ELECTRIC POWER
RESEARCH INSTITUTE

Distribution Fault Anticipation

Phase III: System Integration and Library Enhancement

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EPRI Project Manager
A. Sundaram

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Texas A&M University

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Department of Electrical and Computer Engineering
Texas A&M University
College Station, Texas 77843-3128

Principal Investigators
C. Benner
B. Russell

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PRODUCT DESCRIPTION

Distribution Fault Anticipation (DFA) technology is demonstrating ground-breaking advances in the use of sensitive monitoring to detect subtle electrical precursors that signal impending failure of line apparatus. Many failures and incipient failures have been documented with advanced instrumentation of 60 feeders across North America. Current efforts are taking advantage of the installed equipment to expand the library of signatures while concurrently studying requirements and constraints for integrating the technology into systems for practical use.

Results & Findings

This report provides information about multiple issues regarding implementation and integration of DFA technology for practical use and an update on recently documented failure signatures. It also provides information about other projects that are complementing the EPRI-funded effort.

Challenges & Objectives

Distribution Fault Anticipation technology impacts a wide spectrum of utility engineering and operating personnel. It has the ability to detect precursors to failures, thereby giving utilities tools to achieve greater awareness about the health of their systems and to take preemptive action to avoid outages. New signatures continue to be added to the library of documented failures, with three previously undocumented failure signatures added as a direct result of the most recent year's efforts. Significant progress has been made to define system integration requirements, with this project's efforts advantageously proceeding in parallel with a separately funded effort for pilot demonstration of the technology that is better integrated into utility practices.

Applications, Values & Use

Locating apparatus that are exhibiting signs of degradation and imminent failure remains quite challenging. Distributed application of DFA technology has been discussed for addressing this challenge. First-ever installations of distributed DFA monitors will occur in the coming year at a limited number of locations. A Project Opportunity is available for EPRI members to expand this effort to instrument additional monitoring sites to obtain broader, more robust results.

EPRI Perspective

DFA technology represents the state of the art in intelligent monitoring of distribution feeders. Many capabilities have been demonstrated and work is underway to enable utilities to realize benefits in day-to-day operations. Significant potential remains to be tapped, and the technology continues to expand.

Approach

In a continuing effort to develop DFA technology, the project team updated recently detected failure signatures from advanced instrumentation of 60 feeders at 14 substations of 11 utility companies across North America. The team also continued work on system concepts that will enable the technology to be transitioned from a research project to a practical application.

Keywords

Reliability
Distribution
Failure prediction
Signature analysis

ABSTRACT

Reliability and operational economics drive today's electric utility company. Both are critical, yet they are at odds with one another. Traditional maintenance programs can help achieve and maintain high levels of reliability, but these programs are very expensive. EPRI-funded research is investigating the detection and characterization of electrical signals to determine when faults and incipient faults are developing on distribution feeders and to use this information to target maintenance resources where most needed.

Early efforts demonstrated the proof of this concept and collected data from operating feeders by capturing, documenting, and characterizing signatures indicative of failures and incipient failures. This work entailed the instrumentation of 60 feeders at 14 substations of 11 utility companies across North America and resulted in the collection of a massive amount of operational feeder data and numerous signatures associated with various stages of apparatus failure. Researchers developed algorithms to characterize collected data and demonstrated the ability to use this data to diagnose many faults and fault precursors.

Prior work was performed using methods conducive to discovery of information and development of fundamental characterization. Some facets of the research instrumentation and methodologies are not practical for widespread deployment and day-to-day use by utility companies. The current project is developing system concepts that enable the technology to be transitioned from research project to practical application.

Prototype data collection equipment continues to build the failure signature waveform library. In the past year this process has added signatures related to multiple previously undocumented failure modes, thus providing the basis for recognizing additional failure modes in the future.

EPRI has licensed the technology for commercial development. There is significant synergistic benefit to having the conceptual system integration work proceed in parallel with the licensee's implementation of commercial beta hardware and systems so that the two projects can feed off and complement each other. Other complementary projects are underway to explore the application of Distributed Fault Anticipation (DFA) technology and to assess unconventional sensors that may provide sensing alternatives with lower installed cost in order to make widespread deployment of DFA and other advanced monitoring functions more feasible.

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- American Electric Power
- BC Hydro
- Consolidated Edison
- CPS Energy
- Exelon
- Keyspan Energy
- MidAmerican Energy
- Northeast Utilities
- Southern Company/Alabama Power Company
- Tennessee Valley Authority/Pickwick Electric Cooperative
- Oncor Electric Delivery

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1
PROJECT BACKGROUND

Rationale and Justification

The advent of deregulation, retail competition, and other factors has forced electric utility companies to change their mindset and practices. The historical position of a utility as a regulated geographic monopoly offered steady, predictable rates of return to utility companies and their investors. As long as the utility provided an acceptable level of service by doing things they always had done, there was little incentive to seek innovative avenues of reducing operating costs or pushing reliability to a higher level. These business and technical environments no longer exist.

In today's environment, utilities must offer affordable service if they are to attract and retain customers. At the same time, there are ever-increasing pressures to provide more reliable service. Traditional means to achieve high reliability include significant expenditures in the area of preventative maintenance of system components. By their nature, preventative maintenance programs are expensive, spending considerable sums of money and resources maintaining line equipment, in full recognition that much of that equipment is perfectly healthy and would continue to operate well for a long period of time. However, the alternative is to defer maintenance, testing, etc, which reduces reliability because of the failure of those few components that are operating in a degraded condition and nearing catastrophic failure.

Utilities have always had to make tradeoff decisions between costly maintenance and acceptable reliability levels. The advent of microcomputer technology offers alternatives that did not exist 20 years ago. Protective relaying is arguably the best example of system functionality to take advantage of microcomputer technology, with digital relays now being the technology of choice for most new installations and many retrofit applications. In addition to mimicking the function of their electromechanical predecessors, these digital devices provide additional functions and value, as well as performing self diagnostics, which has reduced the need for periodic maintenance of the devices themselves.

The process of digitizing and processing electrical quantities has gained acceptance for substation devices and applications and to a lesser extent for distributed devices. Besides relays, other digital devices have made significant inroads into monitoring and control functions for substations and feeders. In the late 1990's, EPRI contracted with Texas A&M University to investigate the feasibility of using microcomputer-based digital monitoring to detect electrical changes that were believed to accompany deterioration of line apparatus, to alert utility personnel to developing problems before they or their customers knew a problem was developing. This concept became known as fault anticipation, because it would allow utilities to anticipate that problems were developing and thereby avoid failures and outages by taking preemptive action – with less reliance on inefficient, time-based, preventative maintenance programs.

Phase I: Proof of Concept

Texas A&M began its first formal EPRI-funded project in the area of fault anticipation in 1997. The goal of that project was to determine the validity of the premise that detectable electrical changes occur as line apparatus begin to fail. The scope of that project involved the design, construction and installation of equipment to perform sensitive substation-based monitoring of three feeders, one at each of three host utility companies.

Data collection was accomplished by means of continuous monitoring that detected subtle changes in a variety of electrical parameters and recorded high-fidelity data when such changes occurred. Researchers periodically connected to the substation-based data collection equipment via dial-up modem to retrieve newly captured data. A member of the research team then examined each data capture to determine the likely cause on the power system and queried utility personnel to investigate where appropriate.

The Phase I proof-of-concept project provided encouraging results. Over a period of approximately two years, the project documented several examples of line apparatus exhibiting detectable changes in electrical parameters before the utility company or its customers experienced problems or knew that anything was developing. A primary limitation of this phase of the research was that its scope was limited to three feeders. A further limitation was that the process of retrieving and processing data was quite manpower intensive.

The data collection protocol was to install the monitoring equipment and then wait until failures developed. There were no artificially created or accelerated incipient failures. All utility maintenance on the monitored feeders continued according to normal utility protocols and procedures. Therefore the number of incidents of incipient failures on three feeders over a nominal two-year period was limited. The incidents that were discovered, however, encouraged EPRI and its members to expand the scope in a Phase II project.

Phase II: Field Data Collection and Algorithm Development

In 2000, Texas A&M undertook the second phase of the EPRI-funded fault anticipation project. This effort expanded the number of monitored feeders significantly, increased the number of utility companies directly involved, and increased the level of interaction between the research team and utility engineers.

Texas A&M designed a prototype data collection system with capabilities that were greatly enhanced in comparison to the systems used in the initial phase. This redesigned system made it feasible for utility companies to purchase these prototype systems and instrument more feeders. Approximately eleven utility companies installed prototype monitoring systems in fourteen substations across North America. Each prototype was designed to monitor between two and eight feeders, depending on the desires of the participating utility company and the configuration of the selected substation. A total of sixty feeders were instrumented and monitored at the aforementioned fourteen substations, as illustrated in Figure 1-1.

Data retrieval and analysis procedures were performed manually in Phase I. The research team recognized that these manpower-intensive procedures would not be feasible for the expanded number of sites and feeders to be monitored in Phase II. Therefore the master station for the prototype system was designed to automate many of these processes in this second phase.

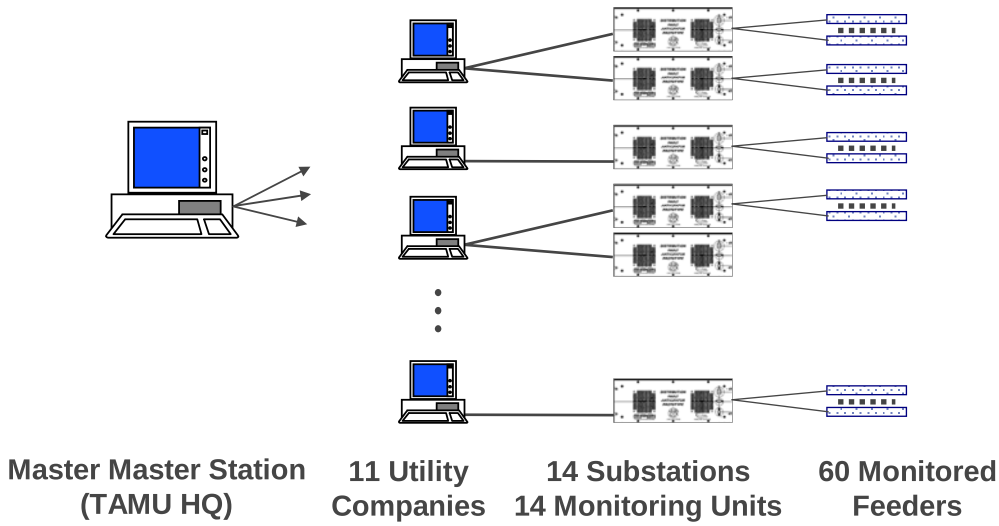

Figure 1-1
Network of Distribution Fault Anticipation (DFA) Prototypes

The system took advantage of the growing availability of high-speed Internet for data retrieval. It also created processes to automate the retrieval of data from the field equipment to master stations at each utility and a “Master Master” station at Texas A&M headquarters. This made data collection much more efficient and greatly reduced the level of manpower required for this function.

Participating utilities were more directly involved during the second phase as well. After installing prototype equipment in their substations, they had responsibility for investigating the cause of any interruption, outage or other abnormal occurrence on the monitored feeders. They also had responsibility for determining which data from their prototype was associated with these events. The utility companies needed direct access to the data to do this. Design of the prototype system therefore included master station software that allowed each utility to access the collected waveforms from its own prototype(s) and attach classification codes and other information related to those waveforms.

The expanded effort resulted in the acquisition of a large volume of data and the characterization of numerous normal and abnormal feeder events. When configuring data collection devices there is an inherent tradeoff involved – set triggers sensitively and capture a large amount of data, much of which is of little direct value or interest, or set triggers insensitively and miss some events that truly would have been of interest. The tradeoff analysis and decisions were particularly important and difficult at the beginning of the DFA data collection effort. There was no prior body of work to guide researchers regarding the types or levels of signals they might encounter. There was little knowledge about apparatus failure modes and even less knowledge about how progressive failures might manifest themselves electrically. A further consideration was that incipient faults do not occur with great frequency. Therefore it is important to be configured sensitively enough to capture these infrequent events when they do occur.

