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ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Redwood Coast Airport Microgrid

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Redwood Coast Airport Microgrid is the final report for the EPC-17-055 conducted by the Schatz Energy Research Center at Cal Poly Humboldt. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

This report describes the Redwood Coast Airport Microgrid project, the first front-of-the-meter, multi-customer community microgrid in Pacific Gas and Electric Company's service territory, and key takeaways and lessons learned from the project. The 100-percent renewable microgrid features a grid-forming, front-of-the-meter 2.2-megawatt (direct current) solar photovoltaic array direct current coupled with a 2.3-megawatt (alternating current), 8.87-megawatt-hour lithium-ion battery energy storage system, and a grid-following, behind-the-meter 300-kilowatt (alternating current) solar photovoltaic array, along with four 20-kilowatt (direct current) bi-directional, behind-the-meter electrical vehicle chargers. The microgrid serves 19 retail customers at the end of the Janes Creek 1103 distribution circuit with an aggregate peak load of approximately 330 kilowatts, including the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station. The microgrid provides dispatchable solar power, as well as regulation up and regulation down ancillary services in the wholesale electricity market. The microgrid features seamless transitions to and from islanded mode and has provided reliable, safe, grid quality renewable power to critical loads during 63 islanding events (including a 6.4-magnitude earthquake and winter storms) covering 71.8 hours of grid outage over a 38-month period.

The project team developed a community microgrid tariff and an associated microgrid operating agreement that allow a third-party-owned, grid-forming generator to supply power to an islanded section of the utility's circuit. The team's policy work led to the development of the Community Microgrid Enablement Tariff and the Community Microgrid Enablement Program, and eventually to the statewide Multi-Property Microgrid Tariff and the statewide Microgrid Incentive Program. These developments codified much of the work accomplished in the project and created a regulatory pathway for replication. However, replication of community microgrids still faces significant barriers.

Key challenges include:

- A challenging business model — costs outweigh monetizable benefits partly because the value of resilience is difficult to quantify.
- Complexities involved in developing and deploying a multi-customer community microgrid.
- The high cost and complexities involved in owning and operating a multi-customer microgrid that participates in the wholesale electricity market.

Keywords: front-of-the-meter, multi-customer, community microgrid, renewable, direct current coupled, microgrid tariff, microgrid operating agreement, business model, resilience, wholesale electricity market

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Rationale

Climate-change-driven extreme weather events and wildfires are increasing in frequency, straining California's electrical grid and causing more frequent power outages. These trends underscore the need for enhanced grid reliability and resilience.

A front-of-the-meter, multi-customer microgrid can deliver reliability and resilience benefits to communities. When powered by renewable sources, such microgrids also contribute to decarbonizing the grid. The Redwood Coast Airport Microgrid demonstrates these benefits. This replicable community microgrid provides enhanced resilience for two critical facilities — the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station — while also supplying carbon-free renewable power to the local community.

The Redwood Coast Airport Microgrid features a grid-forming, front-of-the-meter, 2.2-megawatt (direct current) solar photovoltaic array coupled with a 2.3-megawatt (alternating current), 8.87-megawatt-hour lithium-ion battery energy storage system. The front-of-the-meter solar array with battery system provides dispatchable renewable power that feeds the local grid while delivering energy and ancillary services into California's wholesale electricity market. During local grid outages, this system provides backup power to the microgrid circuit. In addition, a co-located grid-following, behind-the-meter 300-kilowatt (alternating current) solar photovoltaic array offsets retail bills for key airport facilities, providing compensation to the site host, which is a different entity than the microgrid owner-operator. This microgrid also features four 20-kilowatt (direct current), behind-the-meter bi-directional electrical vehicle chargers.

The microgrid serves 19 retail customers at the end of the Janes Creek 1103 distribution circuit, including the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station. The microgrid circuit has an aggregate peak load of approximately 330 kilowatts.

Project Purpose and Approach

The project team comprised the Schatz Energy Research Center as the prime contractor and technical lead, the Redwood Coast Energy Authority (a community choice aggregator) as the microgrid owner/operator, Pacific Gas and Electric Company as the distribution system owner/operator, and Humboldt County as the site host and airport owner/operator.

The project aimed to:

- Design, deploy, and operate a renewable energy microgrid serving critical facilities, including the California Redwood Coast-Humboldt County Airport and U.S. Coast Guard Sector Humboldt Bay Air Station.

- Develop and implement agreements, operating procedures, safety protocols, and tariffs required for a front-of-the-meter, multi-customer microgrid.
- Quantify the benefits and costs of the microgrid and its distributed energy resources.
- Evaluate the business case and market opportunities for replication.
- Document results and lessons learned to guide communities, electric utilities, community choice aggregators, and other entities pursuing similar systems.

Key Results

Accomplishments

Key accomplishments of the Redwood Coast Airport Microgrid project include the following.

- The project team deployed a community microgrid that provides resilience to critical facilities, including the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station. The Redwood Coast Airport Microgrid facility delivers dispatchable solar photovoltaic power, as well as regulation up and regulation down ancillary services in the California Independent System Operator wholesale electricity market. System performance has largely met or exceeded expectations in both grid-connected and islanded modes.
- Expected annual revenues for a fully operational front-of-the-meter solar photovoltaic and battery system, based on actual market performance, are approximately $150,000 to $200,000 from energy and ancillary services. However, due to performance issues with the direct current converters connecting the solar array to the batteries, actual revenues ranged from $80,000 to $128,000 annually from 2022 through 2024. These issues were resolved by replacing the direct current converters in May 2025, and 2025 revenues from energy and ancillary services are now expected to reach approximately $160,000. The Renewable Energy Certificate value of the generated solar electricity was estimated at $50,000 to $60,000 per year for a fully functioning system, but it totaled only about $28,000 from January through November 2025. Additionally, had Resource Adequacy revenue been available from 2022 through 2025, it could have added an estimated $160,000 annually, according to The Energy Authority (California Independent System Operator scheduling coordinator for the Redwood Coast Energy Authority). These revenue shortfalls have significantly increased the challenge of achieving economic viability for this front-of-the-meter community microgrid.
- The total net carbon-free renewable power delivered to the electric grid from April 2022 through August 2025 was 2,846megawatt-hours, with a total estimated reduction in carbon dioxide emissions of 663 metric tons, or 194 metric tons per year. This is lower than the original estimated goal of 882 metric tons per year. The failure to meet the original goal is mainly due to the performance issues with the direct current converters and to reductions in California's annual electricity generation carbon dioxide emissions factors as the state moves toward a carbon-free electric grid.

- The microgrid, with its seamless transitions to and from islanded mode, delivered reliable, safe, and grid-quality renewable power during 63 islanding events totaling 71.8 hours of grid outage over a 38-month period. These events included a 6.4-magnitude earthquake and severe winter storms. The duration of islanding met or exceeded expectations in all cases.
- The team developed a community microgrid tariff and an associated microgrid operating agreement, as well as other processes, protocols, and procedures that were necessary to deploy a multi-customer community microgrid on the local utility's distribution circuit. These policies and agreements allow a third-party-owned, grid-forming generator to supply power to an islanded section of the utility's circuit. This regulatory pathway did not previously exist in California.
- The team's policy efforts resulted in the development of the Community Microgrid Enablement Tariff, the Community Microgrid Enablement Program, and eventually to the statewide Multi-Property Microgrid Tariff and the statewide Microgrid Incentive Program. These initiatives codified the project's achievements, creating a regulatory framework, incentive program, and utility support structure to facilitate the replication of community microgrid projects statewide.

Challenges

When evaluating opportunities for replication, the project team identified several challenges to achieving scalability. These include the following.

- The community microgrid presents a challenging business model, with costs exceeding easily monetizable benefits. While resilience can potentially offset costs, its value is difficult to quantify and depends on the critical services provided and their perceived value to the community. Characterizing reliability and resilience benefits, securing community support, and developing robust revenue streams during normal (blue sky) operations are essential. Currently, the financial viability and replicability of community microgrids depends largely on the availability of grant funding or other financial incentives.
- Developing, owning, and operating a multi-customer microgrid and participating in the wholesale electricity market is a complex endeavor. For small municipalities, community groups, or Native American tribes lacking experience in microgrid development, operations, and wholesale electricity market participation, it can be challenging and costly. Ongoing, reliable, and cost-effective technical support is essential.
- Achieving full deliverability for a front-of-the-meter generation asset entails significant costs and challenges. While this can unlock substantial revenue from Resource Adequacy payments, it may extend the project timeline and incur considerable expenses for upgrades to the transmission and distribution systems. Assessment of this aspect of the project, both in terms of expected cost and potential revenue, is essential during the project development phase.

- Community microgrid developers face substantial risks, which may deter small community organizations or local governments. These include the economic challenges of the business model, the complexity of owning and operating a microgrid, and the potential need for costly upgrades or restrictions on future islanded operation due to additional loads on the microgrid circuit. These risks must be evaluated and mitigated where feasible.

Knowledge Transfer and Next Steps

Knowledge Transfer

To facilitate knowledge transfer for prospective community microgrid developers, the project team implemented a comprehensive plan, including:

- Presentations at approximately 50 conferences, workshops, and meetings, reaching over 1,500 stakeholders, including key policy discussions with the California Public Utilities Commission, the California Energy Commission, and the California Independent System Operator.
- Nine project-specific webinars engaging over 500 participants.
- Multiple interviews with local and national media, including radio, television, and print and digital outlets.
- Over 20 site tours and hosted visits for stakeholders.
- More than 20 direct responses to inquiries and engagements with local government, community stakeholders, and Native American tribes pursuing microgrid projects.

The most impactful knowledge transfer for community microgrid replication consists of publicly available informational materials documenting the tariffs, agreements, and processes required to deploy a front-of-the-meter, multi-customer community microgrid in California. These resources detail the Community Microgrid Enablement Tariff, the associated Microgrid Operating Agreement, and the Microgrid Islanding Study, providing essential guidance for effective deployment within Pacific Gas and Electric Company's service territory under the Community Microgrid Enablement Tariff and the Microgrid Incentive Program

Recommended Next Steps

To advance the deployment of community microgrids in California, the project team recommends the following actions.

- Support funding for community microgrids in suitable locations, particularly for at-risk and disadvantaged communities. As more microgrids are implemented, their performance can be evaluated, lessons learned can be documented, and technologies can be refined to enhance reliability and cost-effectiveness.
- Invest in research on advanced community microgrids incorporating innovative technologies, including vehicle-to-grid integration and the use of frequency regulation

and smart inverter droop settings to manage inverter-based distributed energy resources.

- Allocate funding to investigate protection methodologies for inverter-based community microgrids, including nested architectures. This research should assess how microgrid assets, telemetry, and control systems can enhance circuit reliability, minimize outage duration and scope, and facilitate outage identification to expedite power restoration.
- Support research to evaluate grid services provided by inverter-based distributed energy resources (for example, non-wires alternatives that can defer transmission and distribution upgrades and provide voltage or reactive power support) and develop compensation mechanisms for these services. This should include deploying distributed energy resources and directly measuring system performance and benefits.
- Develop standardized methods for quantifying the value of resilience provided by microgrids and establish guidelines for using these valuations to assess the cost-benefit ratio of proposed community microgrid projects.

In addition to these recommendations, the Schatz Energy Research Center is pursuing the following initiatives to advance community microgrid research, development, and demonstration:

- Partnering with Pacific Gas and Electric Company to conduct additional testing at the Redwood Coast Airport Microgrid facility, including the use of frequency regulation to manage distributed energy resources.
- Conducting microgrid controls and protection research at the Blue Lake Rancheria, utilizing a behind-the-meter campus to test innovative architectures and protection methodologies for integrating nested microgrids on a single distribution circuit.
- Deploying a behind-the-meter microgrid at the Cal Poly Humboldt campus that will serve all campus facilities located behind a single point of interconnection with the PG&E grid, and establishing a microgrid research center featuring a control and hardware in the loop testing facility with real-time digital simulation.

CHAPTER 1: Introduction

Climate change is increasing the frequency and severity of extreme weather events, placing significant stress on electrical infrastructure and leading to a rise in weather-related power outages. Concurrently, efforts to decarbonize the energy sector through widespread electrification and a transition to 100-percent renewable, carbon-free energy sources are accelerating. These converging trends underscore the urgent need for enhanced reliability and resilience in the electricity system to ensure consistent performance and adaptability in the face of growing environmental and operational challenges.

Another shift in California has been the establishment of Community Choice Aggregation. Community Choice Aggregators (CCA) now serve approximately 30 percent of the in-state retail load in California (Bailey et al. 2023). The establishment of CCAs has given retail customers more of a say in where their electric power comes from, and this has allowed customers to push for more renewable power, including the development of local renewable energy projects. If these local projects are solar electric, as is often the case, energy storage is also needed to meet Resource Adequacy (RA) requirements and to shift energy dispatch to higher-priced hours.

If these local, community-scale, solar-plus-battery projects can be located near a cluster of critical facilities, then microgrid controls and protection can be added to create a community microgrid. With proper planning and access to adequate technical and financial resources, communities can develop local renewable energy projects that also provide increased reliability and resilience for select critical facilities. This is the business model and the technology configuration envisioned for the Redwood Coast Airport Microgrid (RCAM).

According to the U.S. Department of Energy, 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. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or islanded mode" (Ton and Smith 2012).

Behind-the-meter (BTM) microgrids are defined as microgrids where the point of interconnection with the grid is on the customer side of the retail meter. In this case, the customer owns and has full control of all the electrical generation and distribution equipment when the system is islanded. This is generally allowed via existing utility tariffs and is a relatively easy project to implement. In contrast, a front-of-the-meter (FTM) microgrid, also referred to as a "community microgrid," has an interconnection point that is on the utility's distribution grid; when the isolation switch(es) open to create an islanded community microgrid, a cluster of facilities, loads, and generation resources are all interconnected via the utility's electrical distribution lines. If a third-party owns and operates the grid-forming generation, this adds substantial regulatory and technical complication.

While an FTM microgrid is more complicated, in some cases it may be the preferred solution. For example, where a community microgrid is able to serve a cluster of critical facilities, this could be the best approach. The RCAM project set out to design, deploy, operate, and evaluate a community microgrid that could serve 19 retail electric accounts on Pacific Gas and Electric Company's (PG&E's) Janes Creek 1103 distribution circuit. The key critical facilities on this circuit are the county's regional airport (California Redwood Coast-Humboldt County Airport) and the U.S. Coast Guard Sector Humboldt Bay Air Station, which provides search and rescue operations for 250 miles of remote, rugged coastline. In the event of a regional disaster, these facilities become critical lifelines for transporting people and supplies into, out of, and around the region.

When the RCAM project started, there was no regulatory pathway to support its implementation. There were no tariffs, processes, procedures, or technical standards to support the deployment of an FTM community microgrid where a third party owned the grid-forming generation. The RCAM project set out to develop tariffs, processes, procedures, and standards that could be applied to ensure the safe and effective operation of an FTM community microgrid and that could pave the way for other community microgrids to follow.

In terms of technical hurdles, some of the challenges the RCAM project faced were:

- Developing and implementing effective fault protection schemes for an inverter-based microgrid.
- Developing and conducting effective testing that could validate safe project performance before going live on the distribution system.
- Socializing the system with grid operators who tend to be concerned about the risks associated with such projects.
- Developing and implementing an effective cybersecurity plan.
- devising a microgrid controls configuration that established a clean delineation between assets owned by the distribution utility and those owned by the third-party community microgrid owner/operator, thereby mitigating potential liability issues.

The primary goal of the RCAM project was to demonstrate a replicable community microgrid project that could provide resilience to critical community facilities when needed, while also providing renewable power to the local community during normal (blue sky) conditions. More detailed project goals were to:

- Successfully design, install, and operate the first FTM renewable energy microgrid in California that could serve critical facilities, including the California Redwood Coast-Humboldt County Airport and U.S. Coast Guard Sector Humboldt Bay Air Station.
- Develop and implement the agreements, operating procedures, safety protocols, and tariffs necessary for a multi-customer, FTM community microgrid.
- Measure the benefits and costs of the microgrid and the distributed energy resources included in the project.
- Evaluate the business case and assess market opportunities for replication.

- Report on results and lessons learned for the benefit of electric utilities, CCAs, and others wishing to install similar systems.

This report demonstrates that the project team successfully met its objectives, often exceeding expectations. Key achievements include the development of performance metrics for the microgrid, as well as the establishment of tariffs, agreements, protocols, and procedures that form the foundation of PG&E's Community Microgrid Enablement Program (CMEP) and California's statewide Microgrid Incentive Program (MIP).

Additionally, this report presents the results of the business case evaluation and identifies critical lessons learned to guide future replication and deployment of community microgrids.

These findings offer valuable insights for policymakers, regulatory officials, distribution system planners and operators, microgrid developers, CCAs, and communities seeking to establish their own microgrids.

CHAPTER 2: Project Approach

This chapter outlines the purpose and primary research objectives of the project, introduces the project team, and describes the methodology employed to achieve the stated objectives.

Research Objectives

The purpose of the RCAM project was to develop a multi-customer, renewable energy microgrid implemented under a partnership between PG&E, an investor-owned utility (IOU), as the microgrid distribution circuit owner, and the Redwood Coast Energy Authority (RCEA), a CCA, as the grid-forming generation asset owner. The key purpose of the microgrid was to add resiliency to 19 electric accounts on PG&E's Janes Creek 1103 distribution circuit, which includes two critical facilities in the host community: (1) the California Redwood Coast–Humboldt County Airport (ACV Airport), and (2) the United States Coast Guard Air Station. The project aimed to demonstrate a replicable business model and illustrate a clear path to community microgrid deployment throughout California.

In addition to the overall purpose described above, the project was guided by a set of more specific research objectives that could spur needed advances. These included:

- Developing tariffs, agreements, operating procedures, and safety protocols that are necessary to allow a third party to own and operate grid-forming generation to serve an FTM multi-customer microgrid on a utility's distribution circuit.
- Developing and deploying a safe and functional FTM microgrid system that deploys 100-percent renewable, inverter-based resources and utilizes effective protection schemes that meet utility standards.
- Developing a control and power hardware-in-the-loop microgrid testing facility and utilizing the facility to conduct a microgrid islanding study to help ensure safe deployment of the microgrid on the utility circuit.
- Developing an effective approach to cybersecurity and to the ownership configuration for the microgrid controls to meet the needs of both the utility and the third-party owner of the grid-forming generation.
- Developing and deploying a safe and functional direct current (DC) coupled solar photovoltaic (PV) plus battery energy storage system (BESS).
- Establishing wholesale electricity market participation for a community microgrid project and developing and implementing an optimal market dispatch methodology.
- Developing a control system that allows for electric vehicle (EV) charging and load shedding in an islanded microgrid.
- Working with the IOU to develop the institutional capacity to support future community microgrids.

- Assessing the costs, quantifying the stacked benefits, and assessing the economic viability of community microgrids.

Project Team

The RCAM project represented a significant undertaking, requiring a cohesive group of partners with a strong commitment to success, a dedication to collaboration, and perseverance to address challenges and identify solutions that served the greater good. The project benefited from the assembly of such a team.

The core project team consisted of:

- The Schatz Energy Research Center (Schatz Center).
- The Redwood Coast Energy Authority (RCEA).
- Pacific Gas and Electric Company (PG&E).
- The County of Humboldt.

This core team actively participated in the early stages of conceptualizing the project and developing a project proposal in response to the California Energy Commission (CEC) solicitation. This early collaboration and partnership proved instrumental to the project's success. During this period, the team developed a detailed 30-percent design for the microgrid, enabling the creation of an accurate project budget, which was essential for ensuring a successful outcome.

In addition to the core team, the project involved several subcontractors and vendors. Key subcontractors included TRC Solutions and The Energy Authority (TEA). Key vendors included Tesla, Inc. and Schweitzer Engineering Laboratories (SEL). The core team, along with these key subcontractors and vendors, fostered a robust partnership critical to the project's success. Team members treated each other with respect, welcomed diverse perspectives, and consistently sought equitable and mutually acceptable solutions to challenges. This approach built the trust necessary to solidify the steadfast commitments of all team members, which were vital to the project's success.

Table 1 provides a complete list of project participants and their respective roles.

Table 1: Project Team Members and Roles

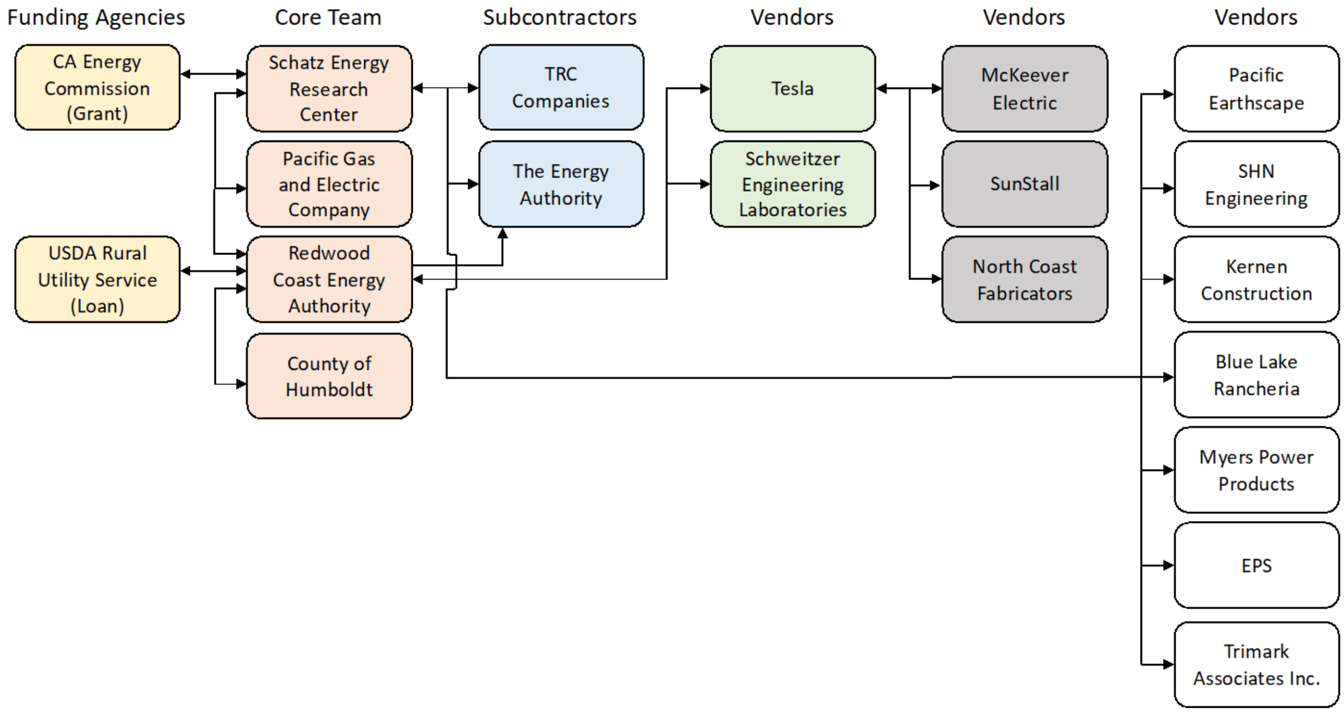
Entity	Role
California Energy Commission (CEC)	Funder
Schatz Energy Research Center	Prime contractor: technical lead, owner's engineer
Redwood Coast Energy Authority (RCEA)	Subcontractor: community microgrid owner/operator, match funder
Pacific Gas and Electric Company	Local utility, distribution system owner/operator
County of Humboldt	Site host, regional airport owner/operator

Entity	Role
TRC Companies	Subcontractor: business case and market evaluation, cybersecurity plan
The Energy Authority (TEA)	Subcontractor: California Independent System Operator (CAISO) scheduling coordinator
Schweitzer Engineering Laboratories (SEL)	Vendor: microgrid controls and protection
Tesla, Inc.	Vendor: battery storage system and PV system vendor
Sunstall	Vendor (subcontractor to Tesla): installation of PV system
McKeever Electric	Vendor (subcontractor to Tesla): installation of PV system
North Coast Fabricators	Vendor (subcontractor to Tesla): fabrication
Pacific Earthscape	Vendor: civil earthwork and site preparation
SHN Engineering	Vendor: civil testing
Kernen Construction	Vendor: mobile crane and hoisting service
The Blue Lake Rancheria	Vendor: electrical contracting
EPS	Vendor: electrical testing
Myers Power Products	Vendor: switchgear fabrication
Trimark Associates Inc.	Vendor: CAISO meter validation

Source: Schatz Energy Research Center

The overall team organizational structure is shown in Figure 1. The relationships were somewhat more nuanced than are shown in Figure 1. For example, RCEA was technically a subcontractor to the Schatz Center (which was the prime contractor to the CEC), but the Schatz Center also acted as the RCEA owner's engineer and, in that regard, served RCEA as a client. TRC Companies and TEA were also both subcontractors to the Schatz Center; however, TEA also had a standing contract with RCEA to provide services as its California Independent System Operators (CAISO) scheduling coordinator. Also, while the vendors Tesla, Inc. and SEL were under direct contract with RCEA, the Schatz Center, as the RCEA owner's engineer, provided direction to these vendors.

Figure 1: Project Team Organizational Chart



Source: Schatz Energy Research Center

In addition to the project team, a Technical Advisory Committee was established and convened multiple times throughout the project's duration. The advisory committee consisted of 17 individuals representing a diverse range of organizations, including investor-owned and publicly owned utilities, CCAs, airport executives, emergency services personnel, regulators, National Laboratory personnel, and consultants and professionals from the energy industry. Table 2 lists the members of the Technical Advisory Committee.

Table 2: Technical Advisory Committee Members

Sector	Organization	Name	Title
Investor- or publicly owned electric utility	San Diego Gas and Electric	Laurence Abcede	Distributed Energy Resources Manager
Investor- or publicly owned electric utility	Sacramento Municipal Utility District	Patrick McCoy	Distributed Energy Strategy, Grid Strategy and Operations
Investor- or publicly owned electric utility	Pacific Power	Erik Anderson	Strategic Manager-Renewable Energy and Emerging Technologies
Community Choice Aggregator	CalCCA	Beth Vaughan	Executive Director
Community Choice Aggregator	San Jose Clean Energy	Lori Mitchell	Director

Sector	Organization	Name	Title
Airports	San Francisco International Airport	John Galloway	Carbon Neutral Airport Program Manager
Airports	ADK Consulting	Rod Dinger	Senior Project Manager
Airports	Rocky Mountain Institute	Adam Klauber	Director, Sustainable Aviation
Emergency services	Humboldt County	Ryan Derby	Emergency Services Manager
Regulators	California Independent System Operator	Peter Klauer	Senior Advisor, Smart Grid Technology
Regulators	California Public Utilities Commission	Jessica Tse	Senior Public Utilities Regulatory Analyst – Grid Resiliency & Microgrids
National Labs	National Renewable Energy Laboratory	Kumaraguru Prabakar	Researcher, Power Systems Engineering Center
National Labs	Pacific Northwest National Laboratory	Allison Campbell	Power Systems Data Scientist
Consultants/energy professionals	Clean Coalition	Craig Lewis	Executive Director
Consultants/energy professionals	HOMER/UL	Peter Lilienthal	Chief Executive Officer
Consultants/energy professionals	Electric Power Research Institute	Arindam Maitra	Senior Technical Executive
Consultants/energy professionals	Olivine	Beth Reid	Chief Executive Officer

Source: Schatz Energy Research Center

Project Tasks

The following is a list of the project technical tasks, along with a brief description of the approach and/or methodology.

- **Project Initiation and Operational Agreements:** This task was primarily concerned with developing the necessary tariffs and agreements that would govern the operational roles and responsibilities, service obligations, and commercial terms and conditions to facilitate long-term operation of the FTM community microgrid with a third-party-owned grid-forming generator. This included the Community Microgrid Enablement Tariff,[1] the

[1] The Community Microgrid Enablement Tariff, or CMET, was developed as part of the RCAM project and received approval from the California Public Utilities Commission to be used as an experimental tariff. See https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CMET.pdf

Microgrid Operating Agreement (MOA), the Microgrid Islanding Study (MIS), and related documents. Key players in this task included RCEA, the Schatz Center, and PG&E.

- **Design and Permitting:** This task involved the development of: design documents (civil and electrical plan set), a Concept of Operations (CONOPS) document, and a Functional Design Specification (FDS) for the microgrid control system; an engineer's opinion of probable cost; a cybersecurity assessment; and a nonconfidential cybersecurity plan. In addition, the Schatz Center obtained required permits, conducted the interconnection process with PG&E, completed the CAISO New Resource Implementation process, and completed registration within the Western Renewable Energy Generation Information System (WREGIS) to obtain Renewable Energy Certificates (RECs). The Schatz Center led this task, with key vendors providing additional design services.
- **Procurement, Construction, Testing, Commissioning and Training:** The goal of this task was to: procure equipment and construction services; construct, test, and commission the various components of the microgrid; and then commission the complete microgrid system. This included obtaining permission to operate in both grid-connected and islanded modes from PG&E, as well as obtaining approval for commercial operation from the CAISO. Included in this task was preparation of system documentation, as well as operation and maintenance training for responsible personnel. The Schatz Center worked closely with RCEA to procure the necessary equipment and services and served as the RCEA owner's engineer to oversee construction and installation. The Schatz Center team worked with vendors and PG&E to develop and carry out the testing and commissioning activities.
- **Operation, Data Collection and Analysis:** The Schatz Center developed and implemented a data collection and analysis plan that allowed for tracking and reporting on the operational success of the RCAM system. In addition, the Schatz Center continues to serve as the RCEA owner's engineer and provides 24/7/365 operations support for the microgrid system. To ensure continued smooth operation of the RCAM system, the Schatz Center team works closely with: PG&E, as the distribution system operator; CAISO, as the wholesale electricity market operator; and TEA, as RCEA's scheduling coordinator.
- **Business Model Evaluation and Market Replication Assessment:** TRC Companies led the effort to evaluate the RCAM business model, assess the market potential for the business model, and develop a market replication plan. TRC Companies worked closely with the Schatz Center and RCEA to conduct these analyses.
- **Technology and Knowledge Transfer:** The Schatz Center developed and implemented a Technology/Knowledge Transfer Plan for the RCAM project, with strong support from other project partners.

Schedule and Milestones

This project was initially scoped with a four-year project duration. However, due to numerous complications, including the COVID-19 pandemic, the project schedule extended beyond six years. The RCAM microgrid has been fully functional since May 2022 and, allowing for one year of operation and monitoring, the project could have reasonably wrapped up by the end of 2023. However, equipment malfunction issues associated with the DC-coupled PV array extended the project schedule. Tesla and the Schatz Center attempted troubleshooting and repair strategies for an extended period. It was finally determined that the DC-DC converters that had been supplied by Alencon Systems, LLC were not capable of meeting their functional specification. Tesla identified Dynapower as a replacement vendor and new Dynapower DC-DC converters were installed and became fully functional in January 2025. For this report, performance data collected from April 2022 through August 2025 are assessed and reported.

Table 3 provides a list of key project milestones, along with the dates the milestones were reached. Note that, from approximately March 2020 through March 2021, there were significant delays in the progress of the project due to the COVID-19 pandemic.

