Improved Fault Location on Distribution Circuits Using Advanced Inputs

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Executive Summary

Following a power outage, locating the fault that caused the outage constitutes a substantial part of repair and restoration efforts. The complex, multi-branch topology of distribution circuits and the dearth of fault information make fault location inefficient and time-consuming. This is particularly true for faults that do not trip the substation circuit breaker. It also has particular relevance to locating latent conditions that cause recurrent momentary interruptions but not sustained outages. Evolving technologies, such as Distribution Fault Anticipation (DFA) technology, can provide better information and hold promise for enabling more efficient location of faults and latent fault conditions.

Because power line failures can cause catastrophic wildfires, the legislature of the state of Texas is supporting a demonstration of how the use of DFA technology can help mitigate wildfire risks. At the foundation of that effort, seven participating utility companies are instrumenting 58 distribution circuits with DFA technology. As of this writing, installations have been active on 50 of those circuits for up to nine months. These deployments provide an opportunity to develop and test methods for using advanced information to improve fault location on distribution circuits.

DFA-provided information has been used to test enhanced fault location methods in a limited number of cases. These efforts have been underway for several months and have involved collaborative efforts between the authors' organizations. Initial proof-of-concept results have been quite encouraging. Future work is expected to include additional testing, refinement and expansion of location techniques, and automation of underlying processes.

Texas Power Line-Caused Wildfire Mitigation Project

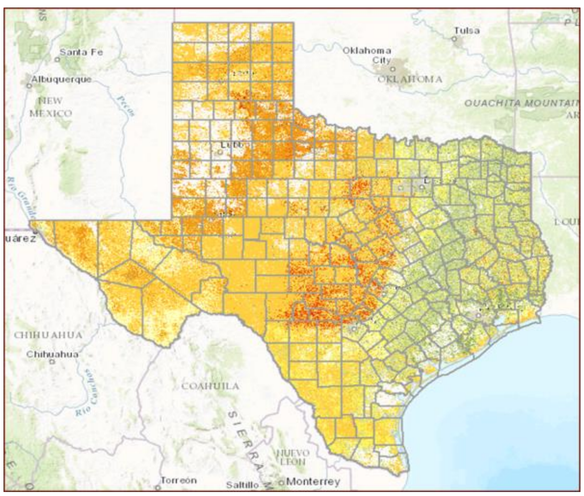
Wildfires, also known as wildland fires and bushfires, annually inflict enormous economic and societal costs, including direct damages, fire suppression costs, provision of other emergency services, and disruption of lives and commerce, not to mention threats to health and even life. Failures of power line apparatus are implicated as the cause of a substantial number of wildfires. Downed power lines represent the most obvious risk, but other line conditions and events also constitute competent ignition sources. Clashing conductors and catastrophic failures of oil- and vacuum-filled apparatus can ignite ground-level fuels. In addition certain latent and incipient conditions can erode and weaken conductors, eventually leading to downed lines. For example, low-level incipient arcing (i.e. a "hot spot") in the jaws of a hotline clamp can erode a conductor, weakening it and eventually causing it to break.

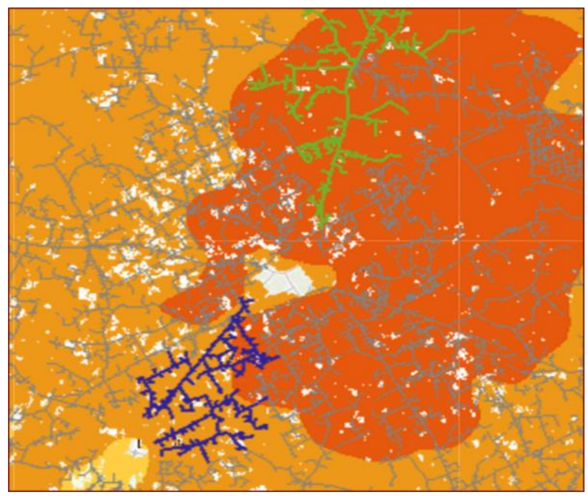
Consequently the legislature of the state of Texas is supporting a field demonstration of advanced on-on-line monitoring of distribution circuits for the purpose of helping to mitigate risks associated with wildfires. The monitoring technology for this project, known as the Texas Power Line-Caused Wildfire Mitigation project, is based on Distribution Fault Anticipation (DFA) technology. DFA technology, described more fully in a subsequent section, uses substation-based on-line monitoring to provide awareness of circuit events and conditions, including latent or incipient conditions.