As a result of these sensitivity considerations and tradeoff analysis, and in light of the fact that early weeks and months of the project held much uncertainty in terms of the types and levels of signals to be discovered, the data collection equipment was designed with considerable flexibility in its ability to be configured and initial default threshold settings were quite sensitive. The systems allowed remote reconfiguration to adjust sensitivity if a particular unit clearly was capturing more or less data than appropriate. A bias was maintained toward high sensitivity to avoid missing important events, although that meant that a large amount of normal system data would be captured and would have to be retrieved, processed, archived, etc.

As expected this data collection philosophy resulted in the capture of a very large number of events, the vast majority of which were normal system events such as capacitors switching, large motors starting, and the like. Project personnel developed considerable knowledge about the types and levels of signals that occur as various apparatus begin to deteriorate. They also became quite adept at analyzing captured waveforms and using these waveforms to recognize the underlying causal power system events. Utility engineers provided much-needed feedback to determine details about failures that occurred and the resulting captured data. As the project progressed and personnel became better able to diagnose failures and incipient failures from captured data, feedback from utility engineers continued to validate those diagnoses.

A significant number of failure modes were documented during this phase of the project. During the current Phase III project, personnel have continued to take advantage of the now-installed network of prototype systems. Continued data collection and analysis help to refine characterization methodologies. These efforts also continue to document additional types of failure modes and enhance the robustness of their characterization.

To date the projects have successfully identified and documented a wide variety of failures, incipient failures, and operational problems with apparatus, including one or more episodes of each of the following.

- Voltage regulator failure
- LTC controller failure
- Lightning arrestor failure
- Repetitive overcurrent faults
- Line switch/cutout failure
- In-line splice failure
- Cable failures
  - Main substation cable failure*
  - Primary URD cable failure
  - Secondary overhead cable failure
  - Secondary URD cable failure
- Tree/vegetation contacts
  - Contacts with primary
  - Contacts with secondary services
- Substation bus capacitor bushing failure
- Service transformer failures
  - URD transformer failure*
  - Poletop transformer winding failure*
  - Poletop transformer bushing failure
- Capacitor problems
  - Controller failures (excess operations)
  - Failed capacitors
  - Blown fuses
  - Switch restrike
  - Switch sticking
  - Switch burn-ups
  - Switch bounce
  - VAR tolerance problems
  - Pack failure

Items marked with asterisks represent events first documented during last 12 months.

Some types of failures were quite common and numerous instances were documented. As may be obvious from the list above, the most prevalent problems involved capacitor failures of one sort or another. Some types of failures are statistically less probable and less frequent than others. The project documented large numbers of certain types of failures but relatively few episodes of other types of failures. For some, there was only one example that occurred and was documented during the project.

Researchers developed methods for characterizing many of the captured events. Clearly those failure modes with the greatest representation in the accumulated database provided the best opportunity to develop, test, and refine characterization methods, with events that occur less frequently providing more limited opportunity for this development. These methods continue to be evaluated and refined as additional time passes and new episodes occur on the monitored feeders.

Conclusions From Phase II Project

The large-scale data collection activity of Phase II of the Distribution Fault Anticipation (DFA) project demonstrated the ability to detect, characterize, and recognize a wide variety of normal and abnormal behavior on distribution feeders. The field devices served primarily as data capture devices. Master station computers at each host utility company and at Texas A&M headquarters retrieved captured event data from these field units for analysis and processing. Researchers developed algorithms for characterizing captured events. They created processes for running these algorithms on captured events automatically as they occurred and were captured. Over time the continued processing of new events allowed researchers to evaluate the efficacy of various algorithms and to refine them where appropriate.

To facilitate a reasonable mechanism for developing, testing, and refining algorithms for processing data coming from the 14 substations, the algorithms initially were developed in MatLab™ and were run on a computer server system at Texas A&M headquarters. This required all captured data to be retrieved from the substation devices to Texas A&M's server, via Internet connections to the substations. The volume of data was immense, but manageable for a research project monitoring 60 feeders. It would not be desirable to be forced to retrieve, store, archive, etc. such a volume of data on an ongoing basis for the hundreds or thousands of feeders a typically utility would monitor with fully deployed DFA technology. In addition this processing hierarchy also meant an absolute requirement for high-speed data transfer (e.g., cable modem, DSL, and the like) to transfer this volume of data back to Texas A&M for processing. Industry trends are beginning to result in more substations having high-speed Internet service, but such presence is far from universal and will remain so for many years to come. In addition if DFA technology were to be applied at poletop locations outside the substation, it would not be reasonable to assume that high-speed Internet would be available to most of those locations.

This phase purposely relied on centralized data retrieval, processing and archiving to facilitate learning for the first time what kind of electrical signals incipient failures produce and to facilitate development and testing of methods for characterizing these signals and signatures. Some of the processes (e.g., archiving) were not fully automated and would be unreasonably cumbersome in full deployment. Communications, storage, and processing realities and limitations dictate that a significantly different architecture is needed to make DFA technology practical. Considerable work is needed to develop the appropriate architectures and determine requirements for system integration. That work is the focus of the current project. In addition, while the Phase II project greatly expanded the knowledge base about apparatus failures, it did not result in the acquisition of the entire universe of failure modes and mechanisms, particularly for events that may be statistically infrequent but that may have very significant ramifications when they do occur. The existence of the system of data collection systems put in place during Phase II make it natural to continue learning from these in-place systems to further develop and refine characterization algorithms. Therefore the current project focuses on development of concepts related to system integration to make DFA technology more practical and on continued data collection and algorithm development and refinement.

2
SYSTEM INTEGRATION CONSIDERATIONS

Research efforts in pursuit of Distribution Fault Anticipation (DFA) technology have always had as their goal the development of concepts that can be put into practice to improve a utility's operations. Early phases of the research were directed toward validation of the concept of monitoring electrical signals for signs of degradation and imminent failures and toward developing techniques for recognizing subtle signs of failure and improper operation.

Practical implementation of DFA technology is made possible in large part by sweeping advances in microelectronics. DFA technology is arguably the most advanced continuous, real-time system ever contemplated for widespread deployment in utility substations and on feeders. The level of data acquisition, storage, processing and the like would have been impossible or at least cost prohibitive even ten years ago. Even with today's advances, careful attention must be devoted to providing sufficient digital capability to perform DFA functionality properly, without creating requirements that would make its practice cost prohibitive.

Current tasks are directed toward determining appropriate means for performing the DFA's basic tasks in ways that are practical for implementation in hardware and software systems for widespread deployment by utility companies. Because this work is in progress, the following discussion does not attempt to provide final details or solutions but rather a discussion of the chief considerations and constraints for such a system.

Important considerations conceptually fall into several broad categories, as discussed in the following. As will become clear to the reader, there is considerable overlap between these categories.

Data Fidelity

Distribution Fault Anticipation (DFA) technology acquires and analyzes waveform data representing line currents and voltages. Other substation devices acquire and analyze similar data quantities. The most obvious example is the digital relay, which senses current and perhaps voltage waveforms, analyzes these waveforms in real-time, and makes control decisions about when to trip a circuit breaker or take other control action.

Basic quantities used by the DFA are similar to those sensed by other substation- or feeder-based devices. However the purpose for which these quantities are sensed is vastly different and therefore the specifications for the fidelity, rate, duration, etc. also are very different. Relaying applications, for example, generally require the ability to represent and recognize relatively high current levels, typically in the range of hundreds or thousands of primary amperes. Protection coordination and other considerations require relays to have reasonable accuracy and resolution, but there is little absolute need to discriminate relatively minor differences in current. For example, a feeder relaying application set with a 600-amp pickup value would be indifferent to feeder current that changes from 300 amps to 310 amps for a cycle or so. Such variations happen routinely as a result of normal system activity, such as a motor starting. Neither of these readings would indicate a need to trip the feeder. Even above the pickup level, there is little substantive difference between, say, 900 and 910 amps from the perspective of system protection or the time the relay takes to make a trip decision.

By contrast, DFA functions work on subtle changes in current and voltage levels. The ten-ampere change in the example above might be an early indication of an incipient fault condition (failing apparatus, tree contact, etc.). However a fault precursor and a small motor both might produce momentary ten-ampere increases. Differences in temporal and spectral behavior before, during, and after the momentary increase may be the differentiating factor between a normal event that should be “ignored” and a precursor to a fault that should be further analyzed and reported. The DFA relies on the data acquisition system to have the ability to faithfully reproduce voltage and current waveforms and to do so with sufficient resolution to sense these minor variations and reproduce their shape, magnitude, and frequency content appropriately for the application.

Some digital substation- and feeder-based devices are influenced negatively by transient signals and frequency components other than the fundamental frequency. Devices and applications for these purposes may go to great lengths to filter and otherwise condition signals to exclude transients and other non fundamental frequency components. By contrast applications like the DFA rely on the analysis of transients and other non fundamental frequency components to function properly.

Digital platforms routinely state the number of bits of resolution of their analog-to-digital (A/D) converters. This is an important specification but can be misleading unless additional factors about the fidelity of the analog conditioning and other circuitry are known. For example if a device had a full-range reading of 20,000 amperes and incorporated a 14-bit A/D converter, this would imply that the resulting data would be able to discriminate a signals that was $20{,}000/2^{14} = 1.22$ amperes. However the related electronics may introduce electromagnetic noise onto the signal path so that the A/D converter sees the real signal plus white noise at its input. Some signal-conditioning electronics can introduce white noise equivalent to several bits of the A/D converter’s range, negatively impacting the <u>effective</u> resolution. For example, if circuitry introduces white noise equivalent to the three least significant bits of the A/D converter’s output, then the effective number of bits of resolution will be reduced from 14 to 11 and the effective ability to discriminate small changes in signals would become $20{,}000/2^{11} = 9.77$ amperes. Signals and signal changes below this effective resolution are buried in electronic noise and are not reliable for analysis. The cited resolution likely would be adequate for traditional applications such as relaying, but would not be sufficient for sensitive applications like the DFA. Parenthetically, it should be noted that digital signal processing techniques exist that can effectively recover bits lost to white noise but these work only on signals that are periodic and steady-state in nature. These techniques are not effective during transients or when signals are dynamically changing from one cycle to the next. It is during these dynamic periods that the

DFA performs much of its function, making such techniques of little or no value to DFA applications.

Sampling rate is another key consideration with regard to data fidelity required for practicing DFA technology. As with most such considerations, there are tradeoffs involved. Every data sample must be acquired, moved, managed, and processed by the processor. Applications like conventional overcurrent relays are interested in fundamental frequency current and do not require high sample rates. Early digital relays used very limited sample rates, such as four samples per cycle. These devices were able to perform their protective function adequately with this limited sample rate. Over time sample rates have increased significantly, largely because it was recognized that sampled currents and voltages could be stored and used for other purposes. However many protective relay implementations still do not have adequate sample rates to provide for full practice of DFA technology, because of the relatively broadband signals that the DFA uses.

In summary there are multiple aspects related to data acquisition that directly affect the ability of a platform to support DFA technology properly and optimally. Requirements are being evaluated in terms of the various aspects discussed above.

Data Storage and Management

Proper practice of DFA technology requires the acquisition, manipulation, management, and storage of a large volume of data. As in the previous section, it is useful to contrast DFA data requirements with those of traditional digital devices such as relays. Modern relays and other digital devices have provisions for storing acquired data waveforms so that engineers can later evaluate fault current levels, determine whether protective devices operated correctly, and the like. Relays typically store several cycles of data per event and have the capability of storing multiple such events before exhausting their available memory. Total storage may be on the order of multiple seconds when all event records are considered together.

Some of the types of events that DFA technology analyzes and characterizes happen over considerably longer periods of times than most faults. In addition the types of events captured and processed by the DFA may only give intermittent signs of their presence. For example a tree limb contacting a primary conductor may make actual physical contact only intermittently. During these contacts there may be sufficient electrical signal to be detected but when the limb mechanically moves away from the line (e.g., because of varying wind conditions) there is no detectable signal. The DFA may see multiple episodes over a period of hours, days, or weeks. Proper diagnosis of the problem therefore may require analysis of multiple distinct episodes spread over a long period of time.

