Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors***
Reference Name	***EPIC 2.34 RF Sensors***
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Table of Acronyms

ADC	Analog to Digital Converter
AHPC	Asset Health and Performance Center
AMI	Advanced Metering Infrastructure (SmartMeter)
API	Application Programming Interface
ATS	Applied Technology Services
CPUC	The California Public Utilities Commission
CT	Current Transformer
CYME	CYME is a Power Engineering software that performs fault current magnitude calculation and location of circuit areas with a given magnitude
DRLM	Distribution Reliability Line Monitors
ECCVM	Event Classification through Current and Voltage Monitoring
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
FFT	Fast Fourier Transform
FPGA	Field Programmable Gate Array
GFRM	Grid Failure Risk Metric
GIS	Geographic Information System
GPS	Global Positioning System
HFTD	High Fire Threat District
IoT	Internet of Things
IPAC	Integrated Protection Auxiliary Cabinet
iPCGrid	Innovations in Protection and Control for Greater Reliability Infrastructure Development
LIDAR	Light Detection and Ranging
LPWAN	Low Power Wide Area Network
MV	Medium Voltage (1 - 35kV)
PD	Partial Discharge
PG&E	Pacific Gas & Electric
PHC	Proprietary Hardware Component
PSPS	Public Safety Power Shutoff
PT	Potential Transformer
RF	Radio Frequency
RFI	Request for Information
RMS	Root Mean Square
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
TAM	Texas A&M University
TD&D	Technology Development and Deployment
VPN	Virtual Private Network

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for EPIC Project 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors, also referred to as EPIC RF Sensor Project as listed in the EPIC Annual Report. The project was authorized in December 2017 and concluded in July 2020.

Many types of distribution faults and equipment failures have the potential to cause outages and even ignite wildfires. Insulators with partial discharge, or dielectric breakdown between conductors, can cause pole fires that can spread to vegetation or cause equipment arcing. Asset failures and conductor slap can rain sparks and molten metal to the ground, and most of these types of hazards have precursor signatures that can be detected by grid sensor technologies. In this project, PG&E sought to apply grid asset monitoring technology to locate developing hazards, issue targeted field patrols, and where appropriate, create corrective maintenance tags.

Through demonstration of the technologies evaluated in this project, PG&E was successful in detecting and locating multiple examples of conductor damage, vegetative encroachment, internal transformer discharge, fault-induced conductor slap, and arcing at a loose conductor clamp.

During 2018, PG&E demonstrated fixed-mounted prototype RF sensors for grid asset monitoring. The RF sensors collected both radiated and conducted RF emissions, and machine learning models were applied for prediction of the locations of deteriorated grid assets. Field verification was conducted using a directional ultrasonic acoustic detection tool. While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology.

In 2019-2020, PG&E evaluated RF Network Monitoring and Event Classification through Current and Voltage Monitoring (ECCVM) sensor technologies for application in grid asset performance monitoring. The RF Network Monitoring technology, with sensors distributed over the circuit, can detect and locate partial discharge (PD) activity on grid assets, while the ECCVM waveform analysis technology logs classified disturbance events and waveforms for the feeder from the substation.

PG&E observed that RF Networking Monitoring and ECCVM are complementary and together deliver high value in grid asset condition monitoring for reduction of wildfire risks. Although this project has provided a good evaluation foundation for both technologies, more work is planned to develop operational processes and system integrations to support larger scale deployments for wildfire risk reduction.

The RF Network Monitoring technology was demonstrated on a 12 kV 3-Wire distribution feeder in the Napa Valley area. The technology was successful in detecting “hot spots” of partial discharge activity that were field investigated and confirmed to result from asset conditions including conductor damage, vegetative encroachment, crossarm degradation, insulator and clamp issues. The technology provides an accurate source location to within +/-30 Feet to tightly target the field inspection.

The ECCVM technology was deployed on the same feeder as the RF Network Monitoring Technology, as well as five other feeders in the same vicinity. During the field evaluation, the ECCVM technology logged more than 38,000 events across all six feeders. Most of these events were normal operating events (e.g. motor starts, load variations, capacitor switching, regulator steps) which demonstrates the

ECCVM technology's capabilities in detecting operational issues, while around 8% were abnormal events (e.g. faults, arcing, transients, unbalanced capacitor switching). Of the abnormal events, about a quarter were low-level series and shunt arcing events.

ECCVM technology by itself cannot provide the location of developing grid asset conditions. However, it was confirmed that the RF Network Monitoring technology and other distributed sensors, such as Advanced Metering Infrastructure (AMI) and current/fault monitoring Line Sensors can be used to identify event location. Of these options, RF sensors provided the most tightly defined event location, while the AMI and Line Sensors can identify branches or sections of the feeder as source locations when aligned by timestamps.

Although originally thought of as competing technologies, PG&E found that the RF Network Monitoring and ECCVM technologies are complementary due to strength of RF technology in locating events and strength of ECCVM in classifying the events. Other types of grid sensor information could be added to the analysis in an ensemble technology monitoring approach to enrich overall solution capabilities.

The RF Network Monitoring and ECCVM technologies were manually monitored and analyzed for grid asset risk during the field evaluations. Under continued technology deployment, manual monitoring processes could continue for several years, beyond which a more automated, immediately proactive, and scalable monitoring solution would be recommended, especially for combined application of information from multiple sensor technologies.

PG&E envisions a data integration and analytics platform that could consume all grid asset data and apply analytical models to the correlation, risk assessment, decision making, work order management and tracking of detected grid asset conditions.

Key Objectives
Evaluation of real-time grid asset monitoring technologies to detect and locate developing hazards on the grid for interventional maintenance to mitigate wildfire risk.

Key Accomplishments

The following summarize some of the key accomplishments of the project over its durations:

- Demonstrated stationary RF sensor grid asset health monitoring with prototypes and an analytical model for locating deteriorated grid assets.
- Successfully demonstrated both RF Network Monitoring and ECCVM technologies in a field deployment and compared the performance and value of each technology
- Confirmed RF Network Monitoring technology's ability to identify and locate conductor damage, vegetative encroachment, and arcing conditions
- Demonstrated ECCVM technology's ability to identify and classify various normal and abnormal grid events. ECCVM relies upon other grid sensor information to determine event source location and has been shown to add value in an ensemble approach to effective grid asset health monitoring.
- Developed an understanding of analyzing and interpreting the sensor technology data through weekly calls with respective technology suppliers.
- Confirmed that both RF Network Monitoring and ECCVM technologies can be effectively applied to wildfire risk mitigation.

- Determined that RF Network Monitoring and ECCVM each have gaps in event detection that the other technology can detect, and developed an understanding of the reasons why and possible resolutions.
- The ECCVM technology offers high resolution current/voltage waveform analytics that can detect <2 cycle duration arcing events. These brief duration arcing events are not reliably detected by the current implementation of RF Network Monitoring technology, or by Line Sensors or AMI, leaving a gap presently in the locating these short duration arcing events. The RF Network Monitoring product monitors for 1/25 of each second, and often missed detection of short duration arcing events in the sampling window. The technology vendor is evaluating the ability to develop continuous RF monitoring which would close the gap.

Key Takeaways

This project has confirmed that RF Network Monitoring and ECCVM technologies are effective and complementary in grid asset monitoring for wildfire risk reduction. Further work is necessary to improve the technologies and integrate them into Operations, Distribution Management Systems and with other emerging technology applications such as the Rapid Earth Fault Current Limiter system.

The RF Network Monitoring sensors are distributed on the grid at approximately 3-mile spacing. Finding pole space for the sensors was an issue during the project, and total installation cost needs to be reduced for wide-scale deployment. PG&E continues to work on an improved design which would ideally use a low partial discharge (RF quiet) potential transformer mounted on the sensor pole as the power source. Some rural circuits may present challenges with wireless communication coverage for the sensors and PG&E continues to evaluate this issue. The RF Network Monitoring technology supplier is working toward a next generation sensor product that will have multiple feature improvements. PG&E plans to continue evaluation of this technology under expanded deployment and to refine strategies for deployment at scale.

Evaluation of ECCVM technology will continue to further develop techniques for investigation of short arcing events. PG&E is planning on staged expansion of ECCVM deployment on prioritized HFTD circuits, and continued effort to integrate the technology into operations.

Recommendations

This project has identified several areas that should have continued effort. The following summarizes these recommendations:

- Expand to larger scale RF Network Monitoring technology deployment to formalize operations integration and refine operational interfaces.
- Move Event Classification through Current and Voltage Monitoring (ECCVM) into production with a staged and prioritized deployment to higher risk circuits.
- Expand research into the technology gap on shunt-arcing.

Conclusion

Utility real-time health monitoring practices have been stagnant while available technologies have been unable to respond to the challenges presented by aging grid infrastructure and the increasing wildfire risks driven by climate-change. This project has demonstrated and evaluated the potential of recently commercialized technologies for the application of continuous grid asset health and performance monitoring. Just-in-time maintenance is an optimal strategy with lower cost and risk than periodic inspection-based maintenance that can miss rapidly developing grid asset hazards.

RF Network Monitoring Technology is effective in the detection and location of grid asset hazards that can be mitigated before materializing as faults and asset failures that can cause wildfire ignition. The technology is highly sensitive and able to detect low level partial discharge activity such as primary conductor damage and vegetative encroachment on secondary conductors. The technology can detect these conditions through accumulation of detections of energy dissipated in “hot spots” over extended durations (e.g. weeks). The RF Network Monitoring Technology presents moderate challenges and costs for widescale deployment but is worthy of continued investment and optimization given the potential benefits, including operational cost reductions and wildfire mitigation value. There may be some locations that cannot be cost effectively included in RF Network Monitoring strategies due to a lack of cellular network coverage.

The ECCVM technology detects and classifies normal operating events and abnormal events that can be predictive of developing hazards. The ECCVM technology is not able to detect the same low-level persistent conditions that RF monitoring can, but it is able to detect brief <2 cycle duration arcing events that the RF Network Monitoring Technology may not detect, or may not detect in a timely manner. ECCVM technology cannot determine the source location of detected events and relies upon distributed sensor technologies for this purpose. Asset hazard location identification has been demonstrated with RF Network Monitoring Technology, Line Sensors and AMI.

PG&E has concluded that effective grid asset health and performance monitoring is best delivered through combining sensor technologies in an ensemble approach, with each technology adding uniquely to the event classification, location and prioritization of detected hazards. The ensemble approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance of the distribution system. When there are areas that cannot be served by RF or Line Sensor components, AMI may be able to provide some of the necessary information for effective grid monitoring. PG&E’s Distribution and Grid Monitoring Roadmap and Implementation Plan proposes to expand deployment and operation of emerging technologies, such as those demonstrated in this project, that provide grid event data for real-time monitoring and analytics of asset health and performance. PG&E strives to become more predictive of developing hazards on the electric distribution system for implementation of proactive maintenance in order to reduce wildfire risk and improve public safety. This work focuses on Tier 2 and Tier 3 High Fire Threat District areas of PG&E’s service territory.

During the technology demonstration with limited deployment, the sensor data was manually analyzed and reacted upon. PG&E recognizes that the manual approach is not scalable from a resource allocation perspective or due to the need to address detected grid asset conditions in a timely manner. Wide-scale adoption of grid monitoring technologies would require a sensor data integration and analytics platform to provide automated analysis and response for asset hazards. PG&E has plans to investigate approaches to this problem, which can enable timely analysis and response to data from multiple grid sensor technologies that report asset health conditions.

2 Introduction

This report documents the EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors project results and achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[1], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*[2], which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[3]

The decision also required the EPIC Program Administrators[4] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial

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[1] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF

[2] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF

[3] Decision 12-05-037 pg. 37

[4] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)

investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[5]

On February 7, 2017, PG&E filed a Tier 3 Advice Letter 5015-E[6] to request CPUC approval of additional EPIC projects for its EPIC 2 triennial plan, which included EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors. The CPUC granted approval of the project on August 10, 2017 through Resolution E-4863[7]. Through the annual reporting process, PG&E kept CPUC staff and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

3 Project Summary

This project demonstrated the application of grid sensor technologies for predictive risk identification and wildfire risk mitigation. The path of the project developed incrementally between 2017 and 2019, with each step providing additional discovery on the application of sensor technology in support of wildfire risk mitigation.

The initial effort focused on integrating RF monitoring into conductor-mounted energy harvesting Line Sensors that monitor load current and faults. Upon a Request for Information, no supplier responded with a direct path to integration of RF monitoring into Line Sensors, or even offered a fixed-mounted RF technology. The best proposal came from a supplier with mobile RF survey expertise, that proposed a demonstration of pole-mounted prototype sensors and the application of machine learning to identify and locate grid asset hazards. The prototype RF sensor, called a Distribution Reliability Line Monitor (DRLM), was developed and demonstrated in the field.

The supplier manufactured ten of the prototype sensors, called Distribution Reliability Line Monitors (DRLMs) and completed lab testing to confirm operation with two communication gateways to deliver the sensor data to a Microsoft Azure portal. The DRLMs measured both radiated and conducted RF emissions to assess the condition of the operating electrical equipment. Radiated RF emissions broadcast radially in all directions from the emission source. Conducted RF emissions couple onto the distribution line and travel in both directions on the continuous conductor. The conducted emissions provide a direction to the emission source, along the electric conductor path. Deployment of multiple DRLMs in the project study area was necessary to provide for geospatial analysis and triangulation to the RF emission source from the radiated and conducted RF emissions recorded by multiple DRLM units. The battery powered DRLMs recorded RF emissions for 30 seconds of each hour.

The devices were deployed on the San Francisco Peninsula in a 1 sqkm area around a known RF-active grid component, which would provide model training data. The machine learning model predicted

[5] In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

[6] Tier 3 Advice Letter 5015-E: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5015-E.pdf

[7] Resolution E-4863: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M193/K790/193790420.PDF

locations with asset issues, which were confirmed in the field with the use of directional ultrasonic detection tools. The model predicted asset hazard location with 1-2 conductor spans of actual location. Conducted RF emissions alone provided the best model forecast accuracy, and inclusion of radiated RF emission data detracted from model forecast accuracy.

While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology. The project is discussed in more detail in section 4.1 Technology Demonstration 1 – Prototype Fixed-Mounted RF Sensor.

During summer of 2018, PG&E benchmarking for wildfire risk mitigation discovered an early commercial pole-mounted RF Network Monitoring technology that had early success in detecting grid asset conditions in limited deployments outside of America. This technology was evaluated under EPIC 2.34 and is discussed in section 4.2 Technology Demonstration 2 – RF Network Monitoring System. The RF sensors are deployed at approximately 3-mile spacing on overhead distribution poles to cover mainline and significant branches of each feeder. The technology was evaluated on a 12kV, 3-wire feeder in the Napa Valley. The strategy to locate RF emissions used time-of-flight (proportional to distance) for the signal to reach two adjacent sensors and proved to be accurate within 30 Feet. The RF sensors in Technology 2 monitor RF for 40ms of each second, which proved valuable to monitoring and trending “hot spots”.

Late in 2018, PG&E learned of a third sensor product “Event Classification through Current and Voltage Monitoring” (ECCVM) with application for grid asset health monitoring. PG&E determined that ECCVM would be useful for both confirmation of asset hazards identified in the RF Network Monitoring evaluation, and as a comparison technology to help PG&E in determining a strategy for effective for grid asset monitoring. This third technology demonstration is discussed in Section 4.3 Technology Demonstration 3 – ECCVM. The ECCVM technology classifies events well and detects even very brief <2 cycle arcing, but requires supplemental technologies to be able to determine event location. During the evaluation, there was success with using the RF Networking technology, AMI, and Line Sensor data to determine the location of ECCVM events.

In the evaluation of the RF Network Monitoring System and ECCVM technology, there were some events that both technologies detected, and these were long arcing events. RF Network Monitoring detected partial discharge hot spots caused by damaged conductors and vegetative contacts that the ECCVM technology did not detect. The ECCVM technology detected short series and shunt arcing events that the RF Network Monitoring technology did not detect. We attribute these findings to the fact that the RF Network Monitoring technology measures RF for 1/25th of each second, and may often miss brief arcing events in the sampling window. However, the RF Network Monitoring technology is very good at detecting persistent partial discharge patterns over many accumulated sampling periods. ECCVM technology, through advance signal processing, is able to detect less than 2 cycle duration arcing. A solution to this disparity in detection would be provided through continuous RF monitoring, which the technology supplier is evaluating for future products.

RF Network Monitoring and ECCVM are complementary and work well together. The ECCVM performs classification and captures waveforms of events which are useful in understanding the phenomena observed. The ECCVM can be used successfully with a variety of other sensor technologies to determine event location.

PG&E concludes that the best approach to grid asset condition monitoring is to apply an ensemble of sensor technologies that best fit the circumstances of each feeder. ECCVM is low cost sensor technology that covers the whole feeder with one substation installation. RF Network Monitoring technology is valuable for monitoring persistent partial discharge activity and can accurately locate asset issues. There may be areas unsuitable for either RF Sensors or Line Sensors, due to poor cellular coverage. For these locations, more advanced SmartMeter technology, able to stay energized and record voltage sags, could be a low-cost solution.

PG&E will continue evaluation of both RF Network Monitoring and ECCVM technologies as components of the long-term strategy for grid asset condition monitoring.

3.1 Issue Addressed

Some types of grid failures cannot be predicted in advance, such as vehicle collisions with assets, trees falling into assets, and many types of animal contact incidents. However, many types of grid asset hazards can be detected in the incipient stages, offering utilities the opportunity to intervene with corrective maintenance before the hazards materialize as faults and asset failures. Predictive maintenance is beneficial due to lower operating costs, reduced fault and collateral asset damage to the grid, safer working conditions during normal business hours, better reliability and reduced risks for the public and the environment.