Seven Texas-based utility companies currently participate in the Texas Power Line-Caused Wildfire Mitigation Project and have instrumented selected circuits on their distribution systems with DFA monitoring. Participating utility companies also constitute a project council.

- Austin Energy
- Bluebonnet Electric Cooperative
- Bryan Texas Utilities (BTU)
- Mid-South Synergy
- Pedernales Electric Cooperative
- Sam Houston Electric Cooperative
- United Cooperative Services

The Texas A&M Forest Service, which has responsibility for Texas wildland management, including fire prevention and fighting, provides GIS-based wildfire risk assessment tools that factor in weather, fuel load, the wildland-urban interface, and multiple other factors. The two images below come from this on-line service. The image on the left shows a “heat map” indicating relative wildfire risks across the state. The image on the right zooms in on a smaller area. Overlaid on the right-side image is electrical circuit model information for circuits in this region, with DFA-monitored circuits highlighted in color. The synergy of technologies is intended to enable location-specific information on electrical activity and relative wildfire risks.



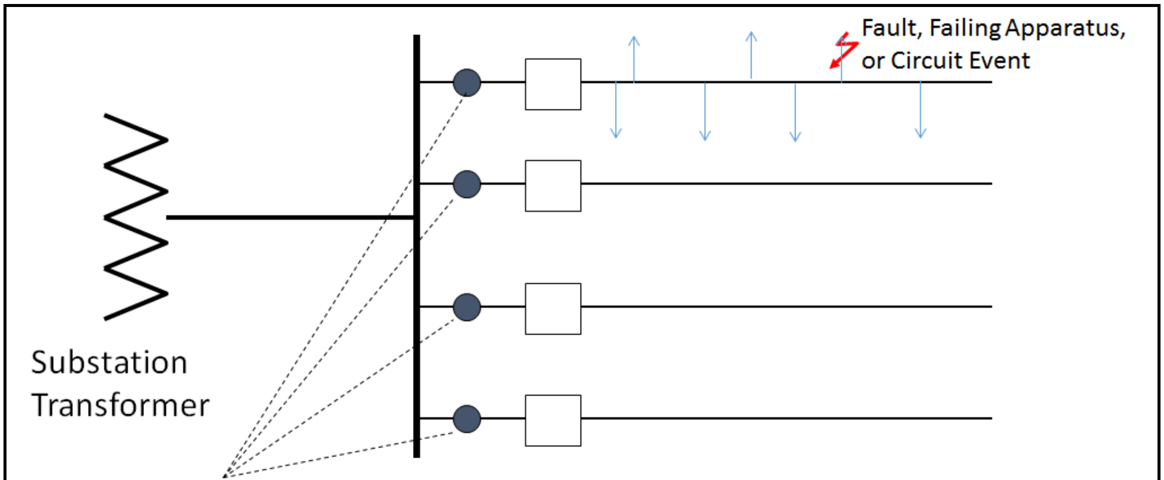


<u>**Distribution Fault Anticipation (DFA) Technology**</u>

At its most fundamental level, DFA technology is about providing enhanced <u>**awareness**</u> of circuit events and conditions, to enable a utility company to manage its circuits better.

Texas A&M Engineering developed DFA technology over a period of more than fifteen years, with substantial support of the Electric Power Research Institute (EPRI) and more than fifteen utility companies that installed various generations of DFA devices on well over 100 distribution circuits.

Deployment of DFA technology involves installation of one 19" DFA device per distribution circuit and providing communications from each of these DFA devices to a central DFA master station server computer. DFA devices use conventional current and potential transformers (CTs and PTs) as inputs and do not require communications with other substation devices or line devices. The figure below illustrates the application of DFA devices in a four-circuit substation.



High-fidelity DFA devices, connected to conventional CTs and PTs, one per distribution circuit.

Each DFA device monitors high-fidelity current and voltage waveforms continuously and detects minor and major anomalies in those waveforms. When an anomaly occurs, algorithms embedded in each DFA device apply digital signal processing and pattern recognition techniques to recognize specific failure signatures. The device then uses secure communications to send a concise event report to the master station, which stores the reports in a relational database and provides users with secure, browser-based portal for accessing those reports.