Data collection equipment used during early phases of the project used commercial-grade components and had hard disk drives for long-term data storage. This likely is not practical for ruggedized equipment that is meant for long-term substation or distributed installation. Other forms of data storage generally have better reliability, temperature performance, etc. but more limited capacity. Therefore issues related to data retention, archiving, etc. become more important considerations for commercial deployment and application.

In addition to having large amounts of storage for retaining captured data on the data collection field units, captured events and other data of interest were moved to Texas A&M's server. Archiving of the data was done from this server. Therefore the data collection units in the field could retain data for a relatively long period of time (e.g., many months) before nearing capacity, and they could simply delete their oldest data when they neared their storage limits. Data storage and management functions require more careful thought and planning when less space is available and when the bulk of the collected data is not being sent to a server for archival purposes. As previously noted the vast majority of events that the DFA captures are normal system events, like capacitors or large loads switching. Keeping high-fidelity records of these events generally is less important than keeping records related to incipient faults or other system problems. The simplistic "FIFO" (first-in-first-out) approach of simply deleting events and other data based solely on time results in "old" but important events being discarded while "new" episodes of routine system events are retained. Clearly this is not an optimal solution.

Requirements for these and other issues related to data storage and management are being studied and evaluated to determine appropriate approaches for performing DFA functions properly within commercial constraints and limitations.

Processing Architecture

DFA prototypes relied on characterization functions to be performed at a remote master station server at Texas A&M. This was appropriate and desirable for research purposes. It allowed the use of user-friendly software and development tools. It also allowed refinements and modifications to be implemented without the burden of distributing new software to the multiple field units each time such a change was made. One of the significant ramifications of this was that it required all data to be retrieved to Texas A&M's master station and it required the master station to perform all of the characterization processing.

The time between an event's occurrence on the power system and when it has been characterized was limited primarily by the ability to get captured event data to the server. Time is not critical for responding to many developing incipient conditions and delays of a few hours have no real consequence. For other types of events, however, time delays become more critical. For example, consider a case that one of the DFA prototypes captured in which a forked tree limb broke and hung over a single-phase overhead line. It pulled the line down and caused intermittent contact with the neutral wire mounted several feet below the phase conductor. This caused an overcurrent fault, which was cleared temporarily by a poletop recloser operation. The fault/trip/reclose sequence recurred about an hour later when the limb again made contact. Then nothing further happened over the next 16 hours. Following that the fault/trip/reclose cycle occurred 14 more times over the next few hours and finally resulted in the line burning down, causing a downed conductor situation and an outage for 140 customers. The utility believes it could locate such a problem within a few hours of notification and thereby prevent the ultimate damage and outage, but to do so obviously requires notification as soon as possible after the activity begins. Each event that the DFA captures creates a waveform file that is several megabytes in size. The speed at which these files are transported from the substation back to a central processing location is highly dependent on the communications available to the substation. This determines the speed at which assessments can be made and results delivered, which affects the utility's ultimate ability to respond and prevent escalation, faults, and outages.

Scalability is also a significant concern when considering an application that is as data- and processing-intensive as the DFA. The master station server at Texas A&M handles data from the 60 instrumented feeders well but it is clear that it could not handle the data or the processing burden for a utility that fully deployed DFA technology on several thousand feeders.

An obvious part of the solution is to move as much of the data handling and processing burdens to the lowest possible level of the system hierarchy. Certain diagnoses can be made based upon individually captured events, while others require sequences of such events or information from events on other feeders (such as is the case when an event on one feeder causes sympathetic data captures on other feeders or when events upstream of the substation cause perturbations and event captures).

All of these aspects are being considered in the development of appropriate system architecture concepts for deployment of DFA technology.

Processing Burden

Another concern for any digital device that is responsible for real-time processing is the burden placed upon the processing assets. Clearly the processor must be able to meet the average processing burden, such as continually computing RMS values from samples, checking values against thresholds, and the like. For a truly continuous process, these functions must proceed without interruptions in the data stream or latency that would be significant enough to cause undesirable delays. In addition to this continuous, baseline processing, the processor and supporting systems must be able to characterize incoming data, without exceeding acceptable delays between the time an event occurs on the power system and the time at which information is brought to the attention of appropriate users. The amount of delay that is acceptable may be different depending on the type of event and the utility’s planned response to that type of event. To use an example cited earlier in this report, if a tree limb is hanging on a line and causing intermittent faults that eventually may burn the line down, delays of a few minutes likely are acceptable but delays of multiple hours are not. Conversely, if a capacitor is switching ON and OFF too frequently, a delay of hours or even a few days likely would be acceptable.

During the research phases, the processing architecture was such that all functions related to data acquisition, threshold comparisons, triggering, and data capture occurred on the field units, but all characterization functions were done on a centralized server. For full deployment this is not a desirable architecture, for a variety of reasons. If a utility were to fully deploy DFA technology on thousands of feeders, the processing burden soon would overwhelm a centralized system. Multiple centralized servers clearly could be used, but this still would not be an optimal solution because of the other issues, like transporting the voluminous data to the central location, requirements for high-speed communications at all locations, etc.

If all processing is not to be done at a centralized location, the most obvious location for it to occur is at the data collection device itself. Prototype systems had limited processing capabilities and characterization algorithms were optimized for ease of implementation and evaluation, not for optimal processing. Issues related to distribution of processing responsibilities at various levels of the architecture are being considered and evaluated.

Communications

Prototype systems used for research required high-speed Internet to every field data-collection device. It is clear that making this a requirement going forward would limit the locations in which DFA technology could be deployed. The possibility and ramifications of applying the technology in distributed, pole-mount locations are receiving considerable discussion as well. Communications to these distributed locations generally will be more limited than in substations. Therefore one key to the deployment of DFA technology is to minimize its reliance on communications, particularly high-speed communications. This again dictates toward performing more of the processing on the field devices and transporting less information back to a centralized location.

Connection to Electrical Signals

In the prototype hardware, a “feeder module” card provided standard terminal strip connections for connecting to a three-phase feeder via the secondary connections of five-amp current transformers and 120-volt potential transformers (CTs and PTs). The prototype system consisted of one chassis in each monitored substation and this chassis could accommodate up to eight feeder modules, as well as providing peripheral connections such as keyboard, mouse, monitor, and Ethernet connections for connecting to the outside Internet and for allowing a user to connect via laptop.

This configuration required a utility to bring the CT and PT leads from all feeders that the DFA was to monitor to one central location in the substation. The degree of difficulty to accomplish this was determined by the configuration of the substation and other factors. Some utilities had little difficulty accommodating the wiring for this, but others had considerable difficulty, with those utilities that had eight-feeder units generally having more difficulty than those with fewer feeders to monitor.

Some participants expressed their opinion that it would be quite difficult for them to deploy DFA technology on a widespread basis if they had to bring CT and PT wiring for a significant number of feeders to a central location. Therefore it is desirable to have the ability to distribute the sensing and data acquisition circuitry around the substation, so that CT and PT wiring lengths can be kept to a minimum. However doing this creates other technical challenges. For example it is relatively straightforward to synchronize the sampling of the data acquisition circuitry for multiple feeders when all of the feeder modules physically reside in a common chassis. This becomes less straightforward when the modules are distributed at multiple locations in the substation. While most DFA functionality does not strictly require absolute sample synchronization between the various feeder modules, it is necessary to maintain reasonable synchronization between the modules to best classify data captures that result when an event on one feeder causes sympathetic data captures on other feeders.

Sampling synchronization and multi-feeder diagnoses require signaling and communication between the multiple feeder module locations. There are multiple types of candidate media to accomplish this, but each has its limitations and costs. Conventional media such as copper wiring may be unacceptable between dispersed modules because of concerns about ground potential rise within the substation. Wireless communications have been suggested to overcome this and to achieve a low-cost solution. Wireless communications have certain limitations as compared to conventional communications, such as latency, bandwidth, and reliability. Wireless systems also raise concerns about data security vulnerabilities, so some utilities are unwilling to allow wireless communications in substations. Also the effects of electromagnetic interference on wireless systems are not well understood, particularly at the times when communications are most needed, such as during major system faults and other events. Fiber optic communications offer immunity from electromagnetic interference and from ground potential rise, but the expense of acquiring and installing the fiber optic cables is higher than with the other media.

Integration With Existing Platforms

Preceding sections have noted that other digital systems exist in substations today. The most common of these are digital relays, and to a lesser extent, power quality monitors and other devices. These existing platforms perform some of the same fundamental functions that are required for DFA technology. Each connects to power system sensors (e.g., CTs and PTs, or other sensors), conditions and digitizes electrical signals representative of currents and/or voltages on the power system, and performs some type of processing on these signals. Virtually all modern platforms also have the capacity to store current and/or voltage waveforms when the waveforms exhibit specific behavior, making these captured signals available to utility personnel for subsequent analysis.

It is obvious that integrating multiple functions in a single device would produce benefits as compared to having multiple, individual, single-function devices. There should be potential for savings in terms of the devices themselves. There also should be potential for considerable savings in terms of panel space and CT/PT wiring costs.

As previously outlined the DFA is able to detect subtle changes in electrical parameters and determine individual failure characteristics and trends. This places higher requirements on the system than most other functions may require, in the various areas outlined in preceding paragraphs. Manufacturers wishing to incorporate DFA technology into their product lines will have to determine what modifications are needed to their existing designs to provide the foundation for practicing DFA technology in parallel with their existing functions. Ongoing work continues to assess these requirements.

Sensing

Current DFA prototypes receive their inputs from conventional current and potential transformers (CTs and PTs). For many applications this is the most logical means of acquiring current and voltage signals from the power system. In many traditional substation installations it is straightforward to tap into existing CT and PT secondary circuits to obtain inputs for the DFA.

A logical extension of DFA technology is distributed application at multiple points along feeders. This has the potential to provide more sensitive monitoring and more accurate location of failures and incipient failures. At these distributed points, there often will be no existing CTs and PTs and sensing will have to be added. The cost of installing a full complement of CTs and PTs can be considerable and may be a limiting factor in the widespread application of DFA technology in distributed applications. Even where conventional CTs and PTs exist, connecting to them can be difficult or prohibitive in some circumstances. This can be true both for distributed applications and for substation installations.

Multiple alternative means exist for sensing current and voltage signals. Some are commercially available and others are in various stages of development or field testing. The cost of some of these sensors may be considerably lower than the cost of new CTs and PTs, particularly when considering total installed costs. Therefore it is natural to consider various alternative sensing means as inputs to the DFA.

Variations in the transfer characteristics of sensing devices will have an effect on the end application. This is true in general, and particularly in the case of a technology like DFA, which looks for subtle parametric changes.

The ramifications of various differences in input signal characteristics are unknown. Many alternative sensor types may have been qualified for specific purposes. For example, a particular sensor may have been qualified according to conventional standards of accuracy, making it acceptable for sensing RMS current or voltage levels for SCADA application. That sensor may not have been tested or qualified for sensing harmonics, however. Other sensors may have unknown performance with respect to transients, saturation, or a number of other considerations. Phase shifts may be introduced at different frequencies, changing the overall shape of the resulting waveforms. Any of these factors may affect performance of DFA functionality in unknown ways.

It might be possible to modify DFA functions if a particular sensor's performance were well understood, even if that performance differed from the performance of conventional CTs and PTs. However at the current time, there are many unknowns. Going forward it will be important to better understand the performance of various alternative sensing means, particularly to the types of subtle, time-varying signals the DFA uses.

Chapter 4 discusses a complementary project that will attempt to answer some of the questions concerning comparative characterization of certain non conventional current and voltage sensors and their potential for fulfilling the sensing needs for DFA and other advanced technologies.

Summary and Current Status

Distribution Fault Anticipation prototypes currently are installed in 14 substations, monitoring 60 feeders. These installations have provided a wealth of data that has led to the better understanding of failure processes of line apparatus. Researchers at Texas A&M have documented numerous failures and failure precursors and have developed techniques for recognizing many of the underlying power system causes.

System Integration Considerations

There are many factors to consider for successfully transitioning this technology from a research project to widespread availability and deployment by utility companies. Researchers currently are developing and refining requirements for system integration, in parallel with efforts by the commercializer of the technology to develop a standalone platform for further field demonstration of the technology in day-to-day utility operations.

