

Understanding Ground Fault Detection Sensitivity and Ways to Mitigate Safety Hazards in Power Distribution Systems

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Abstract—Detecting ground faults in power distribution systems is a challenging task. The challenge comes from system grounding configuration, load connection, and available fault current from faults with fault impedance. Due to the proximity of power distribution lines to homes and buildings, ground faults can pose a safety risk through potential electrical contact or fire ignition. The risks require utilities to reexamine the challenge of reliably detecting a ground fault in order to minimize hazards of a downed power line.

This paper revisits different grounding practices in distribution power systems. It discusses how system grounding and load connection impact the sensitivity of detecting higher-impedance ground faults. The paper discusses possible ways of improving the ground fault detection sensitivity for different systems. The paper illustrates that no single economical technology or practice available today can guarantee a 100 percent reliable high-impedance ground fault detection. To provide a perspective with respect to ground faults versus fire ignitions, the paper reviews several staged downed conductor tests and summarizes key research findings in released energy of arcing faults and fire ignition.

I. INTRODUCTION

Statistically, ground faults account for over 80 percent of all faults occurring on overhead line power distribution systems. Ground fault detection and isolation is therefore an important task for protection engineers. Some ground faults pose additional challenges to detecting when they involve high fault impedance (which corresponds to minimum fault currents). Downed power lines typically create high-impedance fault (HIF) situations when the ground surface includes poorly conductive materials such as dry sand, deep snow, or asphalt. Additionally, ground faults in distribution systems often occur near human activities and thus have a higher probability of causing damage to life and property. Detecting such faults quickly and reliably therefore provides great social benefits.

Throughout the evolution of power distribution systems, different grounding systems have emerged. Ungrounded systems have no intended system grounding. Uni-grounded systems have only one grounding point, typically at the substation transformer neutral point with or without grounding impedance. Multi-grounded systems consist of a neutral wire that extends outside the substation and is grounded in multiple places along the distribution feeder. Reference [1] summarizes the advantages and disadvantages of each grounding scheme. Not all distribution systems are created equal in terms of reliability, sensitivity, and speed of ground fault detection.

There are many existing techniques to deal with security and selectivity. For example, we typically use time delays to prevent overcurrent (OC) elements from operating during transformer inrush or cold load pickup and inverse-time OC elements to coordinate with downstream fuses and reclosers to achieve selectivity. To effectively detect high-impedance faults, however, we must examine the sensitivity of protection elements. A digital relay can reliably measure currents in the range of a few milliamperes. With a low-ratio current transformer (CT) such as 50-to-5 (50:5), an OC element can detect a fault with a primary fault current in the order of tens of milliamperes. The ground fault detection sensitivity is often limited by factors external to the protective relay, such as system grounding schemes, load connections, and asymmetrical constructions of power equipment.

In this paper, we first devote a section to each grounding type of the distribution systems and introduce corresponding ground fault protection practices, examine the sensitivity of ground fault detections, and explore possible ways to increase detection sensitivity for high-impedance faults. Section II discusses multi-grounded distribution systems and the need for purpose-designed methods for high-impedance fault detection. Section III is dedicated to uni-grounded systems with or without grounding impedance. Section IV summarizes the characteristics and ground fault detection sensitivity of ungrounded systems. In Section V, we examine several staged downed-conductor faults and subsequent fires. These tests reveal important parameters that affect the dynamic process of fire ignition. Section VI summarize some studies on released energies and current levels of ground faults that can ignite fires.

II. GROUND FAULT DETECTION FOR MULTI-GROUNDED SYSTEMS

A. Typical System Characteristics

Four-wire systems with a multi-grounded neutral wire are commonplace in medium-voltage distribution systems in North America. These systems use three-phase conductors with a neutral wire to supply electrical power. The substation transformer typically has a wye-connected secondary winding. The neutral wire is connected to the neutral of the transformer wye winding which is then connected to the substation ground grid without any intentional impedance. The neutral wire is solidly connected to ground at every distribution transformer location. The National Electrical Safety Code (NESC) requires

that, at a minimum, the neutral wire has four grounding points per mile.

Fig. 1 shows a typical multi-grounded distribution system with a single-phase load.

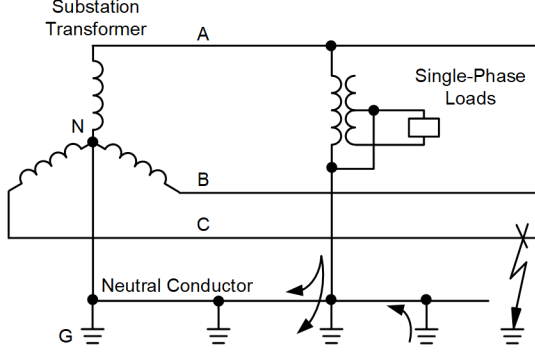


Fig. 1. Typical multi-grounded distribution system.

The multi-grounded distribution system has several desirable characteristics. One of these solves some safety concerns economically. Without grounding the neutral wire at multiple points, the neutral wire can develop a lethal high voltage because of the load current return. Utility line workers must exercise extra precautions when servicing the distribution system. Grounding the neutral wire multiple times per mile mitigates this concern without requiring the neutral wire to be fully insulated.

Grounding the neutral wire multiple times also alleviates the insulation requirement associated with the electrical equipment, therefore achieving additional economic benefits. For example, during a single-line-to-ground (SLG) fault, the voltages on the unfaulted phases may increase from the nominal phase-to-neutral voltage level to 1.73 times that level on systems that are not effectively grounded. The transient overvoltage can be even higher. The conductor insulators, distribution transformers, shunt capacitors, and surge arresters all need to be designed to withstand this temporary high-voltage condition, thus increasing equipment costs. IEEE Standard C62.92.1-2000 uses coefficient of grounding (COG) [2] to measure the performance of system grounding. The COG is defined in (1):

$$\text{COG} = 100 \cdot \text{ELG} / \text{ELL} \quad (1)$$

where:

ELG is the highest power-frequency line-to-ground voltage in rms on an unfaulted phase at a selected location during a line-to-ground fault affecting one or more phases.

ELL is the line-to-line voltage at the same location without the fault.

In effectively grounded systems, COG does not exceed 80 percent. With multiple grounding points, a multi-grounded distribution system provides a measure of assurance that the system is effectively grounded even when some of the grounding points become bad or ineffective.

Another benefit of the multi-grounded system is the flexibility and economy of supplying loads. Loads can be supplied with phase-to-phase and three-phase connections

similar to other types of distribution systems. Remote loads, especially in rural residential areas, can be supplied with a single-phase conductor and the neutral wire, as shown in Fig. 1. In this configuration, the distribution transformer only requires one bushing (instead of the two bushings required if the load were supplied from two phases). The transformer insulation level can also be lowered because of the lower COG on multi-grounded systems. These both contribute to reduction in cost.

One perceived advantage of multi-grounded systems, as compared to systems that use other grounding schemes, is the higher fault current generated during SLG faults. Higher fault currents make it easier to detect faults, which improves protection speed and selectivity. Although higher fault currents were an advantage with electromechanical relays, with today's digital relays, system conditions impose more limits to the sensitivity of ground fault detection. Because of this, multi-grounded systems are the most difficult system for high-impedance ground fault detection.