Many types of faults and equipment failures have to potential to ignite wildfires. Insulators with partial discharge can cause pole fires that can spread to vegetation, equipment arcing. asset failures and conductor slap can rain sparks and molten metal to the ground, and most of these types of hazards have precursor signatures that can be detected by sensor technologies.

Arcing, sparking and partial discharge conditions emit Radio Frequency (RF) and utilities have for many years applied mobile RF survey technology to detect these incipient conditions. Mobile RF survey technology simultaneously records GPS coordinate and RF emission data as asset corridors are patrolled by vehicle or helicopter. Multiple patrol passes are necessary to eliminate spurious RF signals and determine locations with RF detection on multiple passes. The data is analyzed after the series of patrols are completed, and then field personnel return to the hot spots with a directional ultrasonic acoustic detection tool to identify specific components at risk.

Due to the repeated patrol requirement over long distances, mobile RF surveys are expensive to perform and provide only a snapshot of the grid asset health at the time of the patrols. The health and performance of aging grid infrastructure is dynamic and can change rapidly under operational stress and extreme weather patterns. For these reasons, PG&E sought to evaluate fixed-mounted RF sensors for continuous, real time grid asset health and performance monitoring.

At the inception of the EPIC 2.34 project in 2017, PG&E was planning to expand deployment of conductor-mounted energy harvesting Line Sensors which monitor load and fault current, and capture fault waveform patterns. The primary use cases for Line Sensors at the time were load switching and outage restoration. PG&E wanted to expand on the benefits of Line Sensor through the addition of RF monitoring technology and proposed EPIC 2.34 to explore this possibility.

After the wildfires of Fall 2017, the priority use case for continuous RF monitoring shifted to grid asset health and performance monitoring for wildfire risk mitigation.

3.2 Project Objectives

To accomplish the objectives for the EPIC 2.34 RF Sensors project, the following key items were performed:

- Deploy the RF network monitoring system on the PG&E network and assess its capabilities over several months
- Perform a technology review of the RF network monitoring system and understand its limitations and strengths relevant to PG&E's needs.
- Assess the information provided by the RF network monitoring system and work with local PG&E crews to gauge its accuracy and take action where appropriate.
- Provide key input for the RF network monitoring technology roadmap and determine how the technology may be applicable to PG&E's long-term objectives for preventive maintenance:
    - Assess the scalability of the solution architecture and develop roadmap options for operational deployment opportunities; and
    - Define predictive maintenance strategies for improved distribution network performance and fire safety.

To supplement the RF sensor technology the following key objectives were developed for the ECCVM technology:

- Deploy ECCVM monitoring on the same feeders as the RF sensors over the same project period.
- Deploy ECCVM monitoring on an additional 5 circuits that do not have RF sensing to capture conditions that RF might not capture, giving a further indication of potential value of RF technology, as well as demonstrate an alternative to RF technology.
    - Utilize other existing monitoring technology, such as line sensors and Advanced Metering Infrastructure (AMI), in an ensemble approach to identify incipient conditions.
- Assess the information provided by ECCVM in conjunction with the RF sensor information and other sensor information, to determine location of incipient and systemic field conditions.
- Evaluate how ECCVM can complement PG&E's long-term objectives for operations and preventative maintenance.

More detailed technology specific objectives are discussed under each technology in Section 4.

3.3 Scope of Work and Project Tasks

Per our commitment as documented in PG&E's 2017-2019 EPIC Annual Reports, the project Scope of Work is defined as:

- Assess technical feasibility of various sensor products and validate opportunity for business benefits;
- Develop solution designs, develop test plans, and conduct testing at ATS; and
- Conduct field demonstrations of various products and develop post-EPIC roadmaps for integrating capabilities in production.

Consistent with these high-level statements detailed tasks and milestones were defined for each of the sensor technologies. These are included, by technology, in Section 4 of this report.

3.3.1 Tasks and Milestones

This project had multiple technology streams which added to the complexity of task scheduling and definition of milestones. However, the overall project structure followed the major tasks and milestones listed below:

Task 1: Benchmarking and Planning – Initial efforts required significant review of literatures, assessment of different supplier technologies and benchmarking these technologies. An RFI was issued to broadly assess available technological options. Once key suppliers were selected, contracts were developed and executed per program requirements.

Milestone 1.1 – RFI for sensing technologies

Milestone 1.2 – Execution of contracts with key suppliers

Task 2: Engineering Design and Constructability Review – Sensor technologies were reviewed by internal engineering groups as needed. Each technology went through a formal constructability review. Complete material lists and construction schedules were developed. Testing of devices was conducted as needed to ensure field installations went smoothly.

Milestone 2.1 – Testing of devices

Milestone 2.2 – Develop schedule for procurement and construction

Task 3: Construction and Commissioning – Key hardware was collected prior to field installation. Final construction was done by internal resources with assistance from suppliers as needed. Once installed the sensor technologies followed supplier and corporate commissioning process.

Milestone 3.1 – Receive key hardware

Milestone 3.2 – Constructed/install sensor technology

Milestone 3.3 – Commission sensor technology

Task 4: Demonstration and Operation – Once each sensor technology was operation assigned team members conducted daily review of event activities. Periodic team reviews of the collective data for the sensors was conducted to identify system issues and direct field patrols or corrective action. Periodic meetings were also held to keep key stakeholders informed of activities and monitor progress.

Milestone 4.1 – Periodic meetings for review of recorded events

Milestone 4.2 – Field visits for key events

Task 5: Project Closeout – Completion of the project required collective compiling of sensor data. Final reporting was done first within each technology stream and then collected for full project results. Presentations on the results were made internally to key stakeholders.

Milestone 5.1 – Complete final report

Milestone 5.2 – Complete final presentations

4 Project Activities, Results, and Findings

This section describes the activities, results and findings from field evaluation of three grid asset monitoring technologies.

RF Sensor 1 is a pre-commercial prototype fixed-mounted RF sensor that was evaluated to demonstrate that fixed-RF sensors can be used to locate grid asset showing deterioration. In this project, the battery-operated prototype RF sensors recorded hourly measurements and applied machine-learning to assess asset health on distribution poles in project study area.

RF Network Monitoring System is an early commercial fixed-mounted RF sensor that monitors the distribution assets between each pair of sensors that are mounted up to 3 miles apart on distribution poles. PG&E learned about the availability of this technology halfway through the evaluation of RF Sensor 1 prototype technology. Each distributed RF sensor evaluates measurements for approximately 40 mS of each second, and reports the data to an application portal. The application portal is preloaded with the distribution circuit GIS with distribution pole locations representing conductor paths. To determine RF detections that arise from the monitored path between two sensors, RF data from individual sensors are matched to RF detections of the other sensor in pair, and RF source locations are determined by time-of-flight (proportional to distance) for the matched RF detections to reach each sensor in the pair.

Event classification through current and voltage monitoring (ECCVM) technology is a substation mounted sensor system that monitors three-phase voltages and currents at the circuit level. The technology has undergone years of development to produce a rich library of event signatures and patterns, allowing waveform capture and classification of grid disturbances.

4.1 Technology Demonstration 1 – Prototype Fixed-Mounted RF Sensor

A prototype RF sensor called a Distribution Reliability Line Monitor (DRLM) was developed and demonstrated in the project. The DRLMs measured both radiated and conducted RF emissions to assess the condition of the operating electrical equipment. Radiated RF emissions broadcast radially in all directions from the emission source. Conducted RF emissions couple onto the distribution line and travel in both directions on the continuous conductor. The conducted emissions provide a direction to the emission source, along the electric conductor path. Deployment of multiple DRLMs in the project study area was necessary to provide for geospatial analysis and triangulation to the RF emission source from the radiated and conducted RF emissions recorded by multiple DRLM units.

4.1.1 Technology Objectives

To accomplish the objectives of the project, the following key items were developed:

- Evaluate the effectiveness of fixed-mounted RF sensors in monitoring and locating grid asset conditions.
- Develop prototype RF Sensors to record both radiated and conducted RF emissions and evaluate their effectiveness in monitoring and locating grid asset issues.
- Compare the value of radiated and conducted RF emissions in determining source location.

- Design a data communication network to collect hourly data from sensors during field trial evaluation.
- Determine the value of environmental variable data in grid asset condition assessment
- Apply machine learning analysis of sensor data and make predictions about deteriorated assets and their location.
- Field verify predicted distribution asset failures and their location.

4.1.2 Tasks and Milestones

Project delivery was set up through the following tasks and milestones:

- Kick-off Meeting
- Knowledge transfer to PG&E
- System Design Presentation
- Circuit analysis to determine sensor and communication component layout
- Design and Develop Field Trial Components
- Test Field Trial Components
- Deliver Field Trial Equipment with Installation and Commissioning Instructions
- Provide Access to Application Portal
- Field Trial Report
- Technology Roadmap Workshop
- Technology Roadmap Presentation
- Final Report

4.1.3 Technical Development and Methods

DRLM Prototype RF Sensor

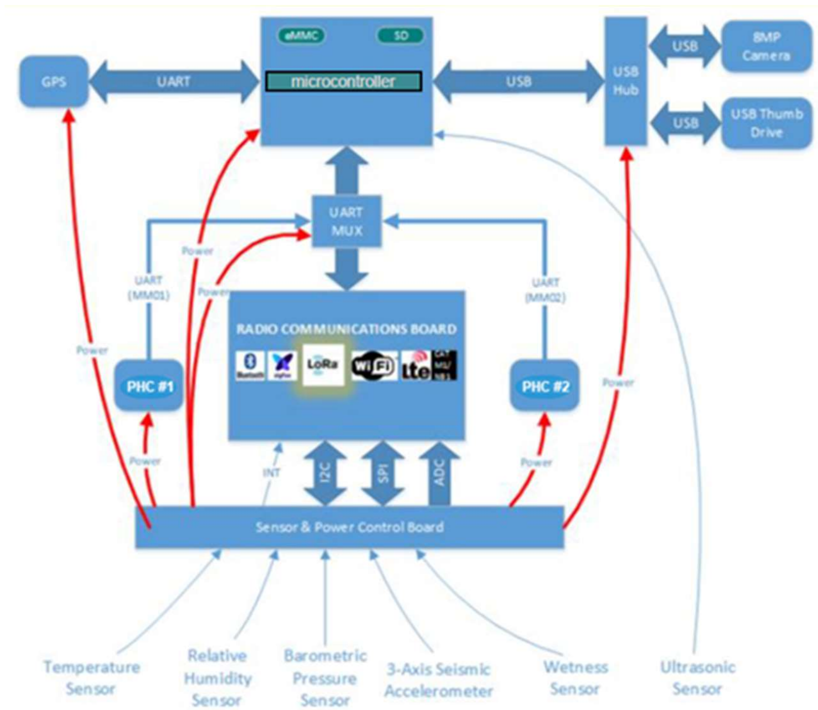
The DRLM RF sensor prototypes employed the use of the supplier's proprietary hardware component ("PHC") to process RF emissions through Fast Fourier Transform (FFT) and other techniques used to analyze the RF signal and discriminate grid asset failure patterns from other RF emissions. The analytical techniques resulted in a proprietary "Grid Failure Risk Metric"(GFRM) indicating the magnitude and persistence of RF emissions and the severity of asset risk.

The PHC provided for Edge Computing analysis of grid failure signature pattern and reduced the data volume transmitted to the Azure analytical platform which focused on machine learning algorithms and geolocation predictions of deteriorated equipment.

A vertically oriented antenna was connected to one of the PHC components to detect radiated RF emissions. A horizontally oriented antenna was connected to the second PHC component to detect conducted RF emissions emanating from conductors.

Figure 1 shows the DRLM block diagram of components.

Figure 1 DRLM Block Diagram



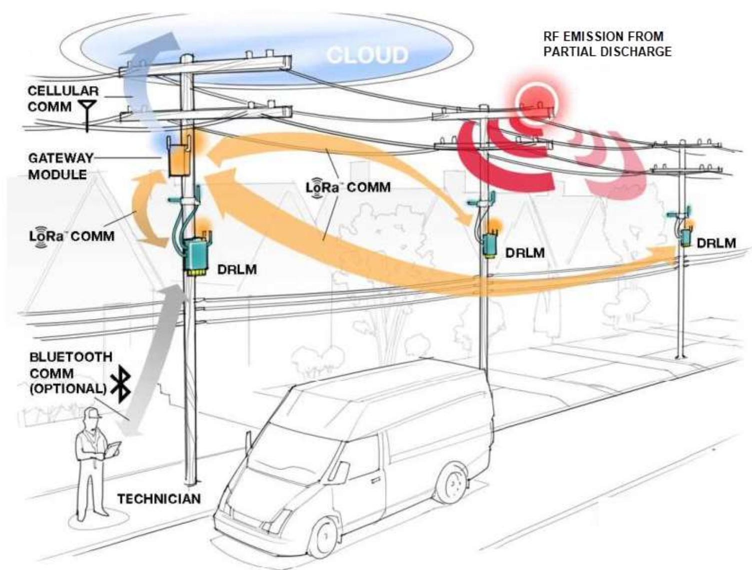
LoRaWAN Spoke-and-Hub Communication

The DRLMs were designed to collect data regularly on an hourly schedule. The collected data was transferred to a cloud Microsoft Azure Web Portal via two deployed LoRaWAN gateway Hub units.

LoRaWAN is a Low Power Wide Area Network (LPWAN) specification intended for wireless battery-operated Internet of Things (IoT) in a regional, national or global network. LoRaWAN targets key requirements of IoT such as secure bi-directional communication, mobility and localization services.

The DRLMs were equipped with peer-to-peer LoRaWAN Spoke networking capability to form a linear mesh data communication network to the LoRaWAN gateways. This allowed the DRLMs to transfer data through other DRLMs to the gateway and reduce the number of required network gateways deployed for the evaluation project, as well as decrease the likelihood of communication issues caused by inability of the DRLMs to reach a gateway directly. Figure 2 illustrates the communication network for the field demonstration. The DRLMs were not installed on every pole, the illustration is for concept only.

Figure 2. Illustration of the installed DRLM and Network Components



DRLM Power Source

Lithium cell battery banks were used to power the DRLMs. A battery pack was selected to supply the DRLMs for more than the duration of the field evaluation period. Not needing to connect the DRLMs to pole secondary power greatly simplified the requirements, planning/design scope and lead time for deployment.

The main processor remained constantly powered. The sensors, CPU, PHCs, and GPS assemblies were powered on as needed.

The system was designed to power up once per hour, record sensor measurements, and then go back to sleep. The total time required for each measurement sequence, including startup, acquisition, processing, and shutdown was approximately 30 seconds. To extend battery life, individual circuits were powered up only as long as needed and then restored to their sleep state.

Data Storage

Two data storage facilities were designed in the DRLM. A non-volatile, removable SD memory card was used to record all data recorded by the DRLM. Additionally, all data was backed up onto a memory stick.

DRLM Lab Testing

Prior to delivery and field installation, the DRLM sensors were tested in a laboratory environment. A High Voltage Laboratory contracted to create radiated and conducted RF emissions by energizing a deteriorated insulator at line voltage. The sensor was operated to confirm that all measurements were being captured and that the Data Network could receive the data from the sensor.

The DRLM system of partial discharge emission detection, discrimination and analysis, and data transport was successfully tested. The DRLM Dual PHC detection was demonstrated to perform well both to discriminate and measure partial discharge from a deteriorated equipment sample both as radiated and conducted emissions. The system also demonstrated the rejection of RF emissions that were not related to the deteriorated equipment sample.

There was expected attenuation of sensitivity as the antennae were moved away from the source, but there was no interruption of operation or analysis in this result. The attenuation effect was be used in the Geospatial Vector Analysis to recognize near field vs. far field emissions. The folded dipole antenna design was more sensitive (can hear further) than the tested monopole antenna for radiated emissions and will be used in the field deployment.

The LoRaWAN network demonstrated proper operation in an electrically noisy environment and passed all data without error or any need for repeated messages.

Grid Analysis and Deployment Plan

A goal of the field trial was to plan the deployment around a pre-existing and known RF-active distribution grid component. The RF-active component with confirmed location would provide training data for the machine-learning analytical model. It was expected that additional incipient asset failure conditions would develop and manifest of the duration of the active field trial. The targeted field trial area was the San Francisco Bay Peninsula area.

PG&E provided the supplier GIS asset location data for the selected distribution feeders in the target area. The supplier performed mobile RF surveys in the area to identify locations with RF-active grid components. The DRLM deployment was then designed to surround the RF-active grid component with the 10 DRLM sensors covering an area of approximately 1 km^2.

DRLM Delivery and Installation

The ten DRLM sensors and two LoRaWAN Gateways were delivered to PG&E and installations were completed by 8/21/2018. Following installation, the entire network was tested and found to be functioning properly.

Figure 3 shows the DRLM sensor and gateway during installation, and mounted to a pole.

Figure 3. DRLM Sensor Installation

Figure 4 shows the locations of the 10 DRLM sensors and two Gateways. The Orange callouts indicate DRLM locations, Green callouts are the Gateway locations, and the original RF-Active Distribution Grid component is noted by the yellow circle. DRLM unit A4 was placed on the pole with pre-identified defective grid component to provide training for the analytical model.

Figure 4. DRLM and Gateway Locations, showing original RF-Active Grid Component

4.1.4 Analytical Approach

The supplier's data scientists developed a model for the evaluation of DRLM sensor data and the forecast of deteriorated equipment location within the study area. The model was based upon scientific formulae for radiated and conducted RF emission detections and their decay rates over distance from source.

Distribution component failure RF analysis (e.g. processing of RF file to remove noise and discriminate information relevant to asset health monitoring) was completed at the DRLM unit through proprietary processing to avoid large RF file transmission. A Digital Twin cloud-based network allowed the Artificial Intelligence Network (AIN) to evaluate a variety of sensor/detector scenarios. Sensors could be removed from the analysis and the resultant change in the AIN output could be evaluated.

