High-Impedance Fault Detection—Field Tests and Dependability Analysis

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***Abstract*—Because of low-fault currents, high-impedance faults neither interrupt service to customers nor cause thermal damage to power system equipment. However, high-impedance faults resulting from downed conductors are potentially hazardous to humans and livestock and are a concern for public safety. A high-impedance fault should be rapidly isolated when detected. Traditional substation–based overcurrent protection relays reliably detect high-current, short-circuit faults. The same cannot be said about substation-based high-impedance fault detection devices because of low or nearly zero fault current. In some situations, the standing load unbalance in multigrounded systems can be higher than the high-impedance fault current. Therefore, the detection rate of a high-impedance fault is often used to verify the presence of a high-impedance fault. This paper uses several high-impedance fault field tests to explain how to develop a detection rate and answers the question of whether there is a detection rate applicable for all circumstances. The paper first introduces details of the field tests: test setups, weather conditions, ground materials, and fault currents. It then provides comparative test results. Finally, the paper analyzes the security and dependability of high-impedance fault detection and provides the reader with insight into the statistical detection rate.**

I. Introduction

High-impedance faults are those with a high resistance in the fault path. The value of the fault resistance for a fault defined as a high-impedance fault depends on interpretation and circumstances. For the purpose of this paper, high-impedance faults are ground faults that produce fault currents below the traditional ground overcurrent element pickup level.

Some typical causes of high-impedance faults are listed below:

- incipient insulator failure
- trees or bushes that come into contact with overhead power lines
- conductors that fall onto poorly conductive surfaces

For distribution networks with voltage levels lower than 35 kV, high-impedance faults resulting from downed conductors are a concern for public safety. High-impedance faults do not cause traditional ground overcurrent elements to operate, so these faults can exist in a distribution system for an extensive period without being detected. The small current from a high-impedance fault does not impact normal power distribution, but such a fault can appear so harmless that humans or livestock can be electrocuted from accidental contact with a downed conductor. The downed conductor can also cause fire damage to structures and other properties.

Since the early 1970s, the problem of high-impedance faults has caught the attention of the public as well as that of protection engineers. Over time, utilities worldwide have conducted many field tests to support research and development of detection algorithms for these low-current faults. Today, there are several commercial devices available that can increase the possibility of detecting these faults.

As we shall see, high-impedance faults are dynamic and random. Some downed conductors cause no fault current to flow. Therefore, substation-based detection devices will not reliably detect all downed conductor or high-impedance faults. The tangible objective in dealing with high-impedance faults is to increase the possibility of fault detection while maintaining detection security.

Because of this nondeterministic detection of less than 100 percent, the first thing we generally discuss when evaluating high-impedance fault detection devices is the so-called fault detection rate. What percentage of high-impedance faults can a particular device detect? Some relay manufacturers have associated values ranging from 80 percent or even closer to 100 percent to their devices.

In this paper, we look at some details of several high-impedance field fault tests and summarize the results. The aim of this paper is to evaluate the validity of any specific number associated to the detection rate. So that the reader can better appreciate the challenges of high-impedance fault detection, we shall first provide some background on high-impedance faults. We will discuss how different system grounding schemes govern the best fault detection methods and provide some high-impedance fault detection fundamentals.

II. High-Impedance Faults

High-impedance faults generate low-fault currents. Field tests on distribution systems in North America with a typical voltage of 12.5 kV indicate that fault currents of high-impedance faults are less than 100 A. Higher distribution voltage tends to increase the fault current and cause less high-impedance fault concerns.

The fault current level relates closely to the type of ground surfaces that a conductor touches. The level also depends on the ground surface moisture level. Other factors such as surrounding soil types and nearby structures also impact the fault current level. Fig. 1 summarizes the fault current ranges for different ground surface materials when a bare conductor touches them [1]. We see that asphalt and dry sand are good insulators. There is no measurable fault current when a conductor touches these surface materials. By using 12.5 kV as the mean test voltage, we can conclude that the minimum high-impedance fault resistance (approximately 95 Ω) is for reinforced concrete.

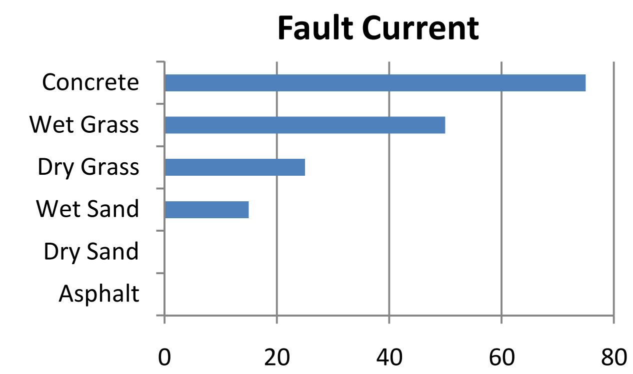

Fig. 1. High-impedance fault currents depend on ground surface types

High-impedance fault currents are rich in harmonics and nonharmonic content. The harmonic content results from a fault that involves an arcing process. In their experiments of electric arcs, Kuffman and Page [2] found that the arc current starts to flow when the applied voltage reaches a breakdown voltage level of an air gap. The arc current continues to flow after the applied voltage is less than the breakdown voltage level and until satisfaction of an equal-area criterion. The voltage across the arc remains constant when arc current flows. The arc can restrike during the next half cycle when the voltage reaches the breakdown voltage level again. The upper plot of Fig. 2 shows a fault current from a downed conductor on bare ground. The lower plot shows the large percentage of odd harmonics resulting from arcing activities.