Multi-grounded systems have several drawbacks in addition to high-impedance fault detection. The largest issue comes from the original attempt to solve the safety concern from an overvoltage on the neutral wire by grounding it multiple times. With multiple grounding points on the neutral wire, the return current from single-phase loads is not confined to the neutral wire. Rather, the load return current follows the path of least resistance and flows uncontrollably through both the neutral wire and the ground, as shown in Fig. 1. The return current through the ground, often referred to as stray current, can be dangerous to human and animal life. Even when not lethal, ground currents have been shown to cause documented health issues and even impact the milk production at dairy farms [3]. One way to mitigate the neutral wire overvoltage concern is to insulate the wire [3] and treat it as you would with a live phase conductor. This practice would reduce the economic benefits of the multi-grounded systems because of increased COG, but would greatly improve safety.

Another drawback is the thermal stress on power system equipment from a large ground fault current that the system may produce. The protection system must operate at high speed to reduce thermal damage. However, this is not always possible because of the coordination consideration to achieve selective fault clearance.

B. General Practice of Ground Fault Protection

According to a recent Power System Relaying Committee (PSRC) survey [4], most utilities use ground fault protection on their distribution feeders. Among those utilities, many use inverse-time overcurrent elements (51). Over half of the utilities surveyed also use instantaneous overcurrent elements (50). Fourteen percent also use definite-time overcurrent elements.

When choosing the pickup settings for the ground fault protection, utilities must consider many factors to achieve their desired protection sensitivity, selectivity, and speed. Often, they must find a compromise among these protection requirements.

One important consideration for distribution feeder protection is time coordination. The purpose of coordination is to achieve selective fault clearance by coordinating the trip time among protection devices on the same feeder. In general, fault current decreases as the fault moves further away from the substation. However, the selectivity of a feeder protection system cannot rely solely on this fault current property. One reason is that an upstream protection device does not see the fault current level change immediately before or after a downstream device. For a short line or a system having a high system impedance ratio, the fault current changes very little as a fault moves further away from the substation. In addition, the upstream protection device normally overreaches the downstream device for backup purposes. If the downstream protection device fails for any reason, the upstream protection device can clear the fault without losing a larger service area.

Fig. 2 illustrates a typical distribution protection system, in which A is a substation breaker that is controlled by an overcurrent relay and B is a three-phase recloser with C and D being two single-phase sectionalizers. The lateral fuses in the system are denoted by E, F, and G. Fig. 3 shows the basic idea of time coordination of the protection devices in Fig. 2. For example, a fault down lateral section F produces relatively low fault current. The time-overcurrent curve of Fuse F will time out first according to Fig. 3 and clear the fault without operations of upstream devices B or A. The instantaneous tripping curve of Relay A in Fig. 3 is for a fuse-saving scheme to clear temporary faults beyond close-in fuses (like on lateral G) without blowing a fuse. The compromise is that the entire feeder sees an interruption because of the operation of Breaker A.

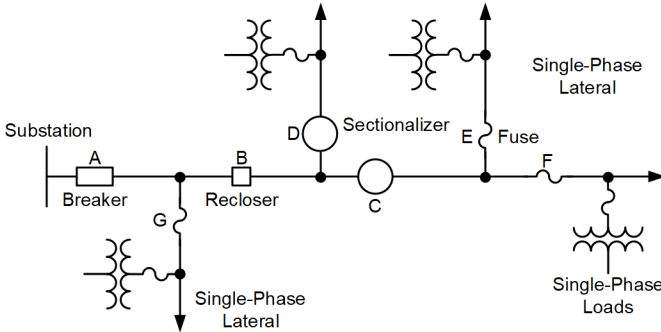


Fig. 2. A typical distribution protection system.

In addition to time coordination to achieve selective fault clearance, utilities must consider the following situations when setting the ground protection device. Most of these are the same considerations typically taken into account when setting the phase protection device.

- Maximum possible load unbalance, which may occur when a large single-phase lateral is out of service.
- An emergency overload condition that may last for several hours.
- Cold load pickup after an extended feeder outage.
- Transformer inrush that may last for several seconds.

Because of all the factors that can impact ground fault protection operations, setting the ground fault protection is

more often art than science. The latest PSRC survey [4] indicates that most utilities use the available end-of-line fault current as the criterion by which to establish the pickup settings for ground overcurrent fault protection. Its previous survey results in 1995, however, indicated that a percentage of phase fault relay pickup is often used as the ground fault relay pickup setting. The compromised ground protection pickup setting thus diminishes their effectiveness for ground fault protection, especially for ground faults with fault impedance.

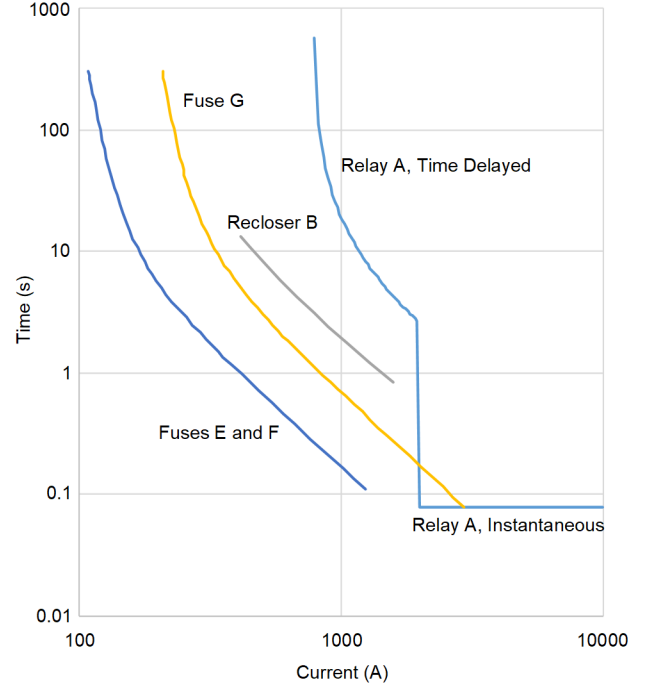


Fig. 3. Coordination curves of protection devices.

C. Ground Fault Detection Sensitivity

Fault detection sensitivity is a protection system's capability of differentiating a fault from the normal operating conditions of the power system. Protection devices can pose a limit to the protection sensitivity. In today's digital relay age, however, the power system operating conditions are possibly the most limiting factor with regard to ground fault detection sensitivity.

Because of their short duration, time delays can be used to prohibit protection element from operating on cold load pickup and transformer inrush conditions while keeping the element sensitive. For multi-grounded distribution systems, the system unbalance from single-phase loads ultimately limits the sensitivity of ground fault protection. From Fig. 1, we see that because of multiple ground points of the neutral wire, the return current from single-phase loads is not confined to the neutral wire. Rather, it flows in an uncontrolled manner through both the neutral wire and the ground, back to the substation. The same is true for a ground fault (as shown in Fig. 1) because the fault current not only flows through the ground, but also through the neutral wire back to the substation. In other words, there is no way for a protection device to differentiate a ground fault current from the load unbalance current of single-phase loads. Most utilities have a policy or practice to limit their load unbalance at the feeder breaker or substation transformer

secondary level [4]. In practice, the ground fault protection must be set above the worst possible system unbalance that may occur when the largest single-phase lateral is out of service for an extended period.

Reference [5] uses an example to illustrate how load unbalance limits the ground fault detection sensitivity, or the fault resistance coverage. Fig. 4 shows the three-feeder system for this example.

