Preventing Certain Powerline Caused Wildfires by Early Detection and Repair of Failing Devices

B. Don Russell, *Life Fellow, IEEE*, Jeffrey A. Wischkaemper, *Member, IEEE*, Carl L. Benner, *Fellow, IEEE,* and Karthick Manivannan, *Member, IEEE*

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***Abstract*--Long-term drought and elevated environmental temperatures are contributing to a significant increase in the number and severity of wildfires in United States. One major west coast utility attributes 8-10% of wildfires to failures and faults on electric utility distribution circuits. Ignition mechanisms that can cause fires may develop over weeks or months before ignition occurs. Existing monitoring and protection systems cannot detect many incipient failure conditions before a catastrophic event causes fire ignition. This paper presents a real-time diagnostic technique capable of detecting developing fire ignition mechanisms. Operators can utilize actionable information, dispatching crews to find and fix certain developing ignition conditions prior to fire start. Actual case studies from utility trials are presented.**

***Index Terms*—incipient fault detection, fault location, high impedance faults, apparatus failures, distribution reliability, wildfire mitigation**

I. Introduction

It has long been known that the failure of powerline parts and apparatus, conductor line slap, and downed conductors represent competent ignition mechanisms for wildfires. However, there are other conditions necessary for a fire to start. These include dry fuels, high temperatures, and low humidity conditions. Wind speed often dictates the rate of fire spread. These environmental conditions now exist throughout much of the western part of the United States. These conditions exacerbate the ignition and large-scale spread of any wildfire, no matter the cause. As a result, the western United States is now experiencing a catastrophic number and size of fires that endanger life and property [1].

It is not possible to know exactly how many wildfires are started by faults and failures on electric distribution circuits. The cause of many fires is never determined, and some fires are wrongly attributed to utility circuits. However, Southern California Edison has estimated in recent years that approximately 8%-10% of wildfires are directly or indirectly related to distribution circuit events [2].

Many powerline-caused fires happen precipitously with no warning. A danger tree (e.g., off right-of-way tree) that falls and tears down a line and causes line-to-ground arcing cannot be electrically predicted. While the electrical system supplied energy for the ignition mechanism, the true root cause of the fire is the tree fall! By contrast, an equipment or device failure such as a failing clamp or switch or repetitive phase-to-phase vegetation contact may occur aperiodically over days or even weeks before developing into a competent ignition mechanism that occurs simultaneously with the necessary environmental conditions. The time to ignition of such events cannot be predicted, but as the failure develops and exhibits measurable electrical signals, ignition of a fire can in some cases be preempted by finding and fixing the incipient failure (i.e., the failing device or the repetitive fault).

Existing protection and fault recording devices react to relatively high-current events. A line-to-ground or line-to-line fault across a failing bushing causes an overcurrent that likely will trigger a protection operation or event recording. Unfortunately, these devices cannot extract (i.e., detect) the low-magnitude signals of the initial stages of failures of many parts and apparatus on a distribution circuit. A circuit that may carry 300 A of load current may have a failing clamp producing series arcing that modulates only a few amperes and exhibiting electrical characteristics similar to many loads on the circuit.

II. Preemptive Diagnostic Approach

Waveform analytic techniques have been developed employing sensitive triggering, high-fidelity waveform capture, and intelligent, near-real-time analytic algorithms to detect and discriminate low-grade failing device electrical signals [3-5].

To capture data necessary for waveform analytics capable of detecting and possibly identifying failing circuit devices, it is necessary to monitor circuits with high fidelity in real time. Data reported in this paper was obtained from a data monitoring and analytics system comprised of data collection devices, installed on a one-per-circuit basis, which connect via encrypted network connections to a "master station" server at the enterprise level. One master station is required for the entire system, not one per substation.