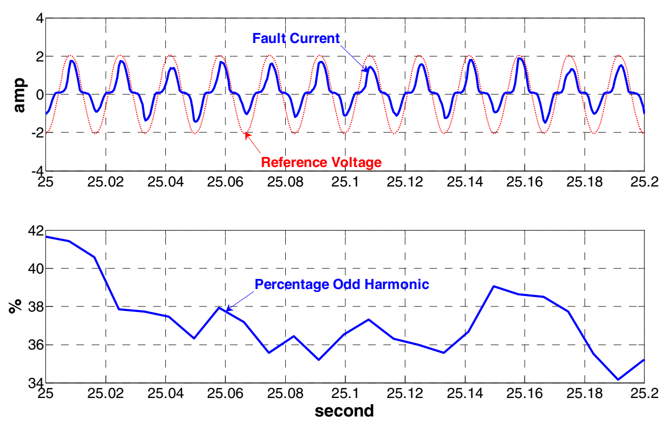

Fig. 2. High-impedance fault current contains rich harmonic content

High-impedance faults have a dynamic behavior. The heat generated by the arcing fault tends to remove moisture in most ground surfaces. The high temperature can cause chemical reactions that change surface conductivity. The electromagnetic force associated with arcing can also make the downed conductor move about. Different seasons and different times of day can also impact ground surface conductivity. These dynamic characteristics of high-impedance faults change the level and content of fault currents accordingly and make fault detection a random process.

III. System Grounding and High-Impedance Fault Detection

Distribution systems use different grounding methods to achieve the following objectives [3]:

- minimize equipment voltage stress
- minimize equipment 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 ground methods. The practice of grounding the system seems more localized, as references [3] and [4] indicate. Each region normally has its own preferable grounding scheme, although some grounding methods are more common for industrial plants. Grounding methods include the following:

- ungrounded or isolated neutral
- resonant grounding
- high-resistance grounding
- effective (solid) grounding (includes unigrounding or multigrounding)
- low-impedance grounding

The first three grounding methods (ungrounded, resonant, and high-resistance grounded) have similar characteristics. We sometimes refer to these as small ground-fault-current, or small-current, grounding methods. By contrast, we refer to the last two grounding methods (effective [solid] and low-impedance groundings) as large-current groundings. These methods possess characteristics almost opposite those for small-current grounded systems.

There is no single grounding scheme that can achieve every objective listed previously. Each grounding method brings certain benefits but sacrifices other properties.

A. Small Ground-Fault-Current Systems

Ungrounded systems, as Fig. 3 shows, have no intentional grounding. Fault resistance and stray capacitances of distribution transformers and feeders determine the ground fault current. The fault current is normally quite small. Some of the benefits of ungrounded systems include minimum equipment thermal stress, continued service during a single ground fault condition, and self-extinction of ground faults when the capacitive fault current is small.

The stray capacitance of a large ungrounded system can support enough fault current so that a fault is less likely to self-extinguish. In this situation, we can connect a reactor known as a Petersen or arc-suppressing coil to the neutral point of a station transformer. The reactor is ideally tuned to match the system phase-to-ground capacitance, thereby reducing the fault current to about three percent to 10 percent of an ungrounded system.

To reduce transient overvoltage in an ungrounded system, we can connect a resistance to the neutral point of a station transformer to obtain a high-resistance grounded system. The resistance value is typically equal to or slightly less than one-third of the total system zero-sequence capacitance. This limits the transient overvoltage to less than 2.5 times the peak nominal phase-to-ground voltage and keeps the ground fault current to less than 25 A.

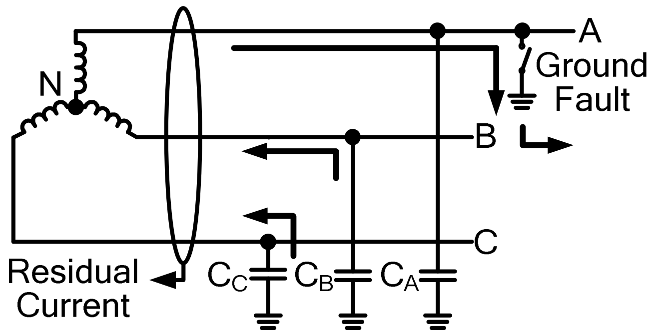

Fig. 3. An ungrounded distribution system

These three grounded schemes (ungrounded, resonant grounded, and high-resistance grounded) limit ground fault current to such a small value as to pose a challenge for selective and fast ground fault protections.

However, as microprocessor-based relays improve their measurement sensitivity, and relay manufacturers design improved detection algorithms, ground faults on these types of grounded systems become easier to detect.