3
DATA COLLECTION AND CASE STUDIES

The Phase II project resulted in instrumentation of approximately 60 feeders in 14 substations at 11 host utility companies. This created a substantial infrastructure of data collection equipment that continues to operate and collect data.

In addition to developing system integration concepts in the current Phase III project, researchers continue to collect data from this existing network of data collection systems. The project team also continues to support utility engineers in the interpretation of anomalies that occur on their systems and are recorded by Distribution Fault Anticipation (DFA) prototypes.

The DFA prototypes record numerous episodes of faults, incipient faults, and operational problems with power system apparatus. Many of these episodes are similar to events recorded one or more times in the past. Additional episodes of events that already have significant representation in the existing database allow researchers to assess the efficacy of characterization algorithms and to make adjustments where suboptimal performance is observed. For those types of events that have been captured previously, but for which there are relatively small numbers of episodes in the existing database, additional episodes allow researchers to make characterization algorithms more robust than they otherwise might be. Finally there are failures of types not previously recorded or documented during any previous phase of the project.

The following case studies document a variety of failures and failure precursors. Unless otherwise noted, utilities involved in these cases had no monitoring equipment or other information source to tell them failures were developing or to help them assess problems after they occurred, other than the DFA. Of particular note, three of the case studies represent failure types that had not been documented prior to the most recent twelve-month monitoring period.

Case Study: Substation Cable Failure

A substation with a Distribution Fault Anticipation (DFA) prototype has 25 feeders, eight of which are monitored by the DFA. The substation has multiple large step-down transformers to provide 12.47-kV distribution. Substation cables run from the 12.47-kV terminals of each substation transformer into the substation control house, where they serve as the supply for multiple feeders (see Figure 3-1).

Shortly after 11:00 AM on the day in question, there was a violent failure in one of the substation cables in the ductwork between one of the transformers in the substation yard and the control house. This failure caused a fault and resulted in additional damage that ultimately required tripping all of the substation's feeders. This resulted in an outage affecting 26,000 customers for several hours.

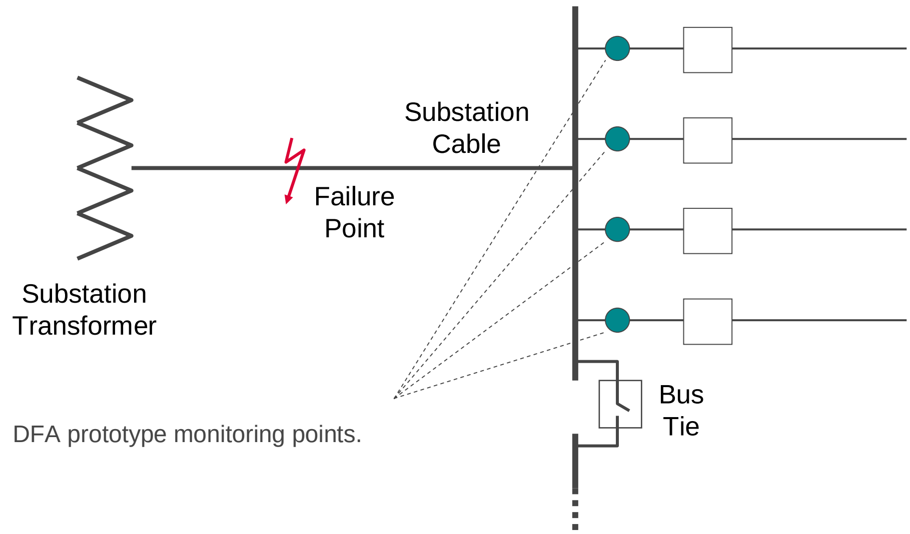

Figure 3-1
Diagram of Substation and Monitoring Points

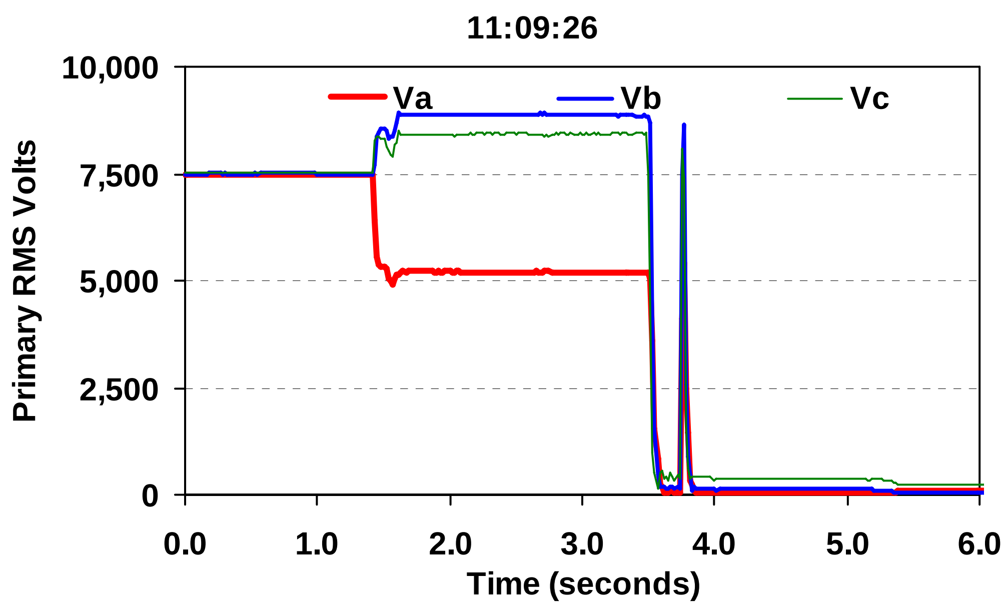

Figure 3-2
Voltages During Cable Failure

Figure 3-2 shows the RMS bus voltages measured during the cable failure. The phase-A voltage dropped precipitously to 69% of nominal when the failure began and stayed at roughly this level for 2.1 seconds, at which time substation protection tripped the transformer. During the faulted period, the phase-B and phase-C voltages experienced swells to 118% and 112% of nominal, respectively.

Interestingly, 13 cycles after substation protection tripped the transformer and removed power from the faulted cable, the voltage was restored for approximately 1-1/2 cycles. Analysis indicates that the voltages during this period of 1-1/2 cycles were roughly the same as during the 2.1-second fault period (i.e., approximately 69%, 118%, and 112% of nominal, respectively). It is believed that the normally open bus tie switch closed automatically in response to the transformer tripping off. This momentarily fed the fault from another substation transformer for 1-1/2 cycles.

Figure 3-3 shows anomalous voltage readings at 11:07:38, approximately 110 seconds before the final cable failure. Over a period of just over one-half second, the voltage experienced multiple dips. Over the next 80 seconds, there were four other distinct times at which voltage anomalies occurred, one of which is illustrated in Figure 3-4. Then, 108 seconds after the initial anomalies, the ultimate fault of Figure 3-2 began, resulting in the transformer tripping 2.1 seconds later. In summary, voltage perturbations and anomalies related to this failure were recorded at each of the following times:

- 11:07:38 – Multiple significant voltage dips recorded at bus (Figure 3-3)
- 11:07:47 – Voltage dip recorded at bus
- 11:08:36 – Voltage dip recorded at bus
- 11:08:52 – Voltage dip recorded at bus (Figure 3-4)
- 11:08:58 – Voltage dip recorded at bus
- 11:09:26 – Sustained voltage dip (final fault), followed by trip 2.1 seconds later (Figure 3-2)

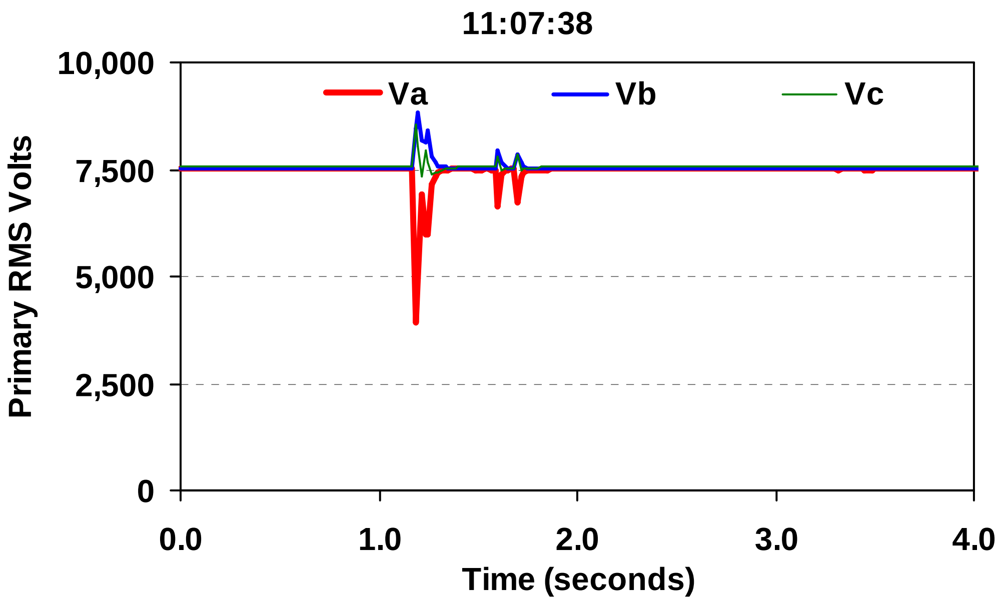

Figure 3-3
First Voltage Anomaly Preceding Cable Failure

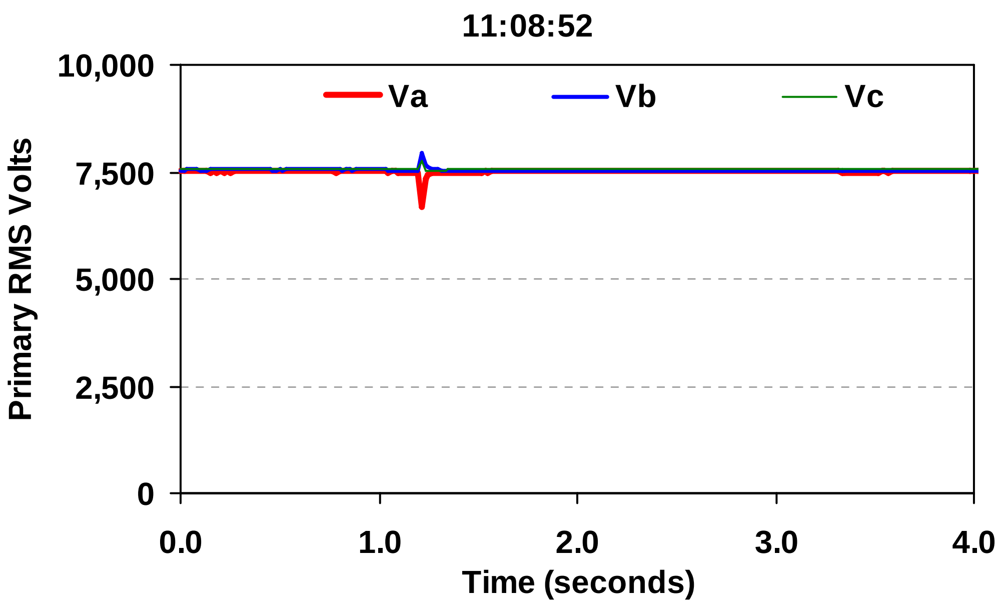

Figure 3-4
Fourth Voltage Anomaly Preceding Cable Failure

The DFA has recorded multiple instances of distribution cable failures. It also has recorded precursors prior to many of these episodes. The elapsed time between when precursors have been detected and when the cable ultimately fails varies considerably. In some cases there is no precursor activity detected prior to the failure. A significant number of the cases, however, show advance warning periods that range from a few minutes to a few hours to a few days. There have been instances in which the warning period has been multiple weeks.

The failure of this substation cable represents new knowledge for the DFA database. This is the type of event that is statistically infrequent but that can have significant impact on reliability when it does occur. A single outage affecting 26,000 customers for an average of 2-1/2 hours adds 26,000 customers x 2.5 hours x 60 minutes/hour = 3 900 000 customer-minutes to calculations of reliability indices such as SAIDI.

