

Catching Falling Conductors in Midair – Detecting and Tripping Broken Distribution Circuit Conductors at Protection Speeds

William O'Brien, *San Diego Gas & Electric Company*

Eric Udren, *Quanta Technology, LLC*

Kamal Garg, Dennis Haes, and Bala Sridharan, *Schweitzer Engineering Laboratories, Inc.*

Abstract—When an overhead electric power distribution circuit conductor breaks—for example, when a car strikes a pole or a splice or clamp fails—the energized conductor falls to ground. The resulting high-impedance ground fault may be difficult or impossible to detect by relays located in the substation. In any case, no ground fault protection relay can operate until well after the time the fault has occurred—after the falling energized conductor has hit the ground and created a hazardous situation. For decades, utilities and equipment manufacturers have worked to develop methods for tripping these hazardous ground faults as quickly as possible.

This paper describes a new falling conductor detection scheme that trips the affected circuit section in the narrow time window between the moment of the break and the time the conductor hits the ground. The affected circuit section is de-energized while the conductor is still falling, eliminating the risk of an arcing ground fault or energized circuits on the ground.

I. INTRODUCTION

When an overhead electric power distribution circuit conductor breaks—for example, when a car strikes a pole or a splice or clamp fails—the energized conductor falls to ground. The resulting high-impedance ground fault may be difficult or impossible to detect via electrical changes monitored by relays and protective devices located in the substation or along the distribution circuit. In any case, no conventional protective device can operate until well after the time the fault has occurred—after the falling energized conductor has hit the ground and created a hazardous situation. The problems with detection and de-energization of downed conductors have plagued the electric utility industry for decades [1].

Utilities and protection equipment manufacturers have worked to develop methods for tripping these hazardous ground faults as quickly as possible once they occur. Detection is never assured since a live conductor can land on high-resistivity earth or on a dry asphalt or concrete surface. There may be no solid electrical signature, yet a nearby witness would see dramatic arcing.

By contrast, this paper describes a new falling conductor detection scheme that identifies the break of a phase conductor and trips the affected circuit section in the narrow time window between the moment of the break and the time the conductor hits the ground. The affected circuit section is de-energized within the milliseconds during which the conductor is falling, eliminating the risks of an arcing ground

fault underneath the distribution line or of energized conductors on the ground.

The falling conductor detection scheme discussed in this paper is one of many functions on a system platform consisting of circuit intelligent electronic devices (IEDs) with the ability to stream phasor measurement unit (PMU) data and substation controllers with high-speed Ethernet radio communication. The scheme detects conductor breaks on circuits with high penetration of distributed generation (DG), as well as those with the utility substation as the only power source.

The development team validated the scheme and its detection algorithms using closed-loop Real Time Digital Simulator (RTDS®) testing as well as staged conductor break tests on a live 12 kV distribution feeder. The scheme is now in trial service on a San Diego Gas & Electric Company (SDG&E) distribution circuit; several more installations will be in service by the end of 2016.

This paper presents the design of the integrated distribution protection and control system on which the falling conductor detection algorithms are implemented. It gives an overview of the falling conductor detection algorithms and describes the differences between fault and open-conductor detection. This paper presents the overall testing approach and concludes with a discussion of benefits and limitations.

II. OVERVIEW OF THE SDG&E ADVANCED SCADA DEVICES (ASD) PROJECT

The State of California has mandated that by 2020, 33 percent of all energy generated in California will be delivered from renewable energy resources [2]. Most of this new generation will be supplied by customers or alternative energy suppliers directly to the distribution system. The bulk of this renewable energy supply is comprised of variable and unpredictable sources, predominantly photovoltaic (PV) and wind generation. Radial distribution circuits and substation designs were not designed to handle the resulting operating conditions, such as large, variable PV sources that feed into the utility system. In-service voltage control equipment may not be able to keep customer voltage supply within the specified range. Power quality may be degraded by large bidirectional inverters delivering or consuming energy. Fault detection and tripping may be compromised by these

additional sources whose designed fault responses have evolved in recent years from immediate disconnection in the face of a circuit disturbance to a role of fault ride-through and sustained delivery of fault current.

The proliferation of large PV sources on SDG&E distribution circuits, along with growing focus on supporting microgrid operation at selected sites, has led to a complete reevaluation of the methods by which the distribution system is to be monitored, controlled, and protected in the future.

A. Applications

The project team began by defining over 60 use cases, or application-oriented function description documents, for capabilities they sought in a new distribution circuit protection, automation, and control (PAC) scheme. The major use-case categories include the following:

- Falling conductor protection.
- Voltage profile monitoring, control, and presentation.
- Accurate and selective load shedding and restoration strategy that considers DG sources.
- Power quality monitoring and power apparatus condition monitoring.
- A secure communications system that enables remote event report retrieval, remote settings, and remote firmware updates.
- Monitoring and alarming for the PAC system equipment itself, including its communications infrastructure.

Implementations of many of the listed use-case categories are still under development. However, SDG&E has assigned high priority to the category of fault protection functions, with a special focus on the need to reduce the impact of downed-conductor events. When the project investigators invented the concept for high-speed detection of a conductor break with tripping of the affected circuit before the conductor falls to the ground, this methodology received special attention during development of the system architecture and selection of the platform equipment.

B. System Architecture

The ASD Project combines three new technical components in an integrated circuit monitoring, protection, and control concept:

- IEDs capable of synchrophasor measurements, IEC 61850 Generic Object-Oriented Substation Event (GOOSE) high-speed status and control messaging, and DNP3 measurement and control, along with event file transfer that modern substation IEDs already provide. Synchrophasor capability means that each IED serves as a PMU in addition to its other functional capabilities. Circuit PMU IEDs include recloser controllers, capacitor bank controllers, switch controllers, voltage regulator controllers, and power quality meters, along with the substation protective relay on the breaker of the subject circuit.
- Substation controllers that include the functions of a phasor data concentrator (PDC), application

measurement and logic processing, IEC 61850 GOOSE publication and subscription, and data presentation to servers at the distribution control center (DCC).

- Ethernet communications paths among the circuit IEDs and substation controllers. For urban distribution circuits, the paths are optical fibers. For suburban and rural feeders, ASD functions require wideband Ethernet radio systems, operating between the substation and the circuit IEDs to support synchrophasor value streaming at 30 to 60 measurement sets per second, and IEC 61850 GOOSE control point transfer in 10 to 20 milliseconds.

Fig. 1 shows an example SDG&E 12 kV distribution circuit with an approximate 12-mile reach, similar to the one on which the first ASD system has been deployed. SDG&E has deployed seven PMUs on the first trial circuit and may install dozens in later, fully instrumented circuit applications. The substation breaker relay is one of the PMU IEDs incorporated in the overall feeder PAC system.