All loads on these systems are connected phase-to-phase, which makes it easier to detect high-impedance faults. There is no residual current from loads. The asymmetry of feeders, transformers, and other equipment causes some standing residual current, but these unbalances are usually very small.

Reference [3] reports that directional overcurrent elements designed specifically for ungrounded systems can detect ground faults with tens of kilohms of fault resistance. The same reference also introduces a delta conductance element that can detect an 80 kΩ fault on a simulated resonant grounded system. In addition to deterministic detection of ground faults, reference [5] also shows faulted-phase selection logic that indicates reliably which phase is at fault.

System standing unbalance and measurement errors determine ground fault detection sensitivity. Use a dedicated toroidal current transformer (CT) to eliminate measurement unbalance error from three phase CTs as one way to improve system sensitivity. Dedicated toroidal CTs also allow a lower CT ratio, to increase the residual current measurement sensitivity of protective relays.

Notice that we define high-impedance faults as those ground faults with fault current less than traditional overcurrent pickups. In this sense, we can categorize many ground faults with large fault resistances in these small fault-current systems as normal ground faults that we can detect reliably.

B. *Large Ground Fault-Current Systems*

An IEEE standard [6] specifies that effectively grounded systems comply with $(X0/X1) \leq 3$ and $(R0/X1) \leq 1$, where X0 and R0 are the zero-sequence reactance and resistance, and X1 is the positive-sequence reactance of the system. Solidly grounded systems have their neutral point of the station transformer connected to the ground without intentional grounding impedance. A solidly grounded system may not be effectively grounded, depending on the quality of the grounding. A well-designed, solidly grounded system should also be an effectively grounded system.

Solidly grounded systems can be unigrounded or multigrounded. Unigrounded systems have a single grounding point typically at the station transformer neutral point. This type of system can be a four-wire system with a neutral wire brought outside the substation, or a three-wire system without the neutral wire. Some utilities connect small loads from a phase wire directly to the ground in unigrounded systems.

Another type of solidly grounded system is a four-wire multiple-grounded system such as Fig. 4 shows. To ensure an effective grounding, a multigrounded system typically grounds its neutral wire at every distribution transformer location and/or regularly about every 1000 feet, if there is no transformer ground point.

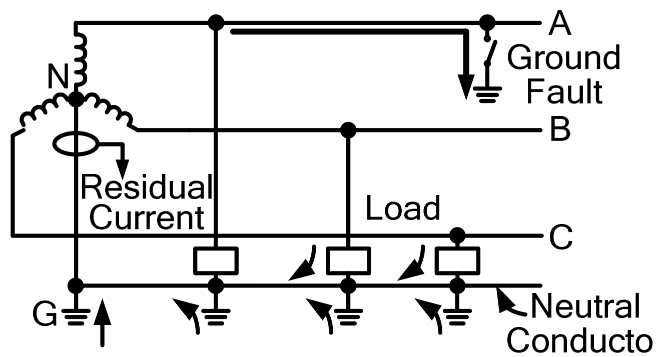

Fig. 4. A multigrounded distribution system

To reduce the ground fault current level for systems with small zero-sequence source impedance, we can use a low-impedance resistor or a reactor to ground the station transformer. This low-impedance grounding typically limits fault current to 100 A–1000 A to reduce thermal stress on equipment.

Solidly grounded systems limit the risk of overvoltages during ground faults and reduce equipment cost; necessary equipment insulation levels can be 1.73 times less than for small current grounding systems.

The drawback of these large current grounding schemes is that single-phase loads produce large standing unbalance that flows in the same path as the ground fault current (Fig. 4). This large standing unbalance therefore reduces ground fault detection sensitivity. System operating engineers do a good job of balancing overall system loads to minimize the amount of standing residual current. However, ground fault protection must consider the worst possible unbalance, because a fault can occur when a large single-phase lateral is out of service.

It should be clear by now that the determining factor for high-impedance fault detection is not the available ground fault current (fault duty) of a distribution system, but the worst system standing unbalance during normal operations. Solidly grounded and low-impedance grounded systems have a much greater ground fault duty than do small-current systems. However, at the fault resistance level of high-impedance faults, the fault currents that large-current systems provide drop to almost the values for small-current systems. It is the worst possible standing unbalance of the large-current systems that makes the detection of high-impedance faults a daunting task.

IV. High-Impedance Fault Detection of Solidly Grounded Distribution Systems

A. Traditional Ground Fault Protection Considerations

To improve protection sensitivities for the most common single-phase ground faults, utilities have been using low-set ground relays [7]. These ground relays work on a residual current that they either calculate by summing the three phase currents or measure directly from a residual connection.

However, the great number of single-phase loads can cause multigrounded distribution systems to be quite unbalanced. Even worse, the amount of load unbalance is dynamic and changes with system operation conditions. As an example, the three-phase loads at a substation may be well balanced. After a permanent fault occurs on a single-phase lateral, and the fuse clears the line, the system loads may become unbalanced. This increased residual current from a lateral outage may inadvertently operate a feeder relay at the substation.

