Field Experience with High-Impedance Fault Detection Relays

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***Abstract*—High-impedance, arcing faults (HiZ faults) are a perennial problem for distribution systems. They typically occur when overhead conductors break and fall, but fail to achieve a sufficiently low-impedance path to draw significant fault current. As a result, conventional protection cannot clear them, resulting in situations that are hazardous both to personnel and to property.**

Texas A&M researchers spent two decades characterizing HiZ faults and developing and testing algorithms for detecting them. In the mid 1990's, General Electric commercialized the algorithms in a relay for detecting a large percentage of these faults, while maintaining security against false operations.

In an effort to mitigate problems associated with these faults, Potomac Electric Power Company (Pepco) installed the HiZ relays. They evaluated the performance of these relays on 280 feeders over a period of two years and gained significant operational experience with them. Being the first utility to apply high-impedance fault detection technology on such a widespread basis makes Pepco's experience valuable to other utilities that are struggling with decisions regarding their own response to the problem of high-impedance faults.

***Index Terms*—Power distribution faults, power system faults, electrical faults, arcing faults, arcs (electric), arcing fault hazards.**

I. Introduction

HIGH-IMPEDANCE (HiZ) faults have been a problem since the beginning of electric power distribution. A HiZ fault is one that draws insufficient current to be detected by conventional means, such as relays and fuses. They often occur when overhead lines break and fall on poorly conducting surfaces.

Extensive testing by Texas A&M University and others have shown that the currents drawn by high-impedance faults are unpredictable, but that they often range from no measurable current to a few amperes or few hundred amperes [1]. Compounding the problem is the fact that these faults often do not achieve steady-state currents. Rather, their currents vary considerably from one cycle to the next. Even if a particular fault draws sufficient current to cause a protective device (e.g., a relay or a fuse) to begin to operate, it may do so for too brief a time to allow the device to complete its operation and clear the fault. This results in a situation in which a conductor remains energized and possibly within reach of passersby for an indefinite period of time, presenting a serious hazard. In addition, these faults often arc, thereby representing a significant fire hazard to property [2-4].

It is difficult to estimate precisely how many broken conductors result in high-impedance faults. Interestingly, early in the history of investigations about the prevalence of the high-impedance fault problem, interviews with utility protection engineers generally indicated their belief that downed conductors almost never remained energized for more than a few seconds. However, interviews with line crews at the same utility companies indicated that as many as one-third of all downed conductors were still energized when they arrived on the scene. The problem was that trouble-reporting systems often lacked means for noting whether a broken conductor remained energized, so protection engineers naturally assumed that the line cleared and was not hot.

II. Fault Detection Algorithms

Texas A&M researchers began working on the high-impedance fault detection problem in the late 1970's, under a project sponsored by the Electric Power Research Institute (EPRI) [1]. This research consisted of staging faults, recording the resulting current and voltage waveforms, characterizing the faults' behavior, and developing and testing detection algorithms.

Over the years, Texas A&M worked with multiple utility companies across the United States to stage fault tests on operating utility company feeders. Obviously, the planning, preparation, and execution of tests of this kind represented a significant undertaking, both for the utility companies and for the research team. Therefore, Texas A&M designed and constructed their own Downed Conductor Test Facility (DCTF). This permanent facility is located near the Texas A&M campus and is served by one of the local utility company's operating, multi-grounded wye, 12.47-kV feeder of standard overhead construction. This feeder serves several megawatts of residential and light-commercial load in the surrounding area. The DCTF provides current and voltage transformers (CTs and PTs) to monitor the currents and voltages at the test site. Texas A&M also has access to, and records data from, CTs and PTs at the utility company's substation, which is located about 1-1/2 electrical miles from the test facility.