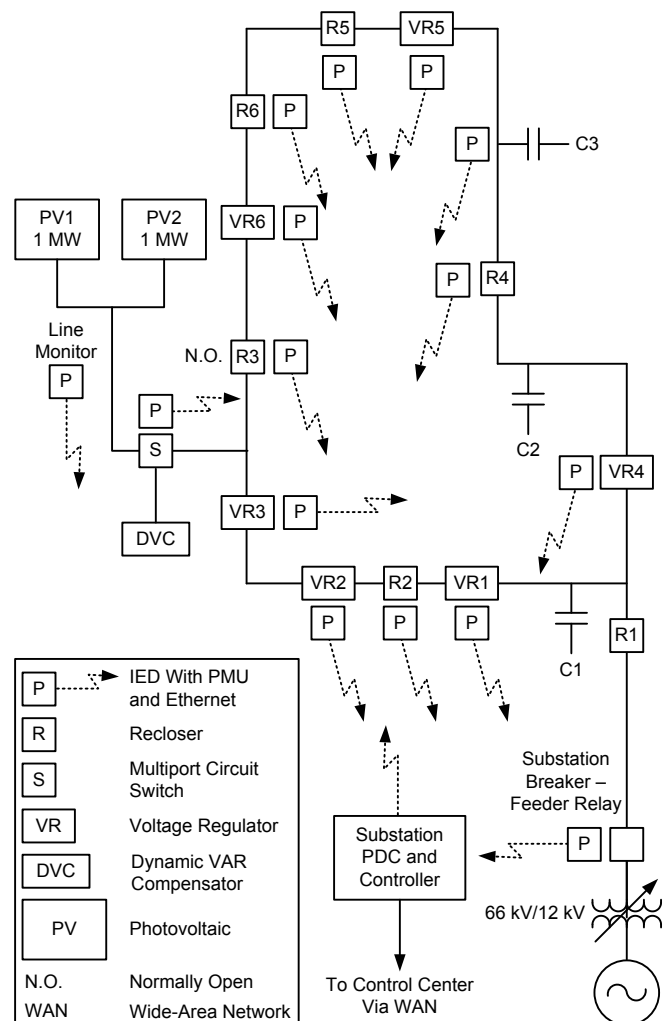


Fig. 1. Example deployment of PMU IEDs

Fig. 1 shows the Ethernet radio paths between each PMU IED and the substation controller. The first working installation uses a combination of wideband mesh radio nodes

supplemented with point-to-point links to handle communications in mountainous terrain. Other feeders now being equipped with ASD systems have point-to-multipoint radio systems. SDG&E benefits from multiple radio technologies to handle the terrain demands and spectral limitations across 1,100 distribution circuits.

Each PMU IED streams synchrophasor measurements of phase voltages, phase currents, real and reactive load flow, frequency, and rate-of-change of frequency (ROCOF) over the Ethernet radio or fiber path to the substation controller at a rate of 30 measurement packets per second from each IED. Also included in each synchrophasor packet are binary values that include apparatus state or position, IED status reports, and communications monitoring binary values.

The substation controller includes a PDC for gathering, aligning, and short-term archiving of time-tagged phasor values from the array of circuit IEDs. Aggregated arrays of circuit phasor measurements are transferred to a substation controller that implements control and protection algorithms or logic and that also formats data for transmission to the control center. In new installations, the PDC and controller functions are being combined in a single high-performance substation controller unit. The PDC and controller are connected to an ASD substation local-area network (LAN) Ethernet switch along with the host node of the circuit radio system.

The substation feeder relays also include the PMU function. They communicate with the PDC and controller via fiber connections to the substation LAN rather than by a radio path.

The Ethernet radio or fiber paths also convey control messages and other traffic from the substation to the circuit IEDs. The ASD Project controllers use IEC 61850 GOOSE message publication to issue high-speed status reports or trip commands to subscribing IEDs along the distribution circuit. Section VI gives additional details about the design of data communications services.

Because the ASD Project equipment will also support the control center information displays, processing, and circuit control, the substation controller also serves as a data concentrator, sending processed circuit data back to servers at the control center. Additionally, it serves as the path through which operators or centralized utility control functions can direct the behavior of circuit devices and systems. Ethernet WAN infrastructure connects the ASD controllers to control center servers for operator displays, system-wide control, and central historian functions.

C. New Architecture for Distribution PAC Data Flow

It is important to note that the ASD Project architecture for distribution PAC has evolved to a fundamentally different data flow than is typical in today's distribution automation (DA) systems.

Today's control centers typically communicate directly with circuit IEDs via a low-speed SCADA radio or fiber system (with a typical update or response time of 1 to 5 seconds for control and monitoring only). By contrast, the

control center communicates with an ASD-equipped feeder through an Ethernet connection to the substation controller. The substation controller, along with its high-speed local circuit PAC functions, serves as a data concentrator and provides remote terminal unit (RTU) functionality in a hierarchical scheme for system-wide distribution system control.

In-service protective relays and reclosers perform their fault protection functions via coordination of time curves among devices and with branch fuses. ASD protection retains these coordination features of familiar designs as it adds new protection functions based on high-speed communication among PMU circuit devices and substation relays. The high-speed communications among circuit devices support fault protection on circuits with a high penetration of DG. They also support the falling conductor detection scheme explained in this paper.

III. TYPICAL DISTRIBUTION SYSTEMS

In power distribution systems with voltages ranging from 4 kV to 34.5 kV, high-impedance faults (HIFs) have challenged utilities and researchers for years. HIFs are faults on distribution feeders with fault currents below traditional overcurrent relay pickup settings. Fallen power conductors on poorly conductive surfaces, tree branches brushing against power lines, and dirty insulators are all potential causes of HIFs, which have such small fault currents that they generally do not affect power distribution system operation. However, HIFs caused by downed power conductors are a major public safety concern. If not promptly cleared, these faults can be hazardous. There have been a number of documented cases of costly litigation as a result of damage from undetected downed power conductors [1] [3] [4]. Single-phase loads and multiple return paths for unbalanced currents are two major factors contributing to the difficulty in detecting these faults [1]. Beyond ensuring coordination with downstream devices and fuses and avoiding pickup on cold loads and transformer inrush, one must avoid false tripping by setting conventional ground overcurrent protection above the maximum foreseeable unbalance. Thus, overcurrent protection is ineffective in detecting HIFs. The proposed method avoids these faults altogether by tripping before the conductor reaches the ground.

