DFA Technology Detects Circuit Device Failures – Experience of Mid-South Synergy

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SUMMARY

DFA technology has had extensive field testing and currently is in routine use by several utility companies, including Mid-South Synergy, an electric cooperative utility, headquartered in Navasota, Texas, USA. Mid-South has used DFA to discover, locate, and correct a significant number of line problems of which they otherwise were unaware. Line faults and device failures on distribution circuits can cause outages and unsafe conditions such as downed energized conductors. They also are a frequent cause of wildfires. This paper provides a brief overview of the technology and then describes three such events that help illustrate specific benefits to reliability and to personnel and public safety.

Researchers with Texas A&M Engineering's Power System Automation Laboratory developed the advanced monitoring and diagnostic technology called Distribution Fault Anticipation (DFA). DFA provides 24/7 monitoring and automatic analysis of distribution circuit events. The result is enhanced situational awareness for operators, with automatic diagnosis of abnormal operations, detection of failing devices, and detection of incipient faults. Operating conditions that likely would result in catastrophic faults can often be detected, identified, located and repaired using actionable information.

KEYWORDS

Incipient faults, failure prediction and diagnosis, operator situational awareness electric power reliability, public safety, wildfire/bushfire, power quality.

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BACKGROUND

Current Practice: Operate – Fail – Find – Fix – Operate

The above sequence represents the current utility operating practice for distribution circuits. Circuits are operated until they fail, cause an outage, and sometimes create an unsafe condition. Once customers call, crews are dispatched to find and fix the problem and return the circuit to an operational status.

The state of the art today in utility practice is that some circuits have automatic sectionalizing and restoration devices that attempt to minimize customer interruption, returning as many customers as possible to service on an automatic basis. These systems represent an improvement but remain "reactive," waiting for a failure, fault, or outage to occur, and then responding.

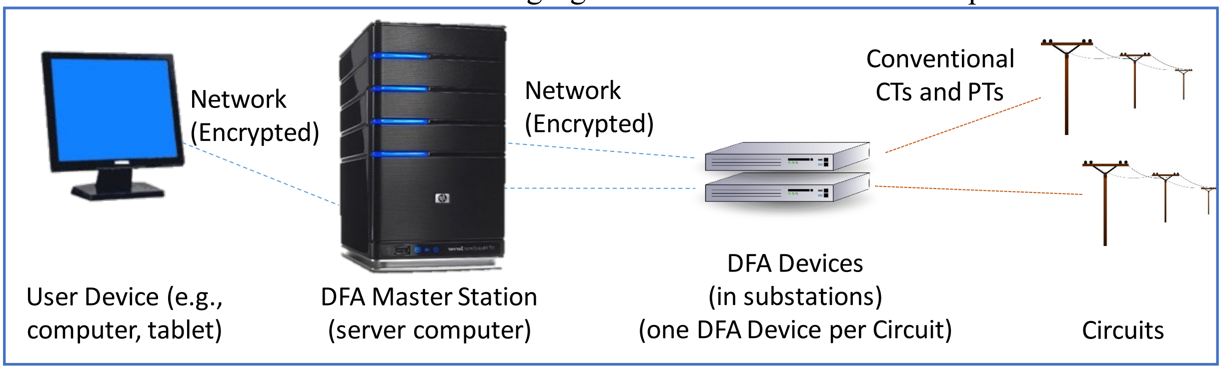
It has long been known that the reliability and safety of distribution circuits could be improved if failing devices could be detected and repaired at an early stage, before an outage occurs. DFA technology embodies advanced waveform diagnostic software that can identify misoperating devices, incipient faults, repetitive faults, and other conditions that ultimately cause long outages or unsafe conditions such as downed energized lines [1,2].

Key DFA functions that will improve operations include identification of the cause of outages or recurring faults. When crews are dispatched with specific knowledge of the cause of an outage or failure, search times are reduced, and repair times shortened. SAIDI metrics are improved. When operators are made aware of failing apparatus in time to effect repairs before an outage, SAIFI metrics are improved.

DFA is the first tool available to distribution circuit operators which enables true condition-based maintenance, often with the result that repairs are made before customers call or are affected. No system can detect all suboptimal or unsafe conditions, but DFA allows certain outages, downed lines, and wildfire ignitions to be prevented, and others responded to in a more informed manner, making electricity delivery more reliable and safer.