Modeling was performed using a Bayesian Hierarchical Model. Radiated and conductive measurements were used to infer a latent Grid Failure Risk Metric value at each pole on each day between the start and end of data collection.

4.1.5 Challenges

The following challenges were encountered during the deployment of this RF sensor technology:

1. Location of RF emission source is a significant issue in the evolution from mobile RF survey technology to fixed-mounted RF sensors that provide continuous monitoring. In mobile RF survey technology, the asset corridor is patrolled while simultaneously recording RF emissions and GPS coordinates, such that strong persistent RF emissions can easily be associated to asset location. With fixed-mounted RF sensors, remote RF source locations must be inferred from multiple stationary RF sensors. This problem is approached by the machine learning component of project.
2. DRLM A9 stopped reporting new data on 9/20/2018 at 4:30PM. At the end of the field trial, the USB drives were retrieved, and it was found that the DRLM recorded data to end, but had not transmitting the data to gateway, possibly due to a defective antenna. The recovered data was included in the analysis and results.
3. Azure, the Microsoft platform on which the DRLM data was collected, was down for 36 hours between 9/4/2018 and 9/5/2018. This time period appears as a gap in all data collected.

4.1.6 Results and Observations

Analytical Model Performance

The DRLM sensors collected hourly data samples from August 21 through October 29, 2019, except for the 36 hours when the Azure platform was down. The sensors were able to detect both radiated and conducted emissions from a known deteriorated equipment location that was selected for the project. This known location provided a benchmark for the AIN network and supplied initial study data. As the project progressed, RF emission data from other deteriorated devices in the project area was sensed, evaluated and transmitted to the AIN for use in the grid resiliency forecast algorithms. The DRLM preprocessed data called Grid Failure Risk Metric (GFRM) along with the data from the other detectors allowed the AIN Machine Learning Algorithms to create forecasts of potential deteriorated equipment locations.

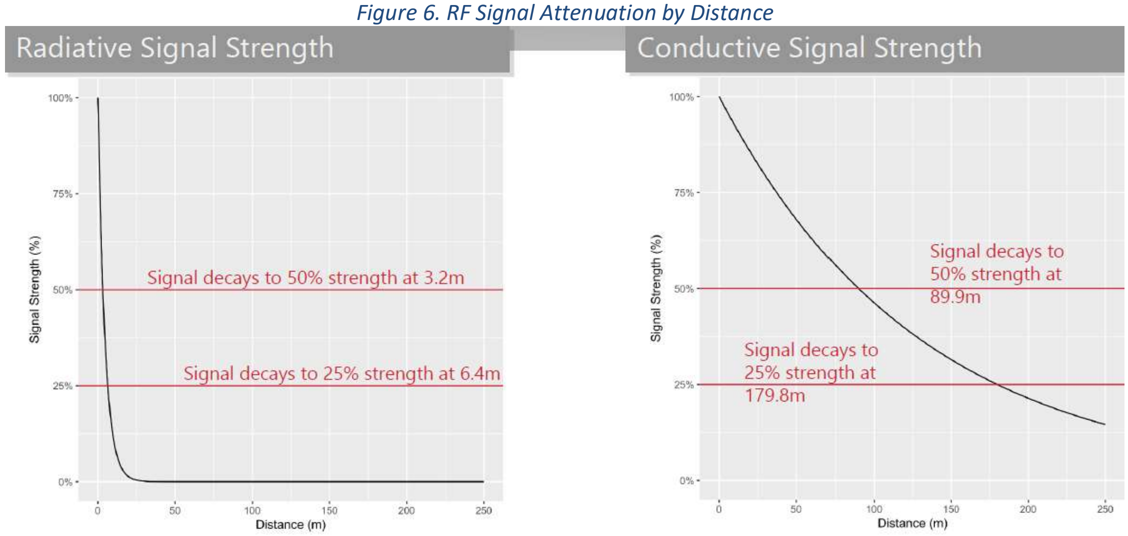
The final inferred deteriorated equipment locations are shown in Figure 5, where distribution poles are represented by rectangles shaded with predicted relative Grid Failure Risk Metric. The lightest colored rectangles indicate poles with highest Risk Metric. The DRLM sensor poles are indicated by rectangles with a yellow border. At the end of the field trial on 10/22/2018, engineers verified ground-truth defective equipment poles with commercial directional ultrasonic acoustic measurement tools, and located five asset issues indicated by the blue circles. The model forecast degraded equipment locations within 0 to 2 conductor spans from field verified locations.

Figure 5. Machine-Learning Model Accuracy

Radiated and Conducted RF Emission Measurements

Conducted RF Emissions travel 30x as far as radiated emissions. Figure 6 shows the signal attenuation by distance.

Figure 6. RF Signal Attenuation by Distance



The analytical model was formally assessed with a Receiver Operating Characteristic (ROC) Curve. The Area Under the Curve (AUC) metric gives a general measure of accuracy. Comparing the model accuracy with inclusion of both radiated and conducted RF measurements, with radiated RF measurements alone, and with conducted measurements alone, the conducted RF alone provided the best accuracy. In contrast, radiated RF measurements alone indicate performance with the worse than random chance (<50%) of prediction accuracy. The Model Accuracy Comparison is summarized in Table 1.

Table 1. Model Accuracy Comparison

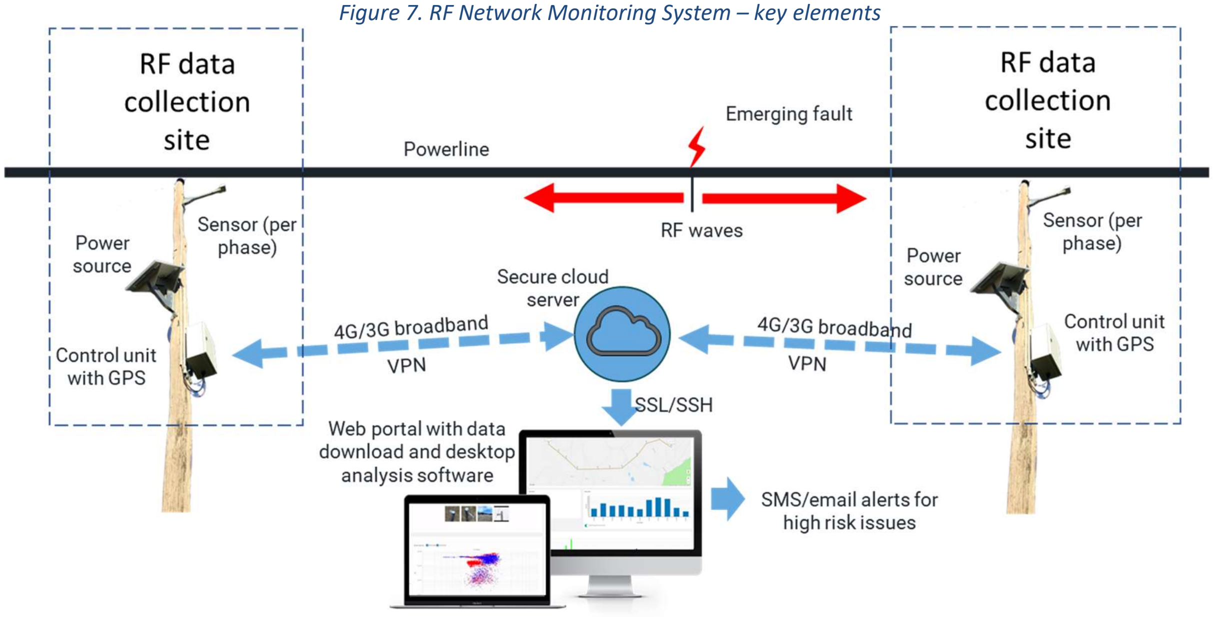
RF Data Included in Analysis	Model Accuracy (AUC)
Radiated RF Only	42.7%
Conducted RF Only	91.3%
Radiated and Conducted RF	81.6%

While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology. The supplier indicated forward strategies to offer a more compact pole-mounted version of the RF sensor as well as continued pursuit of integration into a conductor-mounted Line Sensor product.

4.2 Technology Demonstration 2 – RF Network Monitoring System

The RF network monitoring system is illustrated schematically in Figure 7. The tangible elements of the system are a set of pole-mounted RF data collection units spread across the network at (nominal) three-mile spacing. The more complex and powerful elements of the system are a set of 'big data' processes and algorithms running on secure cloud-based IT infrastructure accessed by utility teams from their desktops via encrypted secure browser sessions.

Figure 7. RF Network Monitoring System – key elements



The RF network monitoring technology deployed in the trial was based on architecture in which geographically distributed set of smart sensors performing edge-computing (RF data collection units installed on poles up to three miles apart along monitored powerline paths) deliver data via encrypted and authenticated data communication links to a secure cloud-based storage and data processing platform. Results can be explored remotely using a secure web-based data-visualization portal. Alternatively, data can be downloaded for local desktop analysis.

Each RF data collection unit monitored signals on powerline primary conductors using wide-band RF coupling devices (sensors) located outside safe approach distance limits. RF data collection units performed initial signal pre-processing and sent a digest of signal data to the secure cloud server to enable 'big data' analysis of data from multiple locations.

Items installed on the pole at each selected RF data collection site included RF-coupling sensors, a control unit with GPS and data communication antennas and solar system battery, and the solar panel. An ADC-FPGA combination performed on-site high-speed signal processing. Each unit also contained a Linux-based set of processes to manage and monitor dataflow and overall unit health.

4.2.1 System Concepts

The RF network monitoring technology deployed for the trial was designed to realize a specific set of concepts: continuous monitoring; incipient fault detection and location; and risk classification.

- Continuous monitoring of network condition: Experience of powerline-caused fires around the world has demonstrated the inherent limitations of routine inspections at set intervals, often years apart. These limitations were confirmed in the trial project by incidents that developed material risk of a fault within hours or days of initial detection. All incipient faults detected in the trial proved to be intermittent in activity and continuous monitoring proved essential to understand the development of an asset defect to the point of failure. Point-in-time detection of intermittently active threats is necessarily limited to the chance the issue is active when the inspection or test occurs. Hence, the desirability of continuous monitoring.

- Detection of incipient faults: The hypothesis underlying RF network monitoring is that high-frequency signals are emitted in the early stage of development of many asset-failure faults. Asset-failure faults have historically been prominent in extreme fire-risk conditions and have caused catastrophic fires. Examples include tree branch-touch, wires down (both due to conductor failure and failure of fittings such as clamps), flashover due to partial discharge or micro-arcing within or on the surface of assets. The trial confirmed these problems generate RF signals in early stages of their development and these signals can be detected at a distance of some miles by suitable monitoring equipment. Continuous monitoring allowed progressive development of incipient faults to be tracked over time so response decisions could be taken remotely with confidence well before the fault occurred.

- Location of incipient faults: Rural powerlines can be more than fifty miles long, so automated accurate location of any identified problem is a high priority for network operators. The fault location concept used in the RF network monitoring system deployed for the trial was 'time-of-flight', i.e. signal sources were located using the time of arrival of signals at multiple RF data collection units operating on a common clock derived from precision time synchronization via the GPS satellite network. This technique is enabled by GIS asset data on the conductor path between adjacent sensors, and the fact that 'time-of-flight' is proportional to distance. Experience in the trial confirmed location accuracy to be thirty feet or better in many cases.

- Classification of risk: Whenever an incipient fault is detected, the type of fault is important information for network operators. Efficient deployment of responder resources relies on the ability to distinguish signals that indicate significant risk such as mid-span vegetation touches or broken strands or high-energy in-tank transformer partial discharge, from signals that indicate no (in the extreme) risk such as signals from raindrop impacts or farm equipment. Time-frequency analysis of detected signals provided signature recognition capability as an integral feature of the RF network monitoring system, though other factors were also important in fault-type identification such as signal energy, the local environment at the location (vegetation present or not), frequency of occurrence, signal waveform, intermittency, time-of-day and seasonal variation, weather conditions, metering data, etc.

4.2.2 Technology Objectives

PG&E's 2019 EPIC Annual Report records the project objective as: 'Demonstrate distribution sensor products that provide indicators of imminent asset failure and real time monitoring of PG&E rights-of-way'.

This goal was reflected in four specific project objectives set out in the Contract's Statement of Work:

1. Deploy the RF network monitoring system on the PG&E network and assess its capabilities over a six-month period.
2. Perform a technology review of the RF network monitoring system and understand its limitations and strengths relevant to PG&E's needs.
3. Assess the information provided by the RF network monitoring system and work with local PG&E crews to gauge its accuracy and act where appropriate.
4. Understand the RF network monitoring technology roadmap and determine how the technology may be applicable to PG&E's long-term objectives for preventive maintenance:
    a. Assess the scalability of the solution architecture and develop road-map options for mass deployment opportunities; and
    b. Define predictive maintenance strategies for improved distribution network performance and fire safety.

To accomplish these objectives, the following key items were developed for the project:

- RF data collection units adapted to suit PG&E networks; and
- US-located secure cloud data processing infrastructure.

4.2.3 Tasks and Milestones

The Statement of Work incorporated into the RF network monitoring system procurement contract details nine milestones for the project:

1. Execute contract and place order.
2. Hold project kick-off meeting.
3. Select sites for installation of RF data collection units.
4. Hold knowledge transfer workshop.
5. Deliver, install and commission RF data collection units.
6. Train PG&E staff in use of RF network monitoring system web portal.
7. Field investigate to verify grid conditions identified by the RF sensor system.
8. Deliver preliminary field trial report(s).
9. Develop future technology roadmap.
10. Deliver final project report.

4.2.4 Technical Development and Methods

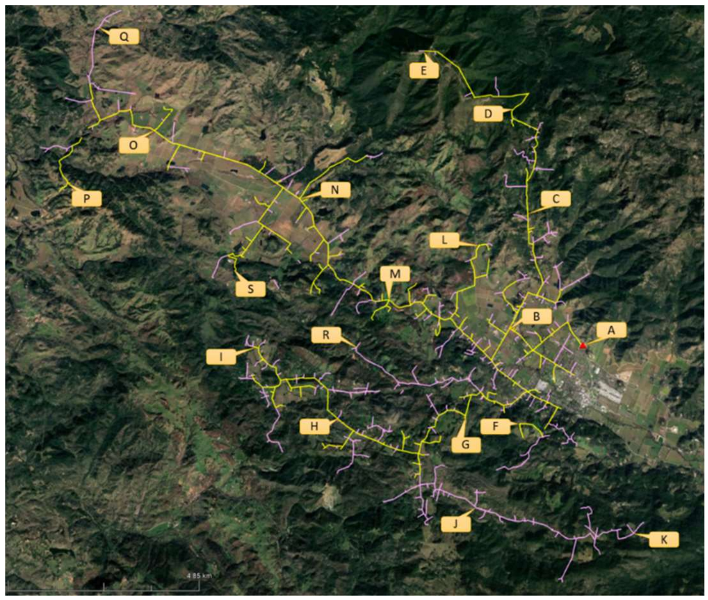
At the time of contract execution and order placement, it was intended that between 30 and 50 data collection units would be deployed in the trial to give coverage of about 75-125 route-miles of network. As the project plans were further developed, it became clear that the availability of field crews to perform equipment installations would be the limiting resource and the trial scope was trimmed to the minimum contract quantity of 30 RF data collection units.

PG&E selected HFTD circuits in the Napa Valley area for the Trial:

- Substation A Circuit 1101, a 12kV three-wire circuit: 19 RF data collection units covering 19 inter-sensor paths with a total length of 46 route-miles (Figure 8 shows the deployment concept for this circuit, Sensor A is the substation); and
- Substation B Circuit 2104 (part), a 21kV four-wire circuit: x RF data collection units covering nine inter-sensor paths with a total estimated length of 23 route-miles.

Using PG&E's network GIS data, the supplier developed concept plans showing suggested locations of RF data collection units to give effective coverage of the selected circuits. Each suggested RF data collection site was audited by PG&E to verify cellular data service coverage, pole mechanical design, pole 'real estate', and construction access. In some cases, PG&E moved the planned location to accommodate constraints in these site qualifications.

Figure 8. Feeder concept plan showing suggested RF data collection sites



4.2.5 System Installation

Installation of the 19 RF data collection units on a Napa Valley Area Circuit 1101 commenced mid-June 2019 and continued at a pace determined by construction resource availability through September 2019. Original plans to use AC-powered sensors with a potential transformer on the adjacent pole were not feasible due to the long conductor spans in the area. Solar power was used for the majoritiy of the installations.

Figure 9. Typical solar-powered RF data collection unit

4.2.6 System Commissioning

As each RF data collection unit was installed and switched on, it immediately commenced VPN dataflow to the secure cloud server. The only exceptions were sites where cellular data service signal strength was zero or intermittent (often despite an earlier PG&E audit visit which showed good signal strength).

Each pair of installed RF data collection units defined a monitored network path displayed on the system's web portal. Latitude and longitude data for each pole along the path was entered into the web portal to allow the path to be portrayed on a map so detected risks could be clearly located on the monitored network, e.g. by pole number(s).

The map-based presentation of network monitoring results allowed drill-down (zoom) into problem locations to check for example, the proximity of vegetation to the powerline near an identified risk.

The 19 monitored paths, shown in Table 2, on Circuit 1101 were commissioned between mid-June 2019 and late September 2019, except for Path P-Q which was commissioned in March 2020. The site of RF data collection unit Q showed zero cellular data service signal strength during earlier attempts at commissioning.

For tap lines and branches without sensors, the system locates RF detections on those branches at the intersection of the branch with the monitored paths of the circuit.