The SDG&E distribution system consists of over 22,000 miles of lines. Approximately 60 percent are underground and 40 percent are overhead. There are three voltage levels: 12.47 kV, 12.0 kV, and 4.16 kV, with 12.0 kV being the most common. Of the overhead portion of the distribution circuits, there are both three-wire and four-wire configurations. The system is grounded at substations, pad-mount devices, substructures, SCADA devices, and cable poles. SDG&E has both wye and delta voltage regulators. The utility has an average annual peak of 4,500 MW and annual sales of approximately 20-billion kWh and serves customers in San Diego and the southern portion of Orange County, including about 25 communities. SDG&E has 393 MW of net energy metering (NEM) renewables connected to its system

across almost 60,000 participating customers with an average of 15 MW per month being added, the majority being rooftop PV solar. Renewable energy sources, mainly wind and solar, currently supply 33 percent of the SDG&E system load.

IV. SYSTEM GROUNDING AND HIF DETECTION

This section discusses various grounding methods. In North America, utilities primarily use solidly grounded, high-resistance or ungrounded distribution systems. Distribution systems use different grounding methods to achieve the following objectives [3]:

- Minimize equipment voltage and thermal stress.
- Provide personnel safety.
- Reduce interference to communications systems.
- Assist with quick detection and isolation of ground faults.

Other factors such as overall system cost and service delivery reliability also influence the selection of grounding methods.

Over time, distribution systems have used many grounding methods including the following:

- Ungrounded or isolated neutral.
- Resonant grounding.
- High-resistance grounding.
- Effective (solid) grounding (includes ungrounded or multigrounded systems).
- Low-impedance grounding.

The first three grounding methods (ungrounded, resonant, and high-resistance) have similar characteristics. We sometimes refer to first grounding method as low-current grounding. By contrast, we refer to the last two grounding methods (effective and low-impedance grounding) as high-current grounding.

A. Low Ground Fault Current Systems

Ungrounded systems, as Fig. 2 shows, have no intentional grounding. Fault resistance and stray capacitances of distribution transformers and feeders determine the ground fault current, which is normally quite small. Some of the benefits of ungrounded systems include minimum equipment thermal stress, continued service during single-line-to-ground fault conditions, and self-extinction of ground faults when the capacitive fault current is low.

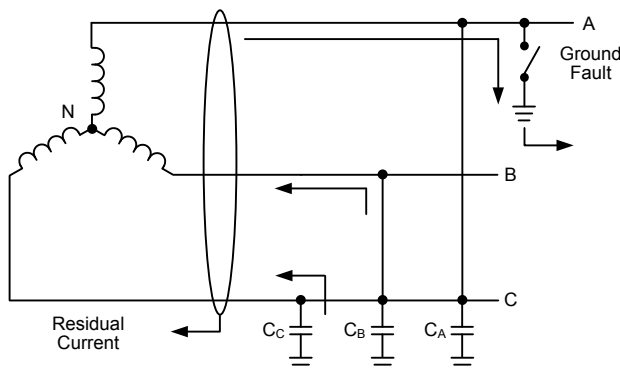


Fig. 2. An ungrounded distribution system

The three grounded schemes (ungrounded, resonant, and high-resistance) limit ground fault primary current to less than 10 amperes and pose a challenge for selective and fast ground fault protection.

B. High Ground Fault Current Systems

Effectively grounded systems comply with $(X_0/X_1) \leq 3$ and $(R_0/X_1) \leq 1$ [3] [5], where X_0 and R_0 are the zero-sequence reactance and resistance, and X_1 is the positive-sequence reactance of the system [5]. Solidly grounded systems have their neutral point of the station transformer or a grounding transformer connected to ground without intentional grounding impedance. Some systems have a single grounding point typically at the station transformer neutral point. Fig. 3 shows a multigrounded distribution system.

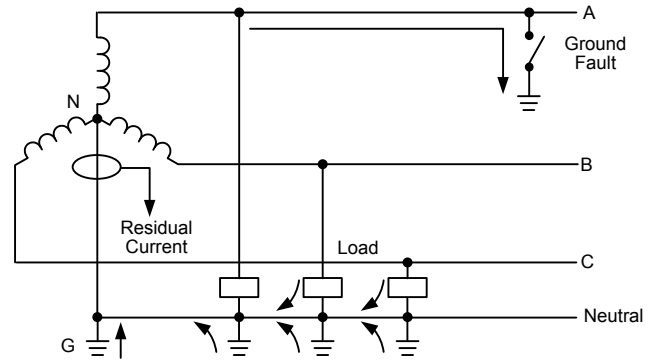


Fig. 3. A multigrounded distribution system

To reduce the ground fault current level for systems with low zero-sequence source impedance, we can use a resistor or a reactor to ground the station transformer. This low-impedance grounding typically limits fault current to 100 to 1,000 amperes to reduce thermal stress on equipment.

V. FALLING CONDUCTOR AND HIF DETECTION

The falling conductor detection method de-energizes the falling conductor before the conductor touches the ground and causes an HIF.

Note that HIFs have fault current less than 10 amperes. To detect these faults, the traditional HIF protection methods apply detection algorithms that use current waveform signature instead of current magnitude. Arcing activity often accompanies HIFs because of poor conductor contacts to the ground surface or because of poor conductivity of the ground surface itself. These arcing activities, together with the dynamic nature of the HIF, are responsible for the large harmonic and nonharmonic content in the fault current. For this reason, most HIF detection algorithms use the harmonic or nonharmonic content of the fault current.

A. Falling Conductor Versus HIFs

Many technologies for detecting HIFs include statistical hypothesis tests, inductive reasoning, expert systems, neural networks, third-harmonic angle analysis, wavelet decomposition, decision trees, and fuzzy logic [4]. Regardless of the many available advanced detection algorithms, the detection of HIFs remains a challenging problem [3] [5].

Because detecting HIFs is challenging, this paper investigates the benefit of falling conductor detection versus HIF detection. The falling conductor detection method uses patterns of changes in voltage synchrophasors to detect the falling conductor in the milliseconds following the break.

The falling conductor detection methods can trip the affected circuit section well before the conductor hits the ground to initiate an HIF. Hence it can avoid the problems of HIF fault detection.

B. Synchrophasor Basics

Synchrophasors are widely used today to monitor the state of the power transmission system. However, as variable generation (PV, wind, and energy storage) is being integrated more at the distribution voltage level, synchrophasors will play a vital role in the monitoring and control of distribution systems in the near future.

IEEE Standards C37.118-2005, C37.118.1-2011, and C37.118.2-2011 define synchronized phasor measurements as well as the message format for communicating these data in a real-time system. While most people think of these standards with regard to sending time-coherent voltage and current phasors, IEEE C37.118 messages can be used to provide much more information (such as additional analog data, digital status information, and control signals) as part of the synchrophasor packet.

A phasor is a representation of a voltage or current of the ac system and can be represented in the steady state by a sinusoidal function. Fig. 4 shows an example of a sinusoidal voltage function called $v(t)$, with a period of T seconds.