As a consequence, utility engineers consider the worst system load unbalance when setting the pickup of a ground relay. The worst load unbalance, on top of the considerations of cold load pickup, transformer inrushes, and coordination with downstream ground relays, makes the ground relay protections not as promising as they initially seemed to be. Some utilities have even quit using all ground relays because of unpredictable load unbalances. Of utilities that use ground relays, a survey [7] indicates that engineers often set the ground relay pickups as a percentage of estimated load unbalance, a percentage of phase relay pickups, or a percentage of feeder load rating. The protection functions of these ground relays for high-impedance faults are therefore diminished.

B. High-Impedance Fault Detections

High-impedance faults have fault current less than 100 A. These faults are masked by load unbalances in solidly grounded distribution systems. Traditional ground overcurrent elements cannot detect these faults. To detect these faults, we must use detection algorithms that use current characteristics other than magnitude.

Arcing activity often accompanies high-impedance faults because of poor conductor contacts to a ground surface or because of poor conductivity of the ground surface itself. These arcing activities, together with the dynamic nature of the high-impedance fault, are responsible for the large harmonic and nonharmonic content in the fault current. For this reason, most high-impedance fault detection algorithms use the harmonic or nonharmonic content of the fault current.

We must understand that some nonlinear loads in distribution systems generate harmonic and nonharmonic current under normal operating conditions. An extreme example of a noisy load is an electric arc furnace such as foundries use for cast metal production. Other noisy loads include rail train, motor drives, car crushers, and switched power supplies used in modern electronic equipment.

For high-impedance fault detection algorithms that use non-fundamental quantities, the difference between nonharmonic quantities from normal load and a fault will impact the sensitivity of fault detection. This impact is similar to that of load unbalance on traditional ground overcurrent protection. To minimize this impact, a detection algorithm should employ additional technologies to differentiate high-impedance faults from normal noisy loads.

Many technologies have been used for detecting high-impedance faults. These include statistical hypothesis tests, inductive reasoning and expert systems, neural networks, third harmonic angle analysis, wavelet decomposition, decision trees, and fuzzy logic [8]. Regardless of many available advanced detection algorithms, the detection of high-impedance faults remains a challenging problem.

It is important to realize that it is impossible to detect all high-impedance faults with a substation-based device. For those downed conductor faults involving asphalt and dry sand that produce no fault currents, only distributed detection solutions aided by communication and customer calls can provide a complete solution.

Reference [8] proposes a detection algorithm that has a realistic objective in mind. This objective is to increase high-impedance fault detection as much as possible on top of traditional ground fault protections, while maintaining detection security. We have identified the following key elements as necessary for a successful detection algorithm:

- An informative quantity, such as the nonharmonic content of fault current, that reveals high-impedance fault signatures while remaining immune to noisy loads.
- A stable reference for the quantity that effectively quantifies prefault conditions.
- An adaptive learning feature that characterizes each feeder ambient condition while allowing seasonal load changes.
- An effective decision logic that further screens high-impedance fault properties such as the dynamic nature of the faults.

Fig. 5 shows the block diagram of the proposed detection algorithm.

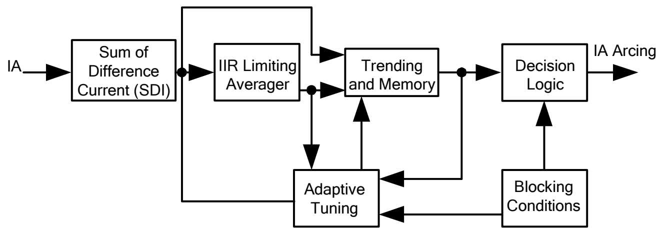

Fig. 5. Block diagram of high-impedance fault detection

The first function block calculates a signal quantity upon which the algorithm bases its high-impedance fault detection. This quantity is called the sum of difference current (SDI). An infinite-impulse-response (IIR) limiting averager then establishes a stable reference for SDI. The trending and memory block compares the present SDI with the SDI average and memorizes the time and ratio of the present SDI, if the present SDI is greater than a set threshold for the SDI average. The decision logic uses the results from the trending and memory block to determine the existence of a high-impedance fault on the processed phase. The adaptive tuning block monitors feeder background noise during normal system operations and establishes a comparison threshold for the trending and memory block. The IIR limiting averager also uses this threshold to prevent the averager input magnitude from becoming too large.

V. Field High-Impedance Fault Tests

Because of the dynamic and random nature of high-impedance faults, it is quite difficult to simulate these faults. We have seen some complex models that use nonlinear resistors and diodes to emulate the arcing phenomenon, but the validity of these models remains questionable in studying high-impedance faults.

There are many factors that impact the outcome of a downed conductor high-impedance fault. Among these factors are the type of ground surface, moisture content, condition of the surface, the voltage level, the type and size of conductor, the weather conditions, and humidity. It would be misleading, for example, if we referred to a ground surface as gravel without giving additional details such as the size of rock fragments, the thickness of the gravel surface, and the purity and types of gravel.

To study high-impedance faults and test the fault detection algorithm, we performed several staged fault tests with different utilities. These tests covered a large geographical region in North America and one in South America. Some of the tests are similar to those reference [9] describes. Table I shows the summary of these tests.