Table 2. Monitored Network Paths on Circuit 1101

Path	Length (Miles)	Poles	Path	Length (Miles)	Poles
A-B	1.93	47	H-I	2.15	42
B-C	1.85	53	H-J	2.66	52
B-F	2.92	79	J-K	1.66	29
B-G	3.40	80	L-M	2.67	58
B-M	3.05	76	M-N	2.69	63
C-D	2.22	41	N-O	2.87	48
D-E	3.22	81	N-S	1.63	33
F-G	3.20	72	O-P	1.45	24
G-H	2.17	41	P-Q	1.01	16
G-R	3.21	48			
Total 19 Monitored Paths:				**45.96**	**983**

4.2.7 Challenges

The installation and commissioning phase of the project produced some valuable insights:

1. Costs: The installation of RF data collection units was the most significant component of the project's total cost. Efforts to optimize overall system cost in any future rollout would be best focused on the reduction of installation cost and level effort to perform the Estimating, pole qualification and loading analysis, and installation.

2. Construction resource availability: The installation phase was extended over many months by field crew resource constraints due to other higher priority work, mostly emergency, compliance and public safety power shutdown related. This reduced the period of experience of RF network monitoring system operation in the trial. Use of a dedicated specialized installation team might facilitate faster installation to mitigate risks, achieve earlier system commissioning and potentially reduce installation costs.
3. GIS data: The GIS data used to populate the web portal (pole latitude and longitude) was found to have errors ranging up to 500 feet at some locations. If not addressed, this would have compromised accurate location of detected network risks. For the trial, an extra process step was incorporated in the commissioning process to determine correct (±10 feet) pole location data using Google Earth images wherever possible and enter this data into the web portal to replace PG&E's GIS data. Where a pole could not be accurately located on Google Earth images, such as in forests, a best estimate of the pole location was derived from the nearest accurately determined locations. Some poles and tap-lines were found to be missing from the GIS data. In some cases, this may have been because the assets were privately owned, though the issue was not investigated in depth to confirm this.
4. Cellular data service coverage: In rural locations, cellular data service coverage was found to be intermittent and variable over time. A particular cellular data service might have had strong signal at a location during installation, only to have no signal at all some months later (and vice versa). Post-fire reconstruction and reconfiguration of cell networks may have been the cause. However, this issue was observed widely across the trial area. It was not feasible to restrict units to a single preferred cellular data service. All available cellular data services were considered in a 'best signal strength' on-site selection decision. Verizon required its certified modem hardware to be used; SIMs from all other cellular data service providers fitted the US-standard modem provided in the RF data collection unit. Even this approach did not prevent continuing problems, with inability to connect occurring at some sites multiple times each hour. Ability to connect was not always reflected in low signal strength and investigations are continuing into root causes to see if further design changes can improve dataflow continuity.
5. Solar coverage: Insolation was inadequate in many locations due to trees located to the South of the installed unit. Some sites with adequate solar in Summer had very little solar capability during other seasons. The preferred option to overcome this challenge in future rollouts is to move AC-powered RF data collection units supplied if necessary, by a micro-transformer (or a customer supply transformer if policy is changed) mounted on the same pole.
6. Correct phase identification: For RF network monitoring to be fully effective, it is important the individual RF-coupling sensors at each RF data collection site are pointed at the correct phases of the electricity network. This requires installation crews to use specialized phase identification equipment at each site, which could not always connect to cellular data network for reference signal acquisition.

The above listed challenges were successfully managed, and the RF network monitoring system operated in the later stages of the trial with good levels of availability.

4.2.8 Results and Observations

The predictive risk identification capability of the RF network monitoring system was proven in the trial. The system successfully identified and located a range of common threats to network operation before these developed into faults that could potentially cause interruptions to supply or create safety hazards such as fires or facility damage.

First results followed immediately upon commissioning as pre-existing incipient fault conditions were revealed at locations on Path O-P, the first Circuit 1101 path to be commissioned. New emergent risks continued to be identified throughout the duration of the trial. Not all of the identified threats were high-risk, though all were detected with high signal-to-noise ratio and accurately located by the RF network monitoring system.

Fully resolved case studies are listed in Table 3 and documented in more detail in the Appendix.

Table 3. Summary of case studies of network issues revealed by RF network monitoring

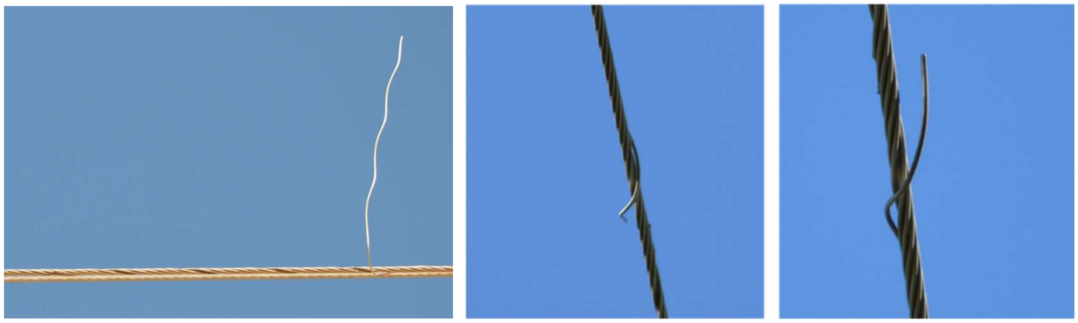
Case	Path	Month	Issue	Inspected	Resolution
1	O-P	June 2019	Vegetation on bare secondary wires (multiple)	Y	Cleared vegetation from the secondary. Detection remained on customer premise wiring.
2	O-P	July 2019	Secondary crossarm fail, insulator pulled out	Y	Cleared by reconstruction.
3	N-S	July 2019	Primary crossarm failure (on tap-line)	Y	To be repaired
4	N-S	July 2019	Covered secondary wiring in tree (on tap-line)	Y	To be repaired
5	D-E	Aug/Sep 2019	Primary conductor broken strands (multiple)	Y	Repaired after inspection
6	O-P	Sep/Oct 2019	Vegetation on secondary (on tap-line)	N	Cleared by reconstruction
7	D-E	October 2019	Primary conductor slap damage (multiple)	Y	Damaged conductor (multiple) to be repaired/replaced
8	A	January 2020	Gunshot primary conductor (Circuit 1102)	Y	750 feet beyond Circuit 1101 monitored path
9	A	January 2020	Transformer internal discharge (Circuit 1102)	Y	2,300 feet beyond Circuit 1101 monitored path
10	E	February 2020	Primary conductor arcing at loose clamp	Y	1,500 feet beyond Unit E, repaired

<u>Key Results</u>

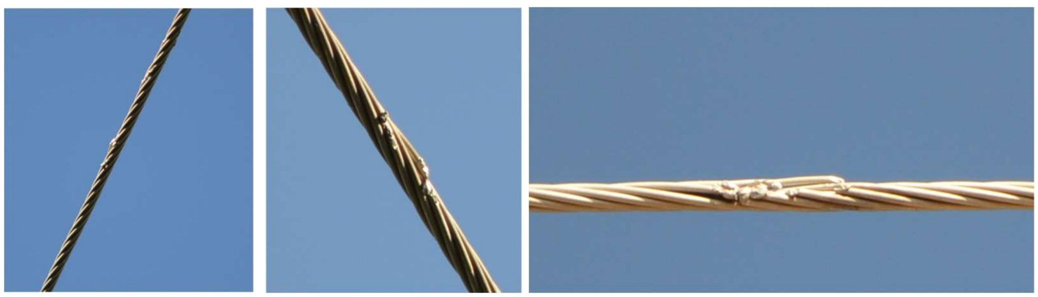
Conductor Damage

Following commissioning of RF network monitoring of Sensor Path D-E in August 2019, the RF network monitoring system detected multiple instances of conductor damage on a high-altitude section of powerline exposed to extreme wind speeds and temperatures. The damage included: broken conductor strands; residual damage from conductor slap; and conductor bird-caging. The RF network monitoring system also identified gunshot damage on a conductor near feeder substation. Figure 10 shows examples of conductor damage.

Figure 10. Examples of conductor damage found by the RF network monitoring system

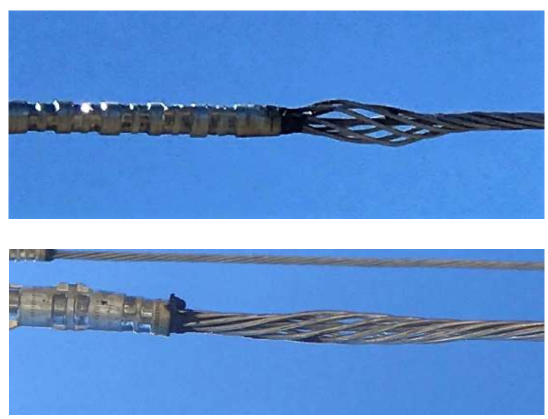


Broken strands



Conductor slap damage (molten droplets, broken strands)

Gunshot damage



Bird-caging

Vegetative Encroachment

Immediately upon commissioning of Path O-P on the 25th June 2019, the RF network monitoring system identified a problem, which on-site inspection proved to be vegetation on bare secondary conductors as shown in Figure 11 below. Also shown is a covered secondary service line run through a tree from a tap-line transformer 1,000 feet from monitored Path N-S which was also detected by the RF network monitoring system and located to the tap-pole. One of the ten pressure points on the service cable in the tree appeared to have insulation worn away from rubbing against the tree branch.

Other similar instances were detected and located during the course of the trial, but they were not confirmed by inspection prior to their disappearance coincident with passage of a fire through the area. Figure 11 shows examples of vegetative encroachment detected by the technology.

Figure 11. Examples of vegetation on secondary conductors

Damaged Secondary Crossarm and Cable

A second issue detected and located two days after commissioning of Path O-P was investigated by inspection and confirmed to be a failed wooden crossarm (split with strain insulator pin pulled out) which had caused the secondary supply service line to wrap around the transformer tank and apply full strain to the transformer low-voltage terminals. Since reconstruction and the fitting of a service cable anchor bracket, the issue has not reappeared.

Primary Crossarm Failure

An incipient fault was detected and located to a tap-pole on Sensor Path N-S. Inspection of the tap-line confirmed a failed crossarm 1,500 feet from the monitored path with suspected tracking from a phase conductor to the crossarm. Crossarm failure had allowed an insulator to 'sit down'. Buildup of dirt under the insulator skirt greatly reduced the surface path between the high-voltage conductor and the crossarm. It was assessed as low-risk and has been listed for repair as other priorities allow.

Transformer Internal Discharge

High-energy signals received at RF data collection unit Sensor A showed an emerging transformer defect beyond the end of monitored network Path A-B on Circuit 1102 which is on the same bus as monitored Circuit 1101. A patrol located a very noisy solid-dielectric voltage transformer 2,300 feet away on a pole-mounted capacitor bank. It was connected to the two phases identified by the RF network monitoring system. This transformer type is known for high internal discharge but no other transformers on the trial network exhibited internal discharge energy. The condition is being monitored.

Arcing Conductor Clamp

RF data collection Sensor E started receiving intermittent bursts of high-energy signal on Phase A from beyond the end of monitored path D-E. Intermittent signal bursts continued before the customer at the end of the line 1,000 feet beyond Unit E called in to report arcing at the top of the pole supplying their load. The signal did not recur after the loose clamp was repaired. The load current involved was about two amperes.

The Technical Appendix for evaluation of the RF network monitoring technology can made available upon request (EPIC_info@pge.com).

<u>Key Technical Observations</u>

The system installed for the trial project continues to operate and be monitored. The following findings are based on experience through April 2020.

Good system performance as a predictive risk identifier: The RF network monitoring system performed successfully in the trial to an extent sufficient to deliver material benefits to wildfire risk mitigation reliability. It predictively identified a variety of network risks, many of which were of types known to start fires. They included conductor damage, vegetation encroachment (both primary and secondary), crossarm failures and a loose conductor clamp. All these conditions were found well in advance of their development into network faults. Site inspections confirmed evidence of the presence of the network defects identified by the system.

Good system accuracy in location of risk: The level of risk location accuracy demonstrated by the RF network monitoring system was sufficient for network operational purposes. In many cases, the system located the incipient fault to an accuracy of five or ten feet. In other cases, especially those where the defect was some distance away from the monitored path on a tap-line or secondary service line, accuracy was within 50 to 100 feet on monitored path lengths that ranged up to a little over three miles (16,500 feet). Performance in the trial was consistent with the supplier's specification of a nominal plus or minus thirty feet accuracy.

Good system risk-detection sensitivity and signal-to-noise ratio: The detection sensitivity demonstrated by the RF network monitoring system in the trial was sufficient to detect situations that could pose short-term risk to the network from deteriorated, damaged or compromised network assets. The system exhibited extreme sensitivity and recorded random noise down to the level of one tenth of a picojoule of collected energy, well below the level required to detect and locate impacts of individual raindrops on primary conductors. In detecting defects, it achieved signal to noise ratios of many orders of magnitude when the defect produced high-energy signals, e.g. internal transformer defects. High signal-to-noise ratios (up to a million to one) were also achieved for the lowest-energy defects when data was accumulated over a period of time, e.g. one month. Sensitivity and noise discrimination were sufficient to achieve reliable predictive risk identification.

Adequate system continuous monitoring for risk: The RF network monitoring system produced a signal record every second as designed. All risks it detected showed very intermittent activity, confirming the potential limitations of ‘point in time’ asset inspection and test methods. Interruptions to system dataflow were caused by loss of cellular data service coverage and by loss of power due to low insolation. Firmware patches rolled out to RF data collection units over the secure data communications connection during the trial improved system resilience against temporary loss of cellular data service and the supplier is developing a firmware update that will automatically retrieve ‘stranded’ data recorded during periods of lost connection.

Good system provision of data to identify network risk type: The RF network monitoring system provided data to ascertain the most likely fault-type to guide decisions on field crew attendance priority. It was demonstrated this data could be correlated with data from other sources to create further insights. The system provided risk data including the location of the detected issue (including Pole number, so users could check GIS to ascertain the assets located there, or check Google Earth to ascertain the location of nearby trees or infrastructure), the pattern of occurrence (intermittent activity bursts could be correlated with weather, metering data, field work, likely customer activity, etc.), the phases involved (indicating a primary or secondary problem), signal signature (which could distinguish transformer discharge, conductor damage, loose clamp arcing, etc.).

4.2.9 RF Networking Technology Roadmap

Workshops of PG&E technical staff and supplier experts generated insights into possible technology pathways for larger-scale rollout of RF network monitoring on PG&E networks. Discussions converged to three key issues: lower installation cost, support for fault location, and data integration.

Lower cost installation options

The trial project demonstrated the biggest cost in any larger-scale rollout would be in installing the RF data collection units on poles. In the trial, this cost far outweighed the cost of the units themselves – a disparity that could be expected to increase with scale. The recommendation is to use a larger-scale trial to optimize the design and installation process to reduce this cost before embarking on full-scale commitment.

Three factors were identified for further attention in cost optimization investigations: sensor mounting, power supply, and correct phasing of sensors.

- Mounting of RF coupling sensors

The networks in the trial had a diversity of pole-top designs. The RF coupling sensors had to be mounted with a consistent spacing between each sensor and the primary conductor it monitored. The pragmatic solution adopted for the trial was to change the pole-top to flat construction (all the primary conductors at the same height) before mounting the three sensors underneath on a second crossarm. Instead of this uniform approach, a small set (perhaps only three) of standard sensor mounting arrangements selected to suit the most common pole designs on PG&E networks may offer cost reduction opportunities.

- Power supply to the RF data collection unit

A second factor in the installation cost was the use of solar power. Originally, secondary AC power was planned to be supplied by a transformer on an adjacent pole, but long conductor spans prohibited this option. Mounting an internally fused, 'PD-quiet' micro-transformer on the crossarm holding the sensors may offer cost reduction opportunities, reliable power supply and deserves further investigation.

- Auto-phasing of RF data collection units

Operation of the RF network monitoring system can be impaired if the phasing of the primary conductors allocated to particular RF coupling sensors is not consistent, i.e. RF coupling sensors labelled Red phase must always be pointed at the Red phase conductor. This requirement added some time and effort to the installation task. The phasing tool was not able to connect to the cellular network at installation locations to obtain a reference signal. Experience indicated it was challenging to consistently get it right. All installed sensors were visited and checked, and it was found that only eight of 19 sites had all sensors correctly pointed at the right phase. Errors were easily remedied during the site visit by swapping cables inside the control unit. However, this experience illustrated the challenge of ensuring correct phasing and further, ensuring it stayed correct when networks were rebuilt.

In response, the supplier has committed to investigate system design concepts whereby the RF network monitoring system itself automatically allocates the whole cohort of sensors installed on a network consistently to appropriate primary conductors. This would remove the phase-check task from the installation process. The auto-phasing should be repeated at regular intervals to check and adjust for changes due to network reconstruction. Site visits to check and remedy phasing issues would be eliminated.

Fault location using RF network monitoring

During the course of the trial, a number of network faults occurred - fuse candling, tree fall, etc. The RF network monitoring system was not designed for fault location. However, system records for the time of occurrence of a small number of faults were retrospectively investigated in depth to see if RF monitoring might add value in this key operational task. The results were encouraging enough to prompt the supplier to commit to exploration of design changes to enhance the fault location capability that was apparent. Changes to provide fault location capability would likely require significant changes to the system's architecture. The supplier's investigations into this potential opportunity are continuing.

Continuous RF Network Monitoring

The supplier is investigating the potential to advance the current sampling window of 1/25th of each Second to continuous monitoring that would more reliably detect infrequent <3 cycle duration arcing events.

Integration for enhanced network operations

PG&E is committed to the enrichment of network monitoring data to support enhanced network operations. It has made investments in trials and installation of smart line sensors and substation-based network monitoring systems. The RF network monitoring trial demonstrated the rich data available from this technology. It prompted consideration of the potential benefits of integrating this data with that from other sensors and systems and of presenting it on existing field operations information delivery platforms.