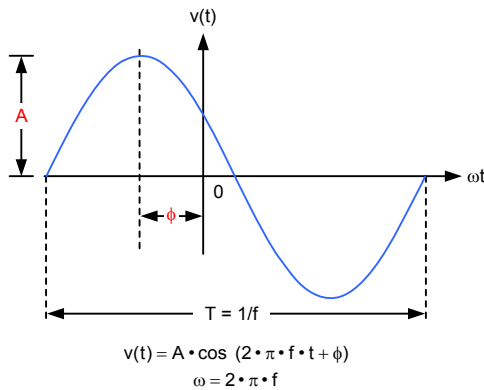


Fig. 4. Sinusoidal voltage time waveform

Phasor measurements are particularly useful when the measurements across a large physical area are time-synchronized from a common reference such as a precision Global Positioning System (GPS) or a common time distributed over the communications network. Then phase angles of measurements from diverse locations on a circuit or system can be directly compared to observe phase differences and changes in real time. Synchrophasors measured according to IEEE C37.118 specifications bring this capability.

It is anticipated that by 2020, 33 percent of all energy provided to customers in California will be delivered from renewable energy resources [2]. More and more renewable energy sources mean less rotating mass. Traditional grids are

designed to have a lot of inertia, which allows the system to absorb and recover from disturbances. Most of this generation is planned to interconnect at the distribution voltage level. The California Public Utilities Commission (CPUC) is evaluating smart inverters with control systems and various protocols. It is imperative that synchrophasor measurements be incorporated in the design of the smart and future distribution grid.

Some synchrophasor applications include the following:

- State measurement
- Real-time monitoring (V, I, P, Q, and f)
- Power system model validation
- Situational awareness
- System restoration
- Stability analysis

Traditional information management systems and protocols (e.g., DNP3 and Modbus[®]) communicate updated information every few seconds to every few minutes. Additionally, the data are not time-coherent or may not be even time-stamped, making it difficult to accurately compare system conditions among different locations at a particular instant. Using synchronized measurements helps overcome these shortcomings and provides many additional benefits. One possible application is to use synchrophasor measurements for dynamic model verification [2]. The SDG&E distribution synchrophasor project has already yielded multiple advantages, including situational awareness, voltage profile presentation, and load monitoring across the circuit. One specific example is the detection of bad voltage sensors on the reclosers, which is discussed in Section VII.

VI. DESIGN DETAILS

Fig. 5 shows the conceptual communications diagram. All PMUs observe the system voltages and provide PMU data to the central controller via radios. Local PMUs are connected to the LAN via fiber, while remote PMUs communicate via Ethernet radios. The PDC aligns all of the PMU data and provides the information for analysis to the central controller, which processes the information and provides GOOSE commands to remote PMUs for action if any falling conductor is detected [6] [7]. The central controller also provides data for remote and local monitoring, in addition to archiving the data for future analysis.

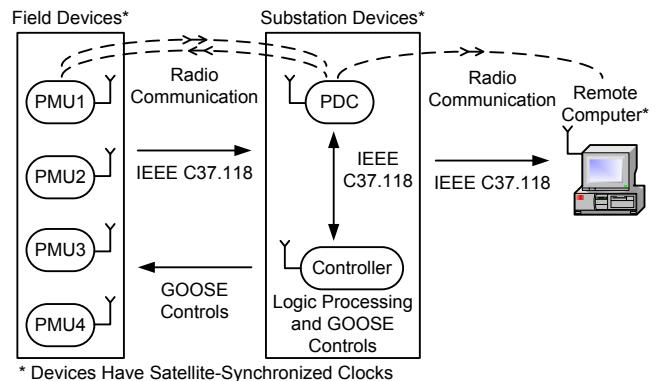


Fig. 5. Simplified system communications diagram

A. Detection Methods

Synchrophasor measurements from the PMUs located on the power distribution circuit are conveyed to PDCs for time alignment [6]. The time-aligned data are monitored in real time in the central controller for detecting falling conductor events that may occur on the distribution circuit. The voltage sequence components along with derivatives of the phase voltages are calculated in the PDC. These calculated quantities are monitored for abnormalities that have the specific behavior patterns of falling conductor faults.

The system uses three methods for detecting falling conductors:

- dV/dt
- V_0 and V_2 magnitude
- V_0 and V_2 angle

B. dV/dt Method

The rate-of-change of per-phase voltage magnitude with respect to time (dV/dt) detects the falling conductor in distribution circuits. The dV/dt signatures at PMUs on opposing sides of the break have opposite polarity. When the dV/dt value rises above the threshold value, a supervision check is performed with the help of the dV_0/dt threshold. When all of the above conditions are satisfied, the controller issues trip commands to the PMU IEDs controlling the interrupting devices that straddle the apparent break location.

C. V_0 and V_2 Magnitude Methods

The V_0 and V_2 sequence voltage magnitudes are other algorithms for detecting falling conductor events. For a falling conductor event in a given phase, occurring between two PMU locations, the PMU farther away from the source has a steep increase in the V_0 and/or V_2 magnitude compared with the PMU closer to the source. When the sequence voltage magnitude rises above the threshold value and persists for a given time duration, the observance of a falling conductor fault is confirmed and trip commands are issued to the interrupting devices associated with the PMUs.

D. V_0 and V_2 Angle Methods

In addition to sequence magnitude methods, the controller also implements sequence components angle methods. If a break occurs, phasor sequence measurements from PMUs on the two sides of the break location show specific angular relationships that point to the falling conductor location.

Fig. 6 shows the example of the data flow and detection algorithm implemented for this application. All four PMUs will provide IEEE C37.118 formatted data to the central controller. As shown in this example of a falling conductor

location, adjacent PMUs, such as PMU1 and PMU2, will correctly identify and issue a GOOSE command to the adjacent devices to open and clear a falling conductor.