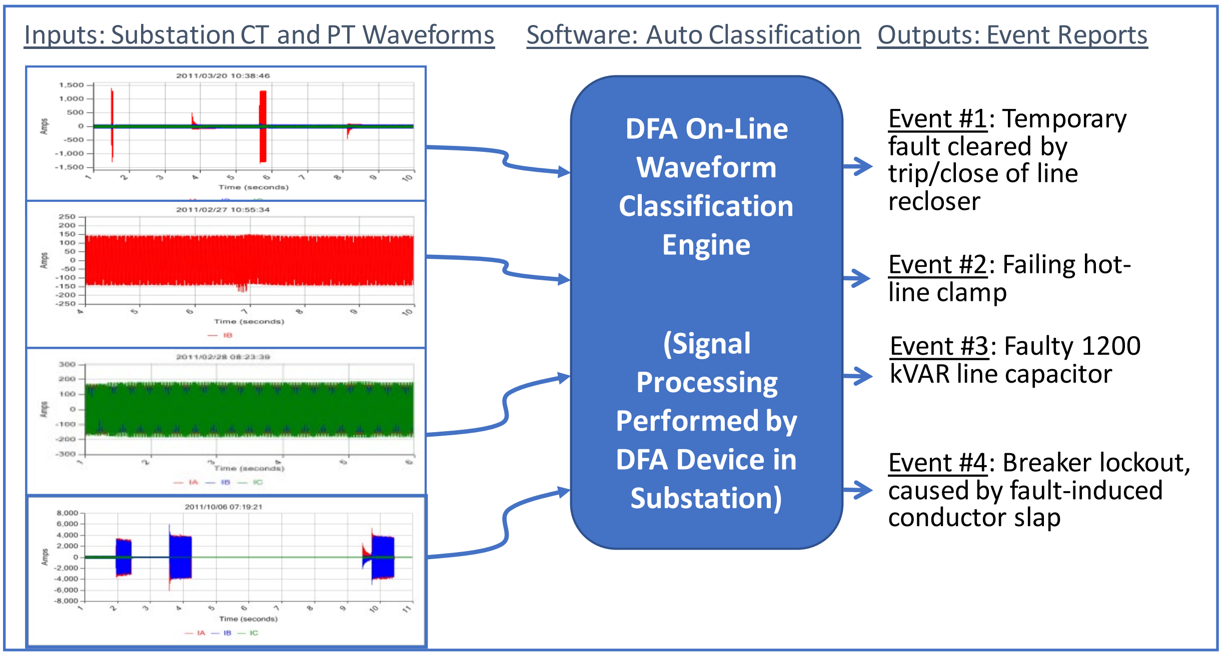
HIGH-LEVEL DESCRIPTION OF TECHNOLOGY

This paper contains real-world data related to problems that utility companies learned of and solved using the DFA system. This section provides a high-level overview of the DFA system itself, to aid the reader in understanding the source of the data presented. From a hardware perspective, the system consists of DFA devices that monitor individual circuits and a central master station computer that accumulates reports from the fleet of DFA devices and makes those reports available to users. Each of the fleet of DFA devices communicates with the DFA Master Station via Internet. The following figure illustrates these main components.



Each DFA device is a 19" rack-mount device that monitors one distribution circuit via the circuit's CTs and PTs (typically bus PTs), converts current and voltage inputs to digital waveforms at 256 samples/cycle and 18 bits of precision, and records multi-second waveform files when it detects waveform anomalies. To enable detection of certain types of incipient failures, DFA devices intentionally trigger on smaller waveform anomalies than do power quality meters, relays, or other devices that record waveforms.

Sensitive triggering causes DFA devices to record substantial numbers of events, typically multiple events per device per day. Manual analysis of the records would require substantial skilled manpower and therefore generally is not feasible. Further, manual analysis generally is not done in real-time, thus limiting its operational usefulness. DFA system software uses embedded signal processing and other software techniques to recognize multiple types of line events. The software, known as the On-Line Waveform Classification Engine, executes in each substation-mounted DFA device and processes waveform recordings in near real-time. As R&D personnel improve algorithm software over time, the DFA Master Station deploys the new software to the fleet of devices.



ILLUSTRATIVE CASE STUDIES

This section details selected case studies. The following bullets apply to each of those cases.