For simplicity and ease of installation, the data collection system, installed in the substation, utilizes the existing magnetic

B. D. Russell is a Distinguished Professor at Texas A&M University, College Station, TX 77843 USA (e-mail: bdrussell@tamu.edu).
J. A. Wischkaemper is an Associate Research Professor at Texas A&M University, College Station, TX 77843 USA (e-mail: jeffw@tamu.edu).
C. L. Benner is a Research Professor at Texas A&M University, College Station, TX 77843 USA (e-mail: carl.benner@tamu.edu).
K. Manivannan is an Associate Research Professor at Texas A&M University, College Station, TX 77843 USA (e-mail: karthick@tamu.edu).

current transformers and potential transformers used in substations for typical relay or metering functions. No special sensors are required. All signal processing, triggering, data collection, and waveform analytics are performed in the per-circuit distributed processing unit.

The sole purpose of the master station is to aggregate and distribute information to various utility stakeholders who need the information. This includes operators and engineers using the data for diagnostic purposes.

Each per-circuit monitoring device embeds a waveform classification engine that incorporates signal processing and pattern classification techniques. Features are extracted from waveform recordings, with the results of individual classifiers adjudicated by a fuzzy expert system to produce a final output.

Processes embedded in the per-circuit monitoring device are schematically represented in Figure 1. Inputs from the current and potential transformers come as signals shown in the left of the diagram. While some failures produce large current magnitudes, many failure events produce signatures smaller than normal load devices. To detect these low-level failures, the monitoring system necessarily records many "normal" load events (e.g., inrush, motor starts, etc.) which must be triaged by the waveform classification engine. For example, the second waveform in Figure 1 shows the failure of a hotline clamp, modulating only a few amperes of load. The monitoring system specifically detects this type of condition and automatically alerts operators. Moreover, some events may be "normal" in one context, but "abnormal" in another. For example, a routine capacitor switching event on a distribution circuit would not be problematic, but fifty capacitor switching events in a single day could be an indication of a capacitor controller failure. The waveform classification takes a generic waveform input with no a priori knowledge and produces a best-determination of event cause with no human analysis or interaction. The following cases were captured and documented by this system.

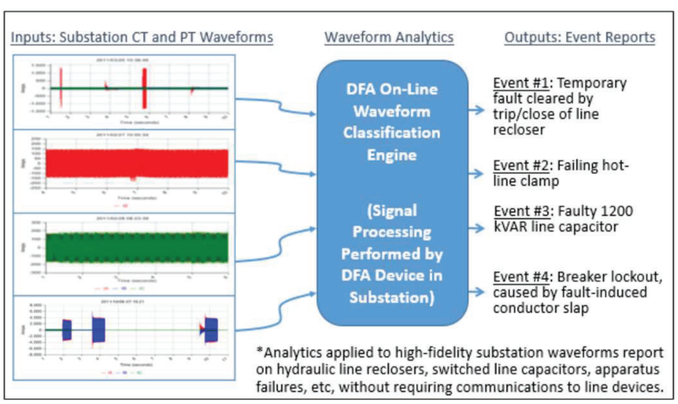

Figure 1: Block diagram schematic of DFA waveform classification engine

III. Real World Examples

The monitoring technology described in Section II has been applied in trials and operationally on over 250 circuits at more than 20 utilities. The resulting 1400+ circuit-years of data contain hundreds of thousands of signatures of failing devices and abnormal events on distribution circuits, many of which represent potential ignition mechanisms. The following representative case studies have been selected from real-world operational cases to illustrate how real-time monitoring and autonomous analytics can detect and alert operators to certain powerline ignition mechanisms, thereby enabling condition-based maintenance to prevent some wildfires.

A. *Case 1 – Incipient failure of arrester in substation*

Late one evening, a circuit monitor reported indications of a developing high-impedance fault condition. The initial fault events had short durations and small magnitudes, lasting less than two cycles with a peak magnitude of only about 100 amperes. For the next several hours, the monitor recorded sporadic, low level arcing signatures (i.e. less than 5 amperes) on the affected phase. Approximately four hours after the initial arcing events, the monitor began detecting multiple, subcycle current bursts with peak magnitudes ranging from approximately 60 amperes to almost 700 amperes. In addition to these subcycle events, the monitor continued to record frequent low-magnitude arcing signatures of between 5 and 15 amperes on the same phase.