DFA technology complements conventional technologies and modern "smart grid" technologies by providing on-line monitoring to better inform the utility company of distribution circuit conditions and events. Heightened awareness, for example of latent or incipient failure conditions, can enable utility companies to know of and remediate circuit conditions that otherwise could fail and possibly create the potential for a wildfire ignition sometime in the future. Algorithms in each DFA device recognize a variety of line conditions and events, including latent clamp failures, fault-induced conductor slap, recurrent fault conditions (e.g., cracked bushings or branches pushing lines together) and various types of failures of capacitor banks. DFA provides unique information the other technologies do not, and vice versa.

Fault Location – State of the Art

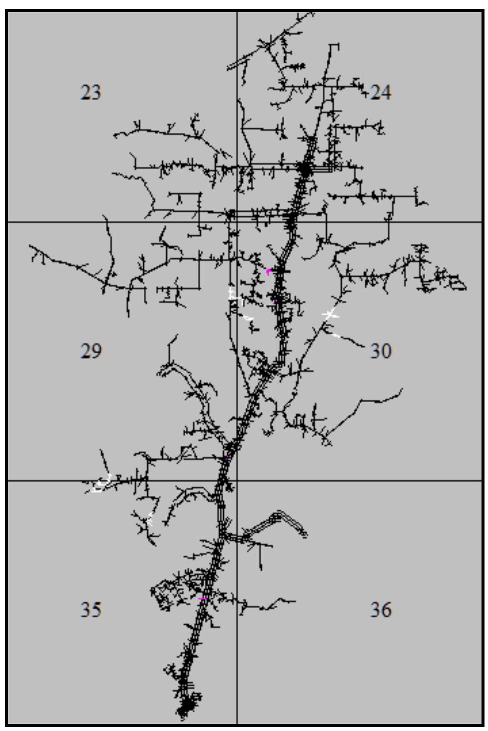
Location of faults on distribution circuits is a difficult process that has existed since the beginning of electric power distribution. When a fault causes a service outage, the offending fault must be located before repairs can begin, making timely location important.

Distribution circuits generally have complex topologies. Emanating from a substation, a distribution circuit typically consists of some length of main three-phase trunk, plus numerous branches and laterals, often spread across large geographic regions, particularly in rural areas. Line conductors typically tend to be large near the substation and progressively smaller farther out on the circuit, particularly on laterals and taps.

Digital protection devices measure electrical quantities during a fault and can use those measurements to estimate fault current magnitudes and/or the line impedance between the measurement point (e.g. the substation) and the fault location. Some of these devices allow the user to specify per-unit-length line impedance, based on the size and type of the circuit conductor. Upon occurrence of a fault, such a device uses real-time electrical measurements to calculate an impedance-to-fault value and then converts the impedance to a physical distance. This approach assumes uniform conductor size and therefore is intended for application on the portion of the circuit near the substation. It does not apply well beyond the main three-phase trunk or where smaller conductor makes up a portion of the fault-current path.

A single fault on the main trunk may trip the substation circuit breaker and therefore affect more customers than a single fault beyond a downstream protection device, but the rest of the circuit has vastly more apparatus and circuit-miles of exposure and consequently experiences most of the faults. The utility may have a relatively large amount of information, pertinent for fault location, for the close-in fault but little about faults elsewhere.

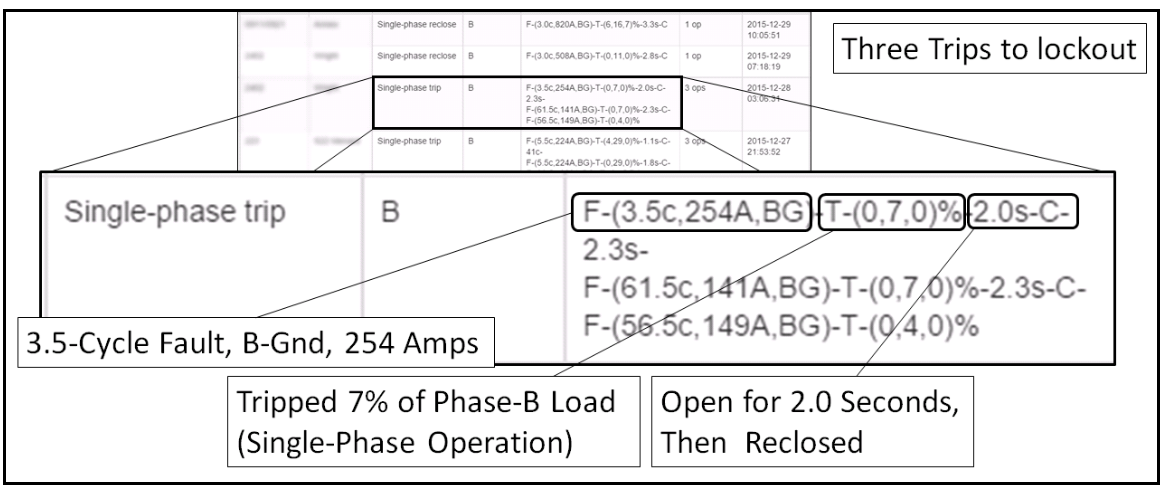
Circuit models do not assume uniform conductor along the fault-current path and therefore can be used to predict expected current magnitudes for faults on any line segment on the circuit, not just on the main trunk. When a fault occurs, current magnitude can be estimated from electrical measurements and then compared with the model-based fault current predictions, to generate in a list of possible fault locations. Unfortunately the list of possible fault locations may contain a large number of line segments, particularly for the relatively low fault current levels typical of locations far from the substation. For example, the figure below shows a typical rural circuit. On that circuit, 96 segments, scattered across the circuit's geography, correspond to a fault current level of 500, with a tolerance of +/- 2% (+/- 10 amps).