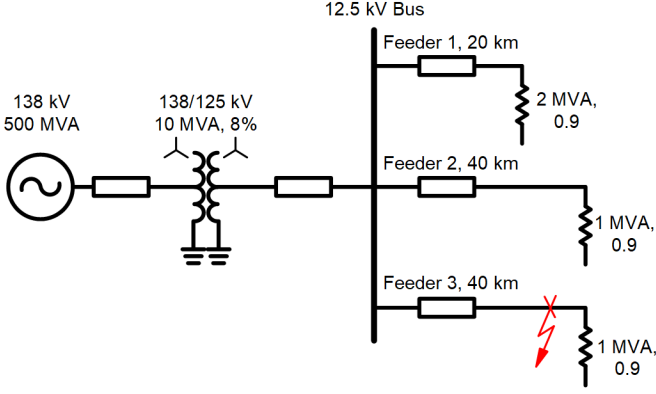


Fig. 4. Three-feeder system for sensitivity study.

In this example, the B- and C-phase loads of Feeder 3 are 0.33 MVA but the A-phase load is 0.13 MVA, all with a power factor of 0.9. This can be a situation where the feeder load was balanced with a 1.0 MVA load to begin with, and then a large single-phase lateral with a 0.2 MVA load is out of service on the A-phase. Fig. 5 shows that a feeder relay measures a residual current as high as 20 A on Feeder 3 due to this load unbalance. An A-phase ground fault with 200 Ω fault resistance occurs at the middle of Feeder 3 at 0.35 seconds and clears at 0.7 seconds in the simulation study. From Fig. 5, we see that the residual current measured by the feeder relay hardly changes during the fault. In fact, the residual current decreases to 18 A. Although it can be a rare situation and one can readily predict the outcome, this example illustrates that this feeder ground protection cannot detect a ground fault with a fault resistance larger than 200 Ω . The protection sensitivity is entirely limited by the normal system operation, which includes load unbalance.

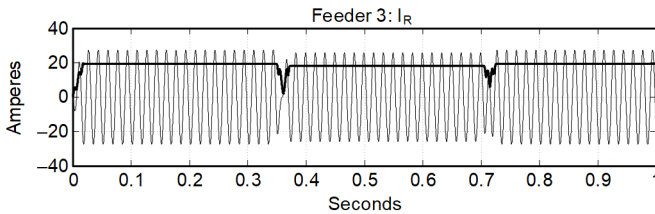


Fig. 5. Feeder 3 residual current with and without a fault.

D. High-Impedance Faults

One of the desired characteristics of a multi-grounded system is available fault current for reliable protection device operations. Available fault current can be so high that utilities frequently limit the fault current level to reduce thermal damages to power system equipment. The PSRC survey [4]

indicates that utilities set the fault current limit anywhere from 6,000 A to 23,500 A. An early Electric Power Research Institute (EPRI) report [6] indicates that average SLG fault current is 1,530 A with no fault impedance, with a recorded minimum of 250 A and a maximum of 5,000 A.

High-impedance faults on distribution systems produce much lower fault current. High-impedance faults can result from dirty insulators, vegetation touching overhead conductors, and most frequently, from downed conductors. For many reasons, an overhead conductor can lose its support on a pole and fall on the ground. When the ground surface is a poor electrical conductor, such as dry earth or sand, the fault current generated from a downed conductor fault can be low. Studies [7] [8] [9] [10] [11] [12] from many staged high-impedance fault tests conclude that high-impedance fault current from downed conductors vary anywhere from zero to under 100 A. Fig. 6 shows the fault current ranges for different ground surfaces. The fault impedance from asphalt and dry sand surfaces is so high that there is no perceivable fault current produced. There are no substation-based protection devices available today that can detect these types of high-impedance faults.

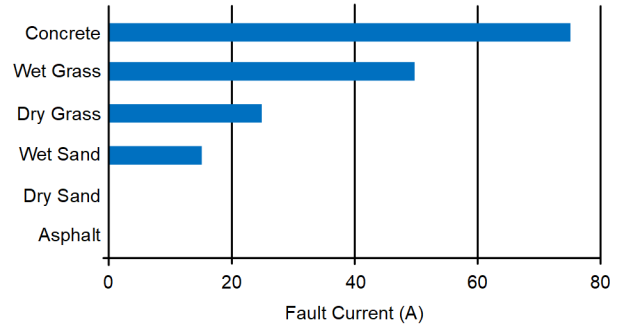


Fig. 6. Downed conductor fault current for different ground surface types.

For high-impedance faults resulting from downed conductors that do produce some fault current, such as when the ground surface is wet grassy land or concrete, the fault current can still be less than the system load unbalances and the traditional ground overcurrent protection cannot differentiate downed conductor faults from single-phase loads. For the 200 Ω ground fault discussed in previous sections, the A-phase ground fault current at the middle of Feeder 3 is about 36 A, which is in the range of typical downed-conductor related high-impedance fault currents.

Although a high-impedance fault may not interrupt normal distribution system operations due to its low fault current, it can be a major public hazard. A downed-conductor related high-impedance fault is a major human safety concern, and many incidents and injuries have been documented in papers and news reports. High-impedance faults resulting from downed conductors or vegetation touching energized conductors are also possible sources of wildfire ignitions. Utilities as well as relay manufacturers are increasing their efforts to detect and prevent high-impedance faults and mitigate the safety concerns from these faults.

E. Purpose-Designed Methods for HIF Detection

As discussed in previous sections, multi-grounded distribution systems have the sensitivity limitation of ground fault detection posted by the unbalance produced by single-phase loads. Because the high-impedance fault current level is in the range of single-phase loads, traditional overcurrent elements cannot differentiate between the two. This sensitivity limitation leaves high-impedance faults often undetected.

To increase the possibility of detecting high-impedance faults, research began as early as the 1970s [7] to stage downed conductor tests. EPRI and the Canadian Electricity Association (CEA) directed several studies and published their results [8] [9] [10] [11] in the late 1970s and early 1980s. This research sparked a round of interest in developing algorithms specifically targeting the detection of high-impedance faults. A later study [13] provides a good summary on most published detection algorithms. As expected, all detection algorithms use some signals other than the residual current magnitude. In addition, all algorithms exploit one or several signatures presented from the electric arcs that are commonly involved in high-impedance faults. To enhance the signature extraction of arcing faults, detection algorithms typically use data analysis techniques and artificial intelligence (AI) algorithms, including wavelet decomposition, neural networks, statistics, and expert systems.

One high-impedance detection algorithm [12] starts with filtering out total interharmonic energies of phase currents. Interharmonics are signal components with frequencies that are not integer times of the fundamental frequency. The algorithm then establishes a stable reference of the interharmonic energies with an infinite impulse response (IIR) filter that has a long time constant. The algorithm then checks the magnitude and time interval of the incremental changes of the interharmonics for the arcing fault signature. Fig. 7 shows the function blocks of this detection algorithm.

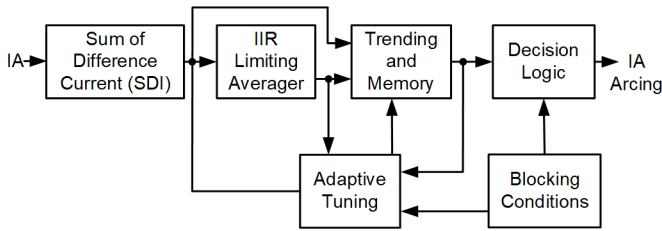


Fig. 7. Block diagram of high-impedance fault detection shown for A-phase current, similar for B- and C-phases.

