EPIC Final Report

Program	Electric Program Investment Charge (EPIC)
Administrator	San Diego Gas & Electric Company
Project Number	EPIC-3, Project 4
Project Name	Safety Training Simulators with Augmented Visualization
Module Name	Module 1, Focused Patrol Simulator
Date	December 31, 2021

Attribution

This comprehensive final report documents the work done in this EPIC activity.

The project team for this work included the following individuals, listed alphabetically by last name.

SDG&E® Staff

Anthony Asmar
Sundar Balagangadharan
Dan Bedell
Ronald Blankenship
Brian Braidic
Chris Brown
Mike Colburn
Casey Cook
Ramakrishna Dhanekula
Karl Doering
Sarah El-Kuffash
Frank Goodman
Lamont Girton
Chippy Impreso
Alicia Jenness
Melissa Jones
Kurt Kauffman
Kristina Lukin
Kenneth Macpherson
Cory Mitsui
John Marchesino
Jamie Padilla
Betty Pelgen
Beverly Raposa
Steve Rochester
Subburaman Sankaran
Lucie Sidibe
Dustin Soeker

Vendor

Dave Baily
Charlie Buck
Umang Deora
Tom Eyford
Lorry Falk
Jeff Grose
Brad Harkavy

Kevin Hughes
Palak Jain
Craig Knox
Scott McDonald
Mike Mohar
Terry Nielsen
Marcio Pivatelli
George Stockdale
Brad Williams
Vahraz Zamani

EXECUTIVE SUMMARY

Project Objective

The objective of SDG&E's EPIC-3 Project 4 was to demonstrate and evaluate augmented reality applications for field focused design, operations, and asset monitoring and management solutions in utility power systems. The project was split into two modules. Module 1 was center on focused patrol for the benefit of operator trainees. Module 2 was centered on safety procedures for underground distribution field work. Module 1 is the focus of this document and Module 2 is covered in a separate report. Both are available on SDG&E's public website.

This report covers the work done in Module 1. The objective of Module 1 was to conduct a pre-commercial demonstration of a functioning fault location system that was utilized to create a training stimulator for electric distribution system operators and other prospective users.

Approach

When outages occur on the distribution system, there are many steps required to correct the underlying cause and restore power. The typical restoration process stages are 1) Detection, Prioritization and Queuing; 2) Dispatching & Patrolling; and 3) Restoration Plan & Restoring the Service. The goal of this demonstration project is to investigate additional tools that can be used to optimize and reduce the "Dispatching & Patrolling" times.

A pre-commercial demonstration system was constructed that included a replication of the commercial Advanced Distribution Management System (ADMS) environment with new software modules and integrations with new sensors including: 1) Wireless Fault Indicators (WFI), 2) Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms, 3) Weather Data, 4) Advanced Protective Relays, and 5) Phasor Measurement Units (PMU)s.

The most valuable data sources were incorporated into training scenarios that can be used to train system operators on how to use the data to direct field crews to patrol the most likely faulted locations first. And finally, the training scenarios were demonstrated to a team of experienced system operators and trainers to review and critique the findings and potential training scenarios.

Recommendations

The following recommendations are determined based upon the analysis done as part of this project:

- Establish and maintain a permanent Training Simulator in a non-production environment and mirror the production system
- Add new data sources to the production system (weather data, AMI low voltage alarms, Wireless Fault Indicators)
- Maintain a regular training program for the operators, reviewing scenarios analyzed during this project
- Continue to investigate new scenarios and new data sources (including Phasor Measurement Unit (PMU) data) in an Innovation Lab environment, as a continuous improvement practice to feed the Training Simulator with new valuable scenarios

Conclusions

In order to incorporate existing multiple new and enhanced data sources that can assist in identifying the most likely locations of faults to reduce restoration time, additional training for system operators is required to properly interpret the new data sources. In addition, new User Interface (UI) configurations can assist in limiting the clutter caused by the presentation of too much information. These user interface enhancements can reduce the amount of training required for operators to properly interpret the additional data.

The Training Simulator provides a controlled environment to test scenarios with current and future sensor data. With the addition of more devices and more data, operators can be overwhelmed with information that is difficult to interpret and utilize. Analyzing data, simulating scenarios and training in a non-production system provides the foundation to build a process before additional data is displayed in a production system. Additionally, the training simulator enables operators to be trained on relatively rare and numerous unique fault situations.

Overall, the recommendation is made for commercial adoption of this technology solution. It is recommended that the stakeholder groups within SDG&E who participated in this project pursue commercial adoption by organizing a commercialization team and appointing one key stakeholder group to lead the effort. A commercial adoption plan should be developed as a next step.

TABLE OF CONTENTS

List of Figures

List of Tables

List of Acronyms

Acronym	**Acronym Description**
AC	Alternating Current
ADC	Analog to Digital Converter
ADMS	Advanced Distribution Management System
APR	Advanced Protective Relay
AMI	Advanced Metering Infrastructure
ARP	Auto Reclose Process
API	Application Program Interface
CAIDI	Customer Average Interruption Duration Index
CEV	Compressed Event Report
COMTRADE	Common Format for Transient Data Exchange for power system (COMTRADE)
CPUC	California Public Utility Commission
DA	Distribution Automation
DER	Distributed Energy Resource
DOE	Department of Energy
DSO	Distribution System Operator
EAM	Enterprise Asset Management System
EMS	Energy Management System
EPIC	Electric Program Investment Charge
ETS	Electric Troubleshooters
EV	Electric Vehicle
FCI	Fault Current Indicator
FLA	Fault Location Analysis
GIS	Geospatial Information System

Acronym	Acronym Description
HV	High Voltage
HMI	Human Machine Interface
IEEE	Institute of Electrical and Electronic Engineers
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
NMS	Network Management System
OMS	Outage Management System
OTV	Onramp Total View
PDC	PMU Data Concentrator
PDO	Predicted Device Outage
PMU	Phasor Measurement Unit
PQ	Power Quality
PQM	Power Quality Meter
PSO	Predicted Service Outage
RDO	Real Device Outage
RMO	Real Momentary Outage
RTAC	Real Time Automation Controller
SA	Substation Automation
SDG&E	San Diego Gas and Electric
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
WFI	Wireless Fault Indicators

SECTION 1. INTRODUCTION

Project Objectives

The objective of SDG&E's EPIC-3 Project 4 was to demonstrate and evaluate augmented reality applications for field focused design, operations, asset monitoring, and management solutions in utility power systems. The project demonstrated the ability of the latest simulator technologies to train utility industry personnel on safety-related issues, including electric potential zones and grounding techniques associated with construction work practices. Capabilities demonstrated included the utilization of augmented reality tools to visualize and provide rich contextual information at the point of work.

The project was divided into two modules. Module 1 conducted a pre-commercial demonstration of a functioning fault location system that was utilized to create a training stimulator for electric distribution system operators and other prospective users. The system simulator integrated input from multiple sources that utilize different technologies. This document is the comprehensive final report on Module 1.

Module 2demonstrated the use of virtual-reality visualization tools to aid in training field employees in safe practices for working in situations where there is the possibility of unexpected hazardous levels of electric potential. A separate final report has been prepared for Module 2 and is posted on the SDG&E EPIC internet site.

Issues and Policies Addressed

In the context of electric utilities and wildfire risk, improving operator situational awareness is a key aspect of safe, successful real-time operations. This addresses a major California Public Utility Commission (CPUC) focus.

The 2018 California Senate Bill 901 requires all utilities to create an annual wildfire mitigation plan [1]. The Office of Energy Infrastructure Safety approves the plans from each utility, and they are then certified by the CPUC.

Grid Operations and Protocols are a required element of the wildfire mitigation plan and identifies risk and mitigation efforts. This project provides insight into new technologies and training techniques that could potentially be deployed to further mitigate wildfire risks and improve customer and field personnel safety. Enhancing the training experience for operator trainees will improve the pipeline of new operators and help to ensure adequate staffing for real-time operations, keeping operators rested and fresh as they begin each shift.

Project Focus

The focus of the project was to present actionable data from disparate sources to system operator trainees, in a unified manner, for improved situational awareness, and improved safety and reliability outcomes. The more reliable the system becomes, the greater the public safety.

Technical Issues

A Distribution System Operator (DSO) is responsible for planning and executing operational functions associated with an electrical distribution system. DSOs operate and maintain the local distribution area, separate from the transmission operator, and are responsible for providing a highly safe and reliable distribution service.

The DSO strives to improve the quality of the service and the safety of the public and field crews. DSO also work to minimize the overall Customer Minutes Interrupted (CMIs) and shorten the time that is required to restore an outage.

Currently, there are multiple tools available for utilities to manage the reliability of the distribution system including:

- Substation Automation (SA) to monitor voltages, currents, and control device operations inside distribution substations.
- Distribution Automation (DA) monitors and automatically controls devices along the distribution circuits, such as switches, reclosers and auto-sectionalizers.
- Outage Management System (OMS) is used to manage the restoration process; the process is triggered by a customer reporting an outage via a phone call, or other electronic reporting methods through a website, text message, mobile application, etc.
- OMS tied with an Automated Metering Infrastructure (AMI) solution can automatically identify the meters that are out and those that are restored.
- Distribution Supervisory Control and Data Acquisition (SCADA) that remotely monitors device operations and measurements at select points on a feeder and enables switchable devices to be opened and closed remotely.

There are several key performance metrics related to system reliability that all Load Serving Entities (LSEs) use to measure their performance and benchmark their current reliability against past performance and other utilities. The most used metrics are:

1. SAIDI (System Average Interruption Duration Index) – minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) – number of sustained outages per customer per year.
3. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.
4. MAIFI (Momentary Average Interruption Frequency Index) – number of momentary outages per customer per year.

These four metrics are used in the electric utility industry to measure its reliability and quality of its service at the distribution system level as defined in The Institute for Electrical and Electronic Engineers (IEEE) Guide for Electric Power Distribution Reliability Indices (IEEE Standard 1366).

Reducing the amount of time to perform restoration has a direct impact on customer service reliability as measured by SAIDI and CAIDI. It is important to understand the overall restoration process and the individual steps that are part of the process so that it can be systematically analyzed and improved.

The common or typical restoration process steps are explained in ***Error! Reference source not found.***.

Table 1 Outage Restoration Steps

Stage	**Time Steps**	**Description**
Detection, Prioritization and Queuing	T0	Start of the outage
	T1	Outage “Ticket” generation in OMS
	T2	Outage created and prioritized in OMS
Dispatching & Patrolling	T3	Electric Troubleshooter (ETS) crew dispatched
	T4	ETS crew arrives on-scene

Stage	Time Steps	Description
	T5	ETS crew completes patrolling and troubleshooting of outage
Restoration Plan & Restoring the Service	T6	ETS Crew performs partial or full restoration, if possible
	T7	Additional crew(s) assigned in OMS (if required)
	T8	Additional crew(s) dispatched
	T9	Additional Crew arrives on-scene
	T10	Crews perform full restoration

The relevant times in the process are described in further detail in *Table 2 Outage Process Time Steps*.

Table 2 Outage Process Time Steps

Time:	Outage Process Activity
T0	The time the outage begins, this is the time the outage is identified by customer calls, AMI, or SCADA.
T1	The time the outage is created in the Outage Management System (OMS).
T2	The outage priority will be analyzed based upon policies by dispatchers. This is the time that the outage is assigned a priority. Based upon priority, the outage may be queued behind other outages waiting for a crew to be available.
T3	This is the time ETS crew is actually dispatched to location of outage determined by OMS. Typically, this is the location of a protective device (i.e., fuse) that operated to isolate a faulted section.
T4	The time the ETS crew arrives on-scene at the location provided by the OMS.
T5	The time the ETS crew completes patrolling downstream of the protective device and identifies the actual fault location(s) and damage location(s); the outage cause is determined at this time.
T6	The time when ETS crew completes partial or full restoration (if possible). ETS crews are only able to restore certain types of outages that do not require multi-person crews or special equipment.
T7	The time additional crew(s) are assigned (if required). The crew(s) assigned are based upon the specific outage location, cause, and damage.
T8	The time additional crew(s) are dispatched to the location of fault and/or damage.
T9	The time the additional crew(s) arrives on-scene.
T10	The time of full restoration. This occurs after the additional crew(s) arrive. The crews may perform some step (partial) restoration to restore customers outside of the faulted and damaged area before addressing the fault, repairing the damage and performing the final full restoration.

This project investigated additional tools that can be used to optimize and reduce the “Dispatching & Patrolling” times. These “tools” used information from new sensor technologies to supplement current fault location analysis and provide additional fault location information before the patrolling begins. The proposed approach was to train operators to use computer systems to analyze and present information from new sensor technologies that can provide additional insight into the location and cause of the outage before the crew is dispatched, ultimately reducing the patrolling time required (T4-T5).

Project Scope and Benefits

The scope of this module was to demonstrate a functioning pre-commercial training simulator that can help instruct system operator trainees how to narrow the patrol or search location of a fault for a set of selected test circuits. This new training simulation platform was utilized to teach the system operators/trainees as well as other prospective users to recognize, understand, and utilize the signals provided by new sensor data sources, including an installed array of Wireless Fault Indicators (WFI's). The training was in conjunction with existing SCADA, WFI's, upgraded AMI functionality, and a revamped Advanced Distribution Management System (ADMS) with built-in algorithms. This scope was intended to enhance the ability to more quickly and accurately predict the region of a fault. The use of real-time data from the AMI was incorporated, along with advanced SCADA functionality (i.e., synchrophasors). Minimizing the duration of fault location process and allowing operators to dispatch fewer, more-focused field personnel more strategically to the scene was the scope of the project with the following targeted benefits:

- Safety to SDG&E's Personnel

  Because the training simulator is based on a more efficient approach for determining fault location and directing field personnel to the fault location, it inherently improves safety for field personnel, reducing their driving exposure especially into more rural areas and sometimes dangerous weather conditions. Nighttime operations will especially be improved.

- Safety for the Public

  The new training process and improved field equipment allows the operators to locate wire down events quicker, reducing public exposure to a potentially energized system. Any system that hastens service restoration inherently improves safety to the public, ensuring local infrastructure operates as intended (e.g., lighting, communications, water and sewer systems, traffic signals, and fire-fighting equipment), after faults of any kind cause service interruptions.

- Risk Reduction

  Since a fault location can be identified more quickly, and the correct personnel deployed with greater accuracy and speed to that location, it:

  - Enables the organization to be better prepared for the future by offering more measures to mitigate/decrease the risk of starting fires due to wire down or possibly other events, thus significantly reducing the overall risk that the company and its customers face as it relates to wildfires.

  - Reduces the need for test closures, which could make a more resilient utility by extending the life cycle of distribution equipment. Test closures into faults are extremely violent events and contribute to wear and tear on equipment. Reducing the frequency of test closures improves safety, reduces operating costs, and improves power quality.

- Reduced Cost
    - Focused patrol training allows for quicker fault identification, effectively reducing crew effort and therefore potentially reducing the overall System Average Interruption Duration Index (SAIDI) impact of outages, making the DSO more efficient. It will also increase customer satisfaction and reduce their exposure to wildfire-related issues and other risks associated with outages.
    - This training module naturally leads to process improvements, which allow a utility to do the same job with fewer resources (i.e., if the location of the fault is determined more quickly, personnel can be deployed to the location more quickly, and released from duty earlier so they can be assigned to subsequent tasks as needed).
- Improvements in Training Efficiency
    - Improved training outcomes in terms of training effectiveness and speed, student learning outcomes.

SECTION 2. APPROACH

The project started with a list of Use Cases and a proposed set of sensor data sources that would be used in the Training Simulator environment. During the set-up of the new Training Simulator environment, the use cases were reviewed, and information was gathered on the data sources. This initial data analysis and discussions with operators showed potential value from creating multiple fault location and detection scenarios, with and without new sensor data. A significant amount of time was spent analyzing the new data sources, comparing current fault location processes and identifying real situations where devices tripped or did not trip, as well as situations where faults occurred but were not detected. The analysis details are provided in Section 3 – Demonstration Development.

Fact Finding

The team reviewed and detailed the initial **seven use cases** that represented areas of focus. The use cases were developed based on the review of fault events. The use cases were prioritized based upon potential benefits and applicability to the focus of the project. The following lists the use cases in priority order:

- UC1: Wire Down
- UC2: Proactive Fault Detection
- UC3: Foreign Object in line
- UC4: Tree/Vegetation Contact
- UC5: Overload Mitigation
- UC6: Underground distribution
- UC7: Primary Voltage Customer Problem

Data from five new sensor types were used in the analysis

- Wireless Fault Indicators (WFI)
- Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms
- Weather Data
- Advanced Protective Relays

- Phasor Measurement Units (PMUs)

See **Appendix A** for the details of each of the Use Cases. The Demonstration Development section includes the detailed analysis performed on each new sensor type as well as the simulations and specified findings.

Potential Benefits Identification

At the beginning of the project, the targeted benefits identified in the project scope were reviewed with the detailed use cases. The process aimed to produce a list of potential benefits that would result from the commercial adoption of the demonstrated training solution in the EPIC-3, Project 4, Module 1, Focused Patrols of Distribution System Overhead Lines. These initial benefits identified were used as guide in the demonstration phase of the module.

Due to the intangible nature of this project (Staff Training), the plan was to document the current fault location process (establish the baseline) and compare how the training simulator helps train DSO's to improve the process of conducting fault location analysis. The benefits gained by the implementation of the training stimulator were the focus of this study.

This is supported by the findings from a Department of Energy (DOE) study in 2014 [2] from seven successful projects from the Smart Grid Investment Grant (SGIG) program across the US in five distribution operating companies. Similar fault restoration technologies that reduced outage durations found that significant process changes were required and that greater expertise in information technology, database management, and grid analytics necessitated new educational and training programs [2]. Leveraging these "lessons learned" from other utilities, the training simulator and associated training programs are necessary. The following fault location process was documented and referenced in determining the benefits defined in the scope of the project.

When an outage occurs, the DSO begins service restoration as soon as possible. Unless damage reports indicate where the cause is located, the DSO directly uses non-tripped fault targets (when available) from the distribution line SCADA site(s) to determine if a line segment is free of faults. For all other cases, and during the non-fire season outside of fire zones, as allowed by protocol, the location of faults is sometimes confirmed through test closure of the feeder breaker or service restorer. The current process not only diminishes the resiliency of the system by weakening it each time a test closure into a fault occurs, but also increases inefficiency in the work force. Given that multiple field personnel must arrive on scene before any testing occurs, the duration of the outage is prolonged with multiple electric troubleshooters driving from device to device. System operator practice also demands that individuals check in from the field on an outage, to be confirmed in the clear by company radio before any closure attempts are made, sometimes extending the time for ultimate restoration.

Reduced Cost

During the project, scenarios were developed in the training simulator using a copy of production data with and without the addition of new sensor data. Through the addition of new sensor data, it was apparent that reduced cost would result from the addition of new sensor data to the existing process with the appropriate training for the operators. Below is a list of the reduced cost benefits identified:

- Focused patrol training will allow for quicker fault identification, effectively reducing the patrol time required to find the fault location, isolate the fault and restore service more quickly. Faults often occur after normal work hours, and thus crew call outs to restore outages are often associated with overtime labor rates. Shortening the restoration will reduce overtime costs and can reduce the number of crews called to help patrol the line. During normal work hours crews will become more efficient in the restoration, allowing them to get more work done during their workday or shift.

- By using the training simulator to improve the fault identification process, faster arrival at the actual fault location reduces the duration of power interruption and the overall System Average Interruption Duration Index (SAIDI) impact of outages is reduced, improving reliability and reducing lost revenue.
- Using the training simulator will also increase customer satisfaction and reduce utility company exposure and costs associated with wildfire-related issues and other outage related risks.
- This training module will naturally lead to process improvements, which will allow a utility to do the same job with fewer resources (i.e., if the location of the fault is determined more quickly, personnel can be deployed to the location more quickly, and released from duty earlier, or assigned to subsequent tasks as needed).

Improvements in Training Efficiency

Focused Patrol reduces the overall time needed to accomplish the training of new operators.

Metrics

One outcome is the improvement in the ability to more easily simulate and configure the training simulator. This will result in improved student learning outcomes with greater improvements in operating practices that achieve the metrics of improved SAIDI and fewer test closures.

Pre-Commercial Demonstration

A pre-commercial demonstration system was constructed that included a replication of the commercial ADMS environment and new software modules listed below:

- Network Management System (NMS) – Network Management System is another name for an Advanced Distribution Management (ADMS) System.
- Outage Management System (OMS) – This is the module of the ADMS/NMS that is used to manage grouping of customer calls, AMI events and other inputs into logical outages, as well as support the prioritization of outage restoration, tracking of the progress of outages and the restoration processes.
- Fault Location Analysis – This is a module of the ADMS/NMS that is used to identify the location of an electrical fault. This is done based upon an electrical connectivity model combined with measured fault currents and electrical impedances of every element in the electrical model.
- Training simulator – This module of the ADMS/NMS that supports the development of scenarios and simulation of actual power system behavior for the purposes of training system operators.
- Power flow – The Power Flow module of the ADMS/NMS analyzes the electrical power flow and voltage profile of every element in the distribution system using available measurements, an electrical connectivity model, electrical impedances, and load information.
- SCADA adapter – The SCADA adaptor of the ADMS/NMS, provides the ability for the ADMS to obtain information from one or more external Supervisory Control and Data Acquisition (SCADA) systems.

- Analytics - The Analytics module of the ADMS/NMS provides the ability to analyze historical data captured in the ADMS and produce reports and other analysis of the data in a summarized fashion. This allows managers, engineers, and other people to identify trends and potentially take action to improve aspects of the system in the future.
- Operational Technology Message Bus – The Operational Technology Message Bus is a module of the ADMS/NMS that connects the ADMS to multiple other internal and external systems, typically other operational technology (OT) systems.

Additional data sources were part of the demonstration. The new data sources included:

- WFI data – Wireless Fault Indicator data is information that comes from fault indicators in the field that are connected via a wireless communications network.
- AMI LV Alarms – AMI Low Voltage alarms are generated from AMI meters when they detect that the voltage at the meter drops below a predetermined threshold.
- Weather data – Incorporate direct integration of relevant weather data into the NMS for easier operator training and improved operator usability.
- Advanced Protective Relay data – Advanced Protective Relay data is information from microprocessor-based protection relays with embedded sensors that provide advanced data streams such as fault currents and other protection information.
- Phasor Measurement Unit (PMU) data – Phasor Measurement Units collect measurements of voltage and current at very rapid rates that are GPS time synchronized.

Fig. 1. Software **ArchitectureFig. 1** represents the high-level view of the software that was deployed as part of this EPIC project. The system was deployed on two additional servers.

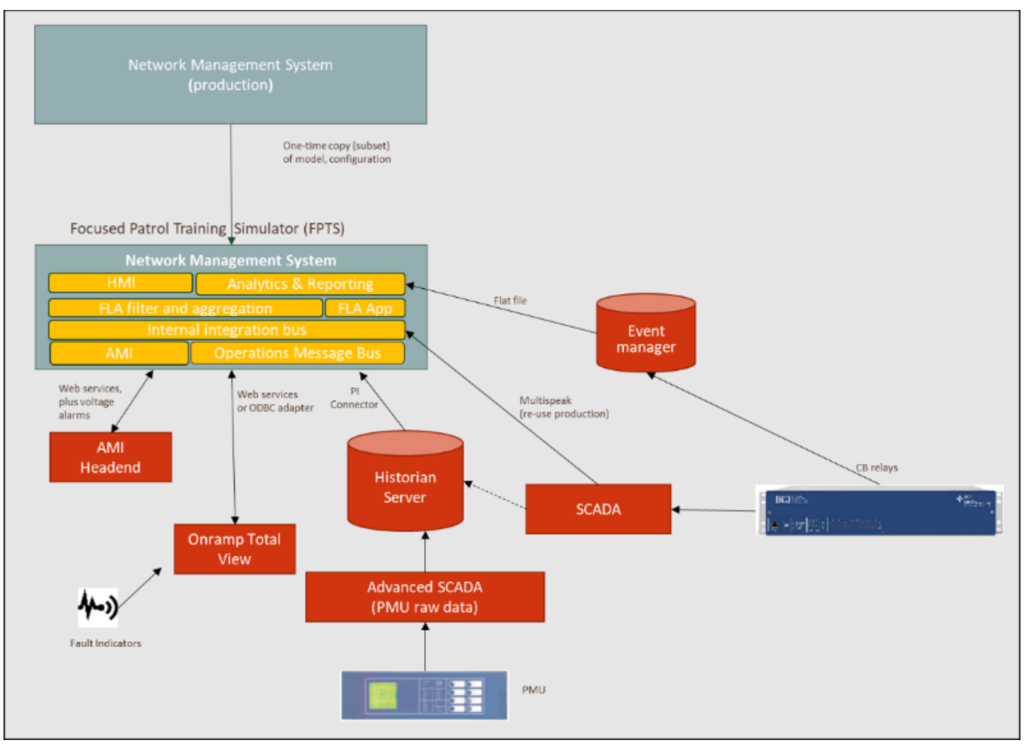


Fig. 1. Software Architecture

SECTION 3. DEMONSTRATION DEVELOPMENT

Approach and Description of Demonstrations

The final approach utilized in this project was to analyze each of the data sources identified and determine the use cases impacted and demonstrate how they could be used to improve operator response. This section of the report describes how each data source was investigated, the impacted use cases and the findings associated with that data source. The following data sources were investigated and demonstrated:

1. Wireless Fault Indicators (WFI)
2. Advanced Metering Infrastructure (AMI) Low Voltage (LV) alarms
3. Weather Data
4. Advanced Protective Relays
5. Phasor Measurement Units (PMU)s

The following sections cover the details of each of the investigations done for each data source itemized above.

Wireless Fault Indicators

Wireless Fault Indicators – Introduction

Fault indicators are a common device placed on distribution overhead conductors and used in the field to assist in trouble shooting by indicating that fault current has been detected and the actual fault should be downstream of any fault indicator that reported a fault current. Fault Indicators are typically located on the feeders and present status of the fault current detection in a way that can be seen by a patroller with a flag or light. Wireless Fault Indicators are battery-operated and have a radio allowing them to reach out through a wireless network and provide the status back to the NMS. The communications network is designed to provide data within a few seconds allowing the data to be used in the FLA algorithm similarly to how it is used in the field. Several typical wireless fault indicators as deployed in the field are shown in *Error! Reference source not found.*

Fig. 2. Wireless Fault Indicator (WFI) Devices installed in the field

Since the Fault Location Analysis algorithm often produces multiple possible fault locations, which requires field crews to patrol multiple branches to confirm a fault location, it is desirable to add sensors to assist in further narrowing down the possible fault locations. Fault indicators are a sensor device that detects the presence of a fault current at the location they are installed on the distribution system. A simple state of fault current was detected or not detected is all that is needed to improve the fault location algorithm.

Placing WFIs at strategic locations such as at the bifurcation of branch segments can help identify which branch should be patrolled. This is because the fault indicator will have a positive state at the head of the branch where the fault occurred and a negative state at the head of all other branches that didn't see the fault current. When one branch segment is directly downstream from another segment, the fault indicator status also indicates the upper and lower bounds of a fault location when the upstream fault indicator reported a fault current detected and the downstream fault indicator indicates no fault current detected. See **Fig. 3.** for an example of placements of WFI devices at branch locations of a feeder.

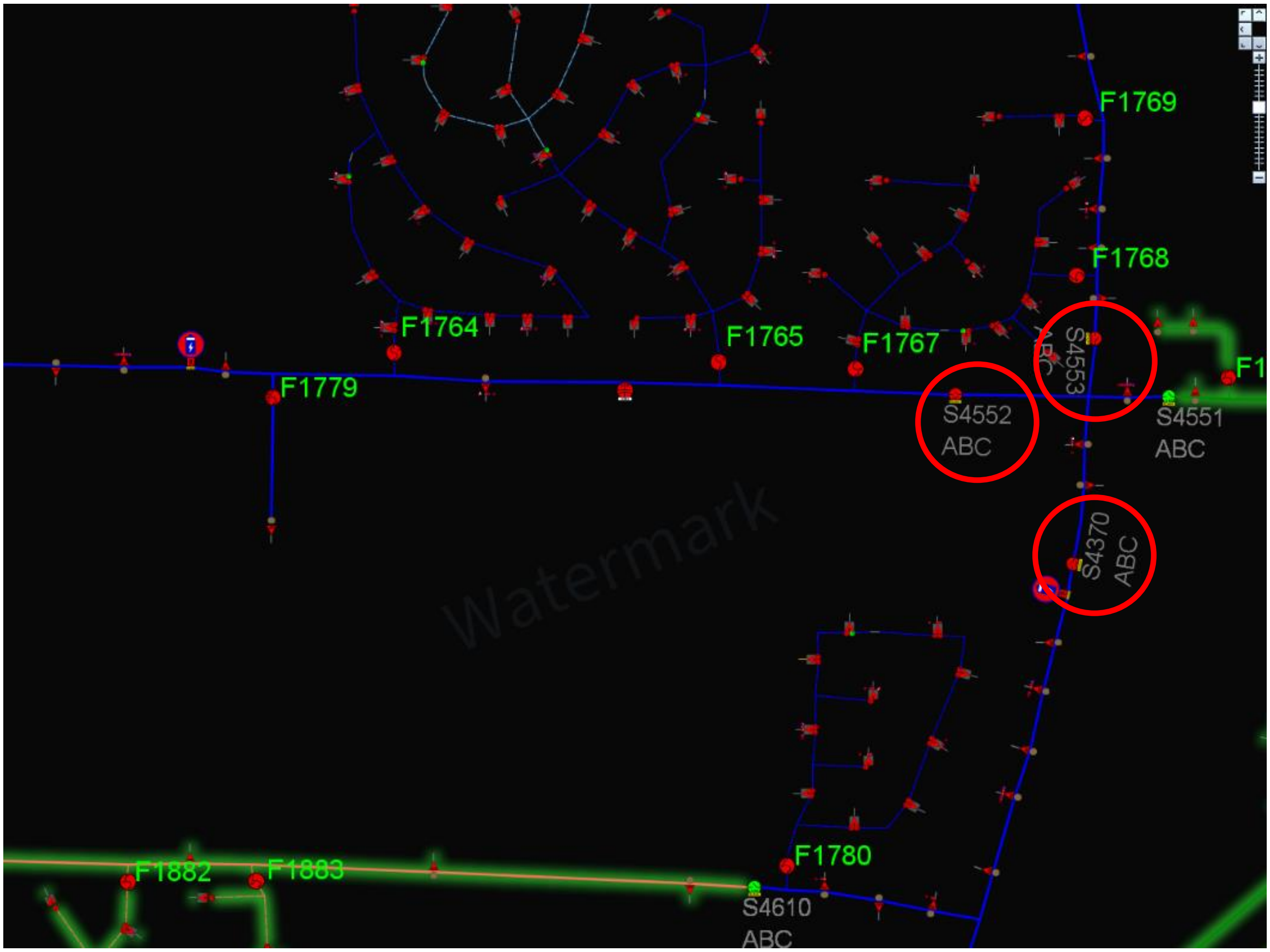


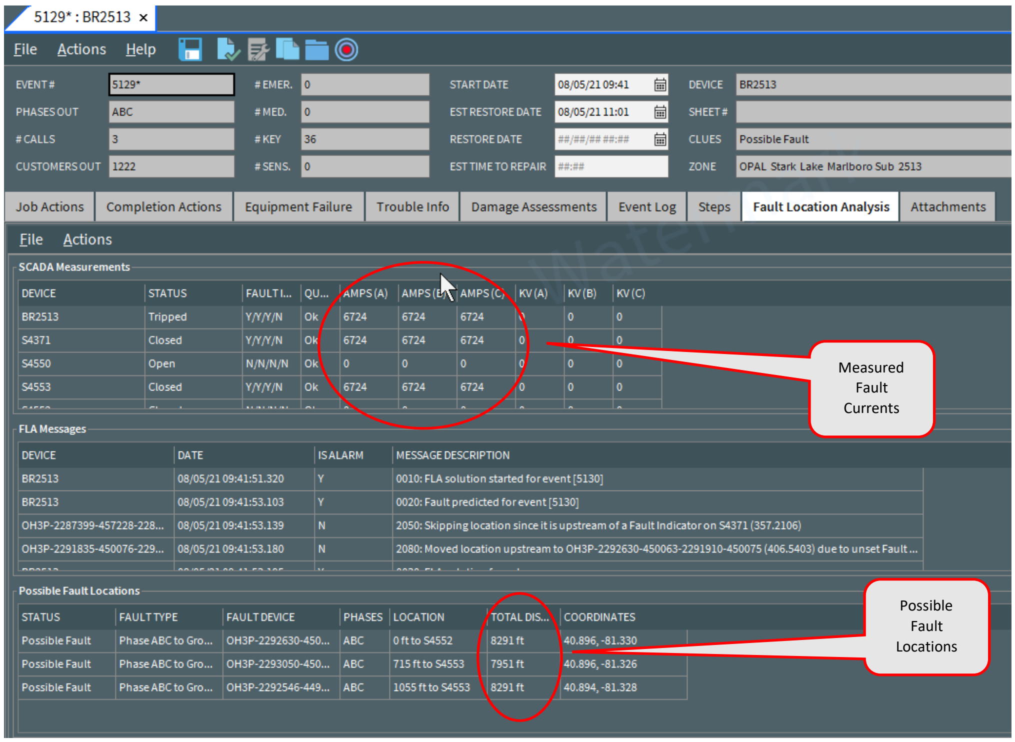
Fig. 3. Strategy for Locating Wireless Fault Indicators (WFI)

Wireless Fault Indicators - Data Source Analysis

The following describes the use of an ADMS Fault Location Analysis (FLA) function, first without any Wireless Fault Indicators (WFI) and then with the WFI data source added to the FLA function.