Current magnitudes and behavior are governed in large part by the impedance of the contact between the downed section

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of line and any grounded surface that it contacts. Many factors influence the magnitude and behavior. For example, the fault current that results when a section of line comes into contact with a slab of reinforced concrete generally is significantly different than the fault current that results if the same section of line comes into contact with grass turf [3]. Some surfaces tend to produce relatively spectacular arcing and fault currents, yet the current over time is too small to operate conventional protection. Other surfaces, the most prominent being certain types of asphalt, produce no electrical or visual sign that the conductor is even energized! To provide the basis for robust detection algorithm, the DCTF provides a variety of test surfaces, including concrete, asphalt, sand, and grass turf.

Tests at the DCTF and at cooperating utility companies provided hundreds of staged fault cases on a variety of contact surfaces. Current and voltage waveforms from these tests provided the research team with data for characterizing the temporal and spectral behavior of faults under a wide variety of test conditions. Based upon these characterization activities, Texas A&M developed algorithms for recognizing these characteristics.

Texas A&M conferred with utility companies to determine practical constraints for implementation of a system for effectively dealing with high-impedance faults [5]. Using the combination of the results of hundreds of fault tests and the philosophical and operational input from utility companies, they developed detection techniques to achieve a balance between detection sensitivity and security against false operations [6-7].

III. Security Is Essential

Early fault characterization efforts by Texas A&M and by other groups found that most high-impedance faults produce arcing, and that this arcing generally produces detectable changes in multiple electrical parameters. Every fault is different, and surface conditions have a significant influence on the behavior of any given fault. However, in general, researchers found that many faults produce only subtle changes in fundamental frequency current, but marked changes in low-order harmonic and non-harmonic frequencies and in higher frequency currents (e.g., in the kilohertz range). In other words, these efforts demonstrated that electrical parameters often contain significant information indicative of the presence of high-impedance faults.

Here's the catch. Many normal system events affect the same parameters that high-impedance arcing faults affect. One of the best examples of this is the switching of capacitor banks. A large percentage of distribution feeders incorporate capacitor banks that switch ON and OFF, as needed for voltage and VAR support, typically on a daily basis. When a capacitor bank switches ON, it causes changes to multiple electrical parameters. The initial switching event itself causes high-frequency current and voltage transients. In addition, the presence of the capacitor raises the voltage along the feeder, which in turn affects the amount of fundamental and harmonic currents drawn by various connected loads. Finally, the presence of the capacitor also changes the topology of the feeder, particularly if connected in a common grounded-wye configuration. This alters current flows at various frequencies. Other examples of events that affect potential detection parameters are too numerous to list and discuss here, but some of the most common include load tap changer (LTC) operations, large motor starts, line switching operations, etc.

It was relatively easy to stage and collect data on individual instances of events that had known potential for causing false alarms, and then to test the detection algorithms' response to these individual operations. Much more difficult, however, was determining algorithm performance in real operating environments, in which complex sequences of numerous such events occur as a result of normal feeder operation, with individual customers switching loads at random intervals. Texas A&M used several generations of prototype field hardware, installed at multiple cooperating utility companies for periods of years, to assess the vulnerability of various detection techniques to real operating environments, and to develop methods of achieving high levels of sensitivity while maintaining a very high level of security against false operations.

As the technology was transitioned to GE and migrated into a product, additional field experience was sought. To this end, GE established a utility Advisory Committee of Experts (ACE) team. This team installed devices in their utilities and reported back on their operation. In particular, several utilities staged both fault and non-fault events that were digitally captured and later played back into the HiZ relay in order to test both the sensitivity and the security of the Texas A&M algorithms. This testing resulted in several improvements to the algorithms and resulted in overall improvement in performance.

In short, utilities stated the following requirements for success of any high-impedance fault detection system:

- Operate only if a high-impedance fault truly is present. Do not operate for anything else.
- Even if 100% certain that a high-impedance fault is present, give conventional protection an opportunity to operate first and sectionalize the fault, operating only if conventional protection fails.
- Where compromises must be made between sensitivity of detection and security against false alarms, bias the system toward security. Significant false alarms will cause the system to be turned OFF!