Each distribution feeder has a unique interharmonic characteristic. This characteristic is feeder load related and cannot be obtained from the short-circuit fault study programs that utility engineers routinely use. The high-impedance fault detection algorithm attempts to obtain the feeder harmonic characteristic through an autotuning period and derives a detection threshold from the harmonic characters obtained during that period.

As discussed, not all downed-conductor related high-impedance faults produce appreciable fault currents. The substation-based detection devices alone will never detect

100 percent of high-impedance faults. In 1989, the IEEE recognized this issue and published a report titled “Downed Power Lines: Why They Can’t Always Be Detected” [14]. The primary emphasis for substation-based detection devices should be on detection security to minimize false positives. This is a challenging task. Arcing faults do not always relate to downed power conductors. Dirty insulators and vegetation touching live conductors also generate arcing faults. However, these types of arcing faults are mostly transient in nature. It is difficult to correlate the occurrence of these transient arcing faults with high-impedance detection results.

III. GROUND FAULT DETECTION FOR UNI-GROUNDED SYSTEMS

A. Typical System Description

Uni-grounded (or single-point grounded) distribution systems are not common in North America, but they are used extensively in portions of the western United States, Australia, and most European countries. The substation transformer neutral is usually solidly grounded or grounded through a small resistance or reactance if fault currents need to be limited. In many European countries, the neutral is grounded through a variable impedance reactor to form a resonant-grounded or compensated distribution system. The reactor, also known as Petersen coil, compensates the system phase-to-ground capacitance during an SLG fault. When the compensation is close to 100 percent, the reactor and phase-to-ground capacitance becomes a parallel resonant circuit, thus making the zero-sequence network a very high-impedance path and effectively reducing the fault current such that most fault arcs would self-extinguish.

Distribution circuits of uni-grounded systems are three wires with all load connected phase-to-phase. One advantage of this load connection is that the standing ground current is very low, typically around several amperes. This standing ground current is mostly due to phase CT differences. Asymmetries of distribution circuits, substation transformers, and other power equipment also contribute to this standing ground current. Fig. 8 shows the standing ground current of a distribution feeder from a uni-grounded system for a period of one month. We see that the standing current is approximately 2 A. The two outliers shown in Fig. 8 resulted system ground faults. The actual ground fault currents were much higher than the values shown in Fig. 8 from SCADA.

Ground faults typically generate several hundred to several thousand amperes, depending on system grounding impedance and fault resistance. Similar to all distribution systems, high-impedance ground faults can occur. The large difference between the standing ground currents and ground fault currents on uni-grounded systems allows relays to be set more sensitively and detect more high-impedance ground faults than relays on multi-grounded systems [15].

Because all single-phase load transformers are connected phase-to-phase, a broken conductor that falls on the ground from the load side can result in partial voltage on the downed conductor because of back feed through the primary winding and coupling with the secondary winding to load [16]. This

downed conductor from the load side with back feed presents a unique challenge for the high-impedance fault detection. This back-feed condition also exists on four-wire multi-grounded systems for equipment that is connected between phases. This includes three-phase transformers, line regulators, or capacitors. This back-feed condition with partial voltage has resulted in fatalities and fire ignition incidents. One protective relaying scheme that detects these back-feed conditions requires synchrophasor measurements and communication for each segment of distribution circuit [17]. This relaying scheme may not be practical for all distribution systems.

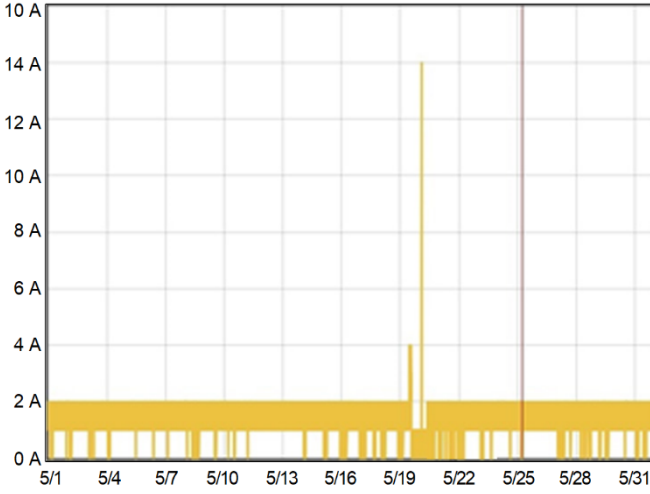


Fig. 8. Standing ground current of a typical distribution feeder of uni-grounded systems.

B. General Practice of Ground Fault Protection

Ground fault protection for uni-grounded systems is typically provided by ground time-overcurrent and ground instantaneous elements. With electromechanical relays, the three phase CTs are summed or residually connected to feed a 50/51N relay. Digital relays either mathematically calculate zero-sequence quantities from three-phase currents or measure the ground current with a dedicated residual current input. The dedicated residual current input can have a higher sensitivity than phase current inputs. As in the ground protection of multi-grounded systems, utilities typically consider coordination with downstream devices when deciding on the pickup setting of ground fault detection elements at substations. The protection coordination provides desired power distribution dependability but sacrifices the fault detection sensitivity. Due to the lack of any standing ground currents, the ground relays can be set more sensitively than on multi-grounded four-wire distribution systems. To provide a perspective, one utility sets the ground fault pickup at 240 A or higher for a four-wire multi-grounded distribution circuit, but at 180 A or lower for a three-wire uni-grounded circuit with similar system conditions.

C. Ground Fault Detection Sensitivity

The ground fault minimum-to-trip setting must be low enough to detect all in-section faults with a safety factor. Some utilities use a safety factor of 30–70 percent of the minimum end-of-line ground fault current as a maximum limit and some

utilities use an end-of-line fault plus 25 Ω or 50 Ω of fault resistance as an upper safety limit. The lower setting limit is based on coordination margins between the largest fuses and line reclosers. Load unbalance and transformer inrush do not need to be considered when setting a ground relay on uni-grounded three-wire systems.

A wattmetric element is a typical element for the ground fault detection on resonant-grounded systems. This element measures the active component of the product of the zero-sequence voltage and zero-sequence current. The sensitivity of the wattmetric element is often limited by the zero-sequence overvoltage element that is used to ensure the fault detection security.

D. High-Impedance Fault Considerations

High-impedance faults will occur with the same frequency on uni-grounded systems as on systems with other grounding schemes. The key factors driving high-impedance fault current magnitudes are the surface contact and the voltage level. Because the ground fault pickup setting does not depend on load unbalance or inrush current, the lower ground minimum to trips threshold increases sensitivity to detect high-impedance faults. This is documented in Section 5.4 of [15].