When the utility engineer arrived in the office at 0700 the next morning, the monitoring system had reported the incipient condition and multiple short-lived (i.e., less than one cycle in duration) faults. At that point, the system had reported 10 short-lived faults ranging in magnitude from 165 to 369 amperes (RMS). Early events were separated by 30-45 minutes, but more recent events occurred within five minutes of each other. Moreover, the magnitudes were increasing. The increased frequency and increased magnitudes suggested the condition might be progressing toward final failure and a low-impedance fault, meaning the utility likely had limited time to find and fix the failure before it resulted in a more serious problem.

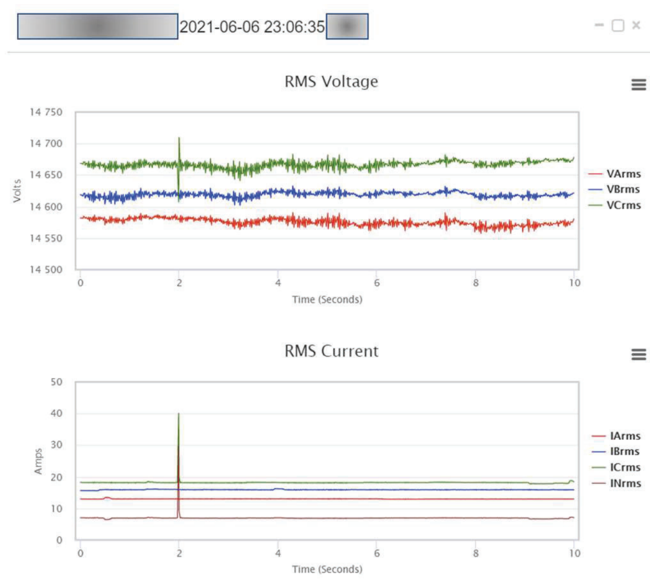

Figure 2: RMS voltages and currents, measured from substation PTs and CTs showing the initial high-impedance fault produced by the failing arrester.

For many utilities, targeting patrols is straightforward if the utility possesses a competent model of their circuits. Experience at multiple utilities has shown that the location of traditional low-impedance faults frequently can be predicted within a few pole spans, which is almost always close enough for a skilled lineman to locate the underlying issue. This procedure relies on the fact that for many faults, the magnitude of the fault impedance is much smaller than the magnitude of the system impedance to the location of the fault. While no fault impedance is literally zero, assuming a zero fault impedance is functionally acceptable for the purpose of locating traditional, higher magnitude faults. Locating high-impedance faults is substantially more challenging, because the fault impedance may be on the order of or even larger than the system impedance. Because the contact impedance at the fault point is the primary factor governing the behavior of high-impedance faults, and because the mechanical conditions at the fault point are changing and unknowable, the fault current magnitude may vary widely, in some cases resulting in fault currents spanning three orders of magnitude (i.e., less than 10 amperes to thousands of amperes) for repetitions of a fault at a single location. These factors make the use of engineering models unsuitable for efficiently locating most high-impedance faults, because the fault impedance cannot be known and can be chaotically variable.