A workshop was held with PG&E and supplier experts focused on IT and data networks to consider options that may become available if wider rollout of RF network monitoring goes ahead. Three options were considered: the software-as-a-service approach used in the trial; a new message-based application programming interface; and, hosting of the system on PG&E's IT infrastructure. Integration opportunities for data networks and collection of weather data were also explored.

- Software as a service

The standard baseline RF network monitoring system provides capability for download of all system data via secure browser session from the system's cloud-based IT infrastructure. This capability was used extensively by both PG&E and supplier teams during the trial. It is simple, easy to use and has few cyber-security threat exposures. However, it is unlikely to be efficient as rollout scale increases. All parties in the workshop confirmed this model would likely be sufficient to meet PG&E needs for the next few years in all likely rollout scenarios, after which it would need to be supplemented by a fully automated capability.

- Message-based Application Programming Interface

A message-based API would be a natural next step. This would simply automate the data download process to allow PG&E network operations support systems to automatically reach into the RF network monitoring system's cloud IT infrastructure to retrieve the data they require. The API itself would not involve major cost and any associated cyber-security issues would likely be manageable. IT changes on the PG&E side to enable its systems to initiate data requests and to integrate and present the retrieved data would likely constitute the majority of the work in implementing this option. This was seen as the natural next step in evolution of integration as rollout scale increases.

- PG&E hosting

The option of moving all the RF network monitoring system's data and algorithms onto PG&E's internal IT infrastructure was also explored. However, this option would involve multiple major challenges as PG&E would be required to license and operate software from both the supplier and the cloud infrastructure provider. It was seen as requiring major long-term IT investment and would have substantial cyber-security issues, both of which would require very careful consideration.

- Use of PG&E data network

The workshop on integration also assessed the option of using PG&E's FAN data network to link RF data collection units to the secure cloud IT infrastructure. There appeared to be no technical barriers that would prevent this. However, it was confirmed that extending FAN coverage for this purpose alone would not be economically justified.

- Collection of weather data

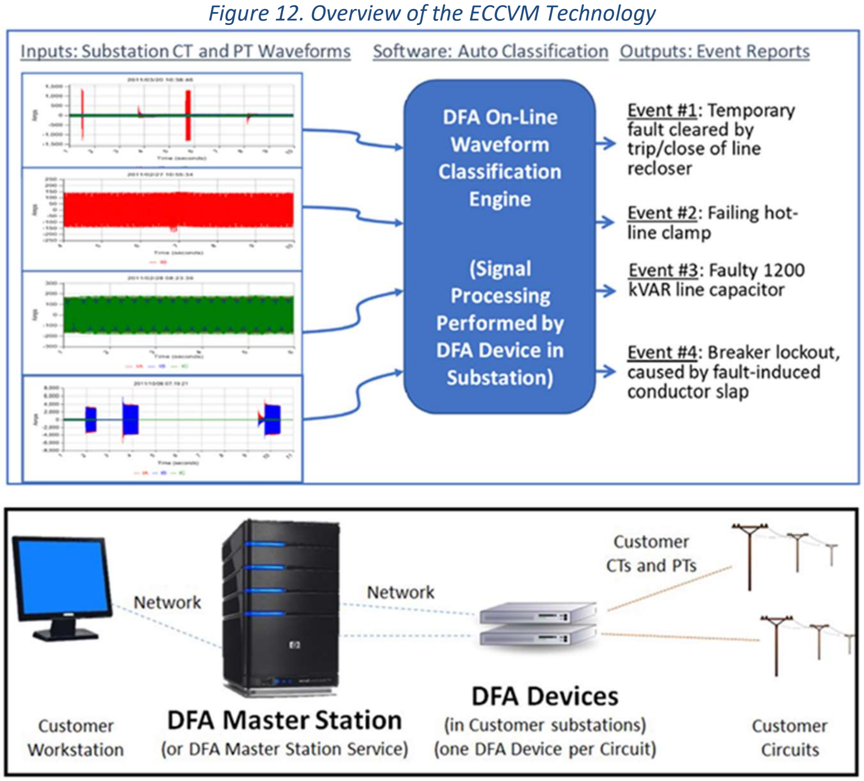
Local weather data is becoming more important in utilities, especially to indicate wind-related risk at a more granular level to minimize the impact of Public Safety Power Shutoffs. The standard RF network monitoring product includes an optional integrated weather station which shares power supply and data communications with the RF network monitoring system. The device has no moving parts and uses ultrasonics to measure wind speed and direction. For comparative evaluation, one of these devices was installed at RF data collection Unit E approximately 200 feet from an existing 'propeller and vane' weather station.

4.3 Technology Demonstration 3 – ECCVM

Event classification through current and voltage monitoring (ECCVM) technology is a sensor technology that monitors three-phase voltages and currents at the circuit level. The sensor is in the substation and connects directly to the circuit breaker Current Transformers (CTs) and the bus voltage Potential Transformers (PTs). The sensors continuously monitor voltage and current waveforms, in high fidelity, and detect electrical anomalies using sophisticated digital signal processing, pattern matching, and other techniques to report ongoing and developing circuit conditions. Figure 12 is a diagram that shows the conceptual structure of the ECCVM technology.

The ECCVM technology was developed over several decades by Texas A&M Engineering and the Electric Power Research Institute, Inc (EPRI). The initial effort was focused on improvement of system reliability and was built on early high-impedance fault detection work. Texas A&M hypothesized that failing equipment would causing arcing well in advance of ultimate failure and the key to anticipating failure through electric signal monitoring was detection of this arcing.

Figure 12. Overview of the ECCVM Technology



The ECCVM algorithm can report 29 different classification of events that it captures. Several of these are related to normal operating events such as motor starts, capacitor switching, and regulator operation. ECCVM classifies 26 different abnormal grid events which are summarized into the broad categories of overcurrent, shunt arcing, series arcing, and capacitor problems. All the grid events are capture within the ECCVM interface under the waveform tab. The abnormal events are captured both in the active grid event tab but also under the grid reports.

4.3.1 Technology Objectives

RF sensor technology is geographically located along a distribution circuit. Limitations to access, both physical and communications, can inhibit deployment. The ECCVM sensor technology, which is located at the substation to sense voltage and current waveforms, was used to compensate for these limitations.

The technology was also used on distribution feeders that do not have RF technology deployed both to capture conditions that RF might capture, giving an indication of potential value of RF technology, as well as demonstrating an alternative to RF technology.

The ECCVM technology is being demonstrated within the EPIC 2.34 project even though the primary objective of the EPIC project is to demonstrate RF sensors. The ECCVM technology is also being demonstrated by Southern California Edison under their 2019 Wildfire Mitigation Plan clearly defining the ECCVM technology as a commercial product and hence not eligible by itself under the EPIC mandate. PG&E still felt the technology needed to be demonstrated at a smaller level for its system since there were several other technologies that it was considering. The EPIC 2.34 seemed a good fit because ECCVM could help validate the RF technology as well as provide a comparison at a reasonable scale.

4.3.2 Tasks and Milestones

To align with the overall EPIC project structure, the scope of work was spread over four main tasks. This permitted periodic review and project offramps if needed.

Task 1: Benchmarking and Planning – ATS's technical team did a thorough review of the ECCVM technology. The results of this work and formal process effort were needed to harden the projects execution plan. Specific tasks performed under this phase included:

> Task 1.1 – Historical Field Performance Review and Benchmarking: Detailed benchmarking with current ECCVM utility users was conducted. This did not include any "in-plant" visits.
>
> Task 1.2 – Literature Review: A literature review of related technical papers and documents was also conducted.
>
> Task 1.3 – Feeder Screening: Initial screening of substation and feeders within wildfire areas was conducted in coordination with the PMO's office and the business leaders.
>
> Task 1.4 – Contracting: Project coordination to finalize contacts and purchase agreements was also performed during this phase.

Task 2: Engineering Design and Constructability Review – Installation of the ECCVM devices in the field required full engineering and construction by PG&E's substation department and some initial laboratory testing to reduce the risk and burden on field physical forces. Task performed under this phase include:

Task 2.1 – Substation Pilot Process: Before any work related to new technology can be introduced into a PG&E substation it has to go through a project review process. This engages all components of the substation design and construction teams in PG&E and insures buy-in from these key members. Evaluation of work methods and constructability is also addressed under this task.

Task 2.2 – Detailed Design: After the project has been reviewed and approved by the substation team, the substation design group developed the detailed design. This includes a procured material lists and schedule.

Task 2.3- Material Procurement: Equipment needed for completing the installation was ordered or procured from company stock. The longest procurement equipment item was the installation cabinet as it required hand wiring by the substation tech group within their shop. However, since similar cabinets are used for other substation applications the component supply chains were already in place and all components were acquired well ahead of schedule.

Task 2.4 – IT/Telecom Survey: Communications requirements were evaluated both by ATS Grid Technologies and Substation Telecom. Substation Telecom conducted site surveys of the proposed substation locations to determine the best carrier options. Once the evaluations were completed cell modems and related carrier cards were procured.

Task 3: Construction and Commissioning: Most of the construction was done by the substation group with support from ATS and the TAM teams. Under this phase the following tasks were performed:

Task 3.1 – Field Construction: Field construction work performed by substation construction included installation of the ECCVM cabinets, installation of the ECCVM units into the cabinet, and wiring and validation of the completed construction. The construction process followed all standard PG&E safety and construction practices.

Task 3.2 – ECCVM Device Configuration: Prior to sending the ECCVM units into the field they were put through a series of communications and performance test just to make sure there were no problems with the units in the field. All this testing was done at ATS's communication lab by the ATS team. Any firmware or performance issues were addressed prior to deployment.

Task 3.3 – Field Commissioning: Once the installations were completed, commissioning and functional testing was performed by substation personnel in coordination with both ATS and ECCVM team members. Communication data rates and actual voltage and current measurements were verified. The portal interface was exercised to insure access to all data by team members.

Task 3.4 – Training: A full training session not only on how to use the ECCVM portal but also how to begin to interpret the ECCVM data was given by the TAM team to both the operational engineering component at ATS and the distribution grid operations Asset Health and Performance Center (AHPC). Training covered how the sequence of events are recorded by ECCVM and examples of key types of events and the associated data.

Task 4: Demonstration & Operation – The core of this project was to evaluate the performance of the ECCVM system in relation to the key objectives. Operation of the ECCVM devices was led by ATS with help and coordination of PG&E's substation/telecom (support for any potential field problems with the devices), AHPC (coordination with the RF sensor monitoring) and TAM. The following tasks were performed and coordinated through this phase:

Task 4.1 – ECCVM Monitoring: Daily review of ECCVM detect events was performed. Key events, specifically those that indicated incipient conditions or systemic issues, were investigated across companion data sources. These events were logs and events files create to collect related data. Weekly review meetings were held with TAM and the RF sensor teams. The detailed evaluation methodology can be found in Section 4 of this report.

Task 4.2 – Analysis with RF: Specific to project goals, additional investigation was conducted for events occurring on the feeder with RF sensing. These investigations were in two directions: events detected by ECCVM were validated with RF and events detected with RF were validated with ECCVM.

Task 4.3- Analysis with Other Data Sources: As data was collected Data and statistical analysis was performed to gain better understanding of the ECCVM event data and to correlate the results with other data sources. This work was primarily performed in Jupyter Notebooks.

Task 4.4 – ECCVM Technology Transfer: Once the project is completed a determination will be made, with key stakeholders on whether the ECCVM technology is to be handed off or to be decommissioned. If deemed necessary, the physical decommissioning of the devices will be performed.

Task 4.5- Final Reporting: Full documentation of the results and findings of this demonstration project will be collected in two primary reports: an ATS technical report and an EPIC final report. The EPIC final report will be created collaboratively with the RF sensor team. A final report from the supplier will also be reviewed. Presentations, both intermittent and final project will also be prepared under this report.

4.3.3 Technical Development and Methods

The installation of the ECCVM sensor is relatively simple when compared to other substation sensor packages because it can piggyback on the same CTs and PTs that a standard feeder breaker relay use. As such, the ECCVM unit needs to be located near, and preferable on the same device stack, as the distribution circuit breaker relays. Its installation requirements are like what a relay would require. The ECCVM device requires phase CT connections and line-to-ground PT connections. This was added as a criterion in the substation selection process to help limit the amount of work required within the substation.

The complete substation design went through the substation pilot project review (TD-3340P-04) and the complete detailed design was done by PG&E's substation engineering group. It should be noted that the substation team's timely responses and diligence was the key to the successful installation of the ECCVM devices.

PG&E uses what is called the Integrated Protection Auxiliary Cabinet (IPAC) to house the relays and test switches for a typical distribution substation breaker. This self-contained cabinet is located at the breaker in a substation. Ideally, the IPAC cabinet would have additional space for a new circuit device such as the ECCVM unit, and in some versions of this cabinet there is the space, however, for the majority of the project's installations the existing IPAC cabinets at the breaker did not have enough room for the ECCVM devices. An additional cabinet had to be added to house the ECCVM unit, its power supply, test switches, and the cell modem on the rear side of the steel pillar that supported the existing IPACs. A conduit between the IPAC and the auxiliary cabinet was used to complete the wiring. A small antenna was located on the top of the cabinet for the cell modem.

4.3.4 Challenges

<u>ECCVM Workflow:</u>

Prior to final commissioning of the ECCVM devices, the ECCVM supplier team developed a process for documenting findings and investigation of critical events. As monitoring progressed modifications were made to further streamline the process while still capturing the relevant data.

Monitoring of the ECCVM devices and investigation was conducted by ATS technical personnel with input from the ECCVM supplier team. The ECCVM portal was reviewed by ATS personnel every workday. The portal was not reviewed for weekend and holidays however since all data that is capture events that occurred during these periods could be investigated the following workday.

Initially, within the portal all events that were displayed on the Grid Event page were reviewed and logged into the event log. Also, events identified by the RF sensor team were also investigated for relevant ECCVM data. After a couple of months of review and working with the data from the ECCVM portal it was determined that not all the events identified on the Grid Event page were of significance. One-off overcurrent events were no longer logged. All arcing and recurrent overcurrent events were continued to be logged.

<u>ECCVM Operational Performance</u>

On 8/16/20 t of the 21-kV feeder ECCVM units began to experience data dropout. This was first noticed by the supplier. After three days of conducting remote diagnosis on the unit, ECCVM supplier recommended replacement of the unit. The unit was successfully swapped out by substation personnel on 8/30/20 and was back operating the same day. A replacement unit had also been received from ECCVM supplier and the failed unit was shipped back.

4.3.5 Results and Observations

Considering the limited number of feeders that had ECCVM deployed and the short period that data was collected, it is impressive the amount and type of data that was collected by the ECCVM sensor technology. Because of this it will not be possible to list and detail every event recorded. The approach for the documenting the results involves two components: an overview will be given on the ECCVM data; and a more detailed presentation for several key results that highlight the capability and performance of ECCVM technology.

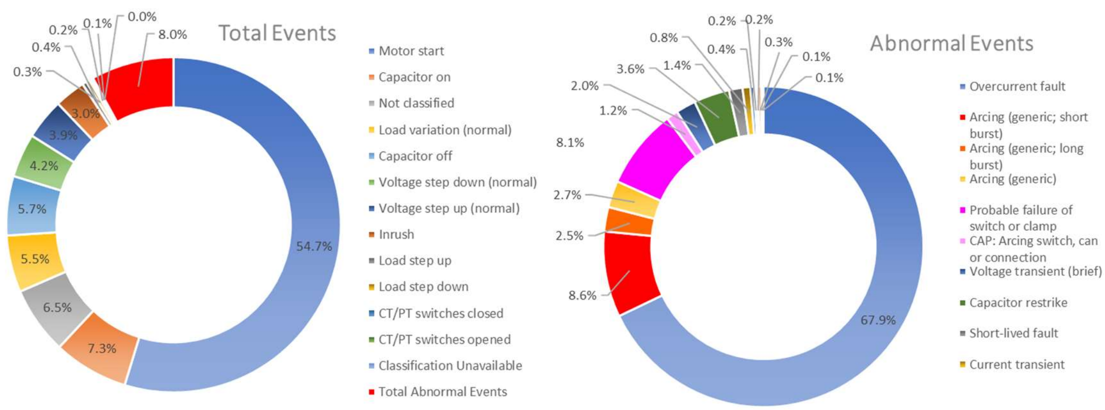
<u>Overview</u>

At the end of May 2020, the ECCVM system had collected over 38,000 events from the sensors deployed on the six project feeders. Most of these events can be classified as normal operating events (motor starts, load variations, capacitor switching, regulator steps, etc.) with motors starts being the most common normal operating event (approximately 50% of all events captured). This is expected from a device that monitors voltage and current waveforms. Motors are very common on the feeders located in the Napa Valley and motor starts would happen multiple times each day. Figure 13 shows a chart of the percentages by different types of events captured to the end of May for ECCVM.

The abnormal events (faults, arcing, transients, unbalanced capacitor switching) represented over 8% of the total number events in the same period. This seems reasonable since it can be assumed that the distribution systems should behave normally most of the time. Of the abnormal events the majority (68.7%) are overcurrent faults, however, 21.4% events are low energy arcing. Figure 13 shows a chart of the percentage of different types of abnormal events capture in this time frame.

Figure 13. ECCVM Events Captured by ECCM to the end of May 2020

a) Total Events *b) Abnormal Event Only*



Key Results

Series-arcing

Series-arcing is an arcing event that creates low-amplitude voltage/currents and results intermittent changes of the source impedance, a direct interruption of the load current. Series-arcing events can indicate an incipient failure and, since they impact the load current, can be collaborated from sag voltage alarms. ECCVM, using its localized digital signal process algorithm, is unique in its ability to identify these types of events. Sag alarms alone can't identify series-arcing as the cause.

ECCVM defines two classifications of series-arcing events: "Probable failure of switch or clamp" and "CAP: Arcing switch, can or connection". The "CAP: Arcing switch, can or connection" classification is only associated with capacitors and is generally identifiable by the additional change in reactive power. "Probable failure of switch or clamp" classification covers all other types of series-arcing events.