The initial intent of the DFA has been to detect failures and developing failures on distribution feeders. It monitors feeder currents and voltages to perform this function. Bus voltages and feeder voltages are effectively the same quantity when measured at the substation level, so the typical DFA installation is such that its voltage inputs come from bus PTs (potential transformers). When an anomaly occurs on a feeder that the DFA monitors, it sees the currents and voltages related to that anomaly. When an event occurs on a feeder that the DFA does not monitor, the DFA still may see a voltage perturbation if the event is significant and draws enough current to affect the bus voltage noticeably, although the current drawn by the event is not available to the DFA. A similar situation exists when an event occurs on the substation bus or upstream of the bus (e.g., at the substation transformer or on the transmission system that feeds the substation transformer), in that significant events can affect the bus voltage sufficiently to be detected and recorded by the DFA.

The subject failure occurred in the cable upstream of individual distribution feeders. It caused voltage perturbations sufficient to trigger the DFA, although the DFA did not have access to measurements of the current being drawn directly by the failure and fault. The recorded patterns in the voltages were quite interesting. Analysis shows that the voltage characteristics before and during this substation cable fault were very similar to voltage characteristics before and during multiple previous examples of failures of cables that serve end customers. This is significant because it seems reasonable to extrapolate from this incident to say that there is a high probability that failures of substation cables like this one may behave similarly to distribution cables that serve end customers. If that is true, then full deployment on all feeders might make it possible to detect similar failures in the future. If DFA monitoring of all feeders indicates perturbations in the bus voltage that are characteristic of cable failure precursors, but none of the monitored feeders indicate that the failing cable is downstream of the substation, the failure may be presumed to be in the main substation cable. As has been noted, previously documented examples of cables serving end users have shown that a significant number of these begin to produce detectable precursors hours or days before final failure. This amount of warning period could prove sufficient for a utility to take preemptive action to avoid the significant damage and extended outage that accompanied the subject failure.

Another interesting observation about this case regards the amount of information, or lack thereof, that a utility often has in its distribution substations. Other than the DFA, the utility in this case had no other electrical information to help it perform a root-cause analysis for this catastrophic event. Information like this is critical to the proper understanding of what went wrong, what worked, and what did not. This is a concrete example of one of the many uses for which utility companies use DFA data, in addition to the benefits of anticipating failures.

Case Study: Avoided Outage From Failing External Transformer Bushing

Figure 3-5 shows an overcurrent fault a DFA prototype registered at 07:39:58 on December 11, 2005. The fault produced approximately 2 400 RMS amps of fault current. A single-phase poletop recloser (i.e., not the substation breaker) tripped after two cycles and then closed back in two seconds later, at which point the fault did not persist. There was nothing particularly remarkable about this event. The recloser detected and cleared an overcurrent fault and there were no outages or customer complaints. The utility company was unaware that anything had happened, except from the DFA.

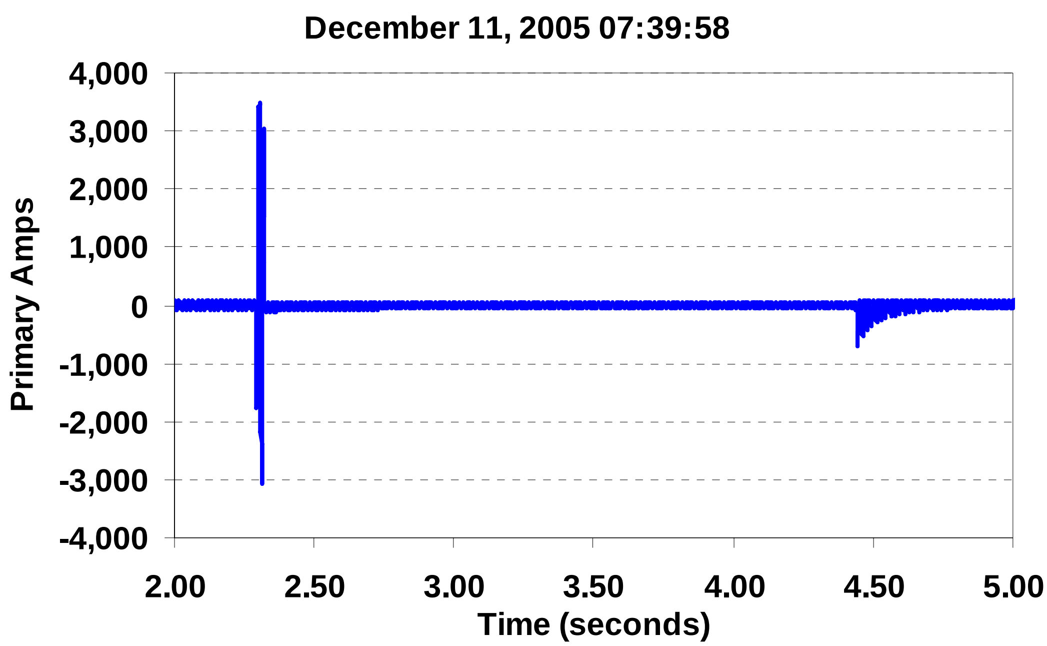

Figure 3-5
Routine Single-Phase Fault Cleared by Poletop Recloser

Another fault happened two days later, at 8:21:05 on December 13, 2005. The fault produced approximately the same current level as the event two days earlier and it was on the same phase. A single-phase recloser again interrupted the fault after two cycles and closed back in two seconds later. As before there was no outage, there were no customer complaints, and the utility had no indication of the event, except from the DFA.

Alerted to these two nearly identical faults by the DFA, utility personnel searched for the cause the next day. A two-man crew used information from the DFA to find the problem in less than one hour. They found a poletop service transformer (see Figure 3-6) with a damaged bushing intermittently causing a short circuit. They also found a dead squirrel at the base of the pole. The obvious conclusion was that the animal's body had caused the first short circuit (December 11, 2005). The poletop recloser cleared the fault properly. The squirrel's body fell away and did not result in a permanent fault. However, the short circuit across the transformer bushing caused permanent damage to the bushing. This compromised the bushing's insulating ability and resulted in the later fault.

Figure 3-6
Transformer With Damaged External Bushing That Caused Intermittent Faults

After identifying the problem, the utility added replacement of the transformer to its work list. Before the repair was made, the fault recurred on December 18, 2005, prompting the utility to expedite the repair. The fault did not recur after the replacement was made.

The third episode was interesting and instructive from a research perspective. It provided evidence that the damaged insulator would continue causing intermittent faults. Repetitive short circuits and arcs are known to escalate and create larger problems if left uncorrected. For example repetitive high-current events likely would cause arc damage to the transformer housing, potentially resulting in a breach that would allow moisture to enter the transformer and mix with its oil. This has potentially catastrophic consequences, including an explosion inside the transformer that can cause a “lid launch” and eject burning oil and ignite proximate items and structures.

These faults occurred on a feeder with multiple reclosers distributed along its length. The utility used information from the DFA to narrow the search to a small area, allowing them to find the failure efficiently. This is significant, because the normal process of finding an intermittent fault can be tedious and time-consuming. An investigation often begins with a customer complaint about “blinking” or “flickering” lights. Customers generally are not able to differentiate between voltage sags and momentary interruptions. Therefore the utility has no guiding information about whether a problem really exists on the distribution system, what kind of problem it might be, or where it is located. It is not uncommon for the process of finding an intermittent fault to require multiple days or even weeks, during which the utility company makes multiple patrols, checks recloser operations counters, and the like. By contrast, in the subject case, the utility knew of the problem without customer complaints and made one trip to find the problem in less than one hour.

In summary the utility benefited from the DFA in several ways:

- Notification that a problem was developing – Absent the DFA, the utility had no other indication that a problem existed. No other device indicated any problem and there were no customer complaints.
- Locating the problem – Locating a fault can be difficult. It becomes even more difficult when it is an intermittent fault that has not caused a sustained outage, particularly if the feeder is long and geographically dispersed. This utility has seen all of these factors come into play with recurrent fault events. The utility was able to use the DFA to locate the subject problem with a two-man crew in less than one hour.
- Zero customer complaints – This incipient failure was detected and repaired without any event that caused any customer complaints at any time.
- Avoidance of sustained outage – This recurrent fault caused three momentary interruptions in a one-week period but did not cause a sustained outage. As will be described in the next case study, recurrent faults do not tend to go away by themselves. They can be quiescent for significant periods of time, but eventually they recur. Given enough time they can escalate and cause sustained outages. In the present case, the utility avoided a sustained outage.

Case Study: Outage Following Recurrent Faults

The single-phase fault of Figure 3-7 occurred on the morning of June 3, 2006. A recloser carrying most of the feeder load tripped and reclosed and there was no sustained outage. Multiple similar faults occurred over the next several weeks, each causing the recloser to trip and reclose without causing a sustained outage:

- 6/3/2006 08:02:46 – First episode of subject fault (Figure 3-7)
- 6/10/2006 07:27:38 – Second episode of subject fault
- 6/17/2006 10:16:34 – Third episode of subject fault (Figure 3-8)
- 6/24/2006 08:29:46 – Fourth episode of subject fault
- *6/28/2006 07:32:45 – Unrelated single-phase fault (Figure 3-9)*
- 7/4/2006 06:07:12 – Fifth episode of subject fault
- 7/24/2006 07:29:25 – Sixth episode of subject fault (Figure 3-10), resulting in outage

All of the faults during this period were similar, except the one on June 28, 2006 (Figure 3-9). It too was a single-phase fault involving phase A, but there were significant differences in the amount of fault current and the fault's duration. This fault also tripped a different recloser.

The sixth episode (Figure 3-10) occurred on July 24, 2006, and tripped the recloser to lockout. This resulted in a sustained outage for 907 customers. When the utility investigated, they found a situation very similar to the one in the previous case study. It is believed that a squirrel on a transformer caused the initial fault on June 3, 2006, and that this event caused latent damage to the transformer. The five other fault episodes, including the one resulting in a sustained outage on July 24, 2006, occurred as a direct result of this damage.

This utility has experienced multiple past cases of recurrent faults on DFA-monitored feeders, and has used DFA information to locate and solve the underlying problems before they caused sustained outages. The present series of faults occurred over a seven-week period, so why did the utility not recognize and fix the problem before an outage occurred?

The answer becomes clear when one examines the time between episodes. The first four were at precise one-week intervals, occurring on June 3, 10, 17, and 24. There was a momentary interruption each time but the interruptions happened just once per week and there were no customer complaints or other indications of trouble. The engineer with access to the utility's DFA prototype examined DFA records regularly. His practice was to examine the previous seven-day period to look for problems, including recurrent faults. This was reasonable because previous cases typically had shown periods of minutes to hours to perhaps a few days between episodes, and he successfully avoided multiple outages using this practice. In this case, however, the faults were just far enough apart that no two showed up together in a seven-day history.

This case makes an important point about practical widespread application of DFA technology. Sensitive monitoring results in a large number of events being captured. Chapter 2 discusses the volume of data that sensitive systems produce for each feeder, in search of early indications of subtle problems. Application on hundreds or thousands of feeders across a large utility's system will produce an overwhelming volume of raw data. The present case study is a good illustration of the need to extract and organize from that mass of data the relatively few "actionable items" needed by utility personnel. Otherwise the volume of routine data and the passage of time conspire to bury the morsels of truly useful information.