Table 3: Project Milestone Schedule

Date	Project Milestone
August - November 2017	Proposal with 30 percent design submitted November 7, 2017
November 2017 - June 2018	California Environmental Quality Act (CEQA) work
August 8, 2018 – August 10, 2018	Project start, CEC contract began, project kick-off meeting
August 2018 - March 2019	Contracting
March 12, 2019	PG&E interconnection application submitted
June 28, 2019	50% plans and specifications completed
July 29, 2019	PG&E System Impact Study results available
September 3, 2019	90 percent plans and specifications completed
November 22, 2019	PG&E Facilities Study results available
February 21, 2020	Small Generator Interconnection Agreement executed between RCEA and PG&E
April 30, 2020	100% plans and specifications completed
April 30, 2020	Draft building permit issued
February 4, 2021 – February 24, 2021	Final National Environmental Policy Act (NEPA) Environmental Assessment submitted to Federal Aviation Administration (FAA) and Finding of No Significant Impact posted
March 10, 2021	Final building permit received
April 9, 2021	Construction start date

Date	Project Milestone
December 21, 2021	Commercial operation date in CAISO market
March 11, 2022	Completed islanded function testing
May 26, 2022	Permission to island granted by PG&E
December 21, 2021 - December 2023	System operation and monitoring, troubleshooting for DC-coupled PV array (ground fault issues)
December 2023	Decision to remove the Alencon DC-DC converters and retrofit the system with Dynapower DC-DC converters
January 2024 - January 2025	System operation and monitoring; design, procurement, permitting and installation of Dynapower DC-DC converters
January 2025	Dynapower DC-DC converters operational
June 2025	Full functionality for Dynapower DC-DC converters coupled with solar PV system

Source: Schatz Energy Research Center

CHAPTER 3: Microgrid Deployment

This chapter summarizes the process for deploying the RCAM project.

For those seeking more detailed information, key resources are listed in Table 4. Additional key resources are included in the appendices to this report and the list of project deliverables available from the CEC.

Table 4: Key Information Resources

Name	Description	Where to find it
Community Microgrid Enablement Tariff (CMET) (Pacific Gas and Electric Company 2023a)	PG&E's experimental tariff that governs the eligibility, engineering studies, development, and island and transitional operation of community microgrids.	PG&E's tariff webpage, Electric Schedule E-CMET. See link in References section.
Microgrid Operating Agreement (MOA)	Specified in CMET tariff; governs the development, testing, and commercial operations of the community microgrid. Extensive Appendices include the MIS. See Appendix A for table of contents.	The RCAM MOA serves as an example and is available on request from the CEC.
Microgrid Islanding Study (MIS)	Specified in CMET tariff. A study conducted by PG&E to ensure the operational safety and stability of the community microgrid during islanded operations. See Appendix B for table of contents.	The RCAM MIS serves as an example and is available on request from the CEC.
EPIC 3.11 Redwood Coast Airport Microgrid (RCAM) Final Report (Pacific Gas and Electric Company 2024)	Final PG&E report for *EPIC Project 3.11 – Location-Specific Options for Reliability and/or Resilience Upgrades*	See link in References section.
Community Microgrid Technical Best Practices Guide (Pacific Gas and Electric Company 2023b)	Initial version was drafted by the Schatz Center. Covers key technical concepts and approved means and methods for deploying multi-customer community microgrids on PG&E's electric distribution grid.	PG&E's Community Microgrid Technical Best Practices Guide. See link in References section.

Source: Schatz Energy Research Center

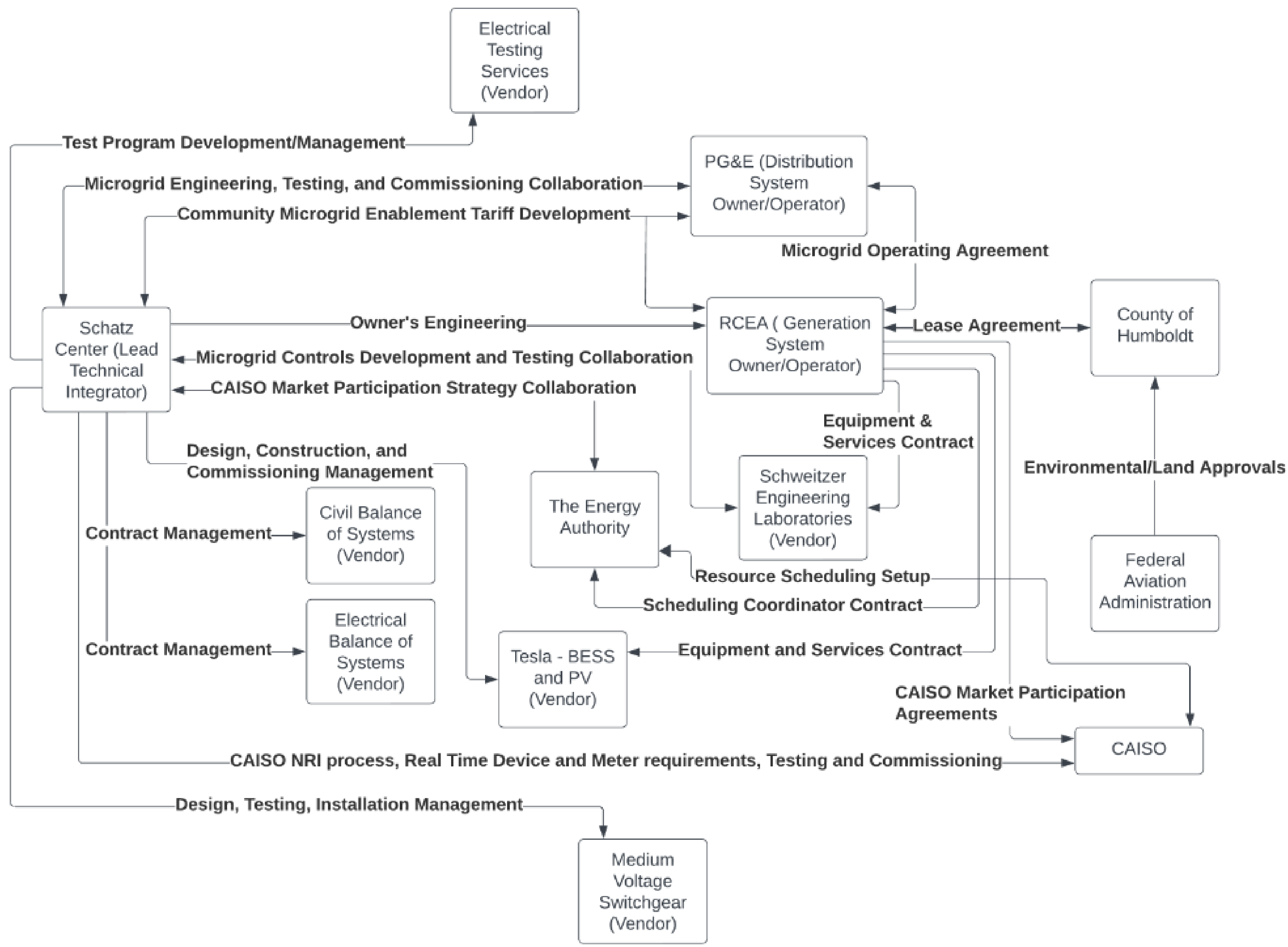
Technical Integration Framework

Deploying RCAM involved integrating a variety of technological systems and design concepts that were provided by a broad range of partners and stakeholders. For the project to meet the intent of the proposal and operate safely and reliably, careful coordination was needed, from the initial contracting phase through to achieving full permission to operate. One of the key roles that the Schatz Center filled was serving as the lead technical integrator.

Some of the most consequential technical integration work happens at the beginning of a project, when contracts are being negotiated between all parties. As the lead technical integrator, the Schatz Center brought a comprehensive understanding of what was needed to deploy the microgrid according to the budget and the schedule and of how to go about procuring the required equipment and services within the constraints of the governing procurement processes. The Schatz Center supported RCEA's legal team with the development of Requests for Quotes and Proposals, the review and selection of vendors, and the execution of contracts. Establishing the contractual framework for the RCAM project took approximately one year, and careful attention to detail by the Schatz Center and RCEA proved to be well worth the effort.

Figure 2 shows the technical integration framework for the project, outlining the roles and responsibilities for the project partners and stakeholders, as well as the relationships between them.

Figure 2: RCAM Technical Integration Framework

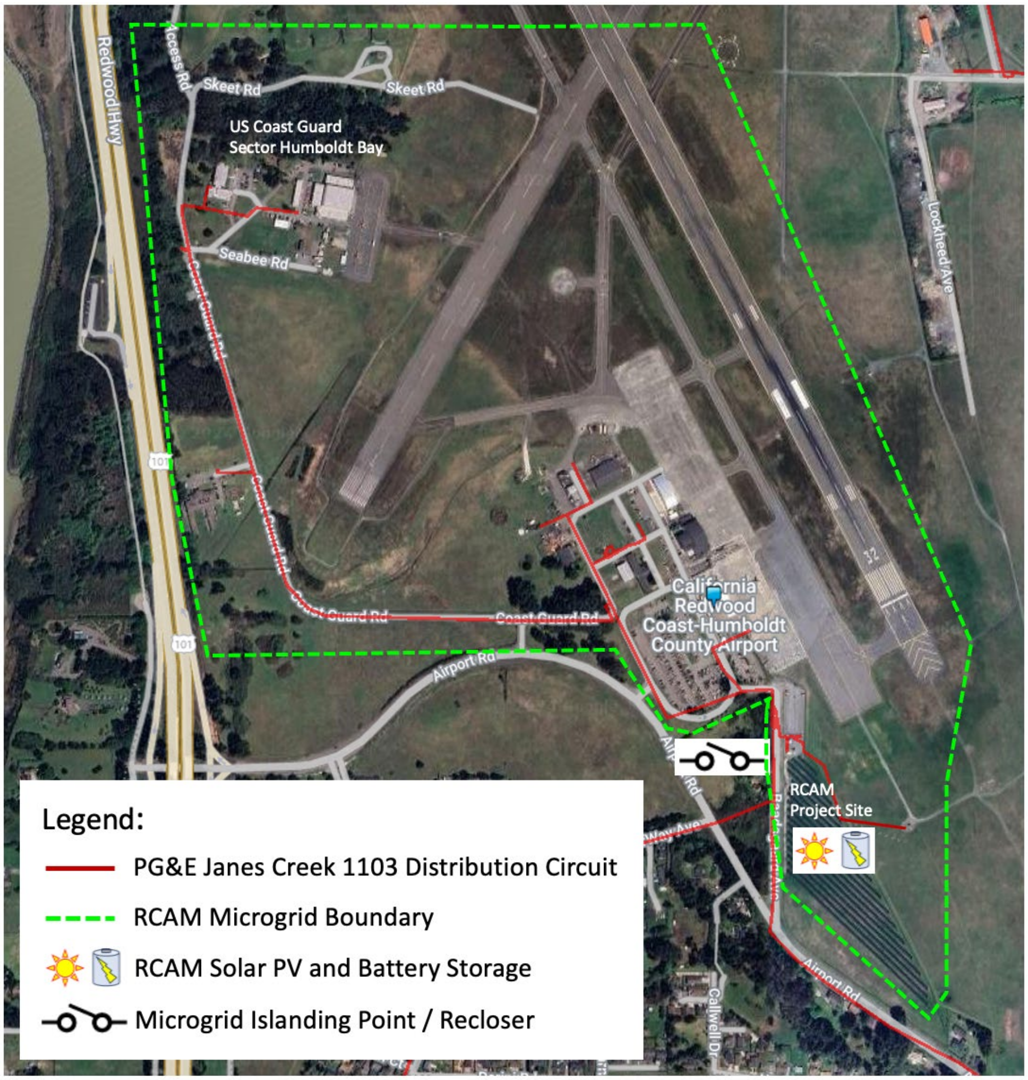


Source: Schatz Energy Research Center

Engineering Design

The Redwood Coast Airport Renewable Energy Microgrid is an end-of-line, FTM, multi-customer community microgrid. The electrical boundary encompasses 19 customers at the end of the Janes Creek 1103 distribution circuit in McKinleyville California, including the regional commercial airport[2] and the U.S. Coast Guard Sector/Air Station Humboldt Bay. Figure 3 shows a map of the microgrid boundary, the location of the project site, and the section of the Janes Creek 1103 circuit that is served by the microgrid.

Figure 3: Map of RCAM Project



Source: Schatz Energy Research Center, adapted from PG&E ICA Map

At installation, the average load on the RCAM circuit was about 175 kilowatts (kW), with a peak load of approximately 330 kW. Figure 4 shows the load duration curve inside the microgrid.

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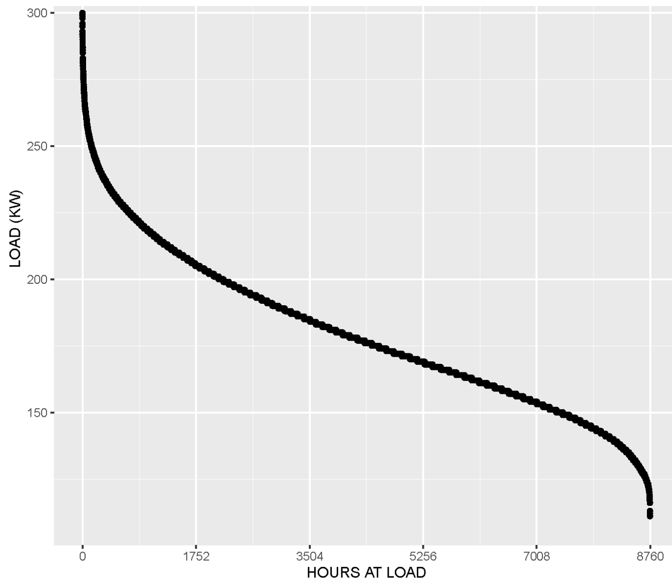
[2] California Redwood Coast-Humboldt County Airport

Figure 4: Load Duration Curve



Source: Schatz Energy Research Center

The generation resources inside the microgrid are as follows:

- Grid Forming
  - 2.2-megawatt (MW)DC ground mount PV array that is DC-coupled to a 2.3-MW_{AC}, 8.87-megawatt-hour (MWh) battery energy storage system (three Tesla Megapacks)
- Grid-following
  - 300-kW_{AC} ground mount PV array co-located with the DC-coupled array
  - Four 20-kW_{DC} bi-directional EV chargers
- Legacy Deep Backup
  - 175-kW non-paralleling diesel generator at the airport main terminal (existed pre-project)
  - 150-kW non-paralleling diesel generator at the U.S. Coast Guard Air Station (existed pre-project)

The grid-forming resource is sized to participate in the CAISO wholesale energy and frequency regulation markets. During the interconnection study process, PG&E determined that the circuit could support a 1.778-MW discharge rate from the BESS and a charge rate of -1.480 MW. As a result, during grid-connected operations, the real power output is limited to 1.75 MW export and -1.45 MW import. During islanded operation, the full output of 2.3 MW_{AC} is available.

The grid-following 300-kW_{AC} PV array is sized to provide energy for airport operations through an aggregated net metering arrangement. A new retail electric account was established and serves as the generation account, while three other airport facilities, including the main terminal, are included as aggregated accounts. The cost savings for these electric accounts serve as an annual lease payment to Humboldt County for the use of the airport property.

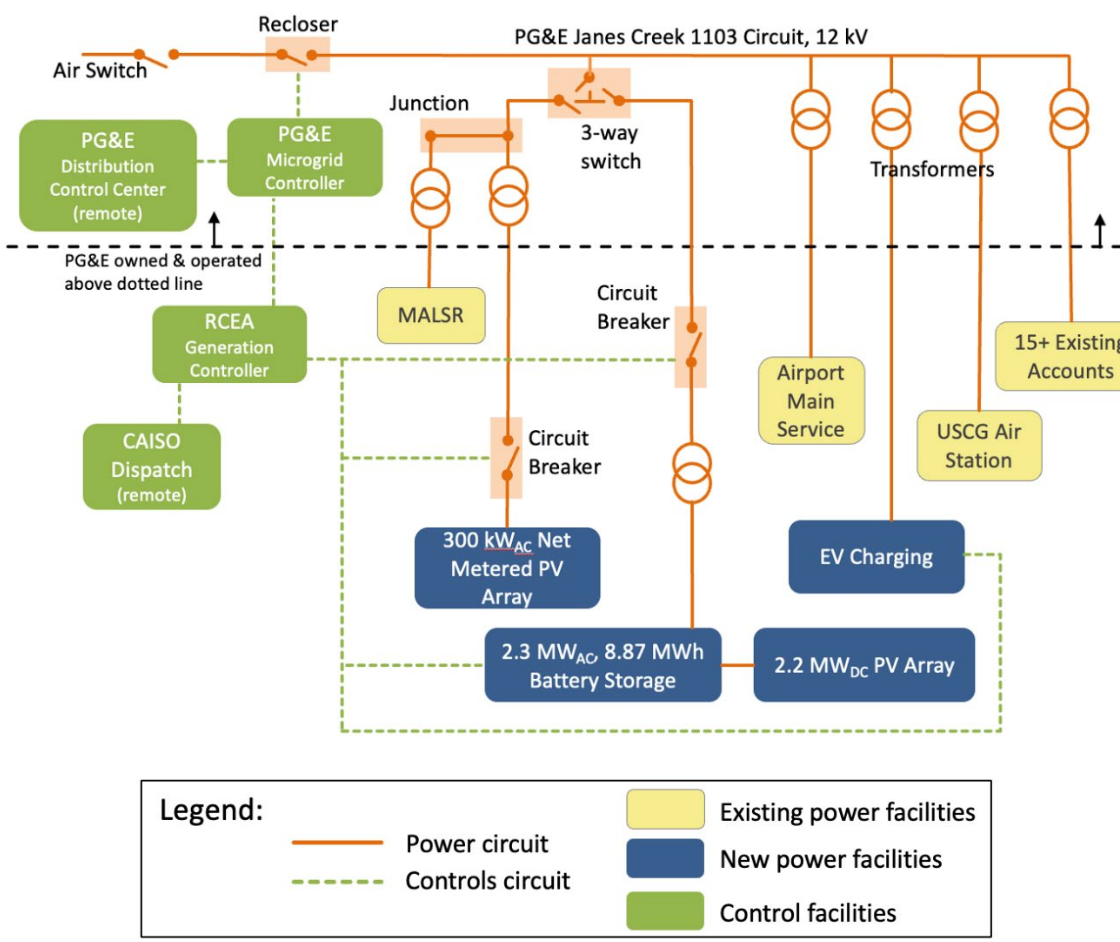
The four 20-kW_{DC} bi-directional EV chargers were a late addition and were a result of a PG&E vehicle-to-grid pilot project. Originally, the project scope included four conventional Level 2 chargers,[3] which are still planned, but installation of the Level 2 chargers has been delayed beyond the completion of the project.

The four bi-directional chargers will provide bill savings through peak shaving and energy arbitrage under grid-connected conditions when cars are connected. When the microgrid is islanded, these bi-directional chargers will be controlled to help balance the load and the distributed generation on the islanded circuit.

The legacy deep backup generators use conventional automatic transfer switches and act as a third-tier backup if the PG&E grid source and the microgrid generation source are both unavailable.

Figure 5 provides a simplified, single-line schematic of the RCAM system showing the section of the Janes Creek 1103 circuit, the generation and storage resources, the microgrid controls and switching components, and the retail customers on the circuit.

Figure 5: RCAM Simplified Electrical Single-line Diagram



Source: Schatz Energy Research Center

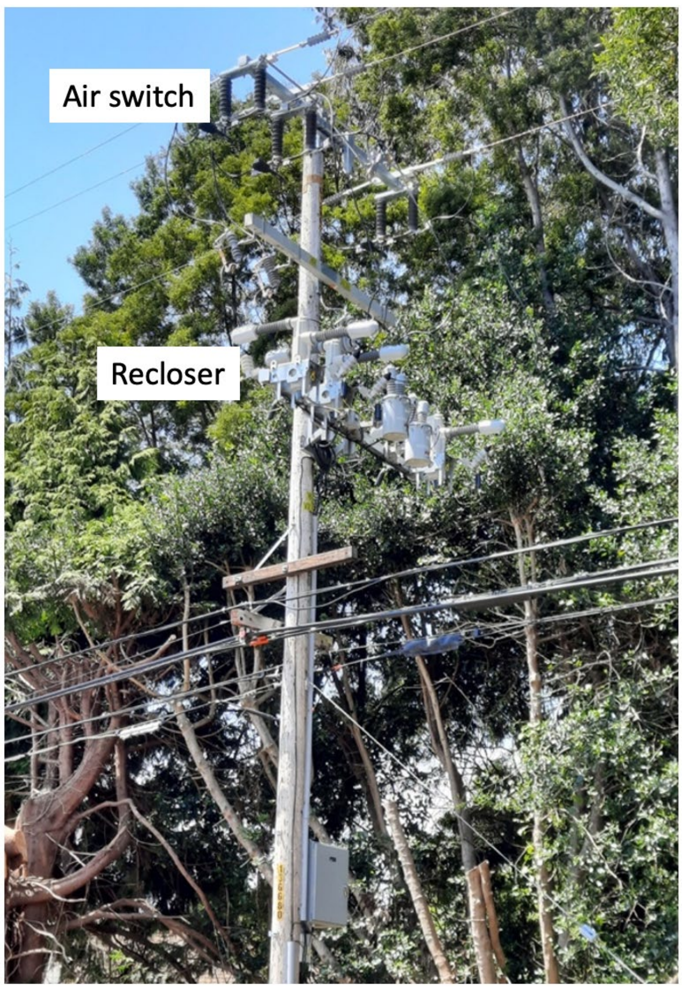
3 Level 2 chargers are EV chargers that charge at a rate of up to 19.2 kW.

Electrical

This section describes the RCAM electrical circuit configuration, including electrical protection and controls equipment associated with the microgrid islanding point recloser and the generation circuit breaker.[4] Refer to Appendix C for a more detailed technical summary, and to the MIS for very detailed information, including construction as-built drawings and protection description of operations.

The electrical boundary of RCAM is delineated by a pole-mounted line recloser (G&W Viper-ST) that is automatically controlled by a SEL-651R recloser control relay. A manually operated air switch is included at the top of the pole for bypass operations, such as prior to commissioning. This is shown schematically in both Figure 3 and Figure 5; Figure 6 shows a picture of the pole, recloser, and air switch. This configuration represents a standard recloser assembly for PG&E.

Figure 6: Microgrid Islanding Point Recloser and Air Switch



Source: Schatz Energy Research Center

4 A recloser is an automatic, high-voltage electric switch that can shut off power when trouble occurs and can be automatically reset when it is safe to do so. Reclosers are used throughout the electric power distribution system.

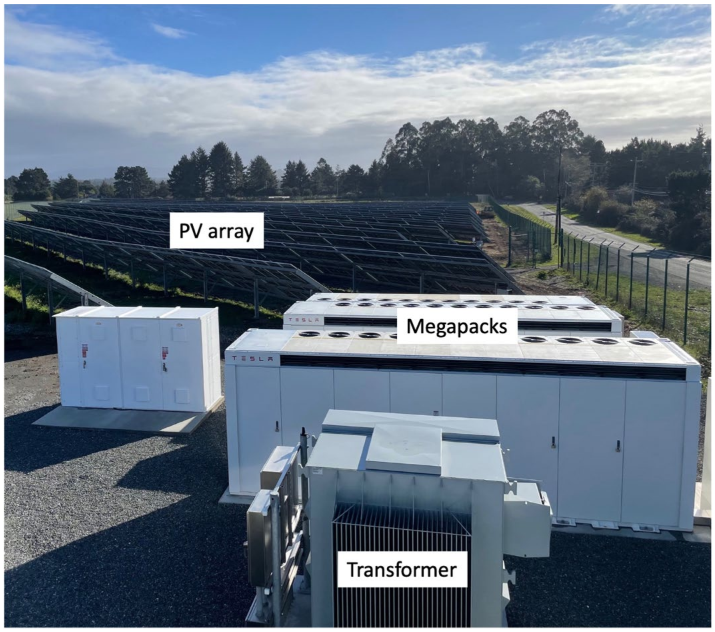
Other modifications to the Janes Creek 1103 circuit included a new primary underground service drop to interconnect the RCAM project. This included a subsurface three-way switch feeding the main microgrid switchgear, and a four-point junction. The four-point junction provides connections for a 300-kilovolt-amp (kVA) PG&E transformer for the 300-kW_{AC} BTM PV array, and a new feeder for the airport's Medium Intensity Approach Lighting System with Runway Alignment Indicator Lights (MALSR). The MALSR was previously fed from a point outside the microgrid boundary without a backup power source and its service was rearranged through this four-point junction to provide it with backup power service from the microgrid (see Figure 5).

The three-phase, three-wire main microgrid switchgear (Figure 7) houses the generation circuit breaker and is rated for 1,200 amps and 15 kilovolts (kV); it is fed by PG&E's subsurface three-way switch. On the load side of the main microgrid switchgear is an S&C PMH-3 Medium Voltage Alternating Current (AC) Disconnect and a 2.5-megavolt-amp (MVA), 12.0-kV Delta to 480-volt (V) Wye transformer. The battery storage system consists of three 786.5-kVA, four-hour Tesla Megapacks that are connected to the 480-V side of the transformer (Figure 8). The simplified electrical diagram in Figure 5 shows most, but not all, of these components.

Figure 7: Microgrid Main Switchgear

Source: Schatz Energy Research Center

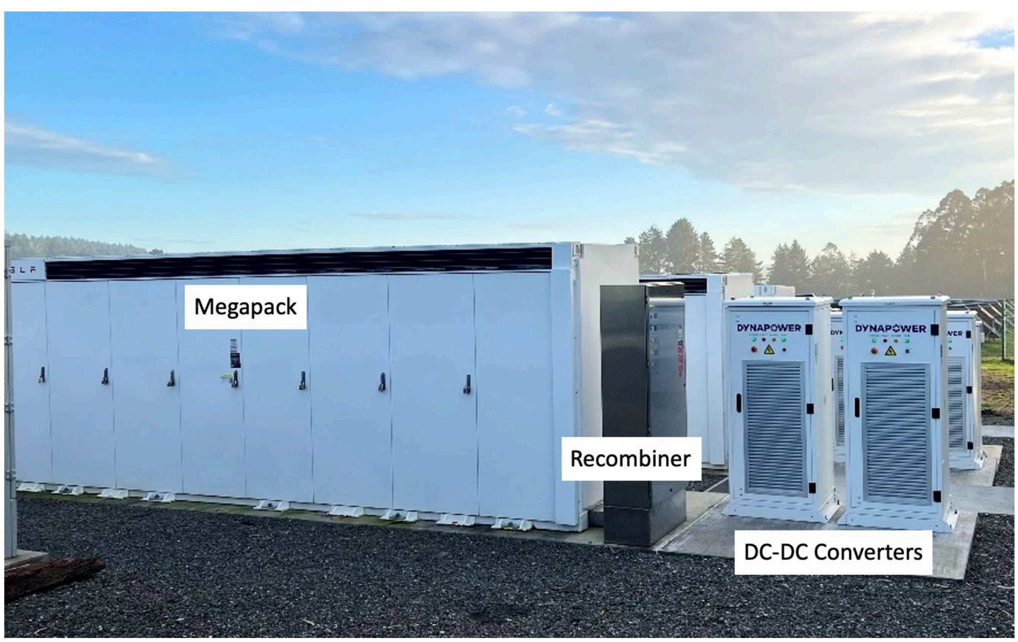
Figure 8: Tesla Megapacks and Transformer



Source: Schatz Energy Research Center

The DC bus of each Megapack is connected to approximately 730 kW of solar PV generation through a custom recombiner enclosure that contains DC metering and a ground fault protection relay that can disconnect the solar PV system via a set of contactors. Power flow from the PV array was originally regulated by 51 DC-DC converters (Alencon SPOTS, 17 per Megapack). However, these units had persistent internal ground faults that ultimately could not be remedied by the manufacturer. As a result, in late 2024 Tesla replaced the 51 Alencon SPOTS with six Dynapower DPS-500 DC-DC converters (see Figure 9).

Figure 9: Tesla Megapacks, Recombiners, and Dynapower DC-DC Converters



Source: Schatz Energy Research Center

The 300-kW_{AC} solar PV array is conventional and grid-following, with five 60-kW Chint Power System inverters feeding low-voltage switchgear that is interconnected through a 300-kVA PG&E transformer. The switchgear houses a SCADA-controlled circuit breaker that can be used to automatically disconnect the 300-kW PV array, if necessary, during islanded operation.[5]

An aerial view of the RCAM solar PV array is shown in Figure 10. The PV array includes both the FTM and the BTM PV systems. The battery storage and the main switchyard can be seen at the top right corner of the PV array, and the southeast runway approach for Runway 32 at the California Redwood Coast-Humboldt County Airport is visible at the top of the photo.

Figure 10: Aerial View of RCAM Solar PV Array

Source: Schatz Energy Research Center

For personnel safety, a grounding grid is installed in the vicinity of the Megapacks, 2.5-MVA transformer, and main microgrid switchgear. The fencing around the switchyard is also grounded.

System protection is provided with the SEL-651R recloser control relay at the microgrid islanding point and two SEL-700G relays located in the main microgrid switchgear that control the generation circuit breaker. PG&E can enable and disable the microgrid from its control interfaces.

Civil

Civil engineering began by commissioning a land survey and a geotechnical report for the project site. A horizontal control plan was prepared using the land survey to geolocate the BESS, 2.5-MVA transformer, PMH-3 AC Disconnect, main microgrid switchgear, three-way

[5] SCADA stands for Supervisory Control and Data Acquisition.

switch vault, AT&T fiber optic service vault, four-point junction, 300-kVA transformer, low-voltage switchgear, concrete pads, fencing, solar arrays, and other equipment.[6] The geotechnical report provided the necessary data for concrete slab design, solar array racking H-pile depths, compaction testing requirements, and soil resistivity for electrical grounding system design.

The horizontal control plan and a detailed project description were used by the environmental permitting team to characterize the limits of disturbance and to analyze environmental impacts. A stormwater pollution prevention plan was prepared, and site preparation activities were planned in accordance with the prevention plan and the mitigation monitoring plan (see the permitting section below).

Since the RCAM project site was located at an airport, the Federal Aviation Administration (FAA) had specific requirements that had to be met. No infrastructure could be built in the Runway Protection Zone or on the airfield side of the Building Restriction Line, so the land survey and horizontal control had to account for these jurisdictional boundaries. Fencing bordering the Air Operations Area had to meet specific FAA standards, which were incorporated into the civil design plans and specifications. The height of the top corners of all equipment installed above grade had to be shown on plan sheets and provided to the FAA so it could check for potential impacts to the airplane landing approach zone. A glare analysis had to be completed for the solar arrays to ensure that pilots would not be impacted on approach to the airport runway. A lifting plan for placing large components with overhead cranes had to be approved by the FAA so that it could evaluate potential impacts to air traffic. Compliance with these requirements was supported by Schatz Center civil engineers.

Controls

The microgrid controls development began with a preliminary Operational Responsibilities and Controls Framework document authored by the Schatz Center, which outlined the components and basic functionality of the microgrid control system and delineated the proposed operational responsibilities of PG&E and RCEA during grid-connected and islanded operations. This document was a starting place for building a consensus between partners that would ultimately become counterparties in the first MOA under the CMET.

After eight revisions of this initial document, the project team developed a preliminary consensus around the high-level operational roles and responsibilities and the electrical and controls architecture for the project. That consensus included three high-level guiding principles:

1. PG&E, as the distribution system owner/operator, has responsibility for the microgrid circuit, including determining which source is energizing it (BESS or substation). PG&E's intention is to allow the community microgrid to island and to provide service to the islanded customers via the RCEA-owned grid-forming generator any time there is a fault on the PG&E side of the islanding recloser, as long as it is safe to do so, and power quality conforms with Rule 2. In addition, PG&E will not unreasonably prevent

[6] A horizontal control plan is a dimensional control plan that establishes the positions of objects and points on a site.