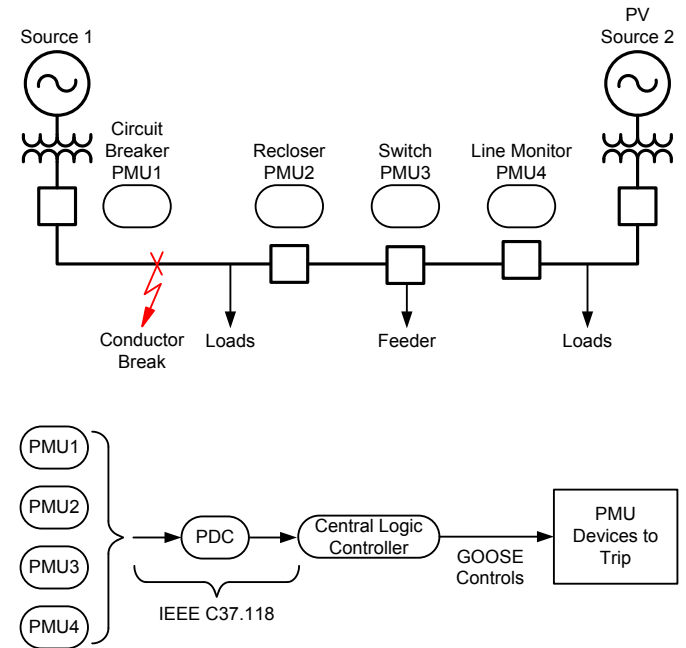


Fig. 6. Typical distribution circuit and data flow

E. System Model and Validation

Design verification and benchmarking of the system model and results are critical steps for this project [2] [8]. Software modeling and hardware-in-the-loop (HIL) testing provides confidence in the design. The feeder circuit modeled in the software is based on the distribution feeder details provided by SDG&E using real-time digital simulation software. Fig. 7 shows the detailed model. The system model, as compared with the real-time digital simulation model, is simplified with regard to the number of buses and loads. Developing a model that meets the project needs and accommodates all of the relevant information is critical for this application. Fig. 8 shows the simplified system model, which includes voltage regulators, transformers, reclosers, capacitors, switches, a variety of loads, and PV generation with inverters. Model validation for load flow and short-circuit cases compares the results to those for the model [8]. Fig. 9 shows the software model simplified one-line screen. For simplicity, only some components of the model, including the substation, PV generation, and two PMUs, are shown. The feeder circuit is configured as a loop with the normally open recloser (indicated as Recloser PMU in Fig. 9).