Series-arcing events generally come in clusters of time. These clusters can come and go in flare ups as the failing of the equipment progress. ECCVM supplier has seen series-arcing events cause unidentified operation of protective equipment. Both RF and infrared signatures are also effective at identifying possible series-arcing events, however, caution needs to be considered for the RF sensors piloted on these circuits as was discussed in the previous section. The series-arcing events captured during this project had long durations increasing the opportunity of RF sensor capture.

There were 5 specific case examples capture in this project. Three of them were on the EFD-monitored Circuit 1101 so there was opportunity of RF sensors matching. Two of the events were candling fuses. In both cases the RF sensors captured the location of the series-arcing source. In the remaining case, however, the RF sensors did not capture the location. Using AMI data ("Sag" and "Last Gasp"), the approximate location of the series-arcing was determined. Unfortunately, because of the time lag to obtain the AMI information no patrol was conducted so the cause was never determined.

Two series-arcing events occurred one of the 21-kV circuits, which did not have RF sensors, and in both cases AMI data was successfully used to determine the approximate location of series arcing. In one case, the series arcing began 10 days before final failure with AMI data showing a consistent location. A field patrol was not conducted because of time-lag in getting AMI data. In the other case, the series-arcing began only hours before final failure. The patrol of the line in this case did not identify the cause.

Shunt-arcing

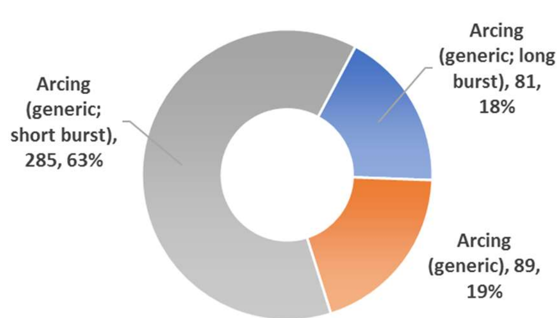
Shunt-arcing is not a faulted event; they are low current events that typically last for only a few cycles. Shunt-arcing does not trigger magnitude/duration sensing such as protective relays or fault analyzers. The signal preprocessing on ECCVM sensor looks for specific characteristics of the abnormal component of the current and voltage signal.

The technical difference between shunt-arcing and a high-impedance fault is the nature of what these two technical terms are defining, and a brief description will help with the subtleties. A shunt-arc is an ionization of air as a result of electrical potential energy. A high-impedance fault is fault in which its impedance limits the fault current. It is not necessary for arcing to occur for there to be a high-impedance fault. When ECCVM identifies a shunt-arcing event it is looking for characteristics of the ionization of air from an electric field.

ECCVM defines three types of arcing events:

1. Arcing: generic – 2 to 3 cycles
2. Arcing: short burst – less than 2 cycles
3. Arcing: long burst – more than 3 cycles

Figure 14. ECCVM Recorded Shunt-Arcing Events by Type



There has been a total of 429 shunt arcing events captured by the ECCVM sensors for this project since its inception until the end of April 2020. Figure 15 shows the breakdown by shunt-arcing type for the recorded events, with short burst being the most common. Figure 15 shows the number of shunt-arcing events for each of the six feeders with ECCVM installed. The first feeder is monitored with the RF sensors. The other feeders have no other sensor package that has the potential for capturing shunt-arcing events.

Figure 15. ECCVM Recorded Shunt-Arcing Events by Feeder

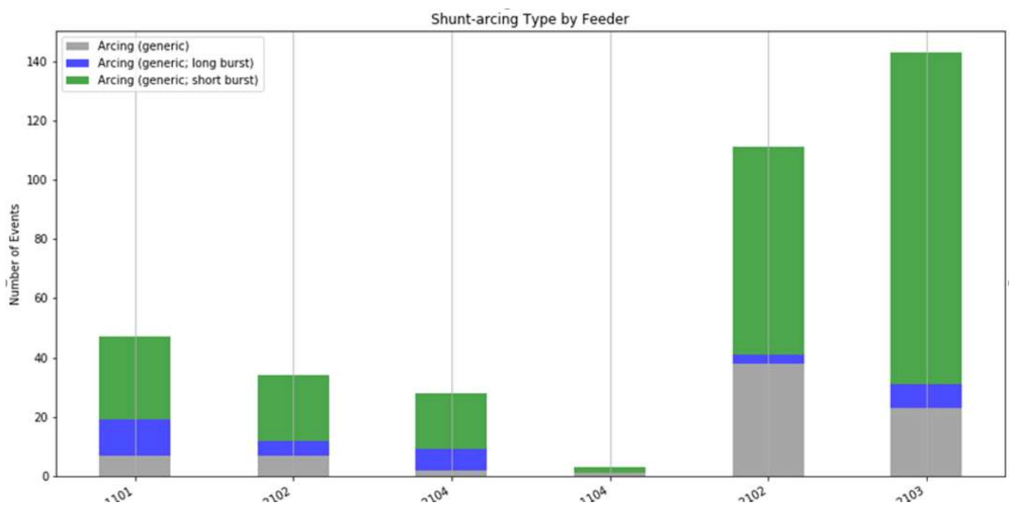
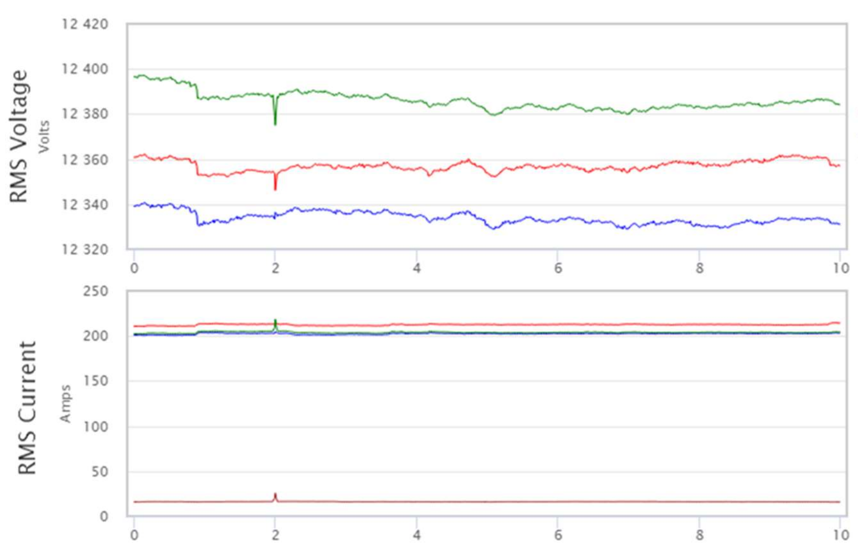


Figure 16 shows the typical RMS current and voltage as result of a shunt-arcing event. Note the small magnitude change in current and voltage. Validation of these events being shunt-arcing comes from two sources: ECCVM supplier research and field verification. ECCVM supplier has conducted years of research on the nature and characteristics of shunt-arcing. They have collected data from both laboratory testing and field studies through the ECCVM product. One 21kV series-arcing event migrated into shunt-arcing (see case studies above) and had shunt-arcing just prior to the final failure, thus providing field validation of shunt arcing for this project. On the EFD monitored feeder, a series-arcing event also had shunt arcing for the “candled” fuse in the case study above.

Figure 16. ECCVM RMS Voltage/Current for Shunt-Arcing Event



Specific causes of shunt-arcing have been difficult to come by other than immediate predecessors for a catastrophic failure, however, there have been 2 representative cases that begin to point to the value of identifying shunt-arcing and highlighting the existing technology gap in locating.

The first case, which occurred on the EFD monitored circuit, were a clustering of shunt arcing events around a momentary outage. A recloser on the circuit opened and reclosed for a fault of approximately 763A. The fault started on phases BC and then migrated to all three phases. Prior to the fault there were two shunt-arcing events, one 12 hours before, and the other 2 hours before. Both occurred on phases BC. Since it was a momentary outage no patrol was conducted after the initial event alarm. RF sensors did not capture data related to either the momentary outage or the shunt-arcing events.

Line sensors also capture the momentary fault and that data, in combination with a CYME model fault location analysis, narrowed the potential problem area. This data allowed operations to conduct a field patrol of the area. The field patrol located “a newly fallen tree”. “The tree crossed the road and appears to have possibly hit the primary wires.”

The second case, which also occurred on the EFD monitored circuit, were a clustering of shunt-arcing events within a five-minute period. There were other “Non classified” events that were captured in this same timeframe, their RMS readings looked like the shunt-arcing events. The ILIS report for that day identified burned conductor as a result of a third-party structure fire. The report located the fire near a section of line that was between the B-F RF sensor pair. The processed data from the sensor pair did not show any correlating data, however, examining the raw data from each of the sensors showed that the B sensor had signal problems but sensor F did capture some signal that correlated with the later “Not Classified” ECCVM events.

Fault-induced Conductor Slap

The ECCVM technology directly identified a fault-induced conductor slap on a 21kV 4-Wire circuit.

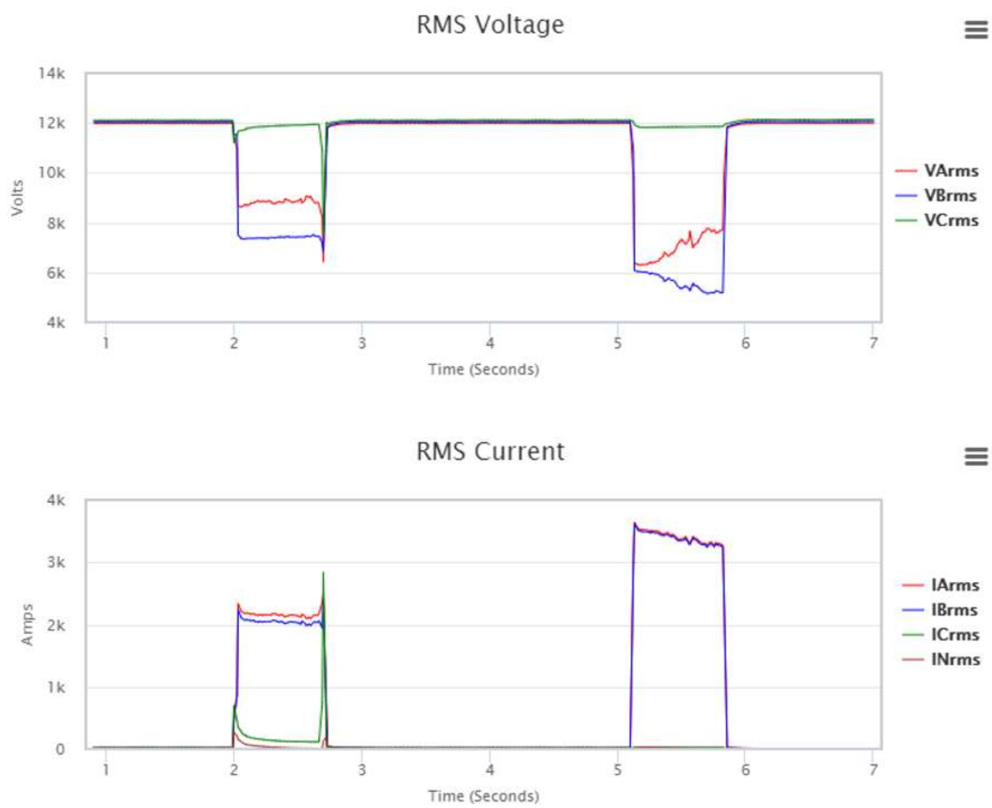
Figure 17 shows the RMS voltage and current for this event. The second reclose has significantly larger fault current. For the second reclose the current ramps down as would be expected for the resulting Jacobs-ladder as the conductors separate. ECCVM also identified a breaker trip that occurred eleven seconds before the first recloser operation.

SCADA logs validated the operation of both the recloser and circuit breaker, however, the timestamps for these logs do not have enough detailed to see their time-series proximity. The outage report incorrectly identifies this as a “miscoordination”. The outage report for this event identified the cause as a branch falling on the line.

Line sensors on the circuit captured some of the faults around the ECCVM identified event, however, only one waveform captured both the fault and the conductor slap but even this was a residual of the breaker trip from eleven seconds earlier.

A patrol was performed based upon CYME “Fault Location” analysis but did not identify the location of the conductor slap.

Figure 17. ECCVM Recorded Fault Induced Conductor Slap



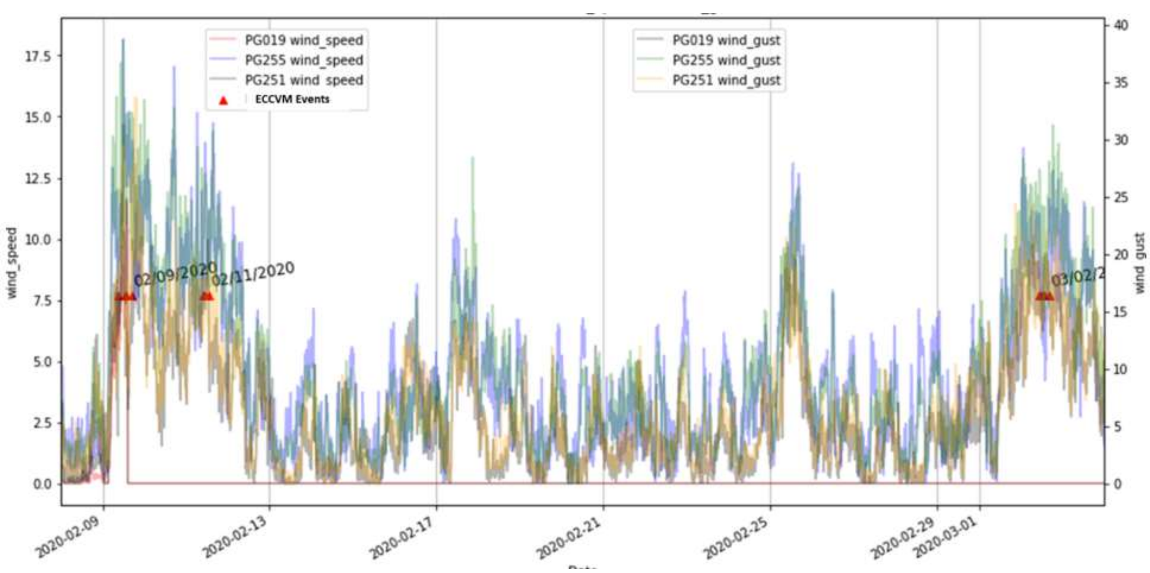
Recurrent faults

ECCVM can identify recurrent faults; faults that have the same magnitude of fault current, occur on the same phases, and last for the same duration. These types of faults are systemic and involve some type of construction or operational deficiency.

An example of this was a recurrent fault that occurred on a 21kV circuit over a 22-day period, which clustered around three specific days. Line sensors also identified these faults but, at the time, did not classify them as recurrent. Based upon the data from ECCVM the settings for recurrent faults were adjusted so that the line sensor portal now identifies these faults as recurrent.

Examining nearby weather stations for wind conductions for these events there was a correlation with wind speed/wind gust. Figure 18 shows the wind speed/wind gusts timeseries with the ECCVM recurrent faults. These faults seem to always cluster around peaks in wind speed.

Figure 18. Wind Speed/Wind Gust Timeseries Data for Weather Stations with ECCVM Events



A CYME fault location model was run and, along with line sensors data, a location for a patrol was identified. Operations completed the field patrol and located a section of circuit in which there appeared to have been phase conductors slapping together, probably caused by wind. A spacer was added to this circuit and no additional faults have recurred.

Cable Failure

Cable failures can have precursors that can be detected by ECCVM sensors. The ECCVM sensor deployment for this project was primarily driven by wildfire concerns so the distribution feeders targeted by this technology tend to have a relatively small quantity of underground circuit. There was one cable failure that illustrative of how ECCVM would be able to help in identify incipient cable failure.

ECCVM began reporting a series of “Current Transients” and “Load Variations” that were of very short duration, typically under a single cycle. These events were occurring on average 30 seconds apart but ranging from a few seconds to minutes. A total of 52 events occurred over a two-hour period.

Line sensors identified these events as “line disturbances” but gave a “Insufficient Waveform” for classification, the events were too short for classification. This data did provide information on where on the circuit they were occurring.

These events were occurring just before a Public Safety Power Shutoff (PSPS) event. A PSPS is when PG&E intentionally de-energizes a circuit because fire risk it too high. These events are identified 48 hours in advance, require notification of local customers and agencies, and mobilization of large amounts of physical forces to implements and ensure public safety. The identification of the ECCVM events were given to distribution operations with the suggested area to patrol and the project team’s suspect of an incipient cable failure but because of the PSPS operation could not be acted upon.

The circuit was de-energized for the PSPS. After weather conditions improved a complete visual inspection was made of the circuit. The circuit was re-energized which was recorded by ECCVM. No additional incipient events occurred. Later that day ECCVM recorded a multi-phase fault of short duration. Line sensors also detected the fault. Field inspections by operations located a failed elbow on the sections of circuit that was identified for patrol.