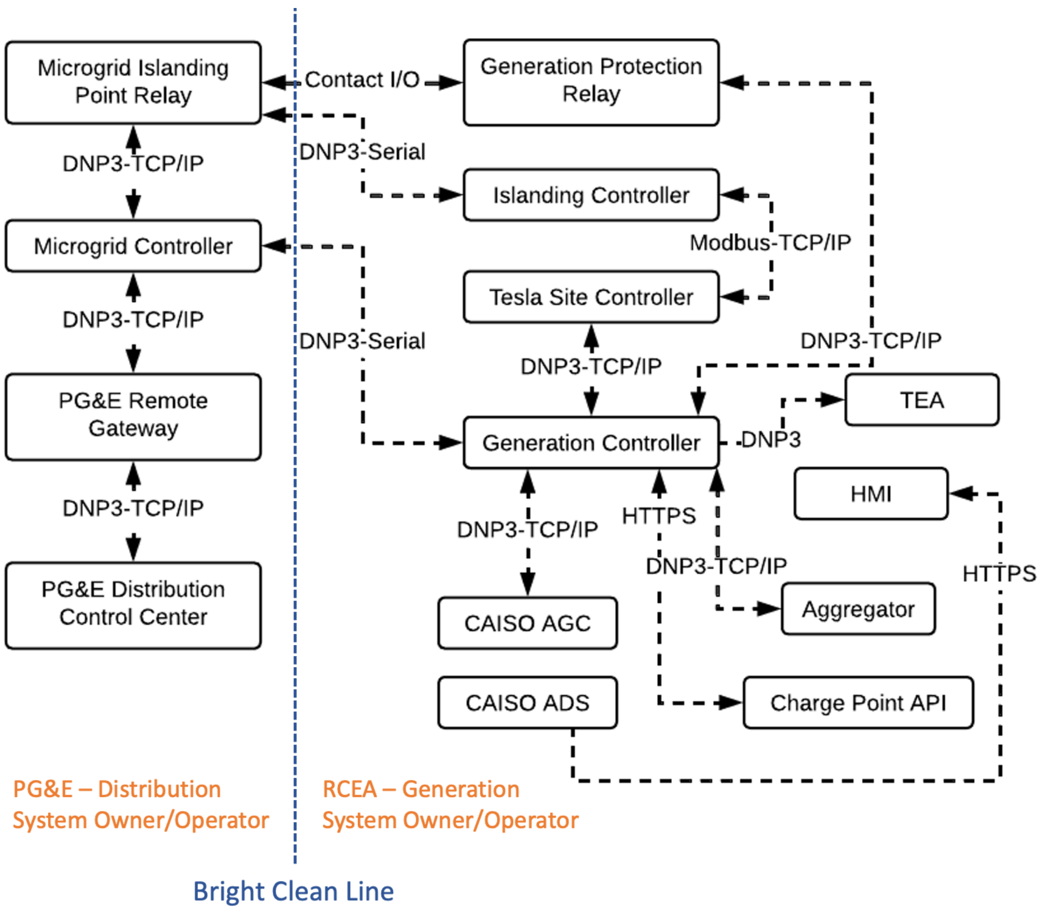
RCEA's wholesale generation resource from operating within the charge and discharge limits specified in their interconnection agreement.

2. RCEA, as the generation system owner/operator, has responsibility for the grid forming resource, rights to operate the resource within the charge and discharge limits established in the interconnection agreement, and will make reasonable efforts to maintain its readiness for microgrid duty.
3. A "bright clean line" would be established between RCEA and PG&E in terms of ownership of equipment, operations and maintenance responsibilities, cybersecurity, and legal responsibilities.

From a purely technical perspective, the overall microgrid control system would have been simpler if a single control system were used to cover all the necessary control functions. However, to support the principles above, the team decided that RCEA and PG&E each needed to have independent control systems that clearly delineated cybersecurity and operations and maintenance responsibilities.

Figure 11 shows the high-level controls diagram with a bright clean line delineating the RCEA and PG&E control systems. The main control devices for each organization are shown, along with the inter-device communication channels and protocols.

Figure 11: Simplified Microgrid Controls Diagram



Source: Schatz Energy Research Center

With a preliminary control architecture established that supported guiding principles, the controls engineering advanced to the next level of detailed development, which involved the Schatz Center drafting the CONOPS document. The initial version of the CONOPS was released in August 2019 and, after multiple iterations with PG&E and RCEA, the fifth and final revision was released to RCEA's controls vendor, SEL, later that year.

SEL engineers used the CONOPS to develop the FDS document, which contained the implementation details needed for configuring and programming the protection and control system. In parallel with this effort, the Schatz Center worked with PG&E's system protection, automation, telecommunications, and standards teams to develop fail-safe functionality, SCADA interface designs, cybersecurity architecture, and protection and control settings. The Schatz Center then worked with SEL engineers to incorporate the information from PG&E into the protection and controls designs. Where there was uncertainty about how operators wanted the system to function, configuration variables were built in to allow flexibility to adjust operational characteristics after commissioning.

The controls development process described above resulted in a microgrid control system that enables automated "blue sky" operations (normal operations, when there is no electrical grid outage) for CAISO market participation, as well as automatic seamless islanding when necessary for resilience purposes. To ensure safe operation, however, the automated system incorporated a monitoring system that can detect electrical faults, damaged equipment, and controller and communication system failures. If a failure or abnormal condition is detected, the system is placed in a fail-safe state that interrupts automated operation and alerts human operators.

The microgrid normally operates in automatic mode, though RCEA and PG&E both have manual control modes. PG&E's manual mode inhibits automatic transitions, so that any non-protection-related circuit breaker or line recloser actuations are blocked. RCEA's manual mode makes the BESS unavailable to CAISO (for dispatch) and PG&E (for islanding). As an additional safeguard, if any of the key controllers' source code or relay settings are changed, PG&E controls render the system non-operable, meaning that the controller output servers stop processing commands. Only PG&E can reauthorize the system to become operational after this safeguard is tripped, which ensures that PG&E consents to any settings changes on key controllers.

For PG&E to be able to effectively control the microgrid circuit, its microgrid controller can trip and lock out RCEA's generation circuit breaker in case of emergency. This functionality is analogous to direct transfer trip and is used as a fail-safe state for extreme cases, like if a car crashes into a pole inside the microgrid while the microgrid is not islanded. In that case, the SEL-651R at the microgrid islanding point would detect an internal fault, trip, and lock itself out while also sending a trip and lockout command directly to the SEL-700G via a contact I/O device (see Figure 11).[7]

At a high level, the automatic transfer scheme considers the PG&E Janes Creek substation as the normal voltage source for the microgrid and the BESS as the emergency voltage source.

[7] A contact I/O device is an input/output device that uses a physical contact, like a switch or a relay, to register an input signal or activate an output action.

The microgrid control system attempts to keep the loads energized from the normal source whenever possible. If the normal source is not available, the controls automatically transfer the loads to the emergency source and then monitor the normal source terminals at the microgrid islanding point. When the normal source returns and is deemed stable, the controls transfer the loads back to the normal source.

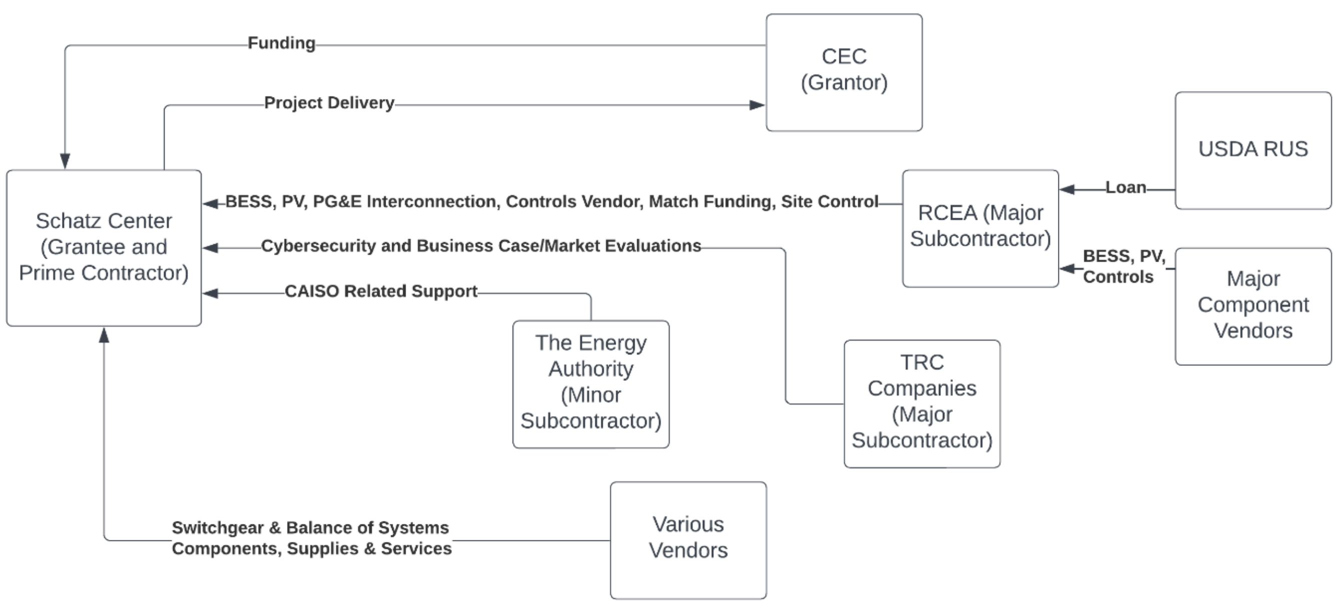
When the microgrid is islanded, the 2.3-MW_{AC} grid-forming generator matches the loads on the circuit by maintaining stable frequency and voltage. In addition, the 300-kW_{AC} grid-following PV array also serves as a source of generation for the islanded circuit, reducing the net load. In the event that there is an excess of generation, both the grid-following and the DC-coupled arrays are curtailed. In addition, the four bi-directional EV chargers are controlled to help balance the load and generation on the islanded circuit. If the BESS state of charge (SOC) is low, the microgrid controls shift the frequency down and the car/charger combos export energy onto the grid. If the BESS SOC is high, the microgrid controls shift the frequency up and cause the car/charger combinations to charge at the maximum rate before the 300-kW PV array curtails its output.

See Appendix C for more summary information on system control and protection, and the RCAM MIS for detailed information.

Procurement

Procuring equipment and services involved several contracts. The high-level contractual framework that governed procurement for the CEC-funded RCAM project is shown in Figure 12. In most cases, arrows show the flow of goods and/or services in one direction from the vendor/subcontractor to the customer, but it is important to clarify that funds are also flowing in the opposite direction as compensation to the respective vendors or subcontractors.

Figure 12: Procurement Contractual Framework



Source: Schatz Energy Research Center

As Figure 12 depicts, the Schatz Center was responsible for delivering the project to the CEC. To deliver a successful project, it was necessary to procure goods and services from numerous major and minor subcontractors and vendors. RCEA's subcontract included the major project components, and RCEA provided the majority of the funding for the project via a $6.6-million loan from the U.S. Department of Agriculture (USDA) Rural Utility Service (RUS). Engineers from the RCEA owner's engineer, the Schatz Center, collaborated with RCEA staff and legal counsel to negotiate a contract with Tesla to provide the 300-kW_{AC} BTM PV array, the 2.2-MWDC DC-coupled PV array, and the 2.3-MW_{AC} BESS. Through that contract, RCEA delivered major components to the project, and Schatz Center engineers helped manage the work and coordinate it with other contracted work on the site.

RCEA also provided the microgrid control system through a contract with SEL that was initiated by the Schatz Center through a detailed request for proposal that described the control system concept based on the CONOPS. With that contract in place, RCEA delivered the control system hardware and software for both its system and PG&E's system. The Schatz Center helped manage that contract and worked closely with SEL, PG&E, and RCEA to ensure that the control system met project needs. Ultimately, PG&E tested the controls at its Applied Testing Services facility using separate EPIC funds that were available to it for research and development. PG&E also paid for the hardware in the control system that was specifically required for islanding, using a Special Facilities Agreement and accessing funds authorized by the California Public Utilities Commission (CPUC) under the Community Microgrid Enablement Program.

Balance of systems components were procured directly by the Schatz Center and integrated as described in the Technical Integration Framework section above. One of the most complex components in the microgrid was the medium voltage switchgear that interconnects the BESS to the microgrid circuit and houses much of the protection and control equipment. This was procured directly by the Schatz Center. The Schatz Center also procured services from subcontractors TRC Companies and TEA that were necessary to successfully complete all project tasks.

Permitting

Permitting was complicated because the project site was at a commercial airport and the FAA had jurisdiction over project construction. The County of Humboldt owns and operates the California Redwood Coast-Humboldt County Airport and is considered the Airport Sponsor in the eyes of the FAA. This meant that the county was the lead agency for the CEQA process and the FAA was the lead agency for the National Environmental Policy Act (NEPA) process. The county hired Mead & Hunt, Inc. to complete both the CEQA and the NEPA processes for the project.

The county posted a Notice of Intent to Adopt a Mitigated Negative Declaration on March 28, 2018, with a 30-day review period. The Mitigation Monitoring Plan included mitigation measures for:

- Biological Resources — Vegetation removal in the PV array field needed to be completed outside of the raptor nesting season, which runs from March 15 through August 15 each year.

- Cultural Resources — The project site presented a slight risk that culturally significant artifacts could be present, so cultural monitoring was required for any construction work where soil greater than one foot below ground surface would be disturbed. A local Native American tribal representative was hired to provide monitoring services.
- Noise — One residence was in close proximity to the PV array, and driving the H-piles for the racking system would cause noise and vibration that could impact residents. To mitigate this, pile driving was restricted to normal working hours and vibration monitoring was required with a not-to-exceed threshold of 0.2 inches per second peak particle velocity.

The CEQA Notice of Determination was adopted on May 8, 2018.

The NEPA process built on the environmental analysis under CEQA and resulted in an environmental assessment. A draft environmental assessment was submitted to the FAA on March 4, 2019. In approximately March 2020, the COVID-19 pandemic hit, and this caused significant disruption across the project, particularly with the FAA's environmental assessment review timeline. In addition, the FAA had to approve a ground lease between the County of Humboldt and RCEA, which involved officially releasing 11.1 acres of airport land outside the airfield for non-aeronautical use. This lengthy process was not foreseen by the project team and was complicated by reduced FAA staff availability due to the pandemic. Final FAA approval was provided on March 2, 2021, leaving just 13 days to complete site preparation activities before the start of the raptor nesting season.

The Humboldt County Building Permit, with a General Construction Storm Water Permit, was issued on March 16, 2021, with the following project description: "Install new ground-mount 2.2 MW PV array, battery storage system and associated power, protection, collection, conversion, distribution, and medium voltage interconnection and communication equipment on parcel 511-071-005 and 10-foot surrounding fence."

The building permit was officially considered closed on December 22, 2021.

Interconnection and Operational Agreements

As noted previously, prior to the RCAM project and the development of the CMET, there was no clear regulatory pathway in California to interconnect an FTM community microgrid with a third-party-owned, grid-forming generator. The project team (RCEA, PG&E, and the Schatz Center) worked together to explore and develop possible pathways. This resulted in an approach where existing tariffs and procedures were utilized to interconnect the generation resources and enable their grid-following operation. For islanded operation, a new tariff and process was created; however, the payment and revenue mechanisms that exist under grid-following operation still apply when islanded.

Grid-connected operational functions were permitted under a Small Generator Interconnection Agreement (SGIA) approved by the Federal Energy Regulatory Commission, and islanded operational functions were permitted under a new process developed in parallel with the project, which resulted in the first CPUC-approved CMET tariff and associated Microgrid Operating Agreement. These agreements were all executed between PG&E, as the distribution system owner/operator, and RCEA as the generation owner/operator. These agreements and the supporting documentation are available as noted in Table 4.

Grid-following Functions

The SGIA process is a well-defined and mature process for interconnecting grid-following, FTM (specifically, wholesale) generation resources to the grid. PG&E's Electric Generation Interconnection group administers this process for projects in its service territory. Final technical details are needed before an application can be filed, and applicants must decide whether to pursue Full-Deliverability (a two-year process) or apply under the Energy Only pathway (a one-year process). The Schatz Center and RCEA chose the Energy Only pathway because the grant timeline would not allow for a two-year interconnection process. This choice meant that RCAM could not qualify to provide Resource Adequacy (RA) because that requires more detailed study under the Full-Deliverability process. RA can be a valuable revenue source. The project team was under the impression that, after coming online as an Energy-Only resource, the project could still be studied for full deliverability, which could potentially unlock RA revenue. That possibility has not materialized, and the process to obtain Full-Deliverability status is still unclear.

The SGIA application was submitted on March 12, 2019. PG&E studied the project and released the initial System Impact Study on July 29, 2019. The System Impact Study indicated that operation of the BESS at full capacity for charging or discharging would require grid upgrades costing more than the project budget could support. The Schatz Center and RCEA asked PG&E to revise the study and determine a lower BESS operating capacity that would avoid any substation upgrades or reconductoring on the Janes Creek 1103 circuit. PG&E obliged and released the subsequent Facility Study results on November 22, 2019. The Facility Study found that, if the project could operate between -1,480 kW charge and 1,778 kW discharge, then the grid upgrades were minimal and could be funded within the available project budget. The SGIA was fully executed on February 21, 2020. Additional SGIA milestones included Temporary Permission to Operate for Testing Only and Final Unconditional Permission to Operate, which were granted on September 24, 2021, and October 28, 2021, respectively.

Grid Forming Functions

The interconnection pathway for grid-forming functions did not exist prior to the RCAM project, and one of the key outcomes of the project was to develop a standardized process to allow a third party to energize an islanded section of PG&E's distribution grid. To facilitate this process, the Schatz Center supported PG&E and RCEA in developing the CMET and the associated MOA. Development of these agreements was enabled by a consensus-building process regarding operational roles and responsibilities. PG&E and RCEA each had their own legal counsel who collaborated with their respective engineers, and the engineers for both organizations were closely aligned on the technical requirements.

These agreements are also supported by a new technical approval process called the Microgrid Islanding Study (MIS). For RCAM, the MIS process consisted of much of the work described in the testing, commissioning, documentation, and training sections of this chapter, which ultimately culminated in the Permission to Island Confirmation Letter being signed on May 13, 2022. For subsequent community microgrid projects, PG&E has refined the MIS process.

CAISO New Resource Implementation

The RCAM community microgrid grid-forming generation is interconnected as a wholesale generator to the electrical distribution system. Generators connecting at the distribution level must register via the New Resource Implementation (NRI) Process to sell power into the CAISO wholesale energy market. The NRI process is divided into six "buckets," each of which contains a set of milestones that must be met to proceed to the next bucket. The deliverables required for each bucket are the same for each project and are available on the CAISO website. Required information includes key design documentation such as the interconnection agreement, stamped electrical drawings, generator interconnection technical data, network technical data, metering configuration, and telemetry, control, and protection information. The process culminates with trial operations and, finally, issuance of a signed Certificate of Compliance and declaration of a Commercial Operations Date. CAISO granted Commercial Operations Date approval for the RCAM project on December 21, 2021.

Renewable Energy Certificates

Renewable Energy Certificates, or RECs, are a measure of the amount of renewable energy generated. In California, RECs can be used by load serving entities (LSEs) to help meet their Renewable Portfolio Standard (RPS) requirements. The RPS sets a standard for what portion of renewable power is required when LSEs are serving their retail customer load. Currently in California, LSEs are required to procure at least 44 percent renewable power, with a target of 60 percent by 2030 and 100 percent by 2045. In addition, the majority of this power must be generated from facilities within California. This requirement provides added value to qualified renewable power resources, especially those located in-state.

To secure RECs, generating facilities must become RPS-certified according to CEC standards. In addition, LSEs are required to use WREGIS to track and report their RPS procurement as part of California's RPS compliance.

While the RPS program and the tracking of RECs are well established, securing RECs for the RCAM project was unique due to the hybrid nature of the RCAM wholesale generator, which comprised a solar PV system coupled with a battery storage system, with the solar PV and battery components connected on the DC bus. This configuration was unprecedented for the teams at the CEC and WREGIS. Consequently, the Schatz Center collaborated with the CEC and WREGIS teams to establish an acceptable system for metering and reporting the RCAM RECs. The agreement reached sets a precedent for future DC-coupled hybrid resources.

The key issue was that there was only one AC meter for the DC-coupled system. Both the CEC and WREGIS had dealt with hybrid systems before, but only those that were coupled on the AC side. AC-coupled systems have an AC meter for each component (the PV array and the BESS), making it easy to determine how much power is generated by the renewable resource. However, with a DC-coupled system like RCAM, there is only one AC meter, and hence no way to determine where the power is coming from on the DC side. The key issue is that the battery system can be charged from the grid, as well as from the DC-coupled PV resource. If the battery is charged from the grid and then discharged back into the grid, the power fed back into the grid cannot be counted as renewable.

The simple solution is that the **net output** from the hybrid PV plus battery system has to come from the PV system, because there is no other generation source in the system. Any time grid power is used to charge the BESS and then is discharged back into the grid, there are always efficiency losses associated with the BESS. This results in a net import of power, not a net export. Consequently, over any given time period, any net output from the system is attributable to the PV system.

Therefore, the single certified AC meter for the DC-coupled solar PV plus BESS resource was adequate for tracking RECs from RCAM, and the net export was considered to be from the renewable resource.

Cybersecurity

One key design feature that simplified cybersecurity was the physical disconnection between the PG&E and RCEA controllers with respect to routable connections (see Figure 11). Routable connections can allow devices on different networks to communicate with each other, including accessing the public Internet. In contrast, a non-routable connection means it cannot be accessed directly from the public Internet. The non-routable connections included DNP3 serial[8] and contact I/O devices. This largely eliminated the possibility of RCEA's control system being an entry point for cyber-sabotage to PG&E's system.

PG&E handled cybersecurity for its microgrid network using its own in-house expertise, and it participated in a cybersecurity working group with RCEA, the Schatz Center, and cybersecurity subcontractor TRC. TRC was responsible for conducting a cybersecurity design review and developing a non-confidential cybersecurity plan. For the cybersecurity design review, the Schatz Center provided the network diagram, the CONOPS, and a control device interface, and PG&E provided a data flow diagram for its system. TRC analyzed the information, participated in working group meetings, and prepared the Redwood Coast Airport Microgrid Network Cybersecurity Assessment.

The network cybersecurity assessment was provided to SEL, which attended several cybersecurity working group meetings to understand the project cybersecurity requirements and make recommendations. The cybersecurity working group continued to meet periodically throughout the design development process, and TRC continued to provide input on design documents, including the FDS.

TRC also prepared a Non-Confidential Cybersecurity Plan (see Appendix D for the table of contents). This non-confidential document provides generic information and a framework for the cybersecurity operational requirements of RCAM.

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8 Distributed Network Protocol 3 is a set of communication protocols used between components in a process automation system. "Serial" means that data are sent sequentially, one bit at a time, from one device to the other.

Since RCAM is a model for community microgrids developed under the Community Microgrid Enablement Tariff, this Non-Confidential Cybersecurity Plan can be used as a starting point for other community microgrid projects.

Construction

After the FAA granted final approval of the land lease, construction began with site preparation activities on March 3, 2021. To be compliant with biological mitigation measures related to the raptor nesting season, these activities needed to be completed before March 15, 2021. Site preparation activities included installation of a fence to delineate the lease hold area from the Air Operations Area, vegetation removal, light grading, and application of ground woody biomass for erosion control.

After site preparation was completed, construction continued with the installation of the underground service infrastructure for PG&E and AT&T. This work was performed by balance of systems electrical and civil contractors, Blue Lake Rancheria, and Pacific Earthscape, according to PG&E plans and the horizontal control plan prepared by the Schatz Center. Self-performing this work to PG&E's specifications provided more control over costs and schedule compared to having PG&E handle the work itelf. Figure 13 shows the process of installing the underground service equipment for PG&E and AT&T.

Figure 13: Installation of PG&E and AT&T Underground Service Equipment

Source: Schatz Energy Research Center

Tesla's contractor, McKeever Energy and Electric, began work on the BESS and PV system installation in May 2021 by installing the H-piles for the PV racking and installing conduit for the battery system, followed by installation of the batteries and transformer (Figure 14). With the H-piles in place, Sunstall Inc. installed the racking and PV modules.

Figure 14: Installation of Transformer and Electrical Conduit

Source: Schatz Energy Research Center

This work involved close field coordination between four teams of contractors and cultural monitors from the Wiyot Tribe throughout the construction period. Local tribes were consulted during the environmental review process and, due to the slight possibility of the presence of significant remnants of cultural activity at the project site, the Wiyot Tribe was hired to provide cultural monitors to observe all ground disturbing activities.

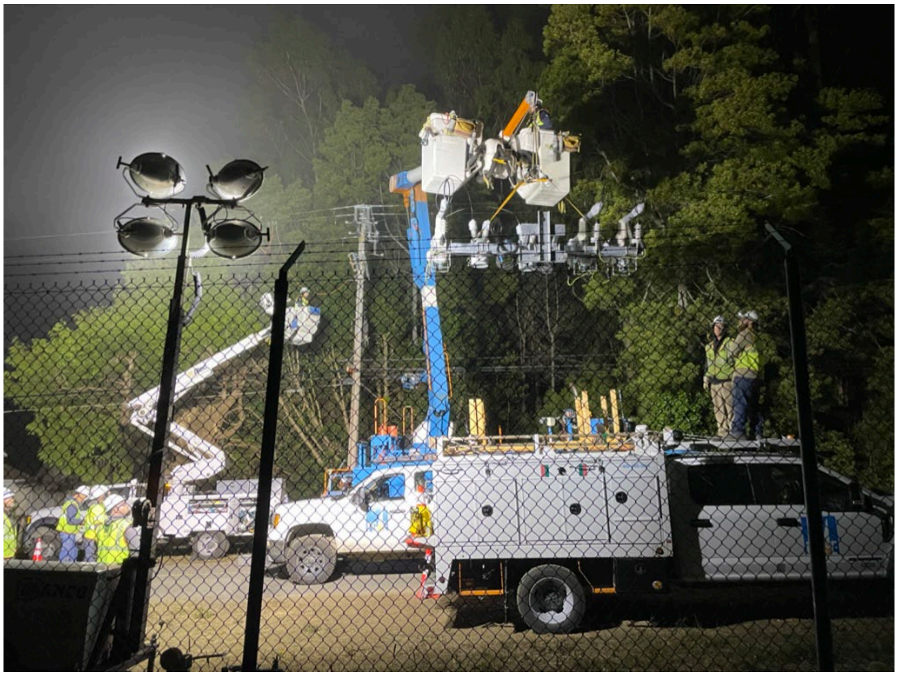
The balance of systems electrical and civil contractors coordinated to install the medium voltage switchgear (Figure 15) and S&C PMH-3 Utility Disconnect.

Figure 15: Installation of the Medium Voltage Switchgear

Source: Schatz Energy Research Center

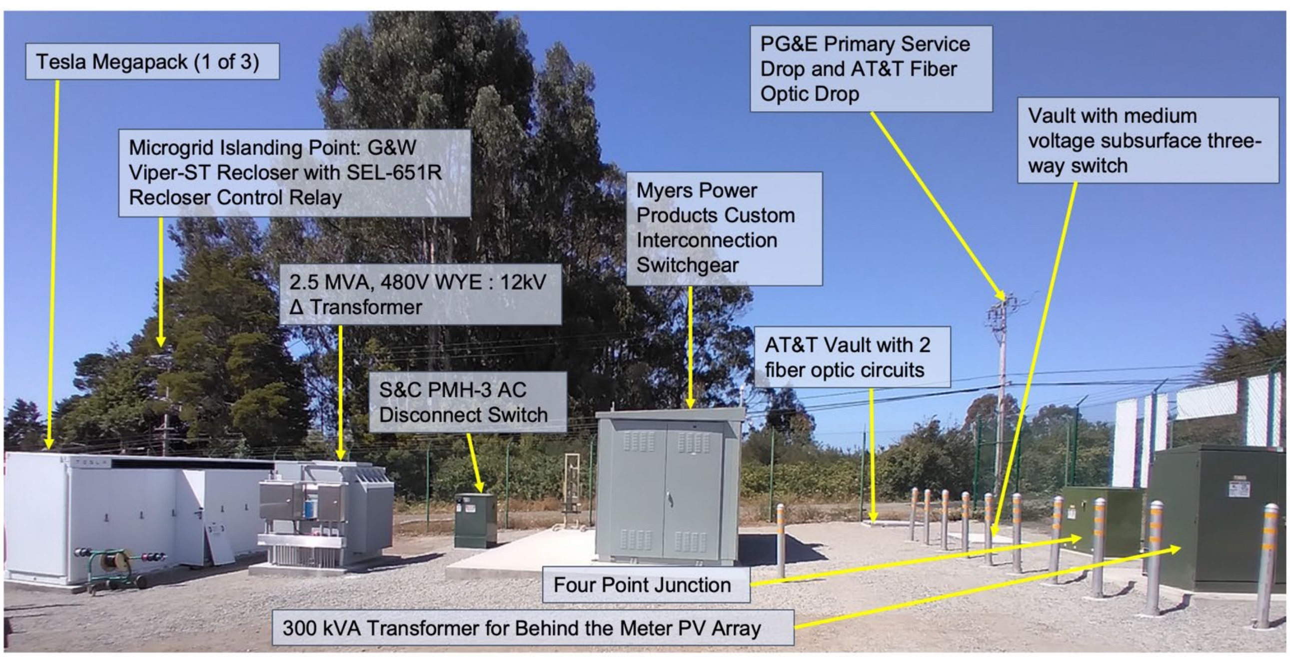
PG&E installed the microgrid islanding point in July 2021, including a G&W Viper-ST recloser with a SEL-651R recloser control relay and an air switch for bypass operations (Figure 16). After installation, the microgrid islanding point was left in bypass mode until the control system was ready for commissioning. The microgrid switchyard was substantially complete in August 2024 (Figure 17).