Fault Location Analysis without WFI

Fault Location Analysis (FLA) is a standard function in modern ADMS platforms. It uses short circuit analysis and three-phase telemetered fault currents measured at a circuit breaker to calculate the distance to a fault. The calculated distance to the fault is a function of the measured fault currents, and the impedance to the fault and the location of the fault as well as taking into consideration the loading on a circuit at the time of the fault. This approach has been researched extensively and implemented successfully [9] [10] [11]. Since distribution circuits typically branch out in many different directions, with various conductor sizes and configurations, the fault location algorithm potentially will identify more than one possible fault location. The predicted locations can also potentially be different distances from the breaker if the impedances differ on each path. An example where FLA identifies multiple fault locations on different branches at different distances is shown in **Fig. 4** and ***Error! Reference source not found.***



STATUS	FAULT TYPE	FAULT DEVICE	PHASES	LOCATION	TOTAL DIS...	COORDINATES
Possible Fault	Phase ABC to Gro...	OH3P-2292630-450...	ABC	0 ft to S4552	8291 ft	40.896, -81.330
Possible Fault	Phase ABC to Gro...	OH3P-2293050-450...	ABC	715 ft to S4553	7951 ft	40.896, -81.326
Possible Fault	Phase ABC to Gro...	OH3P-2292546-449...	ABC	1055 ft to S4553	8291 ft	40.894, -81.328

Fig. 4. Fault Location Analysis Calculation Results

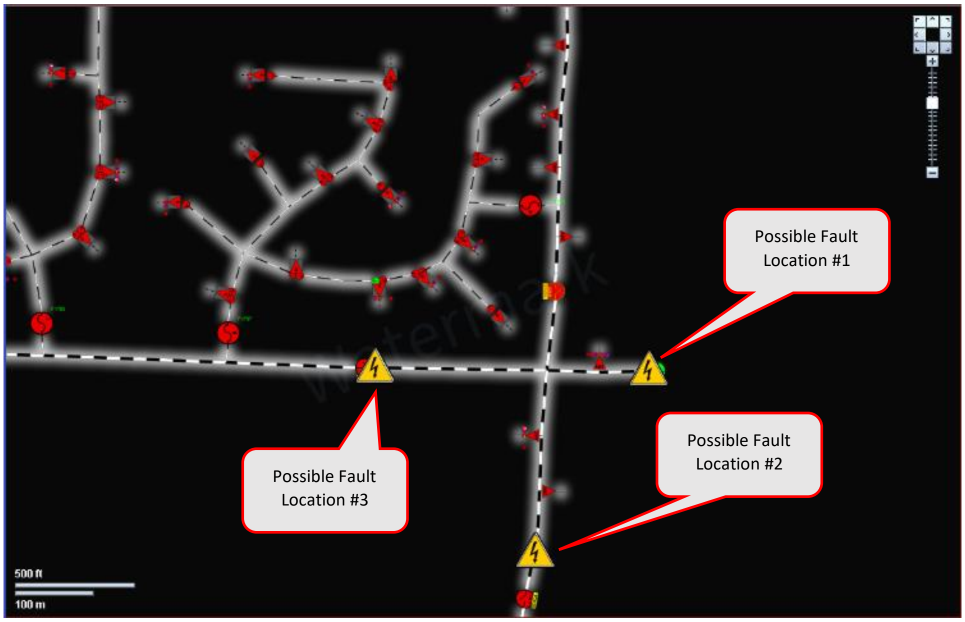


Fig. 5. Graphical Results of FLA showing three possible fault locations

In situations where the FLA algorithm identifies multiple fault locations, dispatching a crew to patrol the different branches is required to determine the correct location. Within the NMS, the operator can confirm, mark "incorrect" or "correct" the fault location based upon information provided by the crew in the field. An example of the dialog used to report this information is shown **Fig. 6**

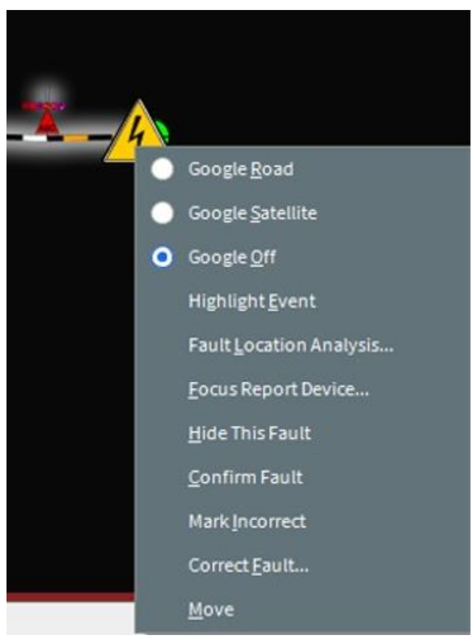


Fig. 6. Fault Location Options

After the fault the has been confirmed at the correct location, the symbology changes to indicate the confirmed fault location, as shown in *Error! Reference source not found.* The FLA function is also able to indicate that the other possible fault locations are incorrect as shown in **Fig. 8**.

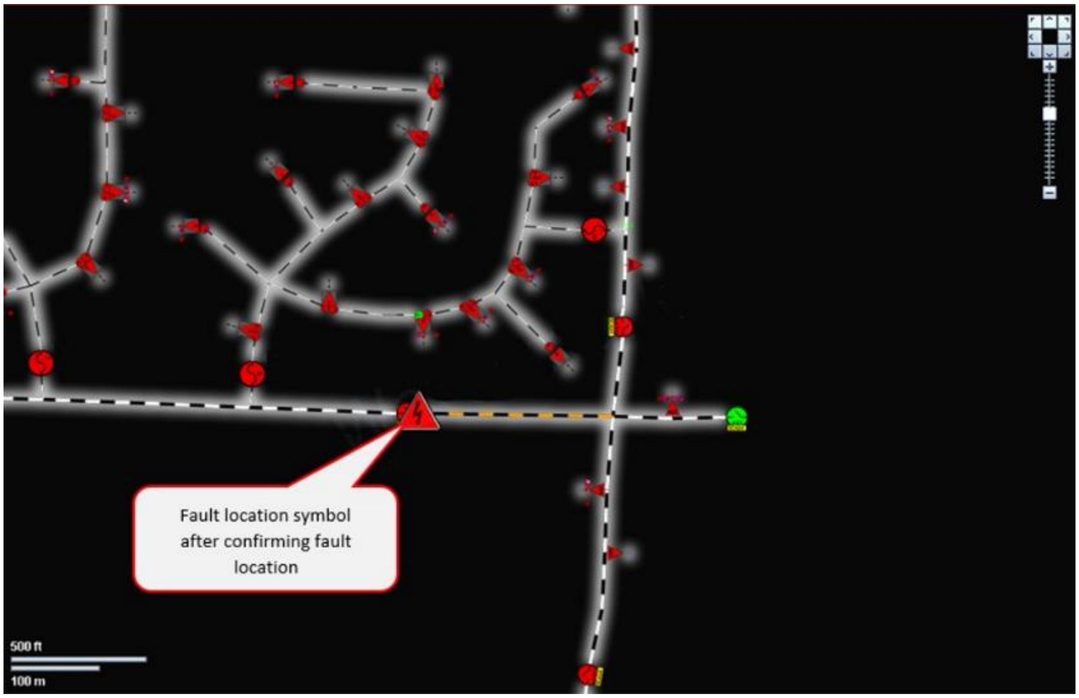


Fig. 7. FLA Results After Confirming Actual Fault Location

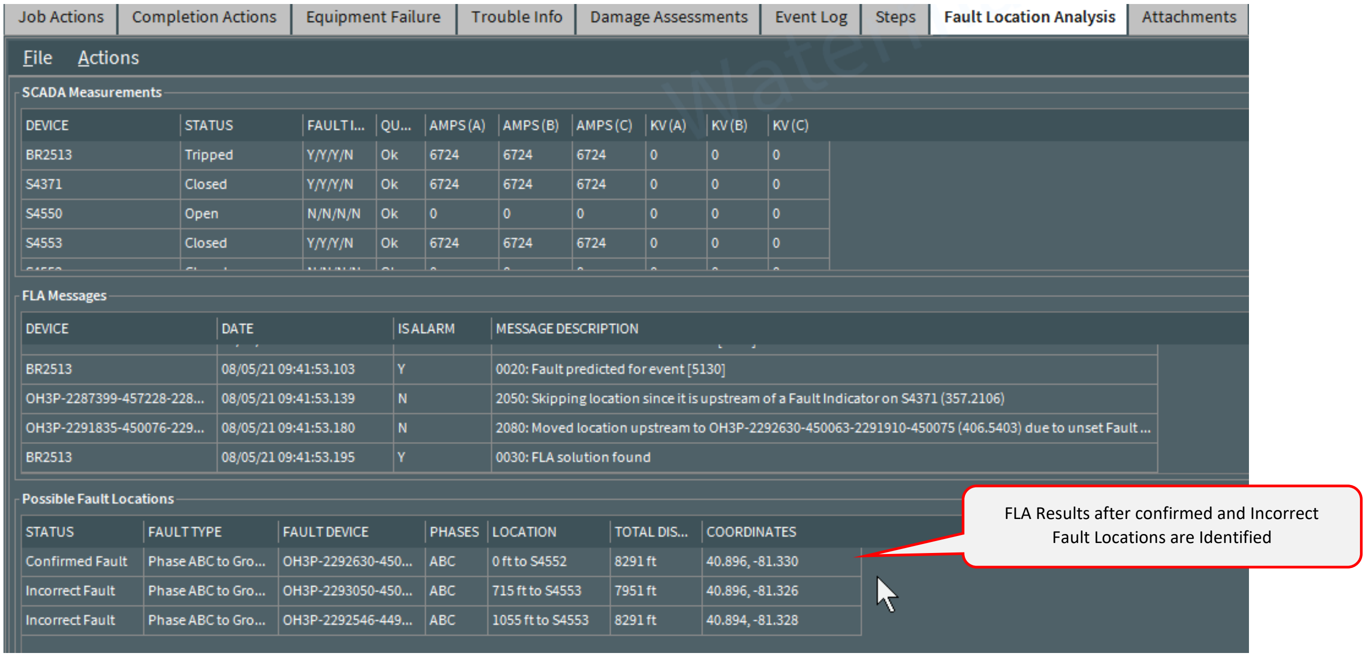


Fig. 8. Fault Location Analysis Tabular Results

FLA Using Wireless Fault Indicators (WFI)

When WFI devices are placed strategically and included in near real-time data in the FLA algorithm, the ADMS can identify the potential branches where the fault occurred and then eliminate the branches where the WFI data indicates that no fault occurred. An example of the results of FLA disregarding potential branches based upon fault indicator data is shown in *Error! Reference source not found.*

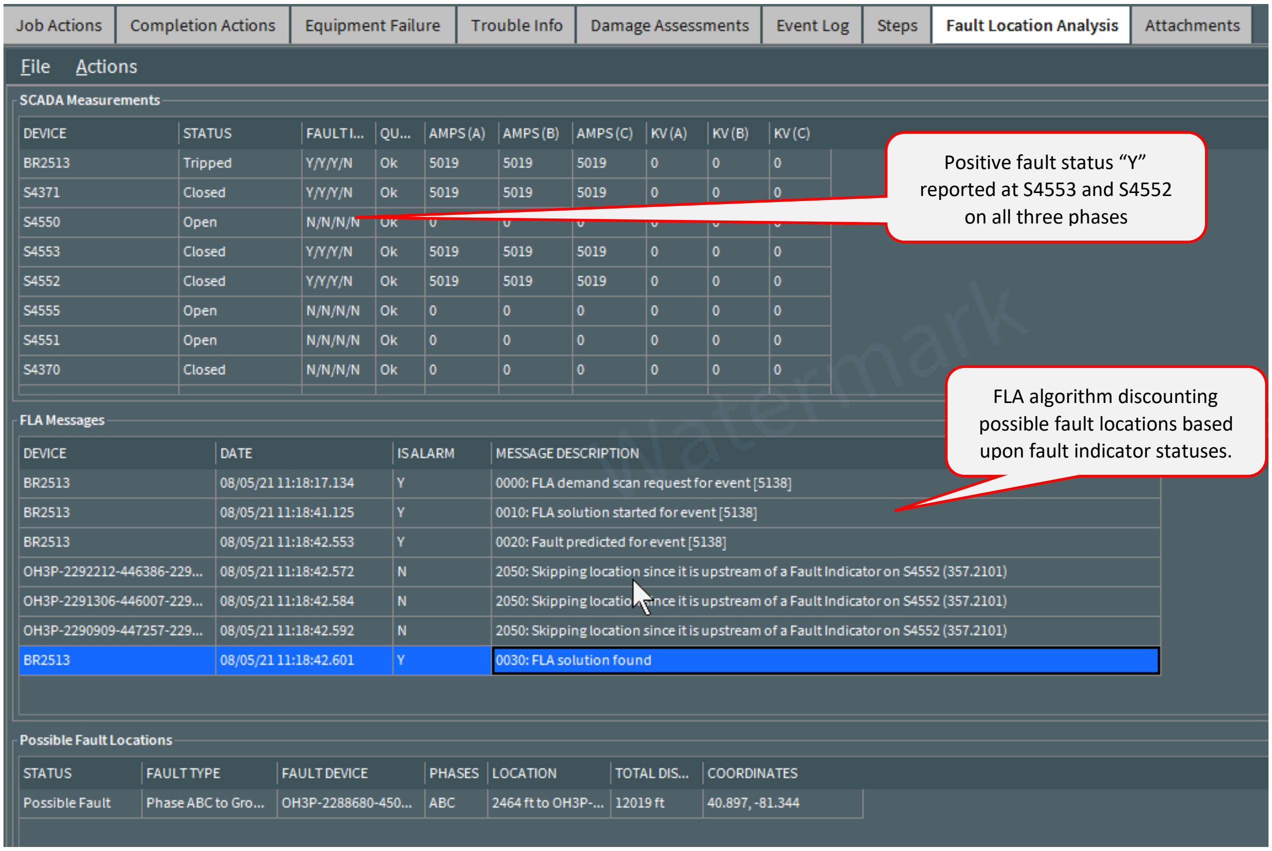


Fig. 9. FLA Tabular results of Fault Location showing additional WFI analysis

The single fault location is shown graphically in the map viewer in **Fig. 10.** Although the FLA has not confirmed the location and it still requires the crew to patrol the branch with the identified fault, it is still valuable because the need to patrol multiple branches is eliminated and the crew can focus on confirming the location of actual fault on a single branch. A reduction in patrol time and driving incident exposure will be realized.

Fig. 10. FLA graphical results with WFI analysis

Wireless Fault Indicators – Data Source Findings

The standard FLA functionality in NMS can be setup to do a traditional demand scan via SCADA to ensure all SCADA data is current before calculating fault locations. Since WFI communications are event driven and not performed with traditional SCADA, a demand scan is not possible. There are two possible alternatives that could be implemented: 1) the FLA algorithm could be modified to support waiting for WFI device response instead of or in addition to a demand scan, or alternatively, 2) the FLA could perform the fault location analysis and initially provide multiple fault locations and then using the WFI events correct and eliminate any possible faults that are not consistent with the WFI event data.

Even without the modified FLA algorithm, NMS can be configured to prominently show the locations of all WFI, providing the operator with visual indicators of WFIs that should be examined for fault reports before dispatching crews to patrol multiple branches. This would be considered a manual equivalent to the automatic mode described above. The software could be configured to be modal and support both the manual mode and the automated feature.

AMI Low Voltage Meter Alarms

AMI Low Voltage Meter Alarms - Introduction

Automated Meter Infrastructure (AMI) systems are used to automatically collect meter readings from the point of connection between the distribution system and the point of service for a customer. Initially developed for the purposes of automatically reading power demand and consumption for the purposes of billing, AMI systems are also able to provide additional data from the meters that can be used in electrical operations. The use of AMI data for multiple purposes is often called smart metering.

AMI meters can report the loss of power, sometimes called a "last gasp" message because it is the last message that can be sent due to the loss of power. They also can report the energization of the meter after power is restored. These two messages from an AMI system are often sent to the Outage Management System (OMS) functions of an ADMS.

Additional messages from AMI meters such as the detection of low voltage and high voltage events are also available from an AMI system. Low Voltage Alarms are potentially valuable during fault scenarios because the fault conditions can cause sustained or momentary low voltage situations during the time the fault is present.

AMI Low Voltage Meter Alarms - Data Source Analysis

Current as-is Use Cases for patrol work, other sources of information not currently being sent to the NMS system but available through other systems/means were investigated. Low voltage meter messages fall into this category. The investigation carried out was to identify any benefits to focused patrol teams, narrowing down potential fault areas allowing the team to isolate the fault area in the quickest possible time. This kind of data would be specific to "downed conductor/open jumper outages" and, more importantly, "energized downed conductor".

Table 3 shows the current meter Power Off message filters currently used in the NMS software. This will be used as a reference and may be useful to apply to any additional meter messages.

Table 3 Current LV Meter Power Off Message Filters

Category	Rule Name	Rule processing order	Power off/on or both	Description
Unplanned	Correct message	1	Both	Ensure it's a correction message: power off/on
	Old Alarms	2	Both	If the new 'Timestamp' field on the alarm is >15min old, discard the alarm. Power off and on.
	Dups – Same Meter	3	Both	Filters out duplicate alarms based on distinct (ESN + Power Off/On) if within 10min.
	Dups - Same Outage ID	4	Both	Filters out duplicate alarms based on distinct (Outage ID + ESN) as unique key on which to

Category	Rule Name	Rule processing order	Power off/on or both	Description
				filter. The Outage Filter would discard any duplicates received within 60min.
	Service Orders	5	Both	Look for existing service order for that ESN, +/- 2 days (uses date only, not time), then discard power on/off.
	Power Off - Active Outage Filter	6	Power Off	Compares the Power Off message to the OUA Active Outages view. If the Power Off message timestamp is either (1) at or before the outage start time or (2) is >=10min after the outage start time, the message will be discarded
Planned	Power Off - Planned Outage Filter	7	Power Off	Filters Power Off alarms that have a related planned outage record in Planned Outages view.
	Power On - Restored Outage Filter	8A	Power On	Filters Power On alarms that have a related restored outage record in OUA Restored Outage view.
	Power Off - Restored Outage Filter	8B	Power Off	Filters Power Off alarms that have a related existing restored outage record in OUA Restored Outage view.
	Power Off - TLM process	9	Power Off	Gets Transformer Load Management data for power off - to get the transformer. If no matching transformer found, discard power off
	Single power off	12	Power Off	Wait for a 2nd power off on a transformer before sending it to NMS.
	Single Meter on Transformer	13	Power Off	Outage Filter will check if that meter is the only meter on the transformer/primary meter. If it is, it will send through.
	Duplicate Filter - Single Meter	14	Power Off	Will not allow duplicate meter through within 2 mins

Relevant Use Cases

The following use cases were identified for investigation into the value of AMI Low Voltage messages:

- Use Case 1: Wire Down
- Use Case 3: Foreign Object in line
- Use Case 4: Tree/Vegetation Contact

- Use Case 6: Underground distribution – need to investigate (might depend on transformer type delta vs wye primary)

Current State

LV meter messages are currently sent from smart meters within the network. The system has practically a full rollout of smart meters throughout the network. At present, loss-of-power messages are sent from the Meter Management system to the NMS system and are used to help determine the scope of a fault/de-energized section of the network. Low Volt messages are sent from the meters but are currently not sent on to the NMS system. This concept was recently proposed and validated on several distribution systems [3]. This investigation was to determine if receipt of such messages in the NMS system will benefit the patrol crew dispatch.

Network Area

An area of the network was identified from a list of potential substations and circuits provided by the customer. This area has been selected as it has good power flow information and is an overhead section of the network abundant with distribution transformers with associated customers, several protection devices, and several lateral lines being fed from the main feeder with different phase configurations. The environment is primarily rural, typical of the eastern sector of the county. The area selected is:

- Substation R, Feeder: 6, Feeder Head Breaker: 12kv-111
- Downstream Normally Open Points:
    - NOP point: 6-T2-9 (Gang-operated OH LB switch)
    - NOP Point: 6-T3-10 (SCADA Fault Interrupter)

Simulations

Several scenarios in line with the Use Cases were identified and demonstrated to determine the value of AMI low voltage messages.

Fig. 11 shows a simulation where the star symbol represents a potential wire down location. At the time of the fault, the DSO would be unaware of the fault location.

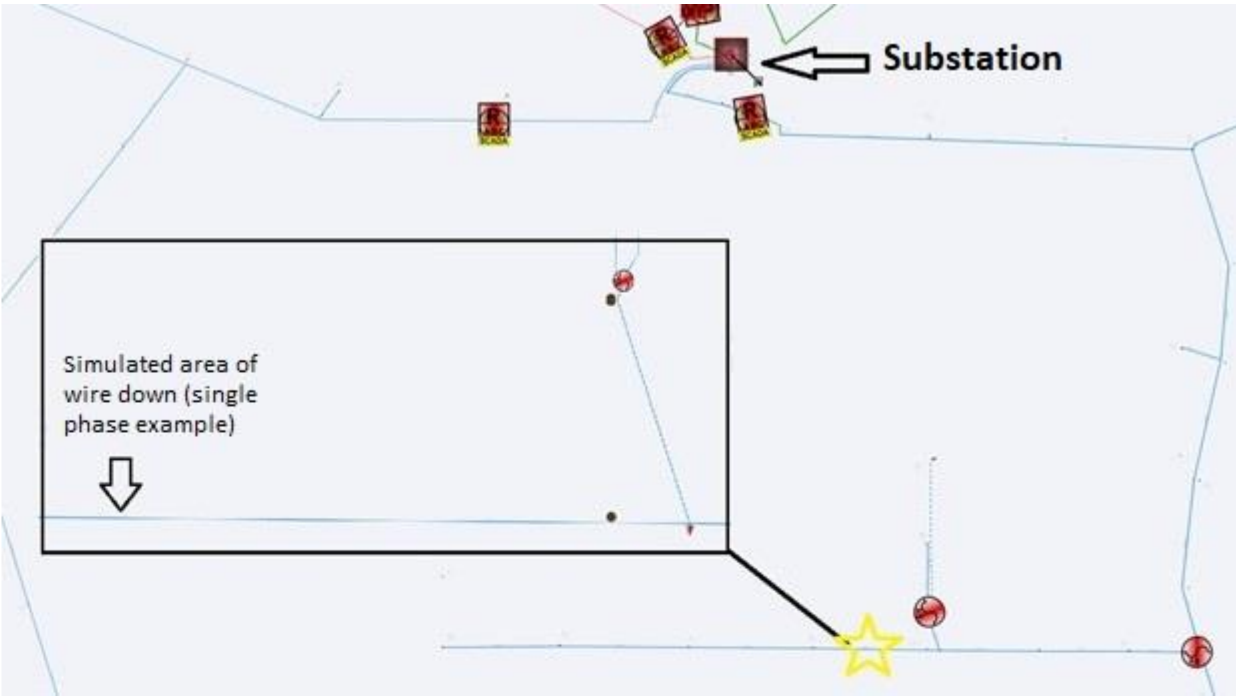


Fig. 11. Wire Down Simulation in NMS

Use Case #1, Scenario 1: Trip and Successful Reclose

In this scenario, it is assumed the recloser upstream of the fault trips and after one or more attempts successfully recloses. The assumption is that the protection device at the start of the lateral has operated on one of the phases clearing the fault and allowing the recloser to successfully reclose. Alternately, a foreign object such as a tree branch could have cleared itself from the line. The lateral line is 2-phase (Phases A and B). For these purposes, we will assume Phase A fuse has operated.

As documented in ***Use Case #1 of*** *Error! Reference source not found.*, several tasks will be carried out by NMS regarding the managing of the successful reclose (capture of a momentary outage). As only one phase fuse has blown, there will be no *complete* "Loss of Power" messages received from any downstream meters. Until a customer calls in, the operating staff will not be aware of the outage.

Table 4 shows how to perform the steps to simulate this Use Case scenario.

Table 4 Test Steps for Use Case Use Case #1, Scenario 1: Trip and Successful Reclose

Basic flow			
Step	Actor	Action	Expected result
1	NMS simulator	Action	Simulated Trip open on Recloser 1
		Expected Result	NMS shows nothing. Recloser timer is started
At this stage Phase A fuse operates. This device is not SCADA capable so the operator will be unaware			
2	NMS simulator	Action	SCADA recloser 1 automatically recloses

Basic flow			
		Expected result	The recloser closes and remains closed. The timer in NMS expires. A momentary outage is opened to manage the momentary outage caused by the recloser open in the previous step.
3	NMS Simulator	Action	After an amount of time calls are received from customers on lateral #2 Customer Account #: Call 1 – Customer 1 Call 2 – Customer 2 Call 3 – Customer 3 ****See note***
		Expected result	The first call would result in a PSO event being raised. This would be associated with transformer Tx 1 – the Tx the customer is associated within the system. Second call is associated with transformer Tx 2. This would extend the scope of the PSO to a PDO. Both calls would be associated to this PDO. The predicted scope would be up to Fuse 1. The 3rd call is within the scope of the PDO and would be automatically associated with it.
4	Tester	Action	Clear all events and calls
		Expected results	All events and calls are cleared.
Alternative flow This flow assumes we are receiving “Low Voltage” messages from meters within the scope of this network area			
2a	NMS Simulator	Action	Within minutes of the recloser closing and the timer expiring, meter “low voltage” messages are received from meters Meter 1, Meter 2, Meter 3.
		Expected results	As with calls, the first meter message would create a PSO associated with Tx 1. The second message would extend the scope of the PSO to a PDO. Both meter messages would be associated to this PDO. The predicted scope would be up to Fuse 1. The 3rd meter message is within the scope of the PDO and would be automatically associated with it.

***Note**: There are only 4 customers fed from this lateral line. This reduces the likelihood of calls arriving close to the time of the initial recloser action.

Findings – Use Case #1, Scenario 1

In this scenario, a single fuse has operated (blown), but the power is not actually out due to the other phase being live. This is due to the 2-phase supply and the wiring at the sites on the line and use of Delta transformer configurations. No "Loss of Power" messages would be received from meters as they would not completely lose power. The earliest time the operators are alerted to the fuse blown event is when customers or bystanders call in to report an issue with their supply or a dangerous situation. Due to the low number of customers on this lateral, the time to realize the issue and report it is a factor in the time to realize there is a fault situation, possibly with an energized conductor down. There's no doubt that a service interruption has occurred, but the exact nature of the interruption/system failure is not understood until later, perhaps much later in areas of sparse customer density.

The alternative test shows if "Low Voltage" messages were received from the meters along this line, the operators would be alerted to the situation potentially within minutes of the fault. There would be an improvement in the fault realization time and therefore a quicker response to the fault than just relying on on/off AMI or caller information. There are other situations where this is valuable such as when no power-off messages are received because no meter sees an absolute zero voltage. This would reduce the outage duration and potentially reduce the duration of any dangerous situation. The configuration of SDG&E's AMI system is that the meters will continue to communicate even during periods when the voltage is as low as 50% of nominal.

Use Case #1, Scenario 2 - Trip and Lockout

Using the same area of network as before, this scenario sees the SCADA Recloser 1 trip and after one or more attempts to reclose remains in an Open state. In this scenario, all areas of network downstream to the open points would be de-energized. Meter "Loss of Power" messages would be received and sent to the NMS system using the meter notification rules. With this information and SCADA information related to the recloser, the operator would know the recloser has tripped and the circuit is de-energized. There would be no Low Voltage messages from meters as they are all in a de-energized state, and no longer communicating. The as-is process would then be used to find the outage would be required.

Operators would be looking out for any additional information in the scope with regards to dangerous situations. This may give good indications/clues to the location of the fault area.

Findings Use Case #1, Scenario 2

In this scenario, no "Low Voltage" situation on meters would be detected, therefore the addition of these types of messages would not reduce the time or change the process of discovering the fault area.

Dangerous-situation or damage calls are currently received but may not automatically be associated with an event. It is currently up to the operators to recognize this event, potentially using the "hazard" column in the work agenda. Currently, SDG&E has audible alarms disabled on the NMS system. A potential improvement would be to enable audible alerts for damage calls, etc. to improve operator awareness

Use Case #1, Scenario 3 Non-SCADA device operates

Refer to use case #1. Same results but without the SCADA momentary operation

Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Typical examples of this type of fault would be high impedance faults. These faults occur when a conductor touches the ground surface or a tree. The fault current generated is minimal and may not cause protection equipment to operate.