The time coordination of protection devices on a distribution feeder is a common practice by which to achieve the protection selectivity as seen in Section II. This limits a service outage to only the faulted section of a feeder. Such coordination is also proven to increase the dependability of power distribution. However, under today's increased public safety concerns related to power equipment, one may reexamine the practice and find ways to increase the fault detection sensitivity in exchange for some sacrifice of supply dependability. It may not take much fault current to ignite a fire, as detailed in later sections. This fault current may fall under the minimum melting rating of feeder branch fuses. For example, a sensitive-set ground fault detection element at the substation feeder breaker may detect a high-impedance fault beyond a feeder branch fuse. If the fault current cannot blow the branch fuse (or it would take an inordinately long time to blow the fuse), it makes sense to let the sensitive-set ground fault detection element trip the substation feeder breaker, without regard to traditional coordination and dependability, in the interest of reducing fire risk in high fire risk regions or during high fire risk conditions.

The sensitivity of ground fault detection without considering time coordination is limited by the standing ground current of the system. In the example shown in Fig. 8, one can set the fault detection threshold at 3 A, the 2 A standing ground current plus a 50 percent margin. This ground fault pickup provides an equivalent of 2400 Ω fault resistance coverage.

Ground fault detection sensitivity can be further improved by using a flux summation CT (also known as a donut or core-balance CT). In such a CT installation, the three-phase conductors of the primary feeder are run through the opening of the CT core. The secondary current output of this flux summation CT is the effective vector summation of the three-phase current (the residual current), without the false residual current from phase CT matching errors. A further

enhancement for such an installation is by the use of a low-ratio flux summation CT (e.g., 50:5), thereby boosting the secondary current output for the feeder-relay-dedicated residual current input. The major drawback of flux summation CT installation is the challenge of physically running the three phase conductors of the primary feeder through the opening of the CT core and the necessity of each phase conductor being fully insulated.

One way to improve the sensitivity of the wattmetric element for resonant-grounded systems is by use of the incremental quantity of zero-sequence conductance [1]. The incremental conductance element eliminates the standing unbalance of the system and therefore allows detections of ground fault with higher fault impedance.

As with all distribution systems, high-impedance faults can occur with fault currents that are below the standing ground current of a distribution feeder. A percentage of high-impedance faults cannot be detected with any current-based sensing scheme in substations.

E. Rapid Earth Fault Current Limiter

Resonance grounding systems are not commonly applied in North America. However, they are common in other parts of the world. These can only be applied on three-wire uni-grounded systems. The original Petersen coil technology was developed in 1917 in Germany. In its most basic form, a neutral reactor is installed on the substation transformer neutral and sized to match the natural capacitance to ground of all the circuits connected to the substation transformer. When a ground fault occurs, the resonance grounding reduces the current level to low values.

A modern implementation using power electronics is called a rapid earth fault current limiter (REFCL) or ground fault neutralizer. This monitors the capacitance to ground and automatically fine tunes the neutral reactance by adding or subtracting small parallel capacitors. This can match the changing nature of a distribution feeder during switching, operation of tap line fuses, or line recloser operations. When a ground fault starts, an REFCL also injects a very small current into the substation ground grid 180 degrees out-of-phase with the residual current. Testing in Australia on such a system shows that ground currents starting at 2 A primary reducing to about 0.3 A primary are achievable if capacitance to ground is well balanced between the three phases. These schemes claim that extremely high-impedance ground faults can be successfully detected up to several k Ω . New Zealand and Australia have installed several of these schemes. Pacific Gas and Electric Company is scheduled to install the first one in North America in 2020.

IV. GROUND FAULT DETECTION FOR UNGROUNDED SYSTEMS

The use of ungrounded distribution systems is common practice outside of North America. Ungrounded power systems are common in industrial plants worldwide because they allow continued operation in the presence of an SLG fault. In an ungrounded power system, there is no intentional ground on the

power system and loads are connected phase-to-phase, as shown in Fig. 9.

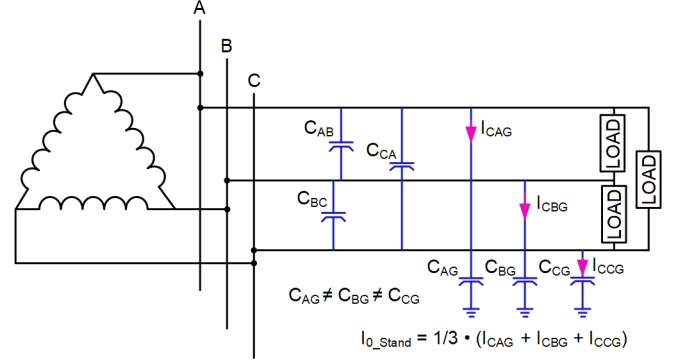


Fig. 9. Simple system diagram of an ungrounded power system showing the feeder capacitances and load connections.

Since the power system has no intentional ground, the only zero-sequence current (I_0) observed in the power system is due to the difference between the phase-to-ground capacitance of the phases (C_{AG} , C_{BG} , C_{CG}) and loads. This difference results in a standing zero-sequence current (I_{0_Stand}) in power systems under unfaulted conditions and is typically in the range of tens of milliamperes primary (50–150 mA). When an SLG fault occurs on the power system, the high impedance of the phase-to-ground capacitance of all the feeders in the system limits the fault current to a few amperes (<10 A) primary. The fault current distribution for an SLG fault on a simple three-feeder ungrounded power system is shown in Fig. 10.

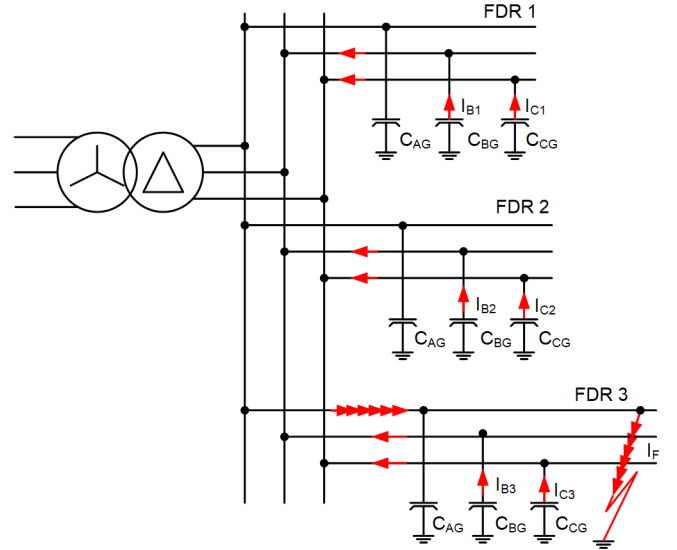


Fig. 10. The distribution of the fault currents in a simple three-feeder ungrounded power system with an A-phase SLG fault on FDR3.

Detecting SLG faults on these power systems is much simpler than in a uni-ground or multi-ground power system, because when a ground fault is present, two changes occur in the power system that are easily noticeable:

- The phase-to-ground voltage of the faulted phase collapses, and the phase-to-ground voltages of the unfaulted phases increase by a factor of $\sqrt{3}$ and shift by 60 degrees. The magnitude of the voltage collapse

in the faulted phase is an indication of the magnitude of the fault resistance. The larger the voltage collapse, the smaller the fault resistance. (Note that the phase-to-phase voltages remain unchanged.)

- The zero-sequence current ($3I_0$) increases in magnitude and lags the zero-sequence voltage ($3V_0$) by 90 degrees.

The phasor relationship between the phase-to-ground voltages and the phase-to-phase voltages for a metallic A-phase-to-ground fault for the simple three-feeder distribution system is shown in Fig. 11. Also shown in this phasor diagram is the phasor relationship of the fault current ($3I_0$) to the fault voltage ($3V_0$).