Figure 16: Microgrid Islanding Point Installation



Source: Schatz Energy Research Center

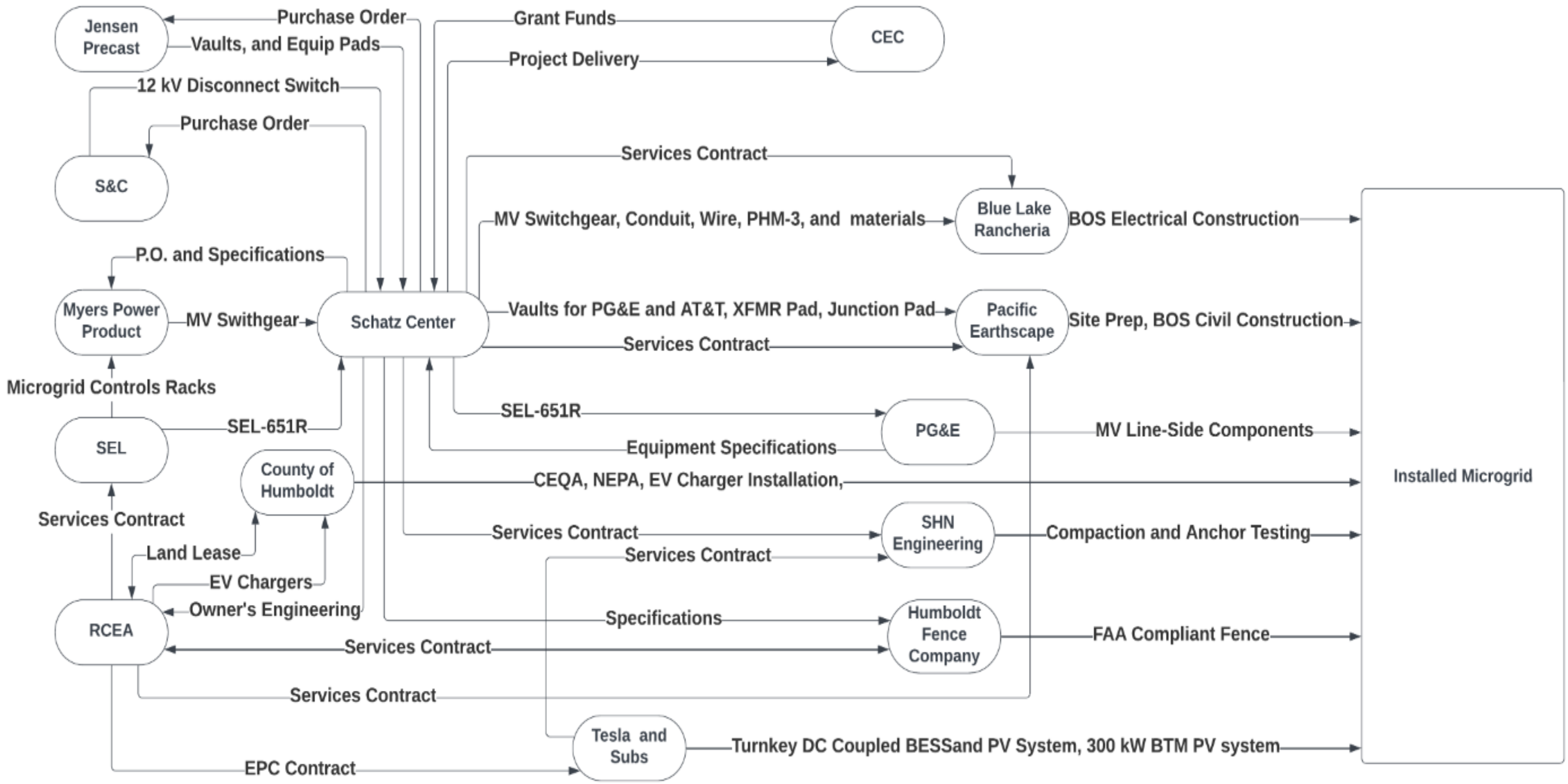
Figure 17: Completed Microgrid Switchyard



Source: Schatz Energy Research Center

The overall construction activity framework is shown in Figure 18. The figure shows which party was responsible for what, with all tasks ultimately leading to successful microgrid installation. As the RCEA owner's engineer and the project's lead technical integrator, the Schatz Center oversaw all project construction, coordinated work between contractors, responded to Requests for Information, and generally ensured that work was completed according to agreed-upon specifications. Tesla achieved Mechanical Completion on September 20, 2021, and Substantial Completion on September 28, 2021. Tesla, RCEA, and the Schatz Center agreed on a punch list of 15 items that needed to be completed before Final Completion was achieved. The main punch list item was the Alencon Return Materials Authorization process to fix the persistent failures of the SPOT DC-DC converters. Ultimately the Alencon Return Materials Authorization process failed to resolve the ground fault. Alencon attempted multiple fixes but was not successful. Consequently, in December 2023 Tesla agreed to use Dynapower DPS-500 DC-DC converters as replacements. Installation of the Dynapower DC-DC converters was completed in January of 2025, and the units are now fully operational and performing as expected.

Figure 18: Overall Construction Activity Framework



Source: Schatz Energy Research Center

Testing

The testing that was completed can be categorized as either lab testing of protection and control software, or field testing prior to energization.

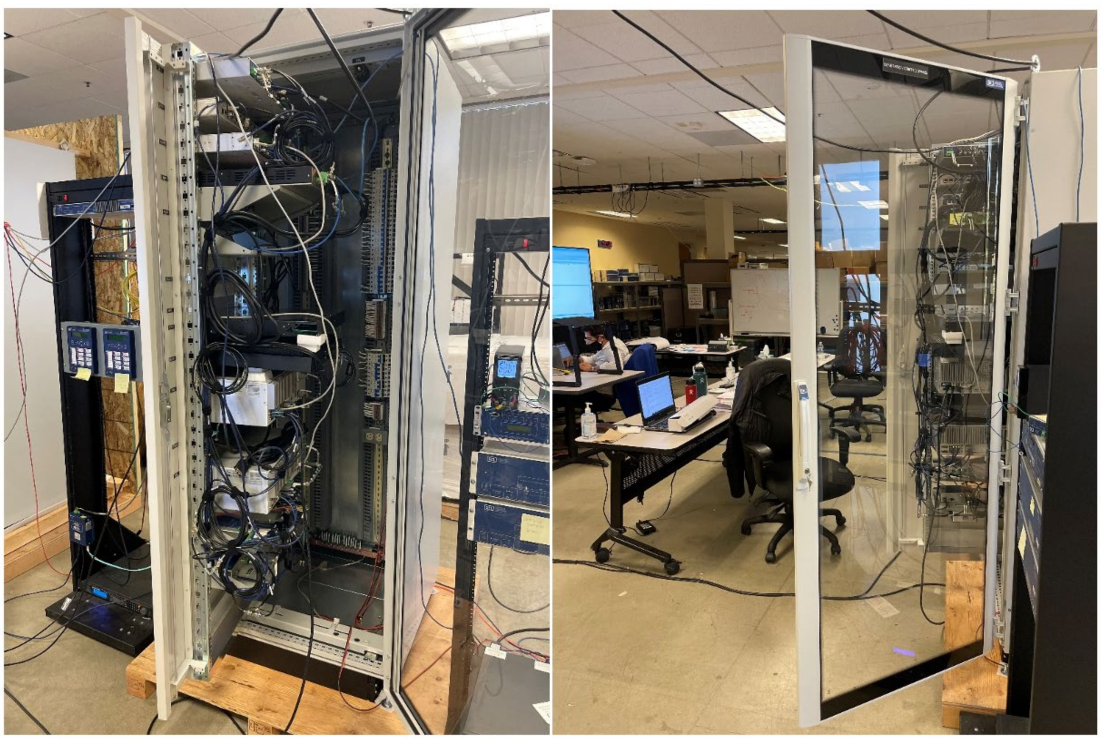
Laboratory Testing

Laboratory testing included: 1) Factory Acceptance Testing of the microgrid controls at SEL's Irvine, CA offices, 2) witness testing of the Alencon SPOT DC-DC converters at Tesla's Palo Alto, CA facility, and 3) Power-Hardware-in-the-Loop (PHIL) testing at PG&E's Applied Technology Services (ATS) facility in San Ramon, CA. The COVID-19 Pandemic significantly delayed in-person laboratory testing activities.

Factory Acceptance Testing of Microgrid Controls

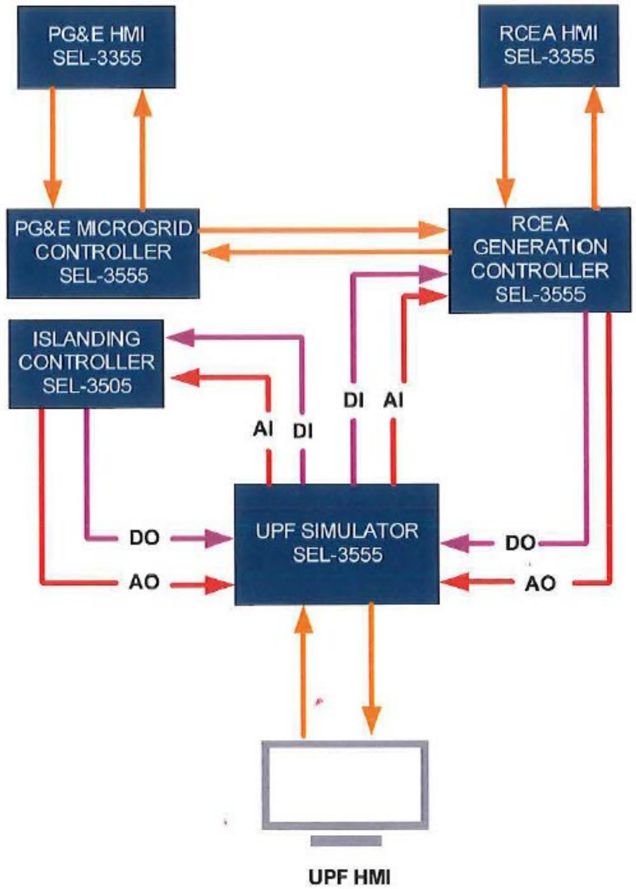
Factory Acceptance Testing (FAT) of the control system occurred in April 2021 (Figure 19). The FAT test setup included most of the controllers in the Microgrid Control System (Figure 20).

Figure 19: Factory Acceptance Testing



Source: Schatz Energy Research Center

Figure 20: SEL Factory Acceptance Test Data Flow Diagram



Source: Schatz Energy Research Center

Certain functionality and communication interfaces could not be tested during FAT due to limitations of the Universal Power Flow Simulator and because the BESS controller and protection relays were not in the control loop. There is a significant amount of control logic implemented in the primary SEL-700G relay at the generation breaker and the SEL-651R at the microgrid islanding point, and that logic was simulated in the Universal Power Flow Simulator, as were CAISO dispatch and voltage and frequency droop functions. As a result, more testing than anticipated was required during PHIL testing.

Witness Testing of the Alencon SPOT DC/DC Converters

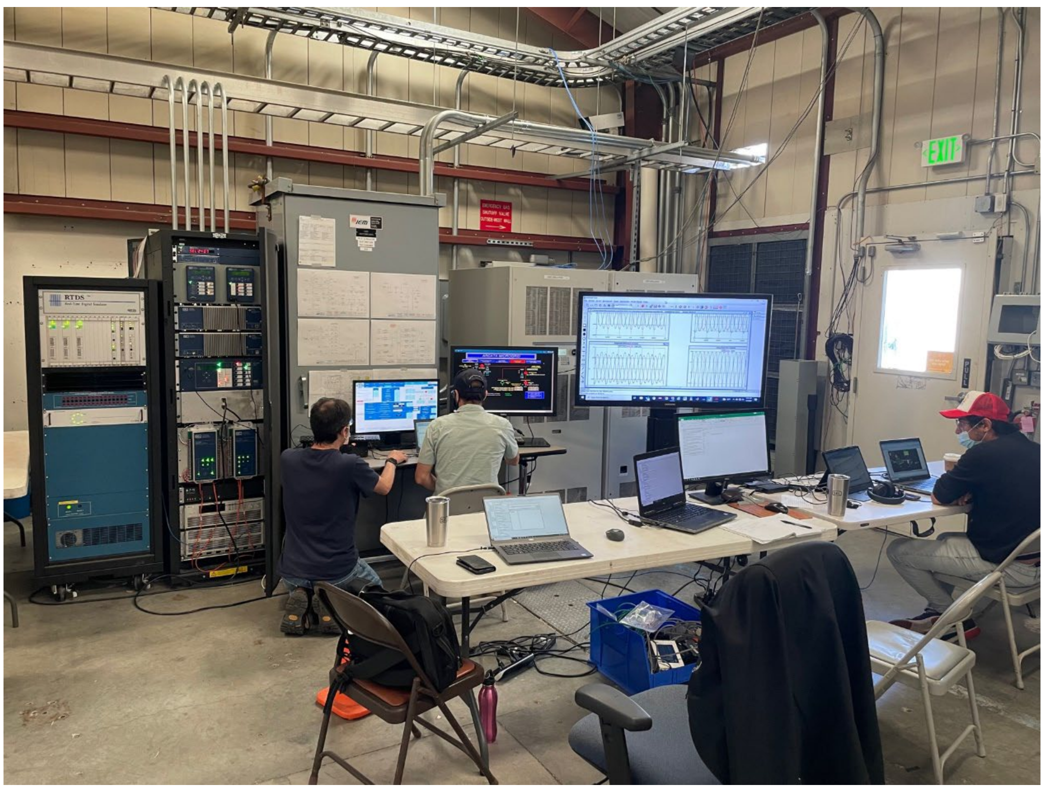
In May 2021, Schatz Center engineers travelled to Tesla's Palo Alto facility for witness testing of the Alencon SPOT DC-DC converters. This testing involved one SPOT DC-coupled to a Tesla Megapack with a DC power supply simulating solar array output to the SPOT. The functionality of the SPOT and Tesla's voltage-based curtailment at high SOC were tested and passed. During witness testing, there were no indications of the persistent ground faults that eventually proved to be insurmountable for Alencon.

Power-Hardware-in-the-Loop Testing

With SEL's FAT complete, testing commenced at ATS according to the ATS PHIL test plan, which was initially released in June 2020, revised in December 2020, and finalized in March 2021, although results from the FAT process led to another revision.

PG&E's ATS team developed an RSCAD® electrical model of the Janes Creek 1103 circuit for use in their Real Time Digital Simulation facility.[9] This electrical model included the distribution circuit back to the Janes Creek substation and the complete microgrid power system. This model was interfaced with a 70-kVA Tesla Powerpack and a 60-kVA Chint Power Systems inverter through two Ametek RS90 amplifiers. A 30-kW Chroma power supply with solar array emulator was used to provide DC power to the Chint Power Systems inverter. All of the essential controllers, hardware I/O, and human machine interfaces (HMI) for both the RCEA and PG&E control systems were installed into the test environment. Figure 21 shows the test environment at the ATS facility.

Figure 21: PHIL Testing Environment



Source: Schatz Energy Research Center

ATS testing began in June 2021, and the final PHIL Test Report was released in November 2021. The ATS test environment was kept operational to support on-site commissioning of the protection and control systems, and it was used for regression testing on two occasions before final Permission to Island was granted by PG&E.

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9 RSCAD® is a real-time simulation software package available from RTDS Technologies Inc. that allows users to configure, run, and analyze power system simulations.

While the PHIL testing took more time and effort than anticipated, it was critical in terms of derisking and saving time during the final commissioning process at the project site. For example, a key finding during testing at ATS was that the BESS inverter fault current was not meeting specifications. This triggered a firmware revision at Tesla, which fixed the issue. Additionally, the islanding controller implementation was complex and also critical to proper operation of the fail-safes. Testing this subsystem at ATS saved significant time and effort that otherwise would have been needed during on-site commissioning. PHIL testing also helped diagnose an undersized central processing unit (CPU) that caused latency issues, leading to failed transitions in the field. The Schatz Center installed a more powerful CPU, and regression testing of the new hardware configuration at ATS validated that the change was successful, with no adverse impacts prior to field testing.

Another testing activity that was completed at ATS was bench testing the SEL-651R settings. This was completed in July 2021 by a senior PG&E distribution line technician with Schatz Center engineers present to support the effort, particularly with respect to Microgrid Enabled/Disabled Mode logic and other microgrid related functions (Figure 22).

Figure 22: Bench Testing the SEL-651R Recloser Control

Source: Schatz Energy Research Center

Field Testing

Testing of physical components on-site prior to energization was completed by Electric Power Systems Testing and Engineering Services (EPS), which was selected from six National Electrical Testing Association certified firms that responded to a Request for Proposal developed by the Schatz Center. EPS's scope of work included three mobilizations. In the first mobilization, EPS technicians travelled to the Myers Power Products factory and completed bench testing of the SEL-700G protection relays. The Schatz Center then provided the relay bench testing report to PG&E, enabling the team to schedule the Pre-energization Test.

The second mobilization, in August 2021, was to conduct pre-energization on-site testing of the medium-voltage switchgear, utility disconnect, station battery drawdown test, current transformer and potential transformer tests, insulation testing, and very low frequency testing on medium voltage cables (Figure 23). This testing verified that the equipment, conductors, and communications cables were ready to put into service.

Figure 23: Pre-energization Testing

Source: Schatz Energy Research Center

With Pre-energization Testing complete, PG&E energized the medium-voltage switchgear with the utility disconnect locked in the open position on August 16, 2021. With the switchgear energized, Schatz Center, AT&T, PG&E, and Blue Lake Rancheria electricians completed various installation, configuration, and testing activities to prepare for commissioning.

The third EPS mobilization, on September 8, 2021, supported the PG&E Pre-parallel Inspection by testing the protection settings in the SEL-700G relays that supervise and control the medium-voltage circuit breaker in the medium-voltage switchgear. A PG&E technician was on-site directing the EPS engineer to test various protection and control settings to verify proper operation and to inspect the medium-voltage switchgear and utility disconnect. This was completed prior to PG&E granting Temporary Permission to Operate for test purposes on September 24, 2021.

Commissioning

Commissioning began after Temporary Permission to Operate was granted and the generation systems were cleared to exchange power with the grid. CAISO provided a preliminary window for unstructured testing from September 8 through October 2, 2021. The Schatz Center set up a weather data server for RCEA's CAISO scheduling coordinator, TEA, and did point-to-point testing with TEA on September 20, 2021. The Schatz Center conducted point-to-point testing with CAISO between September 20 and October 1, 2021, and conducted point-to-point testing with the PG&E Distribution Control Center between October 4 and October 15, 2021. The Schatz Center conducted the following non-CAISO, Blue Sky Operations Functional Tests:

- Manual full load testing between PMIN (-1,450 kW) and PMAX (1,750 kW)
    - Tesla conducted its thermal system checks during this test.
- Verification that Tesla's DC-coupled PV system curtailment worked when a charge-from-grid command was received
- Verification that PG&E charge and discharge limits effectively coerced external setpoints to within bounds
- Verification that PG&E's emergency control of the generation circuit breaker worked as designed
- Verification that alarms and fail-safe states asserted as expected

The CAISO meter inspection occurred on October 26, 2021, and the final Pre-parallel Inspection, which checked the power factor at full load, occurred on October 28, 2021. After that test was passed, the Schatz Center requested Final Unconditional Permission to Operate in grid-connected mode, which was granted by PG&E on the same day.

The Schatz Center requested initial synchronization with the CAISO grid on October 30, 2021. On November 9, 2021, RCAM received synchronization approval from CAISO and the Schatz Center conducted the official CAISO PMIN and PMAX tests. From November 12 through December 21, 2021, TEA tested CAISO market participation following CAISO test signals. CAISO conducted a 72-hour validation test from December 17 through December 21, 2021. RCAM achieved its Commercial Operations Date on December 21, 2021, allowing the microgrid to operate automatically in CAISO markets. During this initial operating period in grid-connected mode, RCAM operated in Microgrid Disabled Mode as a strictly grid-following resource with the microgrid islanding point bypassed.

With the microgrid now operating in grid-connected mode, the focus shifted to finalizing documentation and training operators in preparation for the islanded functional tests. These tests took place in late January through early March 2022. The Schatz Center led the on-site testing with SEL engineers, Blue Lake Rancheria electricians, RCEA operations staff, PG&E distribution line technicians and troublemen, and Tesla engineers. PG&E system operators and operating engineers participated remotely from their Distribution Control Center in Rocklin, CA.

Table 5 provides a description of the seven islanded functional tests that were conducted. PG&E, the Schatz Center, and RCEA mutually agreed that these tests needed to be passed for Permission to Island to be granted.

Table 5: Description of Islanded Functional Tests

Test Number	Description
1	Manual planned Seamless Islanding Event initiated from on-site Eaton 4260 HMI, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.
2	Manual planned Seamless Islanding Event initiated from DC SCADA HMI, followed by islanding for 20 minutes, followed by manual seamless retransfer to grid-connected state.
3	Manual planned Break-before-make Islanding Event initiated from on-site Eaton 4260 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 from on-site DC SCADA HMI, 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 DC SCADA HMI, followed by load shed testing, followed by manual seamless retransfer to grid-connected state.

Source: Schatz Energy Research Center

Table 6 shows the record of which tests were passed and which were failed over the course of the test period. At the end of the testing period, the Schatz Center prepared the Redwood Coast Airport Microgrid Islanded Functional Testing Report, which includes a complete record of the testing, including diagnostics of failed tests and high-fidelity event reports from the SEL-700G and SEL-651R relays.

Test Number 7 failed three times when exiting load shed because the original control sequence involved a cold load pickup and this caused a phase-to-ground overvoltage trip on the ungrounded primary conductors inside the microgrid. This was related to the BESS properly balancing the secondary voltages at its terminals but lacking visibility into unbalanced primary phase-to-ground voltages induced by sudden energization. To rectify this problem, the control sequence was modified to exit load shed using a black start instead of a cold load pickup. This approach was successful because the black start sequence involves a soft ramp to nominal voltage. A key lesson learned from this result was that grounding transformers should be installed inside microgrids with ungrounded, three-phase delta configured primary conductors. The grounding transformers should be connected by the microgrid control system as fast as possible after the microgrid islands. A grounding transformer would have kept the primary phase-ground voltages equal during the cold load pickup and thus prevented the overvoltage trip that occurred.

Table 6: Islanded Functional Tests Pass/Fail Record

Date	Tests Passed	Tests Failed
January 25, 2022	1,2,3,4	1
January 26, 2022		5,6,7
February 10, 2022	1,5	5
February 11, 2022	5,6	7
February 12, 2022	1,	7
March 11, 2022	1,2,7	

Source: Schatz Energy Research Center

The islanded functional tests were completed on March 11, 2022 (Figure 24). After the islanded functional testing was completed, the microgrid islanding point was left out of bypass with Microgrid Disabled Mode and PG&E Manual Mode asserted so that the microgrid would not attempt to island, but the generation system could operate in CAISO markets.

Figure 24: Islanded Functional Testing at RCAM

Source: Schatz Energy Research Center

Training

PG&E’s operator training program consisted of a Lead System Operator Training at ATS on December 16, 2021. The Lead System Operator Training utilized the PHIL test environment as a teaching tool and allowed lead system operators to have hands on experience with the microgrid controls. Topics covered included operating states and modes, fail-safes, SCADA screens, fault response, alarms, contingency operations for planned and unplanned linework, emergency plans, and RCEA operator expectations and responsibilities. The lead system operators, distribution operating engineers, and grid innovation engineers built on this training and prepared another training for operations staff at PG&E’s Northern Distribution Control Center, which was delivered in January 2022.

SEL provided a three-day training in June 2023 for RCEA operators, which was supported by the Schatz Center. Day one focused on an overview of the microgrid system and an explanation of the main components in the PG&E and RCEA control racks, the microgrid islanding point, and the SEL-700G relay. Day two focused on the RCEA HMI to teach operators how to navigate the ten different screens, how to operate the RCEA-side of the microgrid controls, and how PG&E operates its side of the microgrid controls. The need for RCEA and PG&E operators to understand how their counterparts would operate their respective systems was emphasized to support real-time coordination. Day three of the training focused on maintenance and troubleshooting, with an introduction to software used to view system settings, logs, event reports, control system flowcharts, and the operations manual prepared by SEL.

Documentation

To facilitate operational coordination between PG&E and RCEA, the Schatz Center prepared Description of Operations documents for both parties. These two documents were similar in that the introductory material, safety considerations, alarms, and fail-safes were common to operators from both parties. The control modes sections were different because PG&E’s controls are oriented towards microgrid circuit control and switching, whereas RCEA’s controls are oriented towards BESS dispatch and the generation circuit breaker.

Even with these differences, all operators involved needed to understand how the automation schemes worked and how the manual control modes worked. As the lead technical integrator, the Schatz Center was well positioned to prepare and help build consensus around these operational documents, which became the basis for Appendix XII of the Microgrid Operating Agreement – Operating Procedures and Protocols.

As noted in the Controls section above, the initial document used to start building consensus between RCEA and PG&E was called the Preliminary Operational Responsibilities and Controls Framework. The Descriptions of Operations documents were the ultimate conclusion of that consensus-building process.

The RCEA, PG&E, and Schatz Center teams iterated through four versions of these documents, at which time RCEA’s standard operating procedures were finalized and PG&E’s standard operating procedures were ready to translate into their standardized documentation format, which is based on Technical Bulletins.

PG&E produced the TD-2700P-24-B001 series of documentation to support operations at RCAM. The series included an operational summary of the SCADA screens, an attachment with the Single Line Diagram and a description of components, an attachment dedicated to the 36 distinct alarms that operators may encounter, an attachment for the operational modes quick reference guide, and an attachment for the PG&E Description of Operations. In addition to these documents, the Schatz Center worked with PG&E to prepare specific procedures for PG&E line work and for testing the microgrid islanding point, in case that is needed in the future.

In addition to the above, SEL provided a Microgrid Operation User Manual and Tesla provided an Operations and Maintenance Manual for the Tesla Megapacks.

Operations

On December 21, 2021, CAISO issued the Commercial Operations Date and the RCAM microgrid began automated operations in the CAISO markets. The control system had Microgrid Disabled Mode asserted and PG&E Manual Mode asserted, which ensured that the BESS would only operate in grid-following mode and no automated switching would occur unless a protection related trip occurred. During this period, the Schatz Center and TEA monitored the system, but no operator intervention was needed for blue sky operations until July 2022.

On May 13, 2022, PG&E issued the Islanded Operation Date notice, and PG&E Distribution Control Center operators asserted Microgrid Enabled Mode and PG&E Auto Mode, putting the fully functional microgrid control system into service. Since that time, three 24/7/365 real-time operations teams support RCAM microgrid operations:

- PG&E Northern Distribution Control Center for microgrid circuit operations
- RCEA for microgrid generation system operations (provided by contractor — currently the Schatz Energy Research Center)
- TEA for CAISO market operations

If an alert is triggered in one or more of these teams' systems, the operators coordinate to address the issue. Most islanding events have occurred without incident and the only human intervention needed was for TEA to submit a partial outage card with CAISO to indicate that the resource could not follow CAISO dispatch commands due to an islanding event. After the islanded event had ended, TEA canceled the outage card and normal operations resumed.

The Schatz Center maintains an RCAM Support Incident Journal, where each event that requires human involvement is described. Since May 2021, hundreds of incidents have been recorded. As noted below in Chapter 4, there have been approximately 52 actual islanding events.

Details about system operation and performance are discussed in Chapter 4.

CHAPTER 4:
Microgrid Performance

RCAM became commercially operational in two steps. First, grid-following operations in the CAISO wholesale energy and ancillary services markets began on December 21, 2021. Second, islanded operation was enabled on May 26, 2022. This chapter documents the performance of the microgrid in both grid-forming and grid-following modes, from the time that operations commenced through August 2025.

Data Collection and Monitoring Methodology

Monthly/Cumulative Data Collection and Reporting System

The Redwood Coast Airport Microgrid Data Collection and Performance Reporting Plan was completed and submitted as an interim deliverable in October 2023. The plan described the data collection system, laid out the performance parameters that are monitored and measured, and provided the equations used to calculate the performance parameters.

As part of the RCAM system deployment, including system design, procurement, installation and commissioning, a data monitoring system was deployed. The key metering points included in the data collection system are:

- **Data Collection Point A — Acuvim II BESS meter:** This meter is located at the point of common coupling for the wholesale generation system and measures any power flow imported to or exported from the BESS.
- **Data Collection Point B – Weather and DC meter aggregator:** This data collection point collects weather data from the site, including the solar insolation striking the plane of the solar electric array and the solar array temperature. Also aggregated at this point are the DC power meter readings for each of the three aggregated PV arrays that feed the three Tesla Megapack battery energy storage units.
- **Data Collection Point C — Acuvim II NEM PV meter:** This meter is located at the point of common coupling for the BTM, net energy metering (NEM) PV system and measures all power flow from the BTM PV system to the grid.
- **Data Collection Point D Tesla Islanding Controller:** This device receives a control signal from the PG&E Recloser Controller and controls the islanding state of the Megapack battery system. This control point also provides a data collection point that indicates whether the RCAM system is in grid-following or islanded operation.

These metering points provide the key data needed to assess the state of the system (grid-connected or island mode) and the operational performance of the distributed energy resource assets, namely the wholesale PV array, the wholesale BESS, and the BTM PV array.

Data from the RCAM system is tracked and averaged on a 15-minute interval and written to a log file. The log file is processed on a monthly interval, and monthly performance reports are generated. In addition, a cumulative performance report feature can be used to generate a cumulative results file for a specified period. The key data parameters and system characteristics monitored are listed below.

- FTM system import/export energy
    - Energy flow is tracked on a daily and a monthly basis across the point of common coupling for the wholesale generator. This energy flow is measured at Data Collection Point A — Acuvim II BESS meter. This meter tracks energy exported to the grid from the FTM system, as well as energy imported from the grid to charge the BESS.
- FTM PV Array performance
    - DC energy output from the FTM array is measured for three separate arrays that are each coupled to a Tesla Megapack battery energy storage system. DC current and voltage are measured and used to determine DC power flow. These data are aggregated at Data Collection Point B — Weather and DC meter aggregator. Weather-related parameters are collected here as well. These include PV array operating temperature and plane of array irradiance. Actual array output is compared with expected array output, which is a function of array temperature and plane of array irradiance, and this is reported out as a performance ratio.[10]
- FTM BESS performance
    - BESS performance is assessed in terms of the number of charge/discharge cycles it goes through on a daily and monthly basis, and the round trip energy efficiency for the charge/discharge cycles. A complete charge/discharge cycle is defined as discharging the full rated capacity of the BESS (8,874 kilowatt-hours [kWh]). BESS round trip efficiency is defined as the amount of energy that can be discharged from the battery compared to the amount of energy used to charge the battery through one complete cycle. This efficiency is determined by the Tesla control system, which determines the battery SOC at any given time.
- BTM PV array performance
    - BTM PV array performance is tracked based on the energy flow through Data Collection Point C — Acuvim II NEM PV meter. Hourly, daily, and monthly performance is tracked and compared with expected performance, again based on plane of array irradiance and PV array temperature.
- Islanding performance
    - The islanded performance of the RCAM system is tracked. This includes monitoring the parameters listed below. The islanded state of the RCAM system

[10] A performance ratio equal to one indicates that the FTM array is producing exactly the amount of power that is expected based on its manufacture power rating, PV cell temperature, and incident radiation. A performance ratio less than one means the array is underperforming, and a ratio greater than one means it is performing better than expected.

is determined based on data from Data Collection Point D — Tesla Islanding Controller.

- Number of islanding events
- Duration of islanding events
- Loads served and power generated during islanding events (based on energy flow through the BESS meter and the NEM PV meter)
- Power quality (voltage and frequency, based on data collected from the SEL-700G Generation Protection Relay)

Operations Support Journal

The Schatz Center provides 24/7/365 operational support with a team of four engineers who rotate on-call support duties using a dedicated phone number provided through a telecommunications service provider. This team is referred to as the RCEA Real Time Operations team (RTO) in this document. The phone number is the primary contact for the RCEA RTO when support is needed, and a dedicated email address is also in use for operational activity that can be scheduled in advance.

The RCEA RTO maintains an RCAM Support Journal that is updated as events occur that require support. The RCAM Support Journal is a rich source of operational information. The RCEA RTO maintains lines of communication with the following entities for operational support:

- PG&E RTO
- PG&E Operations Engineers
- TEA RTO
- County of Humboldt Director of Aviation
- RCEA Operations Director
- RCEA Executive Director
- Tesla
- Schweitzer Engineering Laboratories

Challenges

DC-coupled PV System

The major technical challenge that has impacted performance of the RCAM system is the failure of the DC-DC converters to function properly and allow the FTM DC-coupled PV array to effectively output power. This problem is discussed below. It resulted in a nearly 90-percent reduction in the energy output of the FTM DC-coupled PV system over the first three years of operation.

The DC-DC converters provided by Tesla through its vendor Alencon Systems never worked properly. When the units, called SPOTs, were put into service, the ground fault interrupt (GFI) protection relays between the Megapacks and the PV subarrays began to trip on a regular basis. Additionally, the units had persistent firmware issues.

Tesla and Alencon Systems did make slow but steady progress in figuring out the root causes of the GFI trips. In the end, it was determined that the SPOTs were failing in such a way as to allow a DC current path to earth ground, especially under high humidity conditions. Alencon attempted to fix the problem several times over approximately 20 months, including implementing significant design and manufacturing changes.