- Location for Test: Substation W, Feeder 1, Break between Pole 1 and Pole 2 Phase A (line to Ground)

There would be no FLA help in this scenario due to no SCADA trip and no WFIs are present. Meters downstream of the break may detect low voltage (fed from Phases A and B). A Predicted Device Outage (PDO) is automatically created based on Meter LV calls. As shown in **Fig. 12**, the scope of the outage prediction is extensive with the magenta highlighted section downstream of the PDO.

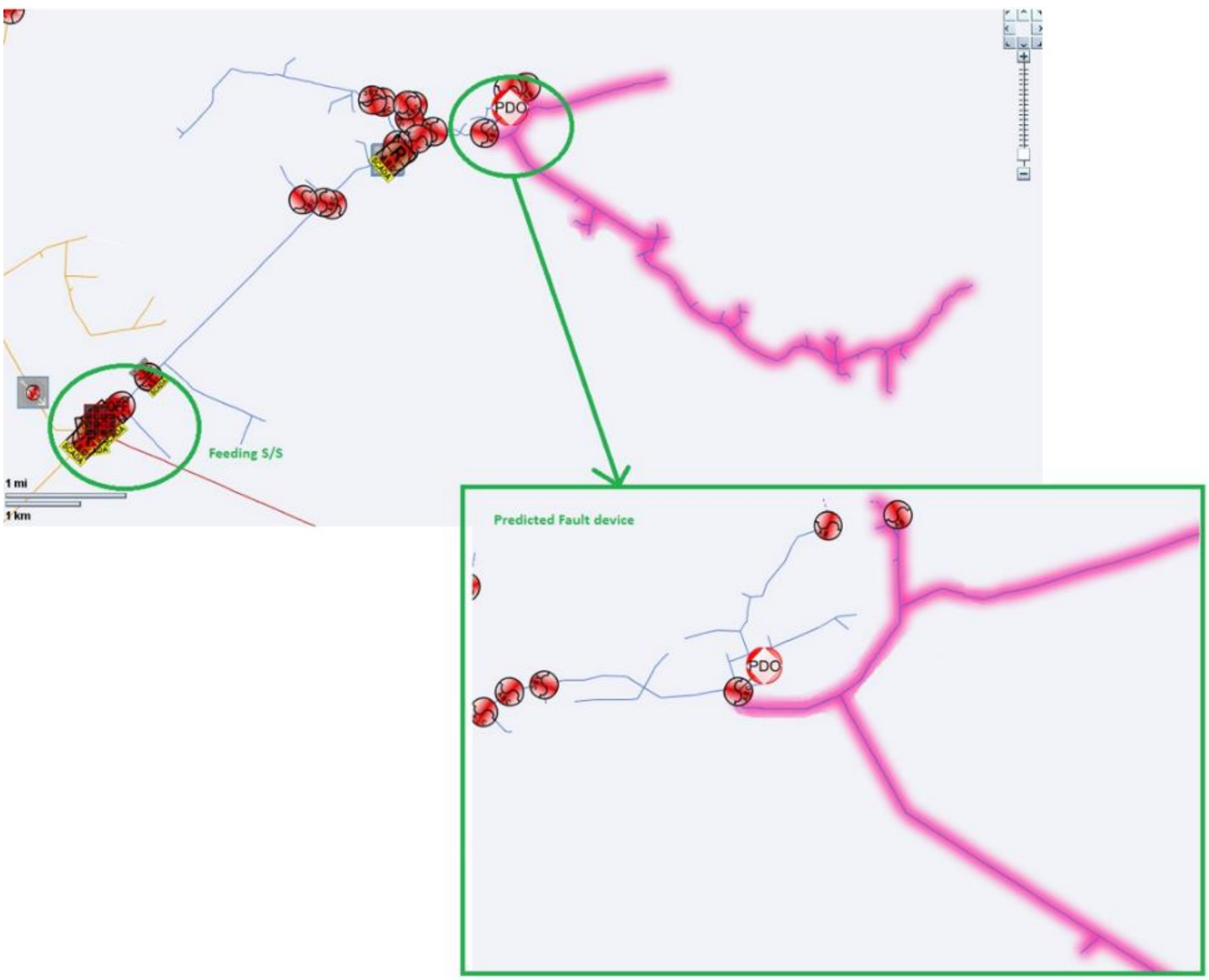


Fig. 12. Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Using the Hide/Display tool, the operators can turn on the AMI LV message indications. This will show the LV messages and their location and narrow down the search. Operators would see the first meter LV messages downstream of the wire down location as shown in **Fig. 13**.

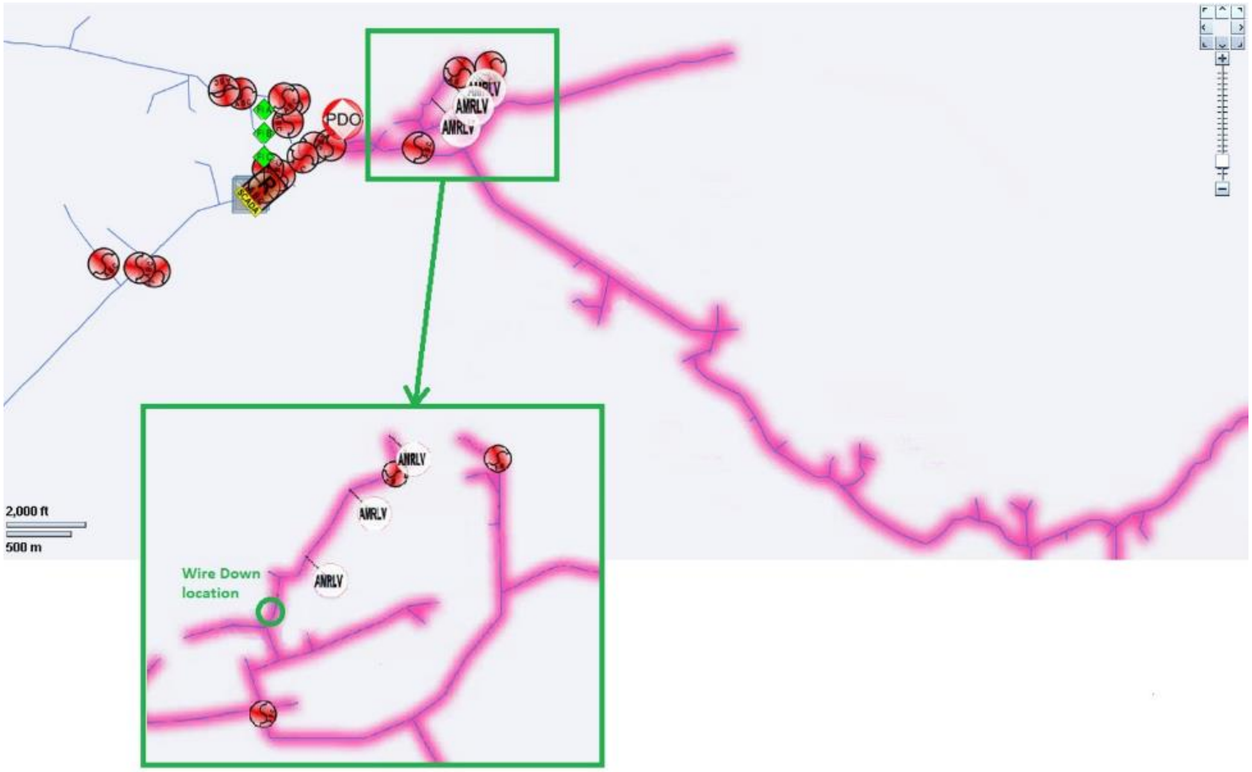


Fig. 13. AMI LV messages for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Patrol crews can then be sent to this location and work upstream to find the fault.

Note – PDO created with meters – otherwise they would have to wait for customer calls to even realize there is a fault. Only 4 customers reside on this lateral. So, a lengthy time lapse may occur before the fault may be realized depending on time of day, residency status of customers, etc.

Fig. 14 and **Fig. 15** shows a similar simulation but where the fault is on Phase B, between two poles. As before the Meter messages are received and a Predicted Device Outage (PDO) is automatically created with a downstream highlighted area in magenta.

Fig. 14. Phase B Fault for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

Again, the scope is significant with lateral lines going in different directions causing potential difficulties in finding the fault location.

Switching on the AMI LV messages significantly reduces the search area as shown in **Fig. 15**

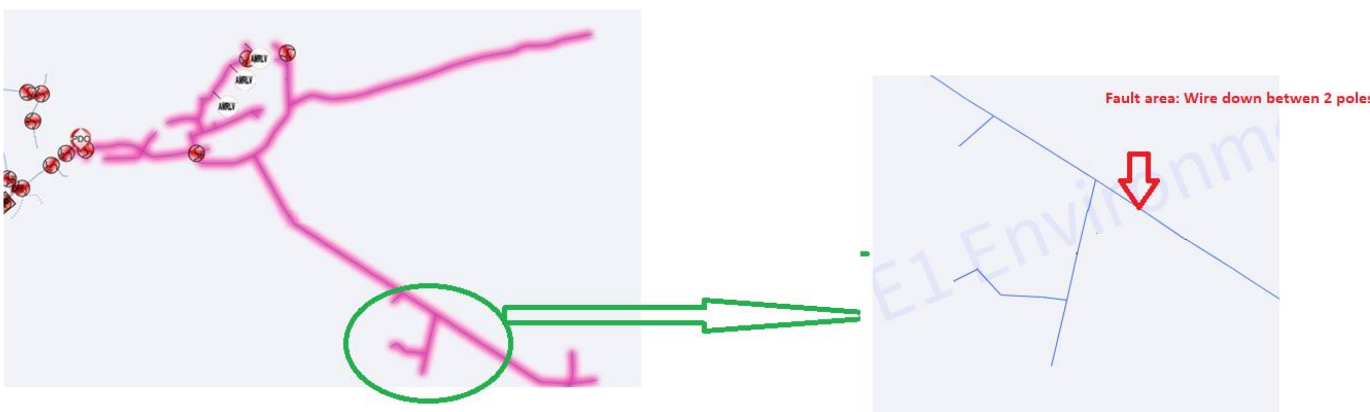


Fig. 15. AMI LV messages for Use Case #1, Scenario 4: Breaker does not trip, fuse does not open

In this scenario, we have simulated some meter messages but not messages from every meter within the fault scope. This is to simulate the fact that not all meter messages will arrive, due to communication issues.

In this case, the first meter downstream of the fault fails to communicate. The presence of the other meter LV reports would enable the Operator to go to the first AMI LV message and work upstream, either pinging/requesting voltage from meters upstream initially and dispatching patrols.

In the current situation, the system operator would have to wait for customer calls. Many more customers may call in, but it is likely that meter messages would arrive first.

Findings – Use Case #1, Scenario 4

Low Voltage messages downstream of the fault would be received and will significantly aid in identifying the fault area. It would save time in identifying if there actually is a fault. Even when some meters fail to communicate, there are likely to be enough messages to determine the best location to start the search.

Note: Use Case #3, Foreign Object in Line and Use Case #4 Tree/Vegetation Contact have similar findings to Use Case #1.

Use Case #6, Underground Distribution

The underground network uses a combination of delta and wye transformers. In the case of the delta transformer configuration, the Low Voltage message may give an indication of an outage in a similar way to the Overhead network as described in Use Case #1 in **Error! Reference source not found.**. The following areas have been identified as potential test areas:

- Underground distribution section (dashed conductors) shown downstream of the fuse.

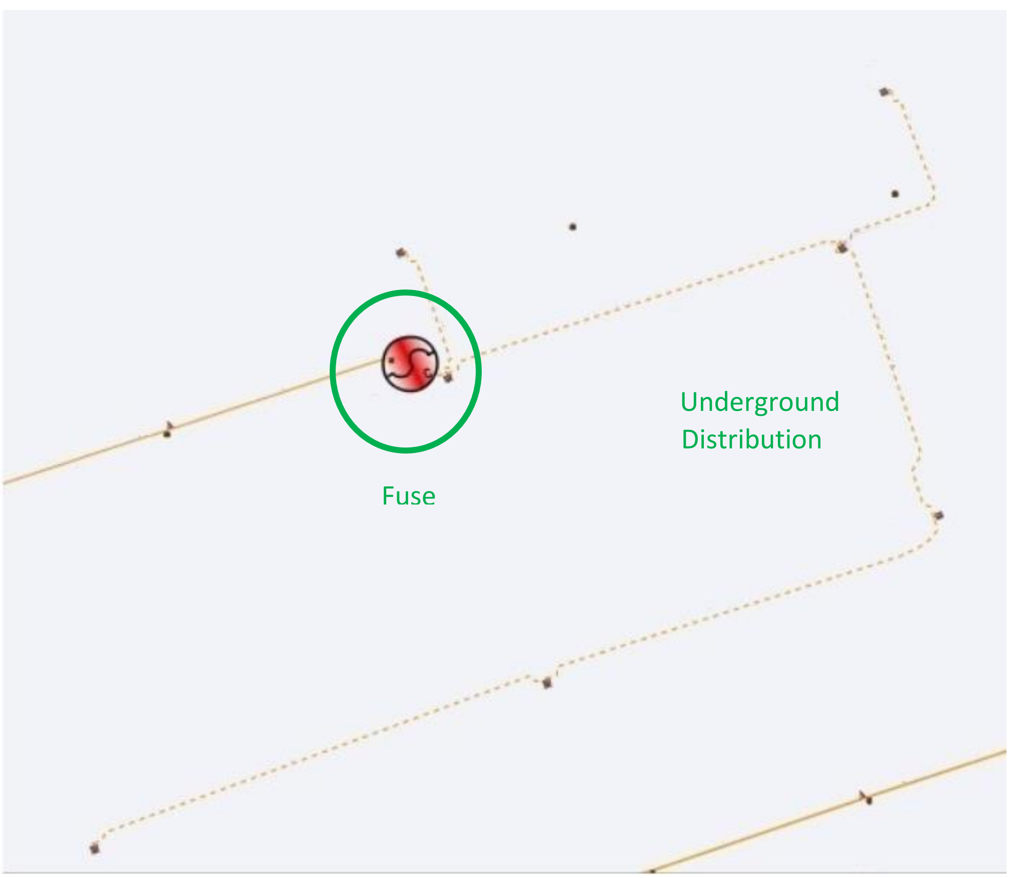


Fig. 16. Use case #6, Underground Distribution

Expected results would be that Low Voltage messages would not help in the case of a wire down as this area is single phase. One would expect Loss of Power messages would be received.

Fig. 17 shows the area around a Transformer fed from a Substation.

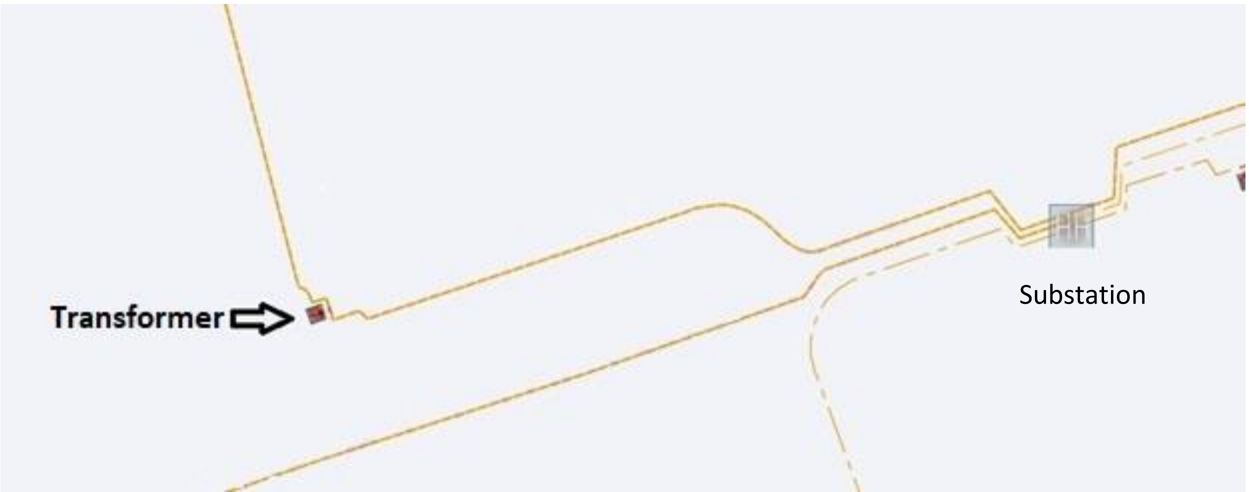


Fig. 17. Location of Transformer in Use Case #6, Underground Distribution

Findings – Use Case #6

Enabling and testing scenarios on the underground network is required to further identify if the use of Low Voltage messages will aid in the identification of a fault that may be reliant on the receipt of customer calls.

AMI Low Voltage Meter Alarms - Data Source Findings

Low Voltage (LV) messages from meters can enhance the operator's current ability to diagnose potential fault areas by providing this additional information.

In conditions where a non-SCADA device has operated on a single phase where there are multiple phases on the line, operators may only be made aware of the outage via customer calls. The timing of these calls will vary depending on time of day and number of customers affected and location. For example, on a rural network in the middle of the night, customers may not call for some time.

Where the configuration of the transformers is Delta, low voltage would be detected from meters. If these messages were passed to the NMS, this would result in automatic outage events being raised in the area of the fault. This would alert operators within minutes (depending on configuration rules) to the fault. This has the potential for saving time and minimizing dangerous situations where an energized line is down, etc.

Dangerous situation or damage calls are currently received but may automatically be associated with an event. It is presently up to the operators to spot that this has occurred potentially using the "hazard" column in the work agenda. Currently SDG&E has audible notifications disabled on the NMS system. A potential improvement would be to enable audible alerts for damage calls, etc. to enhance operator awareness.

Fig. ***18*** shows how the LV Meter messages can help with location finding when used in conjunction with FLA.

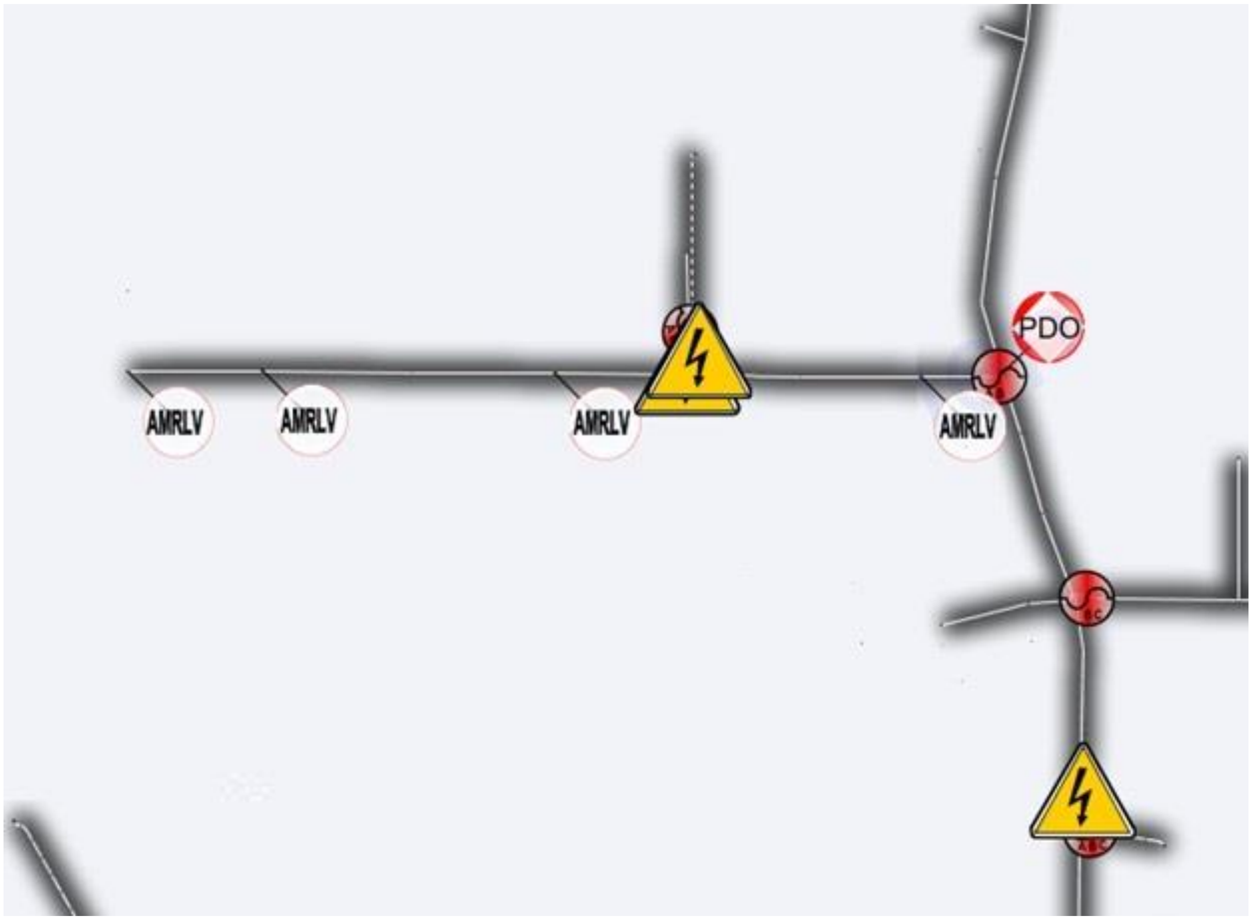


Fig. 18. FLA with LV Meter messages, yellow triangles show the potential fault locations

The yellow triangle symbols are the FLA potential locations. As you can see, there are 3 possibilities. When used in conjunction with AMI LV messages shown in the figure with white circles, you can see the likely location will be the lateral, not the main line in this case.

Configuration of Low Voltage messages and rules associated with them should be defined and configured to allow further testing. From the analysis, the following regulations/requirements have been identified. The "In scope" requirements should be included where possible within the scope of the Focused Patrol project. "Future" requirements identify features that have the potential to be included in the NMS product, although where possible, will be demonstrated via a temporary configuration.

Table 5 Proposed Configuration of Low Voltage Messages

Rule ref	Details	When?	Comments
1	Enable Low Voltage messages to be passed from the AMI system to NMS	In scope	
2	New meter message type to be created for Low Voltage messages	In scope	
3	Define rules for the passing of LV messages from AMI. (Use Power Off filters as a guide)	In scope/future	Some rules can be identified and simulated within the project
3a	Low Voltage messages only when no "Loss of Power" exists on any phase of same feeder/lateral	In scope	If this can be done via configuration for demo purposed
3b	Low Voltage only when Delta configuration is used	In scope	If this can be done via configuration for demo purposed. This is only when more than one phase exists on the line
4	No low voltage messages on wye transformer configuration	Future	But can avoid this configuration during demo
5	Method to group meters and request Voltage measurements from each in the group	Future	Mentioned by SDG&E. Would benefit investigations
6	Method to group meters and send a batch ping to each meter in a cluster (clusters to be defined or made configurable)	Future	May be simulated by a configuration change, possibly
7	Ability to display Low Voltage message indications on supplying transformer on the NMS diagram	Future	Explore configuration with current software
8	Ability to toggle display of Low Voltage Messages on and off from the NMS diagram display	Future	Explore configuration with current software

Weather Sensors

Weather Sensors – Introduction

There are weather sensors that are electronically monitored available from external sources/systems that can be interfaced with NMS to provide additional information to users of the NMS.

SDG&E has approximately 220 weather stations located close to the overhead network. These stations monitor several weather datapoints as shown below:

Fig. 19. Typical Weather Station Details

This data could potentially be accessed by NMS since the weather stations send data at least every 10 minutes. Some data can also be set to temporarily poll much more frequently when needed. Data available includes:

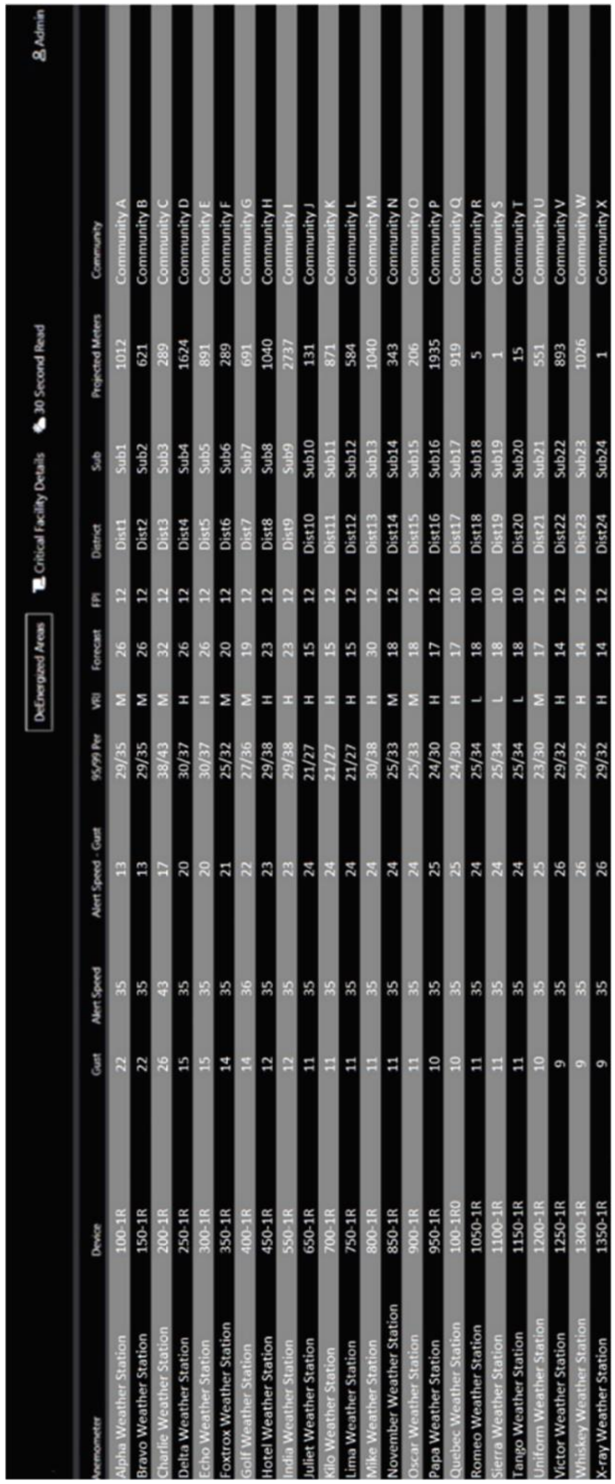
- Station name
- Temperature
- Humidity
- Wind Speed
- Wind Gust
- Wind Compass (N,S,E,W,SE,SW etc.)
- Wind Direction (degrees true)

- Decommissioned
- Latitude
- Longitude
- Retrieval time

Weather Sensors - Data Source Analysis

Weather data is currently used to support processes that improve fault response times and reduce fire risks. The current practice is that when high winds are forecast, patrols are dispatched to areas of high winds to try to position them in the best possible places to locate faults as soon as possible. Lines are also patrolled days in advance of a forecasted event to look for areas of potential trouble. This practice is seasonal, just before and during the times of the year when high winds are expected. If high winds are detected unexpectedly, exceptions will be made, and patrols will be dispatched to these areas. This weather-based dispatching of crews is done proactively and will be done even if no fault has been identified. This is a mitigation strategy that enables crews to get to a fault location as fast as possible. Or, in some cases, avoid a fault from occurring entirely. Faults under these conditions are commonly the result of debris on the lines, vegetation contact, or conductor failure and have a risk of potentially causing fires, as a function of weather and other factors.

Design standards exist for the distribution system that are based upon expected extreme weather conditions and “known local conditions”. However, weather conditions do occur that exceed the design standards (i.e., winds in excess of 100 mph). Weather stations are used to identify areas with a regular history of occurrences of conditions with excessively high winds to use as proactive measures to do additional hardening above the design standards. The accepted design and regulatory guidelines state if weather information is available, then local guidelines can be established that are unique to the conditions in that region. The term used in the regulatory regime is “known local conditions.”



DeEnergized Areas | Critical Facility Details | 30 Second Read | Admin

Anemometer	Device	Gust	Alert Speed	Alert Speed - Gust	95/99 Per	VRI	Forecast	FPI	District	Sub	Projected Meters	Community
Alpha Weather Station	100-1R	22	35	13	29/35	M	26	12	Dist1	Sub1	1012	Community A
Bravo Weather Station	150-1R	22	35	13	29/35	M	26	12	Dist2	Sub2	621	Community B
Charlie Weather Station	200-1R	26	43	17	38/43	M	32	12	Dist3	Sub3	289	Community C
Delta Weather Station	250-1R	15	35	20	30/37	H	26	12	Dist4	Sub4	1624	Community D
Echo Weather Station	300-1R	15	35	20	30/37	H	26	12	Dist5	Sub5	891	Community E
Foxtrox Weather Station	350-1R	14	35	21	25/32	M	20	12	Dist6	Sub6	289	Community F
Golf Weather Station	400-1R	14	36	22	27/36	M	19	12	Dist7	Sub7	691	Community G
Hotel Weather Station	450-1R	12	35	23	29/38	H	23	12	Dist8	Sub8	1040	Community H
India Weather Station	550-1R	12	35	23	29/38	H	23	12	Dist9	Sub9	2737	Community I
Juliet Weather Station	650-1R	11	35	24	21/27	H	15	12	Dist10	Sub10	131	Community J
Kilo Weather Station	700-1R	11	35	24	21/27	H	15	12	Dist11	Sub11	871	Community K
Lima Weather Station	750-1R	11	35	24	21/27	H	15	12	Dist12	Sub12	584	Community L
Mike Weather Station	800-1R	11	35	24	30/38	H	30	12	Dist13	Sub13	1040	Community M
November Weather Station	850-1R	11	35	24	25/33	M	18	12	Dist14	Sub14	343	Community N
Oscar Weather Station	900-1R	11	35	24	25/33	M	18	12	Dist15	Sub15	206	Community O
Papa Weather Station	950-1R	10	35	25	24/30	H	17	12	Dist16	Sub16	1935	Community P
Quebec Weather Station	100-1R0	10	35	25	24/30	H	17	10	Dist17	Sub17	919	Community Q
Romeo Weather Station	1050-1R	11	35	24	25/34	L	18	10	Dist18	Sub18	5	Community R
Sierra Weather Station	1100-1R	11	35	24	25/34	L	18	10	Dist19	Sub19	1	Community S
Tango Weather Station	1150-1R	11	35	24	25/34	L	18	10	Dist20	Sub20	15	Community T
Uniform Weather Station	1200-1R	10	35	25	23/30	M	17	12	Dist21	Sub21	551	Community U
Victor Weather Station	1250-1R	9	35	26	29/32	H	14	12	Dist22	Sub22	893	Community V
Whiskey Weather Station	1300-1R	9	35	26	29/32	H	14	12	Dist23	Sub23	1026	Community W
X-ray Weather Station	1350-1R	9	35	26	29/32	H	14	12	Dist24	Sub24	1	Community X

Fig. 20. Tool used to show weather impact and forecasting (rotated to improve readability)

Existing tools used for weather-related fault risk mitigation include a dashboard that provides quick summary information of weather and associated risk factors including VRI (Vegetation Risk Impact) and FPI (Fire potential index). These are calculated based on the geographic information of the locations and the current weather information. Line items are automatically sorted in terms of highest to lowest maximum wind gust.