IV. Pepco's System and Evaluation Approach

The Potomac Electric Power Company, or Pepco, provides electric service to the Washington, DC area and surrounding Maryland suburbs. Pepco's service area is 640 square miles, with a population of over two million. Pepco's distribution system consists of 1,295 13-kV feeders, 620 of which are overhead. They are of standard multi-grounded wye configuration.

To evaluate the high-impedance fault detection technology in an operational environment for an extended period of time, Pepco installed General Electric F60 Universal Relays with HiZ on several hundred of their overhead feeders. Having no historical or other basis for setting the relays' sensitivity to other than the "medium" setting that comes from the factory, Pepco left the sensitivity setting at this factory default setting, which was designed as a conservative setting with a bias toward security.

The installation of these relays occurred over a period of four years. As the detectors were installed, Pepco began to monitor their performance and collect operational statistics. Their initial evaluation period involved monitoring approximately 280 feeders for an average of about two years.

During the evaluation period, Pepco did not connect the relays to trip. This afforded them the opportunity to evaluate the technology prior to making a commitment to trip feeders automatically. Because the relays were not connected to trip or even to send an alarm via SCADA, Pepco had to use other means to track their performance. To do this, they used two information sources to provide initial indications of downed conductors:

- Operator logs – Pepco examined operator logs on a regular basis, to find occurrences of downed conductors that had occurred on their system. They only considered incidents in which a line was broken and still energized when field personnel arrived on the scene to make repairs.
- Target reports – Pepco requested that field personnel visit substations and report any incidents in which one of the high-impedance fault relays had its Downed Conductor target set. These visits happened at least weekly, and any other time the substation breaker tripped.

When either of these sources of information indicated a downed conductor, Pepco investigated further. In most cases, operator logs provided the initial indication, simply because operators generally had information from lights-out calls and other timely sources, well in advance of substation visits for weekly target reports.

Whenever Pepco received information from either source, they retrieved log information that the relay had recorded, and examined that information to determine relay performance. In those cases in which the first indication came from a target report, Pepco also reexamined operator logs to determine whether they showed reports of downed conductors.

In some cases, a considerable amount of time elapsed between when Pepco received initial indication of a downed conductor and when they retrieved logs from the relays. In some cases, subsequent activity on the feeder caused the time period of interest to be overwritten in the relay log prior to the time that Pepco personnel could retrieve it. At the beginning of the evaluation period, Pepco decided that it was necessary to have information from the log in order to be certain that a lit target truly corresponded to the downed-conductor incident of interest, rather than to some previous event for which the target had not been cleared. Therefore, for purposes of confirming that the relay had operated, they chose not to accept a lit target as positive confirmation of detection. However, this meant that using an unlit target as indication of failure to operate would constitute an improper negative bias in the results. Therefore, Pepco did not record or rely on target status in any way in their assessment.

Given this unbiased criterion for selecting incidents to include in the sample set, there is no reason to believe that there was a statistically significant difference in performance between those cases for which documentation was not available and those cases for which it was available. Operating statistics given in the next section present all incidents of downed conductors, even those for which log information was not available. This provides a sense of the prevalence of the downed-conductor problem itself, without regard to relay performance. Analysis of relay performance then considers only those cases for which there was sufficient documentation available for an accurate, unbiased assessment.

V. Operating Statistics

As stated previously, Pepco's evaluation involved approximately 280 relays for an average of two years. This represents an extensive evaluation period of 560 relay-years of operation.

During that time period, Pepco had several hundred instances of downed conductors on the feeders instrumented with high-impedance fault relays. Of these, operator logs and target logs indicated 71 incidents for which crews found downed conductors that were not cleared by conventional protection and that remained energized when they arrived on the scene to make repairs. Pepco investigated all 71 incidents, but found that there were 23 of them for which the relays no longer had data for the period of interest, because of the passage of time between when the event occurred and when personnel retrieved data from the relay.