After repeated factory tests failed, Tesla made the decision at the end of 2023 to begin the process of replacing the Alencon SPOTs with DC-DC converters from another manufacturer. As of January 2024, Dynapower was selected as the DC-DC converter vendor and retrofit plans were developed. Tesla took responsibility for replacing the DC-DC converters as part of its commitment to provide a functional DC-coupled PV system to RCEA. A Dynapower test unit was installed and performed as designed over a multi-month period. The full set of Dynapower DC-DC converters was then installed and became fully operational in January 2025. Once the full retrofit was completed, the FTM PV array performance was monitored for a trial period between January and May 2025.

In June 2025, a performance acceptance memo was issued verifying the proper performance of the Dynapower DC-DC converters and recommending the acceptance of these converters as replacements for the Alencon units.

Fortunately, because the AC-coupled functionality was independent from the DC-coupled PV system at RCAM, the issues with the DC-coupled PV system did not prohibit CAISO market participation with the battery storage, nor did the issues prohibit islanded operation. However, the issues with the DC-DC converters described in this section are the reason for the poor performance of the FTM PV arrays presented in the Performance Assessment section below.

Other Challenges

A number of other technical challenges had more modest impacts on RCAM system performance. A brief list of these challenges, as well as operations and maintenance activities that impact performance, is provided below.

- Cellular connectivity: RCEA's generation control system at RCAM uses a Cellular Router manufactured by Schweitzer Engineering Laboratories (SEL-3061) to provide an Internet connection. This connection is needed to communicate with the CAISO Automated Dispatch System (ADS) Application Programming Interface, as well as provide read-only telemetry and read/write interface for RCEA RTO remote technical support. Between cellular carrier outages and hardware problems with the SEL-3061, Internet connectivity issues have been an on-going issue and have negatively impacted CAISO market participation. Therefore, a more reliable fiber optic interconnection is being installed.
- A settings issue with the remote PG&E microgrid controls prohibits the PG&E RTO from remotely adjusting the BESS charge and discharge limits. Adjustment to these limits is required in select situations. At this time, PG&E must rely on the RCEA RTO to change these settings. PG&E is working to fix this problem with support from the Schatz Center.

- In addition to these technical challenges, the following operational and maintenance activities have had a modest impact on system performance:
  - Overvoltage trips when islanded due to lack of a grounding transformer
  - TEA optimization tuning (regarding optimal CAISO bids and dispatch)
  - Tuning PV system overgeneration protection algorithms
  - Alarms indicating dropped communications between devices
  - Controls asserting fail-safe states in response to alarms
  - PG&E line work requiring RCAM operational support
  - RCEA controller software updates
  - Isolating the Tesla Megapacks for maintenance

Performance Assessment

Performance Metrics Discussion

This section evaluates the RCAM system performance based on operational data collected from April 2022 through August 2025. The assessment includes both normal grid-connected operation (blue sky operation) and islanded operation. It encompasses a performance evaluation of the FTM PV array, the BESS, the BTM PV array, and the overall microgrid system. For blue sky operation, the entire data record is analyzed. For islanded operation, the period from July 2022 through August 2025 is assessed. Islanded operation was first enabled near the start of June 2022; however, the first month of islanded operation is excluded from the assessment due to its use as a shakedown period, during which the data are not representative of normal operation. The data record for the period from April 2022 through August 2025 is noted to be 89 percent complete, with 16 months having only a partial data record. Reasons for incomplete data include periods when the system was non-operational due to PG&E constraints, downtime for maintenance or repair, or glitches with the data monitoring system. Specifically, the months of July 2022, October 2022, January 2023, January 2024, and April 2025 contain data for half or fewer days in the respective month.

FTM System – Blue Sky Operation

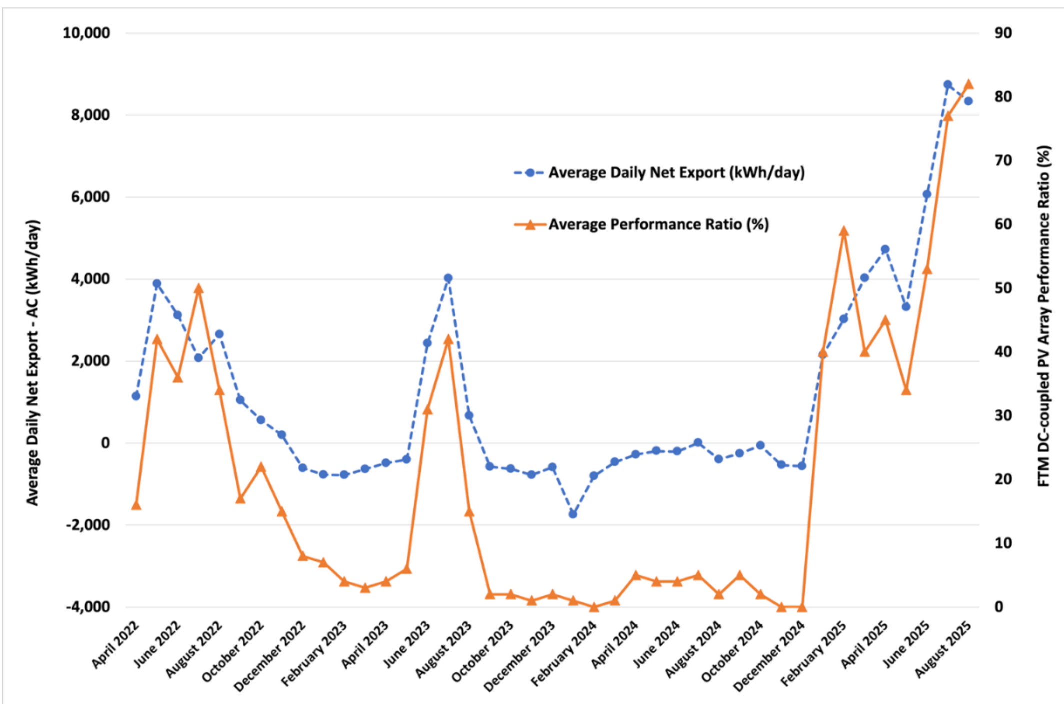
Figure 25 provides monthly data statistics for the FTM system during blue sky operation. The plot shows the total monthly net output in AC kWh. Imports to the system (specifically charging the battery from the grid) are considered negative, and exports are positive. Net exports from the system are made possible by the presence of the FTM PV array. Net imports to the system can occur if the FTM PV array produces little or no power and the BESS is dispatched in the CAISO market. If there is no FTM PV production, there is a net import of power from the grid to make up for the round trip efficiency losses associated with the BESS. The net monthly output indicates whether there was a net import or export of energy.

The plot of average daily net output in Figure 25 shows that the output of the FTM PV array degraded significantly after the first few months, with the exception of a resurgence in the months of June and July 2023 and January and February 2025. As discussed elsewhere in this report, the performance of the FTM PV array was seriously impacted by the failure of the Alencon DC-DC converters and, as time progressed, those failures were more extensive. For much of the operating period, the majority of the FTM PV system was rendered inoperable. For this reason, the overall output from the FTM PV array has been very low, except for the last few months during which data were collected.

During the first 33 months of record, through December 2024, the estimated annual DC output from this system was approximately 310,000 kWh, or about 11 percent of the P90 estimate of expected output for this array.[11] This low performance is also reflected in the performance ratio. Only six months have performance ratios greater than 30 percent, and 22 months have performance ratios less than 10 percent.[12]

However, as of January 2025, the new Dynapower DC-DC converters were installed and became operational. As can be seen in Figure 25, performance immediately and dramatically improved. Since January 2025, the FTM PV array has generated an average of 257,500 kWh per month, or 53% of the P90 estimate, and, by July and August 2025, the FTM PV array was outputting about 80% of the expected P90 output.

Figure 25: Daily Net Export for FTM System and Performance Ratio for FTM DC-coupled PV Array



Source: Schatz Energy Research Center

For months exhibiting a negative net monthly output, a net import of energy occurred during the month. This resulted from minimal FTM PV generation in most months. In the absence of significant PV generation, the BESS continued to be utilized in the wholesale electricity market

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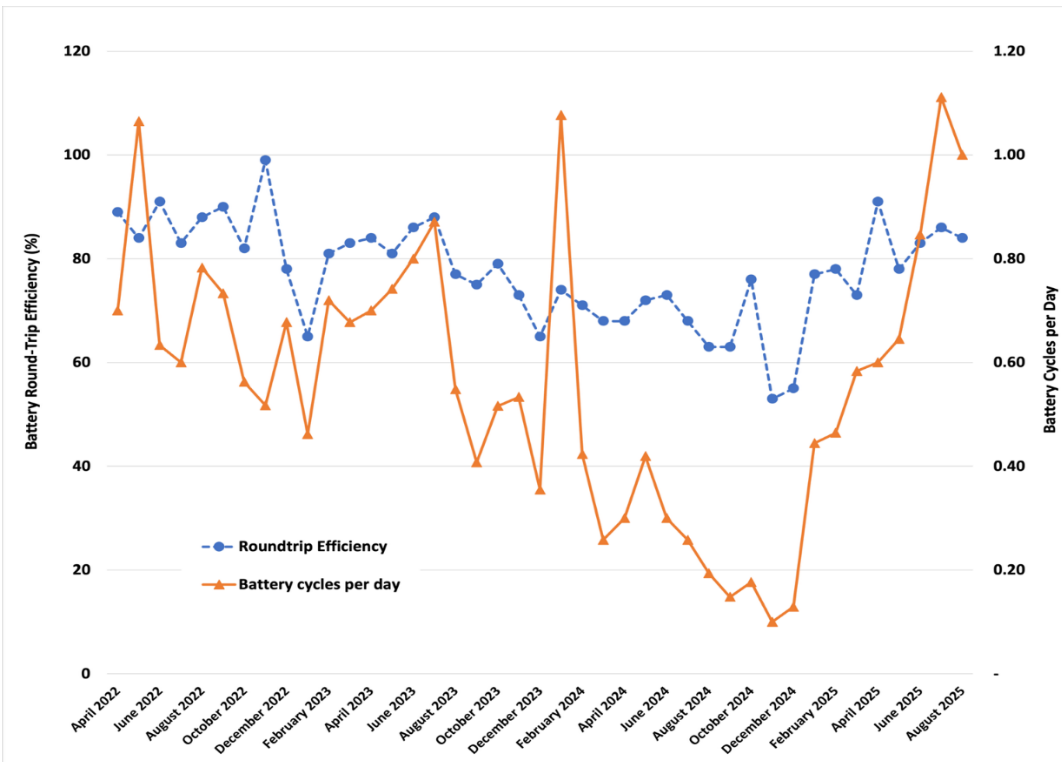
11 A 90 percent probability estimate was developed for the FTM PV array using the National Renewable Energy Laboratory (NREL) System Advisor Model and the NREL National Solar Radiation Database solar radiation data for the project site for the years 1998 through 2017. The estimated P90 output was 2.82 x 10^6 kWh/yr.

12 The performance ratio is discussed in the methodology section of this chapter. It represents the percentage output of the FTM PV system compared to its expected output based on array temperature and incident radiation.

for energy arbitrage and ancillary services purposes.[13] Figure 26 illustrates the average battery cycles per day for each month. Over the period during which data were collected, the battery storage system averaged 0.56 cycles per day, with an average discharge of approximately 4,995 kWh per day. With minimal FTM PV generation available to charge the battery, the majority of this energy was sourced from the grid. The total round trip efficiency of the BESS over the period is estimated at 81 percent.[14]

In months with a net import of energy, the net import was necessary to compensate for the round trip energy efficiency losses of the BESS. The BESS round trip efficiency decreased over time, partially corresponding to a reduction in battery cycling. This trend was consistent with the fact that standby losses, incurred regardless of cycling, have a greater impact on round trip efficiency when cycling is reduced. However, the relationship between standby losses and efficiency likely does not fully account for the observed efficiency losses.

Figure 26: Monthly Battery Performance



Source: Schatz Energy Research Center

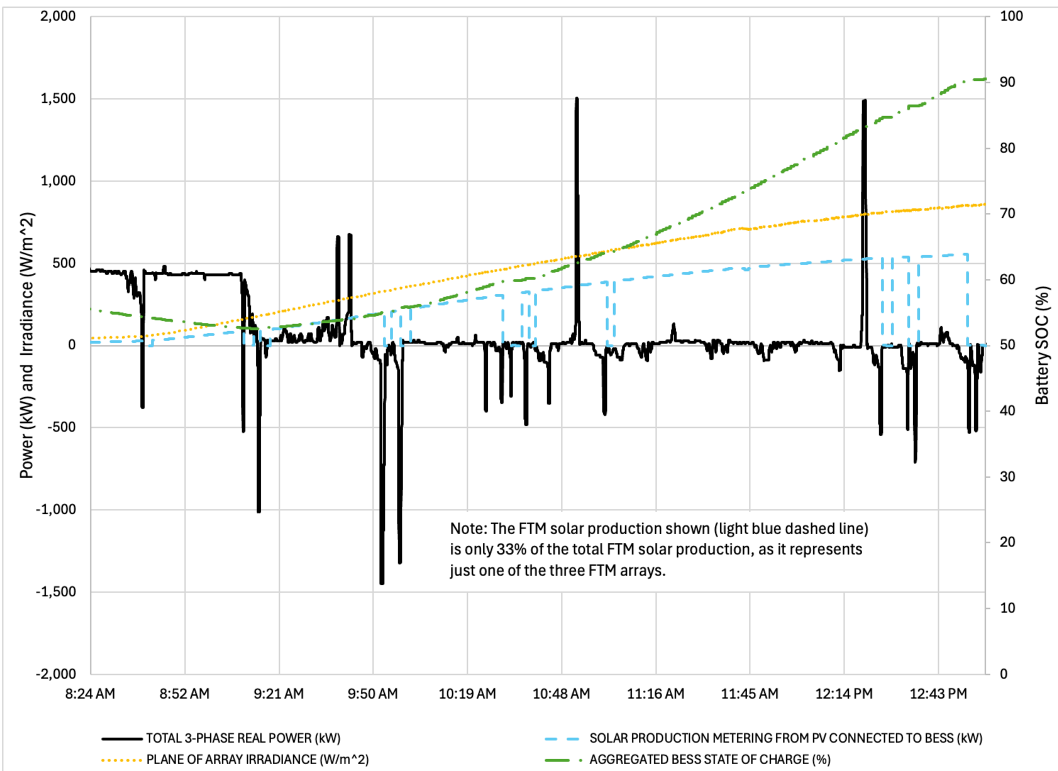
In January 2025, the Dynapower DC-DC converters, which replaced the failed Alencon units, became fully operational, and early indications are that they are performing as expected. As can be seen in Figure 27, as the solar irradiance (yellow dashed line) increases, the solar production (light blue dashed line) increases accordingly. The BESS is usually being dispatched

[13] Energy arbitrage refers to charging the BESS when energy prices are low and discharging when prices are high. Ancillary services include frequency regulation up and down. Regulation energy is used to match systemwide generation to load, thereby controlling system frequency, which must be maintained narrowly around 60 hertz.

[14] Weighted by the number of cycles per month.

by CAISO in frequency regulation up and down between -1,450 kW minimum power (PMIN) and 1,750 kW maximum power (PMAX) at each four-second interval, as indicated by the black line. Since the BESS can be charged from both the grid and the DC-coupled solar, control is needed to ensure that the maximum allowable charge rate of 2.3 MW_{AC} is not exceeded. To accomplish this, the Schatz Center implemented a curtailment program using a SEL-2505 Real Time Automation Controller that commands the DC-DC converters into a standby state if a charge command below -300 kW is received from CAISO. This curtailment explains the solar production going to zero periodically between 8:24 AM and 12:43 PM in Figure 27. The curtailment program also commands the DC-DC converters to a standby state if the specific BESS module they are connected to reaches a SOC of greater than 88 percent. This mode of curtailment can be seen in Figure 27 at around 1:00 PM.

Figure 27: FTM DC-coupled PV Array Operation After DC-DC Converter Replacement



Source: Schatz Energy Research Center

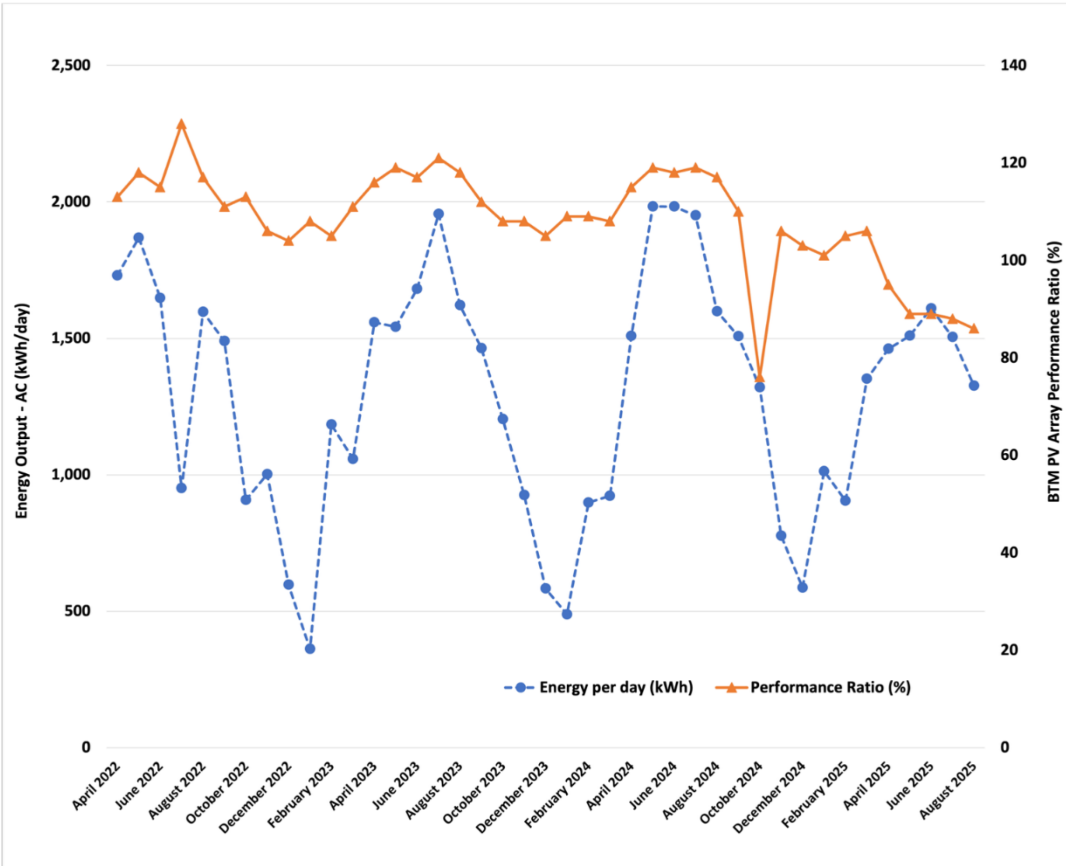
BTM System

The output of the BTM PV array follows the seasonal trend that would be expected — greater output in the summer months and lower output in the winter months. This behavior can be seen in Figure 28. The estimated annual output from the BTM array, based on the period of record, is 456,112 kWh per year. This is 103 percent of the P90 estimate for this system.[15]

[15] As was done for the FTM PV system, a 90-percent probability estimate was developed for the BTM PV array using the NREL System Advisor Model and the NREL National Solar Radiation Database solar radiation data for the project site for the years 1998 through 2017. The estimated P90 output was 4.41 x 105 kWh/yr, and the P50 estimate was 4.89 x 105 kWh/yr.

This better-than-expected performance for the BTM PV system can also be seen in the performance ratio. The weighted average performance ratio for the BTM PV system is 109 percent,[16] which means that the losses are less than expected. However, in April and May 2025, the performance ratio for the BTM PV array dropped. This was due to a failed breaker on one of five BTM PV array string inverters. That inverter was repaired in September 2025.

Figure 28: Monthly BTM PV Array Performance



Source: Schatz Energy Research Center

Islanded Operation

Table 7 and Table 8 show the islanding events for the RCAM system between July 2022 and August 2025. There were 74 islanding events over this period. These included grid outages caused by significant regional events, such as earthquakes and winter storms, as well as localized outages due to distribution system faults or issues.

Of the 74 islanding events, 63 were successfully served by the RCAM grid forming generator. In 11 instances, the RCAM system failed to island successfully, and existing backup diesel generators at the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector/Air Station Humboldt Bay provided emergency backup power.

The unsuccessful islanding events resulted from the absence of a grounding transformer in three cases, control timing issues in seven cases, and, in one case, an issue in PG&E’s system

[16] Weighted by the number of days in a month with complete data.

that will be corrected. The control timing issues have been addressed through software modifications. However, the grounding transformer issue will not be resolved at RCAM, requiring acceptance of rare, unsuccessful islanding events.[17]

There were 71.8 hours of successful islanded operation (90 percent) and only 8.2 hours during which backup diesel generators were needed. During the successful islanding events, the average outage duration was 1.1 hours, the average cumulative customer power demand on the islanded circuit was 170 kW, and the peak cumulative customer power demand was 262 kW. The total outage time of 80 hours during this period of record is equivalent to approximately 25 hours of annual outage time. In the RCAM business case evaluation, a 19-hour annual outage duration was assumed based on Humboldt Division outage data.[18]

It is important to note, however, that a portion of the recorded islanding events would not have resulted in actual power outages on the RCAM circuit but instead were the result of temporary voltage sags or power "flickers." These voltage sags (brief dips in the voltage on the circuit) and flickers (where voltage drops to near zero for a fraction of a second) are due to disturbances, such as faults or switches actuating, elsewhere on the power system. The sensitive RCAM microgrid controls sense these brief disruptions and proactively initiate a seamless transition to the islanded state. When this occurs, the system usually seamlessly transitions back to grid-connected mode within about 15 minutes. During the period of March through August 2025, these brief disruptions accounted for over 60% of the islanding events and 24% of the cumulative islanded hours. Some of the brief islands in this period may have been triggered by periodic overvoltage events at the site due to a nearby upstream PG&E equipment malfunction that has since been repaired.

Table 7: Islanding Events and Load Served*

Month	Year	Number of Islanding Events	Combined Duration of Islanding Events (hr)	Total Load Served During Islanding Events (kWh)	Net Load Served During Islanding Events (kWh)
November	2022	2	0.4	30	30
December	2022	6	18.0	2,825	2,710
January	2023	4	10.2	1,867	1,768
February	2023	6	18.3	3,218	2,327
March	2023	7	1.7	275	250
May	2023	3	0.7	108	15
June	2023	1	0.3	44	-14

[17] A grounding transformer is necessary because the PG&E distribution circuit originates at a grounded wye transformer at the substation and only the three phase conductors are provided along the circuit. When the RCAM microgrid islands, the three phase conductors are disconnected from the substation ground reference, resulting in an ungrounded floating delta circuit. Normally this is not a problem but, occasionally, when a transfer from grid-connected to island mode occurs, it will result in an unsuccessful island due to a voltage imbalance relative to ground on the three phase overhead conductors. Therefore, in future projects where there is a floating delta microgrid configuration connected to a grounded wye distribution circuit, a grounding transformer will be incorporated on the microgrid circuit that will be connected only when the microgrid goes into island mode.

[18] Humboldt Division outage data were based on PG&E's 2018 Annual Electric Reliability Report.

Month	Year	Number of Islanding Events	Combined Duration of Islanding Events (hr)	Total Load Served During Islanding Events (kWh)	Net Load Served During Islanding Events (kWh)
August	2023	1	0.2	34	19
November	2023	2	3.5	590	586
December	2023	1	0.4	0	0
January	2024	2	0.4	68	68
February	2024	2	2.2	6	0
March	2024	4	5.6	892	512
May	2024	2	0.3	41	-31
June	2024	1	0.2	38	-30
October	2024	2	0.2	38	1
November	2024	5	2.7	153	76
January	2025	1	0.2	47	-4
March	2025	7	1.6	298	29
May	2025	4	3.5	484	-30
June	2025	7	8.2	993	815
July	2025	3	0.7	112	103
August	2025	1	0.2	41	41

***Number of islanding events and combined duration include both successful and unsuccessful islanding events. Total load and net load apply only to successful islanding events.**

Source: Schatz Energy Research Center

Table 8: Power Generated and Energy Delivered During Islanding Events*

Month	Year	Peak Power Delivered During Islanding Events (kW)	Total FTM Array Output (kWh)	Total BTM Array Output (kWh)	Net BESS Energy Discharged (kWh)
July	2022	0	0	0	0
November	2022	139	0	0	35
December	2022	224	52	115	1,669
January	2023	262	32	99	1,813
February	2023	220	305	891	2,218
March	2023	190	6	25	238
May	2023	137	73	93	-44
June	2023	-33	222	58	-211
August	2023	90	11	15	18
November	2023	188	0	4	651

Month	Year	Peak Power Delivered During Islanding Events (kW)	Total FTM Array Output (kWh)	Total BTM Array Output (kWh)	Net BESS Energy Discharged (kWh)
December	2023	0	0	0	0
January	2024	175	0	0.3	70
February	2024	0	0	6	0-
March	2024	199	0	381	598
May	2024	0	34	72	-62
June	2024	-16.5	0	69	-35
October	2024	86	0	37	18
November	2024	173	0	78	79
January	2025	-5	339	51	-299
March	2025	180	1,753	269	-1,558
May	2025	151	217	515	-1,452
June	2025	247	1,083	287	-88
July	2025	170	82	9.4	44
August	2025	185	0.3	0	53

***All data include only successful islanding events.**

Source: Schatz Energy Research Center

Key islanding events that occurred during this period include a 6.4-magnitude earthquake that struck Ferndale, California on December 20, 2022. This resulted in a widespread power outage that lasted for nearly 16 hours. Notably, the RCAM system provided backup power for nearly 15 hours and exceeded its expected islanded runtime duration during this event, which occurred on a dark rainy day that was very nearly the shortest day of the year. Other significant regional outages included a winter storm on January 4, 2023, with approximately an eight-hour outage, and another winter storm on February 23, 2023, with a regional outage that lasted approximately 16 hours. The RCAM system successfully served all customers on the islanded circuit for all these events.

During all successful islanding events, the RCAM system maintained acceptable frequency and voltage characteristics on the islanded circuit. All but one successful transition to and from islanded operation were automated and transitions were primarily seamless, meaning that there was no loss of power during the transitions from grid-connected to islanded mode and back to grid-connected mode. In addition, operational status of the RCAM islanding recloser is monitored and controlled by PG&E’s Distribution Control Center in Rockland, CA, and the Schatz Center, under contract to RCEA, provides 24/7/365 operational support services for the RCAM System. Therefore, any failures in the automated RCAM system are quickly identified and rectified via manual intervention when necessary.

CHAPTER 5: Business Model Evaluation and Market Assessment

For FTM community microgrids to be replicable, economic viability is essential. The project objectives included detailed tracking of actual project costs, encompassing both capital costs and ongoing operations and maintenance costs. Additionally, project revenues were tracked and documented. The resilience benefits were assessed, and their potential value was investigated. These cumulative costs and benefits were evaluated on a lifecycle basis in terms of their net present value.

This chapter presents the methodology and results for assessing the economic viability of the RCAM project and, more broadly, FTM community microgrids. The effort involved a business model evaluation and a market replication assessment, resulting in three key deliverables: 1) an evaluation of the demonstrated microgrid business model, 2) an assessment of the market potential for this business model, and 3) the development of a plan to promote market replication. TRC Companies was responsible for conducting the business model evaluation and market replication assessment, producing the following documents:

- Business Model Evaluation Report
- Market Assessment Report
- Market Replication Report

Business Model Evaluation

The table of contents for the Business Model Evaluation Report prepared by TRC Companies is included in Appendix E and the report is summarized below. The business model evaluation was largely completed by the end of January 2023, and the report reflects the information that was available at that time. Since that time, Schatz Center staff, with help from RCEA, have completed a review and provided an update to the cost and revenue data. The updated information is presented as an addendum to the original TRC Companies report. The information provided below reflects the updated cost and revenue data.

Key objectives of the business model evaluation were to:

- Articulate a business model that describes the financial and business arrangements associated with the RCAM project.
- Document the RCAM project costs and projected revenues over the project life.
- Identify potential revenue streams and ways to quantify benefits derived from the microgrid, such as the value of resilience.
- Perform a cost-benefit analysis to evaluate the viability of the RCAM business model and identify and assess alternative configurations.

In evaluating the RCAM business model, TRC conducted a benefit cost analysis for both the RCAM Base Case project, as well as for primary Replication Use Cases for microgrid projects that share similar objectives and features. Note that the details and results presented reflect a snapshot at the time of the analysis; the market is evolving, and many of these assumptions continue to shift over time.

Business Model Assumptions

The assumptions for the FTM community microgrid business model are shown below. These were all aspects of the RCAM Base Case project and are also assumptions that hold true for the Replication Use Cases.

- Front-of-the-meter configuration
- Multiple critical facilities served
- Multiple customer retail meters served
- Public entity ownership of the grid-forming generation
- A primary goal of providing local resilience to critical facilities, with a secondary goal of providing locally generated renewable energy for the community during blue sky operation.

The basic premise of the business model is that a public entity is deploying a community microgrid to provide resilience benefits to a cluster of critical community facilities that provide services during emergencies and natural disasters when the bulk electric grid has failed. In addition, the public entity is interested in advancing clean energy goals for the community that might include reducing greenhouse gas emissions, creating local green jobs, stabilizing energy costs, advancing community ownership of sustainable energy resources, and furthering energy independence. In addition, the model assumes that the legal and regulatory structure of the electric utility industry in the state where the project is located is amenable to the deployment of a community microgrid where a third party owns and operates a wholesale generator that becomes the grid-forming generator and serves retail customers on the islanded microgrid via the distribution utility's electrical distribution infrastructure. A multi-property microgrid tariff that codifies this arrangement was approved by the CPUC in November 2024 (California Public Utilities Commission 2024).[19] A useful report on this topic, *How to Design Multi-User Microgrid Tariffs*, explores the concept of multi-user community microgrids and the associated tariffs and operational structures that can enable them (De Martini et al. 2020).

Benefit-cost Analysis Methodology

TRC employed a standard benefit-cost methodology. The capital costs, the ongoing operations and maintenance costs, and the ongoing revenue streams were assessed, and the cumulative values were determined for the assumed project life of 25 years. A discount rate of 5 percent

[19] In response to California Senate Bill 1339, enacted in 2019, the CPUC initiated a rulemaking on resiliency and microgrids (Rulemaking 19-09-009). In Track 5 of that proceeding, the CPUC adopted a multi-property microgrid tariff for investor-owned utilities Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison Company.

was applied, and all cumulative costs and benefits were expressed in year zero net present values. The benefits and costs were then expressed as a ratio of benefits divided by costs, to determine the benefit-cost ratio. A ratio greater than 1.0 means the benefits outweigh the costs and the project is economically viable. A ratio less than 1.0 means the costs are greater, and the project is not economically viable. If the ratio is less than 1.0, the project may still be deemed worthwhile, as there may be non-monetized benefits that tilt the balance. In this case the project may require subsidization to value the non-monetizable benefits. Alternatively, there could be an effort to reduce costs or increase revenues to improve the benefit-cost ratio.

Quantifiable Costs

The quantifiable costs for the RCAM project encompassed expenses related to distributed energy resources (PV generation, energy storage, switchgear, balance of systems, engineering), the microgrid controls system, and upgrades to the interconnection and distribution systems. These costs are presented in Table 9. Certain costs associated with the RCAM project arose due to its status as a first-of-its-kind pilot project, establishing a new framework for community microgrids. Additionally, research and knowledge transfer components of the grant-funded project were included, which would not typically be incurred in a standard microgrid project. Consequently, not all RCAM project costs were included in the benefit-cost analysis. The total upfront costs for the RCAM project exceeded $11.6 million, whereas the costs included in the benefit-cost analysis amounted to approximately $10.7 million.