- Each of the selected cases comes from Mid-South Synergy's electric distribution system, which serves approximately 30,000 meters in six Texas counties. Mid-South initially instrumented ten circuits with DFA and has added ten more in 2018.
- Events and conditions were not staged or simulated. Each case study represents an event or condition that occurred on an in-service, medium-voltage distribution system.
- The DFA system recognizes events based on software analysis of waveforms that it measures from substation-based CTs and PTs and does not require communications with sensors or other devices installed across the circuit. Each case study represents an event or condition that was detected by the DFA on-line monitoring system, based solely on substation-measured CT and PT signals.
- Except from the DFA system, the utility was unaware of the event or condition.
- Graphs of electrical currents and voltages represent recordings made by DFA Devices in substations and transferred to the DFA Master Station for convenient access.

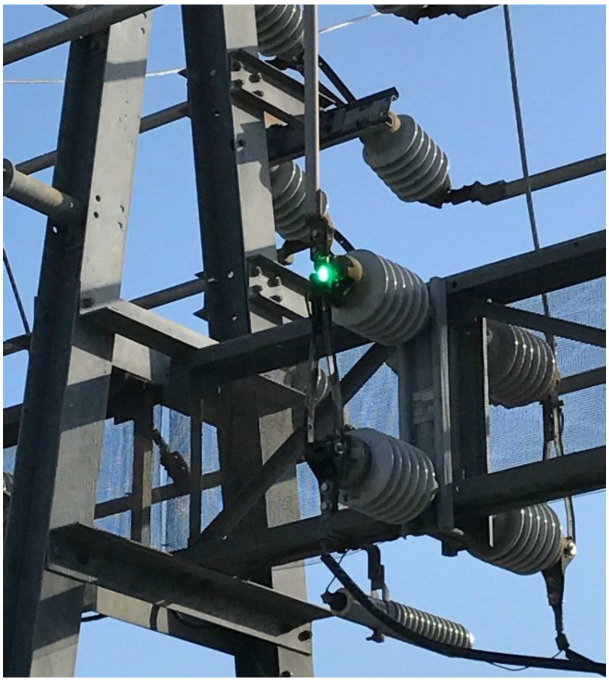
CASE STUDY 1: INCIPIENT FAILURE OF A SUBSTATION SWITCH

Series Arcing Phenomenon – A typical distribution circuit has numerous current-carrying connections, such as switches, clamps, split-bolt connectors, etc. These devices are simple and rugged and experience various mechanical, electrical, and environmental stresses over their lifetimes. Over time, these stresses can cause a connection's contact surfaces to develop imperfections, resulting in elevated contact resistance and, in the presence of the flow of load current, creating a "hot spot." The hot spot is the result of series arcing between the contact surfaces of the connection. Series arcing differs from conventional fault current, because it represents a variable impedance to the flow of load current in an intended path, rather than a flow of current in an unintended path.

Field data collection and research underlying the development of DFA technology have documented numerous cases of series arcing. The series arcing phenomenon remains poorly understood, but analysis of field data from multiple cases provides insights including the following:

- A connection can experience series arcing over an extended period of time. Documented cases have shown that a given connection can experience series arcing for hours, days, or even weeks before final failure.
- Series arcing often is intermittent. Although series arcing may occur over a period of days or weeks, it generally is not sufficiently electrically active for detection by the DFA system over that entire period. Such a connection may be electrically active for several minutes and then not electrically active for several hours or even several days.
- Series arcing progressively erodes the contacts of the connection and of associated conductors. In some cases, progressive erosion of a conductor can cause a broken conductor, such as in the photograph at right.

- Series arcing sometimes causes customer complaints, but the nature of the complaints are not unique to series arcing. For example, series arcing can cause a customer's lights to flicker intermittently, but multiple other distribution system issues also can cause lights to flicker. Because the series arcing is intermittent, it is not uncommon for a customer's voltage and lights to be normal when a lineman visits the customer's site in response to a complaint of flickering lights. This can make diagnosis difficult and lead to repeated complaints.
- Series arcing causes "surges" in current that can cause fuses or other protection (e.g., reclosers) to operate. Because of the intermittent nature of the phenomenon, a blown fuse may be replaced and hold, without the series arcing being diagnosed or repaired. In such a case, blown fuses or other symptoms may recur in the hours or days after the initial event. Counterintuitively, protection can operate upstream or downstream of the location of the series arcing.
- In other cases, such as the subject case study, series arcing results in no protection operations or customer complaints.