Asset condition status is also considered in weather-related fault risk analysis. Any equipment that is not at 100% condition (i.e., poles that may be pending replacement, or are under temporary construction configuration) are marked as a candidate for patrol locations in high winds and operators are informed of these sites.

Weather and equipment not in top condition may ultimately result in operations making the decision to de-energize a section of network that may not be currently experiencing faults, but as preventative measures due to fire risk/safety. This practice is used as the last resort when no other mitigation practice is deemed sufficient. In California, this is known as Public Safety Power Shutoff, or PSPS.

Weather Sensors – Data Source Findings

There is an opportunity to integrate weather data and make it readily available to operators using NMS. This would streamline and improve the accessibility of this data enabling weather related fault mitigation decisions to be made faster and based upon more complete information.

In the NMS the following items are recommended:

- Create a new symbol to show the location of each weather station
- Have condition symbols that show locations where wind speed is greater than a pre-configured threshold, temperature and humidity exceed pre-configured high/low thresholds and gusts higher than a pre-configured threshold at the weather station locations.
- Bring dashboard data into NMS and potentially use the data to influence fault location prediction.
- Show FP and VRI heat map directly within NMS viewer.

Advanced Protective Relays

Advanced Protective Relays – Introduction

Protective relays are devices that trip a circuit breaker when a fault is detected. Early protective relays were electromechanical devices. To protect the distribution equipment on a circuit, protective relays often need to respond and trip a breaker within a few thousandths of a second. Advanced Protective Relays (ARP) are microprocessor-based devices that mimic the behavior of the original electromechanical protection devices. The microprocessor based protective relays are more flexible and have many advantages over the older electromechanical devices. In addition to the savings associated with lower maintenance costs and flexibility, the microprocessor-based relays are often coupled with communications equipment, enabling them to provide data back to a centralized location.

Advanced Protective Relays - Data Source Analysis

SDG&E utilizes advanced protective relays extensively in the protection and control of their distribution and transmission grids. Advanced protective relay manufacturers provide software tools that allow users to analyze system conditions and determine the root cause of relay operations. Event reports from an advanced protective relay contain the date, time, current, and voltage information and the status of multiple relay word bits. An event report can be triggered manually or by predefined programmable logic. Once an event is triggered, the essential data to understand and troubleshoot the system operation are archived for retrieval and analysis. These event archives can be viewed using the proprietary APR software. The following are two file types that APR event viewer software imports for event analysis [4]:

1. Compressed Event Report (CEV)
2. Common Format for Transient Data Exchange for power system (COMTRADE)

The compressed event report (CEV) is unique to APR devices. However, COMTRADE files comply with IEEE C37.111 [5]. This standard allows system events to be digitally stored in a common format. Compressed event reports are essential when analyzing system events, but COMTRADE files can provide additional benefits. Following the current process in the SDG&E operation, per each event these CEV files will be created by APRs and distributed to the different teams: such as operators, protection and control engineers, etc., as shown in **Fig.21**.

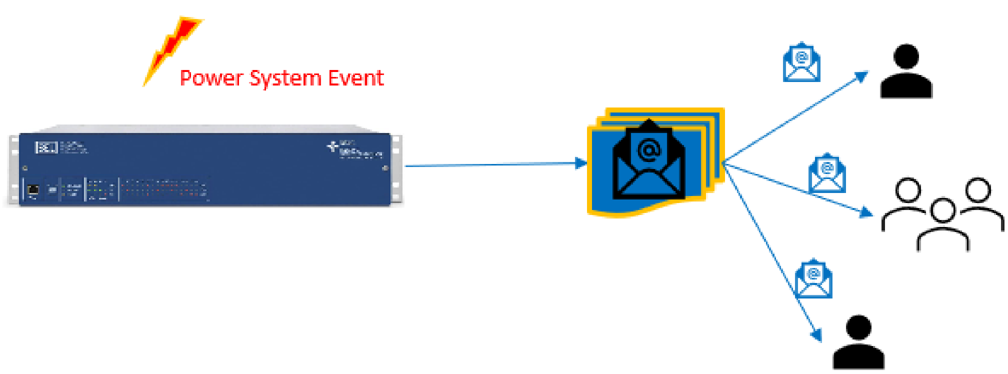


Fig. 21. Submission of CEV file distribution, per each power grid event.

The goal of the investigation was to determine how the information of these CEV files can be helpful for the online operation of the power distribution network by the NMS.

Advanced Protective Relay (APR) File Configuration

To read and visualize the APR files, proprietary software is required to view the following components and capabilities (in basic and advanced):

- Analog and digital charts,
- Harmonic and spectral analysis,
- Phasor value derivation and display,
- Automatic calculation of symmetrical components,
- Reconfigurable display,
- ACB or ABC phase rotation support,
- Searchable signal lists and relay settings,
- View COMTRADE ASCII format event reports.

Sample Advanced Protective Relay File

One sample APR file had been selected to read and investigate in detail.

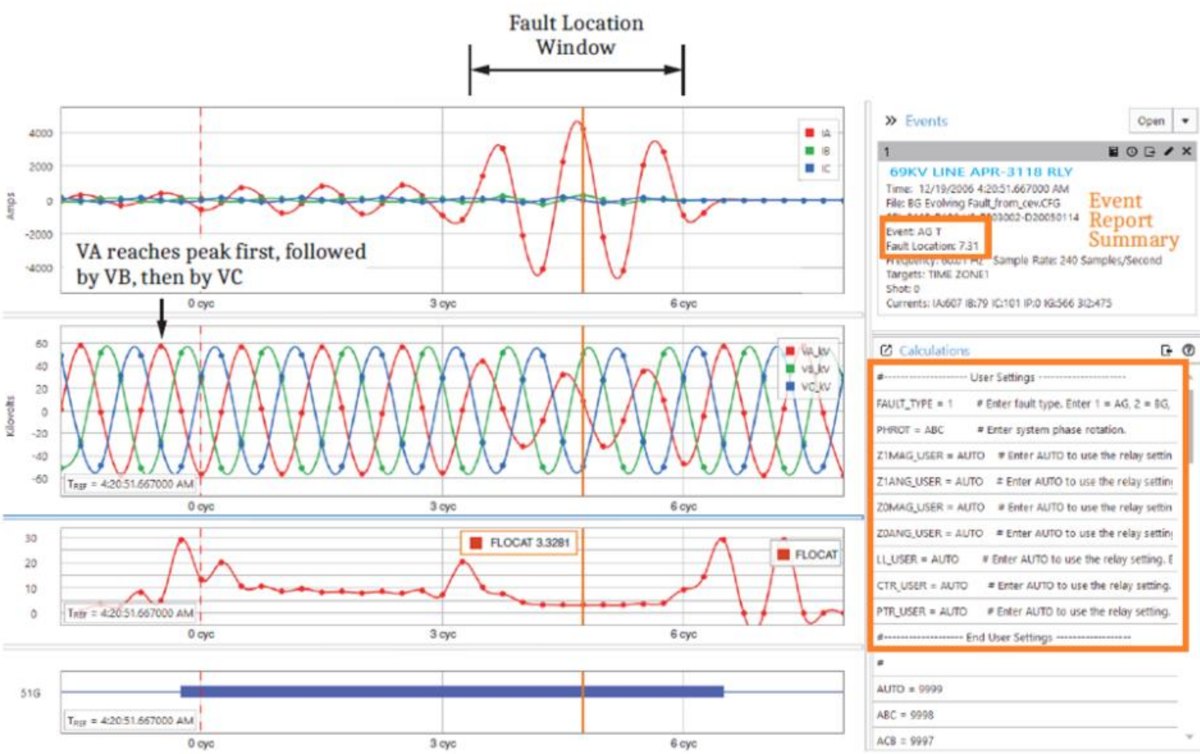


Fig. 22. Sample Advanced Protective Relay file, reference: [3]

In the example in **Fig. 22**, you can tell that the fault evolved from a high resistance to a bolted fault, based on the fact that the A-phase current was only slightly greater than the other phase currents at the beginning of the report and then dramatically increased around Cycle 3.25. That is why we designate Cycle 3.25 as the start of the fault location window. Cycle 6, when the fault is interrupted, marks the end of the fault location window.

In this example, the custom calculations estimate the fault location to be 3.33 miles from the relay. The actual fault location was 3.6 miles from the relay. The event summary shows that the relay estimated the fault to be 7.31 miles away from the relay, meaning that the fault location error was 3.71 miles. Because the relay does not have the benefit of human analysis when determining a fault location, its ability to accurately perform the steps described in this section is limited during an evolving fault. The relay uses the status of fault detectors, typically overcurrent and distance elements, to determine how long the fault was present and the length of the fault location window. Then it calculates fault location with voltage and current data in the middle of that window. In this case, the fault initially started as a high-impedance fault. Relay word bit 51G asserted at around Cycle 0 in Figure 22. It de-asserted when the breaker opened and interrupted the fault at around Cycle 6.5. This resulted in the relay using a fault location window of 6.5 cycles. Notice that right at the middle of this window, the fault evolved from a high resistance to a bolted fault. This dramatic evolution of the fault and its unlikely timing led to the significant fault location error from the relay. Challenging faults like this require manual analysis. These settings are used to calculate the positive and zero-sequence line impedance in primary ohms per unit line length.

This example highlights the importance of the quality of each impedance value and correct configuration of Advanced Protective Relays to detect and identify power system faults.

SDG&E's Advanced Protective Relay files

SDG&E team provided their sample relay files at its distribution networks, as shown in **Fig. 23**:

D SUB-C CIR3 APR-351 2014 Aug 03 12 08 57 663 1.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2020 Oct 12 08 45 04 659 10230.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2020 Oct 12 08 45 25 496 10233.cev	CEV Relay Event file
D SUB-C CIR3 APR-351 2014 Jul 11 01 11 22 294 3.cev	CEV Relay Event file
D SUB-C CIR3 APR-351 2014 Jul 11 03 10 22 303 2.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2021 Jan 19 22 16 19 325 10275.cev	CEV Relay Event file
D SUB-R CIR6 APR-351 2021 Jan 20 00 37 36 576 10276.cev	CEV Relay Event file
D SUB-S CIR2 APR-351-6 2020 May 20 14 10 31 277 10417.cev	CEV Relay Event file
D SUB-S CIR2 APR-351-6 2020 May 20 14 10 33 835 10418.cev	CEV Relay Event file

Fig. 23. Sample Advanced Protective Relay files

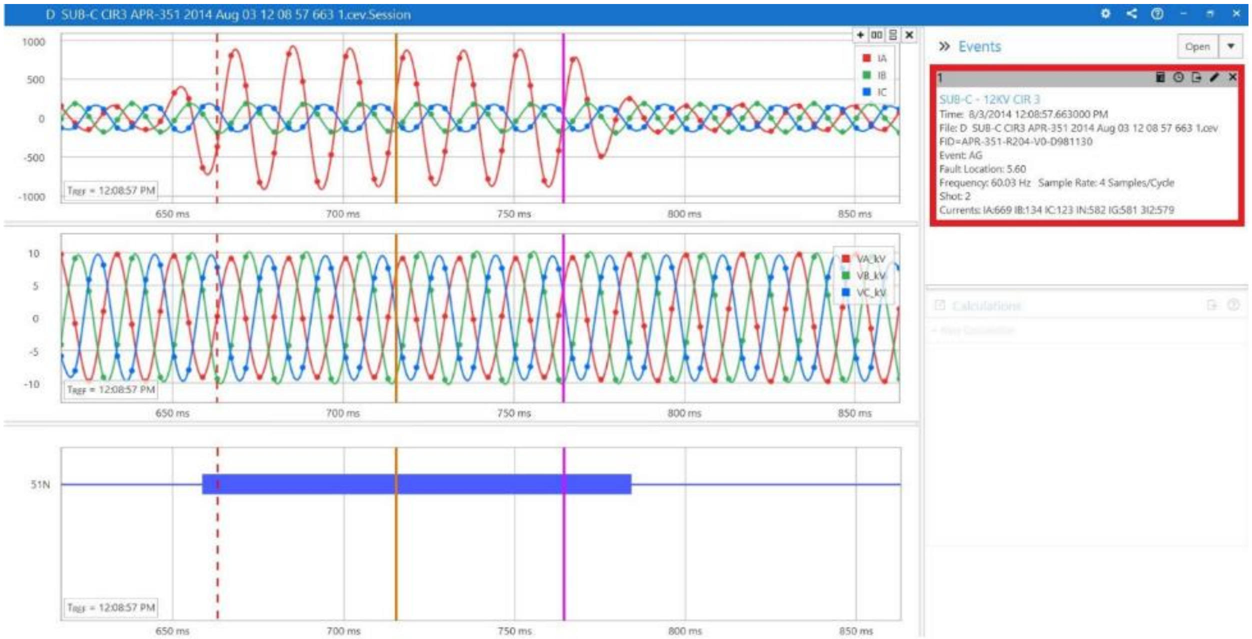


Fig. 24. Sample Advanced Protective Relay file for A-351 at 2014 Aug 03.

The figure above shows the single phase to ground (AG) event on an SDG&E circuit on Aug. 03, 2014. In the summary of this file, this information can be parsed:

- Affected System: C 12 kV CIR-3
- Event Time: 8/3/2014 12:08:57.663000 PM
- Relay Name: FID=APR-3-R2
- Event Type: AG
- Fault Location: 5.60 miles
- Frequency of Measurements: 60.03 Hz   Sample Rate: 4 Samples/Cycle
- Shot: 2
- Event Currents: IA:669 IB:134 IC:123 IN:582 IG:581 3I2:579

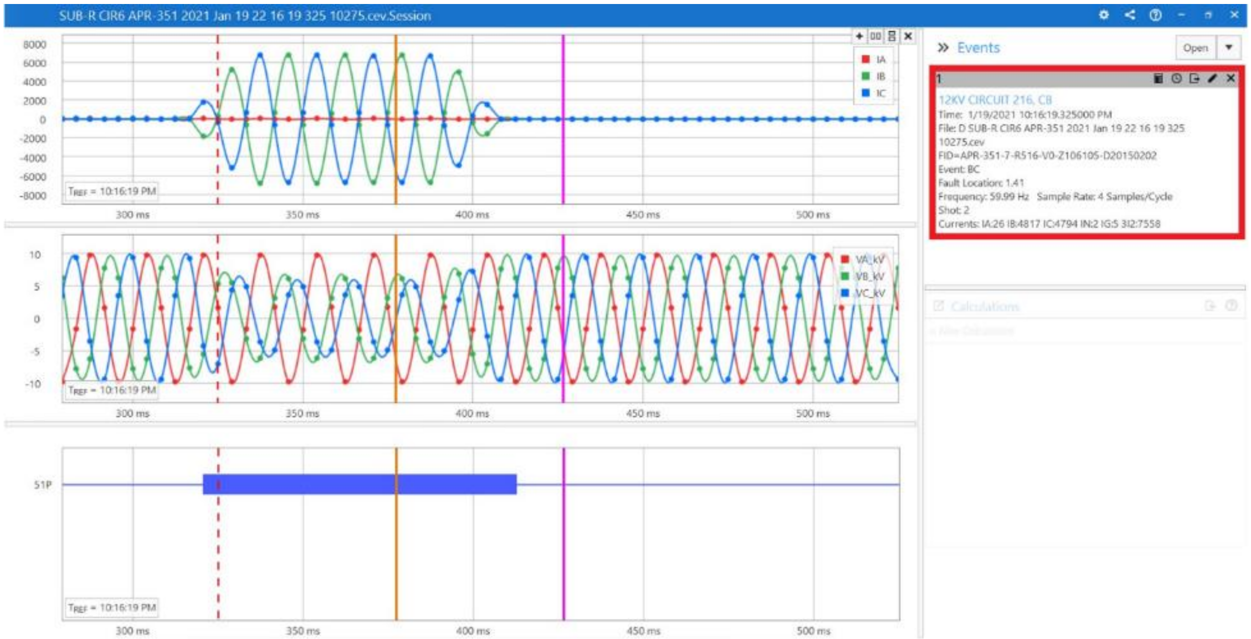


Fig. 25. Sample Advanced Protective Relay file for APR-351 at Jan 19, 2021.

A more recent Advanced Protective Relay file is shown in **Fig. 25**. The event was recorded on Jan. 19th, 2021, at one of the SDG&E distribution feeders, the summary of the event:

- Affected System: 12 kV CIR 6, CB
- Event Time: 1/19/2021 10:16:19.325000 PM
- Relay Name: FID=APR-3-R5
- Event Type: BC
- Fault Location: 1.41 miles
- Frequency of Measurements: 59.99 Hz   Sample Rate: 4 Samples/Cycle
- Shot: 2
- Event Currents: IA:26 IB:4817 IC:4794 IN:2 IG:5 3I2:7558

For both events, the affected system, time of the event, detected relay, type of the event, location of the event, the frequency of measurements with sample rate including shots, and finally event (fault) currents are reported. The format of the file is text ASCII, and this information can be parsed from the body of the file.

Advanced Protective Relay – Data Source Findings

After an internal review of a sample of SDG&E's Advanced Protective Relay files and a meeting with the Protection & Control team of SDG&E, these observations have been identified:

- Due to the complexity of distribution system modeling in SDG&E's service territory, the impedance values for each distribution system phase and their mutual impedance are not accurate enough to determine the fault location properly by using Advanced Protective Relay methodology.
- Impedance models can be changed due to the "Switching Events," which can change the whole circuit impedance model.

- Current settings are based on the fault short circuit duties in the distribution system, not based on impedance calculation and model, which is common on transmission system short circuit modeling and calculation.

***Table 6 Advanced Protective Relay file* information *vs* SCADA for distribution faults6** compares the relay file information with SCADA information regarding the distribution faults.

Table 6 Advanced Protective Relay file information vs SCADA for distribution faults

Inputs	APR files	SCADA	Note
Affected System	Yes	Yes	
Event Time	Yes	Yes	
Reported/ Operated Relay	Yes	Yes	
Event Type	Yes	Yes	
Fault Location	Yes	No	Currently it is not reliable; it should be configured with accurate impedance values.
Event Fault Currents	Yes	Yes	

In conclusion, with the current settings of the Advanced Protective Relay, fault location information is not reliable for the operation purposed due to the aforementioned reasons. In the future, with detailed and accurate impedance models for distribution networks, this feature can be utilized in the ADMS/NMS. In addition, further investigations will be needed to determine the value by considering the communication network latency to integrate with ADMS/NMS solution.

Phasor Measurement Units

Phasor Measurement Units – Introduction

This section describes the applications and analysis of distribution-level Phasor Measurement Unit (PMU) data, deployed across a few feeders in the service territory.

A PMU is an instrument that measures the voltage and/or current waveforms of the electrical power system. SDG&E has deployed many PMUs across its service territory. The measurements are synchronized to a global time standard, Coordinated Universal Time (UTC), using GPS technology.

PMUs digitize the input waveforms, usually all three phases. These digital samples represent the analog input signals as numerical values, which are processed by the PMU. The PMU calculates the amplitude and a phase angle; these two quantities are known as a phasor. The waveforms are sampled and synchronized with a global time base and each phasor is marked with a time code. The combined result is known as a synchrophasor.

The voltage and current waveforms are sampled by using an Analog-to-Digital Converter (ADC). An ADC takes an input and transforms it into a series of numerical values at discrete instances in time. This process is known as sampling, and the series of numerical output data from the ADC are known as sampled values (SV) as shown in ***Fig. 26.*** **ADC Process: Sampled Values from Original Waveforms**

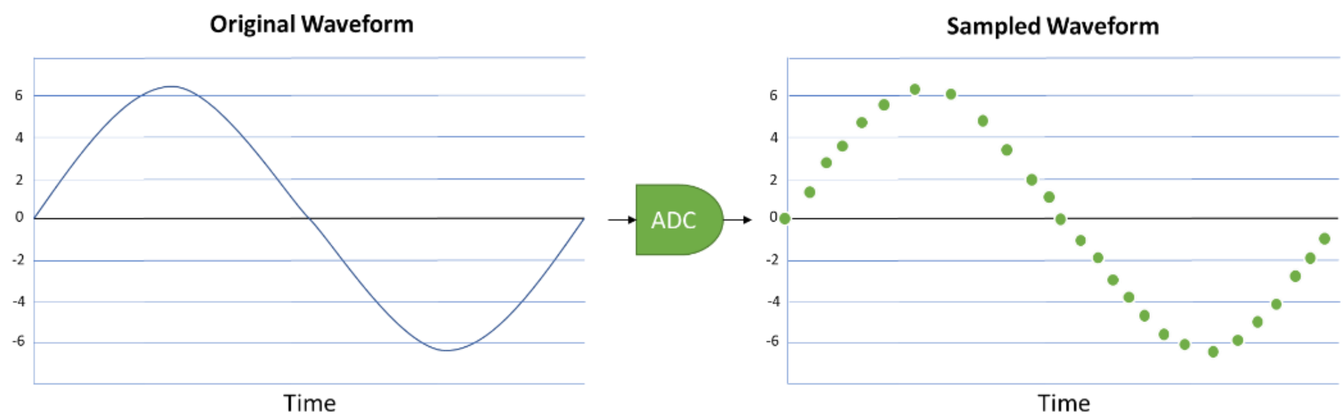


Fig. 26. ADC Process: Sampled Values from Original Waveforms

The difference between the numerical value produced by the ADC and the original waveform is known as the quantization error. The quantization error may be reduced by increasing the bit-depth of the ADC. The required sampling rate is a subject of the Nyquist-Shannon sampling theorem. In brief, one must sample it "at least twice" the frequency of the maximum frequency one wishes to recover. In practice, it is necessary to sample at significantly higher frequencies than the "Nyquist rate." A phasor represents two of the parameters of a sinusoidal waveform, described below:

$$x(t) = A_m \cos(2\pi f t + \varphi)$$

where $x(t)$ is the amplitude of the waveform at time t, A_m is the amplitude of the waveform, f is the frequency, and φ (phi) is the phase angle. Phase must be measured between two things. In the PMU, the phase is measured between the applied signal and a hypothetical reference signal whose frequency is exactly the nominal value of the power system (50 or 60 Hz) and whose cosine peaks at exactly the “tick” of the second of the UTC time base. The objective of the phasor estimator is to adjust the parameters A_m, f and φ until the resulting waveform matches the acquired sample values, as shown in *Fig. 27.* **Phasor Estimator**

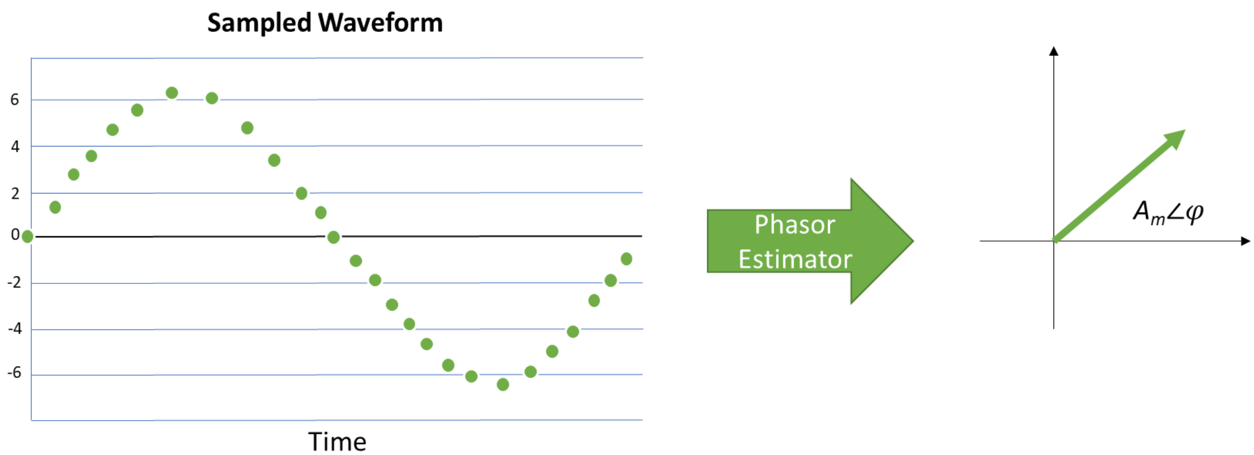


Fig. 27. Phasor Estimator

PMU Applications Background

Historically, electric grid planners and operators had limited information for understanding the status and behavior of the electric grid. Available information included measurements from supervisory control and data acquisition (SCADA) systems, typically available at several-second intervals from substations, and model data based on equipment ratings and specifications. The physical state variables of the AC network–specifically, the complex voltages, or time-shifted voltage waveforms at every node–were not directly observable but could be estimated through these models. This solution worked well enough for many years. But given the growing uncertainties and complexities in grid planning and operations, these methods are increasingly becoming inadequate in time resolution, precision, accuracy, and scope [7].

Transmission planners and operators were the first to recognize the need for new tools that rely on advanced sensors and more comprehensive monitoring to better observe, understand, and manage the grid. The challenge in transmission systems was comparing measurements across long distances (hundreds of miles) that would reveal physical interactions such as oscillations between generators and be able to describe power flows and stability across an entire synchronous AC network. By comparison, distribution systems were simple and posed little need to observe their operation with much granularity in space or time.

With the rapid growth in deployment of distributed energy resources, two-way electricity flows and new customer devices such as electric vehicles, there is a growing interest in sharper observation tools for the distribution grid. The possibility of unanticipated interactions among new and legacy devices, along with opportunities for more active and intelligent control, delivers value from measurements that are both precise and time-synchronized, making electrical events and responses observable and comparable between locations.

A high-value grid monitoring system will possess several characteristics:

- A high degree of time granularity, on the order of a sample per cycle or better, compared to current SCADA and EMS, which provides samples every few seconds.
- Fast communications access for real-time streaming of data for system recovery following disturbances.
- High-resolution data for off-line engineering analysis, and preferably in near real-time to enable operation support analytics.
- Deployment of many measurement devices across the system, which implies both low-cost devices and installation.
- Precise time synchronization of measured data to enable comparison across many electrical locations on the grid.
- Data quality, availability and volume that are appropriate to serve the high priority uses and monitoring needs of operational and planning functions and tools.

A substantial fraction of electric utilities' financial and capital assets is spent on distribution networks. Despite good design, installation, operation, and maintenance efforts, over 90% of customers' electric outages occur due to problems occurring on the distribution system (rather than from transmission-level or generation-level issues). Yet many North American utilities have limited amounts of monitoring on their distribution systems. Typically, there are some SCADA devices on sub-transmission elements and a growing number of advanced meter deployments that provide 15-minute power or energy readings (although often with delayed data delivery).

It is difficult to know what is happening on the distribution system without monitoring and measuring distribution-level and grid-edge activity. Distribution system managers could use high-quality, high-speed, wide-scale distribution-level monitoring (as feasible from a distribution-tailored synchrophasor network), planners and operators could use the data and appropriate analytical tools for many purposes including:

- State or condition monitoring of the distribution system.
- Monitoring and analysis of customer-owned, behind-the-meter distributed generation and energy storage devices, enabling better forecasting and integration of those devices.
- Measurement and verification of customers' energy efficiency, demand response and load management activities (subject to appropriate privacy protections).
- Monitoring and analysis of significant end-user loads (for example, clusters of electric vehicle chargers).
- Identification of asset and equipment problems, including detection and advance warning of equipment operational issues and failures.
- Fault detection (including high-impedance faults), location and event forensics.
- Anomaly detection, including potential cyber-intrusions.
- Detection of previously unknown dynamic events (for example, control instabilities or oscillations) that are not recognizable with traditional monitoring.

Phasor Measurement Units - Data Source Analysis

The PMU data is collected by a PMU Data Concentrator (PDC) using an industry standard approach [8]. This work sets the foundation for a deeper dive analysis to evaluate whether the gathered data is sufficient to meet the requirements of several key use cases including:

- High-Accuracy fault detection and location
- Advanced distribution protection and control

The PMU data will be explored in two parts in the following sections: (1) no disturbance in grid operation and (2) incidence in grid operation.

PMU Data without Disturbance

Circuit 5 has been selected for further investigation. The circuit has one circuit breaker and four reclosers as well as two tie-switches, as shown in ***Fig. 28. Circuit 5***

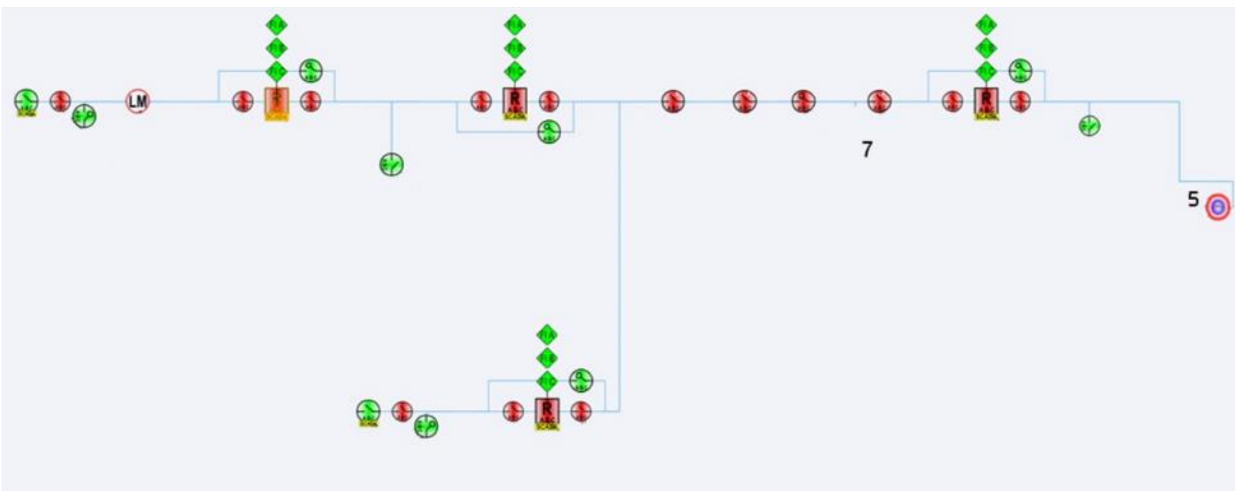
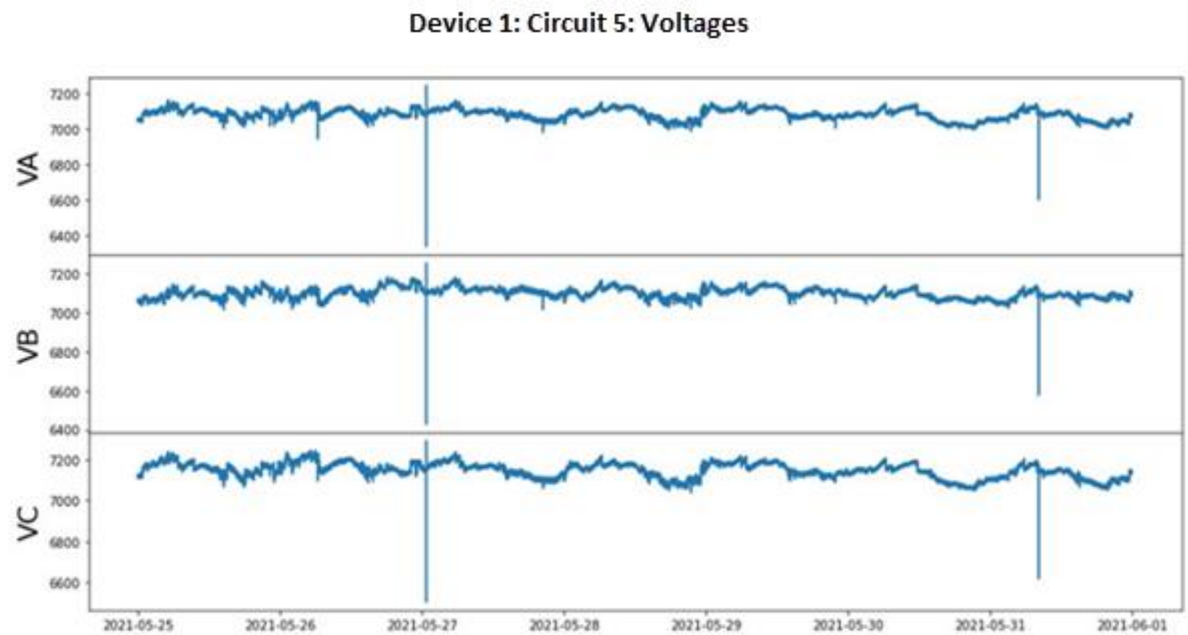


Fig. 28. Circuit 5

The PMUs are placed at the beginning of the circuit and at the tie-switches. The measurements are captured from May 25, 2021 to May 31, 2021.