For several of the incidents, data for the time period of interest had been overwritten by numerous, repetitive, neutral overcurrent alarms. The threshold for this alarm had been set at 100 amperes to obtain data on unbalanced feeder loading, but no time delay or seal-in function had been set. Therefore, whenever the feeder neutral current was near the 100-ampere alarm setting, it frequently moved from just-below to just-above the setting, generating a log entry each time it did so. This quickly filled the log and overwrote other entries, including downed-conductor detections. This chatter problem has since been corrected.

There were 48 incidents that met the criteria of 1) having an indication from an operator log or from a target report and 2) having relay data to support analysis and from which to draw conclusions about the relay's operation. The relays armed the downed conductor algorithm for 46 of the 48 incidents (96%). As a part of the relay's bias toward secure operation, the relay does not indicate a downed conductor unless either a loss of load or an overcurrent immediately precedes the detection of arcing. Even with the bias toward security, the relay's algorithm requirements were met, resulting in the issuance of "Downed Conductor" outputs, for 28 of the 48 faults (58%). This detection rate is quite good, considering the security bias and especially considering that none of these 48 faults were cleared by any conventional means!

Pepco had considerable interest in tracking the security (i.e., false alarm rate) of the relays as well as their detection sensitivity. For the 560 relay-years of operating experience that they evaluated, they had only two incidents in which relay targets or logs indicated that the relay detected a downed conductor fault, but for which the utility found no documentation of an actual downed conductor on their system. Expressed another way, there was only one such indication for every 280 relay-years of operation, a rate Pepco considered to be outstanding. Table I provides a statistical summary of Pepco's experience with high-impedance fault relays. Fig. 1 graphically illustrates the relays' detection performance.

TABLE I
HIGH-IMPEDANCE FAULT RELAY EVALUATION STATISTICS

Feeder-years of experience	560	
Confirmed high-impedance faults evaluated	71	
False alarms	2	
Faults with relay data available	48	
- Faults that armed relay	46	(96%)
- Faults that were detected	28	(58%)

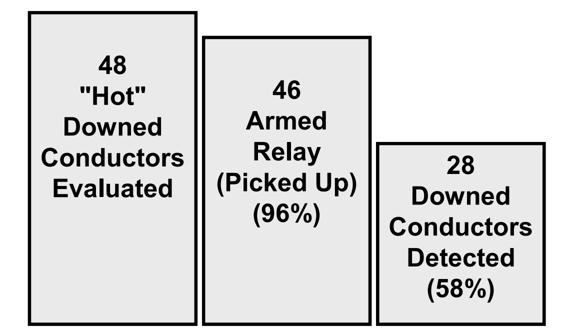

Fig. 1. High-impedance fault relay sensitivity to documented downed conductors that conventional protection did not clear.

In a desire to have a single index to measure the performance of the relays, Pepco developed what they termed a Relay Veracity Index. They defined this index as the ratio of true downed-conductor indications from the relays as a percentage of the total number of relay downed-conductor outputs. Based on this formula, they calculated a Relay Veracity Index of 93% (28 true indications out of 30 total Downed Conductor indications) for the HiZ relays, a level they considered to be very good.

Another important aspect of downed-conductor detection that Pepco tracked was the time it took the relay to detect a downed-conductor condition. For the 28 downed conductors detected, 16 were preceded by substation breaker trips from overcurrents that occurred when the broken conductor brushed against another phase or neutral conductor as it fell, or when the broken conductor first hit the ground. After conventional overcurrent relaying tripped, however, automatic reclosing re-energized the feeder, including the downed conductor. For the 16 episodes with an initial breaker trip, Pepco used the time at which that trip occurred to indicate the beginning of the downed-conductor episode, and then used that as the basis for determining downed-conductor detection time. For these 16 episodes, the average detection time was 2.8 minutes.