Table I.
Summary of HIF tests

Test	Test Date (Y,M,D)	Voltage Level	Distance	Temperature	Humidity	Test Surfaces[a]	Notes
A(1)	20050607	13.2 kV	12.7 mi	90°F	Humid	e, s, c, a, g, tr	Shower day before test.
A(2)	20050608	13.2 kV	1.8 mi	90°F	Humid	e, s, c, a, g, tr, ti	Shower night before test.
B	20050611	13.8 kV	13.9 mi	90°F	Dry	e	Dry season.
C	20050903	13.8 kV	13.9 mi	63°F	~70 %	e	Rainy season, wet ground.
D	20050623	12.5 kV	1.0 mi	80°F	Dry	e, c, g, tr, ti	Wet ground from sprinklers.
E(1)	20080826	13.2 kV	12.7 mi	92°F	Humid	e, s, c, a, g, tr	Hot and humid.
E(2)	20080827	13.2 kV	1.8 mi	95°F	~60 %	e, s, c, a, g, tr, ti	Hot and humid.
F	20090806	13.8 kV	7.3 mi	80°F	Rain	c, g	Rains on and off.

[a] e–earth, s–sand, c–concrete, a–asphalt, g–gravel, tr–tree, ti–tire

We used data acquisition systems that sampled currents and voltages at 20 kHz to record all tests. Normally, we recorded three-phase voltages and currents of the feeder under test and the fault current and voltage at the test site. In Test E, we also recorded the voltage and current at a location between the substation and the test site and those of one healthy feeder in the same substation. In the later E and F tests, we used GPS receivers to synchronize the data recordings of different locations. We attempted to record 1 minute prefault data and 3-minute fault data (or as long as a downed conductor fault could hold without blowing a fuse).

We performed all tests by lowering an energized conductor to a test surface with either a hot rod or control ropes. This test process is designed for personal safety and to control a test on a relatively small pre-made test surface. Reference [9] provides details of tests similar to those in Table I. In Test B, we initially dropped a covered or stripped conductor on the ground to emulate a downed conductor situation. However, the conductor was eventually held to the ground to make a better contact for larger fault currents.

Test A includes two test locations. A(1) is about 12.7 miles from the substation, and A(2) is about 1.8 miles from the substation. We performed Test E three years later on the same feeder and at the same two locations. The weather and ground conditions are very similar in both tests. The test method and the ground surfaces we used are exactly the same for both tests.

Table II and Table III show the fault currents of Test A and Test E. These results should be comparable because of similar test and weather conditions. However, we observed several differences. The earth fault in Test E produced more fault currents than Test A. This is surprising, especially when there was a rainstorm the night before Test A(2). The concrete fault yielded opposite results. The average fault current of Test A is more than that of Test E. We do not recall any differences with the reinforced concrete pads for both tests.

It is hard to compare the results of gravel tests. This is because we constantly changed such surface conditions as thickness and moisture content to try to get different results. When the gravel layer is too thin, the arc may also find a path directly to the ground and invalidate the test as a true gravel test.

The same can be said regarding the tree tests. Because of the variance of tree samples and the length of a test, it is hard to compare a tree fault even at the same location. Reports indicate that developing a fault on a tree limb takes time that depends on the voltage level, the moisture content, and the length of the tree limb. Once we establish a carbon track, however, fault current increases quickly. The current levels listed in the following tables are for well-established faults with arcs passing through the tree limb between the conductor and the ground.

TABLE II
AVERAGE FAULT CURRENTS FOR REMOTE TEST SITE

Test	Earth	Concrete	Wet Gravel	Tree
A(1)	32	10	25	16
E(1)	55	8	30	40

TABLE III
AVERAGE FAULT CURRENTS FOR CLOSE TEST SITE

Test	Earth	Concrete	Wet Gravel	Tree	Tire
A(2)	40	28	14	38	20
E(2)	70	10	12	10	15

We conducted Test B and Test C on the same feeder and at the same location. These two tests are three months apart, but Test B is in the dry season of the region and Test C is in the rainy season. Both tests include a covered conductor (tree wire) on the ground, stripped (bare) conductor on the ground, wet ground, and grounding rod(s). Note that there is no standard on the insulation level of the covered conductors. The cover is to prevent faults from tree limbs touching an overhead conductor.

From Table IV, we see an increased fault current level for the rainy season Test C. The “wet earth” in the table refers to ground that is very wet, almost like a mud hole. Finally, we used one 1-meter ground rod for Test B and three 1-meter ground rods for Test C.

TABLE IV
AVERAGE FAULT CURRENTS OF TEST B AND C

Test	Earth	Wet Earth	Ground Rod(s)
B	3	5	5
C	10	20	35

Table V lists the average fault current magnitudes of Test D for different ground surfaces. The test site was at the utility operating training center, where a sprinkler system was available. The ground is not wet during the test, but, given the high fault current magnitude of the earth test, the adjacent area was probably saturated. The gravel the test used is close to railroad gravel, which has larger size pieces than those we used in Test A and Test E.