Two key pieces of information for fault location are: 1) knowing which protection device has operated and 2) knowing the magnitude of fault current. When an outage occurs, an outage management system (OMS) sometimes can identify which protection device is open. Some line devices (e.g., electronic reclosers or faulted circuit indicators) can signal the passage of fault current and possibly provide an estimated fault current magnitude, but getting this information requires remote communications and may not be quick or convenient to access. In many cases, an unmonitored recloser may operate and provide no information, or a fuse may blow and provide no information. AMI (advanced metering infrastructure) meters may enable the utility company to infer which protection device has opened, but they do not provide an estimate of fault current level.

Enhanced Fault Information Provided by DFA

The image below illustrates the DFA report of a fault that locked out a line recloser after three trips. This report was generated automatically by algorithms analyzing substation CT waveform data and did not require human analysis. It reports a fault and provides a sequence of events describing the fault and the resulting operation of the protection system. The first line, which is highlighted in the image, reports a fault that drew 254 amps of phase-B, single-line-to-ground fault current for 3.5 cycles, and then tripped a single-phase device and interrupted an estimated seven percent of the total-circuit load on phase B. The remainder of that first line of the sequence of events indicates that the single-phase device was open for 2.0 seconds and then reclosed. The second line indicates that 2.3 seconds elapsed, after the reclose, without the fault reinitiating. The final two line of the sequence of events then show the remainder of the sequence (fault-trip-reclose-fault-trip), along with the current level and duration of each fault interval. Overall the sequence of events shows three trips to lockout of a single-phase device, with the first trip on a fast curve and the other two trips on slower curves. It also shows that the two open intervals of the reclosing device were 2.0 and 2.3 seconds, respectively.



The information in the report results from automated algorithms, in the DFA device, assessing current waveforms, as measured from substation current transformers. The DFA system does not communicate with the subject recloser or any other device to determine this information. Rather it generates its report based solely on analysis of substation current measurements. The entire sequence of events shown in the image above was derived and delivered fully autonomously by the DFA system and made available to users via browser-based login on the DFA master station. Note that the fault current levels reported for the three trips are 254, 141, and 149 amps, which are too small to be detected by many fault-detection line devices. Consequently, even on a circuit with fault detection devices, this fault might not be reported. Alternatively, depending on the pickup levels of the fault detection devices, the first fault, which drew 254 amps, might be reported, but same fault detection device might not report the other two faults, each of which drew less than 150 amps.