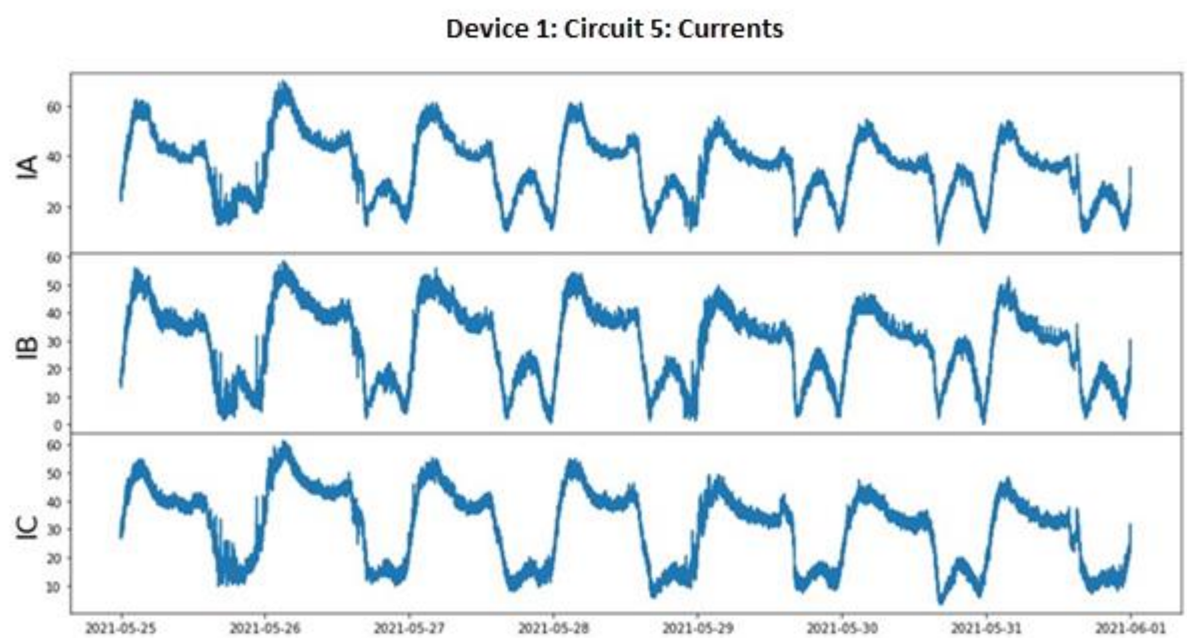


Fig. 29 Voltage and Current Measurements from PMU at Circuit 5's circuit breaker

PMU measurements at Circuit 5's circuit breaker for current and voltage magnitude are presented in **Fig. 29**. As can be seen no major power system incident can be detected.

Along this distribution circuit, PMU measurements at the Recloser 3 for current and voltage magnitude are presented in *Fig. 31. Voltage and Current Measurements* **from PMU** *at* **Recloser 4**. A similar pattern has been observed for the Recloser 4 in **Fig. 31** with lower loading condition.

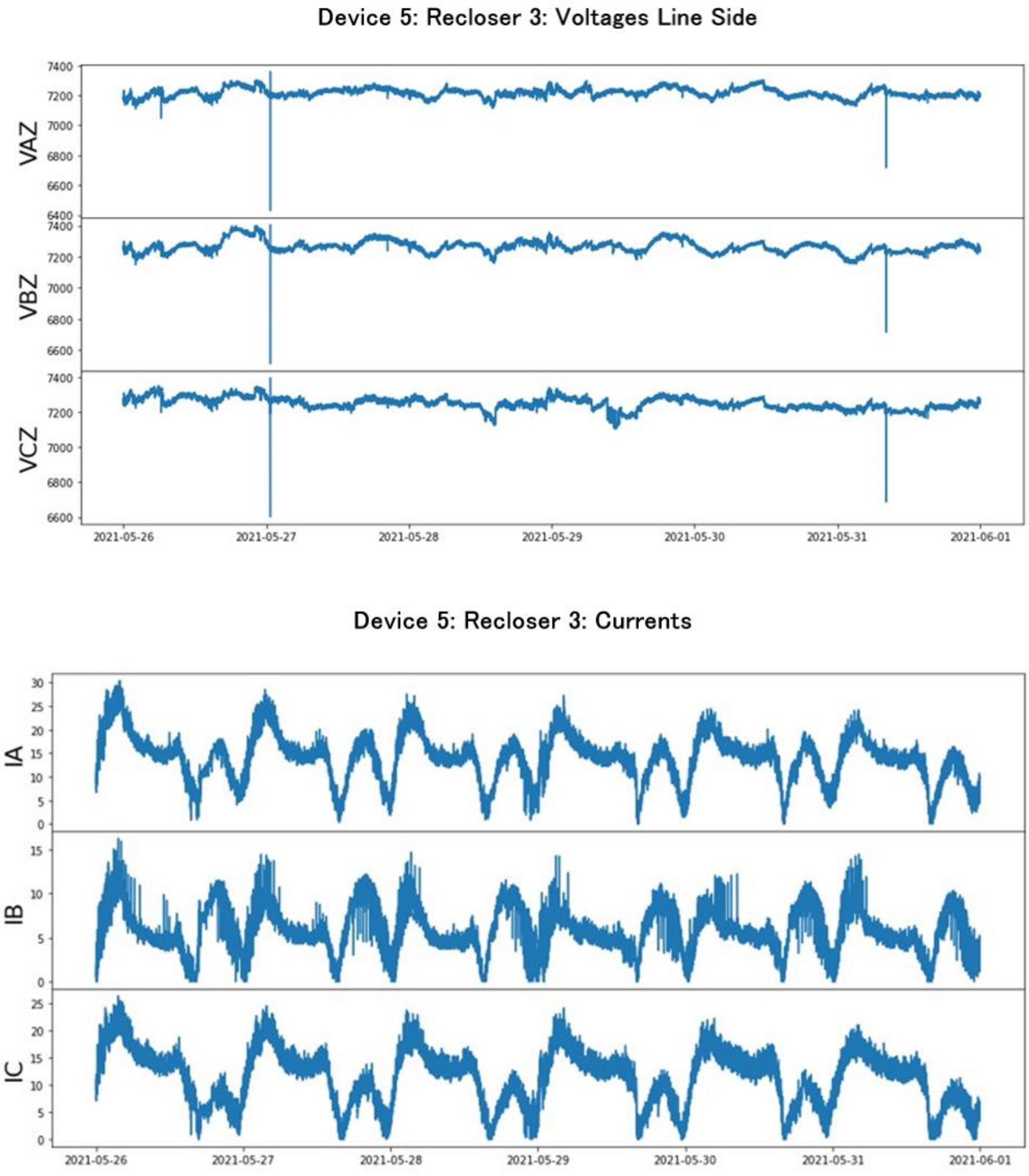


Fig. 30. Voltage and Current Measurements from PMU at Recloser 3.

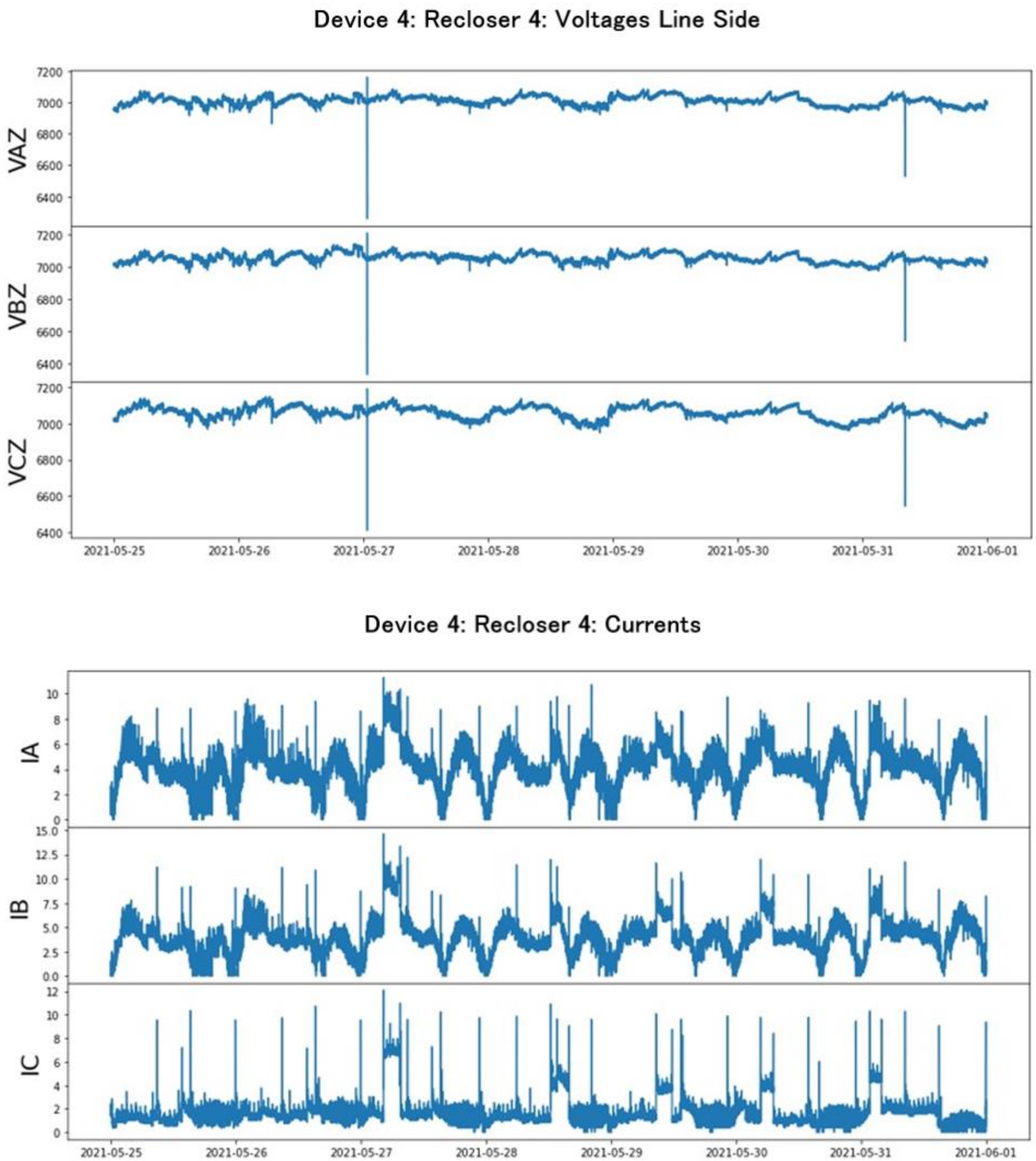


Fig. 31. Voltage and Current Measurements from PMU at Recloser 4.

To check any switching event, PMU measurements at one of the Tie-Switches (T1) for current and voltage magnitude are shown in **Fig. 32**. This Normally Open (N.O.) switch had not closed and current values remained at zero for this period.

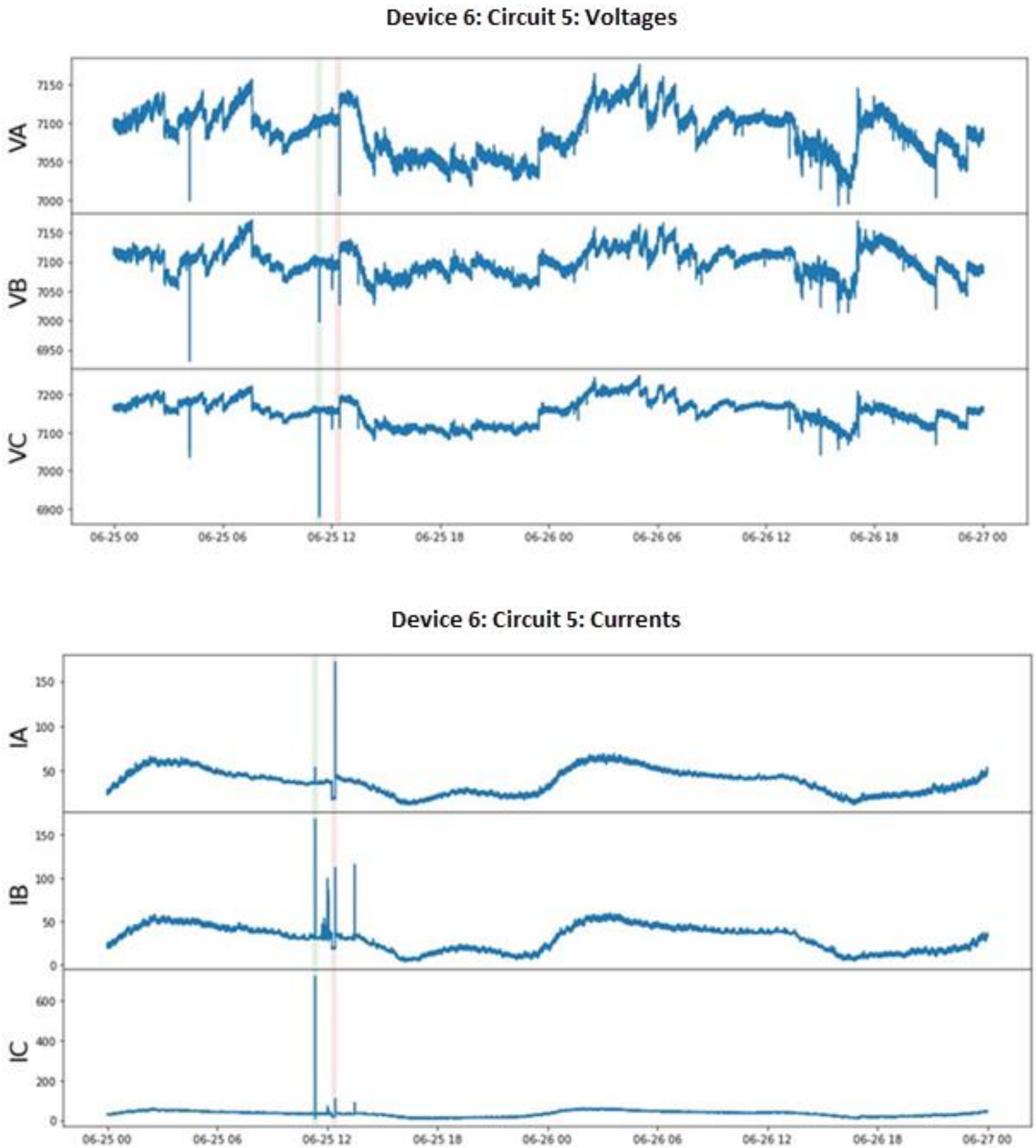


Fig. 32. Voltage and Current Measurements from PMU at Tie-Switch T1.

As can be seen from these previous measurement sets, no events occurred between May 25 to May 31, 2021 on Circuit 5.

In the next section, PMU measurements will be analyzed during an event on the circuit.

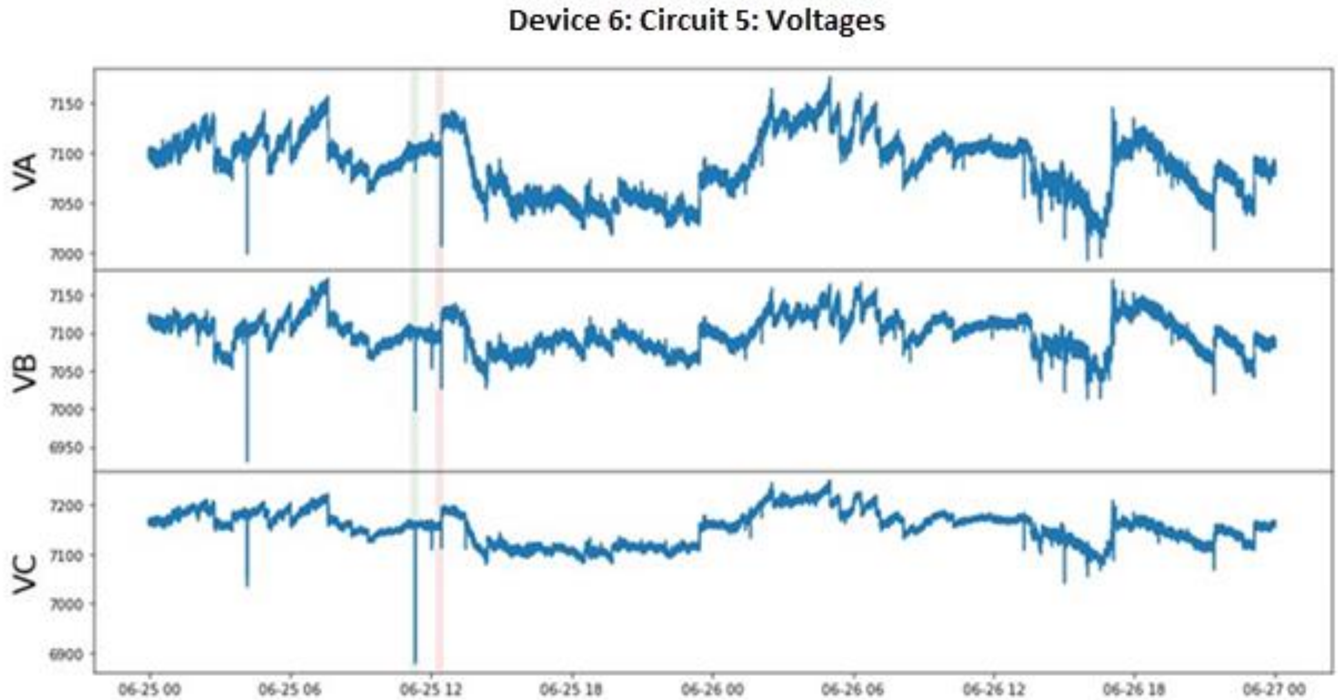
PMU Data with Disturbance

At 5:17 AM, June 25, 2021, SDG&E customers called and reported a fire on one of the poles (P5) associated with Circuit 5. Here, PMU measurements for different devices during this incident were investigated as shown in the details below. It is also worth noting that any of the protective devices along the feeder had not cleared the fault automatically. An operator opened Recloser 2 by SCADA. The series of events were extracted from the NMS has shown in ***Fig. 33.*** ***NMS Incident Report for* June 25th, *2021***

	Version	Operation	Device	Structure	Details	Status	Instructed Date
Default	1						
1	1	CAUSE	Fuse 3	Pole 5	ETS REPORTS C/O WAS ON FIRE ON POLE 5 - NEED TO DE-ENERGIZE FOR SAFETY	Completed	06/25/21 5:17
2	1	Open by SCADA	Recloser 2	Pole 6	DE-ENERGIZED FOR SAFETY	Completed	06/25/21 5:14
3	1	Block Sensitive Ground Protection	Recloser 3	Pole 7	SS#12	Completed	06/25/21 5:15
4	1	Block Sensitive Ground Protection	Recloser 2	Pole 6	SS#24	Completed	06/25/21 5:15
5	1	Block Sensitive Ground Protection	Recloser 5	Z61	SS#48	Completed	06/25/21 5:16
6	1	Open	Fuse 3	Pole 5	CENTER PHASE FUSE WAS BURNING BUT DID NOT BLOW OPEN - OK TO OPEN REMAINING 2-50A FUSES	Completed	06/25/21 5:25
7	1	Close by SCADA	Recloser 2	Pole 6	RESTORING PARTIAL SERVICE	Completed	06/25/21 5:26
8	2	OK to Patrol	Fuse 3	Pole 5		Completed	06/25/21 5:29
9	3	Remarks	#2 AR BC 118.2		ETS REPORTS ROLLED F/I GOING SOUTH AT POLE 8, BUT NOTHING FOUND	Completed	
10	3	Close	Fuse 3	Pole 5	3-50A FUSES RESTORING ALL SERVICE	Completed	06/25/21 5:23
11	4					Completed	
12	4	Block Sensitive Ground Protection	Recloser 5	Z61	SS#48	Completed	06/25/21 5:43
13	4	Block Sensitive Ground Protection	Recloser 2	Pole 6	SS#24	Completed	06/25/21 5:43
14	4	Block Sensitive Ground Protection	Recloser 3	Pole 7	SS#12	Completed	06/25/21 5:44

Fig. 33. NMS Incident Report for June 25th, 2021

PMU measurements at Circuit 5's circuit breaker for current and voltage magnitude are presented in ***Fig****. 34. Voltage and Current* ***Measurements*** **from PMU *at*** *Circuit* **Breaker Circuit 5's circuit breaker for June 25 and 26, 2021**.



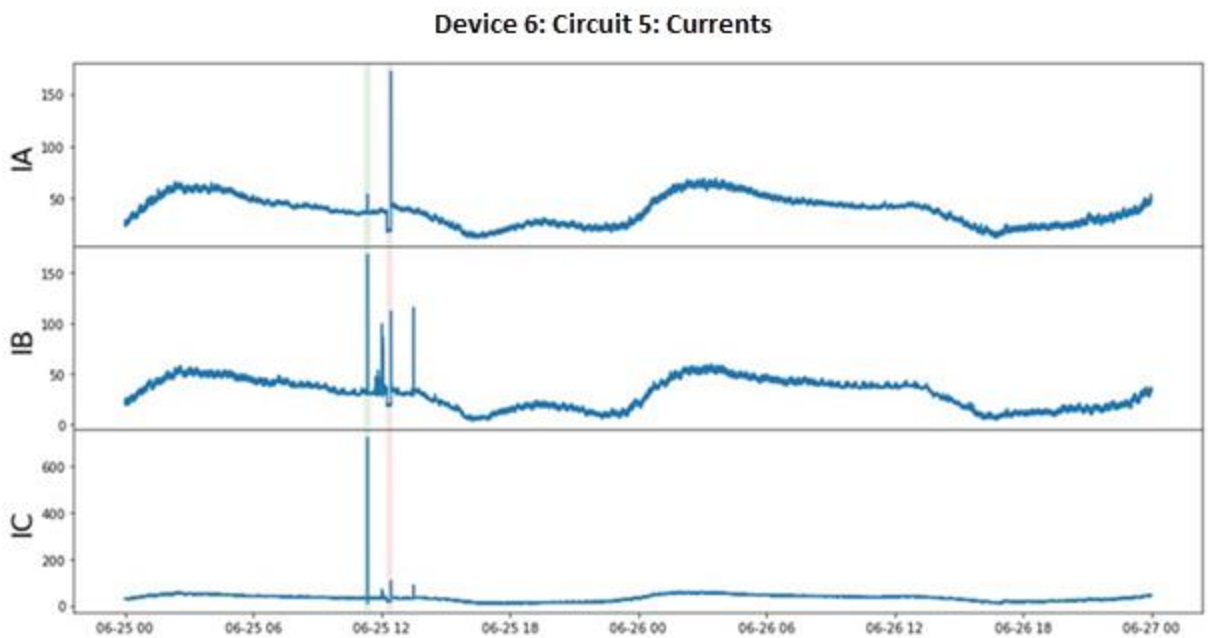


Fig. 34. Voltage and Current Measurements from PMU at Circuit Breaker Circuit 5's circuit breaker for June 25 and 26, 2021.

As shown in **Fig. 35** current spikes can be detected along with voltage drop, light green and red boxes in the Figure. Accordingly, the relay setting circuit breaker could not pick up the fault and clear it, i.e. high impedance fault.

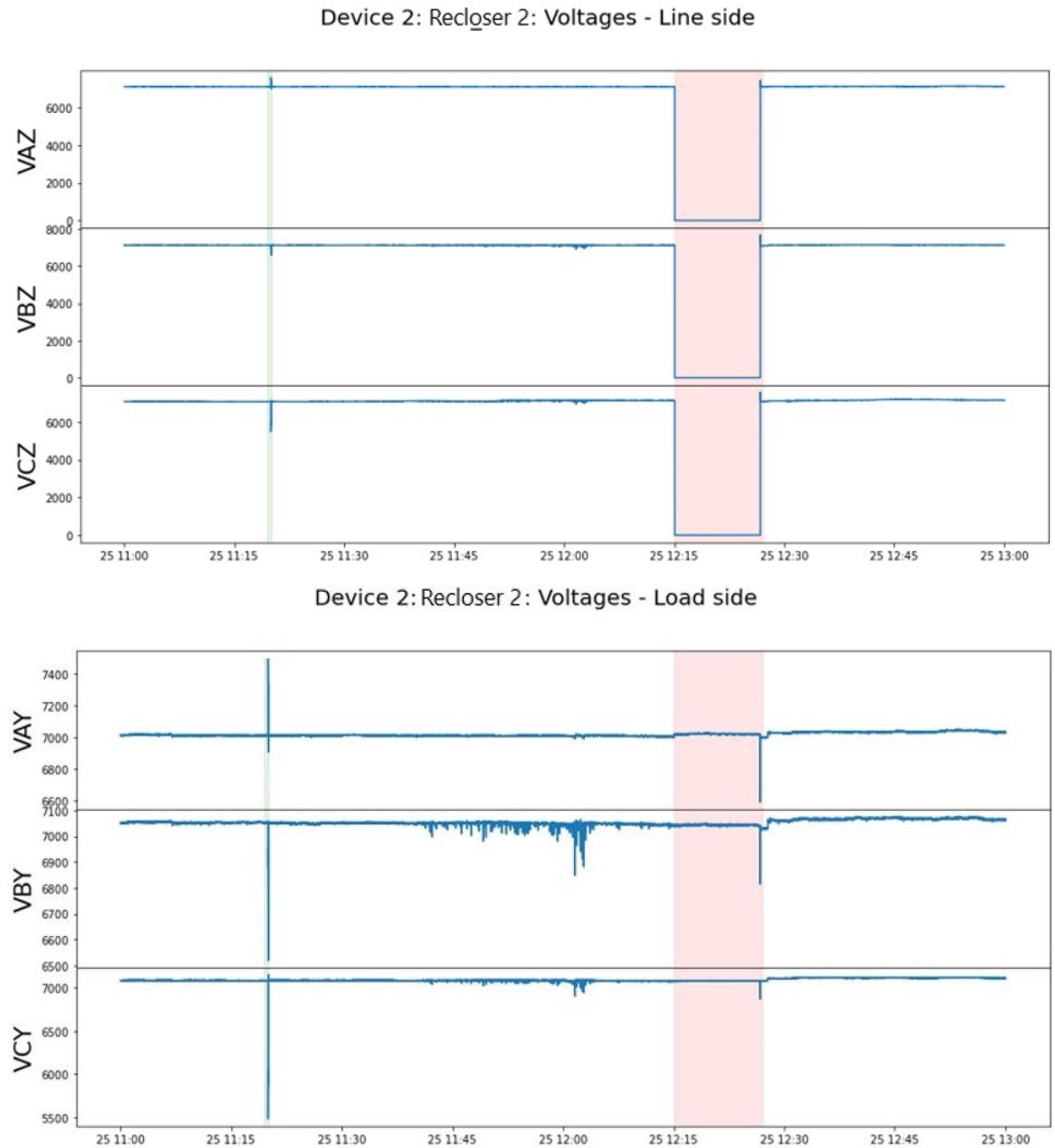


Fig. 35. Voltage Measurements from PMU at the Recloser 1531R for June 25, 2021 in two hours window for both sides: Line and Load.

To investigate in more detail, the PMU measurements near to the incident were explored. **Fig. 36** presents the voltage values in two hours windows for both the line side and load side.

The initial incident has started by highlighting in green and opening of the Recloser 2 is highlighted in red for about 10 minutes. The Line Side voltage had dropped to zero by opening the associated recloser. With this action, the recloser downstream of 2, Recloser 3 had been opened as well.

Along with the distribution Circuit 5, PMU measurements are available from at the Recloser 4 in parallel operation with the Recloser 2. **Fig. 36** shows the voltage values at both Load and Line sides. The voltage variations during the initial incident and switching can be seen in the green and red shading.

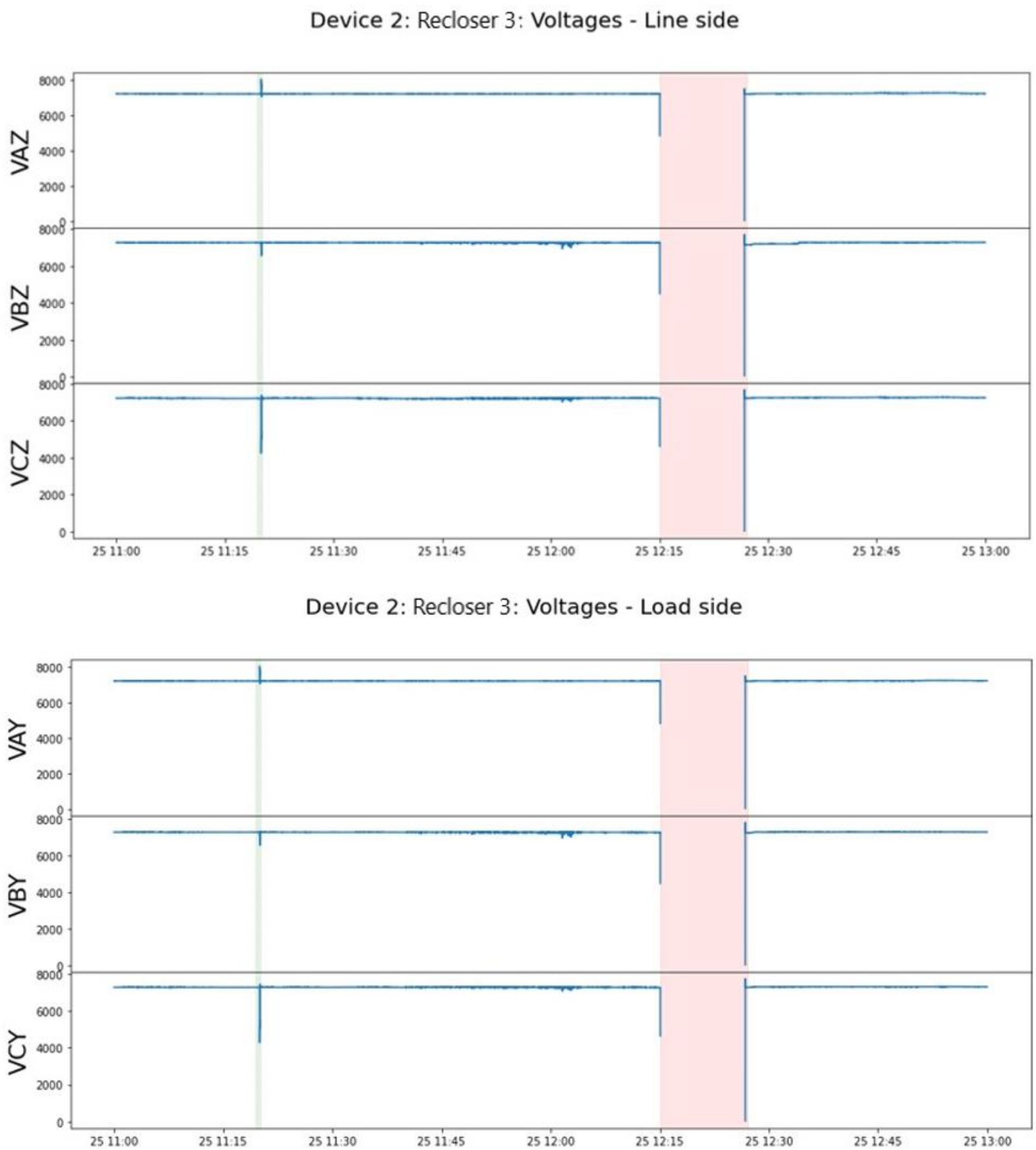


Fig. 36. Voltage Measurements from PMU at the Recloser 2 for June 25, 2021 in two hour windows for both sides: Line and Load.