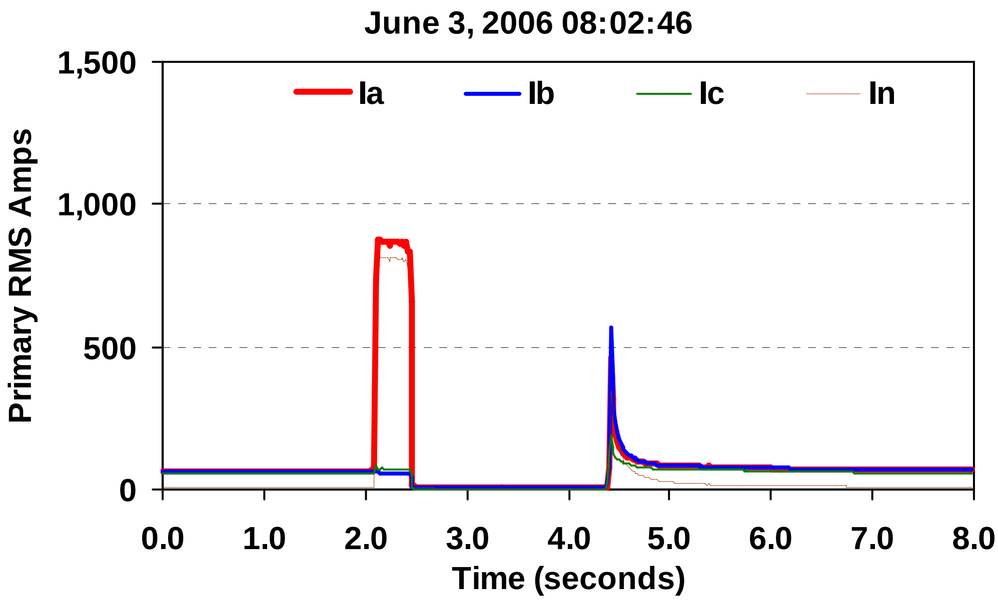

Figure 3-7
First Episode of Recurrent Fault

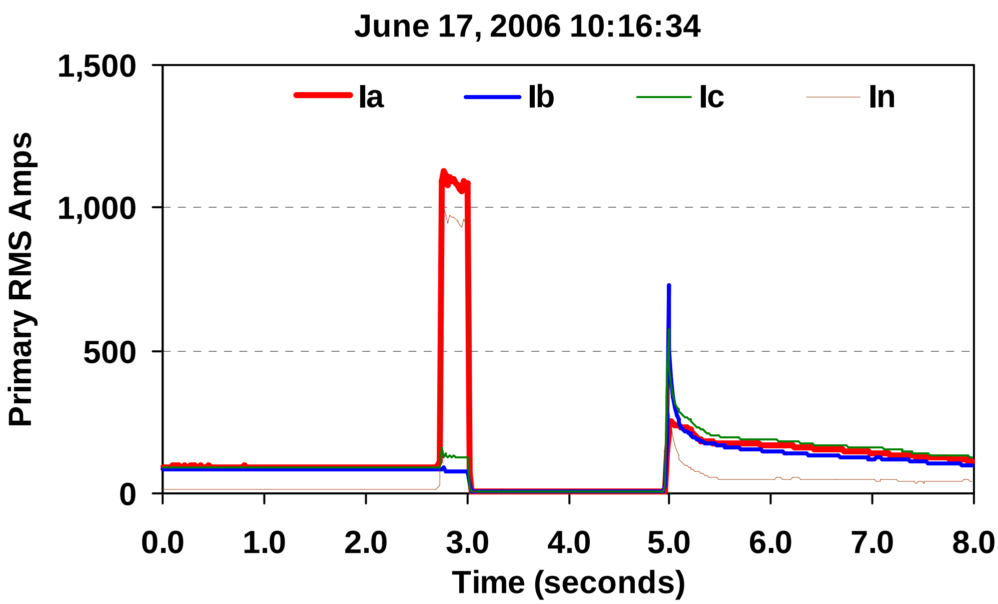

Figure 3-8
Third Episode of Recurrent Fault, One Week Later

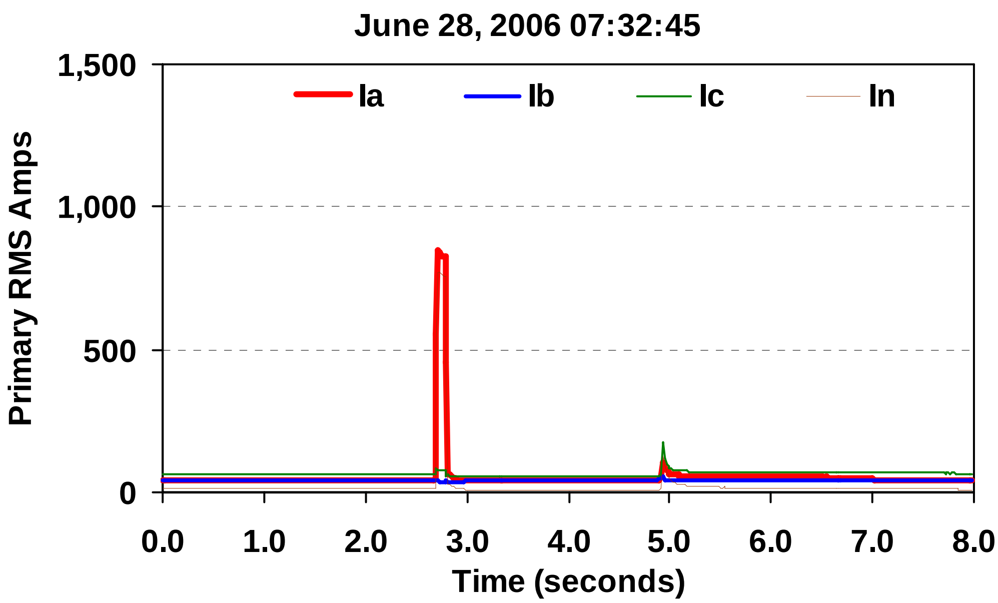

Figure 3-9
Unrelated Fault During Period of Interest

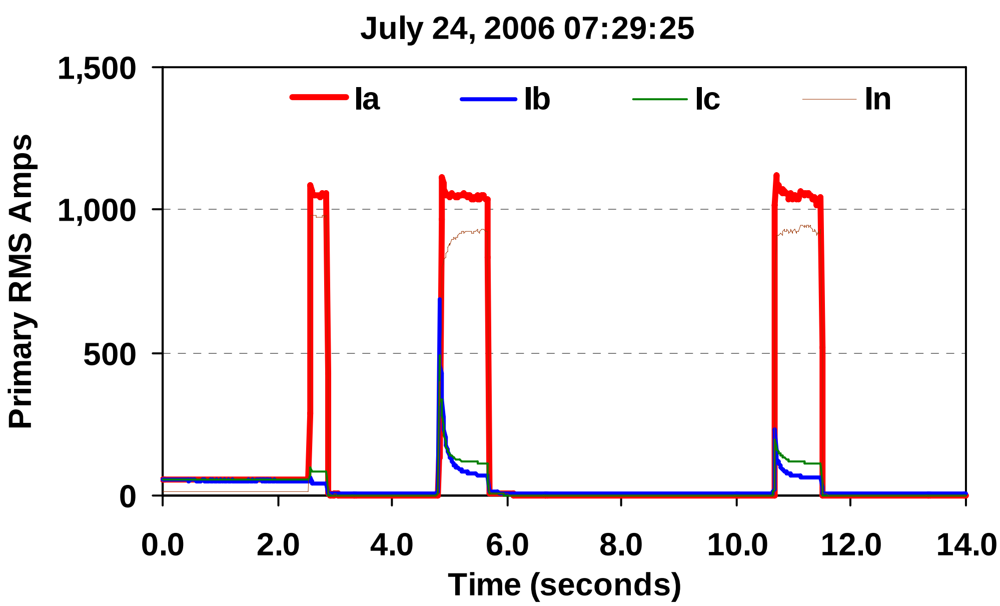

Figure 3-10
Sixth and Final Episode of Recurrent Fault, Seven Weeks After First

Case Study: Repeated Outage Following Cable Failure Misdiagnosis

Customers reported an outage on the evening of April 2, 2006. A troubleman responded and found a blown fuse on a section of primary-voltage URD (underground residential distribution) cable. In accordance with common operating practices, he replaced the fuse. It blew again shortly thereafter and he again replaced it. The fuse held this time, so he left the scene with service restored to all customers. There was no visible sign of damage and there had been storms in the area around the time of the outage, so the trouble ticket was closed with an assumed cause code indicating lightning as the culprit.

Early on April 5, 2006, the same customers experienced another outage. The same fuse that was blown three days earlier was blown again. It was not possible to simply replace the fuse to restore service this time. The cable was found to be defective and customers were out of service for eight hours while repairs were made.

The feeder with the subject cable was instrumented with a DFA prototype at the substation. The DFA recorded the initial failure. It also recorded a second fault waveform approximately one hour later, when the troubleman first replaced the fuse. Both instances produced current waveforms that were characteristic of URD cable failures seen in the past and they were recognized as such. The troubleman did not have this information available to him, however, resulting in the incorrect on-site diagnosis and the premature closing of the trouble ticket.

Figure 3-11 illustrates waveforms recorded at the time of the initial outage. Several hours after the initial service restoration, the DFA recorded the precursor activity shown in Figure 3-12. This measurement indicated characteristics of imminent cable failure but did not result in an outage. Another episode (not shown) occurred on the afternoon of April 3, now some 18 hours after the first episode. This episode also was characteristic of cable nearing failure, but again no outage occurred.

There was no further activity until the third day after the initial fault, at which time the DFA recorded additional cable precursors that culminated in the final failure of the cable. Figure 3-13 illustrates current measured during this final failure.