Subject Case – This case involved a manually operated blade switch mounted on the metal structure in a rural, unmanned 25 kV substation. The switch is shown in the photograph at right. The substation's single power transformer had three distribution circuits, and the subject switch carried the load for one of the circuits. At the time of the incident, the switch was carrying load, and the utility company had no active customer complaints or conventional indication of a problem.

When the switch began to experience series arcing, the DFA system detected the resulting electrical variations in the CT and PT signals, recognized those variations are representing series arcing, and reported the condition via the DFA Master Station web interface. Upon receiving notice from the DFA system, utility personnel checked their other systems for active problems. They had no relevant information from SCADA, customer tickets, or any other conventional system. They used their automated meter reading (AMR) system to ping meters on the affected phase, with the thought that the metering system might be reporting some type of anomaly that would inform the utility's search for the series arcing; the AMR system provided no indication of any anomaly.

Because series arcing is not a conventional fault, conventional (i.e., impedance-based or current-based) means of locating faults are not applicable to the location of series arcing. When the DFA system reports series arcing, it provides a gross estimate of the amount of connected kVA capacity downstream of the affected connection. In the subject case, this indicated that the failing device was carrying most or all of the circuit's load. Therefore, the utility dispatched a line crew to examine switches and other connections near the substation. Upon arrival at the substation, the lineman immediately heard an abnormal audible buzz and saw visible light on the blade switch in the substation, as shown in the previous photograph.

The search occurred on a Saturday afternoon, when linemen were on call but not on regular duty. The elapsed time between the utility's receiving notice from the DFA system and their locating the arcing switch was approximately 1.5 hours. Because of the potential ramifications of catastrophic failure of the switch, the utility called in crews that evening to perform circuit switching and effect repairs.

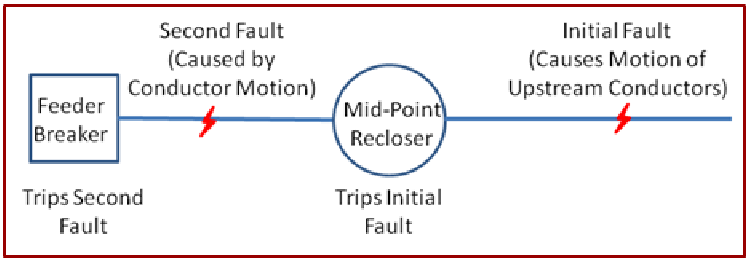
Reliability impact – Had the switch not been discovered prior to failure, the minimum consequence would have been an unplanned outage to at least one entire circuit. Because the switch was located on the substation metal structure, its failure could have caused an outage to all three of the substation's circuits. In an extreme case, it could have caused extensive damage to the substation. Proactive replacement of the switch averted a potentially lengthy outage to hundreds of customers.

Safety impact – Discovering the condition during its incipient stage enabled repairs to be made without the time pressures inherently associated with the desire to restore power quickly, particularly for an outage affecting a large number of customers. In addition, the area served by the switch experienced thunderstorms on each of the next two days, resulting in several faults on the circuit. The passage of fault current easily could have precipitated final failure of the already compromised switch. In that case, lineman would have been responding during adverse weather conditions, which inherently increase risks. In addition, risks normally associated with substation fire or wildfire were averted.

CASE STUDY 2: FAULT-INDUCED CONDUCTOR SLAP THAT CAUSED SMALL FIRE

Fault-Induced Conductor Slap (FICS) Phenomenon – Fault-induced conductor slap, or FICS, is a complex phenomenon [3]. It occurs when an initial fault at one location on a circuit induces a second fault closer to the substation. Although there can be case-specific variations, the typical sequence is as follows:

- An initial fault, typically phase-to-phase, occurs at some location on the circuit. The cause of the initial fault is not relevant to the remainder of this discussion.
- The flow of fault current through the phase conductors, from the substation to the point of the fault, creates magnetic forces between those conductors. For a phase-to-phase fault, the fault current flows in two parallel phase conductors, over a substantial distance, resulting in magnetic forces that repel the two conductors away from one another, mechanically displacing them from their normal resting positions.
- The initial fault causes a mid-point protection device (e.g., the Mid-Point Recloser in the diagram at right) to trip. This interrupts the fault current, thus suddenly removing the repelling magnetic forces. This occurs at all locations between the substation and the location of the initial fault, both upstream and downstream of the mid-point protection device.