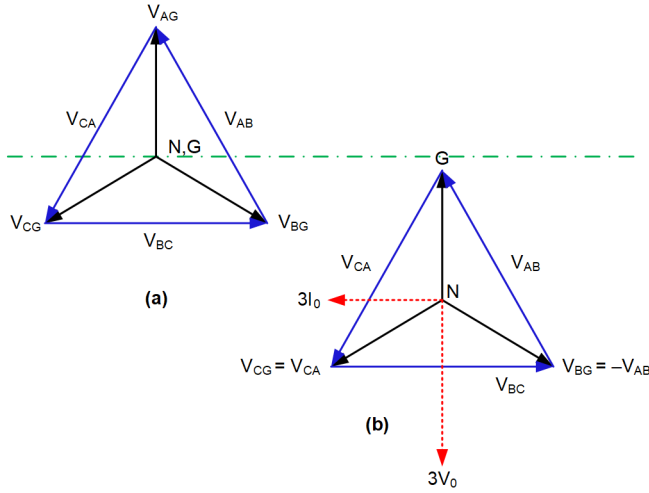


Fig. 11. Voltage phasor diagram showing the phasor relationship between (a) the phase-to-ground voltages and phase-to-phase voltages for an ungrounded power system and (b) the phase voltages, zero-sequence voltage, and current for a metallic A-phase-to-ground fault.

Because the fault current for an SLG fault is so low, it does not distort the phase-to-phase voltages and the power system can continue operating while maintenance crews locate the fault.

A further advantage of ungrounded power systems is that an SLG fault with high fault resistance ($>25 \text{ k}\Omega$) can readily be detected in these systems. This means that a downed conductor is easier to detect in an ungrounded system than in a uni-grounded or multi-grounded power system. The limiting factor in this case is the sensitivity of the measuring devices and the instrument transformers. Therefore, in an ungrounded power system, use a flux summation CT to accurately measure the zero-sequence or residual current. See the flux summation CT discussion in Section III.D.

V. FIRE-IGNITING DOWNED CONDUCTOR FAULTS AND THEIR FAULT CURRENTS

With increased frequency of wildfires in the last decade, the mechanics of wildfire ignition by electric arcing faults has been a topic of much research [18] [19]. Electric arcing faults are dynamic and random in general because they relate to ground surface material, air humidity, and wind speed. As will be discussed in Section VI, the ignition of a wildfire also has positive correlations with ambient air temperature and

humidity, ground fuel supply type and moisture content, and the released energy of arcing faults. In this section, we examine several staged downed-conductor fault tests. The staged tests were conducted on 12.5 kV multi-grounded distribution systems. Although the original purpose of these staged fault tests was to study the characteristic of downed-conductor faults on different ground surfaces, their outcomes also reinforce the importance of fuel type to potential wildfire ignition.

The first fire ignition example is from a downed-conductor test on a small tree. This example shows the dynamic process and the period it took to ignite the tree. The test was performed on a typical early summer day in late June. The weather was sunny with a little breeze. The ambient temperature was around 18.3°C (65°F) and humidity was low. The tree was a small Crimson King Maple, one inch in diameter, from a nursery. The tree was planted at the test location and watered around the root. A 12.5 kV live distribution conductor was set on the tree. It took longer than eight minutes for an arc to establish consistently between the conductor and the root of the tree and for the tree to catch fire. For the majority of the eight minutes prior to ignition, one could hear an occasional hissing sound and see a small amount of steam and smoke. As the test progressed, spot arcing on the tree was visible as well. Fig. 12 shows a picture of when the tree was on a sustained ignition close to the end of eight minutes.



Fig. 12. A Crimson King Maple tree on a sustained ignition.

The fault current for this tree fault was not as dramatic as the fault arcs. Fig. 13 shows the fault current at the test location. We see that the fault current magnitude stays mostly under one ampere all the way towards the sustained ignition at the end. This current level would be very challenging for most high-impedance detection algorithms designed for the multi-grounded distribution systems that use current components other than the fundamental or rms value.

Depending on the system standing unbalance, it may be possible in some cases for a sensitive ground overcurrent element to pick up this fault and trip a breaker before the sustained ignition on uni-grounded or ungrounded distribution systems.

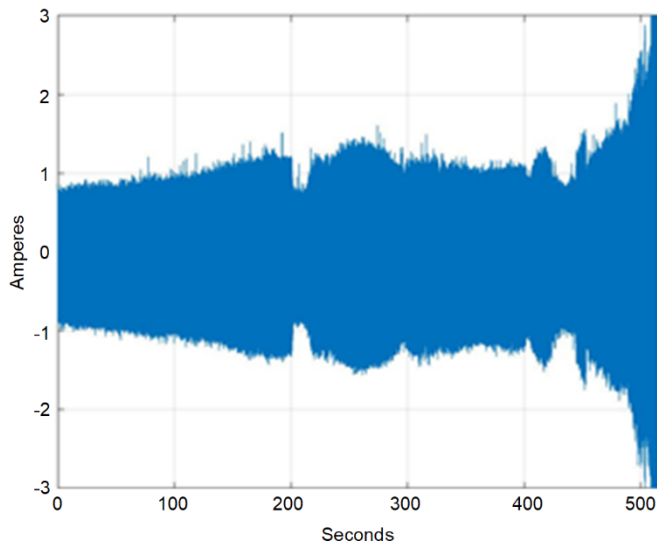


Fig. 13. Crimson King Maple tree fault current at the test site.

The second fire ignition example is a comparison of two downed-conductor faults on vehicle tires. This example demonstrates that even though the ground surface is the same (in this case vehicle tires) the outcome of fire ignition can be totally different. Many factors contribute to the result of arcing ground fault and fire ignition, including ambient temperature, humidity, wind speed, and fuel condition. In this case however, the fuel (tire) condition and the ground surface moisture content was the major determining factor of the test outcomes.

One of the tire tests was done at the same location and time as the tree test previously discussed (i.e., with ambient temperature around 18.3°C (65°F) and low humidity). The tire is a used minivan tire obtained from a tire center. A 12.5 kV live conductor was set on the tire for several minutes. The tire behaved like an asphalt surface that does not conduct any fault current. Later, some water was poured on the tire and the test was repeated. The outcome remained the same. Fig. 14 shows a picture of this test.

The other tire test was done in mid-summer in the southern part of the United States. The test day weather was mostly sunny with the temperature around 32.2°C (90°F). The humidity was relatively high at between 60 and 70 percent. The tire was a used pickup truck tire obtained from an outdoor pile of used tires. The tire condition was a bit more worn than the minivan tire in the previous test, but there was no visible steel belt exposed anywhere on the tire. When performing this test, smoke and flame immediately started when a live 12.5 kV conductor was set on the tire. The ignition time is on the millisecond scale. Fig. 15 shows a picture of this test.

The fault current level of this tire test is shown in Fig. 16. The fault current is about 6 A at the beginning and it slowly increases and levels at around 13 A. High-impedance faults at

this fault current level are typically challenging to detect on a multi-grounded, four-wire distribution system, even for detection algorithms that use nontraditional signal components other than the fundamental and rms residual current.



Fig. 14. A downed conductor on a tire that did not produce any arcing fault.



Fig. 15. Downed conductor on a tire that ignited fire immediately.