One interesting note from Test D is that a test on a wet tire generated no fault current during a 2-minute test. Fig. 6 shows a picture of this test. The tire was a recently swapped-out used minivan tire we obtained from a tire center. This test is quite different from that of Test E for a dry tire, in which the tire caught fire immediately after the energized conductor touched it, as Fig. 7 shows. The tire we used in Test E was also a recently swapped out small truck tire.

TABLE V
AVERAGE FAULT CURRENTS OF TEST D

Test	Earth	Concrete	Gravel	Tree	Tire
D	145	10	3	70	0

Fig. 6. Wet tire test – no fault current during a 2-minute downed conductor

Fig. 7. Dry tire test –generates 15 A fault current immediately

Test F is the only test we conducted on a unigrounded distribution system. The utility reports that most urban loads are fed by three-phase delta/grounded-wye distribution transformers. However, in rural areas, some loads can be 500 km away from a substation. These remote loads are fed single-phase to the ground and may produce as much as 40 A to 60 A standing unbalance.

The test location is close to a coastal area where short and sudden storms are common. The ground was quite wet from showers just before the test. Table VI shows the fault current on two test surfaces: concrete and gravel. The concrete test was short because of a 6 A fuse blow. The 15 A gravel fault current came from an average 3-inch-thick wet gravel pile.

TABLE VI
AVERAGE FAULT CURRENTS OF TEST F

Test	Concrete	Wet Gravel
F	22	15

Several tests include asphalt as a test surface. Asphalt is a good insulator. Regardless of how long we performed a test or how wet the surface was, asphalt tests generated no fault current. We would have measured nothing at the substation, so it is easy to understand that no substation-based detection device will detect this type of fault.

Some tests also included sand as a ground surface. Dry sand is also a good insulator. An energized conductor on a 2-inch layer of dry sand did not produce any fault current. When we made the sand wet or made the sand layer thinner, the test results became more unpredictable. The upper plot of Fig. 8 shows a typical fault current from a 2-inch wet sand test. The lower plot of Fig. 8 shows the faulted phase current at the substation. The upper and lower plots are time synchronized. We observe that the fault current can increase suddenly when it finds a good conductive path. When the heat fuses the sand into silicon composite and changes the conductivity, the fault current drops. Some conductor movements by the test operator may also play a role in finding some good conductive paths.

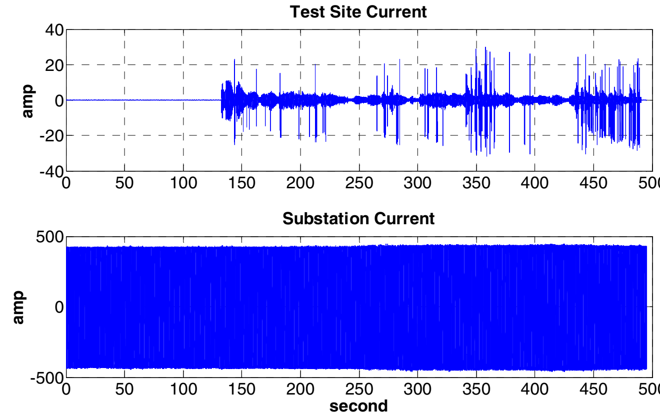

Fig. 8. Typical fault current of wet 2-inch layer sand

VI. The Mysterious Detection Rate

Because a substation-based device cannot detect all high-impedance faults, we tend to use a number or a so-called detection rate to describe the percentage of high-impedance faults that a device can detect. Some device manufacturers have claimed 80 percent detection from their devices, and others even claim a detection rate close to 100 percent.

We have seen in previous sections that a downed conductor on dry sand and asphalt produces no fault current. So what can we claim regarding the detection rate of downed conductor faults in an urban area that unfortunately has mostly asphalt pavement? In the following discussion, we use several comparable cases as examples to demonstrate the complications of detecting high-impedance faults.

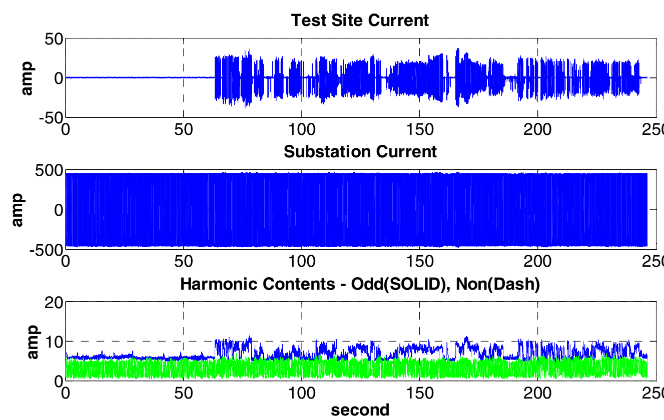

Fig. 9. A gravel fault from Test E(1)

The first example is for gravel faults. Fig. 9 shows a gravel test from Test E(1). The upper plot is the fault current at the test site. The middle plot is the measurement of the faulted phase current. The bottom plot shows the odd harmonics and off harmonics in solid and dash traces, respectively. The fault current is about 25 A. We do not see much off-harmonic activity from the fault, but the fault does generate a large change in odd-harmonic content of the station current. A high-impedance fault device successfully detected this fault.