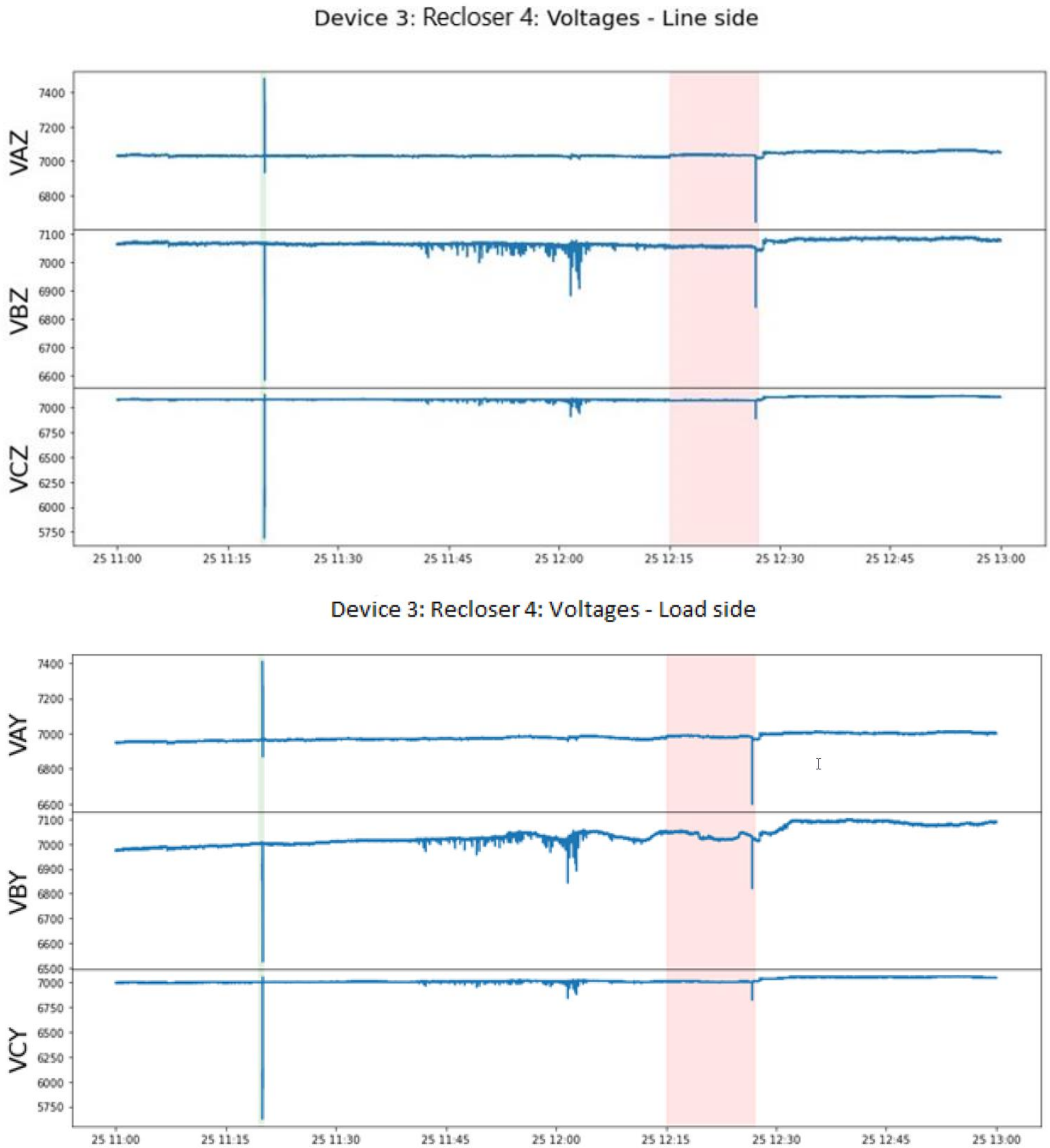


Fig. 37. Voltage Measurements from PMU at the Recloser 4 for June 25, 2021 in two hour windows for both sides: Line and Load.

The location of the incident (fault), the upstream Recloser 4, the downstream recloser 3, the other path Recloser 4, and Circuit 5's circuit breaker are depicted in **Fig. 38. Circuit 5 with the Reclosers 2, *3,* 4 with Fault Location on June 25, 2021.**

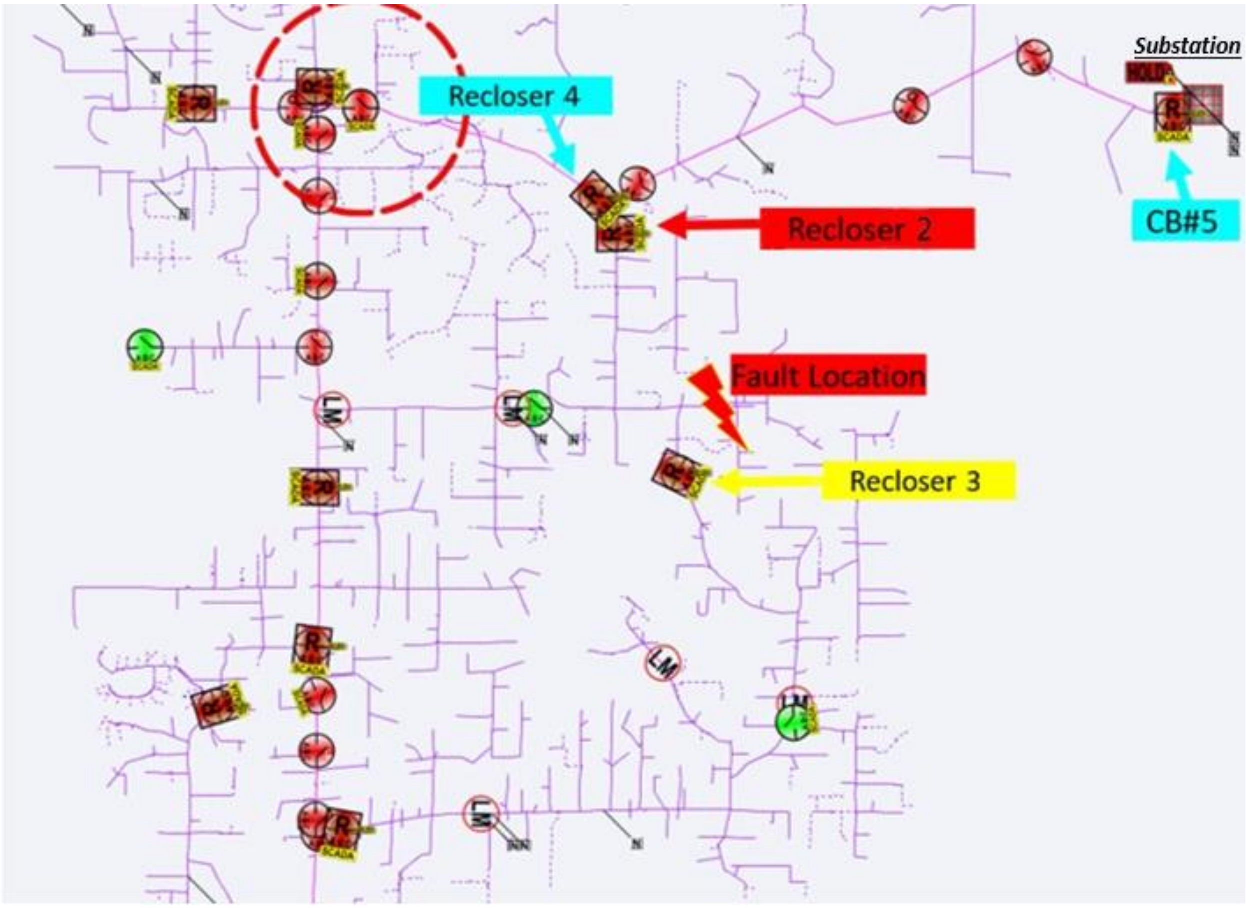


Fig. 38. Circuit 5 with the Reclosers 2, 3, 4 with Fault Location on June 25, 2021.

Phasor Measurement Units – Data Source Findings

1. Further investigation into the feasibility of the proposed techniques is required to demonstrate a solution that shows high enough precision and recall for the application scenario.
2. The requirements of the application (line break, for example), need to be translated into a requirement for precision and recall.
3. Further investigation into the feasibility of the proposed techniques is required for deployment in online scenarios. More work is needed to answer the question, “Can this technique detect line breaks early enough and can the algorithm be deployed at autonomous devices?”
4. More investigation is needed to simplify proposed algorithms without sacrificing performance so they can be easily deployable into field devices.
5. Data sources can be made consistent across the board, or data format for each type of device can be specified.

SECTION 4. STAKEHOLDER DEMONSTRATIONS

There were two demonstration iterations conducted during the project. The demonstrations aimed to obtain stakeholder feedback that can be incorporated into the focused patrol training, product enhancements and future research.

Demonstration Sessions

Demonstrations of the different use cases and scenarios were broken down into two logical groups and demonstrated in two different sessions.

Demonstration Session One Content

The following table summarizes the scenarios demonstrated in Iteration one.

Table 7 Session One Use Cases Demonstrated

Use Case	Scenario	Description	Duration (minutes)	Comments
		Use Case 1 – Wire Down		
UC1 – Wires down (Trip and reclose)	UC1-1.1	***FLA and Meters*** Trip breaker, reclose successfully, raise Meter Low Voltage messages (phase A)	15	***(Switching plan #116216)*** ***FLA delay in starting – system wide config to allow for WFI information to be received***
	UC1-1.2	***FLA, WFI, Meters*** Trip breaker, successful reclose, Trigger WFI, Raise meter calls (Phase B)	10	***(Switching plan #116244)*** FLA fails on test system due to data quality in impedance model. Shows how WFIs can give operators location information
UC1 – Wire down (Trip and lockout)	UC1-2.1	***FLA, customer call*** Trip breaker and lockout, raise customer/damage call	10	***(Switching plan #116276)***
	UC1-2.2	***FLA, WFI*** Trip breaker and lockout, trigger WFI (phase A)	10	***(Switching plan #116245)***
	UC1-2.3	***FLA, WFI*** Trip breaker and lockout, trigger WFI (phase B)	10	***(Switching plan #116253)***
	UC1-2.4	***FLA, WFI***	20	***(Switching plan #116254)***

Use Case	Scenario	Description	Duration (minutes)	Comments
		Trip and lockout recloser, No WFI trigger		Locations from FLA do not identify beyond WFI that did not trigger Repeat scenario with no WFI configuration for FLA – shows all locations Re-enable WFI configuration for FLA
UC1 - Non-SCADA device Operates	UC-3.1	***FLA and Meters*** Raise Meter Low Voltage messages (phase A), raise customer damage calls	10	***(Switching Plan – 116236)*** Same as UC1.1 without recloser trip
	UC1-3.2	***FLA, WFI, Meters*** Trigger WFI, Raise meter calls (Phase B)	10	***(Switching Plan –116279)*** Same as UC1.2 without recloser trip *Note – Impedance model issues – FLA does not fire.
		Use Case 6 – Underground Distribution		
UC6 – Trip and reclose	UC6-1.1	***FLA, FIs Power out***		
UC6 – Trip and lockout	UC6-2.1	***FLA and FIs*** Breaker trips and locks out. FLA activated showing potential locations. FI review and update as patrols investigate		***Switching plan (#116290)*** Added functionality to allow operators to tag FIs as operated

Demonstration Session Two Content

The following table summarizes the scenarios demonstrated in second demonstration session.

Table 8 Iteration Two Use Cases Demonstrated

Use Case	Scenario	Description	Duration (minutes)	Comments
Use case 1: Trip and reclose	(1) UC1.1.1 Substation example A (As-is)	Shows simulation of as-is scenario (RMO created, fault created and FLA potential locations shown)	10	***(Switching plan #223636)***
Use case 1: Trip and reclose	(1) UC1-1.1 Substation example A (Improved)	***FLA and Meters*** Trip breaker, reclose successfully, raise Meter Low Voltage messages (phase A)	10	***(Switching plan #223633)*** FLA delay in starting – system wide config to allow for WFI information to be received
Use case 1: Trip & Lockout	(4) UC2.2 (As-is)	***Recloser trip based on fault current***	10	***(Switching plan #223656)*** *WFIs disabled for this scenario and not considered by FLA*
Use case 1: Trip & Lockout	(4) UC2.2 (Improved)	***As above, with FLA and WFI*** FLAs reporting fault current detection	10	***(Switching plan #223639)*** WFIs re-enabled and used in FLA
Use case 1: Trip & Lockout	(4) UC2.2 (As-is)	***Repeat of previous scenario with WFI considered, but no WFIs enabled***	10	***(switching plan #223656)***
Use case 1: Trip & Lockout	(2) UC1-1.2 Substation example B - Phase B Fault (As-is)	***RMO***	10	***(Switching plan #223654)*** No FLA due to incorrect impedance model No further information on down-stream event
Use case 1: Trip and reclose Use case 1: Trip and reclose	(2) UC1-1.2 Substation example B - Phase B Fault (Improved)	***FLA, WFI, Meters*** Trip breaker, successful reclose, Trigger WFI, Raise meter calls (Phase B)	10	***(Switching plan #223637)*** No FLA due to incorrect impedance model WFIs available giving possible location information

Use Case	Scenario	Description	Duration (minutes)	Comments
Use case 1: Trip & Lockout	(5) UC1-2.3 - RINCON	***FLA, WFI on Phase B fault***	5	***(switching plan #223640)***
UC1 - Non-SCADA device Operates	(8) UC-3.1	***FLA and Meters*** Raise Meter Low Voltage messages (phase A), raise customer damage calls	5	***(Switching Plan – #223663)*** Same as UC1.1 without recloser trip
UC1 - Non-SCADA device Operates	(8) UC1-3.2	***FLA, WFI, Meters*** Trigger WFI, Raise meter calls (Phase B)	5	***(Switching Plan –223646)*** Same as UC1.2 without recloser trip *Note – Impedance model issues – FLA does not fire.

Demonstration Scripting and Development

The demonstration scenarios were scripted in the training simulator and are all available in the training simulator for use in training development. The training simulator utilizes the system switching plan list for easy access and playback of training scenarios. See ***Fig. 39.*** for an example of how the training simulator scripts appear in the switching list.

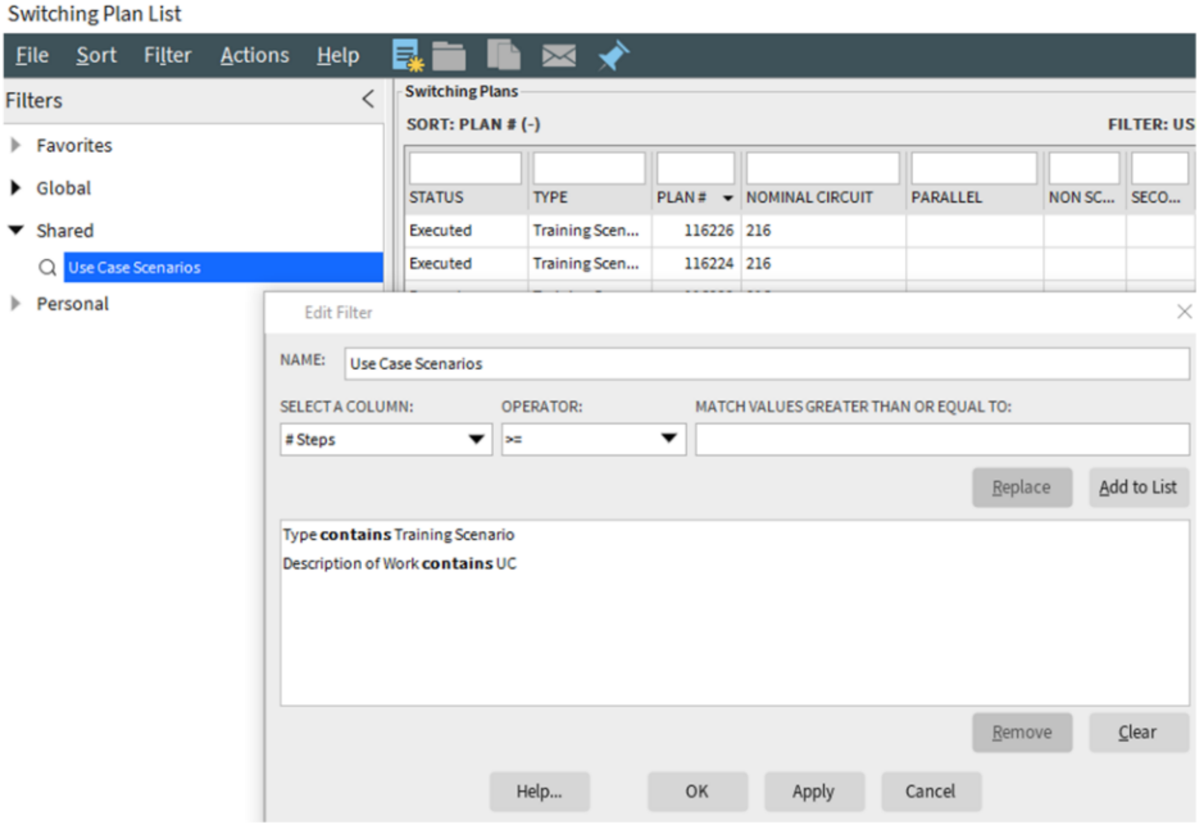


Fig. 39. Example Training Simulator Script

To play a scenario, the trainer must first identify an existing scenario and copy it. Once a training scenario has been executed, it cannot be executed again. The scenarios developed as part of this project can be treated as masters and used to create copies for execution in actual user training. New scenarios or training simulations can be created at any time given the appropriate system access. When using the training simulator functionality, the operator must be logged in as a "Trainer" user type. The operator is then given the choice of the type of switching plan to create. In this case, we want to select the training Scenario type as shown in ***Fig. 40.*** **Selecting Training Scenario Type**

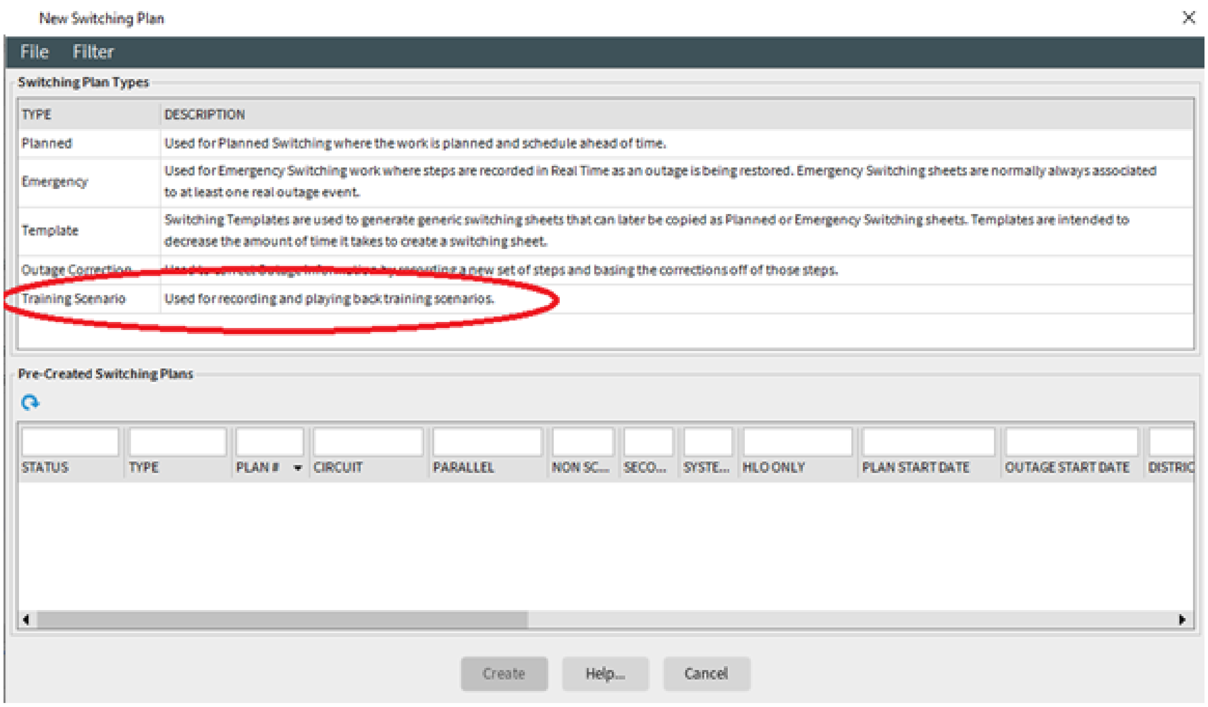


Fig. 40. Selecting Training Scenario Type

On selection, a new Training Scenario switching plan is created and automatically opens in "Record" mode. Recording can be stopped and started as required. It is recommended that activities performed are recorded and are done in "Study Mode" where possible.

To create a copy of an existing training scenario, one enters the plan number you want to copy from the table in the demo content's section, into the "Plan #" column in the bottom pane and press the refresh button. The plan you are searching for will appear in the lower pane. Select this plan and click "Training Scenario" in the top pane and click "Make a copy".

The Use Case scenarios created as part of this project are built up from the simulation of several different actions.

The following sections describe the steps for scripting different scenarios that are able to be performed using the training simulator based upon the use cases identified in this project.

Script #1 - Low Voltage Meter Calls

In real-time mode, perform the following steps (***See* Fig. 41**):

1. Ensure a training scenario switching plan is open and recording
2. Navigate to the transformer associated with meter points you wish to raise a message from
3. Open the Control tool for the transformer
4. Select the "Calls…" button and select "Submit call…"
5. Complete the details in the call entry form selecting Meter LV
6. Save the call

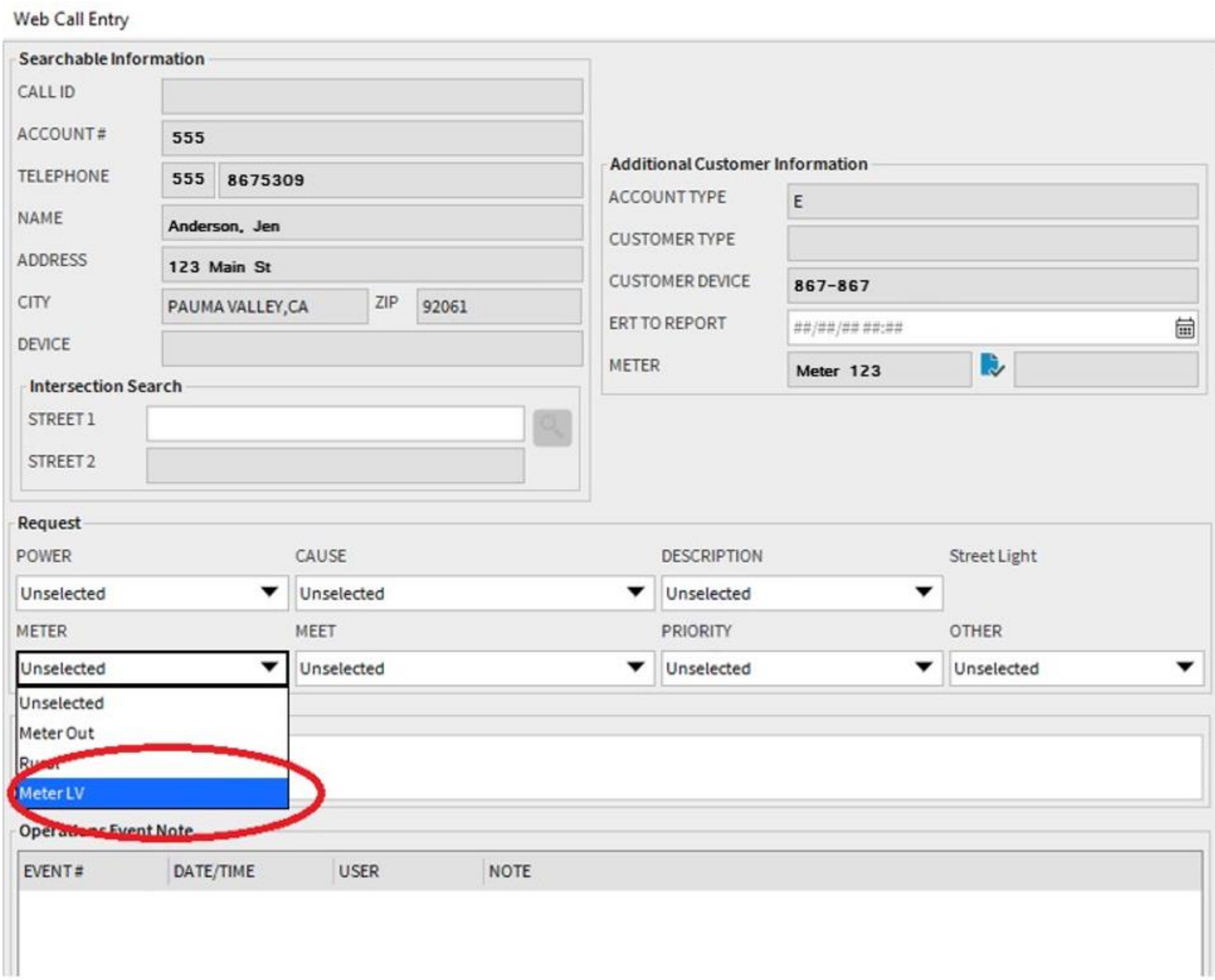


Fig. 41. Recording a Meter Low Voltage

The action will be recorded in the open training scenario switching plan.

Script #2: Wireless Fault Indicators (WFI)

In Study mode, ensure a training scenario switching plan is open and recording, and perform the following steps:

1. Navigate to a WFI and open the SCADA summary (right-click menu option from the NMS diagram)
2. Right-click on the point you wish to update (representing phase A, B or C)
3. Select "Simulate SCADA Entry…" and enter the value you require (1 – Fault Current detected, 0 – WFI normal state)

Script #3: Underground Fault Indicators

In study mode, perform the following steps:

1. Ensure a training plan scenario switching plan is open and recording
2. Navigate to FI
3. Open the Control Tool

4. Select the “Faults…” button and select appropriate action (Place FI, Remove FI)

Underground FIs are mechanical devices with no means of communication to central control systems. Only the visual inspection options available. The configuration was added to allow operators to mark as “Seen fault” and to “Remove fault”. This can be simulated if required.

Script #4: Fault Injections

In study mode, perform the following steps:

1. Ensure a training scenario switching plan is open and recording
2. Note any fault current you require to simulate a fault (provided the impedance model is good, open the device details of a cable/line and examine the fault details tab. This will give you the fault values for the cable/line).
3. Inject the fault current in the appropriate attribute for a Line Recloser via the SCADA Summary
4. Update the TARGET_A SCADA point to “1” (this will put the point in an alarm state)

Script #5: Recloser Actions

In study mode, perform the following steps:

1. Select a Recloser and open the Control Tool
2. Select the Manual Operations button
3. Select the appropriate action (open, close)

Demonstrations Stakeholder Feedback

Because the demonstration was performed via web meeting and not in person, and that there was a relatively substantial number of participants in the demo, the opportunity for interactive feedback was limited. Subsequent follow-up with some key players indicated that the demonstration was well received and that they felt the new functionality that was demonstrated was practical and suitable to be used in training and production. However, there were some additional situations identified and issues commented on that would require additional investigation to ensure that there are no end cases that are not addressed.

Benefits Evaluation by Stakeholders

After the two demonstrations were complete and benefits review was completed. The analysis was designed to determine the impact of adding the new data sources to the system and gather information from the trainers on improvements and useability.

The stakeholder evaluation of each data source (rows) to the use cases (columns) is shown in **Table 9**. The value was rated as high, medium or low based upon the potential improvement in fault location or fault detection for a circuit that has significant patrol time associated with the restoration.

Table 9 Value of Data Source to Use Case Value

Data Source	UC1: Wire Down	UC2: Proactive Fault Detection	UC3: Foreign Object in line	UC4: Tree/Vegetation Contact	UC5: Overload Mitigation	UC6: Underground Distribution	UC7: Primary Voltage Customer Problem
Wireless Fault Indicators	High	Medium	Low	Low	Medium	Low	Low
Advanced Metering Infrastructure (AMI) Low Voltage Alarms	Medium	High	High	High	Low	Low	High
Weather Data	High	High	Low	Low	Low	Low	Low
Advanced Protective Relays	Low	Low	Low	Low	Low	Low	Low
Phasor Measurement Units (PMU)	High	High	Medium	Medium	Low	Low	Low

The usage of each data source (columns) for each fault scenario (rows) is shown in **Table 10**.

Table 10 Usage of each Data Source by Fault Scenario

Scenarios	Wireless Fault Indicators	Advanced Metering Infrastructure (AMI) Low Voltage Alarms	Weather Data	Advanced Protective Relays	Phasor Measurement Units (PMU)
SCADA detects	Yes	No	Yes	Unknown	Unknown
Manual protection device trips	Yes	Yes	Yes	Unknown	Unknown
No protection device trips	Yes	Yes	Yes	Unknown	Unknown

The impact of each type of new sensor on the benefits is shown in **Table 11**. The value was rated as high, medium or low based upon the potential improvement to the stated benefit based upon the sensor type.