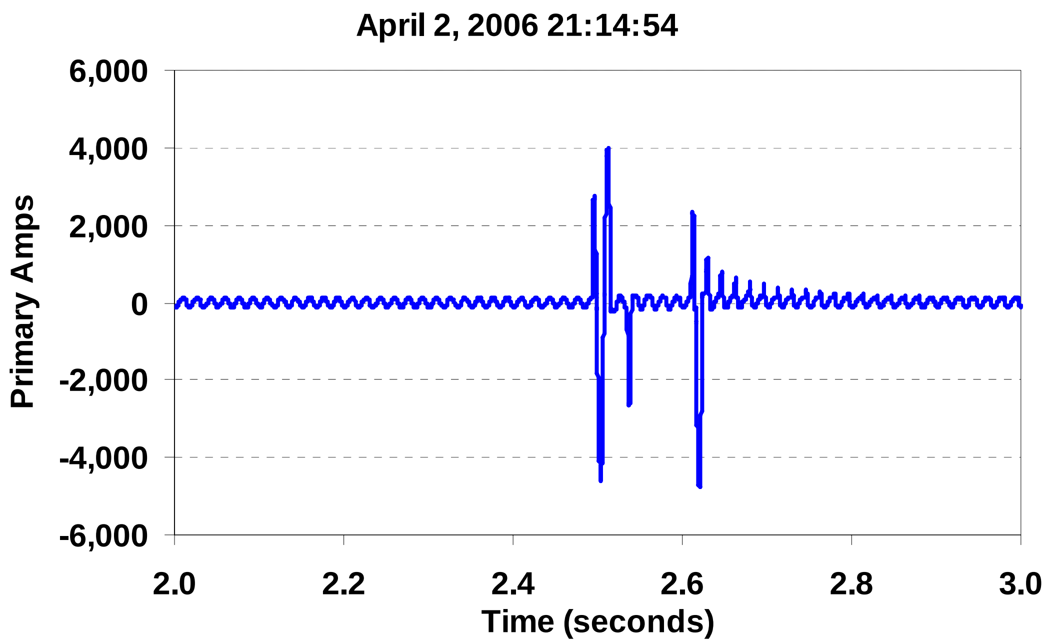

Figure 3-11
Current Waveforms at Time of Initial Outage

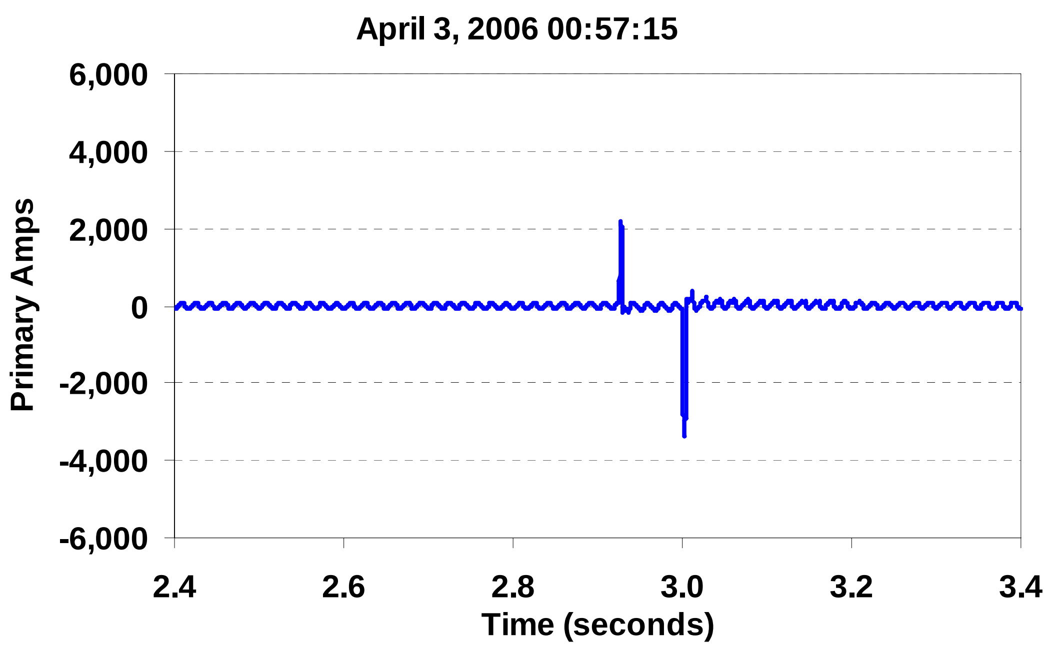

Figure 3-12
Precursor Signals Several Hours After Initial Outage

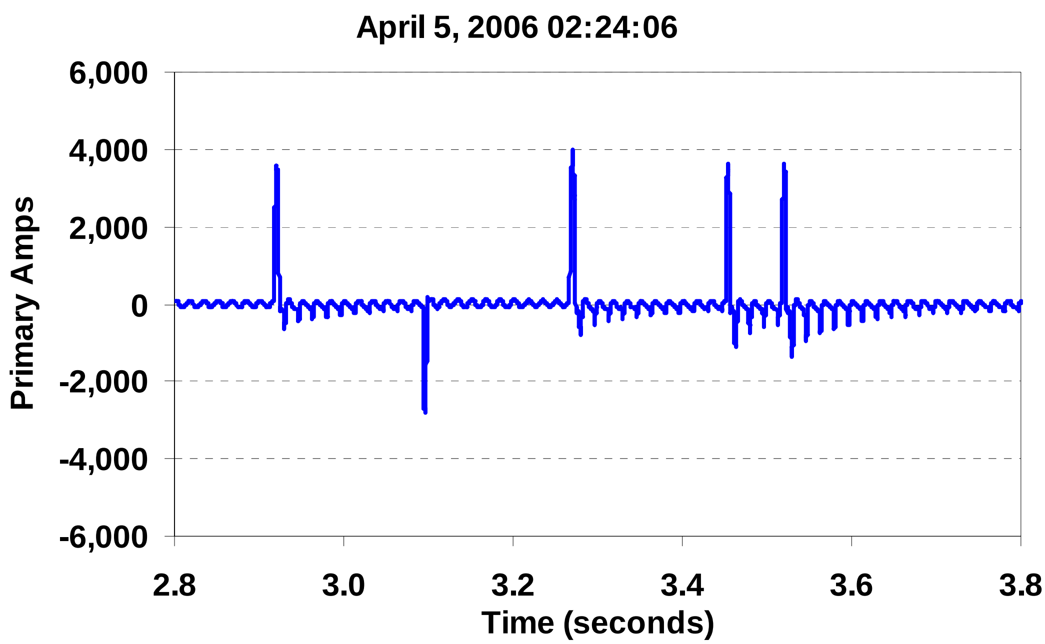

Figure 3-13
Final Failure of Cable, Three Days After Initial Outage

This case illustrates an interesting use of DFA technology. The initial failure on April 2, 2006, provided little precursor activity or warning period before the outage occurred. However the waveforms produced by that failure process were highly indicative of a failing cable. Armed with this knowledge, a troubleman could respond differently. He still might attempt to replace the fuse, to restore service to customers quickly. However, he would not close the ticket but rather would put the cable on a priority repair list. That would allow a crew to test the cable and make repairs during the multi-day period between the initial failure and the final outage.

The additional precursor activity during the next 24 hours also provides an opportunity to respond differently. In the subject case, the troubleman saw no apparent cause for the fuse to be blown and knew there had been storms in the area. He took the reasonable steps of replacing the fuse, determining that service was restored, and closing the ticket with an attribution to lightning as the presumed cause. If the utility knows this and then starts having additional signs of a cable failure over the next several hours, it becomes abundantly clear that the probable cause is that the cable is nearing permanent failure. They can take appropriate action to schedule a repair to avoid the eight-hour outage that occurred in the middle of the night two days later.

Case Study: Anomalous Substation Breaker Operation

Figure 3-14 illustrates a phase-B fault that drew approximately 3 400 amps. The substation breaker tripped in 39 cycles and reclosed 3.6 seconds later. The fault did not persist, no customers reported an outage, and the utility found no cause for the fault. Weather conditions were fair.

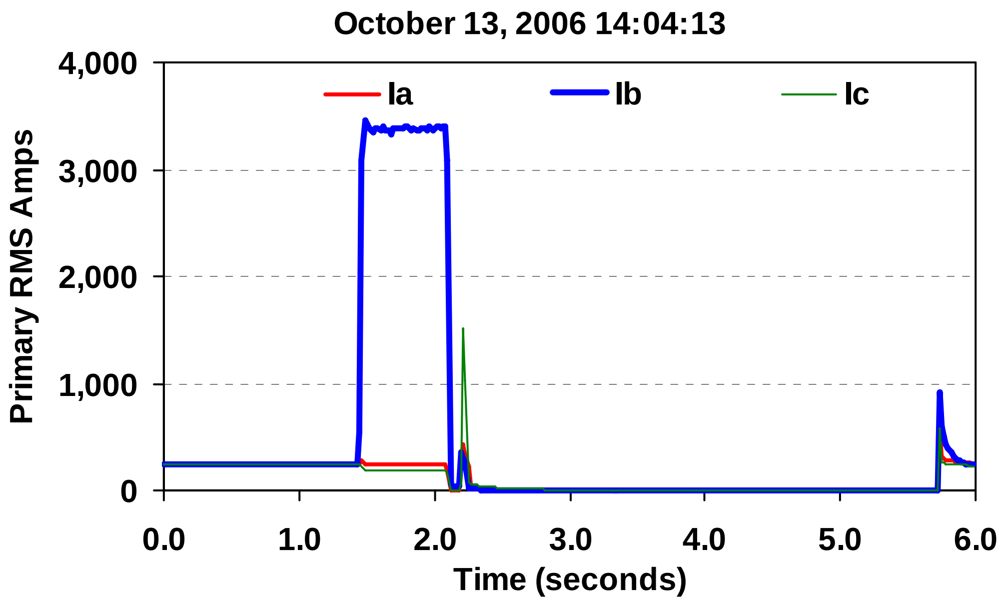

Figure 3-14
Single-Phase Fault Cleared by Substation Breaker Trip and Reclose

At first glance there is nothing unusual about this sequence of events. Something caused a temporary fault that was successfully tripped and reclosed by the substation breaker, with no customer outages resulting. Upon closer examination, however, the data shows a short-lived current "pulse" shortly after the breaker tripped.

Figure 3-15 shows the waveforms associated with the fault and the current pulse. Figure 3-16 shows greater detail for the portion of the waveform containing the pulse. The current pulse begins 100 milliseconds after the breaker opened and lasts about 2-1/2 cycles.

This did not represent intended operation of the protection system so the utility investigated possible causes for the observed behavior. This substation uses electromechanical protection and has no devices that record data of use in this investigation, other than the DFA prototype.

The utility believes a possible explanation for the observed behavior is that the instantaneous "shot" of the reclosing relay at the substation may have closed its contacts while the overcurrent relay's trip contacts were still engaged. This caused the breaker to reclose but to immediately open again as soon as the reclosing relay's contacts opened. Based on this observed anomaly, the utility examined DFA records for prior operations of that breaker and found that it experienced a very similar sequence of events approximately six months earlier. Multiple additional episodes have occurred since. Each noted case has involved a fault whose magnitude was small enough to allow the fault to persist for multiple tens of cycles before tripping the breaker. In other words, the extra "pulse" has not been observed to occur for faults that are large enough to operate the breaker in a few cycles. This observation tends to support the explanation initially proposed. The incidents and their causes remain under investigation.

This case is an example of how DFA data can be used to identify anomalies and problems with regard to system protection. The utility can use this information to determine how the system is performing and what, if any, remedial action should be taken to prevent unusual or improper protective operations.

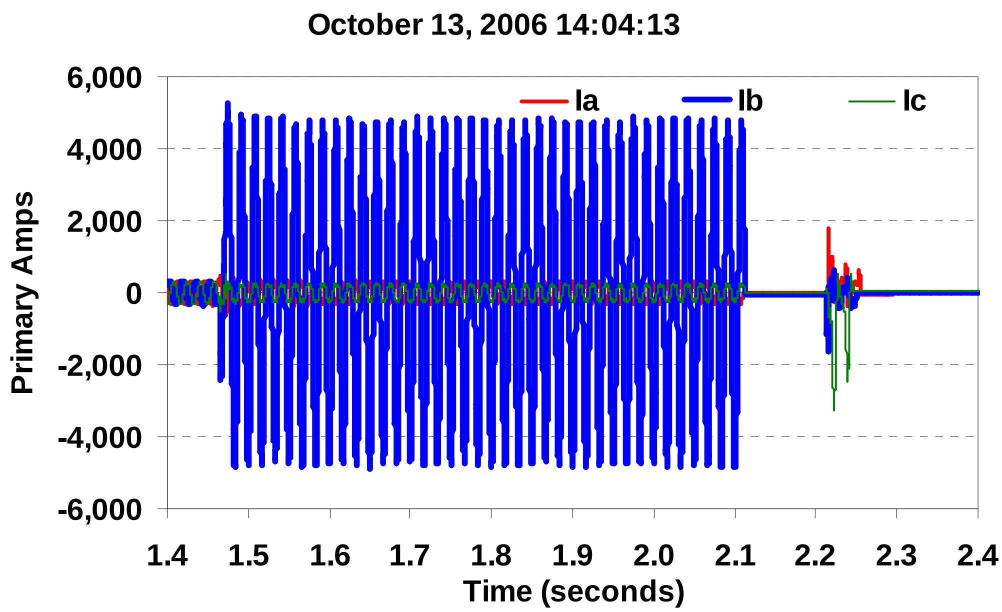

Figure 3-15
Single-Phase Fault With Short-Lived "Pulse" of Current After Breaker Tripped

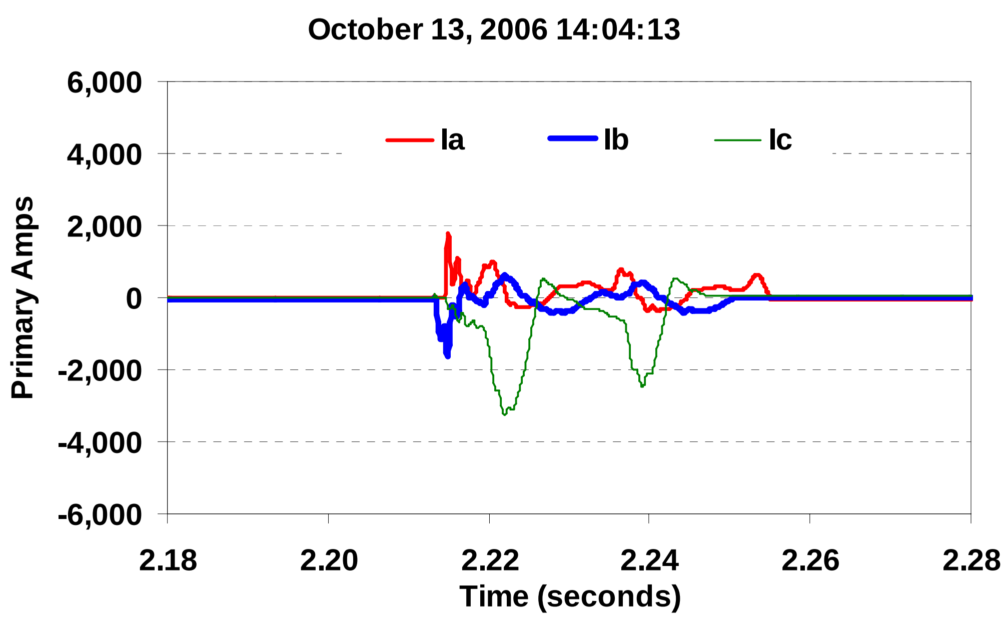

Figure 3-16
Detailed View of Current "Pulse"

Case Study: Improper Recloser Operation

Figure 3-17 shows RMS current measured during a permanent fault caused by a tree limb falling across a three-phase primary. The fault actually started about 45 seconds earlier than the illustrated period and caused two fast trips and recloses of a three-phase poletop recloser. Following the second reclose, there was no fault current for a long enough period that the recloser's sequencing logic reset and started over prior to the time interval illustrated. Those first two trips and recloses do not materially impact this case study and they are omitted from the figure so that better detail can be shown for the period of true interest.