- Because the conductors now are displaced outward from their normal resting positions, and then the repelling force suddenly is removed, gravity causes the conductors to swing back toward their normal resting positions, and momentum causes them to pendulum through normal position and come closer to one another than normal.
- Under the right set of parameters (magnitude of fault, duration of fault, physical separation between conductors, length of span, sag, etc.), the swinging conductors can touch each other. If such contact occurs upstream of the mid-point protection, it causes a second fault. This second fault has been "induced" by the initial fault, thus the name of the phenomenon.
- When the second fault occurs, it necessarily causes operation of protection that is upstream of that second fault. The upstream protection often is the substation breaker.

In summary, what begins as a routine fault that should trip only a mid-point protection device instead escalates into a fault of higher amplitude, closer to the substation, and often necessitates circuit-wide interruption.

FICS has multiple ramifications:

- Arcing contact between conductors causes a shower of sparks, with hot particles falling to the ground. Many overhead lines are made of aluminum, and particles ejected by arcing of aluminum conductors can be in ignition (i.e., burning) as they fall to the ground, not just hot.

- Arcing contact between conductors damages the conductors, causing pitting and “bright spots,” such as shown in the photograph at right.
- Because FICS is a complex phenomenon, conventional investigations seldom diagnose it properly.
- FICS tends to occur repeatedly in the same location. This is because line geometry and parameters that made a span susceptible to one episode of FICS, left unchanged, leave it susceptible to future episodes of FICS. Repeated FICS has been documented multiple times on DFA-instrumented circuits.
- In a given span, episodes of FICS may be separated in time by months or even years. This has been documented multiple times on DFA-instrumented circuits. Because the elapsed time between episodes can be lengthy, personnel typically do not mentally correlate the episodes. In one case, a single span experience FICS between the same two phases five times over a period of four years. The circuit had approximately 4,000 customers. Three of the FICS episodes caused sustained outages, but two years passed between the first and second sustained outages and another two years between the second and third sustained outages, so utility personnel did not make a mental connection between the multiple events. (This case occurred when DFA research was in its early data-collection phase, when operations were observed and documented but DFA generally was not used to initiate corrective action.)
- FICS increases the number of customers affected by interruptions and outages. The initial fault is downstream of a mid-point protection device and therefore should result in interruption of only the customers downstream of that device. Because the induced, second fault is upstream of the mid-point protection, however, protection closer to the substation must operate, inherently affecting more customers. Quite often the second protection device is the substation circuit breaker, so its operation affects all customers on the circuit.
- Though not immediately obvious, FICS often complicates efforts to locate the initial fault. This is because the substation circuit breaker, which often is the device to open for FICS, normally should operate only for faults that are near the substation, upstream of any mid-point protection device. Therefore, line crews will concentrate initial location efforts between the substation and the first-level mid-point protection device, when in fact the initial fault is downstream of a mid-point protection device.

Subject Case – The subject case involved a fault on a long, rural 25 kV circuit and was a textbook case of FICS. A tree on the line caused an initial, phase-to-phase fault, which induced the FICS sequence, ultimately causing the substation circuit breaker to trip multiple times and lock out the entire circuit. Absent the FICS, the initial fault would have locked out a portion of the circuit but left the remainder in service.

DFA system software recorded and autonomously analyzed the substation CT and PT waveforms and reported that the substation circuit breaker had locked out, a fact that the utility otherwise knew via SCADA. It also reported that the cause of the lockout was FICS, which the utility otherwise did not know. The report included a sequence of fault amplitudes that, when put into the utility's existing circuit model software, predicted a specific FICS location between the substation and the mid-point protection that had tripped in response to the initial fault. The utility patrolled the location and found arc marks on the phase conductors in the span predicted by the circuit model software. They also found evidence of a small grass fire under the point of the FICS-induced fault, as shown in the photograph at right. The utility also had a customer report of the fire time-coincident with the FICS.

The DFA system provided the utility's only notice that FICS had caused the conductor clash and fire, enabling them to diagnose the condition, physically locate it, and take corrective action to modify the span to prevent future FICS episodes.

Reliability impact – A span susceptible to FICS often experiences FICS multiple times. Each episode causes one or more interruptions and often locks out the substation circuit breaker. FICS usually is not diagnosed, so repairs are not made. Therefore, the condition remains on the system and can cause future faults, interruptions, and outages. This has been documented multiple times on DFA-instrumented circuits.