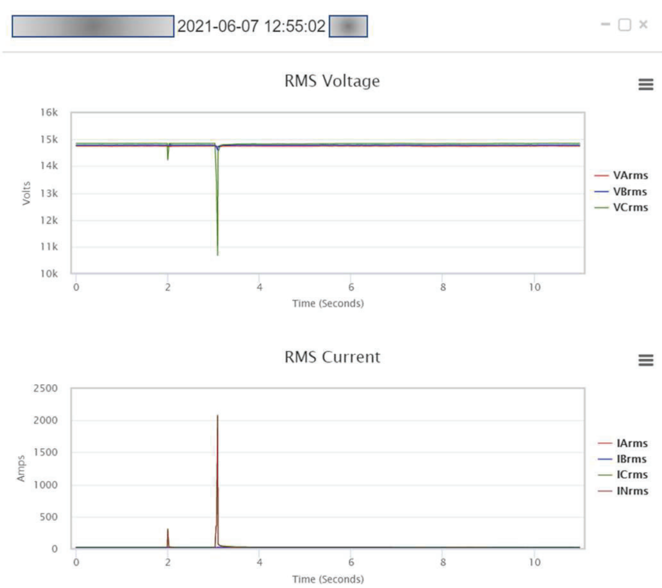

Figure 3: RMS voltages and currents, measured from substation PTs and CTs during the final event from the arrester failure sequence. Based on aggregate data from the monitoring system, the utility dispatched a crew after receiving this report.

Fault magnitudes can, however, be used as a bounding condition for locating high-impedance faults. In this example, the largest magnitude observed by 0700 was approximately 500 amperes (RMS). This eliminated from consideration all circuit sections where the system impedance was large enough to limit bolted faults to less than that value. In this case, however, that still resulted in too many line sections to effectively patrol. At 1143, a higher magnitude fault (610A RMS) reduced the area further. A subsequent occurrence of the fault at 1255 resulted in a magnitude of almost 3,000A RMS, which implied the failing equipment was in or very near the substation. The utility dispatched a lineman to the substation based on the 1255 report. The lineman arrived but did not find anything unusual at the substation. Based on experience, he disconnected a lightning arrester on the getaway cable for the affected phase. All fault activity on the circuit ceased, validating that the arrester or arrester assembly was the source of the fault.

This case illustrates several important points. First, some equipment failures manifest themselves over long periods, in this case multiple hours, giving utilities a chance to correct the condition, but only if they know of it at an early stage. In the subject case, more than 14 hours elapsed from the initial failure signatures detected by the monitoring system until the lineman arrived at the substation and corrected the issue. It is unknown how long the arrester would have survived without intervention, but the escalating magnitudes and frequency of the events suggest that failure was imminent. A failed lightning arrester may have resulted in an outage for all customers on the circuit and potentially created other hazardous conditions, such as a fire ignition. While the incipient failure period may be long enough to enable proactive repairs, the early electrical indications of an incipient failure, including conditions like this one which ultimately produce substantial fault currents, fall well below the reporting thresholds of most utility systems. In this event the only notice from the utility's conventional systems was a relay record at 1255 indicating a "mintrip" (i.e., a relay which began its protective sequence, but did not complete it because the fault current went away). The utility engineer asserted that, absent DFA information indicating a developing problem, he would not have dispatched a crew based only on the 1255 mintrip report. Information produced by the monitoring system provided the only full record of the event sequence developing over time and the only actionable source of information in this event. Finally, while locating high-impedance faults can be challenging, it may be possible in some cases. Fault current magnitudes can be used to reduce the search area for high-impedance faults, and in some cases waveform signatures can provide clues about the nature of the failing equipment. In early conversations with the utility regarding this case, researchers suggested the problem was most likely to be an underground cable but could also be an arrester. Given the difficulty of locating high-impedance faults, such information can prove crucial (e.g., if the fault current magnitudes excluded all sections of the circuit with underground cable, crews could focus on arresters).