Table 11 Sensor Value vs Benefit

Value of new sensors (High, Med, Low, Unknown)		**Wireless Fault Indicators**	**Advanced Metering Infrastructure (AMI) Low Voltage Alarms**	**Weather Data**	**Advanced Protective Relays**	**Phasor Measurement Units (PMU)**
Safety to SDG&E Personnel		High	Medium	High	Unknown	Medium
Safety for the Public		High	Medium	High	Unknown	High
Risk Reduction		High	Medium	High	Unknown	High
Reduced Cost, SAIDI		High	High	Medium	Unknown	Unknown
Improvement in Training Efficiency		High	High	High	Unknown	High

SECTION 5. PROJECT RESULTS AND VALUE PROPOSITION

Due to the intangible nature of this project (Staff Training), how fault location is conducted today (establish the baseline) was compared with how this new simulator will train SDG&E operators to conduct fault location in the future. Hence, the benefits that will be gained by the completion and implementation of the training stimulator will be the focus of the benefits estimate.

Currently, when an outage occurs, the DSO begins service restoration as soon as possible. Unless damage reports indicate where the cause is located, the DSO directly uses non-tripped fault indicator targets (when available) from the distribution line SCADA site(s) to determine if a line segment is free of faults. For all other cases, and during the non-fire season, where reclosing is permissible, the location of faults is sometimes confirmed through test closure of the feeder breaker or service restorer. The current process not only diminishes the resiliency of the system by weakening it each time a test closure into a fault is done, but is also not efficient, given that multiple field personnel must arrive on the scene before any testing occurs, thus prolonging the duration of the outage and having multiple electric troubleshooters drive from device to device. Test closures also degrade power quality for customers otherwise not involved with the outage.

This project has shown that with training, operators can have access to additional fault information to aid in the troubleshooting process and find the fault locations faster, requiring less patrolling. Due to the additional complexity of the data and the analysis required, having a realistic environment to train the operators is necessary to take full advantage of the new capabilities.

Safety to SDG&E’s personnel

Because the Training Simulator will make the operators more efficient at determining fault location and directing field personnel to the correct location, it will inherently make the field personnel safer by reducing their driving exposure into more rural areas and sometimes dangerous weather conditions. Operations during hours of darkness are of special concern.

Safety to the public

The new Training Process and improved field equipment could allow the operators to find wire down events quicker, reducing public exposure to a potentially energized system.

Risk reduction

Since the fault location can be identified quicker, and the correct personnel deployed accurately and faster to that location, it will:

- Enable the organization to be better prepared for the future by offering more measures to mitigate/ decrease the risk of fires due to wire down or possibly other events, thus significantly reducing the overall risk that the company and its customers face as it relates to wildfire issues.
- Reducing the need for test closure could make us a more resilient utility by extending the life cycle of distribution equipment.

Metrics

Focused patrol training will allow for a quicker fault identification reducing the overall SAIDI and CAIDI.

Recent analysis showed that the troubleshooting time for a typical overhead outage that occurs on a distribution branch or circuit is approximately 84 minutes during working hours and approximately 111 minutes during non-working hours. This is the time measured from initial outage report to the time the outage cause was recorded by a troubleshooting crew. As described in ***Error! Reference source not found.***, that would be the elapsed time from T0 until T5. This excludes all outages that were local at a service transformer or secondary where there would be no patrolling time required.

The average time it took the troubleshooter to arrive and begin patrolling for these branch and circuit outages was 53 minutes during workhours and 73 minutes during non-workhours. As described in ***Error! Reference source not found.***, that would be the elapsed time from T0 until T4. Thus, actual patrol time averaged 31 minutes during working hours and 48 minutes during non-working hours. Since the additional data identified in this study will allow the fault location to be identified to a relatively small segment of line, the patrolling should be reduced to the just the time required to get to the predicted area and confirm and/or patrol the smaller segment. It is reasonable to assume that the additional information available will reduce patrol time by at least 66% since it is typical for the fault to be downstream of one of a multiple number of branches and the savings would be based upon not having to patrol all the possible branches, assuming an average of 3 potential branches and the ETS crew only having to travel to the fault on one the three branches. This results in a Customer Minutes of Interruption savings of 20.5 minutes for working hour outages and 31.7 minutes for non-working hour outages.

The number of branch and circuit outages that occurred was 497 outages during working hours and 602 outages during non-working hours. Using these numbers, it is possible to estimate what would be the potential impact on system SAIDI, including Major Event Days (MED), and excluding transmission and planned outages). The calculation is summarized in the table below.

Table 12 Calculation of potential SAIDI Impact

Item	Value	Combined	Working Hours	Non-Working Hours	Units	Notes:
1	Outage Start to Cause Determined (T0-T5)	97.5	84.0	111.0	minutes	From SDG&E data
2	(Outage Start to On Scene) T0-T4	58	53.0	63.0	minutes	From SDG&E data
3	Patrol Time (T5-T4)	39.5	31.0	48.0	minutes	Item 1 - Item 2
4	Reduction in Patrol Time	66%	66%	66%	percentage	Estimated, based upon average of 3 possible branches to patrol
5	Improved Patrol Time	13.4	10.5	16.3	minutes	Item 1 - Item 2
6	CMI improvement for branch and circuit outages	26.07	20.5	31.7	minutes	Item 3 - Item 5
7	2018 Distribution SAIDI (including MED, excluding transmission and planned outages)	73.9			minutes	From page 8 of SDG&E Electric Reliability Report for 2018
8	2018 CAIDI (including MED)	112.3			minutes	
9	2018 SAIFI (including MED)	0.7			interruptions /cust	

Item	Value	Combined	Working Hours	Non-Working Hours	Units	Notes:
10	# of customers served	1458900			# Customers	From 2018 Annual Report
11	Total CMI	107768943			Customer Minutes	Item 7 * Item 10
12	Total # of circuit and branch outages (Jan-Sept 2018)	1099			Interruptions	From SDG&E data
13	Estimated Full year	1465			Interruptions	Convert 9 months to full year, assume uniform
14	# of customers in average circuit/branch outages (customers)	500			# Customers	Estimated average size of circuit and branch outages
15	CMI improved	19100620			Customer Minutes	Item 6*Item 13*Item 14
16	New Total CMI	88668323			Customer Minutes	
17	Estimated New Distribution SAIDI (including MED, excluding transmission and planned outages)	60.8			minutes	
18	SAIDI improvement	13.1			minutes	

Using the Interruption Cost Estimate Calculator at http://icecalculator.com/home, which was developed by Lawrence Berkeley National Laboratory funded by the Department of Energy Office of Electricity the impact of the reliability improvement is valued at approximately $30M per year as shown in **Fig. 42**:

Sector	# of Customers	Total Benefit (2015$)	Benefit per Customer (2015$)		Year	Without Improvement (Baseline)	With Improvement	Total Benefit
Residential	1293600	3,031,730.92	2.34		2021	307,744,078.88	277,484,190.42	30,259,888.46
Small C&I	125189	85,064,766.16	679.49		2022	313,898,960.46	283,033,874.23	30,865,086.23
Medium and Large C&I	25511	167,961,979.90	6,583.90		2023	320,176,939.67	288,694,551.71	31,482,387.96
All	**1444300**	**256,058,476.98**	**177.29**		2024	326,580,478.46	294,468,442.75	32,112,035.72
					2025	333,112,088.03	300,357,811.60	32,754,276.43
					2026	339,774,329.79	306,364,967.84	33,409,361.96
					2027	346,569,816.39	312,492,267.19	34,077,549.20
					2028	353,501,212.72	318,742,112.54	34,759,100.18
					2029	360,571,236.97	325,116,954.79	35,454,282.19
					2030	367,782,661.71	331,619,293.88	36,163,367.83

Sector	# of Customers	Total Benefit (2021$)	Benefit Per Customer (2021$)
Residential	1,293,600	$3,031,730.92	$2.34
Small C&I	125,189	$85,064,766.16	$679.49
Medium and Large C&I	25,511	$167,961,979.90	$6,583.90
All	**1,444,300**	**$256,058,476.98**	**$177.29**

Fig. 42. ICE Calculator Benefits Report

The impact of the reduced usage of test closure to identify fault location, and the resulting longer asset life is not calculated, but it is a noted benefit not quantized, but likely to result in additional savings.

SECTION 6. CONCLUSION FROM FINDINGS

This project demonstrated that some fault locations are difficult to predict based on an impedance only model used by ADMS today. The demonstration showed how better leveraged data from smart devices can complement existing ADMS fault location analysis and outage prediction models to improve overall customer service reliability and restoration costs.

The findings will help operations determine the most likely fault location more quickly and more accurately. Using additional data will also require new user interface (UI) configurations to prevent clutter when multiple alarms and events have been ingested. We found that the ADMS system will need to progressively display the most important prioritized options throughout an interactive process as information becomes available. This can be performed through a manual processes and diligent training in the control room, but the real value is in automation with real-time device streaming and all data available in a single view.

Utilities can identify cost effective projects to deploy additional sensors and related collection systems as needed.

SECTION 7. COMMERCIAL ADOPTION RECOMMENDATION AND TECHNOLOGY TRANSFER PLAN

Commercial Adoption Recommendations

It is recommended that the stakeholder groups within SDG&E who participated in this project pursue commercial adoption by organizing a commercialization team and appointing one key stakeholder group to lead the effort. The following near-term steps for commercial adoption were identified, based upon the results of this project:

- Develop a commercialization plan.
- Establish and maintain a permanent Training Simulator in a non-production environment and mirror the production system
- Add new data sources to the production system (weather data, AMI low voltage, Wireless Fault Indicators)
- Maintain a regular training program for the operators, reviewing scenarios analyzed during this project
- Continue to investigate new scenarios and new data sources (including Phasor Measurement Unit (PMU) data) in the Training Simulator as a continuous improvement practice

Technology Transfer Plan

Plan for disseminating the project results

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs internally within the utility, among fellow utilities in California, and more widely to the industry. To facilitate this knowledge sharing, this report will be posted on SDG&E's EPIC website.

Plan for transitioning to commercial use

There are several areas of investigation that appear promising for future commercialization. One of the main outcomes of the project was the applicability of new telemetry and other alternate datasets. The project was able to leverage data from PMU's, power quality meters and wireless fault indicators, alongside extended data from feeder relays (CEV, COMTRADE). These new data sources not only provided additional relevant facts on their own, but combined with each other in a machine learning environment, showed great potential to provide detailed insights and predictive power that can be leveraged across multiple advanced applications. Commercialization efforts will be undertaken to productize integrations to these new device types and automate the data collection and processing. Data science techniques will be extended and enhanced to capture the potential value of the new data sources, including rapid identification and classification of fault types, accelerated diagnosis and elimination of potential patrol locations, and longer-term evaluation of equipment condition and remaining useful life more fully.

The additional data sources should have a significant improvement on overall outage restoration times, especially as they are integrated into the operator training program. Use Cases 1, 3, 4, and 6 will particularly benefit from these areas. Steps for commercialization should include:

1. Identification of existing network devices where untapped data could be easily integrated
2. Enhancement of integration to these devices to include the new data source(s)
3. Map the new data source(s) to their corresponding device models in the distribution management system

4. Enable and train the new algorithms
5. Identify viable and efficient FLA algorithms tailored for the SDG&E system
6. Incorporate new insights into the operator training program
7. Identify future sites where similar devices may yield high value

Much of the information contained in this report should be useful to other utilities, as well as SDG&E, regardless of the technologies being employed for distribution management and fault detection and location. Although several of the improvements in patrol activities were specific to the methods and procedures used by SDG&E, the goal of outage response across utilities is universal: safely restore service as quickly as possible to as many customers as possible. The methods, technology, and training tools can be readily applied by utilities and their technology partners to evaluate and improve their own performance, even those who are not using the same ADMS.

SECTION 8. REFERENCES

[1] Dobb, *S.B. 901. Wildfires.,* Sacramento: State of California, 2018.

[2] U.S. Department of Energy, "Fault Location, Isolation and Service Restoration Technologies Reduce Outage Impact and Duration," U.S. Department of Energy, 2014.

[3] K. Sun, Q. Chen and Z. Gao, "An Automatic Faulted Line Section Location Method for Electric Power Distribution Systems Based on Multisource Information," in *IEEE Transactions on Power Delivery*, 2016.

[4] A. Rahiminejad and B. M. Cockerham, "Using Analytic Assistant and SYNCHROWAVE Event 2015 to Create a COMTRADE File, SEL Application Note 2016-02," Schweitzer Engineering Laboratories, Inc., 2016.

[5] IEEE, "IEEE Standard C37. 111-2013, IEEE/IEC Measuring Relays and Protective Equipment - Part 24: Common Format for Transient Data Exchange (COMTRADE) for Power Systems.," IEEE, 2013.

[6] R. J. Laverty, P. Best, I. Brogan, A. Khatib, L. Vanfretti and D. J. Morrow, "The OpenPMU Platform for Open-Source Phasor Measurements," *IEEE Transactions on Instrumentation and Measurement,* vol. 62, no. 4, pp. 71-709, 2013.

[7] NASPI Distribution Task Team, "Syncrophasor Monitoring for Distribution Systems: Technical Foundations and Applications," NASPI, 2018.

[8] IEEE Power and Energy Society - Power Systems Relay Committee, "C37.244-2013 - IEEE Guide for Phasor Data Concentrator Requirements for Power System Protection, Control and Monitoring," IEEE, 2013.

[9] D. Bagley and D. Branca, "A New Approach to Find Fault Locations on Distribution Feeder Circuits," in *IEEE Rural Electric Power Conference*, 2007.

[10] S. Kulkarni, S. Karnik, S. Das and S. Santoso, "Fault location using impedance-based algorithms on non-homogeneous feeders," in *IEEE Power and Engineering Society General Meeting*, 2011.

[11] K. S. Das, N. Karnik and S. Santoso, "Distribution Fault Location Using Short-Circuit Fault Current Profile Approach," in *IEEE Power and Engineering Society General Meeting*, 2011.

APPENDIX A—USE CASES

Use Case #1 Wire Down - Description

This Use Case details the process, or steps taken during an indication of an electric power issue identified from data gathered by the network with input from devices and customers impacted by power interruptions. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. The purpose of the Use Case is to simulate events triggered during scenarios where an overhead wire is down, and the event is visualized by a System operator. To build this Use Case, SDG&E provided a real-world situation experienced on the Network. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and usage of existing information. The steps are captured below identifying the process performed. The goal of this Use Case is to assist the System operator to identify and isolate fault areas as quickly as possible. Once the hazard location is confirmed, conditions permitting, an optimal number of customers is restored through alternative power routing. During wildfire hazard conditions, minimal restoration may occur, and it is likely it will remain offline for the remaining duration of the event. Unknown damage could occur while the line is de-energized. If conditions are not extreme for wildfire, immediate restoration is more likely. After the fault is resolved, the System operator returns the system to normal conditions. This Use Case is intended to be used to simulate this process and document results.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Electric Trouble Shooter (ETS)	Person (crew of one qualified electrical worker)	Initial field staff sent to location to execute field operations, locate faults, and execute the operator's restoration plan
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Power Quality (PQ) Meter	Sensor	Field equipment used by SDG&E
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
Protective Device	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch with SCADA
PMU Data Concentrator (PDC)	System	Device that collects PMU generated data
RTAC Real Time Automation Controller	System	Device that gathers line data, and can be programmed to act on the data as a function of pre-determined routines
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system
Customer	Person	SDG&E electric customer
Caller	Person	Caller reporting an outage (customer and non-customer)

Triggers

This section details the triggers that can occur during the Wire Down scenarios. The triggers listed may occur in one or more scenarios and there is a "many to many" relationship between trigger events and Use Cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate.
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down, sending a PON (Power Off Notification)	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to PDC in the substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operated for safety and to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by Sustained outage (loss of current) generates an alarm that is reported asynchronously to OTV.	SDG&E has approximately 2300 devices. WFI will only report a fault followed by loss of current after 3 minutes. Current parameter settings are the default settings. Refer to: WSO-

Triggering Event	Primary Actor	Pre-Condition	Post-Condition	Additional Notes
				11_IM_20171010 OnRamp ver.pdf Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Provides Information stored in a flat CEV file. Tree structure, need to "walk" down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed/resolution current/voltage sampling	

Wire Down

The following scenarios have been identified for the Use Case produced based on current state workshops completed:

- Trip/reclose – A SCADA monitored/controlled breaker or Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled breaker or Recloser trips open and fails to successfully reclose after a pre-determined number of attempts. (Number of attempts may be ZERO)
- Non-SCADA device operates – no SCADA information available to detect the fault or to know real-time status closed/open, load, voltage, real/reactive power, etc.
- No SCADA trip, no fuse, protective relay, or circuit breaker operation – Issue on the line but no protection device operates (ex: conductor failure with insufficient fault current to operate fuse or other device)

The following sections details the scenarios above listing the sequence of events that takes place during the fault restoration process.

Trip & Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered Protection device (namely an auto reclosing breaker or line recloser) opens and successfully recloses. In this scenario a wire is down, the device opened and reclosed, but the fault was not cleared and another protection device (i.e., a fuse) has operated clearing the fault downstream. Power is still provided upstream from the clearing protective device and the Recloser is closed and live.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has automatic reclosing enabled (configured in NMS as momentary capable)	Present practice in the HFTD fire tiers is to not attempt *automatic* reclosing year-round.
2	NMS	A timer is started to time the ARP within NMS	ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
3	Protective device	ARP closes the device automatically. NMS is aware via SCADA, but no action taken	
4	NMS	The NMS timer expires, and device remains closed. ARP is complete.	Assuming a device downstream operates clearing the fault. If a line is down and no downstream devices operate, the recloser would not successfully reclose
5	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
6	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from the Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
7	System Operator	The operator can display the possible locations based on distance to fault calculations, on the NMS network diagram and use this to start the patrols by foot, truck, or aircraft.	
In this scenario, to allow the reclose to be successful, it is assumed a downstream device has operated. This could result in operators receiving alerts related to low Ampere measurements at the feeder head due to lack of load further downstream. ***It is assumed that although the auto-recloser successfully closed, there is still a downstream outage. Steps to identify and resolve this outage are detailed in the following use cases. The type of downstream device will determine which use case applies (i.e., Telemetered/tele-controlled (SCADA) device, or manual only device)***			

Step #	*Actor*	*Description of the Step*	*Additional Notes*
8	System Operator	The operator takes the necessary actions to complete the RMO capturing relevant data for reporting and audit purposes	Typically, this will be complete on the resolution of the downstream outage. Until the downstream outage is identified, it is unknown if the recloser needs to be operated again to allow remedial work

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose one or more times, trips a final time and stops in an open and locked out state.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP	
2	NMS	A timer is started to time the ARP within NMS	
3	Protective device/NMS	Before the ARP timer is complete, the protection device trips open again	
4	Protective device/NMS	AR Processing will attempt to reclose again (this can happen 1 or 2 times before a lockout state, or if it is a one-shot configuration no reclose happens)	
5	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
6	NMS	NMS creates a RDO associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the Work Agenda	
As the recloser has locked out, the outage is confirmed, and the scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

This scenario describes the triggers and Systems available to the system operators for fault location detection (in this case a wire down) and the steps the system performs to aid the system operators in this analysis.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of a fault current	Operators/NMS are not aware of this situation currently
2	SCADA	Measurements at the feeder head may break limits due to loss of load downstream. Operators will be alerted to these breaches	This step may be present but will depend on the limit settings and amount of load lost. This information is unlikely but possible
3	System Operator	Acknowledges the fact that limits have been breached (if reported)	
4	WFIs	**Sustained** loss of current messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts shown in WFI/On Ramp if currents drop below about five Amps.	
5	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
6	NMS	Several meter “no voltage” messages (PON’s) are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception where only 1 meter is associated with a transformer) -
7	NMS	Based on the meter messages, a predicted outage (PDO) is created, and the predicted device is determined	
8	System Operator	Operator investigates the messages and the information in the PDO. Based on this information, they send a Trouble Shooter out to the device identified by NMS as the source	
9	Customer	A number of customers call in reporting loss of power or interruption to power	

Step #	*Actor*	*Description of the Step*	*Additional Notes*
10a	NMS	Assuming meter information has already been received, the calls will be associated with the existing PDO. Call areas may change the scope of the predicted outage.	
10b	NMS	If no meter information is received, the PDO will be created based on the call information	
11a	System Operator	Based on the calls reported the system operator sends out a Trouble Shooter (ETS) to the predicted fault location ****Note – if meter information is received then a trouble-shooter may already be enroute so no need for this step. Alternatively, if further information from callers is received (i.e., I can see a broken wire, etc.) a second trouble-shooter may be sent to the location of the reported wire down***	Location/wire down information may not be available at this point (i.e., if no one has called)
11b (Exception path)	System Operator	An emergency call may come in from the emergency services (or other callers) reporting sparking wire/dangerous situation.	
11c (Exception path)	System Operator	If step 11b exists, the Operator may operate the next upstream SCADA device to de-energize the section of network identified. This would potentially cause a greater outage scope, but it is necessary to make the area safe as soon as possible.	
12	Trouble Shooter	The trouble shooter(s) arrives on-site and reports information back to the system operator. (i.e., The state of the predicted device, the location of wire(s) down, etc.)	
13	System Operator	Based on information from the trouble shooter, the system operator will update the PDO to confirm the fault location or to re-direct the trouble shooter to find the downstream fault (in this case wire down).	If the fault is not found at this stage, the trouble shooter may have to "walk/drive the line" to find the potential fault area. This could be a time-consuming exercise depending on the information available, nature of terrain, etc.
14	System Operator	Once the fault area has been identified, the operator will dispatch a crew to the area to isolate the fault area and to re-energize sections of network where possible to re-connect customers. Crew dispatch, etc. will be managed via the NMS system. Visual representation of the	

Step #	***Actor***	***Description of the Step***	***Additional Notes***
		fault area can be shown on the diagram. In some cases, troubleshooters may isolate.	
15	System Operator/field crews	Once the fault is identified and supply is restored to as many customers as possible, the system operator will work with the available crews to repair the faulty section and restore the network to normal configuration.	
Alternative sources of information: To speed up the fault-finding process, the system operators have other sources of information at their disposal. Note, this information is not sent to the NMS system. This is a “go get” situation to potentially narrow the search for the Trouble Shooters. The alternative sources of information follow.			
16	System Operator	The system operator can ping meters on the line to help narrow down the fault area. This information can be used to estimate the type of fault and the phases affected.	
17	Callers	As the investigation continues, more calls can be received giving more details of the outage – i.e., potential location information based on observations from the public or emergency services	
18	System Operators	With information from these other sources, the system operators can perform Fault type analysis (phase to phase, phase to ground) to help determine fault type. This information may narrow down the search. For example, if it’s a phase-to-phase fault then it can’t be on a single-phase network area as found through the process of elimination.	Information for fault finding may involve downloading of information from relays at substations. This may involve sending technicians to these sites to download and send information via email or other means. Some information may also be automatically emailed to the Control room. This would require the system operators to be monitoring emails during a fault situation.

Breaker Does Not Trip and Fuse Does Not Operate

After review, it was determined that the scenario for this condition is the same as the "Non-SCADA Device Operates" scenario.

High Impedance faults are good examples of faults where protection devices do not operate. The fault current looks like an increase in load and is typically not high enough to cause these devices to operate. In these cases, the line would still be energized and will cause hazards. Examples of high impedance faults include:

- Wire down and resting on a building
- Wire down and resting on a road or the pavement
- Wire down on dry paving, rocks, or sand

Use Case #2 - Proactive Fault Detection Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use Case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location and ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating fault areas as quickly as possible.

The following notes were captured during the SDG&E Use Case Workshops:

- Instantaneous detection of failures
  - Example: A conductor experiences a break due to unknown physical stress (car-hit-pole, tree branch falling through the wire, gunshot damage, etc.). Many of these failures cannot be prevented, but the project will investigate the possibility of detecting this situation using high-speed sensors to de-energize the conductor prior to it striking the ground, causing an arc, and becoming a fire and/or public safety hazard.

- Prediction of near-term failures
  - Example: Utility infrastructure experiences wear and tear due to both normal operations and fault operations, requiring periodic inspection and maintenance. In many cases these points of failure, such as loose ties, broken crossarms, worn contacts, etc., are often not detected prior to causing a fault. The research project will investigate the possibility of detecting leading indicators of these types of failures so that the equipment may be safely repaired or replaced beforehand on a planned basis.

- Estimation of equipment loss of life
    - Example: Utility infrastructure weakens over time due to loading, weather, and other factors. Many factors such as corrosion due to coastal exposure, conductor annealing due to short-term high overloads, etc., may not be fully captured and modeled by asset management systems. The research project will investigate the use of operational data to enhance equipment aging and failure models to improve capital and maintenance spending with the goal of reducing overall equipment failure rates.

Actors

The following table describes the Actors that are present throughout the Use Case within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages, and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the ADMS, AMI, and SCADA.
Line Crew	Person(s)	Person working alone or with other personnel to operate the distribution system under the direction of a system operator
Equipment Inspector	Person	Person working alone or with other personnel to inspect distribution and/or substation equipment for maintenance, repair, and/or replacement
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indictors (FCI)	Sensor	Devices that sense and report when a preset level of fault current occurs at a point on the system
Power Quality (PQ) Meter	Sensor	Power Quality Meter – high resolution waveform data
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device control, most often working in conjunction with circuit breakers or switches.
PMU Data Concentrator (PDC)	System	System that collects PMU generated data.
RTAC Real Time Automation Controller	System	Device that gathers line data, and can be programmed to act on the data as a function of pre-determined routines
OTV (Onramp Total View)	System	Fault indicator data management system.
Distribution Planner	Person	Individual in charge of capacity planning for the distribution system.
Maintenance Engineer	Person	Individual in charge of planning maintenance and capital replacement for the distribution system.
Enterprise Asset Management System (EAM)	Application	A combination of systems, services and software to control assets and equipment.

Triggers

This scenario is not a current part of operations and is a part of maintenance and planning.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that start the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Fault	Service restorers, feeder breakers, Individual device fuses, line fuses, line switches (SCADA only)	Overcurrent occurs	device operates to clear the fault	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Fault	AMI	May see a partial dip or all loss of power. Will see the effect of the fault.	Will see the effect of the operation.	AMI sends event on loss of power and voltage alarm. Not all events will be

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
				received. All voltage and power alarms are received near real time (within a minute).
Fault	PMU	PMU data captures 30 samples per second and sends to distribution substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energized the line.	Line is de-energized.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault	WFI	Sustained outage following a fault, or a sustained loss of current is reported asynchronously to OTV. The data then goes from OTV to the message bus. Currently the data is not getting into NMS.		SDGE has approximately 2300 devices. WFI will only report a loss of current after 3 minutes. Current parameter settings are the default settings.
Fault	Advanced Protective Relay Fault Records	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been sent. Information is also stored in a database.		May not be available at the time of the fault. Could create an email box with an API to send a notification.
Fault	Power quality monitors	Picks up harmonic information, high speed current/voltage sampling		

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
Data Threshold Exceeded	RF Early Fault Detection System	Analyze RF signature of downstream equipment as indicators for potential faults.		
Operations	NMS	Equipment information. Ex: number of operations		Coordination device operations with system conditions (line regulators)
Construction	GIS/NMS	Date of installation.		
Inspections	GIS/NMS	Field inspections		
Study	NMS	Use existing NMS tables to gather information on historical overloads/violations that may be a factor for degradation		
Study	NMS	Coordinate device operations with weather data		Flat files are being sent to NMS
Study	Maintenance/Planning	Is it possible to use/access the information? What information is available that could be used? Discuss to see how NMS data is used historically.		

Step by step analysis

Scenario 1: Instantaneous detection of failure

Example: A conductor experiences a break due to unforeseen physical stress (car-hit-pole, tree branch falling through the wire, etc.). Many of these failures cannot be prevented, but the project will investigate the possibility of detecting this situation using high-speed sensors to de-energize the conductor prior to it striking the ground, causing an arc and becoming a fire and/or public safety hazard.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Conductor breaks	Conductor breaks due to physical stress or unknown defect	
2	Phasor Measurement Unit (PMU)	Phasor Measurement Unit continuously measures voltage and current magnitudes and phase angles	Sends output to the RTAC
3	Power Quality Meter (PQM)	Power Quality Monitor continuously measures waveforms and harmonic content of current and voltage waveforms	Sends output to the RTAC
4	RTAC Real Time Automation Controller	Based on data from PMUs and/or PQMs, RTAC (potentially) detects an instantaneous change in the current, voltage, and/or harmonic measurements to reliably indicate that a component has failed downstream	If this can be detected and analyzed quickly enough, a trip command to open the breaker can be sent directly to the Advanced Protective Relay
5	Advanced Protective Relay	Instantaneously trips and remains open	If this can be detected and acted upon quickly enough, no fault will occur

Scenario 2: Prediction of near-term failures

Example: Utility infrastructure experiences wear and tear due to both normal operations and fault operations, generally requiring periodic inspection and maintenance. In some cases, these points of failure, such as loose ties, broken crossarms, worn contacts, etc. are not detected prior to them causing a fault. The project will investigate the possibility of detecting leading indicators of these types of failures so that the equipment may be safely repaired or replaced beforehand.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Scheduled line inspector	This scenario is not a current part of operations, is a part of maintenance and planning.	Usually driven by GO 165 requirements
2	Line crew	Makes note that a device is not operating properly as part of routine operations (sticky/mis-adjusted switch, etc.), running hot per recent IR check.	Added to NMS as an operational note
3	Equipment inspector	Reports typical or atypical wear and tear on a piece of equipment	Added as a condition assessment in the EAM
4	SCADA	Reports routine measurements from various sensors that are temporarily out of normal tolerances but do not cause a fault condition	Sent to historian but generally not acted upon immediately
5	PQ Meter	Continuous reporting of power quality data	
6	PMU	Continuous reporting of phasor measurement data	
7	Advanced Protective Relay	Generation of fault record after each fault event	Recorded in Advanced Protective Relay fault record system, including oscillography
8	RTAC	Collection of PQ and PMU data	Collects and transmits PQ/PMU data
9	WFI	Indication of faults beyond a point in the network	Also, a source of low-resolution load data reported synchronously
10	NMS and Analytics	Collection of loading, power flow, and fault data from any/all the above sources; could be able to record which devices/conductors were put under stress due to experiencing through-faults (even if they did not fail immediately)	Applying machine learning or other analytics, it may be possible to detect aberrant behavior of devices that could indicate a failure soon

Scenario 3: Estimation of equipment loss of life

Example: Utility infrastructure weakens over time due to loading, weather, and other factors. Many such factors such as corrosion due to coastal exposure, conductor annealing due to short-term high overloads, etc., may not be fully captured and modeled by asset management systems. The project will investigate the use of operational data to enhance equipment aging and failure models to improve capital and maintenance spending with the goal of reducing overall equipment failure rates and unplanned service interruptions.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Scheduled line inspectors	This scenario is not a current part of operations, is a part of maintenance and planning.	Usually in compliance with GO 165
2	Line crew	Makes note that a device is not operating properly as part of routine operations (sticky/mis-adjusted switch, etc.)	Added to NMS as an operational note
3	Equipment inspector	Reports typical or atypical wear and tear on a piece of equipment	Added as a condition assessment in the EAM
4	SCADA	Reports routine measurements from various sensors that are temporarily out of normal tolerances but do not cause a fault condition	Sent to historian but generally not acted upon immediately
5	PQ Meter	Continuous reporting of power quality data	
6	PMU	Continuous reporting of phasor measurement data	
7	Advanced Protective Relay	Generation of fault record after each fault event	Recorded in Advanced Protective Relay fault record system, including oscillography
8	RTAC	Collection of PQ and PMU data	Collects and transmits PQ/PMU data
9	WFI	Indication of faults beyond a point in the network	Low resolution load data available synchronously
10	NMS	Power flow calculations	
11	Maintenance Engineer	Analyzes available data from condition-based maintenance and other sources and systems.	