Table 9: RCAM Project Costs

Component	Cost
Solar PV system and battery energy storage	$7,413,000
Main microgrid switchgear (point of common coupling, 12 kV)	$289,000
Interconnection (includes: service realignment, generator interconnection facilities, distribution system upgrades)	$489,000
Microgrid controls and protection	$695,000
Civil and electrical balance of systems (includes: land clearing, grading, concrete pads, fencing, trenching, underground vaults, conduit, wire, transformers, metering, permitting, inspections, and on-site testing services)	$293,000
Engineering	$1,392,000
Cybersecurity review and plan	$100,000
Operations and maintenance	$145,000/yr

Source: Schatz Energy Research Center

It is important to note that the RCAM project must compensate the site host for use of the land. The County of Humboldt owns the California Redwood Coast-Humboldt County Airport, and the FAA requires that it obtain a fair market value for the land lease. Therefore, the project includes a 300-kW BTM solar PV system that is interconnected with PG&E via a net metering aggregation arrangement. The power generated by this PV system offsets a portion of the site host's on-site electricity costs. At the time the lease was negotiated, the estimated value of the annual electric bill savings was greater than $44,000 per year, and this was shown to be equivalent to the fair market value of the lease. Therefore, the cost of the land lease was effectively covered as part of the capital cost of the solar PV system. With the increased cost of electricity, the bill savings associated with the BTM solar PV system are now substantially higher.

Quantifiable Benefits

The quantifiable benefits for the RCAM project include revenues associated with participation in the CAISO wholesale electricity market, including both energy and ancillary services. The value of the RECs associated with the solar electricity generated by the FTM array are also included. Expected revenues are shown in Table 10. The energy market revenues are estimated based on the system performance to date and projections of what the revenues should be with a fully functioning FTM PV system. As noted above, the output of the FTM PV system was severely constrained due to the failure of the DC-DC converters. The revenue estimate shown in Table 10 assumes a fully functioning FTM PV system. Actual energy market revenues through July 2024 were approximately 17% of expected revenues due to the DC-DC converter failure. CAISO ancillary services revenues (regulation up and down) are estimated based on system performance to date. The REC value estimate assumes a price of $16 per MWh increasing linearly to $20 per MWh over a 10-year period, and then holding constant thereafter.

Table 10: RCAM Projected Project Revenues

Component	Revenue
CAISO Day-Ahead Energy Market	$160,000/yr
CAISO Day-Ahead Regulation Up/Down Market	$170,000/yr
Renewable Energy Certificates (RECs)	$60,000/yr

Source: Schatz Energy Research Center

It is important to note that the revenue estimates in Table 10 are based on simulated CAISO market conditions estimated in 2022. More recent estimates, derived from actual market conditions and realized revenues, suggest that achievable annual revenues from energy and regulation up and down services may be closer to $150,000 to $200,000 per year. It is unclear why the earlier estimates were so far off, but CAISO energy and ancillary services prices appear to have peaked in 2022 (California independent System Operator 2025b; California ISO 2023) — the year in which the estimates were generated — which may explain much of the discrepancy. More recent REC revenue estimates are also lower than those reported in Table 10, by as much as 50%.

As outlined previously, the RCAM grid-forming generation was interconnected as an energy-only resource and therefore does not qualify for RA benefits. If the RCAM project were eligible, the estimated RA value would be approximately $200,000 per year. RA prices are subject to significant volatility, and this estimate may vary considerably based on market conditions.[20]

[20] Potential revenue from RA over the project period was estimated by The Energy Authority and ranged from $60,000 to $240,000 per year. The large swing is due to volatility in the Resource Adequacy market.

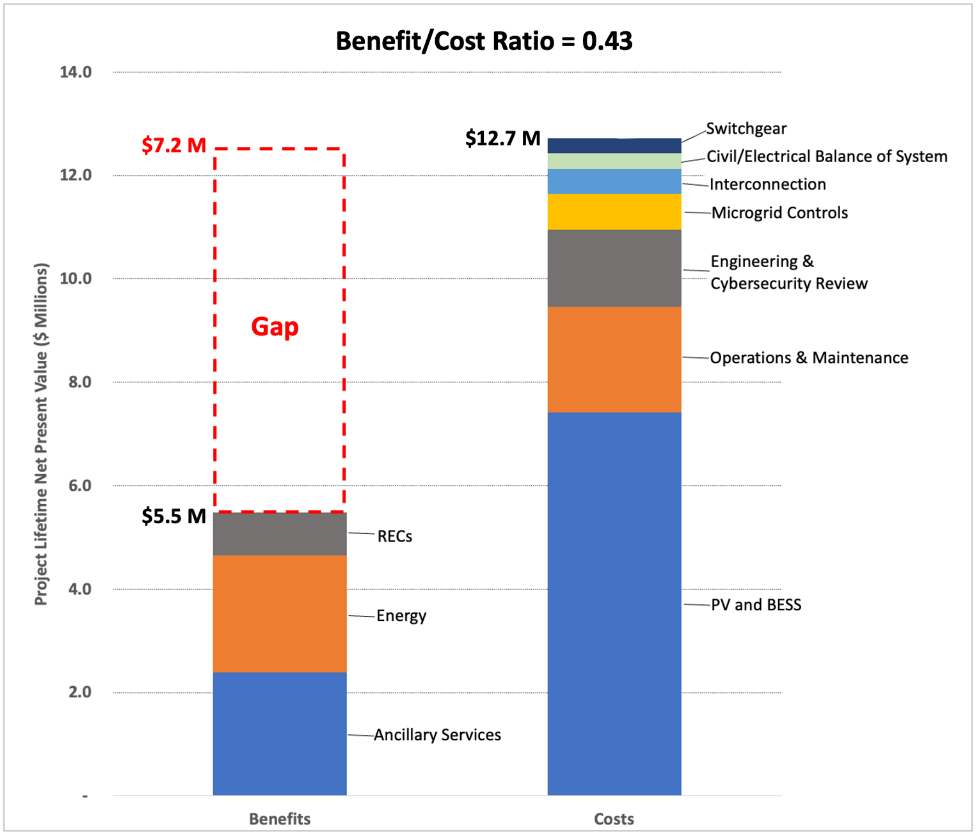
Base Case Project Benefit-cost Analysis Results

Using the methodology and assumptions described above, the project team performed a benefit-cost analysis of the RCAM Base Case project (Figure 29). The stacked cost column on the right shows that the solar PV system and the BESS equipment account for the majority of the cost. This is to be expected, especially since the generation and storage for the RCAM project were sized for wholesale electricity market participation and are substantially larger than needed to meet the peak loads on the microgrid circuit. The stacked benefits column on the left shows that the greatest revenue source is from ancillary services, followed by energy revenues and RECs benefits.

As shown in Figure 29, the RCAM project has a total cost of $12.7 million and a total revenue benefit of $5.5 million, resulting in a benefit-cost ratio of 0.43. The red dashed line shows a gap between costs and benefits of $7.2 million. This gap could be filled by additional revenue streams, and/or by non-monetizable benefits like increased community resilience or other community benefits, such as local job creation, greenhouse gas reduction, and local control and ownership of renewable energy resources. This gap can be seen as the cost of the non-monetizable benefits. If RCAM obtained Full Deliverability transmission access, and thereby qualified for RA benefits, it would reduce the gap between costs and benefits by nearly $3 million and would raise the benefit-cost ratio to 0.65. However, obtaining Full Deliverability status would likely also incur additional costs for distribution upgrades, as well as reliability and deliverability network upgrades to the transmission system, thereby lowering the benefit-cost ratio.

As noted above, more recent revenue data and estimates suggest that actual revenue streams may be lower than previously estimated. Using these reduced revenue estimates, the benefit-cost ratio, excluding RA revenues, could be as low as 0.20, while including RA revenues could result in a ratio as high as 0.50. Recent CAISO market reports — for example, *2024 Special Report on Battery Storage* (California ISO 2025a) confirm declining net market revenues for batteries, from approximately $103/kW per year in 2022 to $78/kW per year in 2023 and $53/kW per year in 2024; this has been driven primarily by lower energy and ancillary service prices. RA remains a key revenue stream for storage resources, supporting the distinction in benefit-cost ratios.

Figure 29: RCAM Base Case Benefit-cost Analysis



Source: Schatz Energy Research Center and TRC Companies

Quantifying the Resiliency Benefit

In assessing the monetizable value of RCAM's resiliency benefits, the project team researched a wide range of industry-accepted tools and methods and vetted each relative to its specific applicability for the RCAM project before including it in the analysis. Ultimately, the analysis leveraged three industry-accepted tools/methodologies to produce RCAM-tailored monetary estimates of the potential resilience benefits offered by the RCAM project. These included:

- U.S. Federal Emergency Management Agency Benefit Cost Assessment for the loss of critical services at the Coast Guard Air Station.
- Interruption Cost Estimate calculator along with PG&E's electricity reliability statistics for the Humboldt region to estimate financial losses incurred during power outages by the small commercial businesses within the microgrid.
- Arcata Airport's annual operations report for the loss of revenues during outages.

The cumulative estimate of the annual resiliency benefit provided by the RCAM microgrid was $150,000 per year, or $2.1 million over the project life. This would increase the benefit-cost ratio to 0.60, significantly closing the gap but still short of a break-even result.

Replication Use Cases Benefit-cost Analysis Results

The project team evaluated two primary Replication Use Cases for the RCAM Base Case business model:

- Critical Facilities Cluster Scenario: inclusion of multiple critical facilities within the microgrid boundaries.
- Natural Disaster Scenario: implementation of a microgrid that can withstand longer outage events resulting from natural disasters.

Using the same methodologies and tools applied to the Base Case, the project team modeled the economic viability associated with each Replication Use Case for comparison.

Critical Facilities Cluster Scenario Results

For the critical facilities cluster, two scenarios were examined. One cluster included a police department, a fire department, and an emergency command center, and the other included a medium-sized, full-service hospital. Both examples were assumed to be located in the City of Arcata, California. In both cases, the same sized microgrid facility and the same ratio of distributed energy resource generation to load served were assumed, and the project costs were assumed to be the same. The lifetime resiliency benefit was estimated to be $2.5 million in the first case, and $8.5 million in the second. This resilience benefit was added to the revenue benefits shown in Figure 29, and the benefit-cost ratio was determined. For the emergency facility cluster (police, fire and command center), the resulting ratio was 0.63; for the hospital cluster, the resulting ratio was 1.1.

Natural Disaster Scenario Results

The natural disaster scenario assumed the same characteristics as the RCAM project. However, the resilience benefit was based on the benefits provided to mitigate long-duration outages (2 weeks in duration) associated with natural disasters, like major earthquakes or tsunamis. A single event and two consecutive events were examined over the project life, resulting in resilience benefits ranging from $4.3 million to $5.7 million. These cases produced benefit-cost ratios of 0.8 to 0.9; if the base case shorter duration resilience benefits were included, the ratio would be closer to or greater than 1.0 in the respective cases.

Business Model Evaluation Conclusions

The economic viability of the FTM, multi-customer microgrid model hinges on what services communities are designing the microgrid to address. From a solely financial accounting perspective and with current costs and monetizable revenues, the RCAM system does not yield a replicable financial model without additional resources. While value is created from the regional airport and Coast Guard Air Station resiliency benefits, standardized approaches to quantifying and monetizing this value as part of a business model are still emerging. At this time, it can be argued that scalable replication of the resiliency-driven, FTM community microgrid business model across many locations and applications requires further subsidization, reduced costs, and higher market values to make it economically viable at scale. Nonetheless, the combination of tangible and intangible values, with benefits accrued and distributed to the community, compels many local communities and governments to explore the potential for community microgrids.

Market Assessment

The table of contents for the Market Assessment Report prepared by TRC Companies is included in Appendix F. The results of that report are summarized here. Key objectives were to:

- Assess the market potential for the RCAM business model.
- Identify relevant stakeholders and conduct stakeholder engagement.
- Identify potential costs and benefits, assess viability, and determine barriers to adoption.

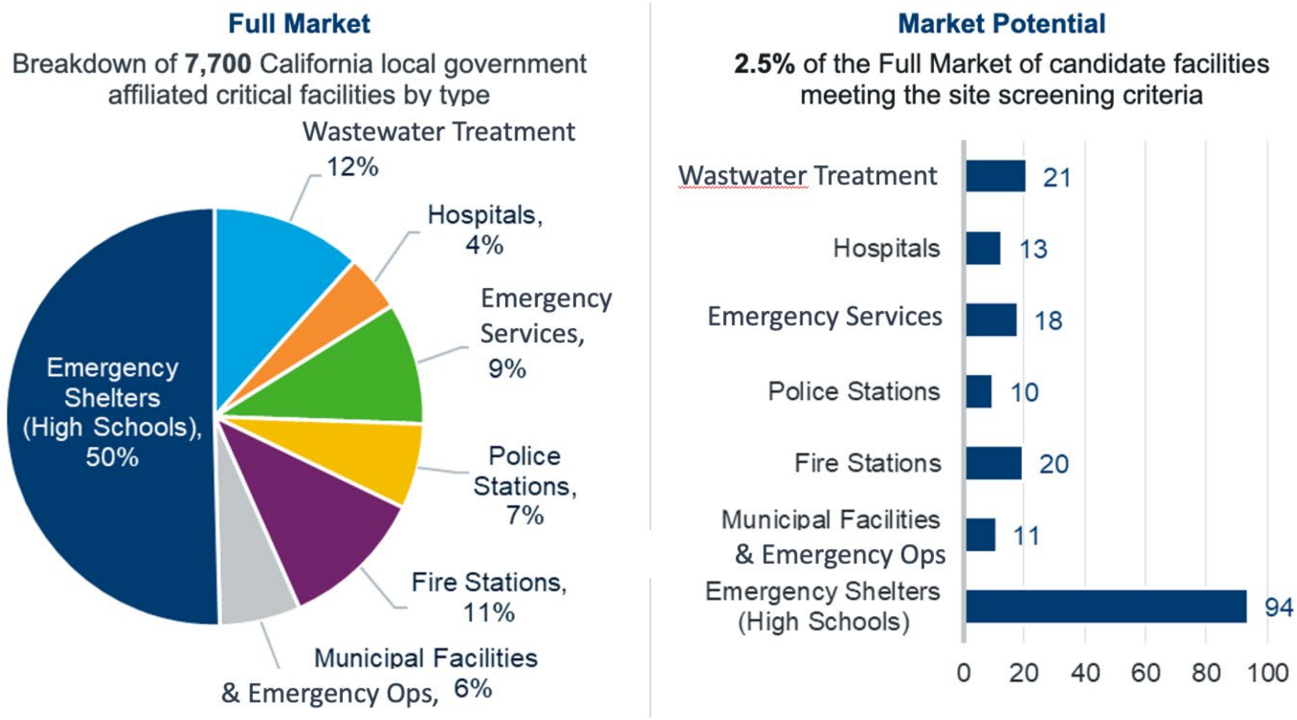
Market Potential

TRC Companies estimated the potential of FTM, multi-customer microgrid facilities in California to be considered economically viable based on the criteria discussed in the Business Model Evaluation Report. The criteria included an anchor to one or more critical facilities and an affiliation with a local government or CCA. To conduct the market potential assessment, the team:

- Identified the full market population of critical facilities throughout California, including wastewater treatment plants, hospitals, emergency medical services, police stations, fire stations, municipal facilities, emergency operations centers, and emergency community shelters.
- Screened for facility size (a minimum facility size was determined based on the results of the business model evaluation described above); 49 percent passed this screen.
- Screened for financing viability based on the credit rating (AA or above) for the associated public entity (municipality or CCA); 51 percent passed this screen.
- Screened for outage risk (located in a Tier 2 or Tier 3 fire threat area or high earthquake impact loss area); 41 percent passed this screen.
- Applied a market scaling factor of 25 percent to account for other barriers, such as siting, cost, access to capital, transmission and distribution system constraints, lack of public support, and so on; other barriers are discussed in the next section.

The total population of critical facilities was identified to be 7,700 and, after applying the screening criteria, 187 facilities, or roughly 2.5 percent, were deemed to be viable candidates. Figure 30 shows the breakdown of the 7,700 critical facilities by facility type and the number that passed the full screening procedure. The team estimated the total capacity of the distributed energy resource associated with these potential community microgrid projects to be 200 MW to 400 MW of renewable generation capacity and 800 MWh to 1,600 MWh of energy storage capacity.

Figure 30: California Critical Facilities Population and Market Potential for FTM, Multi-customer Microgrids



Source: TRC Companies

Market Insights From Stakeholder Engagement

As part of the market assessment process, the project team conducted stakeholder engagement activities. This included a survey that was sent to over 300 targeted stakeholders with about a 20 percent response rate, and targeted interviews with 9 stakeholders representing public agencies, CCAs, utilities, and technology vendors.

Key takeaways from the community microgrid survey respondents are presented below. These responses were not specific to the RCAM project but were based on respondents' general perceptions of community microgrids. Regarding financial barriers, respondents were not asked to consider the impact of potential future cost reductions or potential financial incentives, such as tax credits and grant funds. Such incentives could potentially be helpful in overcoming the cost barrier.

- Over 90 percent of respondents agreed that FTM, multi-customer microgrids involving at least one critical facility are an important solution for communities, customers, utilities, LSEs, and others to achieve greater resilience.
- Respondents totaling 59 percent thought that community microgrids were viable.
- Risk mitigation was the number-one motivation, with 87 percent of respondents indicating this was essential or very important.
- Having 100-percent renewable generation was essential or very important to 68 percent of respondents.

- The number-one adoption barrier identified was regulatory constraints, with 90 percent of respondents indicating this was essential or very important, and 35 percent indicating this was the most important barrier to overcome.
- A close second for most important barriers to overcome was financial barriers.
- With regard to regulatory issues, the number-one barrier identified was the lack of a tariff and an application process for community microgrids; 87 percent indicated this was essential or very important.
- With regard to financial barriers, the number-one issue identified was high project costs, with 82 percent of respondents indicating this was essential or very important.

The full results of the community microgrid survey and other stakeholder engagement activities are presented in the full report.

Market Replication Strategies

The table of contents for the Market Replication Report prepared by TRC Companies is included in Appendix G. The report presents key takeaways from the RCAM project that can inform those considering or facilitating the development of FTM, multi-customer microgrids in California. Following is a summary of the key elements of the report.

- The Market Assessment Report identifies five categories of barriers to the wide-scale deployment of community microgrids. The categories of barriers include regulatory, financial, technology/technical, permitting and development, and internal support. The Market Replication Report identifies policy-based levers and market-based levers that can help address these barriers.
- The Market Replication Report provides a list of approaches that were used in the RCAM project to address barriers to replication and classifies these approaches according to whether they are: 1) ideas/innovations worth further exploration and development, 2) efforts that are already in the early stages of development, 3) established guidelines and practices that are more widely applicable, and 4) one-of-a-kind circumstances that render the solution unique and unlikely to apply elsewhere. Of the 14 approaches identified, only two were deemed to be unlikely to apply elsewhere.
- The Market Replication Report describes a set of RCAM lessons learned and recommendations that the project team highlighted for others exploring the community microgrid model. The recommendations are to:
    - Assemble a highly motivated, multi-disciplinary stakeholder team with a shared vision for success.
    - Understand and plan around risks and costs for both upfront construction and ongoing operations and maintenance.
    - Have a single or a small number of decision makers, which can lead to improved access to financing solutions.

    - Understand the value of resilience for key stakeholders, as this is likely to be key to getting buy-in.
    - Determine if the owner/operator model risk level is acceptable and/or consider a third-party ownership model to de-risk the project, if needed.
- The project team also developed a list of additional replication support needs. These include developing unified vocabularies and methods to quantify resilience, creating assessment tools and guides, expanding tariffs and operations agreements, providing early public funding, developing and promoting third-party financing models, and developing equitable cost sharing models to prioritize and assist disadvantaged communities.

CHAPTER 6: Knowledge Transfer

RCAM is the first FTM, multi-customer microgrid in PG&E's service territory and the first FTM microgrid in California with a third-party-owned, grid-forming generator. The success of this project required the development of an FTM microgrid tariff, as well as agreements, processes, and standards that would allow a third-party generator to form a portion of a distribution system operator's grid in a safe and responsible manner with an equitable and reasonable sharing of responsibility, liability, costs, and benefits.

In addition, an understanding of how a viable business model for an FTM community microgrid could be structured was necessary. This required interconnection and participation in the CAISO wholesale electricity market.

Finally, the design parameters and technical aspects of the project needed to be determined, including how the control system would be structured, who would own which components, how distribution system protection would be accomplished, how SCADA systems and cybersecurity systems would be structured, and what sort of operational protocols would be required between the third-party grid-forming generator owner and the distribution system owner. The solutions determined for each of these challenges paved a path that other FTM community microgrid projects can follow, but making that possible requires an effective transfer of knowledge from this project to other potential project developers.

In an effort to meet these needs, an RCAM Technology/Knowledge Transfer Plan was developed and executed. The purpose of the plan was to make sure the knowledge gained, experimental results, and lessons learned in the Redwood Coast Airport Microgrid Project would be available to the public and key decision makers. The types of knowledge transfer activities covered in the Technology/Knowledge Transfer Plan include:

- Press releases.
- Project fact sheet.
- Presentations at conferences, workshops and meetings.
- Webinars.
- Publications.
- Radio, television, and electronic or written interviews.
- Site tours and hosting of visitors.
- Project web pages.
- Responses to direct inquiries.
- Publication of a final report.

An overview of the technology and knowledge transfer activities for the RCAM project are provided in Table 11, and photos from a couple of the site tours that have been conducted are shown in Figure 31. A discussion of the details for each of the activity types is included in the RCAM Technology/Knowledge Transfer Report.

Table 11: Overview of RCAM Outreach and Knowledge Transfer Activities

Activity Type and Examples	Number of Occurrences and Size of Audience	Time Period
Presentations and participation in conferences, workshops and technical meetings. Includes approximately 17 in-person events over a period that included the COVID pandemic. Key events included: • Hawaii PUC Microgrid Technical Conf. • Oregon Solar Energy Industries Assoc. • Assoc. of CA Airports • CPUC Microgrid/Resiliency Workshops (X5) • CEC IEPR and EPIC Workshops • SEIA/SEPA Solar, Storage, & Smart Energy Expo • Northern California Power Agency Conference • Calif. Renewable Energy Procurement Summit • Community Choice Energy Summit • Microgrid and Distributed Energy Resources (DERs) Summit West • Microgrid Knowledge Conference (X2) • DistribuTECH 2020	• 19 events with up to 20 participants • 17 events with 20 to 50 participants • 10 events with >50 participants	April 2018 to February 2024
Webinars • CalCCA webinar (X2) • Clean Coalition webinar • Clean Power Exchange webinar • SEEC Virtual Forum • Central Coast Microgrid Webinar • RCEA webinars	• 4 webinars with 15 to 25 participants • 5 webinars with 75 to >100 participants	April 2019 to February 2022
Publications • ACEEE Summer Study • PG&E Community Microgrid Technical Best Practices Guide • Energize Innovation web page • Microgrid Operating Agreement and Microgrid Islanding Study	6	July 2020 to February 2024
Published interviews (radio, TV, electronic and print media) • Wired magazine • Popular Science magazine • Sierra magazine • American Public Power Association	9	May 2019 to February 2021

Activity Type and Examples	Number of Occurrences and Size of Audience	Time Period
• Microgrid Knowledge blog • California Current • Green Sense radio interview (X2)		
Site tours • Senator Mike McGuire and Humboldt County staff • Delegation of Japanese utility professionals • CPUC Public Advisors Office • Renewable America solar developer • CalEPA • CSU Mechanical Review Board • Northern California Indian Development Council • Cal Poly Humboldt classes (multiple tours)	>20	July 2021 to March 2024
Direct responses to stakeholder inquiries	24	November 2019 to February 2024
Webpage blog posts	20	February 2018 to June 2022
Fact sheet	1	Initial and final project fact sheet

Source: Schatz Energy Research Center

Figure 31: RCAM Site Tours

Source: Schatz Energy Research Center

In addition to these outreach events and activities, the project received extensive coverage from the external media. Press releases were issued at key points in the project, and external media sources picked these up and broadcast them widely. This, in turn, generated inquiries that the project team responded to.

The project team also participated in CPUC, CEC, and CAISO workshops and policy meetings, and responded to requests for information from these agencies. This included:

- Presentations as part of the CPUC's Microgrid Proceeding (R.19-09-009).
- Individual meetings with the CPUC Energy Division staff.
- An interview with Lumen Energy Strategy to provide input to its Scaling Up and Crossing Bounds: Energy Storage in California report for the CPUC (Aydin and Aydin 2024).
- Participation in the CPUC's Alternatives to Diesel for Substation Power workshop.
- Participation in the CPUC's North Coast Resiliency workshop.
- Participation in the CPUC's EPIC Strategic Goals Grid Modernization workshop.
- Participation in a joint CPUC/CEC Tribal En Banc meeting on the North Coast.
- Participation in a CEC FTM DER Interconnection workshop.
- Participation in a CAISO Hybrid Resource Initiative workshop.

The team also met with other CEC EPIC Microgrid grantees to share information and lessons learned. This included meetings with the Clean Coalition and the Electric Power Research Institute, as well as with the University of California Berkeley EcoBlock team. The RCAM team also engaged dozens of times with local governments, tribes, and other community stakeholders that were interested in pursuing microgrid projects.

Of all of this work, probably the most impactful in terms of replication were the informational materials, now publicly available, that document the tariffs, agreements, and processes necessary to deploy an FTM multi-customer community microgrid in California. These key information resources are highlighted in Table 4. These resources document the Community Microgrid Enablement Tariff and the associated Microgrid Operating Agreement and Microgrid Islanding Study. These are the key information resources needed to deploy an FTM, multi-customer microgrid in PG&E's service territory under the CMEP and MIP programs, which resulted largely from the RCAM project. In addition, the statewide Multi-Property Microgrid Tariff recently adopted by the CPUC requires that similar programs, rules, and processes be made available in both Southern California Edison and San Diego Gas & Electric service territories.

CHAPTER 7: Results

RCAM was a highly successful project that surpassed its stated goals and objectives, delivering critical resilience services to Humboldt County's essential facilities, including a commercial, FAA-regulated airport and a U.S. Coast Guard Air Station.

The project team designed and deployed California's first FTM community microgrid with third-party-owned, grid forming generation, setting a precedent for future community microgrids. RCAM catalyzed the development of the CMET and laid the foundation for the CMEP and California's MIP.

The project achieved numerous regulatory and policy innovations. It is a first-of-its-kind project in many ways. It is the first:

- Community microgrid in PG&E's service territory under the CMET.
- Energy storage project in PG&E's territory using the electric schedule E-STORE station service tariff for FTM storage devices.
- Community microgrid offering services in the CAISO wholesale electricity market.
- DC-coupled hybrid resource participating in the CAISO wholesale electricity market.
- DC-coupled hybrid resource certified for producing RPS eligible renewable power and associated RECs.
- USDA RUS loan awarded to a CCA.
- USDA RUS loan awarded for a community microgrid.

The RCAM microgrid was among the first in California and the United States to serve a commercial, FAA-regulated airport. The rest of this chapter documents the project's goals and objectives achieved and discusses key challenges faced and overcome, along with lessons learned that could apply to future community microgrid deployments.

Meeting Project Goals and Objectives

Project Goals

The RCAM project team met the five project goals articulated in the CEC project agreement scope of work.

Goal 1: Successfully design, install, and operate a renewable energy microgrid to serve the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station.

Accomplishments:

- Installed and operated a 100-percent renewable energy microgrid that successfully served the airport and the U.S. Coast Guard Air Station, successfully participated in the CAISO wholesale electricity market, and provided reliable, safe, and grid-quality power to the circuit during 63 islanding events totaling 71.8 hours of grid outage over a 38-month period.

Goal 2: Develop and implement the agreements, operating procedures, safety protocols, and tariffs necessary for a multi-customer, FTM microgrid.

Accomplishments:

- Developed and executed the agreements, procedures, and protocols necessary to deploy and operate a multi-customer, FTM community microgrid. This included: achieving FAA approval; securing a USDA RUS loan; developing the CMET tariff; developing and executing the MOA; executing a Small Generator Interconnection Agreement, a Special Facilities Agreement, a NEM2 Interconnection Agreement (with an aggregate net metering arrangement), and an E-STORE tariff for station power; executing CAISO agreements for New Resource Implementation and market participation and securing a Commercial Operation Date; securing WREGIS generator registration and getting certified for RECs; and securing RPS certification from the CEC.

Goal 3: Measure the benefits and costs of the microgrid and distributed energy resources included in the project.

Accomplishments:

- Measured the net present value of the costs of the project that were specifically associated with microgrid development, installation, and operation (specifically, the costs that a similar project would incur, excluding costs associated with research and development, business case and market evaluation, and knowledge transfer activities that were particular to this EPIC grant funded project) to be $12.7 million.
- Estimated the net present value of the benefits (specifically, revenue) associated with the project to be $5.5 million, and the remaining value to be a resilience benefit that is difficult to quantify. Estimates for the resilience value ranged from $2.1 million to $5.7 million, depending on the resilience scenario.
- The total net carbon-free renewable power delivered to the electric grid from April 2022 through August 2025 was 2,846 MWh. Assuming a carbon dioxide emissions factor of 0.233 metric tons per MWh,[21] this equates to a savings of 663 metric tons of carbon dioxide emissions, or an average of 194 metric tons per year. With the repair of the DC-DC converters, this number is expected to increase substantially. However, as power on the bulk electric grid in California becomes cleaner, the reduction in carbon dioxide

[21] This emissions factor is based on the total CAISO load served and the total associated CAISO carbon dioxide emissions for the years 2022 and 2023. Data for 2024 and 2025 were not yet available.

emissions will likely be lower than the originally estimated goal of 882 metric tons per year.

Goal 4: Evaluate the business case and assess market opportunities for replication.

Accomplishments:

- Using the net present value estimates of project costs and benefits, a benefit-cost ratio for the RCAM project was estimated to range from 0.60, with minimal resilience value, to 0.90 to 1.0, with a more robust resilience value associated with extended outages in a natural disaster scenario. Broader market opportunities for replication were also assessed.

Goal 5: Report on results and lessons learned for the benefit of communities, electric utility companies, CCAs, and others wishing to install similar systems.

Accomplishments:

- Through extensive knowledge transfer activities, including this Final Report, the accomplishments, results, and lessons learned from the RCAM project have been reported on and shared with CCAs, Native American tribes, local governments, policy makers and regulators, electric utilities, and other stakeholders in the electricity industry in California and beyond.

Project Objectives

The RCAM project team met the 17 project objectives listed in the project scope of work.

Objective 1: Safely integrate a CCA-owned, community-scale, direct DC-coupled PV array and BESS with PG&E's electric grid.

Accomplishments:

- RCEA, PG&E, and the Schatz Center successfully developed and deployed a CCA-owned, FTM community microgrid on PG&E's distribution grid. This required the development and execution of numerous agreements and procedures, including the CMET tariff, the MOA, the Small Generator Interconnection Agreement, the Special Facilities Agreement, the NEM2 Interconnection Agreement, and the E-STORE tariff for station power. The system has operated safely and successfully since December 2021 in grid-following mode, and since May 2022 with the islanding features enabled. The system has met all power quality standards in both grid-following and grid-forming modes. The operational teams from RCEA, PG&E's Distribution Control Center, and the Schatz Center have established functional working relationships and are in ongoing contact on an as-needed basis to ensure the safe and functional operation of the system.

Objective 2: Develop and commission a microgrid control system that will allow the RCAM Microgrid to operate safely and function well.