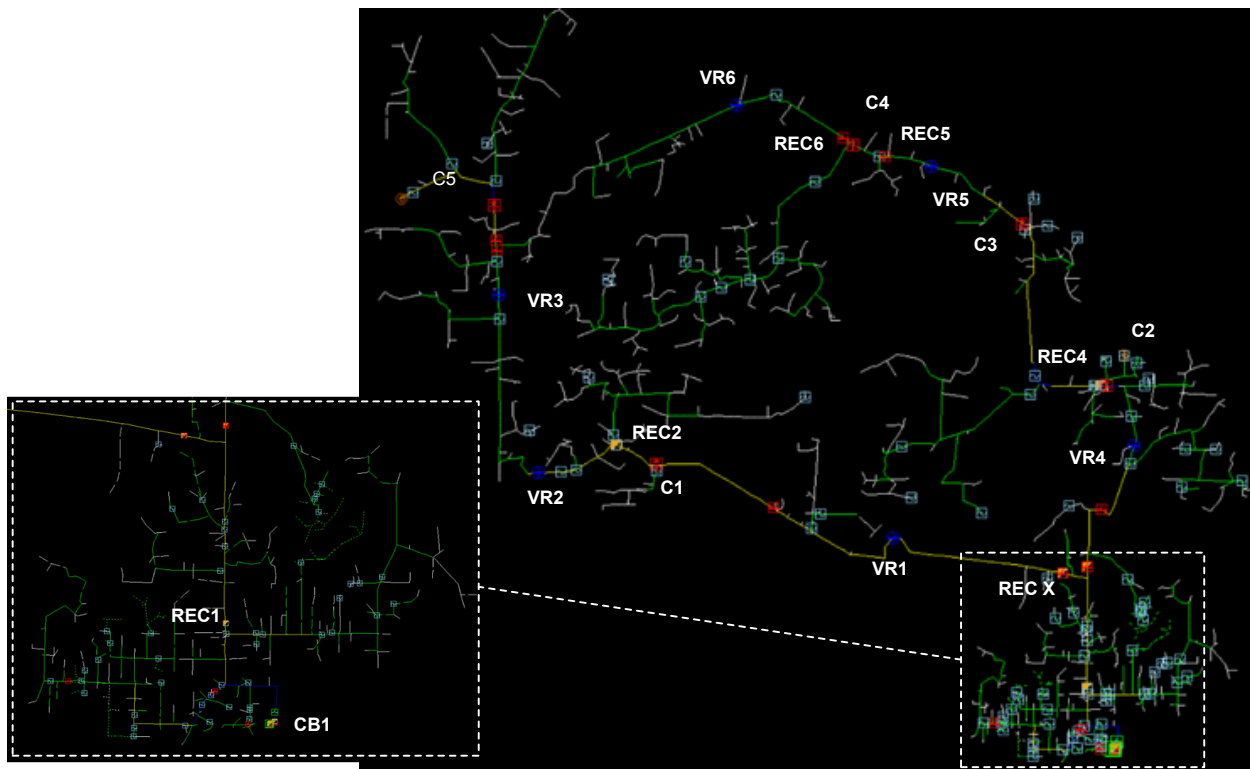


Fig. 7. Example feeder in the SynerGEE® software model

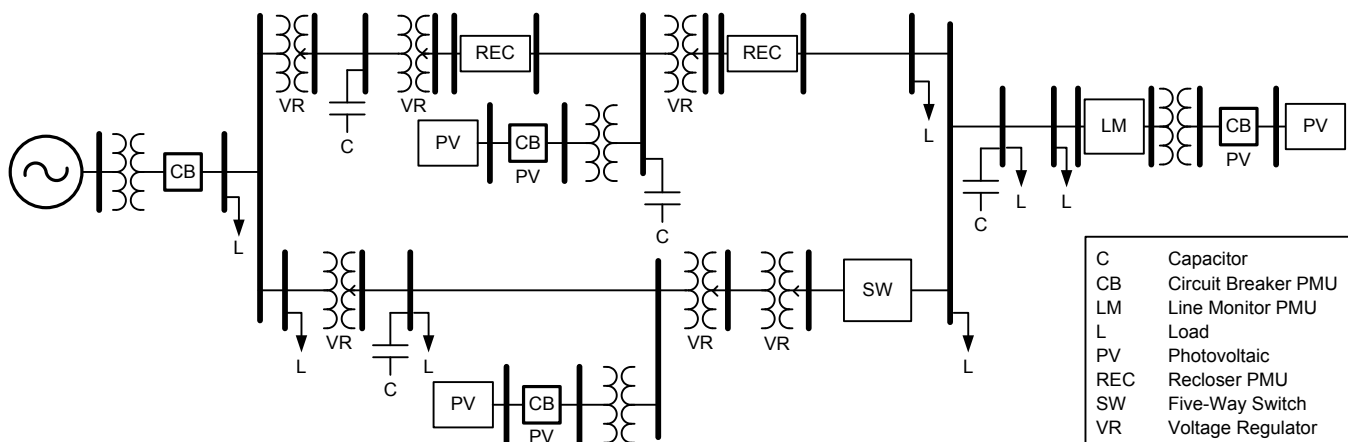


Fig. 8. Circuit model in the RTDS

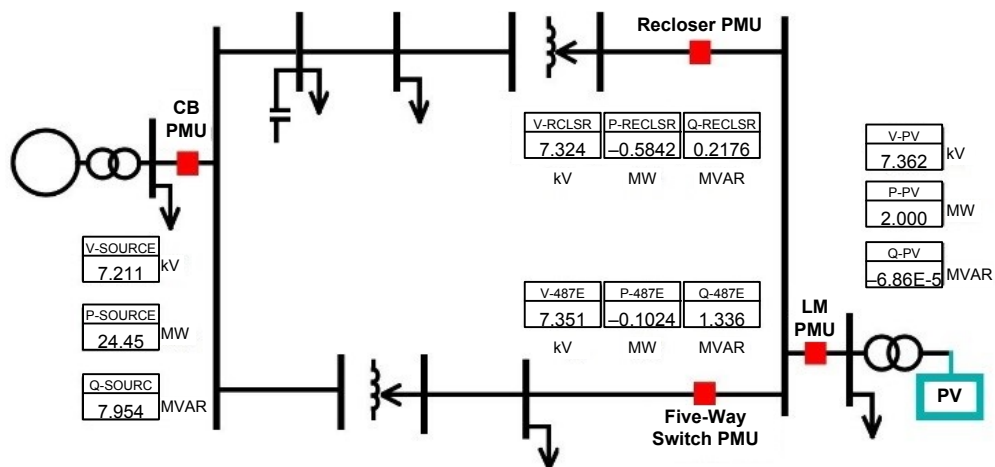


Fig. 9. Example one-line front screen in the software model

The system model was further validated with field results to verify the steady-state and dynamic performance. Fig. 10 shows the comparison of field and laboratory results for an example falling conductor test. Both results indicate that, after the circuit break was initiated, the methods detected this event within 200 to 300 milliseconds. Estimates indicate that a conductor may hit the ground in approximately 1.4 seconds. The dV/dt with $dV0/dt$ method declares that an event above the threshold was detected. The model also included the PV inverter model and a model of the arc that would occur between the separating ends of the loaded conductor. PV inverter response and the arc simulation sometimes slowed the detection of this event. However, the method was able to detect in most of the cases in less than 500 milliseconds.

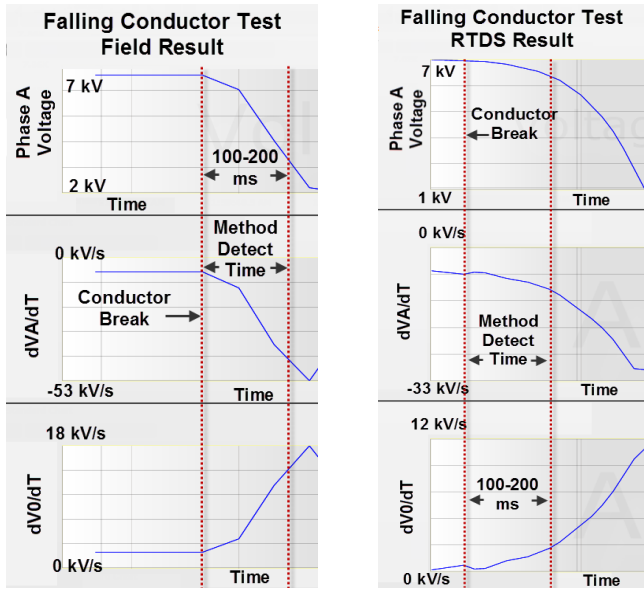


Fig. 10. Field test results for Phase A

All the falling conductor detection methods were enabled in parallel. It was observed that the dV/dt , $V0$ and $V2$ magnitudes, and $V0$ and $V2$ angle methods detected conductor breaks correctly for various operating scenarios. These scenarios include various combinations of load and PV. Negative testing was also performed in the lab. This testing included in-section and out-of-section faults, largest

single-phase load on/off, capacitor bank switching, voltage regulator tap changes, and so on. We observed that none of the methods operated for these scenarios. Only during the single-phase tap change operation with a voltage variation of more than 7 percent between phases did the $V0$ magnitude method misoperate. Because the system will not be operating beyond a 5 percent voltage variation between the phases, this condition will not be a concern.

VII. RESULTS

The falling conductor detection system has been operating in test mode on a feeder at SDG&E since January 2015. As discussed in Section VI, the software model of the feeder circuit was validated with the actual circuit results. The model was further tuned to reflect the normal operating voltages and various conditions, i.e., big load on/off, capacitor bank switching, PV on/off, variation, and so on [2]. During the first two months of operation, the falling conductor detection method overtripped a couple of times while in test mode. These misoperations were attributed to bad voltage sensors, not because of an actual falling conductor event. Fig. 11 shows the results for one of these misoperations. For the nominal phase-to-ground voltage of 6.9 kV, capacitive voltage sensors on the load side were found to be oscillating and the reported voltage signal reached around 10 kV. Resistive source-side voltage sensors still indicated nominal 6.9 kV circuit voltage during this load-side sensor oscillation event. The erratic high voltage measurement resulted in the misoperation of the dV/dt method, which helped in the analysis of the actual circuit during normal operation and led to replacement of the unstable sensors. In addition, the algorithm developers found a way to increase the $dV0/dt$ security margin to block similar misoperations without sacrificing sensitivity.

Customized screens were developed for easy troubleshooting and indication. Fig. 12 shows the screen that provides information about falling conductor location, pickup method, device open/close, and GOOSE commands. For engineering access, additional screens are developed for each PMU to provide information and analysis. All information is continuously archived and can be accessed for analysis.