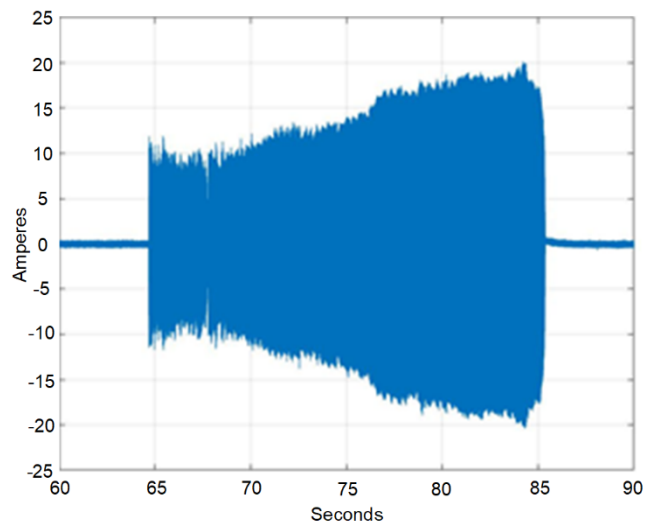


Fig. 16. Fault current of a downed conductor on a tire that ignited fire immediately.

VI. FIRE IGNITION VS. TIME, CURRENT, AND ENERGY

This section discusses factors that determine the probability of a power line fault triggering an ignition. We divide the cause of ignition by means of incandescent emission and by means of electric arc.

The largest fire in California history, the Ranch Fire, occurred in 2018 and consumed 410,203 acres. The Ranch Fire was caused by a spark from a hot metal fragment that came from a hammer driving a 24-inch metal concrete stake into the ground [20]. Even with this low energy, fire can still occur depending on weather and ground fuel conditions.

A. Probability of Ignition by Incandescent Emission

Incandescent emission is when two conductors of a high-voltage distribution line (11–22 kV) come into contact with one another, creating a phase-to-phase fault. The resulting fault current can cause pieces of the conductor (metal) to be ejected either by gas expansion, as a result of the arc, or by mechanical impact. The current in the arc and the duration of the arc determine the amount of material removed from the conductor, the size and number of particles emitted, the ejection velocity, direction, and the thermodynamic state of the particles (molten or burning) [21]. Some of the particles emitted may also be vaporized because of the intense heat.

Another important aspect is the thermochemical state of the particles generated. Depending on the metal type and how the particles are generated, the emitted particles may be solid, molten, oxidized on the surface, or burning and in a gaseous phase. When the particle is formed during conductor contact, the metal particle can be heated above the metals melting or boiling point depending how long the metal particle is exposed to the arc [22].

A study conducted by A.D. Stokes [23] in the 1980s investigated the probability of fire ignition by electrically produced incandescent particles. The study examined the probability of naturally occurring fuels, such as grass, hay, leaves, etc., being ignited by incandescent particles of aluminum, brass, copper, and steel. What the study found was that molten steel and aluminum particles formed during arcing presented a severe hazard. Incandescent steel particles generated during arcing posed the highest fire risk, igniting nearly all the test fuels. Another important outcome of this test was that whilst wind is a clear factor in the spread of fire, still or calm air was more likely to aid ignition.

From this discussion, we can see that sensitivity and speed of operation of the system protection does not come into play in this instance. When two conductors contact one another, a phase-to-phase fault is created, the magnitude of the fault current being dependent on the source strengths and the resistance of the arc. Only once the fault has occurred can protection systems detect this fault. A fast protection element can detect a phase-to-phase fault within one power system cycle and initiate tripping, with the total instantaneous fault clearing time being in the order of 3–4 cycles (50–70 ms at 60 Hz) depending on the breaker speed. However, several incandescent particles can be emitted during this time, so protective systems are not ideally suited to address this problem.

B. Probability of Ignition by Electrically Arcing Faults

In this section we examine what factors influence the probability of ignition when an electrical conductor is arcing and in contact with the fuel. In a 2011 interim report generated by HRL Engineering and Material, titled “Interim Report Probability of Bushfire Ignition From Electric Arc Faults” [18], four variables were investigated: arc duration, wind speed, air temperature and relative humidity. Of the variables investigated, ignition results suggested that arc duration, wind speed, and autoreclosing have the greatest influence on ignition probability. Air temperature and relative humidity appear to have a lesser effect on the probability of ignition.

1) Arc Duration

From the test conducted in the report [18], a set of binomial regression expressions were derived for the three different fault current magnitudes used to generate an arc. What the curves illustrated is that the higher the fault current that generated the arc, the shorter the duration the arcing time required to ignite the fuel. A plot of the arc time versus the probability of ignition under worst-case environmental conditions for different magnitudes of arc current are shown in Fig. 17.

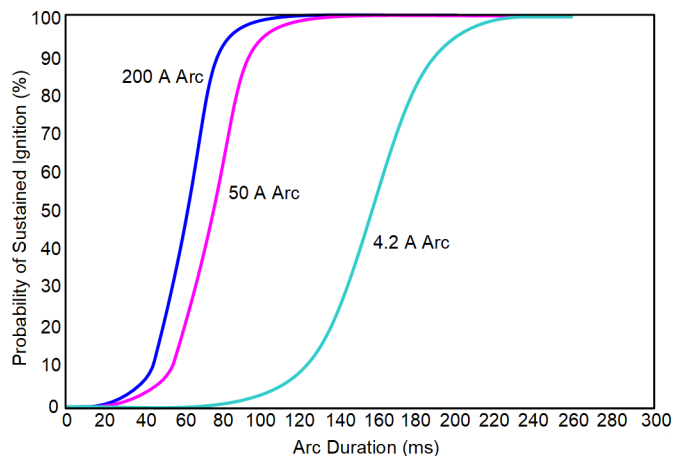


Fig. 17. Arc time versus sustained ignition.

Arc duration is a useful parameter for protection engineers because it relates directly to fault identification and fault clearance time. Arc energy release and arc duration are also related. The longer the arc duration, the higher the arc energy release. For example, assume an arc has an arc voltage equal to 20 V and an arc current of 50 A. If the arc has a duration of 50 milliseconds, the arc energy released is defined in (2):

$$\begin{aligned}
 \text{arc}_{\text{volt}} &= 20 \text{ V} \\
 \text{arc}_{\text{current}} &= 50 \text{ A} \\
 \text{arc}_{\text{time}} &= 50 \text{ ms} \\
 \text{Arc}_{\text{energy}} &= \text{arc}_{\text{volt}} \cdot \text{arc}_{\text{current}} \cdot \text{arc}_{\text{time}} \\
 &= 50 \text{ J}
 \end{aligned} \tag{2}$$

If the same arc lasted for 100 milliseconds, the arc energy released would be 100 J. This is of course if the arc voltage and arc current remain unchanged, which we know is unrealistic, but it reinforces the point that the longer the arc persists the more energy the arc releases.

2) *Wind Speed and Autoreclosing*

Wind increases the supply of oxygen to fire and will fuel a fire, but high wind speeds dramatically reduce the probability of ignition because of the cooling effect of airflow, and the wind removes the pyrolysis gases. In addition, airflow will also extinguish arcs, particularly at low currents. Higher wind speed increases the number of faults because of falling tree branches or mechanical failures of distribution system components. Higher wind speed also increases the spread of fire once an ignition is sustained.