Accomplishments:

- The RCAM microgrid has operated safely and functionally as a grid-following resource since December 2021 in the CAISO wholesale electricity market, and since May 2022 as a microgrid capable of islanded operation. It has successfully provided resilience benefits during grid outages via seamless transitions to and from islanded mode. It has also generated revenue via participation in the CAISO wholesale electricity market, as well as via aggregate net metering for the 300-kW_{AC} BTM PV array. Original revenue estimates for energy and ancillary services from the FTM solar photovoltaic and battery system ranged from $220,000 to $350,000 annually, though actual revenues have been less than $200,000 per year due to problems with the direct current converters that connect the solar photovoltaic array to the batteries. Those problems were rectified with the installation of new direct current converters in January 2025, and the revenue is expected to increase. The REC value of the generated solar electricity from the FTM and BTM solar array has been estimated at $50,000 to $60,000 per year for the fully functioning system, though the certificates have been retained rather than sold.

Objective 3: Install four EV chargers that can participate in demand response.

Accomplishments:

- Four vehicle-to-grid EV chargers have been installed. They are capable of demand response activities during grid-connected mode and are configured to provide grid-balancing services during islanded operation via vehicle-to-grid operation that will be controlled using frequency regulation.

Objective 4: Install an independent net-metered PV system to offset airport electricity costs and to evaluate the microgrid's ability to help ease constraints on distributed PV generation.

Accomplishments:

- A 300-kW_{AC} PV array was installed as a BTM resource and interconnected via an aggregate net metering arrangement under the NEM2 tariff. The array has surpassed its expected output, and the value of the bill offsets serves as a land lease payment to the County of Humboldt, which owns the airport (note that the FAA requires the lease payment to meet or exceed fair market value for any land leased for non-aeronautical purposes). The BTM array has generated an average of 456 MWh/yr at an estimated value of over $50,000/yr in bill savings, and this value will increase as rates increase.

Objective 5: Coordinate with the Humboldt County Department of Public Works on the upgrade of runway lighting to light emitting diode technology.

Accomplishments:

- The upgrades to the runway lighting system to install light emitting diode technology were completed and are estimated to reduce electricity consumption by more than 50 percent.

Objective 6: Provide local renewable energy to CCA customers.

Accomplishments:

- The NEM PV system provides solar electric power directly to Humboldt County airport facilities. Over the period of record, it is estimated that the 300-kW_{AC} BTM PV array has provided an average annual output of over 456,000 kWh per year, exceeding its expected output. In addition, the 2.2-MWDC FTM PV array has provided an estimated annual output of approximately 572,000 kWh per year. This is roughly 20 percent of its expected output. The low output of this PV array has been due to the failure of the Alencon DC-DC converters. After much diagnosis, troubleshooting, and an attempted redesign of the Alencon converters, an alternate vendor, Dynapower, was chosen. Dynapower DC-DC converters were installed in January 2025, have resolved the performance issues with the FTM PV array, and are performing as expected.

Objective 7: Develop a protocol and utilize the BESS to optimize the dispatch of solar electricity according to CAISO day-ahead market prices.

Accomplishments:

- The Energy Authority, RCEA's CAISO Scheduling Coordinator, developed an algorithm to determine the optimal dispatch of the FTM BESS and PV hybrid system. In addition, the project team developed an automated system that receives the resulting CAISO dispatch instructions and dispatches the RCAM wholesale BESS and PV hybrid resource accordingly. Since December 2021, this system has been used to successfully participate in the CAISO wholesale electricity market. Expected revenues from the energy and ancillary services markets are expected to be approximately $330,000 per year, but actual revenues have been significantly less due to the DC-DC converter problems.

Objective 8: Increase the resiliency of critical facilities, specifically, Humboldt County's main commercial airport and the U.S. Coast Guard Air Station.

Accomplishments:

- The RCAM microgrid has increased the resilience of these critical facilities. Since May 2022, the RCAM microgrid has successfully powered these critical facilities on 63 occasions for a cumulative period of 71.8 hours. This included 90 percent of the hours when backup generation was needed; existing diesel gensets provided the small amount of remaining backup power. Unique events included a 6.4-magnitude earthquake that struck Ferndale, California on December 20, 2022. This resulted in a widespread power outage that lasted nearly 16 hours. Other significant regional outages included winter storms in January and February 2023 that resulted in regional outages lasting approximately 24 cumulative hours. The RCAM system has exceeded expected islanded runtime durations during these events and has successfully served all customers on the islanded circuit, providing safe grid-quality power without incident and achieving seamless transitions to and from the PG&E grid.

Objective 9: Provide a demonstration site that will assist PG&E in developing institutional capacity to support future multi-customer microgrids.

Accomplishments:

- The Schatz Center team worked closely with PG&E to develop protocols, procedures, and standards for the deployment of FTM community microgrids on PG&E's distribution system. This included the development of acceptable methodologies and protocols for electrical protection design and deployment, the collaborative development and publishing of the Community Microgrid Technical Best Practices Guide, the approval and standardization of the SEL-651R recloser as an acceptable device for the MIP for community microgrids on PG&E's system, and the development of training materials and protocols for PG&E personnel. Equally important was the socialization of these materials with PG&E's grid operators; the project team was successful in accomplishing this, setting a precedent for future efforts.

Objective 10: Develop necessary tariffs/agreements to facilitate deployment of multi-customer microgrids on PG&E's distribution system, including allowing PG&E bundled customers to be served by a CCA-owned generation asset during islanded microgrid operation.

Accomplishments:

- The Schatz Center team, RCEA, and PG&E worked closely to develop agreements, tariffs, and protocols for the deployment of FTM community microgrids on PG&E's distribution system. This included the development of the CMET tariff, the MOA, and associated procedures and protocols. The development of these agreements and processes has led to the creation of the Community Microgrid Enablement Program at PG&E, the statewide CPUC-approved Microgrid Incentive Program, and the statewide CPUC-approved Multi-Property Microgrid Tariff. Note that the retail tariffs that apply to PG&E and RCEA customers during regular grid-connected operation also apply during islanded operation, as does the wholesale tariff for RCEA's grid-forming generator.

Objective 11: Generate data, results, and lessons learned to inform other communities, CCAs, and electric utilities and aid them in implementing future multi-customer microgrids.

Accomplishments:

- As described in Chapter 4, an automated data collection system and a data processing script were created to collect data and evaluate and track RCAM system performance. The performance results presented in Chapter 4 document the success of the system, as well as some of the technical challenges (for example, the failed Alencon DC-DC converters). In addition to performance data, the protocols, procedures, standards, and technical design approaches used in the RCAM project are all documented and available to help others in deploying community microgrids (for an example, see Table 4). The Schatz Center and RCEA teams have provided tours, information, and consultations to Tribal Nations, communities, CCAs, and electric utilities interested in learning from the RCAM project.

Objective 12: Examine the potential to provide ancillary benefits to the local distribution system, including allowing more distributed energy resource capacity with lower infrastructure upgrade costs.

Accomplishments:

- The RCAM project provides ancillary services in the CAISO wholesale electricity market at the transmission level, not the distribution level. The project team has not identified quantifiable benefits to the distribution circuit. It is possible that community microgrids like RCAM that are connected at the distribution level can provide voltage support and other services to the distribution system. However, these services would need to be effectively coordinated with any services being offered in the CAISO wholesale electricity market — assets cannot be used to provide simultaneously competing services. More research is needed to determine what sort of services could be provided to the distribution circuit and how those services could be coordinated and compensated. Services might include the deferment of needed distribution system upgrades and the increased hosting capacity for expanded load and/or distributed energy resource deployment on the distribution circuit. In addition, it may be possible to coordinate distributed energy resource dispatch with the utility's operations team to support planned work on the circuit.

Objective 13: Quantify stacked benefits from the RCAM microgrid.

Accomplishments:

- As described in Chapter 5, TRC Companies, with assistance from the project team, quantified the costs and benefits associated with the RCAM project. Direct benefits include revenue from the sale of wholesale energy and ancillary services in the CAISO market, as well as the value of the generated RECs. The estimated annual value, based on modeled market data, is approximately $390,000; however, actual revenues suggest that this value is likely closer to $200,000 per year. Additional revenue from RA — which can be highly volatile — is estimated at $60,000 to $240,000 per year if the RCAM project were to attain Full Deliverability interconnection status. TRC Companies estimated the monetary value of the resilience benefits provided by RCAM to be approximately $2.1 million over the life of the project. Potential benefits to the local distribution system beyond resiliency benefits were not assessed.

Objective 14: Evaluate the RCAM business model, assess market potential, and develop a plan to promote replication.

Accomplishments:

- TRC Companies prepared Business Model Evaluation, Market Assessment, and Market Replication Strategy documents. These are described in Chapter 5 and provided as Appendices H, J, and K. TRC Companies found that the business model is challenging but, under some scenarios, community microgrid projects can "pencil out" economically, provided the resilience value is adequate. TRC Companies also assessed the market for community microgrids throughout California and estimated that nearly 200 critical facilities in the state could serve as an anchor for a community microgrid. Finally, based on its market analyses and stakeholder engagement activities, TRC Companies prepared a market replication strategy that identifies barriers to replication, proposes solutions, and discusses replication pathways and drivers.

Objective 15: Develop an approach and lessons learned to support replicability at other facilities.

Accomplishments:

- Since the completion of the RCAM project, the core members of the RCAM project team (RCEA, PG&E, and the Schatz Center) have continued work to replicate the community microgrid model. PG&E, along with the other two major IOUs in California, has implemented the CPUC-approved Microgrid Incentive Program. The CPUC has issued a proposed decision that adopts a multi-property microgrid tariff in California. These efforts create a regulatory pathway forward and provide financial incentives for at-risk and disadvantaged communities throughout the state to develop community microgrids. These actions were set in motion, in large part, due to the success of and lessons learned in the RCAM project.
- In addition to these efforts by the CPUC and the major IOUs in California, the Schatz Center and RCEA continue to work to improve the reliability and resilience of electrical service to some of our most remote and vulnerable local communities, especially local Tribal Nations. The Schatz Center and RCEA have partnered with three local tribes to secure funding to support the development of nested community microgrids on the Hoopa 1101 distribution circuit in PG&E's service territory.[22] These projects will take advantage of the Microgrid Incentive Program, as well as other funding sources. This effort will build on the success of the RCAM project and expand that to a group of nested community microgrids that are capable of supporting a complete substation circuit, as well as operating independently when necessary to serve more localized core zones. The Schatz Center is also working with other Tribal Nations and has begun efforts to build a collaborative network of engineering consultants who can support these projects.

Objective 16: Conduct an effective technology and knowledge transfer strategy.

Accomplishments:

- Chapter 7 discusses the technology and knowledge transfer plan that was developed and carried out for the RCAM project and documents the type and number of activities that were conducted. Information, accomplishments, and lessons learned about the RCAM project have been shared widely through numerous media and types of activities. Perhaps the most significant is the publication of this Final Report and, with it, the planned establishment of a resource web page that makes the many documents listed in Table 4 publicly available. These documents can provide future community microgrid developers with detailed technical, regulatory, and business model information that can support them in developing their own community microgrid projects.
- As the Schatz Center works with local tribes and others on the Tribal Energy Resilience and Sovereignty (TERAS) project, there will be a large workforce development effort as part of that project. The intention is to transfer knowledge and train members of these

[22] This project includes the Hoopa Valley and Yurok tribes on the Hoopa 1101 circuit, as well as the Blue Lake Rancheria. The project is known as TERAS, an acronym for Tribal Energy Resilience and Sovereignty.

tribes so that they can own and operate their own distributed energy systems and community microgrid assets.

Objective 17: By meeting the objectives above, demonstrate a business case for multi-customer microgrids that will lead to significant market penetration.

Accomplishments:

- As documented, nearly all goals and objectives were achieved. However, achieving significant market penetration for community microgrids presents substantial challenges. Key obstacles include establishing a viable business model, minimizing risk, and navigating the complex agreements, procedures, and protocols required for deploying a community microgrid.
- The greatest opportunity for replication is currently identified within California's Microgrid Incentive Program. However, with only $200 million currently available, this program can support only a limited number of projects. Additional funding will be necessary to facilitate significant market penetration.

Key Challenges and Outcomes

This section addresses the key challenges encountered and resolved during the RCAM project, and the lessons learned that could facilitate the successful deployment of future community microgrid projects. The challenges and lessons learned are categorized as technical or regulatory/market/policy based.

Technical Challenges and Lessons Learned

- **DC-DC converter challenge.** RCAM features a DC-coupled solar PV and battery system as the wholesale, grid-forming resource. There are very few vendors that offer DC-DC converters for this application and selecting a functional DC-DC converter option proved challenging. The commitment of the key project partners and vendors to fulfill their contracts and their associated project responsibilities has allowed for project success, but not without significant delays and cost overruns. Nonetheless, the DC-coupled configuration does offer several benefits, including: 1) a significant reduction in the total MW capacity being interconnected, which decreases the need for and cost of distribution and network upgrade costs, and 2) a PV generator that can provide power to the grid as a dispatchable resource so that the grid is totally insulated from the variability of the solar PV resource and power can be dispatched when it is most needed and most valuable.
- **Achieving cybersecurity and separation of controls equipment.** The design of the RCAM controls system features two separate controllers, one owned by PG&E that controls the microgrid circuit and a second owned by RCEA that controls the microgrid grid-forming generator. While this physical split in the controllers added some complications and cost, it also made it easier to meet required cybersecurity standards and required separation in ownership of equipment. With regard to cybersecurity, this physical disconnection between the PG&E and the RCEA controllers allowed for non-

routable connections between the systems (the only connections are via DNP3 serial or contact I/O devices). This means that PG&E can enforce its cybersecurity requirements for the system it owns to prevent the RCEA system from serving as an entry point for cyber threats to the PG&E-controlled grid. This bright clean line principle also separated, and thereby largely eliminated, the complications and issues associated with two parties sharing the ownership, responsibility, and liability of microgrid controls system equipment.

- **Protection scheme for inverter-based microgrid.** Devising a safe and functional protection scheme for an inverter-based microgrid can be challenging, with the availability of sufficient fault current being an issue. For the RCAM project, the large size of the grid-forming generator relative to the peak load on the microgrid circuit provided for more fault current than if the generator were sized to specifically meet the peak microgrid circuit loads. This simplified the protection issues somewhat, but the project still needed to employ a multi-mode protection approach that utilizes a voltage-based approach when islanded.
- **Automated CASIO dispatch.** During blue sky operation, the RCAM wholesale generator participates in the CAISO market, providing energy and ancillary services. The RCAM system, via its on-site control system, is automatically dispatched. RCEA's scheduling coordinator submits bids, and the dispatch of the resource is instructed via two separate systems that have been integrated via the RCAM control system. Ancillary services are dispatched via a CAISO Automatic Generation Control (AGC) signal, and energy services are dispatched based on CAISO dispatch instructions provided via its ADS portal. The Schatz Center developed an automated script that obtains the ADS dispatch instructions, and the automated RCAM control system then processes the AGC and ADS control signals and dispatches the generation asset accordingly. This is a rather complicated system for such a small generator, but it is necessary to allow for automated, unattended operation of the resource and participation in the wholesale electricity market.
- **Distribution system upgrades.** The RCAM project applied for wholesale interconnection of the PV and battery-generating resource through the Independent Study Process. This process began with a System Impact Study for the full rated capacity of the resource. The study identified the need for network and distribution upgrades costing $1.1 million, which was deemed prohibitive for the project. Consequently, a Facilities Study was conducted with the condition that PG&E would determine the permissible import and export capacity without requiring major distribution or network upgrades. The solution involved limiting the generator to an export capacity of 1,778 kW and an import capacity of 1,480 kW. These limits were implemented through the microgrid controls system, with the protection relay programmed to enforce import and export constraints. This approach effectively eliminated the need for costly distribution and network upgrades.
- **Reliable communications.** Microgrids in rural and remote areas may be subject to unreliable modes of telecommunications and telemetry, and securing reliable

telecommunications services, if available, can be expensive. A future with high distributed energy generation will bring the challenge of determining how to achieve reliable telecommunications for many small sites spread across a broad landscape.

The initial design for RCAM specified cellular communication for CAISO market participation. During the first two years of operation, the network downtime was generally in the range of 0.3 percent to 0.5 percent, with a few rare weeks in which the downtime was above 1 percent. While 30 to 50 minutes of weekly downtime may not seem significant, consecutive outages — especially at critical times — can push site telemetry below CAISO's acceptable limits. CAISO required a communications fix, and the only available option was to install a second dedicated fiber-optic line at a cost of roughly $900 per month. After the fiber installation in October 2024, monitoring showed zero percent downtime during the first month of operation.

- **First DC-coupled resource to obtain RECs.** The CEC and WREGIS had never certified a DC-coupled solar PV and battery resource before to be eligible for RECs and qualify for meeting California's RPS. The project team worked with the CEC and WREGIS to arrive at an agreement for how the resource should be metered. At the time, there were no DC metering options that were certified as revenue grade. The simple solution was to treat the net generation (specifically, export energy minus import energy) through the single revenue-grade AC meter as REC and RPS eligible. Any net generation through the meter must be sourced from the solar PV generator, as it is the only generating source behind the meter.
- **Testing and commissioning challenges.** Testing and commissioning a live system at a critical facility can be challenging. Activities must be scheduled during acceptable time windows and coordinated with critical facility operators, and backup generation may be needed to keep critical loads powered during testing. The following approaches allowed the team to succeed.
    - Laboratory testing at the SEL, Tesla, and PG&E ATS test centers were critical for "shaking down" and debugging the control and protection systems before on-site testing began. This process helped rectify problems that would have been more difficult to address during on-site commissioning.
    - Controls design, with the Microgrid Enable/Disable Modes, allowed for the system to operate in grid-following-only mode (Microgrid Disabled) until islanded operation was fully vetted and approved. This allowed the team to first focus on grid-following approvals and operation, while the testing and approval for grid-forming operation took place separately and on its own time schedule.
    - Testing was conducted in the middle of the night when there were no flights into or out of the airport. Activities were closely coordinated with airport operations and U.S. Coast Guard personnel, and they were able to operate their critical loads on their existing backup generators as needed.
- **Revenue generation separated from islanded operation.** The controls design that features the Microgrid Enabled and Disabled Modes allowed for the project to be

deployed in phases, with grid-following operation approved in December 2021 and islanded, grid-forming operation approved in May 2022. The ability to interconnect the wholesale generator and secure permission to participate in the market while the islanding capabilities of the system were being completed, tested, and vetted relieved some of the pressure on the project team and allowed for revenue generation to get started and continue independent of islanded operation approval and functionality.

- **Engagement of Distribution Operations Engineers and System Operators.** While Distribution Operations Engineers and System Operators were informed during the design process, most were passive during that stage and did not significantly engage in the review process. However, as construction neared completion and live testing was being scheduled, these personnel became very engaged. At this time additional vetting needed to occur, but changes to controls design were problematic this late in the process and would have been better handled during the design phase. Luckily, the review and vetting of the design with other teams at PG&E was very good and late-stage design changes were minimized. As a mitigating feature in this regard, the project team suggests that, if an example of what has been previously approved by the Operations Engineers and System Operators is not available, lots of configurability should be built into the controls to allow for late-stage adjustments.

Regulatory, Market and Policy Challenges and Lessons Learned

- **No microgrid tariff.** When the RCAM project started, a microgrid tariff allowing a third-party grid-forming generator to energize a section of the distribution utility's system did not exist. The project team was aware of this during the proposal phase and established a partnership to develop such a tariff, as needed, as part of the RCAM project. That resulted in the development of the CMET tariff and the associated MOA. In addition, the project team agreed that existing tariffs should be used wherever possible, such as for the interconnection of generation resources. Development of the CMET tariff created a pathway for community microgrid development, removing a barrier to replication. However, navigating the process to execute the required agreements and successfully deploy a community microgrid is still challenging.
- **Securing FAA approval.** Securing FAA approval for a construction project at an FAA-regulated airport is complex. FAA has firm jurisdiction over construction activities, and it review a project for potential safety, operations, and environmental impacts. Locations and heights of equipment relative to the airport runways, even for temporary equipment during construction, are critical and all must be reviewed and approved. A glare analysis is required for PV arrays, and fencing requirements are complicated and expensive. The project sponsor (specifically, the airport owner) must have experienced personnel or an experienced contractor to facilitate the FAA approval process, as the FAA will deal only with the project sponsor and its designated representative. The complete review and approval process for RCAM took approximately three years. In addition, because the microgrid project required that airport property be dedicated to a non-aeronautical use, the FAA required that the land be leased at fair market value. For RCAM, NEM bill offsets were used as a lease payment to the airport owner (Humboldt

County). This required the project team to demonstrate that the NEM bill offsets were equivalent to or greater than the assessed fair market value.

- **USDA RUS loan approval.** RCEA secured a $6.6 million loan from the USDA Rural Utility Service to pay for over half of the cost of the RCAM project. For the USDA, this was its first loan to a CCA and its first loan for a microgrid project. Doing something for the first time always presents its challenges, but RCEA and the larger project team prevailed in successfully securing the USDA loan. Hopefully, it will be easier for the next CCA and the next microgrid project.
- **Contracting challenges.** The RCAM project presented several contracting challenges. These included the following.
    - The failure of the DC-DC converters posed a significant challenge in the implementation of the system. Fortunately, the contract was well-drafted, and the vendor responsible for supplying the PV array, battery storage system, and DC-DC converters (Tesla, Inc.) upheld its commitment, ensuring the delivery of a fully operational system.
    - The controls contract suffered significant cost overruns because PG&E did not have specific controls requirements for FTM community microgrids. They were ultimately developed under this project. The lack of clear controls requirements led to change orders with the controls vendor, resulting in significant overruns. Ideally, with the development of tariffs, standards, procedures, and protocols for community microgrids, the controls requirements in the future will be clearly specified and understood up front, thereby avoiding change orders and cost overruns.
    - Deploying the project involved developing and managing multiple contracts, creating a complex web of responsibilities that was difficult to coordinate. Multiple technologies and vendors each delivered key components for this first-of-its-kind, FTM microgrid, and the final integrated solution had to be acceptable to PG&E's distribution engineering and operations teams. As the prime recipient of the CEC grant and lead technical integrator, the Schatz Energy Research Center ensured that the chosen technical solutions were acceptable to PG&E and oversaw the work of all vendors and subcontractors to confirm that everyone followed through and met their responsibilities. The Schatz Energy Research Center: 1) developed and maintained consensus among key partners; 2) provided leadership to navigate the regulatory framework and obtain required approvals; 3) monitored contractors and assisted as needed to facilitate completion and minimize delays; 4) managed the overall project timeline and maintained team alignment around key milestone dates; and 5) managed changes in scope and budget in response to evolving PG&E project requirements or other unforeseen complications, such as supply chain issues related to the COVID-19 pandemic.
    - Cost uncertainties presented significant challenges during the project. Budgetary quotes obtained from major vendors during the initial budgeting phase were

often not honored at the time of contract execution, particularly when delays extended the timeline. The interval between receipt of initial budgetary quotes and execution of service contracts ranged from one to two years, resulting in cost escalations. These increases were likely driven by market dynamics, including tariffs, supply chain disruptions, and other external factors. Consequently, additional resources were required to address funding shortfalls.

    - Project delays often resulted in increased costs. The RCAM project proposal for a competitive solicitation was submitted in November 2017 and the agreement was executed in August 2018. COVID-19 pandemic caused an approximate one-year delay. Federal approvals, including those from the FAA and USDA loan processes caused additional delays. As a result, the commercial operation date for grid-following wholesale electricity market participation was achieved in December 2021 and full permission to operate in islanded mode was granted in May 2022. The failure and replacement of the DC-DC converters also significantly delayed project completion. Hence, it is critical to include contingencies in the budget to address unforeseen challenges.
    - There is a need for project managers at the electric utility who can manage community microgrid projects from start to finish. In the RCAM project there were many processes involving many different departments at PG&E. This can add complexities, as individual groups may struggle to understand the project in its entirety. This is especially likely for an innovative project like a community microgrid — a new concept being implemented on the utility's distribution system. Having a project manager on the electric utility side who understands the project in its entirety and can advocate internally to keep things moving is critical. The RCAM project had the benefit of numerous allies at PG&E. The new Microgrid Incentive Program incorporates a manager on the IOU side to shepherd a project through the process.
- **A challenging business model for community microgrids.** Establishing economic viability for community microgrids presents significant challenges. This section addresses the obstacles encountered by the RCAM project and other community microgrids in implementing a viable business model.
    - For the RCAM project, projected revenues covered less than half of the total project costs. While community microgrids that secure RA benefits and are located in regions with higher solar irradiance may perform somewhat better, an imbalance in the overall net present value of revenues and costs is expected to persist under the status quo. Addressing this imbalance hinges on the value of resilience, which is challenging to quantify and monetize. The question remains: who is willing to pay for resilience, and how can the costs be financed? The CCA model appears to be a suitable approach. If the CCA, as a public entity, determines that the value of resilience provided to the community by the proposed FTM microgrid is commensurate with the added cost, then the CCA can finance the project as part of its power procurement portfolio and the added cost

can be shared by all CCA ratepayers. Community organizations could also opt to invest by securing a bond and repaying it through a tax or assessment. In high value-of-lost-load scenarios in the private sector, a more conventional business case may be viable. In all cases, the service provided is essentially an insurance policy, yielding benefits only when extended power outages occur and the reliability and resilience services of the microgrid are utilized.

  - In terms of revenue generation, the monetizable stacked benefits associated with these systems are critical. These may include energy, ancillary services, RA, and savings on backup energy costs. BTM resources can provide retail bill savings and net metered benefits. In addition, there may be additional services that these distributed systems can provide that could be compensated for and that could help create a viable business case. These services could include deferred transmission and distribution system upgrades, distribution system services like voltage support or reactive power, and so on.
  - Handling the complexities of building and operating FTM systems may be challenging for a municipality, community organization, Native American tribe, or even a CCA. Participating in the CAISO market, providing grid quality power, meeting regulatory and industry standards, and meeting cybersecurity requirements require expertise. Consequently, community-based groups wanting to participate in this space will likely need to hire outside contractors and consultants to operate and maintain their systems, and this can cut significantly into their net operating revenues. These small microgrid systems (specifically, a few megawatts in capacity) also miss out on economies of scale. Fixed costs that must be incurred regardless of project size make the economics of smaller plants challenging.

- **Lack of sufficient supporting infrastructure.** Community microgrids can help improve reliability in remote rural settings; however, challenges are more likely in these locations due to a lack of sufficient supporting infrastructure, such as energy transmission and distribution infrastructure and telecom infrastructure. The cost of upgrades to meet project needs can be a deal breaker. This includes the costs of transmission and distribution system upgrades, especially network upgrades that are needed to achieve full deliverability for the generation and storage assets, as well as the broadband fiberoptic infrastructure needed to support circuit protection requirements, control system needs, and communications needs to support wholesale electricity market participation in the ancillary services market.
- **Deliverability issues.** A key revenue source for wholesale generators is RA, and CCAs are required to secure a specified amount of RA based on the load they serve. To obtain RA, it is necessary for a generator to secure Full or Partial Deliverability status. At the time of interconnection, a decision must be made as to whether the resource will be connected as an Energy Only resource or a Full Deliverability (or Partial Deliverability) resource. If Full or Partial Deliverability is selected, the project must proceed through the Cluster Study process. This is a more expensive process that

typically takes two years to complete as compared to the one year required for an Independent Study process (for Energy Only interconnections).

- Due to schedule and budgetary constraints, the decision was made to interconnect the RCAM project as an Energy Only resource. At the time of this decision, it was understood that an application for Full Deliverability status could be submitted at a later date. However, this understanding was incorrect. It is currently not possible to enter the Cluster Study Process after achieving interconnection as an Energy Only facility.
- It is recommended that policy changes be implemented to allow Energy Only facilities to: 1) re-enter the interconnection process and participate in a Cluster Study to upgrade the status of an existing generator from Energy Only to Full or Partial Capacity Deliverability, or 2) participate effectively in the annual CAISO Distributed Generation Deliverability (DGD) study process.[23]
- Regarding the DGD study process, review of CAISO Distributed Generation Deliverability Assessment Results since 2017 indicate that less emphasis has been placed on distributed generation resources in recent years, and anecdotal information suggests that the DGD study process may be discontinued. It is recommended that the process not only be continued but also enhanced. The current configuration of the process lacks clarity, making it difficult to understand its mechanics and the opportunities available to distributed generators. Enhancements to the DGD process could include improved educational and awareness materials, increased publicity, a more transparent procedure, opportunities for stakeholders to advocate for specific nodes to be studied, greater emphasis by the CPUC on providing distributed generation portfolios for study, and prioritization of nodes that include community microgrid projects.
- For additional information on this topic, see Appendix H.

- **First microgrid in CAISO market.** The RCAM project was the first community microgrid to provide wholesale generator services in the CAISO market, with collaboration between project stakeholders and CAISO to successfully achieve this objective. A critical function of the RCAM community microgrid is to supply backup power to essential facilities during a loss of power from the bulk grid. To fulfill this function, the BESS must maintain sufficient stored energy to meet the demands of the islanded circuit. It was determined that a SOC of 25 percent in the battery is adequate under most conditions to ensure resilience. This 25 percent energy storage is designated as the reserve capacity, which may be increased in certain situations, such as when a storm is approaching or a public safety power shutoff is imminent. Typically, CAISO requires BESS generators to offer their full capacity in the wholesale energy market to prevent gaming or collusion. However, approval was obtained from CAISO to

[23] The Distributed Generation Deliverability (DGD) study process determines the amount, in MW, of potential deliverability at specific nodes on the CAISO Controlled Grid that are available for assignment to specific distributed generation facilities that are already interconnected or seeking interconnection to the distribution system.

reserve a portion of the BESS storage capacity at all times to ensure a backup power supply when needed. This agreement was essential to the success of the RCAM project.

- **High risk for microgrid aggregator.** Language in the MOA states that "At any time and at its sole discretion, PG&E may perform a review of an existing CMET Project's Microgrid Islanding Study and evaluate the impact of any substantive changes in the original assumptions used in the CMET Project's applicable Microgrid Islanding Study regarding customer load, resources, or other operational or safety issues inside or outside the Electrical Boundary of an existing CMET Project that may represent a System Change which could render the CMET Project incapable of safely operating in Island Mode. If PG&E determines, in its sole discretion, that such a System Change has occurred, PG&E will notify the Community Microgrid (CMG) Aggregator of this determination and perform, at its own expense a new Microgrid Islanding Study to determine what modifications, if any, to the existing CMET Project will be needed to allow the CMET Project to be capable of safely transitioning from Blue Sky Mode, operating in Island Mode and transitioning back to Blue Sky Mode." This potential development places substantial risk on the CMG Aggregator. The business model for community microgrids relies heavily on the value of resilience, and if loads increase or other changes occur, the CMG Aggregator could be forced to finance required upgrades or lose the ability to island. For RCAM, the grid-forming generation is sized for wholesale energy market participation, so this risk is minimized with regard to load growth.

CHAPTER 8: Conclusion

The RCAM project has achieved significant success, meeting all major goals and objectives, with several accomplishments substantially exceeding expectations. This chapter summarizes key achievements, outlines primary challenges, and proposes recommendations for future research and policy initiatives.

Key Accomplishments

The RCAM project achieved its primary goals through the following key accomplishments.