These operating times reflect well the design philosophy of allowing conventional protection (e.g., fuses) to have ample opportunity to sectionalize the fault, operating the downed-conductor detector and tripping the substation breaker only when enough time has passed that it becomes unlikely that conventional protection will clear the fault. Operating times measured in minutes clearly are unusual for protection engineers, given that they usually think in terms of operating times measured in cycles or, at most, in seconds. However, it is important to remember that without downed-conductor protection, these faults remained energized and dangerous until after the condition was reported by other means and a crew was dispatched and arrived on the scene, a process that takes considerably longer than a few minutes.

When considering all of the above statistics, it is critical to remember that these results were obtained with the relay's default "factory" sensitivity setting, which is a medium sensitivity level that was designed with a bias toward security. It is not known what quantitative effect increasing the sensitivity would have, either on detection rates or on false alarm rates. It is safe to conclude that detection rates would increase with an increased sensitivity setting, but that false alarm rates likely would increase as well.

VI. PEPCO'S CURRENT AND FUTURE DEPLOYMENT PLANS

Based upon the positive experience gained from the initial 560 relay-years of exposure, Pepco decided in early 2004 to connect the outputs of their existing relays to trip the substation breaker automatically when a downed conductor is detected. A trip for a high-impedance fault blocks all automatic reclosing. Dispatchers at Pepco's Control Center are provided with downed-conductor trip data to help them direct trouble crews as appropriate.

Pepco also has made the decision to install these relays on the remainder of their feeders. This rollout is underway and Pepco anticipates its completion in several years.

VII. NEEDED ENHANCEMENTS

Pepco has been pleased with the results they have obtained from the current embodiment of the high-impedance fault detection technology. However, there always are areas for potential improvement.

It is Pepco's view that one of the main areas in which the current embodiment could be improved is in the area of data storage and retention. High-impedance faults are very different from conventional faults, not only in their magnitude but also in their duration. Conventional, high-current faults must be removed from the system quite rapidly to avoid substantial damage to the system. As a result, such episodes generally are measured in cycles. Naturally, the lengths of fault records also typically are measure in cycles. Even if a protection scheme goes through multiple trip-and-reclose operations prior to a lockout, each of the trips generally is measured in terms of cycles. By contrast, high-impedance faults typically persist much longer. Even if it were possible to make a 100%-certain decision that a high-impedance fault were present in a few seconds, it generally is not desirable to trip the substation breaker that quickly. Instead, it generally is desirable to give conventional protection multiple seconds or even tens of seconds to operate and sectionalize the fault, to minimize the outage area and the search area. Therefore, in order to capture the entire sequence of events associated with a high-impedance fault, it would be desirable to have waveform data and log data stored and retained for significantly more time that the present embodiment provides.

VIII. Summary

Potomac Electric Power Company (Pepco) recognized the need to address the perennial problem of downed-conductor faults several years ago. Because of their commitment to seek a solution to the high-impedance problem, they embarked on a widespread, long-term evaluation of high-impedance fault detection technology developed by Texas A&M University and provided by the General Electric Company.

Pepco evaluated the performance of these relays on 280 operating feeders for a period of two years. During this time, the relays detected arcing associated with 96 percent of the downed conductors that occurred, and produced Downed Conductor outputs 58% of the time. Perhaps more importantly, during the 560 relay-years represented by this evaluation period, the relays produced only two false Downed Conductor indications. Pepco is pleased with the performance they have seen and currently is deploying these relays on the remainder of their feeders.

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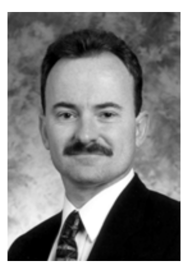
X. Biographies

Alvin C. Depew (M'1981) earned his B.S. degree in Electrical Engineering from Bucknell University in 1981. Alvin joined Pepco in 1981 as a Engineer in System Protection and presently is Manager, Engineering Projects, System Protection & Telecommunication Engineering. His responsibilities include design, application and settings for all protective relays on Pepco's transmission and distribution systems. Alvin is a member of the IEEE Power Engineering Society and is a registered Professional Engineer in Virginia and Maryland.