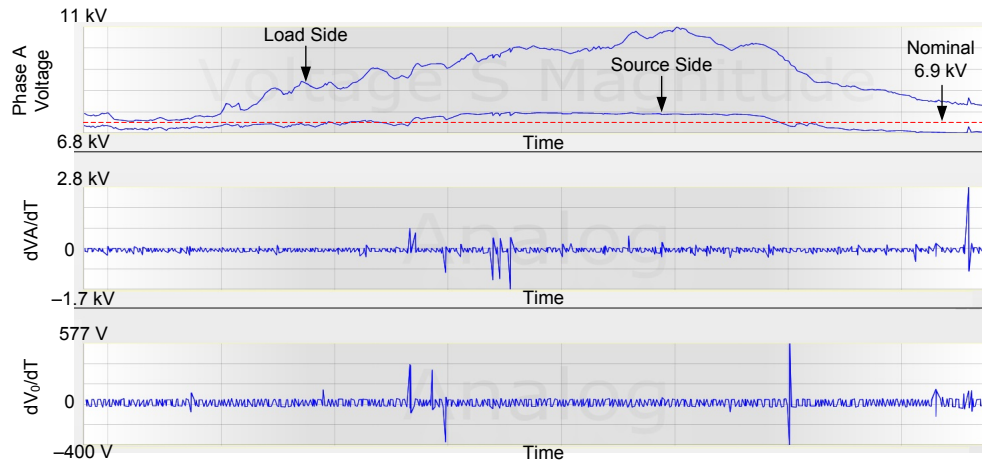


Fig. 11. Voltage time waveform

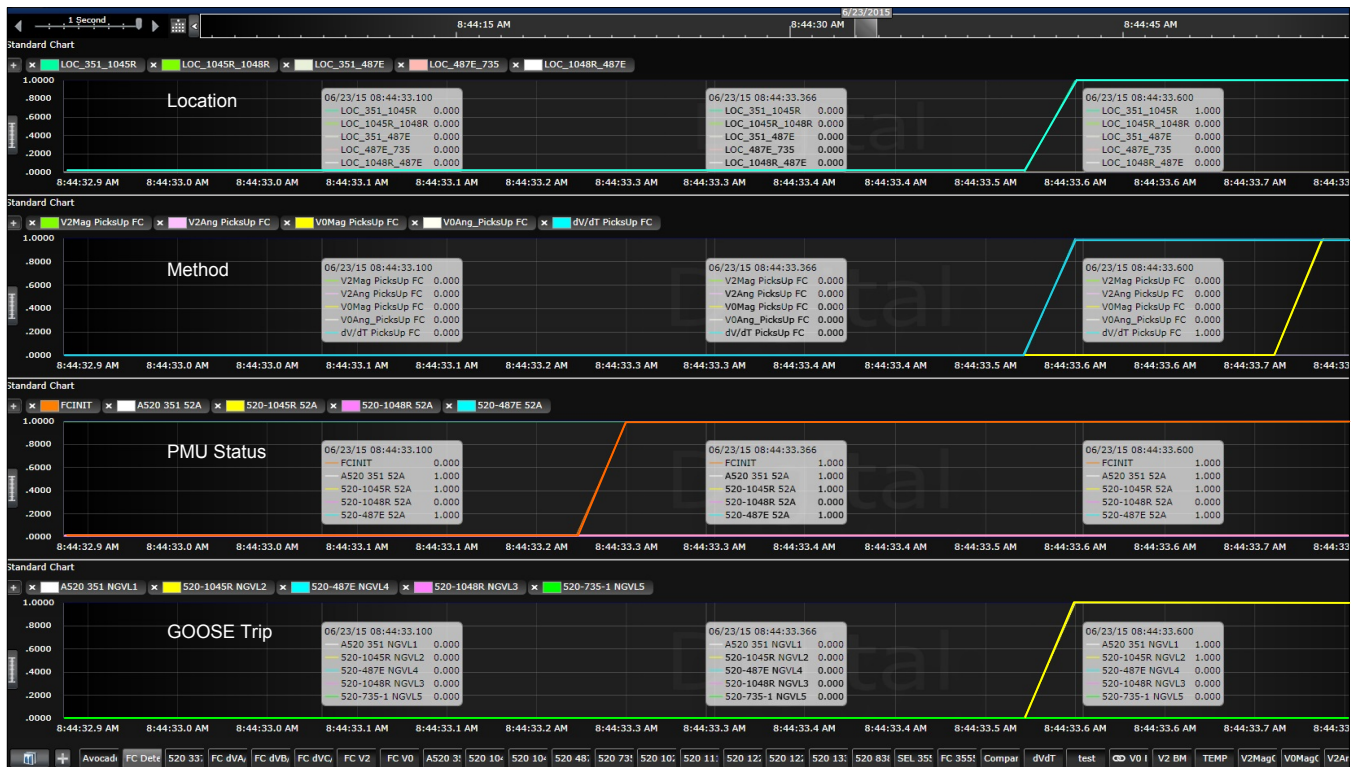


Fig. 12. System results and example screen

VIII. LESSONS LEARNED AND FUTURE PROSPECTS

A. Field Experience Summary

The falling conductor detection algorithms, and their implementation on the new synchrophasor-based ASD circuit PAC platform, have worked correctly for every broken-conductor simulation during field testing. There have been no conductor breaks on the test circuit to date. The observation of the first working installation that has been in service since January 2015 has shown these algorithms to be secure during routine feeder operation and during the few faults that have occurred in the vicinity of the ASD trial system. As mentioned previously, there have been no falling conductor algorithm misoperations, except for several cases triggered by recloser capacitive voltage sensor failure, as described in the previous

section. This misbehavior has since been corrected by the replacement of these sensors. Successful field performance is the result of the extensive laboratory algorithm testing described in the prior section.

The development team has been particularly encouraged by the solid reliability of detection and tripping by the falling conductor algorithms. This reliability contrasts with the historical uncertainty of downed-conductor fault clearing by protective relays, as explained in Section V, even though modern HIF detection techniques can improve the percentage of downed-conductor faults cleared. Furthermore, the authors cannot overstate the public hazard-reduction benefits of completely avoiding downed energized wires and arcing ground faults by tripping well before the conductors land.

B. Continuing Work

During 2016, SDG&E is equipping a number of additional distribution circuits with ASD infrastructure (PMU IEDs, substation controllers, and Ethernet radio systems). However, equipping an entire utility distribution system with ASD-based falling conductor detection and tripping is a journey of years. As stated earlier, SDG&E has over 1,100 distribution circuits. Furthermore, although the majority of the SDG&E past falling conductor incidents have occurred on main three-phase circuits and branches like those already being equipped in the current work plan, complete circuit coverage requires branch-end voltage reporting IEDs for each branch, and not all branch ends are being equipped at this time. Nevertheless, the project team has taken the critical first steps in advancing the effectiveness of protection against falling conductor events.

C. Limitations

Falling conductor detection and tripping methods have the following limitations:

- These methods cannot detect a conductor that has fallen to the ground without breaking. This case is handled only by existing HIF protection methods.
- The development team has designed and tested the logic to handle foreseeable sequences of faults followed by falling conductors, but they suspect that field experience will yield unpredicted sequences and fault evolutions for which the algorithms will not trip.
- The team has already observed that some of the algorithms are delayed or disabled by data communications systems that drop Ethernet packets at critical moments. Accordingly, they have already developed new methods that increase the dependability of tripping even if a packet is lost during the detection event. They have also clarified specifications to radio system installers for dropped-packet performance. The system cannot detect events reliably with sparse delivery of critical measurements. Certain weak communications paths have been tuned or bolstered.
- Voltage measurement devices are required at both ends to cover a segment of circuit—including the ends of branch circuits to be covered.
- The project team is still investigating the effects of fast-acting voltage control devices (i.e., dynamic VAR compensators [DVCs]) and other fast-acting inverters on batteries connected directly to the feeder circuit, which regulate voltage or VAR flow at high speeds. Such devices are theoretically capable of compensating for regulating the voltage changes on a phase whose conductor breaks, making it harder for the falling conductor algorithms to detect the break. The project team is addressing this potential issue with supplemental measurements of electrical signals. One example is measurement of compensating electrical signals at a DVC connection to the circuit as indicators of the change associated with a falling conductor.