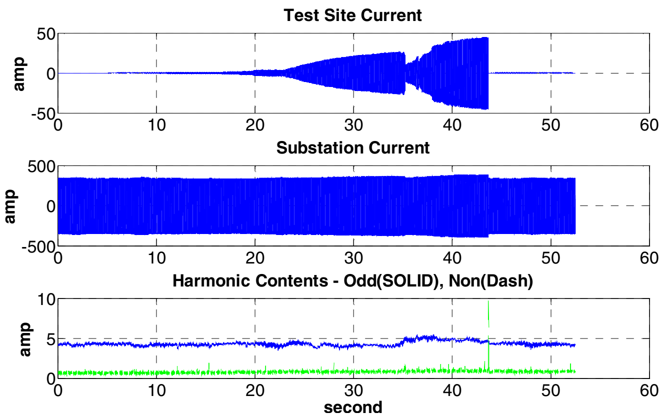

Fig. 10. A gravel fault from Test A(1)

Fig. 10 shows a gravel test from Test A(1). As we pointed out before, the weather, ground, and test conditions are very similar to the fault test in Fig. 9. The fault current is about 31 A, larger than that of Fig. 9. However, the same fault detection device failed to pick up this fault. From the bottom plot of Fig. 10, we see insignificant changes in odd harmonics and off harmonics generated by the fault.

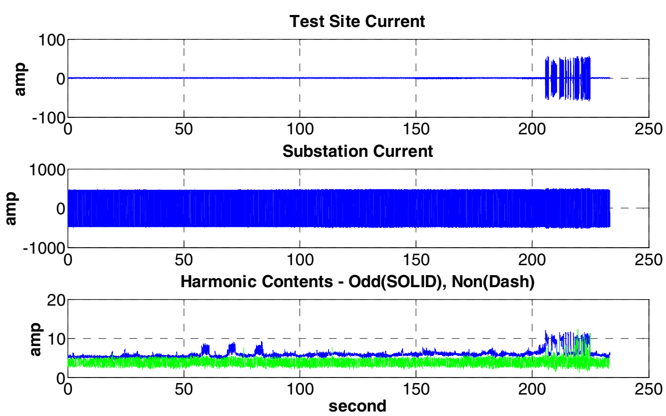

Fig. 11. A tree fault from Test E(1)

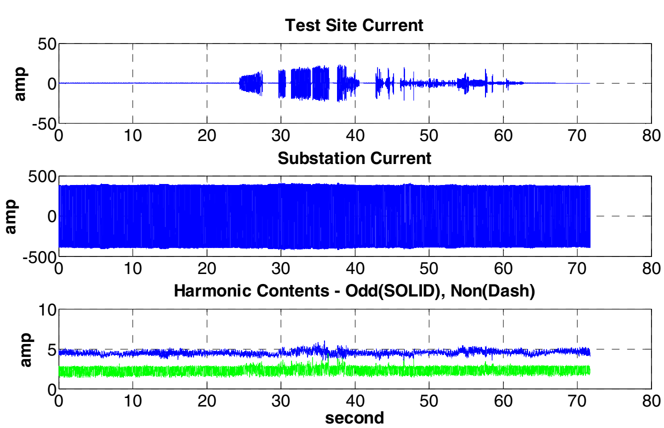

Fig. 12. A tree fault from Test A(1)

The second example is for tree faults. Fig. 11 and Fig. 12 show two downed conductor faults on a tree branch, from Test E(1) and Test A(1) respectively. The fault of Test E(1) generated enough off-harmonic content at the substation so that the fault detection device picked up the fault easily. The fault from Test A(1) however, did not have enough off-harmonic content, so the device failed to detect the fault.

These examples illustrate that faults occurring on the same feeder, at the same location, and on the same ground surfaces have subtle differences in the harmonic contents of fault currents and result in quite different fault detection outcomes. Similar previously undetected faults could be detected at a different time.

Finally, the fault detection device has demonstrated a high probability in detecting such earth faults as in Tests A(2) and E(2). However, the same device did not detect as many earth faults from Tests A(1) and E(1). Fig. 13 shows one of the earth faults from Test E(2) that the device detected. The fault current is about 70 A. We see that there is a large harmonic content in the substation current. Fig. 14 shows one of the earth faults from Test A(1). From the bottom plot, we see that the fault did not produce enough harmonics for the detection device. The comparison of these two tests illustrates that for similar earth faults that are about 10 miles apart, the composition of soil dictates the outcome of the fault current and, therefore, the detection results. It is generally true that a detection device has a greater chance of detecting a high-impedance fault that is closer to a substation because of less attenuation of high-frequency fault signatures by VAR-compensation capacitors of distribution systems.