Use Case #3 Foreign Object Faults Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use Case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identify the process performed to identify the issue, location, and then to restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

This Use Case details the scenario where Foreign Objects are found tangled in overhead lines. This stems from the frequency at which so-called Mylar (celebratory) balloons are left untethered and float into the O/H lines and become tangled. The metallic “foil” coating and helium gas of these balloons conducts electricity and can cause electrical outages when they encounter the O/H network. There is also a real fire risk as contact from these objects can cause sparking. There have also been incidents of explosions when contact is made near an O/H transformer. In 2017, there were over 100 incidents of this type of contact.

Actors

The following table describes the Actors that are present throughout the Use Case within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	Systems	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisor Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control room
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Indictor	Sensor	Provides local indication when fault above a given threshold occurs at a strategic point on the system
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device control, most often working in conjunction with circuit breakers or switches.
Protective Device.	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch (SCADA only)
PMU Data Concentrator (PDC)	System	System that collects PMU generated data

Triggers

This section details the triggers that can occur during the Foreign Object in Lines scenarios. The triggers listed may occur in one or more scenarios. There are many relationships between trigger events and user cases.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to PDC in the substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operated to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by Sustained outage generates an alarm that is reported asynchronously to OTV.	SDG&E has approximately 2300 devices. WFI will only report a loss of current after 3 minutes. Current parameter settings are the default settings Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.

Triggering Event	Primary Actor	Pre-Condition	Post-Condition	Additional Notes
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current and voltage waveform data.	

Foreign Object in Lines

The following scenarios have been identified for the Use Case, derived from workshops completed based on existing conditions:

- Trip/reclose – A SCADA monitored/controlled Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled Recloser trips open and fails to successfully reclose after a pre-determined number of attempts.
- Non-SCADA device operates – no SCADA information available to detect the fault
- No SCADA trip, no fuse operation – Issue on the line, but no protection device operates

The following sections detail the scenarios above listing the sequence of events that takes place during the service restoration process.

Trip and Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered protection device (namely an auto reclosing breaker) opens and successfully recloses.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Foreign Object	A foreign object (e.g., Foil Balloon/tree/animal) hits a line and causes fault current	This event is unknown to the Operator currently
2	Recloser/protection device	The SCADA Recloser detects the fault current and trips open	
3	NMS	A timer is started to time the ARP process within NMS	Recloser is configured as a momentary capable device

Step #	***Actor***	***Description of the Step***	***Additional Notes***
			ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
4	Recloser/protection device	The recloser closes automatically. NMS is aware via SCADA, but no action taken	
5	NMS	The NMS timer expires, and the device remains closed. ARP is complete	
6	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
7	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from the Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
8	System Operator	The operator can display the possible locations based on "distance to fault" calculations, on the NMS network diagram and use this to start patrols.	
9	NMS	Power quality events may be raised by customers. Depending on the NMS configuration and the time of the call, they may be associated with the RMO or handled via a new event	
In this scenario, it is assumed the foreign object has cleared from the line and the fault condition is gone. At this point, the system operator is unaware of what caused the fault (i.e., he/she does not know it's a balloon in the line and has now cleared. ***Should there be a further downstream outage, the operator will be made aware via meters or customer calls. Refer to Use Case 1 – Wire down for further information***			

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose one or more times, trips a final time, and stops in an open and locked out state.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Foreign Object	A foreign object (e.g., "Mylar" Balloon) hits a line and causes a fault current	
2	Recloser/protection device	The SCADA Recloser detects the fault current and trips open	
3	SCADA Fault Detector	The SCADA Fault Indicator reports a fault, and the fault is shown in NMS. The NMS shows how many phases were faulted and if the fault was phase to ground.	
4	NMS	A timer is started to time the ARP process within NMS	Recloser is configured as a momentary capable device
5	Protective device/NMS	AR Processing will attempt to reclose again (this usually happens 2 to 3 times before a lockout state)	
6	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
7	NMS	NMS creates an RDO (Remote Device Operated) associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the Work Agenda	
As the recloser has locked out, the outage is confirmed, and scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI and WFI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

This scenario describes the triggers and Systems available to the system operators for fault location detection (in this case foreign object in line) and the steps performed to aid the system operators in this analysis.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary, is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of fault current	Operators/NMS are not aware of this situation currently
2	SCADA	Measurements at the feeder head may break limits due to loss of load downstream. Operators will be alerted to these breaches	This step may be present but will depend on the limit settings and amount of load lost. This information is unlikely but possible
3	System Operator	Acknowledges the fact that limits have been breached (if reported)	
4	WFIs	Sustained “no current” messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts will be shown in NMS. Current must fall below a threshold of about five Amps.	
5	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
6	NMS	Several meter no voltage messages are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception

Step #	***Actor***	***Description of the Step***	***Additional Notes***
			where only 1 meter is associated with a transformer)
7	NMS	The meter information is associated with the RDO event	
8	System Operator	Operator investigates the messages and the information in the RDO.	
9	System Operator	The operator dispatches a trouble shooter to the Protection device to confirm the status open/closed and patrol the lines downstream to try and determine the fault location	
10	System Operator	The operator continues the investigation using information obtained from other systems. - CEV flat files from Advanced Protective Relays and notification of file availability is sent to operators - The WFI/OTV system can be interrogated to help narrow down the fault location - Fault analysis is conducted. The type of fault may also reduce the volume of fault location predictions. - FLA activation may occur displaying predicted locations based on distance to fault information and the network model information (NMS)	
11	Customer	Several customers call in reporting loss of power or partial power.	
12	NMS	All relevant calls from customers within the outage scope are automatically associated with the RDO	
13a	System Operator	As the investigation continues and further calls are logged, the operator may re-direct the trouble shooter to the most likely location	
13b (exception path)	System Operator	An emergency call may come in from emergency services (or other callers) reporting sparking wire/dangerous situation.	

Step #	***Actor***	***Description of the Step***	***Additional Notes***
13c (exception path)	System Operator	If step 13b exists, the Operator may operate the next upstream SCADA device to de-energize the section of network identified. This would potentially cause a greater outage scope but is necessary to remove the hazard safely, and quickly.	
14	Trouble Shooter	The trouble shooter(s) arrives on-site and reports information back to the system operator. (i.e., location details and fault cause)	
15	System Operator	Once the fault area has been identified, the operator will dispatch a crew to the area to isolate the fault area and to re-energize sections of the network where it is possible to restore customers. Crew dispatch will be managed via the NMS system. Visual representation of the faut area can be shown on the diagram.	
16	System Operator/field crews	Once the fault is identified and supply is restored to as many customers as possible, the system operator will work with the available crews to repair the faulted section and restore the network to normal configuration	
Alternative sources of information: To speed up the fault-finding process, the system operators have other sources of information at their disposal. Note, this information is not sent to the NMS system. This is a “go get” situation to potentially narrow the search for the Trouble Shooters. The alternative sources of information follow.			

Breaker Does Not Trip and Fuse Does Not Operate

This scenario details steps taken when a power quality issue occurs or there is a visual reported network issue that does not result in a power outage and protective devices have not operated.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary, is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*
1	N/A	A celebratory balloon floats into the overhead network bridging live phases (or phase to grounded hardware) and causing sparking.	Balloon coating (metalized) and helium is highly conductive
2	N/A	No protection device activates and no breaker trips and the supply is not compromised. No fault current is detected.	
3	WFI	Sustained "no current" messages will be received from WFI devices in the field if they are present in the scope of the network. Alerts will be shown in NMS	
4	Caller	A member of the public (first responder or a customer) calls in detailing sparking coming from an overhead line giving the location of the sparking	
5	Customer Service Rep.	The call taker receiving the call, logs the information in the web Call Entry system	
6	NMS	The NMS system creates a "NO" (No Outage) event based on the call information. The network model is updated with the information from the call	
7	System Operator	The system operator dispatches a Trouble shooter to the location as described in the call	
8a	Trouble Shooter	The trouble shooter reports no foreign object in line and all lines energized and operating as expected. Troubleshooter MAY find evidence of balloon or other remnants on the ground.	

Step #	***Actor***	***Description of the Step***	***Additional Notes***
	System Operator	Taking advice from the trouble shooter, the operator closes the incident with no further action	
8b	Trouble Shooter	The Trouble Shooter reports a foreign object in the line and confirms a dangerous condition with sparking.	
	System Operator	The operator updates the event with information from the Trouble Shooter	
	System Operator	Based on the information supplied, the operator plans activities to isolate the area of network. Crews are dispatched to isolate and to resolve the issue.	
	System Operator	These are managed via the PSO event to calculate and record outage information, resolution information and any follow-up work required.	
	System Operator	On completion of the work, the operator instructs the field crews to restore the network to normal condition.	
Due to the nature of the foreign object, in this case a celebratory balloon, the situation can change if the object moves. This could cause further automatic operations. For example, a phase-to-phase fault, should the object come into contact with 2 wires. The outcome of such events could cause protection devices to operate and de-energize a section of the network. The use case for this is covered previously depending on the device that operates (i.e., SCADA or non-SCADA)			

Use Case #4 Tree Vegetation Contact Description

This Use Case details the process, or steps taken during an indication of an electric power issue identified from data gathered from the network input from customers impacted from power interruptions. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. The purpose of the Use Case is to simulate events triggered during scenarios where an overhead wire is down, and the event is visualized by a System operator. To build this Use Case, SDG&E provided a real-world situation experienced on the network. The situations were discussed during workshops held to gather information regarding the existing processes, sources of data and usage of existing information. The steps captured below identify the process performed. The goal of this Use Case is to assist the System operator in how to identify and isolate fault areas as quickly as possible and restore an optimal number of customers through alternative power routing, if available. After the fault is resolved, the system operator restores the system to normal conditions. This Use Case simulates this process and documents the results.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	***Actor Type (person, device, system etc.)***	***Actor Description***
Advanced Distribution Management System (ADMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Metering Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network.
OTV (Onramp Total View)	System	Fault indicator data management system.
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
Protective Device	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch (SCADA Only)
PMU Data Concentrator (PDC)	System	System that collects PMU generated data

Triggers

This section details the triggers that can occur during the Wire Down due to vegetation contact scenarios. The triggers listed may occur in one or more scenarios and there is a "many to many" relationships between trigger events and user cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Continuous monitoring.	PMU	PMU data captures 30 samples per second and sends to distribution substation. Then RTAC logic looks for differential (runs through 3 or 4 scenarios) and de-energizes the line.	Differential is detected and device operates to protect the system.	Information goes to Advanced SCADA. NMS doesn't receive the alarm information but receives the device operation.
Fault current detected.	WFI	System operating normal.	Over current (Fault level) followed by sustained outage generates an alarm	SDG&E has approximately 2300 devices. WFI will only report a loss of

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
			that is reported asynchronously to OTV.	current after 3 minutes. Current parameter settings are the default settings. Currently the data is not getting into NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email notification is sent to notify that a file has been added. Information is also stored in a database.	May not be available at the time of the fault. Could create an email box with an API to send a notification. No information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current voltage waveforms.	

Use Case #5 - System Overload Mitigation Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location, and ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

The goal of the system operator is to identify these situations, ascertain the cause, and take corrective action as needed to ensure that as many customers as possible remain energized and the distribution system infrastructure is properly protected. Once the overload condition is corrected, the system operator monitors the situation to take further action if necessary. Once the loading has abated, the operator returns the system to its normal configuration. Ideally, the overload is mitigated with no outages to customers

This Use Case details the scenarios for System Overload Mitigation.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Information System (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
OSISoft PI Historian (Historian)	Application	Data archive system
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Line Crew	Person	Individual(s) working alone or with other personnel to operate the distribution system under the direction of a system operator; includes both electric troubleshooters (ETS) and repair crews
WFI	Sensor	Wireless Fault Indicator – sends status alarm using dedicated RF network to confirm if fault currents were witnessed from strategic points on the distribution network. Also, WFI provide low resolution load data synchronously every 24 hours.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Protective Relay	Sensor/Actuator	Advanced Protective Relay, Fault Relay – microprocessor controlled protective device, most often working in conjunction with circuit breakers or switches.
OTV (Onramp Total View)	System	Fault indicator RF Network and data management system

Triggers

This section details the triggers that can occur during the System Overload Mitigation scenarios. The triggers listed may occur in one or more scenarios and there are many relationships between trigger events and Use Cases.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Distribution transformer experiences overload	System Operator	System operating normally, but loading increases due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	Transformer experiencing oil and insulation degradation due to excess heat from electrical loading over its steady-state operational limit.	
Downstream device experiences overload condition that is detected by SCADA (threshold is exceeded causing alarm in real time)	System Operator	System operating normally, but loading increases due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	Device experiences high temperatures and electrical stress, potentially causing immediate failure or otherwise accelerating need for replacement; mitigation steps have taken place such as switching and/or load curtailment	SCADA alarms and PI e-mails are generated to initiate the process of overload mitigation
Downstream device experiences overload condition	System Operator	System operating normally, but loading increases	Device experiences high temperatures and electrical stress,	Customer calls are often the initiating event but are not

Triggering Event	Primary Actor	Pre-Condition	Post-Condition	Additional Notes
that is not reported by SCADA		due to some stimulus such as abnormally cold or warm weather, or cloud cover restricting output of DER	potentially causing immediate failure or otherwise accelerating need for replacement; mitigation steps have taken place such as switching and/or load curtailment	reliable for overload detection
Circuit breaker or substation bus experiences reverse power flow	System Operator	System operating normally, but generation downstream of the breaker or substation bus has exceeded the current load, for example due to mild, sunny weather on a bank holiday in an area of high solar penetration	Circuit breaker or substation bus experiences power flow in the reverse direction	No action taken currently. Often no action is necessary.

System Overload Mitigation

Distribution substation transformer overload

- Have "watch list" limits for summer with switching steps to off load (shifting load among adjacent circuits/substations). In some cases, to prevent issues, proactively shifting loads.
- List is provided in the summertime on a weekly basis
- Electric Vehicles do not affect load, they charge at night when TOU rates are beneficial. Do not have to notify utility if they have an EV. Will have to notify utility if they replace/upgrade panel. Don't have to notify if they add a circuit to an existing panel.
- Has over 1600 megawatts of solar on their system, adding 15-20 MW every month (over 2000 projects per month)
- Use overall system load, review peak loads, review anything that controls the voltage
- This happens while everyone is busy, crew resources may be difficult to find.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*

Step #	*Actor*	*Description of the Step*	*Additional Notes*
1	Advanced Protective Relay or other line or device sensor	Sends loading data and/or alarms to SCADA	Limits are seasonal
2	SCADA	Triggers an overcurrent alarm if data exceeds a preset threshold SCADA data sent to PI database	PI most likely uses this data to make longer-term assessments of substation transformer loading conditions
3	AMI	Sends periodic usage information to AMI system.	Information available for distribution line transformer load management
4	WFI	Load data from WFI is available every 24 hours, in one-hour increments.	
5	Weather Station Data	Meteorology data.	
6	Historian	PI sends email to leadership	PI identifies overloaded assets using data from SCADA; will need to understand if other data sources such as AMI are also considered
7	System Operator	Determines either through direct SCADA alarm or loading calculations that overload exists or will occur. Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load plans, NMS suggested switching done under real time.
8	System Operator	If no steps are necessary, there may be a device giving false reads, there may be some maintenance work being done; operator makes note	Operator is aware of maintenance if NMS has switch plans
9	System Operator	If steps are necessary, analysis/trend has happened for several days, may shift load by proactively switching	Review watch list suggested switching and plan day of week, time of week, for plan of action.
10	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration.	May run abnormal for duration of summer
11	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

Overload rapidly approaching limits (SCADA)

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Advanced Protective Relay or other line or device sensor	Sends loading data and/or alarms to SCADA	Limits are seasonal
2	SCADA	Triggers an overcurrent alarm if data exceeds a preset threshold SCADA data sent to PI database	
3	WFI	Load data from WFI available every 24 hours in one-hour increments	
4	Weather Station Data	Meteorology data.	
5	System Operator	Determines either through direct SCADA alarm or loading calculations that overload exists or will occur. Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load plans, NMS suggested switching done under real time.
6	System Operator	If no steps are necessary, there may be a device giving false reads, there may be some maintenance work being done; operator makes note	Operator is aware of maintenance if NMS has switch plans
7	System Operator	If steps are necessary, analysis has happened for several days, may shift load by proactively switching	Reactive situation, not involving days of watching/analysis. Watch list will not be used in this situation.
8	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration.	May run abnormal for the duration of summer
9	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

Non-SCADA overload

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Customer Contact Center	Receives customers calls, enters call information into CIS and/or Trouble Call Entry	A couple of calls are not on the operator's "radar". Mostly happen on 4kv circuits. Main customer complaint during overload is lower voltage
2	NMS	Receives call information from customer calls and creates non-outage event	
3	System Operator	Checks current weather conditions	If weather is in the extreme, then we know it may be overload.
4	System Operator	Operator investigates and if necessary, takes steps to alleviate the overload	Use NMS switch plans, DER load profile, NMS suggested switching done under real-time.
5	System Operator, Line Crew	ETS is sent to investigate overload conditions and report back	
6	System Operator, Line Crew	If steps are necessary, may upgrade fuse, if that does not work, may shift load to adjacent circuit, if feasible	Reactive situation, not involving days of watching/analysis. Watch list will not be used in this situation.
7	System Operator	When the event subsides (ex: temperature moderates), network is returned to normal configuration (if applicable)	May run abnormal for duration of summer
8	System Operator	If other mitigation steps do not relieve the overload condition, consider load shed	Discussion between manager & operator

System Overload Mitigation Reverse Flow

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Advanced Protective Relay	Reverse real power flow detected that exceeds acceptable limit.	Reports to SCADA
2	SCADA	Creates alarm condition that reverse flow has been detected	
3	System Operator	Operator acknowledges alarm	Just for awareness, no other action taken

Use Case #6 – Underground Distribution Description

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The Issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during Workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed identify the issue, location and restore power. The Use Case details are designed to be used as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolate fault areas as quickly as possible.

This Use Case details the scenario where a fault is detected in the underground network. The underground network accounts for approximately 60% of the existing distribution network. Faults on this part of the network are typically phase-to-ground faults. The common faults are a result of:

- Cables deteriorating over time (moisture ingress common on older cables)
- Connector failures (due to defect during manufacture or installation and with age)

Such underground outages are most commonly phase-to-ground faults. Faults can sometimes be associated with significant rainfall leading to water integrity issues for connectors. “T” connectors are more prone to fail than the feeder cables themselves. The number of these devices on the network is so great that cost effective replacement via maintenance programs is not achievable.

With underground faults there is potentially less information available. This is due to a lack of visibility of the fault area (as opposed to the overhead network where you might get information from passers-by seeing a wire down or arcing/sparking).

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS) - Outage Management System (OMS)	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	Constant connection to SCADA capable devices to monitor and control.
System Operator	Person	Individual in charge of distribution operations and user of the Distribution Management System (DMS) and Outage Management System (OMS)
Trouble Shooter (ETS)	Person	Initial field staff sent to location to execute field operations, locate faults, and execute the operator's restoration plan
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indicators (FCI)	Sensor	The indicators used in the Underground distribution network are basic devices that will indicate the presence of a fault current. Typically, these will be indicated by a semaphore or flashing light. They are not presently wireless.
Protective Device.	Sensor/Actuator	Service restorers, feeder breakers, Individual device fuses, line fuses, vacuum/gas/air switch, (SCADA only)
PQ Meter	Sensor	Field equipment used by SDG&E

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Fault Location Specialist	Person	Expert team with specific equipment and training to find locations of underground faults
Trouble Shooter	Person	First crew on the scene. Investigates potential fault locations and confirms protection operations or not

Triggers

This section details the triggers that can occur during the Underground fault scenarios. The triggers listed may occur in one or more scenarios and there are many relationships between trigger events and Use Cases.

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	Device opens to protect the network assets from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate.
Power Out condition occurs at some meters.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received.
Under voltage condition occurs at some meters.	AMI	System operating normal.	Sustained under voltage detected and message sent to AMI system.	Sustained voltage duration and voltage limit set in firmware. Not currently sent to NMS.
Fault current detected.	Advanced Protective Relay	System operating as normal.	Information stored in a flat CEV file. Tree structure, need to walk down the tree to find. Files are automatically sent, and an email	May not be available at the time of the fault. Could create an email box with an API to send a notification. No

Triggering Event	*Primary Actor*	*Pre-Condition*	*Post-Condition*	*Additional Notes*
			notification is sent to notify that a file has been added. Information is also stored in a database.	information is sent to NMS.
Continuous monitoring.	Power quality meters	System operating as normal.	Picks up harmonic information, high speed current and voltage waveforms.	

Underground Distribution Network Faults Scenarios

The following scenarios have been identified for the Use Case based on current state workshops completed:

- Trip/reclose – A SCADA monitored/controlled Recloser trips open and successfully recloses
- Trip/lockout – A SCADA monitored/controlled Recloser trips open and fails to successfully reclose after a pre-determined number of attempts.
- Non-SCADA device operates – no SCADA information available to detect the fault

The following sections detail the scenarios above listing the sequence of events that takes place during the restoration process.

Trip and Successful Reclose

This scenario details the actions, inputs and received information in a scenario where a SCADA controlled/telemetered Protection device (namely an auto reclosing breaker) opens and successfully recloses. In this scenario the recloser opened and reclosed but the fault was not cleared and another protection device (i.e., a fuse) has operated clearing the fault downstream. Power is still provided upstream from the clearing protective device and the reclosing device is closed.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc., may also be noted in this column.*

Step #	***Actor***	***Description of the Step***	***Additional Notes***
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP (configured in NMS as momentary capable). First reclose is at 5 seconds, second shot is at 45 seconds to allow downstream automatic isolation to occur.	
2	NMS	A timer is started to time the ARP within NMS.	ARP – Auto reclose process – the process associated with equipment that can automatically reclose when tripped open
3	Protective device	ARP closes in the device automatically. NMS is aware via SCADA, but no action taken	
4	NMS	The NMS timer expires, and device remains closed. AR process is complete.	Assuming a downstream device operates clearing the fault.
5	NMS	NMS creates a Real Momentary Outage (RMO) recording the fact that an Auto-recloser operated and successfully reclosed.	
6	NMS	NMS creates one or more predicted fault locations and visually indicates potential locations on NMS model upon fault current measurement from Advanced Protective Relay. NMS generates an additional alert for the operator from the FLA function.	
7	System Operator	The operator can display the possible locations based on distance to fault calculations, on the NMS network diagram and use this to start the patrols.	
In this scenario, to allow the reclose to be successful, it is assumed a downstream device has operated. This could result in operators receiving alerts related to low measurements at the feeder head due to lack of load further downstream. ***It is assumed that although the auto-recloser successfully closed, there is still a downstream outage. Steps to identify and resolve this outage are detailed in the following use cases. The type of downstream device will determine which use case applies (i.e., Telemetered/tele-controlled (SCADA) device, or manual only device)***			
8	System Operator	The operator takes the necessary actions to complete the RMO capturing relevant data for reporting and audit purposes	Typically, this will be complete on resolution of the downstream outage. Until the downstream outage is identified, it is

Step #	*Actor*	*Description of the Step*	*Additional Notes*
			unknown if the recloser needs to be operated again to allow remedial work

Trip & Lockout

This scenario details the steps and triggers for an event where an auto-recloser trips, attempts to reclose several times, trips a final time and stops in an open and locked out state.

Step #	*Actor*	*Description of the Step*	*Additional Notes*
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	Telemetered Protection device trips open on fault. NMS is aware via SCADA of the trip. No action at this point as the device has ARP	
2	NMS	A timer is started to time the ARP within NMS	
3	Protective device/NMS	Before the ARP timer is complete, the protection device trips open again	
4	Protective device/NMS	AR Processing may attempt to reclose again	
5	Protection device	Protection device trips open for the final time in the AR process. The breaker remains open and in a lockout state. AR processing is complete	
6	NMS	NMS creates an RDO associated with the protection device. Details of the operations are recorded including time of the first event. Scope of the outage is calculated based on the NMS model and a visual indication of the scope is present on the viewer. The event is listed in the work agenda	
As the recloser has locked out, the outage is confirmed, and scope identified. From this point, the operators will carry out various activities to identify the fault area and take corrective action. The NMS system will receive several AMI messages where possible and potentially customer/non-customer calls with information related to the wire down. ***The identification actions are documented in the following use cases.***			

Non-SCADA Device Operates

The following scenario describes the steps to resolve an underground network fault event. The initial steps describe how information is obtained via SCADA on a protection device during an unplanned operation. Protective devices do not always operate, and the issue could be that a downstream non-SCADA event has occurred with no notification from SCADA. In this situation, due to a loss of load measured by SCADA at the feeder head, limits may be breached indicating something downstream has operated.

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	A manual (non-SCADA) protection device on the network operates due to the detection of a fault current	Operators/NMS are not aware of this situation at this time
2	FIs	Where present on the network, FIs will activate.	These FIs are visual indicators only. No information is sent to systems within the Control Center
3	AMI	Messages from the AMI system are sent to the NMS system to make operators aware of the outage	
4	NMS	Several meter "no voltage" messages are received from the AMI system	Meter Power Off messages will be subject to filtering rules, for example: - Less than 10 minutes of outage start time - If more than one Power Off message exists and are within 90 seconds of each other (exception where only 1 meter is associated with a transformer)
5	NMS	Based on the meter messages, a predicted device outage (PDO) is created, and the predicted device is determined	

Step #	*Actor*	*Description of the Step*	*Additional Notes*
6	System Operator	Operator investigates the messages and the information in the PDO. Based on this information he sends a Trouble Shooter out to the device identified by NMS as the source (predicted device)	
7	Customer	Several customers call in reporting interruption to power	
8	NMS	The received calls are automatically associated with the outage event assuming they are within the same scope of network	
9	System Operator	The system operator shares the location of underground FIs and instructs the Trouble shooter to investigate	
10	System Operator/NMS	The system operator analyses the data received to narrow down the fault location. The operator then dispatches a Fault location specialist to find the exact fault location	
11	System Operator/NMS	Once the fault location is identified, the operator instructs crews to various locations to isolate the fault area and to restore as many customers supply as possible. The NMS system is updated throughout restoration to maintain a record and keep operators up to date on progress	
12	System Operator	The operator then plans and works with the field crews to repair the fault (i.e., replace the damaged cable)	

Use Case #7 High Voltage (Primary Metered) Customer Problem

This Use Case details the process performed during an electric power issue on the grid and the steps taken to resolve the issue and/or complete the restoration during a power outage. The Issue is analyzed by system operators using data gathered from the network and other communications such as customers reporting a power outage. The inputs to the Use Case are called Actors and the name, type and description of these Actors are described in the table below. To build this Use case, SDG&E provided a real-world network issue experienced by system operators. The situation was discussed during Workshops held to gather information regarding the existing processes, sources of data and how the information is used by the system operators. The steps are captured below identifying the process performed to identify the issue, location and then to ultimately restore power. The Use Case details are designed to use as a step-by-step simulation guide to explore options and simulate a process assisting the System operators in identifying and isolating faulted areas as quickly as possible.

This Use Case details the scenarios for managing a primary metered customer outage. A Primary Metered Customer is a single customer (for example an Industrial Unit) or a private customer network. The responsibility of the Distribution company is to ensure power to the connection point from the network to the customer. Any issues/maintenance within the private network is the responsibility of the customer.

Actors

The following table describes the Actors that are present throughout the Use Cases within this document. Actors include people, systems, devices, and sensors in or affected by the functions.

Actor Name	*Actor Type (person, device, system etc.)*	*Actor Description*
Advanced Distribution Management System (ADMS	System	A subsystem that is responsible for managing outages including outage grouping of calls and AMI events, confirmation of outages and tracking of assigned crew resources and completion of outage restoration details.
Automated Meter Infrastructure (AMI)	System	The AMI system gathers, and stores information supplied by Smart Meters. It also can ping meters on request, to verify status.
Supervisory Control and Data Acquisition (SCADA)	Application	SCADA controlled/telemetered devices connected to control systems within the control center
System Operator	Person	Individual in charge of distribution operations and user of ADMS and SCADA
Phasor Measurement Unit (PMU)	Sensor	Device that gathers higher resolution line data
Fault Current Indictors (FCI)	Sensor	Fault current indicators
PQ Meter	Sensor	Power Quality Meter

Triggers

This section details the triggers that can occur during the primary metered customers scenario. The triggers listed may occur in one or more scenarios and there is a many to many relationships between trigger events and Use Cases.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***	***Additional Notes***
(Identify the name of the event that started the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*	*Elaborate on any additional description to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
Overcurrent condition detected.	Protective Device.	System operating normal.	device opens to protect the system from the fault.	Every one of these devices will see the fault, but when properly coordinated, only one device will operate
Power Out condition occurs at meter.	AMI	System operating normal.	Loss of voltage detected, and message sent to AMI system. Meter powers down.	AMI sends event on loss of power and voltage alarm. Not all events will be received. All voltage and power alarms are received near real time (within a minute).

Primary Metered Customer Problem

The following scenario has been identified for the Use Case produced based on current state completed:

- Primary Metered Customer Outage – A Primary Metered customer network is experiencing an outage

The following section details the scenario above listing the sequence of events that takes place during the service restoration process.

This scenario details the processes involved in investigating a Primary Metered Customer outage. In this case, the Primary Metered Customers network is not represented in the network model, however, the utility owned switchgear distributing power to the Primary Metered Customer is modelled and potentially has SCADA. *Not all primary metered customers are served through SCADA capable devices.*

Step #	***Actor***	***Description of the Step***	***Additional Notes***
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Protection device	The protection device owned by the customer operates (trips open). Alternatively, a utility owned/operated device immediately ahead of the customer trips. In extreme cases, service to other customers may be interrupted.	
2	NMS	The NMS system receives a trip open from the protection device at the customers location via the SCADA system and creates an event	In the event there is no SCADA information, the Operators will receive notification via a call
3	System Operator	The operator checks the feed going to the switch gear and confirms, *where possible* that the feeder is energized	
4	System Operator	Where possible, the operator calls the Primary Metered Customer to discuss the fault condition. Any actions are recorded in the NMS event	
5	System Operator	If required, the system operator dispatches a Trouble Shooter direct to the Primary Metered Customer site to confirm power is coming in from the feeder side of the switch gear. The actions are recorded in the event in NMS	
6	Trouble shooter	The trouble shooter confirms to the Primary Metered Customer that the supply is good and advises they contact their electrician to diagnose and resolve a potential down-stream incident or an issue with their switch gear.	
In the scenario where the system operator or Trouble Shooter discovers there is a loss of power to the feed for the Primary Metered Customer, the steps in the related use case “UC01 – Wire-down” would be followed to identify and resolve the fault condition.			