- **Successful Deployment of a Community Microgrid in Humboldt County:** The microgrid enhances resilience for critical facilities, including the California Redwood Coast-Humboldt County Airport and the U.S. Coast Guard Sector Humboldt Bay Air Station. The RCAM facility provides dispatchable solar PV power and delivers regulation-up and regulation-down ancillary services in the CAISO wholesale electricity market. System performance has consistently met or exceeded expectations in both grid-connected and islanded modes.
- **Development of a Community Microgrid Tariff and Operating Framework:** The project established a community microgrid tariff, a microgrid operating agreement, and associated processes, protocols, and procedures essential for deploying a multi-customer community microgrid. These efforts culminated in the creation of the Community Microgrid Enablement Tariff (CMET), the Community Microgrid Enablement Program (CMEP), and the statewide Multi-Property Microgrid Tariff (CPUC Decision D.24-11-004, Proceeding 19-09-009), along with the statewide Microgrid Incentive Program (MIP). These developments formalized the RCAM project's contributions and **established a regulatory framework to facilitate the replication of community microgrid projects**.
- **Cost-benefit Analysis and Business Model Assessment:** The project evaluated the costs and benefits of the community microgrid and assessed its business model and potential for replication. The analysis revealed that easily monetizable stacked benefits accounted for less than half of the project's estimated costs. While locations sunnier than California's North Coast may yield slightly improved financial performance, this suggests that the costs of such projects may exceed easily monetizable benefits. However, the value of resilience, which is contingent on the critical services provided, their societal importance, and the extent of islanded electrical load served over the project's lifespan, has the potential to balance costs and benefits.
- **Technology and Knowledge Transfer Activities:** The project team conducted extensive efforts to disseminate key findings, lessons learned, and informational resources to support replication. Many of these findings and resources are documented in this final report.

Key Challenges

Despite the RCAM project's significant success, it encountered several notable challenges, including:

- Diagnosing and retrofitting a failed DC-DC converter system.
- Developing and deploying an automated system for CAISO dispatch.
- Establishing a community microgrid tariff and associated agreements and protocols.
- Securing approval from the FAA.
- Overcoming a challenging business model.
- Pursuing a pathway to achieve full deliverability for the generation asset.

Overall, the project team largely overcame these challenges, delivering a successful project with substantial accomplishments. However, the RCAM project’s ultimate objective was to demonstrate a viable business case for multi-customer community microgrids that would enable significant market penetration. While the project’s achievements have advanced progress toward this goal, replicating community microgrids at scale remains challenging. Key barriers to large-scale replication include:

- **A Challenging Business Model:** Given the current regulatory structure, the costs of front-of-the-meter community microgrids are expected to exceed the easily monetizable benefits. While the value of resilience can be substantial, quantification of this value remains difficult, and the financial viability and replicability of community microgrids currently depends largely on the availability of grant funding or other financial incentives.

- **Complexity of Development and Deployment:** Developing and operating a multi-customer community microgrid, where a third party owns and operates a grid-forming generator capable of islanding a portion of the distribution utility’s grid, is highly complex.

- **High Costs and Operational Challenges:** Owning and operating a multi-customer microgrid that participates in the wholesale electricity market is a costly and complex endeavor. This can be particularly daunting for small municipalities, community groups, or Native American tribes lacking experience in operating microgrids or participating in wholesale electricity markets. While the generation and storage assets associated with multi-customer microgrids are typically small relative to the central station power plants that energize the bulk electric grid, the cost, complexity, and effort to develop and manage these assets is much greater than their proportional size as generators.

- **Achieving Full Deliverability:** Securing full deliverability for an FTM generation asset can unlock significant revenue from RA payments. However, this process often extends project timelines and may require costly upgrades to transmission and distribution systems.

- **Risks to the CMG Aggregator:** The economic challenges of the business model, the complexity of owning and operating a microgrid, and the potential for future load increases or changes on the microgrid circuit, which could necessitate significant upgrades or prohibit islanded operation, pose substantial risks. These risks may deter small community organizations or local governments from pursuing such projects.

Progress Toward Scaling Community Microgrids

Despite the challenges outlined above, numerous communities in California are actively exploring the development and deployment of community microgrids. This interest is demonstrated by the substantial number of applications and inquiries received by PG&E for its CMEP and MIP. On California's North Coast, several Native American tribes and other stakeholders have expressed enthusiasm for these programs and the potential to deploy community microgrids to serve their communities.

One notable project already underway, with partial funding secured, is the Tribal Energy Resilience and Sovereignty (TERAS) project. This innovative initiative involves a partnership among three North Coast Tribal Nations (Hoopa Valley Tribe, Yurok Tribe, and Blue Lake Rancheria), the Schatz Energy Research Center, and RCEA. Building on the knowledge and lessons learned from the RCAM project, the TERAS project aims to develop nested and integrated community microgrids on the Hoopa 1101 circuit within PG&E's service territory. This circuit, located at the grid edge, experiences some of the lowest reliability in PG&E's network. The tribally owned microgrids will be modeled after the RCAM project, incorporating advancements that enable the microgrids to operate as an integrated system supporting the entire Hoopa 1101 circuit or to function independently to supply power to their respective core zones. The project will introduce advanced microgrid architecture, controls, and protection technologies. Additionally, a workforce development and capacity building initiative will train each tribal community to operate and maintain their respective facilities.

Recommended Next Steps

To further advance the development, evaluation, and deployment of community microgrids in California, the following research and policy actions are recommended.

- **Support Ongoing Research in Technology, Policy, and Markets:** Continued funding is essential to advance the development, evolution, and evaluation of community microgrids. As the smart grid of the future integrates a higher penetration of distributed energy resources, advanced community microgrids can enhance reliability and resilience for at-risk communities while increasing the hosting capacity of outlying circuits and providing distribution and transmission services. Research should include vehicle-to-grid (V2G) integration into microgrid systems and the use of frequency regulation and smart inverter droop settings to control and/or curtail inverter-based distributed energy resources.
- **Investigate Protection Methodologies for Inverter-based Microgrids:** Fund research to assess protection strategies for inverter-based community microgrids, including nested microgrid architectures. This research should evaluate how microgrid assets, telemetry, and control points can improve circuit reliability, reduce outage duration and scope, identify outage locations, and accelerate power restoration.

- **Evaluate Grid Services From Distributed Energy Resources:** Support research to identify grid services that inverter-based distributed energy resources can provide, such as voltage or reactive power support or non-wires alternatives to defer transmission or distribution upgrades. This should include deploying distributed energy resources and directly measuring system performance and benefits to establish appropriate compensation mechanisms.
- **Develop Standardized Methods for Valuing Resilience:** Continue efforts to create standardized approaches for quantifying the value of resilience in specific scenarios and applying these valuations to assess the cost-benefit ratio of proposed community microgrid projects.
- **Fund Community Microgrids for At-risk Communities:** Prioritize funding for community microgrids in disadvantaged and at-risk communities to provide reliable, safe, equitable, and affordable electricity. Use cost-benefit analyses to determine when community microgrids are preferable to alternative approaches, such as grid hardening, undergrounding, or redundant circuits.

In addition to these recommendations, the Schatz Energy Research Center is actively pursuing the following initiatives to advance community microgrid research, development, and demonstration.

- **Continued Collaboration With PG&E at the RCAM Facility:** The Schatz Center is partnering with PG&E to conduct further testing and research at the RCAM microgrid facility. This includes exploring frequency regulation to control distributed energy resources, such as V2G electric vehicle chargers connected via Smart Inverters. This research aims to demonstrate the use of frequency regulation (for example, raising microgrid frequency during over-generation or lowering it during under-generation) to balance loads and generation without relying on a centralized control system for every distributed energy resource.
- **Microgrid Controls and Protection Research at Blue Lake Rancheria:** The Schatz Center will continue frequency regulation research, alongside microgrid controls and protection studies, at the Blue Lake Rancheria tribe's BTM campus. This work will test innovative microgrid architectures and control methodologies for integrating nested microgrids on a single distribution circuit. These efforts will validate concepts for later deployment on the Hoopa 1101 circuit as part of the TERAS project. PG&E will be invited to observe these BTM microgrid activities to build confidence in applying similar methods to FTM microgrid applications on the Hoopa 1101 circuit.
- **Development of a Microgrid Research Center at Cal Poly Humboldt:** The Schatz Center is deploying a BTM, multi-facility microgrid on the Cal Poly Humboldt (CPH) campus, creating a living laboratory for CPH students. Additionally, the Schatz Center and CPH are establishing a microgrid research center on campus, featuring a control and hardware-in-the-loop testing facility with real-time digital simulation. This facility will support ongoing innovative microgrid research, benefiting the Schatz Center, the North Coast region, the State of California, and beyond.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
AC	alternating current
AC-coupled	connected on the alternating current bus
ACEEE	American Council for an Energy Efficient Economy
ADS	automated dispatch system
AGC	automatic generation control
API	application programming interface
ATS	PG&E's Applied Technology Services facility in San Ramon, California
BESS	battery energy storage system
Blue sky operation	normal operation when there is not an electrical grid outage
BTM	behind-the-meter, meaning behind a customer's retail electric meter and therefore customer-owned and/or customer-controlled equipment
CalEPA	California Environmental Protection Agency
CAISO	California Independent System Operator
CCA	community choice aggregator
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CMEP	Community Microgrid Enablement Program
CMET	Community Microgrid Enablement Tariff
CMG	community microgrid
CMG Aggregator	The entity that is responsible for and coordinates control of the grid-forming, distributed generation resources per the CMET tariff
CONOPS	concept of operations; describes how the microgrid will function
Contact I/O	A device that uses a physical contact, like a switch or a relay, to register an input signal or activate an output action
CPH	Cal Poly Humboldt
CPU	central processing unit
CPUC	California Public Utilities Commission
CSU	California State University
DC	direct current

Term	Definition
DCC	distribution control center; a centralized location where operators can see and control devices on the electric distribution system
DC-coupled	refers to electrical devices connected on the direct current bus
DC-DC converter	A direct current converter is an electrical device that shifts the direct current voltage from one value to another.
DER	distributed energy resource
DNP3-serial	Distributed Network Protocol 3 is a set of communication protocols used between components in a process automation system. It is mainly used in utility systems such as electric and water. Serial means that data is sent sequentially, one bit at a time, from one device to another.
DNP3-TCP/IP	Distributed Network Protocol 3 transmitted over an Ethernet-based network using the Internet protocol suite known as TCP/IP.
EPIC	Electric Program Investment Charge
EPS	Electric Power Systems Testing and Engineering Services
EV	electric vehicle
FAA	Federal Aviation Administration
FAT	factory acceptance test
FDS	functional design specification
FTM	Front-of-the-meter; on the electric distribution utility's system rather than behind a customer's retail electric meter
GFI	Ground fault interrupt
Grid-following system	A power generation or energy system, such as a photovoltaic array or wind turbine, that operates by synchronizing with an existing electrical grid. It relies on the grid to provide a stable voltage and frequency reference, "following" the grid's electrical characteristics. The system uses inverters to deliver AC power that matches the grid's frequency, phase, and voltage. Grid-following systems cannot operate independently without a stable grid connection and are designed to inject power (active and sometimes reactive) based on the grid's conditions.
Grid-forming system	A power generation or energy system, such as a photovoltaic array, wind turbine, or energy storage system, that uses inverters to independently establish and regulate the voltage and frequency of an electrical grid. Unlike grid-following systems, it does not rely on an existing stable grid for operation and can create a grid reference, enabling it to function in islanded mode (e.g., microgrids) or during black-start scenarios (restarting a grid after a blackout).

Term	Definition
HMI	human machine interface
H-piles	dimensionally square-structural beams designed for deep foundation applications
https	Hypertext Transfer Protocol Secure; an extension of the Hypertext Transfer Protocol that uses encryption for secure communication over a computer network
IEPR	Integrated Energy Policy Report
I/O	input/output
IOU	investor-owned utility
IP	internet protocol
kV	kilovolt
kVA	kilovolt-amp
kW	kilowatt
kWh	kilowatt-hour
Level 2	EV chargers that charge at a rate of up to 19.2 kW
LSE	load serving entity
MALSR	Medium Intensity Approach Lighting System with Runway Alignment Indicator Lights
MIP	Microgrid Incentive Program
MIS	Microgrid Islanding Study
MOA	microgrid operating agreement
MVA	megavolt-amp
MW	megawatt
MWh	megawatt-hour
NEM	net energy metering
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
NRI	new resource implementation
PG&E	Pacific Gas and Electric Company
PHIL	power hardware-in-the-loop
PMAX	maximum power
PMIN	minimum power
PUC	public utility commission

Term	Definition
PV	photovoltaic (solar powered generation)
RA	resource adequacy; a mechanism to ensure that there is an adequate supply of electricity generation to meet peak demand
RCAM	Redwood Coast Airport Microgrid
RCEA	Redwood Coast Energy Authority
REC	Renewable Energy Certificate; a certificate that represents the environmental benefits of renewable electricity
Recloser	An automatic, high-voltage electric switch that can shut off power when trouble occurs and can be automatically reset when it is safe to do so. Reclosers are used throughout the electric power distribution system.
RPS	Renewable Portfolio Standard; a regulation in California that requires electricity providers to ensure that renewable energy constitutes a specified minimum percentage of the power supply
RTO	real time operations team
RUS	Rural Utility Service of the USDA
SCADA	supervisory control and data acquisition
Schatz Center	Schatz Energy Research Center
SEEC	Statewide Energy Efficiency Collaborative
SEL	Schweitzer Engineering Laboratories
SEIA	Solar Energy Industry Association
SEPA	Smart Electric Power Alliance
SGIA	small generator interconnection agreement
SOC	state of charge; referring to the amount of stored energy in a battery energy storage system
SPOT	The Alencon DC-DC converter is called a SPOT.
TEA	The Energy Authority
TERAS	Tribal Energy Resilience and Sovereignty
USDA	United States Department of Agriculture
V	volt
V2G	vehicle-to-grid; referring to bi-directional electric vehicle chargers
WREGIS	Western Renewable Energy Generation Information System

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Project Deliverables

The following list of Project Deliverables associated with the Technical Tasks was prepared and submitted to the California Energy Commission. Copies of these deliverables can be acquired by contacting the California Energy Commission at pubs@energy.ca.gov, requesting the deliverable and providing the project agreement number (EPC-17-055).

- Community Microgrid Enablement Tariff
- Microgrid Operating Agreement
- Microgrid Islanding Study
- Non-confidential Cybersecurity Plan
- Final System Engineering Presentation
- Procurement Lessons Learned Summary
- Construction Lessons Learned Summary
- Microgrid System Interfacing Presentation
- Microgrid Commissioning Plan
- Commissioning and Testing Lessons Learned Summary
- Final Procurement, Construction, Testing, Commissioning, and Training Presentation
- Final Data Collection Plan
- Final Microgrid Performance Report
- Microgrid Business Model Evaluation Report
- Microgrid Market Evaluation Report
- Microgrid Market Replication Plan
- Final Technology/Knowledge Transfer Report
- Final Project Fact Sheet

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1. Project Description
    1. Arcata Microgrid Executive Summary
    2. RCAM-factsheet-20190618
    3. RCAM CMEP Application Final Execution Version
    4. APPENDIX XIII – Facilities List Final Execution Version
    5. Appendix IV–B – CMET Project Special Facilities Agreement
2. Construction Documents
    1. RCAM Construction As-Builts and Permits
    2. Tesla RCAM As-Built
3. Interconnection Agreement
    1. Redwood Coast Energy Authority 2179-WD SGIA
4. ATS Microgrid Testbed Report
    1. ATS PHIL Report RCAM- Final Execution Version
5. Controls Development and Telemetry
    1. Preliminary Controls Description – CONOPs v5 – Superseded
    2. Functional Design Specifications_Rev5_Final Execution Version
6. Factory Acceptance Testing
    1. RCAM Acceptance Testing Scope of Work
    2. Factory Acceptance Test Procedure_Rev2
    3. Factory Acceptance Test Final
7. Networking and Cybersecurity
    1. High Level Network Architecture Diagram 4.7
    2. Solution Blueprint [Not Provided - Confidential]
    3. System Security Plan [Not Provided - Confidential]
8. Protection Settings and Reports
    1. RCAM Protection Description of Operations

    2. Relay Device Test Results Combined
    3. RCAM G5-1 Form
    4. RCAM PS-1 Form
9. Safety Analysis
    1. RCAM Emergency Response Plan
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        1. RCAM-ArcFlash.zip
        2. RCAM-Grounding 480V.zip
        3. RCAM-Grounding-Overall.zip
        4. RCAM-ShortCircuit-Coordination.zip
    5. RCAM Process Hazard Analysis_v2
    6. RCAM Failsafe Summary Updated with 3530
    7. RCAM Failsafe States-Final 042222.xls
10. Commissioning Test Report
    1. RCAM Islanding Commissioning Plan-v8
    2. Island Function Testing Report-v2 [Confidential Information Redacted]
11. Operations
    1. Letter of Jurisdictional Agreement
    2. PG&E - RCAM Description of Operations [Not Provided - Confidential]
    3. RCEA – RCAM Description of Operations [Not Provided - Confidential]

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APPENDIX C: Technical Summary of RCAM Controls and Protection

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APPENDIX C: Technical Summary of RCAM Controls and Protection

The electrical boundary of RCAM is delineated by a pole-mounted line recloser (G&W Viper-ST) that is automatically controlled by a SEL-651R Recloser Control Relay. A manually operated air switch is included for bypass operations. This configuration represents a standard recloser assembly for PG&E. To use this assembly for the microgrid islanding point, the project team developed a new protection settings group for the SEL-651R. As described further below, Settings Group 6 enables microgrid functionality and Settings Group 1 disables microgrid functionality.

System protection is provided with the SEL-651R at the microgrid islanding point and two SEL-700G relays located in the main microgrid switchgear. PG&E can enable and disable the microgrid from their control interfaces, which causes the SEL-651R to switch settings groups. When the microgrid is disabled, Group 1 is active and the SEL-651R provides: 1) basic overcurrent and ground fault protection with reclosing disabled (one shot to lockout), 2) basic operator manual controls, and 3) no microgrid control functions. When the microgrid is enabled, Group 6 becomes active and the SEL-651R provides: 1) overcurrent and ground fault protection and over/under voltage and frequency protection, 2) operator controls, and 3) active microgrid functions as described in the Control section below.

The SEL-700G protection relays also feature their own settings groups. Group 1 in the SEL-700G relays is active when the microgrid islanding point is closed (grid-connected operations), and Group 2 becomes active when the microgrid islanding point opens (islanded operation). In Group 1, the SEL-700G relays provide import/export control via directional power elements, as well as phase and ground overcurrent protection for faults on the load side of the circuit breaker in the main microgrid switchgear (the customer zone). The overcurrent elements in the SEL-651R and SEL-700G are coordinated so that a fault inside the customer zone should be cleared by the SEL-700G without the microgrid islanding point opening.

In Group 2, the SEL-700G relays provide voltage-controlled overcurrent protection, ground fault protection, and over/under voltage and frequency protection in case the power quality inside the islanded microgrid becomes unacceptable. Voltage control on the overcurrent protection is necessary because when islanded, the BESS cannot produce enough fault current for a conventional medium voltage overcurrent element to operate. Voltage control allows the overcurrent element to be set closer to the peak load current without actuating, unless there is a corresponding voltage sag.

During islanded operation, the 12 kV circuit inside the island is an ungrounded floating delta and ground fault protection is provided by a 3V0 element. Phase overvoltage elements protect primary system assets from sustained high voltages that were observed during cold load pickup tests when the relative potential difference between each phase and ground become imbalanced upon sudden energization of the ungrounded primary conductors. This issue can be addressed with a grounding transformer that is switched in during islanded operation, which will be a standard for microgrids developed by the Schatz Center going forward.

The microgrid normally operates in automatic mode, though RCEA and PG&E both have manual control modes. PG&E's manual mode inhibits automatic transitions so that any non-protection related circuit breaker or line recloser actuations are blocked. RCEA's manual mode makes the BESS unavailable to CAISO (for dispatch) and PG&E (for islanding). Table C-1 shows how these manual modes affect operational characteristics relative to whether the microgrid is placed in enabled or disabled mode.

Table C-1: Auto/Manual and Microgrid Enabled Mode Effects on Operational Characteristics

RCEA Auto/ Manual Mode	PG&E Auto/ Manual Mode	Microgrid Enabled	Microgrid Disabled
Auto	Auto	Microgrid will island automatically as needed.	Not used; microgrid will not automatically island.
Auto	Manual	Microgrid will not island automatically but can be islanded by PG&E operators from the DCC or the local PG&E HMI.	BESS cannot enter grid-forming mode. Automatic transitions are disabled. The BESS and DC-coupled PV system can operate as a grid-following CAISO resource.
Manual	Manual (Auto not available)	Not available; BESS cannot island.	PG&E manual mode automatically asserts when RCEA is in manual mode. BESS not available for CAISO dispatch, but RCEA can manually dispatch the BESS.

Source: Schatz Energy Research Center

As an additional safeguard, if any of the key controller's source code or relay settings are changed, PG&E Manual Mode and Microgrid Disabled Mode will assert and the system will become non-operable, meaning the controller output servers will stop processing commands. Only PG&E can reauthorize the system to become operational after this safeguard is tripped, which ensures that PG&E consents to any settings changes on key controllers.

In order for PG&E to be able to effectively control the microgrid circuit, their microgrid controller can trip and lockout RCEA's generation circuit breaker in case of emergency. This functionality is analogous to direct transfer trip and is used as a fail-safe state for extreme cases, like if a car crashes into a pole inside the microgrid while the microgrid is not islanded. In that case, the SEL-651R at the microgrid islanding point would detect an internal fault, trip, and lock itself out while also sending a trip and lockout command directly to the SEL-700G via contact I/O.

At a high-level, the automatic transfer scheme considers the PG&E's Janes Creek substation as the normal voltage source for the microgrid, and the BESS as the emergency voltage source. The microgrid control system attempts to keep the loads energized from the normal source whenever possible. If the normal source is not available, the controls will automatically transfer the loads to the emergency source and then monitor the normal source terminals at the microgrid islanding point. When the normal source returns and is deemed stable, the controls transfer the loads back to the normal source.

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APPENDIX H: RCAM Deliverability Memo

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APPENDIX H:
RCAM Deliverability Memo

Date: May 2021

Subject: Redwood Coast Airport Microgrid Project Deliverability Status – Challenges, Lessons Learned, and Policy Ramifications

Recommendations Regarding Distributed Generation Deliverability

In today's capacity constrained grid, we think there should be more options available to power plants for RA delivery, not fewer. In this regard, we make the following policy recommendations concerning Distributed Generation Deliverability:

1. Allow re-entry into the interconnection process for DG Energy Only resources that are already operational so they can engage in the cluster study process and obtain Full Capacity Deliverability Status if they desire to do so.
2. Continue the annual CAISO DGD study process and enhance the support provided to DG owners/operators/developers. This could include providing: better educational and awareness information, better publicity, a more transparent process, the ability for stakeholders to advocate for the nodes that will be studied, a greater focus from the CPUC on providing DG portfolios to be studied, and a focus on nodes that include community microgrid projects.

The remainder of this paper outlines the experience we had while interconnecting the Redwood Coast Airport Microgrid project and the associated lessons learned.

Background on the Redwood Coast Airport Microgrid Project

The Redwood Coast Airport Microgrid (RCAM) project features a 2.3 MW hybrid resource in the form of a 2.2 MWDC PV array DC-coupled to an 8.87 MWh battery storage system with a 2.3 MVA grid-facing inverter. This system is being interconnected on the Janes Creek 1103 distribution circuit on PG&E's distribution system. The Redwood Coast Energy Authority, the owner and operator of this generation asset, has executed a Small Generator Interconnection Agreement (SGIA) with PG&E under their Wholesale Distribution Tariff (WDT). The expected commercial operation date for this system is November 2021.

As we understand it, there are two options for attaining Full Capacity Deliverability Status (FCDS) for a generation asset, such as RCAM, that is interconnected to the distribution system: 1) apply for FCDS during the interconnection process, or 2) apply for deliverability status during the annual Distributed Generation Deliverability (DGD) study process conducted by CAISO. Below we discuss these two pathways and our experience and challenges associated with them.

Full Capacity Deliverability Study (Cluster Study) Process During Interconnection

When we first applied for interconnection in March 2019, we needed to decide whether to interconnect as an Energy Only or a Full Capacity Deliverability resource. We understood that the process to obtain FCDS would be more costly and would take at least a couple of years due to the requirement to participate in a cluster study. Because of schedule constraints associated with our CEC EPIC funded project, we chose Energy Only.

What we did not realize at the time, however, was that the choice we made to interconnect as an Energy Only resource was a final decision with respect to the cluster study process. We incorrectly understood there would be an opportunity later in the process, either in parallel with our current interconnection process or subsequent to it, where we could request to change our interconnection status from Energy Only to FCDS. We assumed we would simply need to pay the associated fees and get back into the interconnection queue to do so. We have now learned that this is not possible under the current regulatory structure.

We are aware that there has been some discussion about changing this restriction and allowing existing Energy Only facilities to re-enter the interconnection queue and apply for FCDS. We recommend that this policy be changed to open up the additional pathway for Resource Adequacy (RA) delivery, especially in light of today's capacity constrained market. If the generator owner wants to revisit their interconnection status and pay the study fees and cover the cost of any transmission and distribution system upgrades that are required to obtain FCDS, we believe they should have that option. We think this is particularly important for smaller, distributed generators who are not as familiar with the interconnection process and who may have schedule or funding constraints that don't allow them to go through the full cluster study process at the outset of their project; they may only be able to pursue FCDS after commercial operation.

Distributed Generation Deliverability (DGD) Study Process and the RCAM Experience

The DGD Study process is an annual process conducted by CAISO; the study results are released in February of each year. CAISO examines select nodes (substations) on the existing distribution system and determines if there is available deliverability at those nodes that can be assigned to distributed generators that are either in the interconnection queue or are already interconnected as Energy Only assets. The nodes that are recommended for study are determined by the CAISO in accordance with the CAISO Tariff Section 40.4.6.3, and DG forecasts in recent years have declined resulting in fewer opportunities. Unfortunately, it doesn't appear there is any way for stakeholders to advocate for, or influence, which nodes get studied. You must pay attention to when the DGD study is released, examine the results to see if your node was analyzed, and if your node was analyzed see if there is any available capacity. If there is available capacity, you must submit your request for deliverability status. Typically, requests to obtain deliverability through the DGD study process are due in April.

We learned about the DGD study process in March 2020. Looking back at the DGD study results for 2017-2018 and 2018-2019, both of these studies looked at large numbers of nodes in the PG&E system (>500 nodes each year). In 2017-2018, the Janes Creek node was modeled with a target of 3 MW of DG. No DG was found to be deliverable due to a constraint on the Delevan-Vaca Dixon No.2 230 kV line. In addition, there was no Energy Only distributed generation (DG) in the base portfolio nor the WDAT queue, so even if there was capacity for more deliverability, the Potential Distributed Generation Deliverability (PDGD) would have been zero because there was no DG on the node that could utilize it.

In 2018-2019 the Janes Creek node was modeled again, and this time the 3 MW of DG that was modeled was found to be deliverable. However, once again there was no Energy Only DG in the base portfolio nor the WDAT queue, so the PDGD was determined to be zero. Note that in March 2019 we submitted our application for interconnection of our wholesale generator, so we were hopeful that the 2019-2020 cycle would be favorable for us because we would be in the interconnection queue as an Energy Only distributed generation resource. If Janes Creek was evaluated again for 3 MW of DG, we hoped it would be found to be deliverable and we could apply for it.

Unfortunately, in 2019-2020 the Janes Creek node was not modeled. It appears that something in the DGD study process changed during this cycle, as far fewer nodes were considered on the PG&E system and throughout California. According to the CAISO 2019-2020 DG Deliverability Assessment Results, "There was no distributed generation identified in the 2019-2020 renewable portfolios for the PGE service territory" (CAISO 2020). Therefore, the only nodes that were studied were 87 nodes from the previous year's cycle that had unassigned Potential DGD, along with three nodes associated with updated distributed generation plans from public utilities within PG&E's system. Because Janes Creek was not included in the 2018-2019 cycle, it did not show up in 2019-2020 cycle.

In the 2020-2021 cycle, only 29 nodes were examined, and these nodes were provided to the CAISO by PG&E and were related to the Public Safety Power Shutoffs (PSPS). Again, "There was no distributed generation identified in the 2019-2020 renewable portfolios for the PGE service territory" (CAISO 2021). In this cycle, the Janes Creek node again was not modeled. We have tried our best to become better informed about the DGD Study process.

At this time, it appears the likelihood that we will obtain FCDS for the RCAM project is very slim. We forfeited our opportunity to engage in a cluster study as part of the interconnection process when we chose Energy Only and we are not able to revisit that decision. The only sure way to obtain FCDS is to go through the cluster study process and pay for any of the upgrades that are found to be necessary for an FCDS interconnection.

With regard to the DGD study process, we have missed multiple cycles and it doesn't seem likely that the Janes Creek node will be evaluated any time soon. In addition, there doesn't appear to be any way for us to advocate for the Janes Creek node to be evaluated. Finally, we are aware that there are constraints at the Vaca-Dixon substation that are currently limiting all additional deliverability from the northern part of the California.

Lessons Learned about the Distributed Generation Deliverability (DGD) Study Process

As part of our effort to understand the DGD study process, we have spoken with multiple staff at both CAISO and PG&E, and we have also begun to discuss the topic with staff at the CPUC. Below are some of the things we have learned.

Consistent with what we have experienced, Linda Wright at CAISO informed us that the DGD studies prior to 2020 had a robust number of nodes that were examined. Linda noted that "The DGD process in the years before 2020 had always included DG in the portfolio (used to have over 400 nodes in the PG&E area). Since 2020 there have not been any DG identified in the portfolio by CPUC. Therefore, in the 2020 DGD we only studied the unassigned nodes that carried over 1 year plus any PMU nodes. In the 2021 DGD study there were no carry over unassigned nodes and so we only studied the requested 29 PSPS nodes" (Wright 2021).

Apparently prior to the 2019-2020 study cycle, the CPUC developed DG renewable portfolios that were submitted to the CAISO and established which nodes were considered in the DGD study process. However, in the last two cycles (2019-2020 and 2020-2021), the CPUC has not provided CASIO with any DG renewable portfolios. We would like to understand what has changed in this process and why.

We understand that the DGD study process may face risk of elimination due to the low interest from DG owners to apply for deliverability status through this process. We recommend that the DGD study process be continued and we suggest that efforts to promote it be expanded. We think the process, as it has functioned, has been difficult to become aware of, difficult to understand, and difficult to participate in, and that is likely why there has been very little participation. We have paid close attention to and have carefully researched the process over the last couple of years, and we have had a hard time understanding the process. In addition, we have not had the chance to participate in the DGD study process even though we have an Energy Only distributed generator for which we would like to gain FCDS.

We think the DGD Study process is an important opportunity for distributed generators, including those associated with microgrid projects. The ability to obtain FCDS is important to enable these resources to claim RA credit. The value of RA can be an important component when trying to justify the economic viability of a project. In addition, these small DG microgrid projects are often entered into by entities that are not familiar with all the nuances of interconnecting distributed generators. Providing project proponents with another option to obtain FCDS for their DG resources can be helpful, especially given the current and near-term capacity constraints in California's reliability market.

Also, microgrid projects, especially front-of-the-meter, multi-customer types, are more complicated and can often have financial or schedule constraints that prohibit engagement in the cluster study process that is required during interconnection to obtain FCDS. Allowing these projects to first interconnect as Energy Only, and then later apply for FCDS can help reduce barriers that can make projects infeasible. Providing two options to obtain FCDS after obtaining commercial operation would be advantageous. These two options would be: 1) the ability to re-enter the interconnection process and participate in a cluster study to elevate the status of an existing generator from Energy Only to FCDS, and 2) the ability to participate in the annual DGD study process.

References

CAISO, 2021. 2020-2021 DG Deliverability Assessment Results, California ISO, February 26, 2021.

CAISO, 2020. 2019-2020 DG Deliverability Assessment Results, California ISO, February 28, 2020.

Wright, Linda, 2021. Personal email communication.