatch Function.

16.4 Failsafe Tests

The below failsafe tests were added to the test plan to support field commissioning. These tests were better performed at the ATS testbed since they involved faults in the test sequence.

No.	Function	Testing Scenarios	Expected Operation
1	**Zone 1 Primary Fault Failsafe**	**1) AG fault on Internal Protection Zone**	Generation CB trips, Microgrid Control on Eaton 4260 HMI switches from Auto to Manual and Zone 1 LED illuminates in SEL-651R template of Eaton 4260 HMI.
2	**Failed Retransfer to Grid Failsafe**	**2) BESS Site Controller unresponsive to command from Eaton 4260 HMI**	Failed Retransfer to Grid Transition indication on Eaton 4260 HMI

17 Appendix 4 – RCAM Commissioning Test Plan Summary

The following table summarizes the tests performed onsite for field commissioning of RCAM.

Test #	Description
1	Manual planned Seamless Islanding Event initiated from onsite PG&E HMI, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.
2	Manual planned Seamless Islanding Event initiated remotely from DCC SCADA, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.
3	Manual planned Break-Before-Make Islanding Event initiated from onsite PG&E HMI, followed by islanding for 20 minutes, followed by manual Break-Before-Make retransfer to grid-connected state.
4	Manual planned Break-Before-Make Islanding Event initiated remotely from DCC SCADA, followed by islanding for 20 minutes, followed by manual Break-Before-Make retransfer to grid-connected state.
5	Automatic unplanned Seamless Islanding Event, followed by islanding for 20 minutes, followed by automatic seamless retransfer to grid-connected state.
6	Automatic unplanned Internal Fault Event, followed by manual restoration to grid-connected state.
7	Manual planned Seamless Islanding Event initiated from DCC SCADA, followed by load shed testing, followed by manual seamless retransfer to grid-connected state.

Table 4: Field Commissioning Tests for RCAM