At the outset, the developers were concerned with the prospect of creating a new protection application that would require more settings calculations for each circuit. Accordingly, their objective was to develop detection algorithms whose settings are fixed and not at all dependent on the electrical parameters of the protected circuit. Several methods with circuit-dependent settings were discarded. The methods now under field test do not require electrical settings; they only require that the logic be configured for awareness of the circuit topology and the locations of the PMU IEDs reporting the voltage measurements.

D. Making the Business Case

The business case for installing ASD infrastructure can be difficult to make just for falling conductor protection. The benefit is prevention of fault conditions that occur infrequently but have potentially high impact for the utility and the public. Such high-impact low-probability event mitigation is a soft benefit. However, there are other drivers that can harden the business case. As explained in Section II, there are many new functions required for effective monitoring and control of circuits with high PV or DG penetration, as SDG&E is now facing; the ASD infrastructure thus becomes a critical and required deployment for successful future operation of the distribution system. As aging distribution circuit control and protection devices need to be replaced, the incremental installation cost of ASD IEDs and communications compared with the cost of conventional choices is relatively easy to justify. The falling conductor tripping function becomes an overlay with almost no incremental cost. The additional system capabilities resulting from 30 or more phasor measurement reports per second, high-speed logic processing and control, and high-speed wideband Ethernet communication that support functions operating at protection speeds, all make the case even stronger.

IX. CONCLUSION

The authors have been quite enthusiastic about developing the system presented here, comprising equipment and algorithms for detection and isolation of distribution circuit conductor breaks. This paper has explained how the scheme can initiate tripping of the affected segment of the circuit in 200 to 300 milliseconds from the moment of the break, well before the de-energized broken conductor ends hit the ground. The detection algorithms are designed to work even with high penetration of DG, which may energize the load side of the break for some time after the conductor-break event. This new protection function has shown its ability to eliminate most utility exposure to arcing high-impedance ground faults and associated public hazards.

We have explained the challenges of traditional protection schemes that detect arcing ground faults only after broken conductors hit the ground—sometimes tripping slowly and in some cases failing to detect the subtle signature of such a low-current fault. This paper has described the components and operation of the SDG&E ASD architecture for distribution circuit monitoring, control, and protection that is required for

the now-emerging era of high PV penetration. It has explained how newly developed algorithms use synchrophasor measurements from multiple circuit locations to detect a conductor break in a small fraction of a second. Logic in the substation controller processes the PMU data and detects a conductor break; it then initiates tripping of breakers, reclosers, or switches using IEC 61850 GOOSE high-speed control messaging over Ethernet radio or fiber paths to the affected circuit locations. This paper has described the operation of three specific categories of detection algorithms (dV/dt , V_0 and V_2 magnitudes, and V_0 and V_2 angular relationships) that observe the heuristic relationships of measurements across the circuit and detect conductor breaks at high speed for the full range of operating conditions. Extensive HIL testing validated the performance of the methods on detailed models of distribution circuits with PV generation. Field test results have demonstrated high security and 100 percent tripping reliability to date for the cases and conditions presented to the falling conductor detection system. The algorithms do not require circuit-specific settings of values or thresholds.

The falling conductor detection system, if applied to a circuit having only legacy protection and a control scheme, is an expensive solution. Avoidance of arcing ground faults is a high-impact function that might justify the cost, but this paper has explained how the business case for installation of PMU IEDs, Ethernet communication, and substation controllers is broadly based on the array of functions that are required to operate distribution circuits with high penetration of DG. SDG&E is facing high penetration of PV generation on some circuits today and requires the ASD architecture for monitoring, control, and protection of these circuits. Falling conductor protection is then a marginally-free overlay that greatly improves the attractiveness of and business case for the whole ASD deployment program.

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XII. BIOGRAPHIES

William O'Brien received his bachelor's degree in electrical engineering from Arizona State University. He is a system protection and controls engineer with San Diego Gas & Electric Company (SDG&E). Prior to his current position, Mr. O'Brien held positions such as Oracle database administrator, electric distribution district engineer, and transmission grid operations engineer. He has a background in protection settings and remedial action schemes (RAS), including RTDS testing, and is an alternate member on the WECC RASRS and inventor of the falling conductor protection system described in this paper. Presently, he is program manager and lead engineer for the SDG&E Advanced SCADA Program, which incorporates the most modern field intelligent electronic devices with high-speed, high-bandwidth communications, delivering new capabilities to electric distribution systems.

Eric Udren has a 46-year distinguished career in the design and application of protective relaying, substation control, and communications systems. He works with major utilities to develop new substation protection, control, communications, remedial action schemes, and synchrophasor applications; he is coinventor of the falling conductor detection system described in this paper. Eric is an IEEE Life Fellow and outgoing chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee. He is the U.S. Technical Advisor for IEC relay standards and is a member of the working group that develops IEC 61850. Eric serves on the NERC System Protection and Control Subcommittee (SPCS) and Protection System Maintenance Standard Drafting Team. He serves as Executive Advisor with Quanta Technology, LLC, of Raleigh, North Carolina, with his office in Pittsburgh, Pennsylvania.

Kamal Garg is a protection supervisor in the engineering services division of Schweitzer Engineering Laboratories, Inc. (SEL). He received his MSEE from Florida International University and the India Institute of Technology, Roorkee, India, and his BSEE from Kamla Nehru Institute of Technology, Avadh University, India. Kamal worked for POWERGRID India for seven years and Black & Veatch for five years before joining SEL in 2006. Kamal has experience in protection system design, system planning, substation design, operation, remedial action schemes, synchrophasors, testing, and maintenance. Kamal is a licensed professional engineer in the United States and Canada.

Dennis Haes is a principal engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. He has over 20 years of experience with substation automation and 13 years of operations experience with a large electric utility. Dennis obtained his BSEE from New Mexico State University. He is a member of IEEE.

Bala Sridharan is an automation engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. Bala has experience developing protection and automation settings for substation relays and controllers. He also develops, tests, and commissions integrated solutions for power distribution networks. His education includes an MSEE from Arizona State University and a BSEE from Anna University, Chennai, India.