Use of Enhanced Information for Improved Fault Location

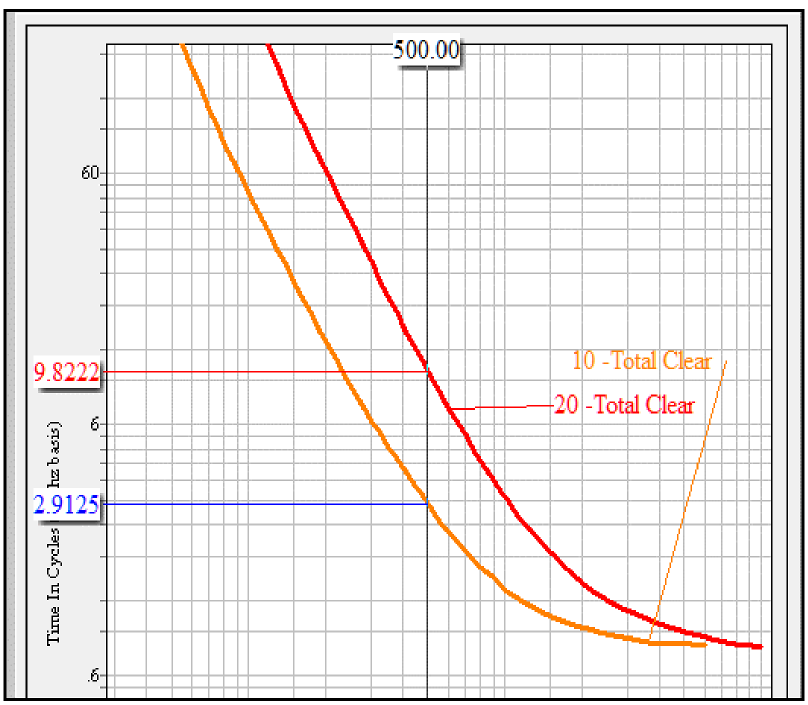
If a protection device is known to have operated, then only line segments downstream of that device need to be considered as possible fault locations. Conversely, if it can be determined that a certain device did <u>not</u> operate, then line segments downstream of that device need not be considered. Sometimes a device has remote reporting capabilities, in which case direct determination of whether it operated may be available. In other cases, the operated device cannot communicate its condition, so device operation must be inferred. Work done by the authors is investigating how information reported by the DFA may be used to infer operation of downstream protection, thereby reducing the list of possible fault locations. It also is examining how fault location is improved by knowing fault current levels, even for faults that may occur near circuit extremities and trip unmonitored protection.

Illustrative Hypothetical Example – Fuse Open

Consider a hypothetical example in which a sequence of events, from the DFA system, provides the following information:

- 500-amp fault on phase B
- Fault duration of 10 cycles before open
- No reclose

Consider that the fault occurred on the previously mentioned circuit, where comparing a 500-amp fault current to the circuit model identified 96 line segments, across the circuit's considerable geography, as possible fault locations. The fact that there was no reclose leads to the inference that a fuse operated to clear the fault. Now compare the fault current level (500 amps) and duration (10 cycles) to time-current curves of fuses on the circuit. The image below shows the time-current curves for 10T and 20T fuses. Curves for larger fuses can be compared but quickly eliminated. The 20T clearing time of 9.8 cycles is close to the measured operating time of 10 cycles, but the 10T clearing time of 2.9 cycle is not. This indicates that a 20T fuse operated to clear this fault. Knowing this enables location efforts to be directed to segments 1) downstream of 20T fuses and 2) having 500-amps of fault current predicted by model.

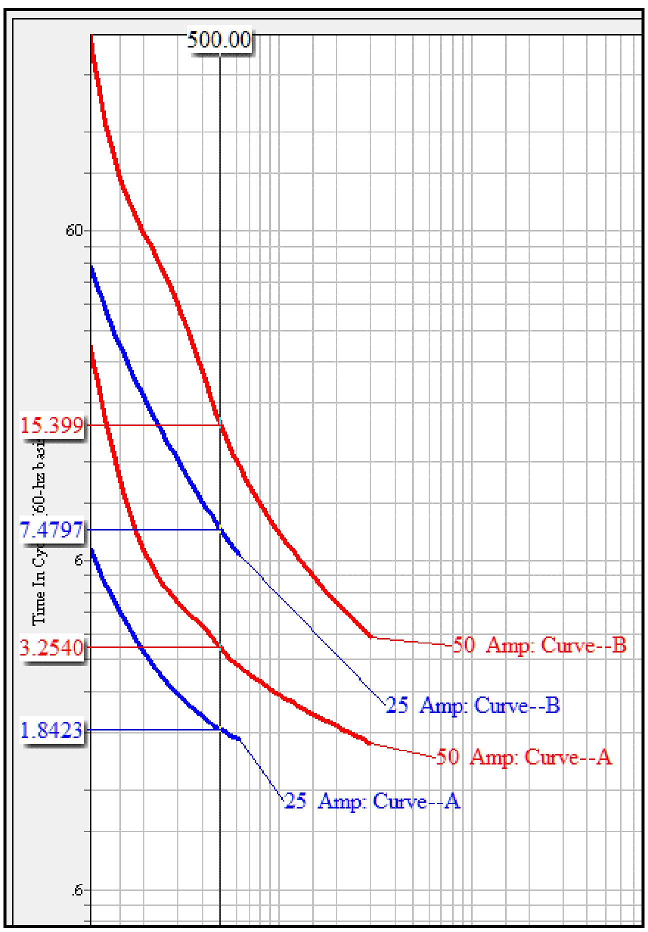


Illustrative Hypothetical Example – Recloser Lockout

Consider another hypothetical sequence of events:

- 500-amp fault on phase B
- Multiple trip/close operations
- First trip at 2 cycles, followed by 1.1-second open interval
- Second trip at 2 cycles, followed by 1.0-second open interval
- Third trip at 9 cycles, followed by 1.2-second open interval
- Fourth trip at 9.5 cycles and no reclose (lockout)

Consider that this fault occurred on the same circuit as the previous example, where comparing a 500-amp fault current to the circuit model resulted in 96 possible line segments. Assume now that circuit model information indicates that the circuit has type-L and type-H reclosers in positions to operate for a 500-amp fault. Because of their design, type-L reclosers have two-second reclosing intervals, and type-H reclosers have one-second reclosing intervals. Because the sequence of events from the DFA report shows one-second open intervals, type-L reclosers can be eliminated from consideration and focus can be placed on type-H reclosers. Now assume that this circuit has 25H and 50H reclosers. Comparing the trip times for the A and B curves of these two devices to the measured trip times (2, 2, 9, and 9.5 cycles) results in selection of the 25H as the device that has operated.



Results to Date

The work described above has occurred over the past several months, during which time four cases have been examined. Each case relates to a fault on a DFA-monitored circuit, and the effectiveness of the location effort was as follows:

Case 1: Squirrel on transformer – Method correctly predicted fuse and location within one span.

Case 2: Self-clearing temporary fault of 6 milliseconds (~1/2 cycle) duration – Experience has shown that fault current estimates are poor for faults that last less than one cycle and tend to underestimate the fault current predicted by a circuit model. Experience also has shown that other (non-DFA) devices tend to yield poor fault current estimates, also underestimating fault current as predicted by model.

Case 3: Squirrel on transformer – Method correctly predicted fuse and actual location of fault.

Case 4: Ice accumulation and wind caused line to break – Method correctly predicted recloser and predicted location within 827 feet.

Continued Efforts and Extension of Work to Location of Recurrent Faults

With the possible exception of the case in which the fault lasted less than one-half cycle, results to date are encouraging. Next steps include refining, formalizing, and automating the process of matching model-based information with measurement-based information. Efforts also are expected to extend to location of recurrent faults (a/k/a latent faults). These recurrent faults result from compromised line conditions that cause intermittent faults and momentary interruptions, without causing sustained outages. Examples include conditions such as cracked bushings, dangling jumpers, and casual tree contacts. Well over a decade of field experience with DFA systems has shown that recurrent faults can cause multiple momentary operations, spread over periods of weeks, without rising to the utility company's attention via conventional or smart grid technologies. Even when a recurrent fault condition becomes known to the utility, perhaps because of customers experiencing "blinking lights," locating the problem can be quite challenging. DFA field experience has shown that these faults often can be located, using concepts similar to those outlined in this paper. Further work is needed to formalize and refine the methods.

About the Authors

Michael Lattner holds the BSEE degree from of The University of Texas at Austin and has worked at United Cooperative Services in Cleburne, Texas since 2009. His duties include distribution system planning and operations support, system protection and coordination, implementation of distribution automation, SCADA support, and power quality analysis. He is the technical lead in installing and analyzing data from the Distribution Fault Anticipation (DFA) technology at his cooperative. Michael is a registered professional engineer in Texas.

Wayne Carr holds the BSEE degree from the University of Texas at Austin (1970). He is a member of IEEE and past chairman of the IEEE Rural Electric Power Conference. He has been a registered professional engineer in Texas since 1976 and the national council of engineering examiners since 1987. He founded Milsoft Utility Solutions in Abilene, Texas, in 1989 and serves as chief development engineer. As chief development engineer, he has been instrumental in the development and implementation of computer algorithms for the simulation and evaluation of electrical distribution analysis systems.

Carl L. Benner holds BSEE (1986) and MSEE (1988) degrees from Texas A&M University at College Station, Texas. He currently holds the position of research associate professor at Texas A&M, where for more than 25 years he has focused on the application of advanced on-line monitoring technologies to electric power distribution systems. He is a fellow of the IEEE, a member of CIGRE, and a registered professional engineer in the state of Texas. He serves on the board of directors for Bryan Texas Utilities.