Operational Visibility

Although this project was primarily focused on detection of incipient failure modes, the ECCVM technology provides improved monitoring resolution that can be leveraged for better operational visibility of the system. Details of specific case examples during this project can be found in the ATS final report. Here are some highlights of ECCVM demonstration of operational visibility:

1. Capacitor Operations: ECCVM is the only sensor package that has a significant amount classification capability specific to shunt capacitors on the distribution system. This is significant to PG&E's operations as over 10% of all 10,000 shunt capacitors on its distribution fail in some manner each year. Annual inspections of all these capacitors requires significant company resources. The capability to monitor and validate performance beyond these annual inspections can help improve system performance. In this project ECCVM captured an unbalance capacitor switching event that was later determined to be a blown fuse on a capacitor bank.
2. Substation Voltage Regulator Monitoring: ECCVM captures and reports incremental voltage steps. Since these are correlated with current, they are identified as voltage regulation. These types of events are considered normal operation but can be used to validate substation regulation. For example, during this project ECCVM capture a voltage step changes that occurred within seconds of each other without any significant change in current. These quick succession voltage steps indicate improper settings on the controller, specifically a change in delay timer settings. Operating engineering was notified of this discovery.
3. Non-downstream Event Detection: Since ECCVM's classification algorithm considers both voltage and current simultaneously it can determine whether a classified event is occurring downstream on the feeder being monitored or not downstream such as on a neighboring feeder or transmission system. During this project ECCVM detected simultaneous overcurrent fault events on all the monitored feeders at the exact same time. The event was caused by a regional transmission fault.
4. Line Sensor Validation: Although one of this project's primary objectives is to validate the RF sensors the ECCVM technology was also used to validate and calibrate the line sensors already extensively deployed on PG&E's circuits. ECCVM's classification of recurrent faults was used to identify the mis-calibration of the recurrent detection tolerance of line sensors. A second example of line sensor validation was for a more troubling discovery of incorrect RMS current during the first cycle of the line sensor capture waveforms. The information has been given to the line sensor manufacture for correction.
5. Hidden Load Detection: ECCVM has higher resolution of measurement then is currently used on most PG&E SCADA devices. This feature enables a more finessed analysis of performance of the distribution system under dynamic conditions. An example is the ability to identify a circuits response to renewable generation sources tripping off after a low voltage condition caused by a fault. This is often referred to in the utility industry as the "hidden load" problem

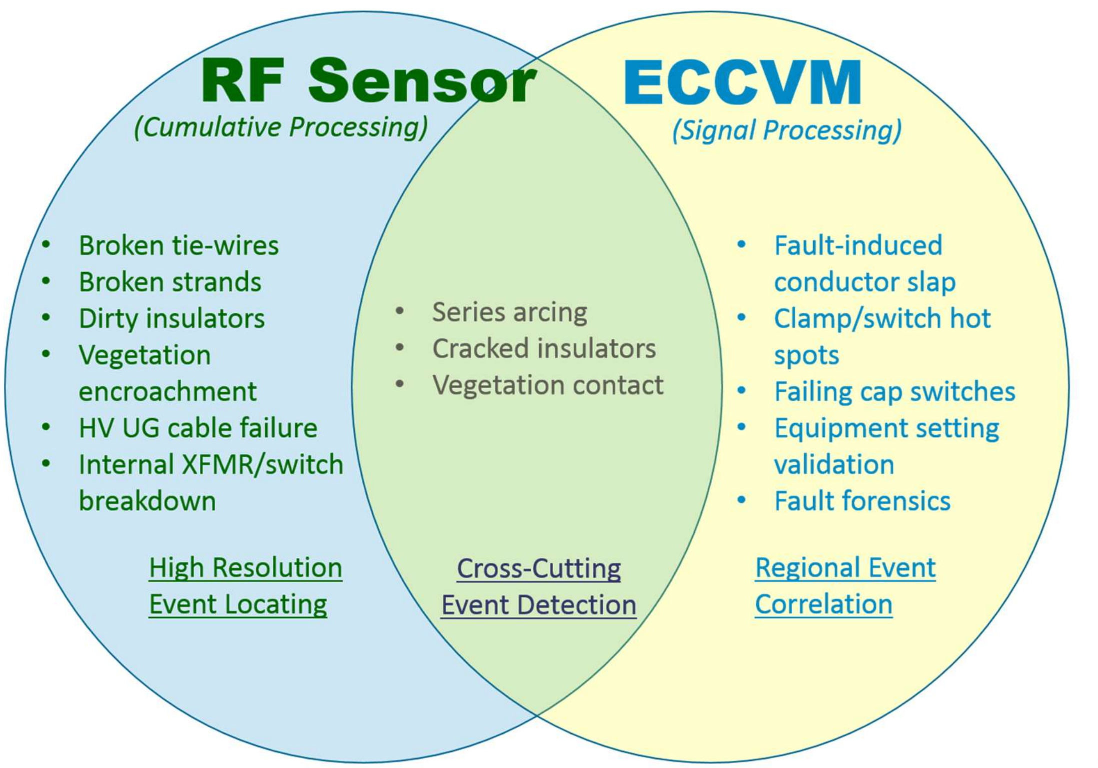
of renewables. During this project ECCVM was able to clearly identify the load increase following a fault.

4.4 Comparison of Technologies

The RF Sensor and the ECCVM technology were both successfully deployed on the 12kV 3-Wire circuit which enabled a side-to-side comparison between the two technologies.

RF sensors utilize a cumulative detection strategy where RF sampling occurs for 1/25th of each second, and "hot spots" are identified as accumulated RF detections at the same location of the circuit. This enable the sensors to identify "hot spots" of partial discharge on the circuit. Arcing that is the result of a single event, or an infrequent period event, can be problematic for RF sensors to detect because the RF sampling window may miss these brief events. ECCVM, in contrast, does continuous monitoring of the waveform with triggering based upon a complex of processed signals so a single arcing event or infrequent events will be detected. Figure 19 shows a Venn diagram of the types of events that will be seen by RF sensors only, ECCVM sensors only, and by both sensors.

Figure 19. RF Sensors and ECCVM Complementary Technologies

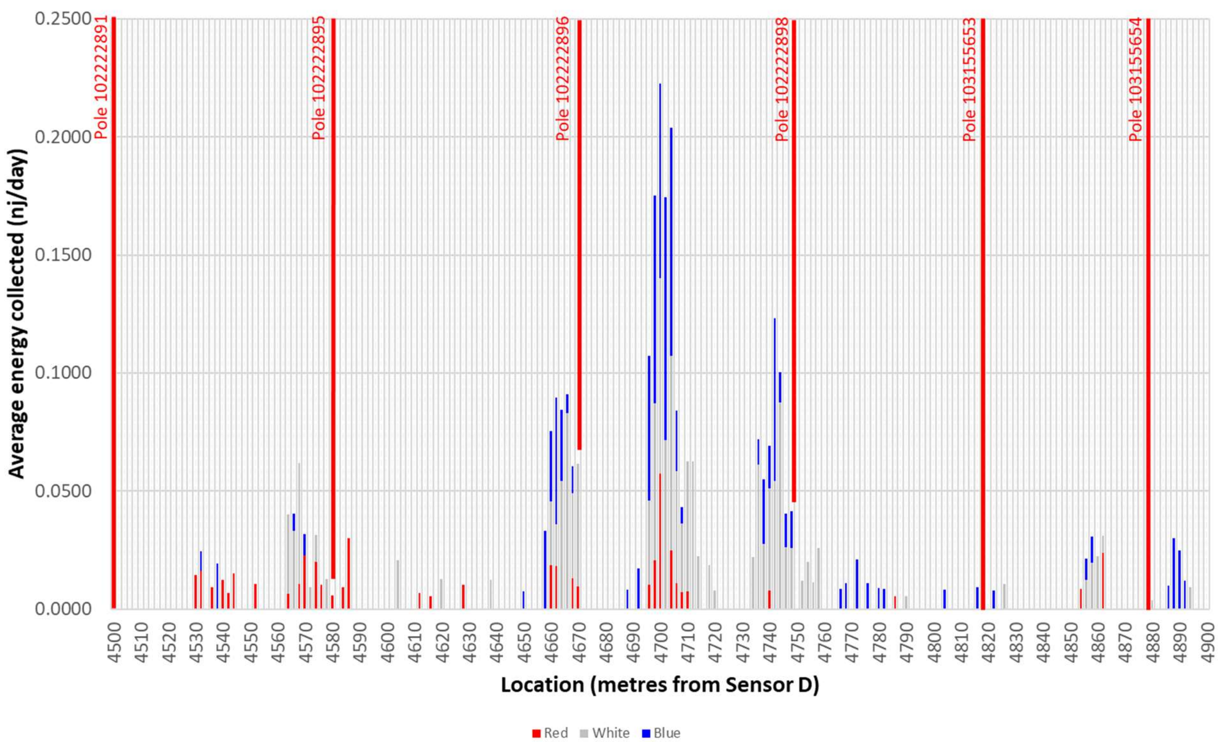


4.4.1 Events detected by only one technology

Events Detected by RF Sensor, but not by ECCVM

The RF sensor technology demonstrated 10 case studies as identified in Section 4.2.8. Of these 10 cases only the conductor arcing event (case 10 in Table 3) was also seen by the ECCVM technology. Of the remaining cases in the table the "damaged conductor as a result of conductor slap" is the only case where ECCVM should have captured data. For that matter, both line sensors and protective equipment should have also detected this type of event. A conductor slaps is a metal-on-metal condition which would have produced a large fault current and resulted in a strong voltage and current signal. The reason ECCVM would not have capture this event is that the conductor slap could have occurred outside of the project monitoring timeframe, such as before the monitoring began. The RF sensors detect RF conducted signal which occurs as a result of the conductor's damage and not just a result of the conductor slap event. Figure 20 shows the D-E RF Sensors pair cumulative energy near the damaged conductor form conductor slap.

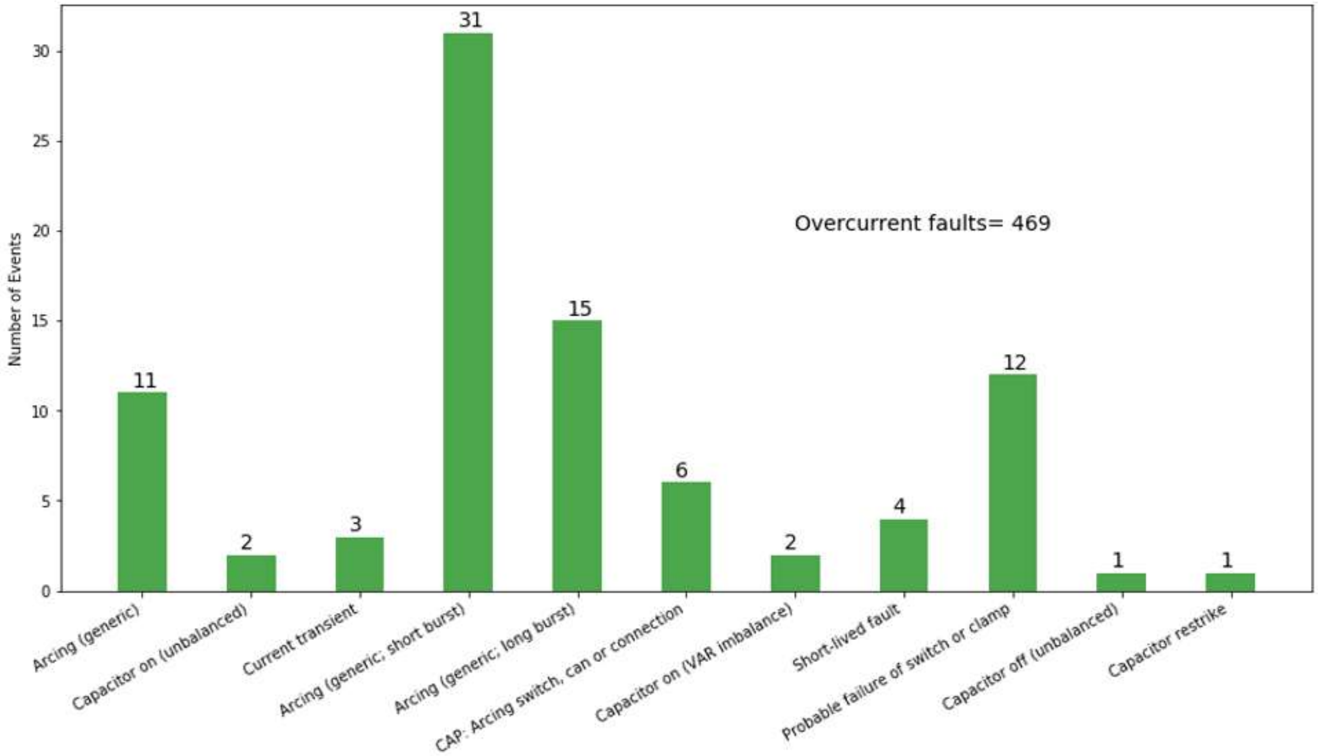
Figure 20. Data from Path D-E Daily Energy (13.71 days, 2-meter segments)



Events Detected by ECCVM, but not by RF Sensor

Figure 21 shows the different types of abnormal event that were capture by ECCVM on the EFD monitored circuit. This figure does not include overcurrent fault, there were 469 overcurrent faults on the circuit during the project. Of these events the RF sensors capture majority of the 12 "Probable failure of switch or clamps" and only one part of a shunt arcing event. This is in part because of the difference in monitoring strategies of the two sensor packages.

Figure 21. ECCVM Captured Abnormal Events on the circuit



4.4.2 Events detected by multiple technologies

The series-arcing events ("probable failure of switch or clamps") were discussed earlier in Section 4.3.5. For two of the ECCVM capture series-arcing events the RF sensors also captured the same events (see Section 4.2.8), with the matching timestamp. Correlation of the two sensors' data can be seen in Figure 22 and Figure 23. Series-arcing events have a relatively long duration for acing events, typically seconds in length. This allows the RF sensors to capture these events with their periodic sampling strategy.

There were some operational problems with RF sensor in proximity to the third event and that may have contributed to the RF sensors not capturing data for that event.

The RF sensor data and the ECCVM event timestamp are shown in Figure 23 for the one shunt-arcing event that was captured by both devices. Most of the shunt-arcing events captured by ECCVM are very short duration, one to two cycles and RF sensors, using a periodic sampling strategy, can't detect this type of shunt-arcing reliably. As Figure 23 shows, the RF sensor only captured data toward the end of the event, just before failure.

For the events detected by both types of sensors none of the alarming was done via the RF sensor's portal. All alarm notifications were done using the ECCVM "Grid Monitoring" portal.