Jason M. Parsick was born in Culpeper, Virginia on November 27, 1980. He earned a B.S. degree in Electrical Engineering from Virginia Polytechnic and State University in 2003.

Jason works in the System Protection and Telecommunications department at Pepco in Washington, DC. His work concentrates on setting, programming, and analyzing data in microprocessor-based protection relays.

Robert W. Dempsey (M'1973, SM'1989) is Manager, Protection and Telecom Operations at Pepco. Mr. Dempsey joined Pepco in 1971 and currently is responsible for all substation construction and maintenance, as well as the protection and telecommunications operations throughout the Pepco Transmission and Distribution systems. Mr. Dempsey received his B.S. degree in Electric Engineering from University of Maryland, and his M.S. degree in Engineering Administration from George Washington University. Mr. Dempsey is a past chairman of the IEEE Power System Relaying Committee and has served as a technical and academic advisor to the Engineering Technology Programs for Charles County Community College and Prince George's Community College. Mr. Dempsey is a registered Professional Engineer in the State of Maryland.



Carl L. Benner (M'1988, SM'2004) earned the B.S. and M.S. degrees in Electrical Engineering at Texas A&M University in 1986 and 1988.

Mr. Benner serves as Research Engineer and manages the activities of the Power System Automation Laboratory in the Department of Electrical Engineering at Texas A&M University. His work centers on the application of advanced technologies to the solution of challenging power system problems, with an emphasis on the application of microcomputer-based monitoring and control. Mr. Benner holds four patents in the area of high-impedance fault detection.

Mr. Benner is a member of the IEEE Power Engineering Society and Industry Applications Society. He is a registered Professional Engineer in the State of Texas.

B. Don Russell (Fellow'1991) is Regents Professor and J.W. Runyon Professor of Electrical Engineering at Texas A&M University. Dr. Russell is Director of the Power System Automation Laboratory. His research interests are in the application of advanced digital technologies to the solution of power system automation, control, and protection problems. Dr. Russell holds multiple patents in the area of digital protection, including high-impedance fault detection.

Dr. Russell is Past President of the Power Engineering Society (PES) and currently serves as Vice President of the PES Meetings Department. He is a registered Professional Engineer in the State of Texas, Vice President of USNC CIGRE, and a member of the National Academy of Engineering.

Mark G. Adamiak (F'2005) received his Bachelor of Science and Master of Engineering degrees from Cornell University in Electrical Engineering and an MS-EE degree from the Polytechnic Institute of New York. From 1976 through 1990, Mark worked for American Electric Power (AEP) in the System Protection and Control section, where his assignments included R&D in Digital Protection and Control, relay and fault analysis, and system responsibility for Power Line Carrier and Fault Recorders. In 1990, Mr. Adamiak joined General Electric, where his activities have included development, product planning, and system integration. He presently is the Advanced Technology Programs manager and is responsible for identifying and developing next generation technologies for the utility and industrial protection and control markets. In addition, Mr. Adamiak has been actively involved in the development of the IEC61850 communication standard and was the Principle Investigator on the EPRI / E2I Integrated Energy and Communication Systems Architecture (now IntelliGrid) project – a guide for development of utility communication architectures. In 1986, he was the winner of the Eta Kappa Nu (HKN) society's "Outstanding Young Electrical Engineer" award. He is a member of HKN, a Fellow of the IEEE, past Chairman of the IEEE Relay Communication Sub Committee, a member of the US team on IEC TC57 - Working Group 10 on Substation Communication, chairman of the Technical Committee of the UCA International Users Group and a registered Professional Engineer in the State of Ohio.