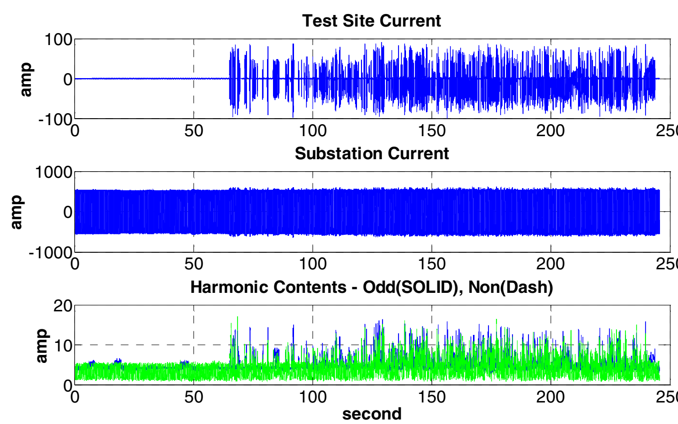

Fig. 13. Fault current of an earth fault from Test E(2)

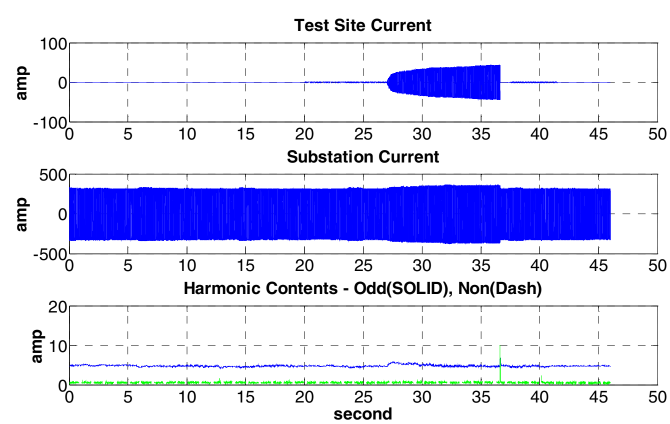

Fig. 14. Fault current of an earth fault from Test A(1)

Given the random nature of high-impedance faults and their detection, using a single value for detection rate to describe the performance of a fault detection device can be very limited and sometimes misleading. For any given number, we want to know immediately under what kind of ground surfaces, surface conditions, and voltage levels the number is derived.

From field test experiences, we believe that it is better to use a statistical way to describe the performance of a high-impedance fault detection device. For each ground surface type, we have a good idea about the likelihood of a fault being detected when a conductor falls on it, although we have seen previously that differences can exist from different fault occurrences. Fig. 15 shows a statistical method of describing a high-impedance fault detection device.

Fig. 15. Statistical description of high-impedance fault detection device

VII. Conclusion

High-impedance fault detection is a perplexing issue facing utilities. A downed conductor-related high-impedance fault is a great public hazard and must be corrected quickly to prevent loss of life and property damage.

High-impedance fault detection depends on the system grounding scheme. For small-current grounding, the fault detection is relatively easy because the standing unbalance comes only from line construction asymmetry and phase CT errors. This unbalance is normally quite small, and today's microprocessor relays can be sensitive enough to detect most high-impedance faults.

For large-current grounded systems, where system standing unbalance is high or unpredictable from single-phase loads, the detection of high-impedance faults is more challenging. Because the high-impedance fault current is less than the standing unbalance, we must explore quantities other than the current fundamental magnitude or RMS value for detection purposes. Most high-impedance fault detection devices today use the harmonic contents of a fault current together with many available techniques such as artificial intelligence.

A substation-based device cannot detect all high-impedance faults. Downed conductors on asphalt and dry sand produce no fault currents and therefore cannot be detected by substation-based devices.

Given the complex nature of a high-impedance fault, it is impossible to simulate faithfully all aspects of a high-impedance fault. Field-staged fault tests are a way to study these faults and validate the performance of a detection device.

Many field fault tests show that you cannot get the same fault twice. The high-impedance fault is a dynamic process. The surface electrical condition changes as moisture evaporates from the heat of arcs, as a conductor burns off and moves around, and as ground material fuses into silicon composites. We may be able to detect a fault at one moment that we cannot detect later. Because of seasonal changes and ground composition changes, a fault test today may not produce the same current and arc signatures as a previous fault test at the same location.

People have been using a single number called detection rate to describe the performance of a detection device. It may be reasonable to use a particular probability number to describe the performance for downed conductor faults on a given ground surface. The use of a single detection rate without discriminating ground surface types can be misleading. If all faults come from downed conductors on asphalt, the detection rate will undoubtedly be zero.

It is therefore more accurate to describe the performance of a detection device statistically according to each type of ground surface.

VIII. References

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IX. Biographies

Daqing Hou received his BSEE and MSEE degrees at the Northeast University, China, in 1981 and 1984, respectively. He received his Ph.D. in Electrical and Computer Engineering at Washington State University in 1991. Since 1990, he has been with Schweitzer Engineering Laboratories, Inc., Pullman, Washington, USA, where he has held numerous positions including development engineer, application engineer, and R&D manager. He is currently a principal research engineer. His work includes system modeling, simulation, and signal processing for power systems and digital protective relays. His research interests include multivariable linear systems, system identification, and signal processing. He holds multiple patents and has authored or coauthored many technical papers. He is a Senior Member of IEEE.