Figure 22. Timeline of Sensor K Maximum Voltage and ECCVM Events

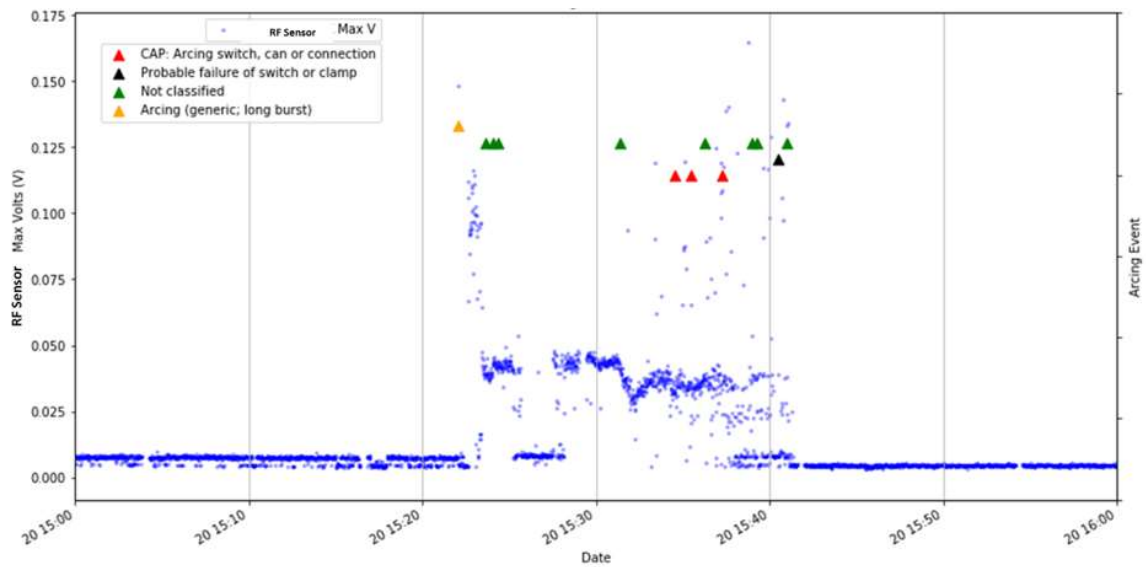


Figure 23. RF Sensor Pair D-E Energy for 3/15 to 3/22

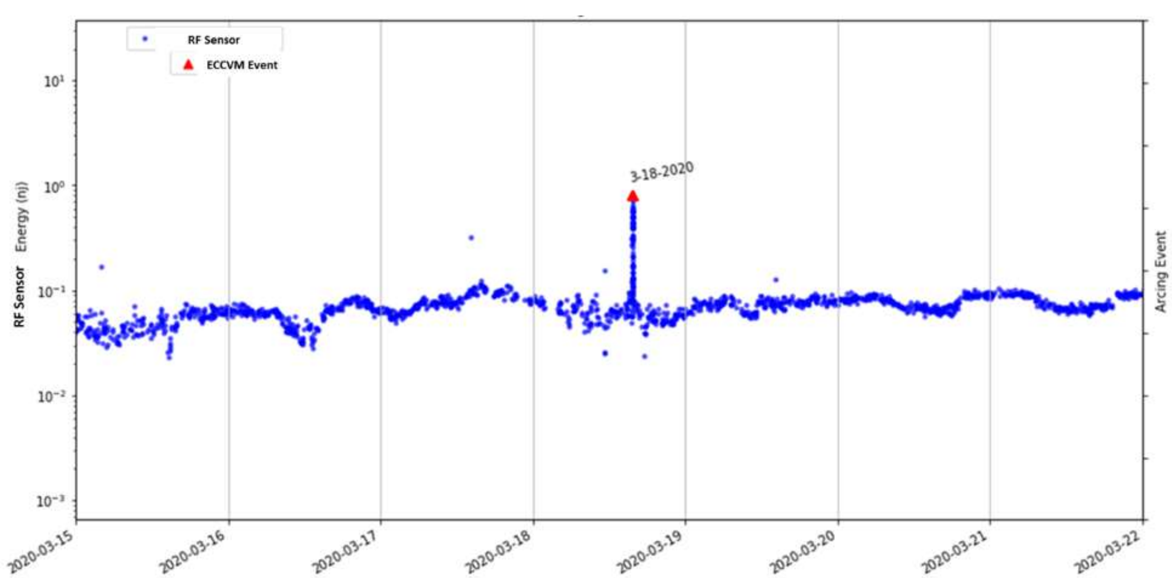
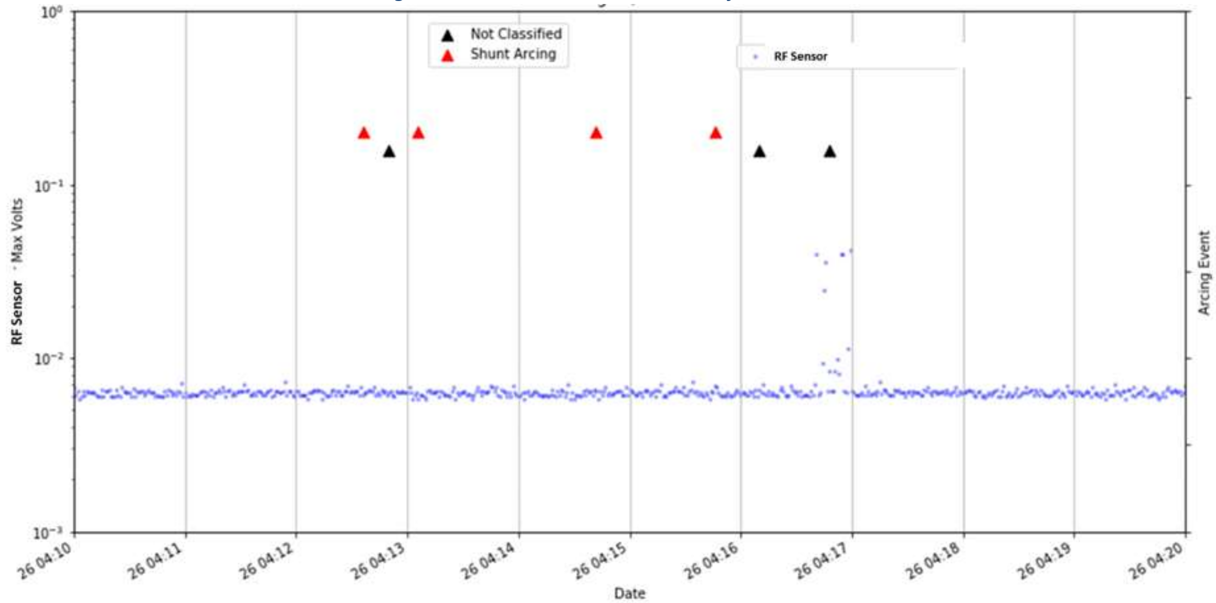


Figure 24. ECCVM/RF Sensor F Data for 5/26/20



5 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC 2.34 RF Sensors project has successfully demonstrated the field deployment of RF sensors to capture incipient system conditions. It has used ECCVM technology to validate the performance of the RF sensors and provided a comparison of the RF and ECCVM sensor technology in side-by-side field deployment. It also showed that sensors can work in an ensemble approach, building on the strengths of each technology, to monitor the grid for developing hazards.

5.1 Primary Principles

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

- **Increase safety**

RF network monitoring offers to reduce the rate of occurrence of many classes of network faults that are known wildfire risks in California and globally. The technology predicts powerline fire risks ranging from vegetation encroachment to conductor (and conductor clamp) failure. Its predictive identification of risks allows them to be addressed proactively before they materialize.

The ECCMV technology provides identification and classification of abnormal series and shunt arcing that the RF networking monitor technology not detect or elevate. The project demonstrated that the ensemble sensor technology approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance and risks of the distribution system.

- **Greater Reliability**

RF network monitoring system offers to reduce the number of network faults caused by deteriorated, damaged and compromised electricity network assets. The risks predictively identified in the trial were all known to be common causes of faults on PG&E's electricity distribution and transmission networks - faults that can and do regularly lead to interruptions to customer supply. Early warning of these risks can prevent the associated supply interruptions, thereby increasing supply reliability. Additional reliability that will result from identification of systemic fault conditions as has been demonstrated with the ECCVM on fault inducted and wind induced conductor slap.

- **Lower Costs**

Cost saving from RF Network monitoring and ECCVM technology will result from the difference between repair to damaged equipment under normal schedule operating conditions instead of emergency conditions. If hazardous asset conditions are allowed develop to faults and asset failure, there is additional damage to asset infrastructure through the wear and tear of faults, as well as collateral damage to equipment near the fault. Additional operational performance savings, such as reduction in system losses, would be achieved through the validation of correct operations of field equipment as was demonstrated with ECCVM's ability to detect asymmetrical capacitor operations and voltage overshoot from regulator control settings.

5.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following secondary principles:

- Societal Benefits

Improved reliability support from both the RF and ECCVM technology achieves a lower cost of service through a reduction in losses and, lessening the overall cost of electric service to all customers, and is extended to society through shared economic interests in efficiency improvements.

- Greenhouse Gas Emission Reduction

ECCVM was able to identify the system condition where PV based distributed generation would trip-off after a fault induced voltage sag, called a "hidden load" event. These conditions have been suspected to occur for some time and the new Rule 21 requirements for smart inverters included features that mitigate the tripping of inverters under fault conditions. The enhanced monitoring fidelity of ECCVM will provide a method to validate this feature. Reducing or eliminating the "hidden load" effect will help with DER deployment on PG&E's system which will help reduce greenhouse gas emissions.

5.3 Accomplishments and Recommendations

5.3.1 Accomplishments

The project achieved much in its short period of operation. The accomplishments are summarized by technology stream. Overall project accomplishments are summarized in their own section.

Technology 1. Prototype RF Sensor Accomplishments

Demonstrated the use of RF Monitoring for Grid Condition Assessment: Evaluated ten prototype sensors and a machine-learning model to assess grid conditions in 1 Km^2 area. Supplier has miniatured hardware components for fitting and integration into a conductor-mounted line sensor. Further development work is needed to define grid deployment strategy, data processing and visualization.

Technology 2. RF Network Monitoring Technology Accomplishment.

Installed RF network monitoring systems on one circuit: Nineteen RF data collection units were installed on poles on three-wire 12kV circuit. Secure cloud IT infrastructure used by RF network monitoring systems in other countries was replicated to a US-located data center in accordance with cyber-security requirements.

Successfully used RF network monitoring to detect real risks: Used the RF network monitoring systems to predictively identify the locations of multiple examples of conductor damage, vegetation encroachment, plus single instances of internal transformer discharge, and arcing at a loose conductor clamp. All of the detected risks are known powerline wildfire risks, and all were identified early and accurately located to within a few tens of feet. Some of the conductor damage was repaired as a priority following identification. Multiple instances of vegetation encroachment were observed.

Trained PG&E team in interpretation and analysis of results: Introduced PG&E team members to RF network monitoring concepts, the functions and operating envelope of the RF data collection units, the web portal data visualizations and the desktop analysis tools.

Successfully managed a range of challenges: Challenges overcome in operating RF network monitoring included challenges with pole space for the sensors, problematic cellular data service availability, poor solar insolation. Acted to ensure RF network monitoring continued throughout the trial. Developed forward management strategies for each of these challenges.

Gained deep appreciation of the value of RF network monitoring for PG&E: The trial revealed the results and data available to utilities from RF network monitoring and provided data needed to assess its tactical and strategic business value.

Developed forward technology adoption scenarios: In collaboration with the Supplier, identified the challenges of wider adoption and developed strategies to manage them to obtain maximum value from RF network monitoring.

Technology 3. ECCVM Technology Accomplishments

Installed ECCVM on six circuits: ECCVM devices were successfully installed on 6 circuits in the Napa Valley. Installation required full substation project design and review, IT security review, and commissioning. The successful installation of the devices provided consistent resource and financial estimates for scaling of the technology.

Successfully used ECCVM to detect incipient, recurrent fault, and operational events: The ECCVM technology captured over 32, 000 events on the 6 monitored circuits for the duration of the project. Most of these events were related to routine operations, but the devices did provide new visibility into operations issues including capacitor asymmetric switching, voltage regulator settings validations, hidden load issues, and non-project sensor tuning. The ECCVM technology was able to provide detailed forensic fault information, such as fault-inducted conductor slap, that identified systemic problems. ECCVM captured incipient conductor clamp arcing and vegetation contact through series and shunt arc detection.

Demonstrated an ensemble approach of the use of sensors to locate and identify events: ECCVM's locating at a substation limited the technologies capabilities to locate on the distribution feeder the exact area of issue. However, using the ECCVM as a compass of "when" and "what" is occurring on the feeder with other sensor packages, such as AMI, locations could be narrowed for operational patrolling. An example of this is when ECCVM's series-arcing was used with AMI to locate a failed jumper connector and fuse candling.

Successfully share operational experience on ECCVM both internally and externally: The project team has conducted internal presentations on ECCVM to operational and engineering departments within PG&E. The project team has also participated in a bi-weekly phone call with technical leads from SCE.

Overall Project Accomplishments

Compared RF and ECCVM technologies in a field deployment: The field deployment of both RF sensing and ECCVM sensing on the same feeder provided a side-by-side comparison of the two technologies. This comparison demonstrated the capabilities of both technologies and contrasted their detection strategies. The comparison also identified technology gaps in the detection of certain types of shunt-arcing events with RF sensing able to detect very low energy shunt-arcing and ECCVM detecting short single event shunt-arcing. RF sensing demonstrated its ability to locate the source of incipient events and ECCVM demonstrated its ability to capture high resolution time characteristics of events.

5.3.2 Recommendations

The successful performance of RF network monitoring and the demonstration of ECCVM technology in the current project leads to the following recommendations:

Expand RF Sensor 2 to Larger-scale Trial: Carry out a larger-scale trial of RF network monitoring to better define the challenges of wider adoption and identify strategies to address these challenges so maximum safety and reliability benefits can be delivered to Californian communities. A first step will be to extend the current deployment and testing to refine monitoring and operating techniques. Further expansion will be scheduled to match resources and technology refinement availability. Investigate the feasibility and benefits of RF Technology integration with the Distribution Management System for fault location, root cause analysis and preventative maintenance enhancement, as well as integration with Rapid Earth Fault Current Limiting technology to identify faulted protection zone.

Move ECCVM into a Production Footing: ECCVM is a very cost-effective technology that enables a significant improvement in data resolution and operator situational visibility into PG&E's electric distribution system. This capability should be moved into a staged production path and exercised as part of a risk assessment activity.

Integration opportunities: In conjunction with larger-scale RF deployment and production footing for ECCVM, explore and assess the potential benefits of integration this network monitoring data with data from other network monitoring technologies and relevant non-network data sources. Develop operational interface and combined data analytics tools for expanded operational usage.

Expand Shunt-arcing Research: ECCVM detection of shunt-arcing has not been seen before with PG&E's existing monitoring technology and the projects companion RF sensors were not able to detect these types of low energy arcing. RF sensors are great at detection of lower-energy partial-discharge events through a cumulative strategy, but the shunt-arcing instantaneous events of greater energy are missed by this strategy. Unfortunately, ECCVM by itself has been unable to help further identify direct causes of these arcing events as it cannot paint the location. Related system faults around shunt-arcing events has been able to provide circumstantial evidence of potential causes but the goal of identifying the cause while still a shunt-arcing event (no fault) has not been achieved. This area needs further research to better understand the shunt-arcing events and close the technology gap in shunt-arcing event locating.

5.4 Key Accomplishments

The following summarize some of the key accomplishments of the project over its durations:

- Demonstrated stationary RF sensor grid health monitoring with prototypes and an analytical model for locating deteriorated grid assets.
- Successfully demonstrated both RF Network Monitoring and ECCVM technologies in a field deployment.
- Demonstrated RF sensing technology's ability to identify and locate conductor damage, vegetative encroachment, and arcing component incipient events in the field.
- Demonstrated ECCVM technology's ability to identify series-arcing events related to conductor clamp failure. Using AMI data with ECCVM, locate the series-arcing events.
- Identified technology gap of shunt-arc detection where current RF sensing technology often misses in the sampling window the ECCVM-detected shunt-arcing such that the source asset cannot be located.

5.5 Key Recommendations

The project's work identifies several areas that should have continued effort. The following summarizes these recommendations:

- Carry out a larger-scale trial of RF network monitoring to better define the challenges of wider adoption and identify strategies to address these challenges so maximum safety and reliability benefits can be delivered to Californian communities.
- In conjunction with a larger-scale trial, explore and assess the potential benefits of integration of RF network monitoring data with data from other network monitoring technologies and relevant non-network data sources.
- Move ECCVM into production with a staged approach to match ongoing technology monitoring and system risk assessment activities.
- Expand research into the technology gap on shunt-arcing.

5.6 Technology transfer plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E will share the results of this project in industry workshops and through public reports published on the PG&E website. Specifically, below is information sharing forums where the results and lessons learned from this EPIC project were presented or plan to be presented:

5.6.1 IOU's technology transfer plans/ Information Sharing Forums Held

- SDG&E Visit to PG&E, San Ramon, CA - February 14, 2020
- California Utility Wildfire Risk Reduction Meeting, Conference Call - February 18, 2020
- PG&E/SCE DFA Demonstration Check-In, Conference Call/February 28, 2020 and June 12, 2020
- PG&E/Duke Energy Discussion of RF Monitoring, Conference Call/May 20, 2020
- PacifiCorp & PG&E Discussion of Asset Health Monitoring, Conference Call/June 12, 2020
- PG&E has participated in multiple information-sharing meetings with SCE and other utility companies in California and elsewhere related to ECCVM-detected events and response, Multiple dates since 1/1/2020 and continuing

5.6.2 Information Sharing Forums Planned

- Texas A&M Conference for Protective Relay Engineers, College Station, Texas, April 2021
- CIGRE Grid of the Future Conference, Providence, Rhode Island, November 2020
- iPCGrid (Innovations in Protection and Control for Greater Reliability Infrastructure Development) Workshop, California, April 2021

5.7 Data Access

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

6 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[8] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

[8] 2015 PG&E EPIC Annual Report. Feb 29, 2016.
http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	3.1, 5.1, 5.2
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
d. Public safety improvement and hazard exposure reduction	3.1, 5.1

7 Conclusion

Utility operational practices have been stagnant while available technologies have been unable to respond to the challenges presented by aging grid infrastructure and the increasing risks of climate-change driven stresses and environmental sensitivities, which in California is predominantly the risk of wildfire ignition. This project has demonstrated and evaluated the potential of recently commercialized technologies for the application of continuous grid asset health and performance monitoring. Just-in-time maintenance is an optimal strategy with lower cost than time-based maintenance and lower risk than periodic inspection-based maintenance that can miss rapidly developing grid asset hazards.

RF network monitoring technology sensors can successfully detect and accurately locate incipient failure conditions for corrective maintenance and wildfire risk mitigation. The technology is highly sensitive and able to detect low level partial discharge activity such as primary conductor damage and vegetative encroachment on secondary conductors. There are additional use cases PG&E plans to explore, including integration with the Distribution Management System for fault location, and potentially integration with Rapid Earth Fault Current Limiting (REFCL) to identify faulted protection zone. Distributed sensors technologies present some deployment challenges such as finding pole space and adequate cellular coverage, streamlining the estimating and installation processes that PG&E will continue to evaluate and optimize. The product supplier is planning several promising technology advancements that PG&E plans to demonstrate through expanded deployment.

The ECCVM technology effectively detects and classifies normal operating events and abnormal events that can be predictive of developing hazards. The ECCVM technology is not able to detect the same low-level persistent conditions that RF monitoring can, but it is able to detect brief <2 cycle duration arcing events that the RF Network Monitoring Technology may not detect, or may not detect in a timely manner. ECCVM technology cannot determine the source location of detected events and relies upon distributed sensor technologies, including RF Network Monitoring Technology, Line Sensors, and AMI, for this purpose. The ECCVM technology was shown to be successful at detecting shunt-arcing events that RF sensors, as currently designed, do not reliably detect, therefore presenting a challenge for the location of shunt arcing source. Through circumstantial data these shunt-arcing events have been validated to be real, and potentially hazardous, events. The RF technology supplier has plans to progress to continuous RF monitoring and if successful, this may close the gap and allow the RF technology to provide the source location of shunt arcing events.

The project has been able to demonstrate incipient conditions can be identified and located with the combining of sensor data into an ensemble approach, with each technology adding uniquely to the event classification, location and prioritization of detected hazards. The ensemble approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance of the distribution system. When there are areas that cannot be served by RF or Line Sensor components, AMI may be able to provide some of the necessary information for effective grid monitoring. PG&E's Distribution and Grid Monitoring Roadmap and Implementation Plan proposes to expand deployment and operation of emerging technologies, such as those demonstrated in this project, that provide grid event data for real-time monitoring and analytics of asset health and performance. PG&E strives to become more predictive of developing hazards on the electric distribution system for implementation of proactive maintenance in order to reduce wildfire risk and improve public safety. This work focuses on Tier 2 and Tier 3 High Fire Threat District areas of PG&E's service territory.

During the technology evaluations with limited deployments, the sensor data was manually analyzed and reacted upon. PG&E recognizes that the manual approach is not scalable for either resource allocation or rapid response to detected grid asset conditions. Clearly wide-scale adoption of grid monitoring technologies would require a sensor data integration and analytics platform to provide automated analysis and response for asset hazards. PG&E has plans to investigate approaches to this problem, which can enable timely analysis and response to data from multiple grid sensor technologies that report asset health conditions.