Part of the ignition report also investigated the effects that autoreclosing had on the probability of ignition if the fault was sustained. Two dead-time interval test series were conducted. In the first test series, the dead-time interval was 5 seconds. In the second test series, the dead-time interval was 30 seconds. What the investigators found was that if the dead time was 30 seconds, the initial fault and the reclose onto the fault had about the same probability of ignition. In other words, if the dead time was 30 seconds, the two faults could be treated independently. If the dead time was 5 seconds, then the reclose attempt had a higher probability of ignition than the initial fault. Therefore, the two events are not independent of each other and a low-risk probability of ignition can nearly double during a reclose attempt. Therefore, on days when the fire risk is extreme, utilities may consider increasing the dead time or canceling autoreclosing.

An important question to ask is “What is the minimum arc current required to initiate ignition?”

In a vegetation conduction ignition test report [19], two specific cases were analyzed to help answer this question for a uni-grounded power system, as found in the Australian state of Victoria.

- Ignition in branch-to-wire ground fault:
A branch-to-wire fault emulates a tree branch touching a live distribution overhead conductor (wire). Applying a traditional ground-fault pickup setting which is 5–10 A primary for a rural feeder, a ground fault that involves a tree branch touching a live conductor will result in ignition under the worst-case condition. However, if the pickup setting was reduced to 0.5 A primary and the time delay was set to 2 seconds, then the probability of ignition for a branch-touching-wire ground fault will be reduced tenfold.
- Ignition in wire-into-vegetation ground fault:
A wire-into-vegetation fault emulates a downed conductor on bushes or grasses without touching the ground directly. This type of fault poses a higher fire risk than the branch-to-wire faults. In these cases, if the earth fault sensitivity pickup setting could be set to 0.5 A primary, the fire risk posed by these faults could be reduced by 80 percent.

From both of these cases we can see that if the pickup setting for the sensitive earth fault protection element can be reduced to 0.5 A primary this will significantly reduce the probability of ignition.

We understand that the conclusions from this test program are derived from designed test setups. There are various factors that will influence the outcome of a particular test. Nevertheless, the numbers provided by the report provide a picture how fault current levels relate to the probability of a fire ignition.

VII. CONCLUSION

The choice of grounding scheme in a power distribution system determines many characteristics of the system. The number of distribution conductors, load transformers, equipment thermal stress, required equipment voltage insulation level, and fault detection all depend on the grounding scheme. This paper focused on the sensitivity of ground fault detection amid well-spread concern of recent reported wildfire ignitions by power distribution equipment.

The multi-grounded, four-wire distribution systems are the most common in North America. Detecting high-impedance ground faults in such systems is very challenging because for a ground relay element, system residual current from load unbalance appears the same as ground fault current. This requires much higher ground relay settings that result in less sensitivity than other grounding systems. Protection design engineers have employed other signal components such as harmonic or high-frequency content of phase currents to improve high-impedance fault detection. These nonfundamental components are much smaller in magnitude than the fundamental-frequency component, as well as more easily attenuated. High-impedance faults resulting from downed conductors on poorly conducting surfaces may have the same electrical characteristics of a cracked and leaking insulator or other scenarios, making it challenging for a relay to detect without false indications.

Uni-grounded and ungrounded distribution systems have their loads connected phase-to-phase with rare exceptions. Phase-to-phase connected loads do not generate residual unbalance currents. Any standing unbalance current that comes from asymmetries of feeder construction, power equipment such as transformers, and mismatched phase CTs is typically a few amperes. This allows for much lower ground relay settings that result in more sensitivity than is possible on multi-grounded systems. With today's sensitive current inputs of digital relays, flux summation CTs to eliminate phase CT imbalances, and low CT ratios, it is possible to detect more high-impedance faults. Ground fault neutralizer methods hold some promise to increase sensitivity and reduce fault current, but they are expensive by requiring unit-grounded systems to implement. They drastically change the time-current coordination practices used by most North American utilities.

Wildfire ignition from power equipment is a complicated dynamic process. A sustained fire ignition depends on many ambient conditions like temperature, humidity, and wind speed. It also depends on the types and conditions of ground surface and fuel. We show that it may take more than eight minutes to ignite a Crimson King Maple tree with a 12.5 kV live conductor. We also show a vehicle tire may or may not be ignited depending on the conditions of the ground and the tire.

Many recent reports provide more complete studies on fire ignitions. In addition to many other parameters, the released energy from an arcing fault has a well-known positive correlation to the fire ignition. Some definite findings, such as less than 0.5 A fault current reducing fire ignitions by 80 percent, provide a target for protection engineers to relentlessly find ways to improve ground fault detection sensitivity. Relay settings and fault current levels can reduce the probability of an electrical fault igniting a fire, but no method can reduce fault energy low enough to eliminate the risk. This is very apparent when we consider the cause of the largest California wildland fire that was started by a spark from someone hammering a metal stake in dry vegetation.

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IX. BIOGRAPHIES

Scott Hayes received his BSEE from California State University, Sacramento in 1985. He started his career with Pacific Gas and Electric Company in 1984 as an intern. Since then he has held multiple positions in System Protection including supervisor, as well as Distribution Engineer, Operations Engineer, Supervising Electrical Technician, Supervising Engineer in Power Generation and is currently a Principal Protection Engineer focusing on standards, procedures and quality. Scott has previously co-authored papers for the Western Protective Relay Conference, Georgia Tech, TechCon Asia Pacific, CEATI Protection and Control Conference and Transmission and Distribution World Magazine. Topics include Thermal Overload Relays for Intertie Lines, Data Mining Relay Event Files to Improve Protection Quality, Effects of CCVT Ferroresonance on protective relays and PG&E's Wires Down Program. Scott is a registered Professional Engineer in the state of California and has served as Chairman of the Sacramento Section of the IEEE Power Engineering Society. He is currently the chairman of the CEATI Protection and Control Program and is a member of the NATF protection core team. He has also served on a NERC Standard Drafting Team.

Daqing Hou received BSEE and MSEE degrees at the Northeast University, China, in 1981 and 1984, respectively. He received his PhD in Electrical and Computer Engineering at Washington State University in 1991. Since 1990, he has been with Schweitzer Engineering Laboratories, Inc., where he has held numerous positions, including development engineer, application engineer, research and development manager, and principal research engineer. He is currently the research and development technical director for East Asia. His work includes power system modeling, simulation, signal processing, and advanced protection algorithm design. His research interests include multivariable linear systems, system identification, and signal processing. Daqing holds multiple patents and has authored or coauthored many technical papers. He is a senior member of IEEE.

Normann Fischer received a Higher Diploma in Technology, with honors, from Technikon Witwatersrand, Johannesburg, South Africa, in 1988; a BSEE, with honors, from the University of Cape Town in 1993; an MSEE from the University of Idaho in 2005; and a PhD from the University of Idaho in 2014. He joined Eskom as a protection technician in 1984 and was a senior design engineer in the Eskom protection design department for three years. He then joined IST Energy as a senior design engineer in 1996. In 1999, Normann joined Schweitzer Engineering Laboratories, Inc., where he is currently a fellow engineer in the research and development division. He was a registered professional engineer in South Africa and a member of the South African Institute of Electrical Engineers. He is currently a senior member of IEEE and a member of the American Society for Engineering Education (ASEE). Normann has authored over 60 technical and 10 transaction papers and 20 patents related to electrical engineering and power system protection.