The DFA system analyzes patterns in currents and voltages, during fault events, to detect the signature of FICS. When it detects FICS, it reports this to the user and provides parameters that, used in conjunction with appropriate third-party circuit model software, typically makes it possible to locate the offending span with minimal effort. Learning of, locating, and repairing a susceptible span, after the first episode, prevents future faults, interruptions, and outages.

Safety impact – The arcing contact caused by FICS ejects hot, often burning particles, with the potential to ignite proximate vegetation or other combustibles, as occurred in the subject case. In the subject case, the fire extinguished itself after burning a small area. The next episode, however, may occur on a "red flag," high-fire risk day and ignite a fire that does not extinguish itself but instead grows rapidly and burns out of control.

Each episode of FICS causes damage to conductors. Because FICS tends to occur repeatedly in a single location, damage can be cumulative, which, in an extreme case, could cause the conductor to break and fall to the ground, creating shock and ignition hazards.

Diagnosing and locating FICS, based on a given episode, prevents subsequent episodes, thereby reducing future risk of ignition and possibly a broken conductor.

Case Study 3: Broken Insulator and Charred Crossarm

The subject case occurred on a long, rural 25 kV circuit and involved a broken insulator that allowed a phase conductor to become dislodged from its normal position and lodge below its wooden crossarm. The photograph at right, taken after repairs had been made, shows substantial charring of the underside of the crossarm.

This condition first manifested itself as an overcurrent fault that caused a mid-point recloser to trip and auto-reclose one time. Most momentary interruptions result from temporary conditions that require no corrective action or response by the utility company, and successful momentary interruptions typically would not be investigated.

The DFA system detects faults and protection operations, including those involving mid-point reclosers and downstream fuses, and reports them via its web interface. Communications with the protection device is not required. Each such fault report provides characteristics of the fault (phase, amplitude, duration) and response of the protection system (interrupting time, amount of load momentarily interrupted, open interval prior to auto-reclosing).

The next day, the DFA system reported a second fault, again with a single momentary trip/close operation by the protection system. The utility engineer responsible for reviewing the DFA web interface noted that the two faults shared many similarities – same phase, similar amplitude, similar duration, similar response of the protection system. He then used DFA information, in conjunction with his existing circuit model software, to predict the likely location. Using a directed patrol, he found the displaced conductor and charred crossarm six pole spans upstream of the location estimated by the model software and initiated repairs.

Reliability impact – The condition caused two faults and momentary interruptions, about 24 hours apart. Neither caused a sustained interruption to any customers. Left unchecked, additional faults and interruptions would have occurred and subjected customers to additional nuisance interruptions. The condition eventually would have escalated to a sustained outage. The crossarm could have burned in two, or the conductor could have burned in two, either of which would have caused an outage of significant duration. Preemptive action reduced the number of interruptions and likely averted an outage.

Safety impact – The circuit runs alongside a forested area, and the grass near the base of the pole was dry. The wooden crossarm already had sustained significant charring. Charring would have increased, potentially resulting in a poletop fire, a burning section of crossarm falling to the ground, or both, creating a risk of ignition. The conductor could have broken in two and fallen to the ground, creating elevated risk of ignition and risk of electrocution.

There also is a reasonably high probability that the eventual sustained outage would have occurred during a storm, when the wooden crossarm was wet and therefore more conductive than when dry. Such an eventuality would have required linemen to make repairs during adverse weather conditions.

Preemptive action eliminated the continuing ignition risk. It also enabled repairs to be made during fair weather rather than foul.

SUMMARY AND CONCLUSIONS

Conventional tools and practices for the operation of electric power distribution are largely reactive in nature – wait until something breaks and then go fix it. This has been necessary, because distribution circuits consist of hundreds or thousands of rugged, long-lasting components spread over large geographic areas, and conventional monitoring technologies typically report only catastrophic failures. Smart grid technologies (e.g., smart meters, automatic circuit reconfiguration) improve response but remain largely reactive.

Some failures occur precipitously. Others develop over time. DFA technology, developed by Texas A&M Engineering, can detect, analyze, and report some types of incipient failures, enabling proactive response. The technology continuously monitors substation-based CTs and PTs, with high fidelity, applies sophisticated software to recognize multiple types of failures and incipient failures, and reports these conditions to utility personnel via a central master station web interface. Proactive response has multiple benefits, including improved power quality and reliability. Proactive response also can improve safety for utility personnel and the public and reduce wildfire ignition risks.

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