B. Case 2 – Failure of current-carrying connector (series arcing)

This case needs to start with a description of "series arcing." The real-world behavior associated with series arcing is poorly understood by industry and academia, but field installations of the monitoring system have enabled Texas A&M to document multiple cases of the phenomenon and to begin to develop an understanding of the failure mechanism, its electrical behavior, and its progression over time. Series arcing occurs when the electrical contact surfaces of a current-carrying device, such a hotline clamp, switch, or fused cutout, develop an abnormally high impedance, resulting in concentrated heat and surface-to-surface arcing as load current passes through the device. There is no unintentional path of current flow but rather an interference with the intended flow of current. This contrasts with shunt arcing, which involves the flow of current in an unintended path, typically because of contact or close approach between conductors or the failure of an insulation system. Shunt arcing and series arcing can both result in current variations that are detectable in substation CT signals, and the waveform classification engine embedded in the per-circuit monitoring device differentiates between the two types. The series arcing itself produces high temperatures capable of igniting proximate fuels. More perniciously, series arcing erodes metal of the failing device's contact surfaces and of the associated line conductor, and, over time, this metal erosion can cause the device or the conductor to break, resulting in an outage and potentially creating elevated ignition risk and shock hazard in the form of a downed conductor. Figure 4 shows multiple examples of series arcing and the resulting conductor damage.

Figure 4: Photos of current-carrying devices with series arcing. The two on the left have failed catastrophically, one resulting in a broken conductor. The photo on the right is a substation switch that was detected and corrected, based on the monitoring system, with final failure avoided.

Field installations of the monitoring system have documented numerous cases of series arcing. Sometimes such a condition proceeds from initial electrical indication to final failure of the device in minutes or tens of minutes, but in other cases, the failure process takes days or even weeks. During that time, all load continues to be served, although with intermittently heavy distortion of the supply voltage downstream of the failing device, and the utility often receives no conventional notice that the incipient failure exists. The series arcing process is a dynamic one. Field data indicates that the elevated contact impedance, and therefore the level of "modulation" of the current flowing through the device, vary from cycle to cycle and second to second. In addition, a device experiencing this type of progressive failure may have active periods of series arcing lasting seconds to tens of minutes, intermingled with quiescent periods that can last days, as will be outlined below for the subject case. Based on examination of failed devices, combined with analysis of associated electrical signatures, the authors speculate that the quiescent periods may occur when the concentrated heat of arcing temporarily welds the contact surfaces and created a fragile but low-impedance contact, which may break due to wind, thermal expansion, or other mechanical conditions, causing series arcing to resume.

The subject case involved a current-carrying connector that broke eleven days after beginning to experience intermittent series arcing. The failure was several electrical miles from the substation. Based on substation measurements, the monitoring system detected the series arcing condition hundreds of times during that period. The timeline of Figure 5 shows the hourly number of detections for the period February 14-26. As shown, there were numerous detections on February 15 and 16, then none during the next eight days, and then many additional detections over a period of twelve hours on February 25. The detections stopped abruptly on the afternoon of February 25, when the series arcing resulted in full separation of the device.

The specialized monitoring system reported series arcing, based on automated algorithmic analysis of substation current and voltage signals. Figure 6 shows ten seconds of this data during a typical series-arcing episode. The failing device was serving single-phase load on phase A of a four-wire circuit, so the resulting current transients appear in the phase-A current and the neutral current (3Io). The load current was around 150 amps. The variation caused by the series-arcing activity appears as current transients of a few amperes. The transients are repetitive but aperiodic. The magnitude of the current transients is too small to trigger conventional protection, and the corresponding voltage variations are on the order of 0.2%, too small to trigger conventional devices, including power quality meters.

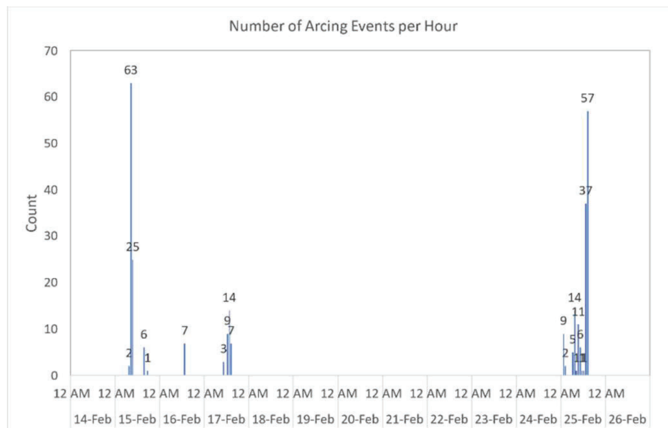

Figure 5: Number of series-arcing events reported by the monitoring system, per hour, for the connector's eleven-day incipient failure period.

Figure 6: RMS voltages and currents, measured from substation PTs and CTs, during one event recorded by the monitoring system during the connector's eleven-day incipient failure period.

The subject case occurred a few months after the utility company's initial installation of monitors, and they still were in a learning period. Consequently, they did not patrol based on the series-arcing detections on the first two days of activity or during the subsequent quiescent days. When the activity resumed on the eleventh day, the utility initiated a patrol but arrived shortly after the final failure of the device. They used this example for learning purposes. For example, they determined that AMI meters downstream of the failing connector had reported multiple power-up/down events, time-coincident with the periods of series-arcing activity reported by the monitoring system, whereas other meters on the subject circuit had not. This information could have been used to target a patrol and locate the connector days prior to its final failure and separation. The series-arcing phenomenon causes "surges" that are variable in magnitude and in duration, so some individual surges cause the AMI meters to register the surge, whereas others do not. When there are hundreds of surges, however, using AMI to target the patrol only requires that a fraction of the surges cause the meters to register. A corollary finding is that, though all AMI meters record energy and demand in essentially the same way, there is significant model-to-model variability in how these meters register events such as sags and power-up/down events. The ability to use AMI therefore depends on multiple factors, including the behavior of the specific event and the model of AMI meters.

Though space limitations do not allow in-depth explanation, the monitoring system provided several other pieces of information that helped narrow the search for the failing device, days in advance of the final failure. In the subject case, the AMI information was most definitive as to location, but in cases where AMI might not be available, those other parameters would provide significant guidance as to location.

IV. Conclusion

Failing arrestors and connection devices such as clamps and switches are known ignition mechanisms for fires under certain environmental conditions. These devices exhibit electrical failure signatures that can be detected by substation-based monitoring of CT/PT Circuits. Finding and fixing these potential ignition mechanisms can prevent some fires and improve the reliability and rigor of circuits, often avoiding circuit outages.

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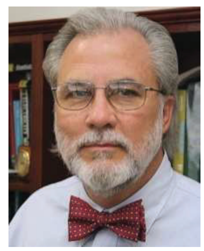
VI. Biographies



B. Don Russell (F'91) is a Distinguished Professor and Regents Professor in the Department of Electrical and Computer Engineering at Texas A&M University. He is director of the Power System Automation Laboratory and for over four decades has conducted research in the design, operation, and protection of electric distribution circuits. Dr. Russell Is past president of the Power and Energy Society of the Institute of Electrical and Electronic Engineers and is a member of the National Academy of Engineering. Dr. Russell is a fellow of five technical societies.

Jeffrey Wischkaemper (M'06) is a Research Associate Professor at Texas A&M University, and a Principal Research Engineer at Texas A&M Engineering. His work focuses on the characterization of power system transients, particularly the detection and remediation of incipient failure conditions on power systems, including those that can lead to wildfire ignition.

Carl Benner (F'14) serves as Research Professor in the Department of Electrical and Computer Engineering at Texas A&M University in College Station, Texas. He holds BS and MS degrees from Texas A&M and has been a researcher at Texas A&M for more than three decades. He is a registered professional engineer in the state of Texas, a Fellow of the IEEE (Institute of Electrical and Electronics Engineers), and a member of CIGRE (International Council on Large Electric Systems).

Karthick Manivannan (M'99) received his M.S degree and Ph.D. in Electrical Engineering from Texas A&M University in 2002 and 2012. Dr. Manivannan is a Research Associate Professor at Power System Automation Laboratory. His work focuses on developing algorithms for automatic classification and reporting of power system events. His research interests include application of signal processing and pattern recognition techniques, data analytics, intelligent reporting and efficient algorithm design.