The subject recloser is a three-phase device that is configured to lock out after four trips, two on its fast curve, followed by two on its slow curve. In Figure 3-17, an overcurrent fault and trip occurred just before the 50-second mark. The recloser properly performed its first fast-curve trip and closed two seconds later. Fault current resumed a few cycles later. The recloser performed its second fast-curve trip and reclosed 30 seconds later, as it is programmed to do. Fault current resumed again within a few cycles and the recloser tripped a third time, this being its first slow-curve trip.

To this point, the recloser operated in accordance with its configuration. However the recloser failed to reclose after the third trip. Apparently contacts on electronic cards in this type of recloser sometimes fail to make sound electrical connection, because of corrosion or improper seating. Failure to close in this case meant that the recloser was open but had not finished its sequence and had not locked out. A responding crew likely would assume that the recloser had locked out, when in reality it was in a state in which it could close and energize the feeder at any time. This is an obvious safety hazard for the crew if they are not diligent to manually lock the recloser open before beginning repairs.

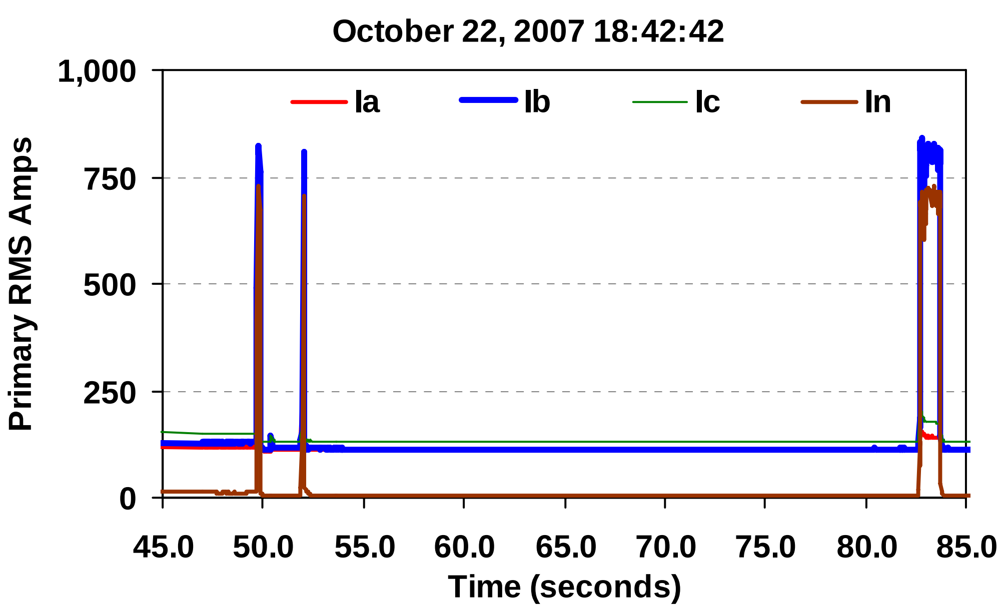

Figure 3-17
Permanent Fault in Which Recloser Failed to Complete Sequence

Case Study: Precursors Related to Internal Transformer Winding Failure

A DFA prototype intermittently registered subtle precursor signals dozens of times during the one-week period prior to the failure of a customer service transformer. Figure 3-18 illustrates one of the first of these measurements. The substation-measured load current was approximately 105 RMS amperes and the failure precursors caused intermittent five- to ten-ampere increases. Figure 3-19 shows the waveforms corresponding to the same episode. The circled region shows slightly accentuated peaks above the load current envelope. This behavior was immediately recognized as indicative of an incipient failure, although the precise cause was unknown at the time.

Precursors occurred intermittently over the next seven days:

- 5/6/2007 – Multiple precursors recorded during a three-hour period starting 9 AM
- 5/7/2007 – No precursors recorded
- 5/8/2007 – No precursors recorded
- 5/9/2007 – One precursor recorded at 6:18 PM, another at 11:32 PM
- 5/10/2007 – No precursors recorded
- 5/11/2007 – No precursors recorded
- 5/12/2007 – Multiple precursors recorded during the two-hour period starting 6 AM
- 5/13/2007 – Multiple precursors recorded 8:08 AM – 9:39 AM

Customer reported an outage at 9:40 AM on May 13, 2007, which corresponded with the time of the final precursor listed above. That episode is shown in Figure 3-20.

The responding crew was not aware of information coming from the DFA prototype. At the customer's premises, they found a 25 kVA CSP transformer with its breaker tripped. They saw no obvious sign of a problem and reset the transformer. They left the customer location at 10:25 AM, with service restored. They closed the trouble ticket with a cause code indicating they suspected the transformer had tripped on overload.

Thirty minutes after the crew reset the CSP breaker and restored service, the DFA prototype began to register and record additional failure precursor activity. The first such episode following service restoration is shown in Figure 3-21. Precursor signals occurred intermittently over the next hour, until the CSP breaker again tripped. Figure 3-22 illustrates signals recorded shortly before this second outage.

The crew visited the site again and again cited overload as the cause of the trip. This time they replaced the existing 25 kVA transformer with a 35 kVA transformer. This solved the problem, but clearly for the wrong reason. Based on information from the DFA prototype, the utility subsequently pulled the transformer for further inspection. At the time of this writing, tear down and inspection had not occurred but it is hoped that it will in the near future.

There are several important observations and conclusions from this case.

- Transformer winding failures produced a signature with characteristics different from those observed for a variety of other failures that produce subtle precursors. These signals were present well in advance (seven days) of the time at which customers were affected in any way. There was no indication of a problem from any other source.
- Location of failures and incipient failures has always been and remains recognized as a significant challenge, particularly for subtle conditions that produce very limited current. The initial charge in the DFA project was to focus on proving the ability to detect and characterize failure signatures. The plan has been to explore location techniques after first detecting and characterizing the signals of interest. Traditional impedance calculations are meaningless in situations like the current case, because the primary impedance that determines incipient fault current levels typically consists of arc impedance, winding impedance, etc., not the line and system impedances that impedance-based location methods assume.
- As soon as the first outage occurred, location was no longer an issue. Imagine that a dispatcher knows the DFA has been measuring precursors indicative of a transformer winding failure on phase B of a particular feeder for the past week. Imagine further that he knows the level of precursor activity has been high for the past hour or so but stopped suddenly coincident with a fair-weather outage call from a customer served by a phase-B transformer on that feeder. It is straightforward to recognize the probable connection between the two events and advise the responding crew to expect to find a transformer with a failed internal winding – a problem that typically will not be obvious from casual inspection.
- This was the first documented case of failure precursors for an internal transformer winding failure. Discovery of this signature and documentation of its cause enable similar future measurements to be recognized and investigated more effectively. Researchers believe it likely that DFA prototypes have recorded previous instances of transformer winding failures, but their causes were unknown at the time. The difficulty a utility faces when investigating unknown anomalies means that the causes of those past cases were not found.

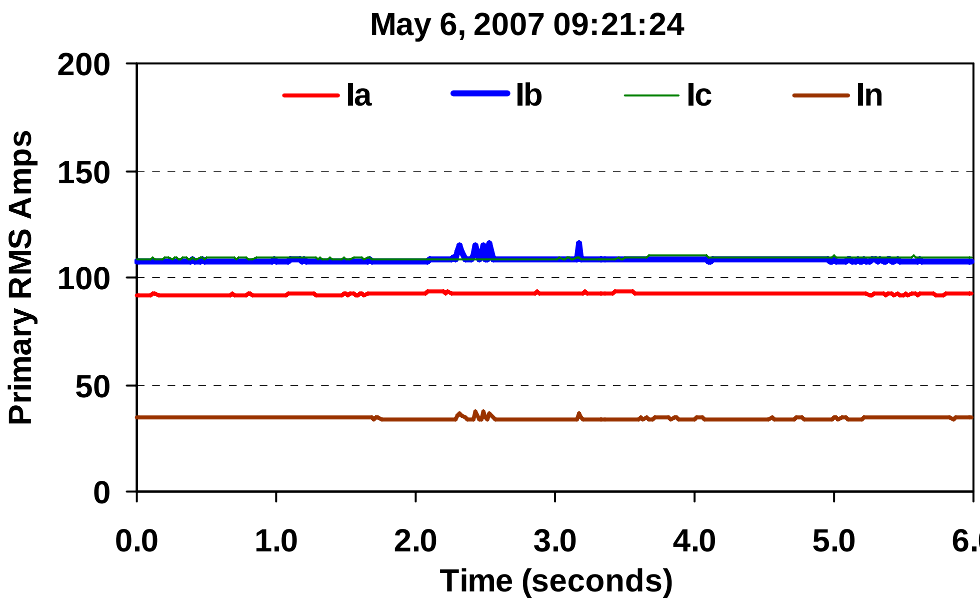

Figure 3-18
Precursor One Week in Advance of Transformer Failure (RMS)

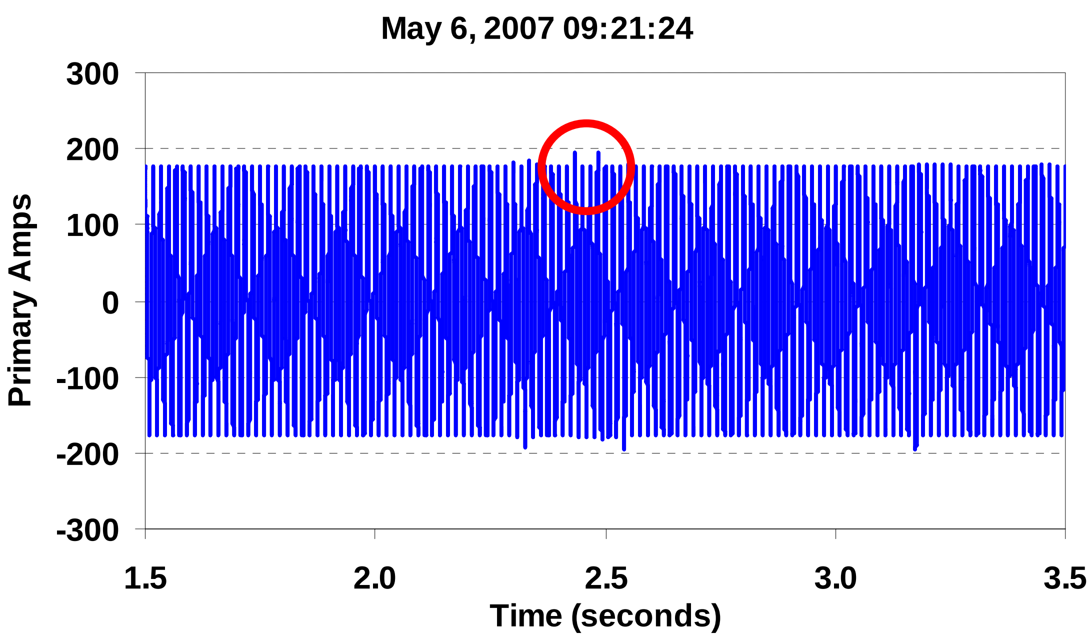

Figure 3-19
Precursor One Week in Advance of Transformer Failure (Waveforms)

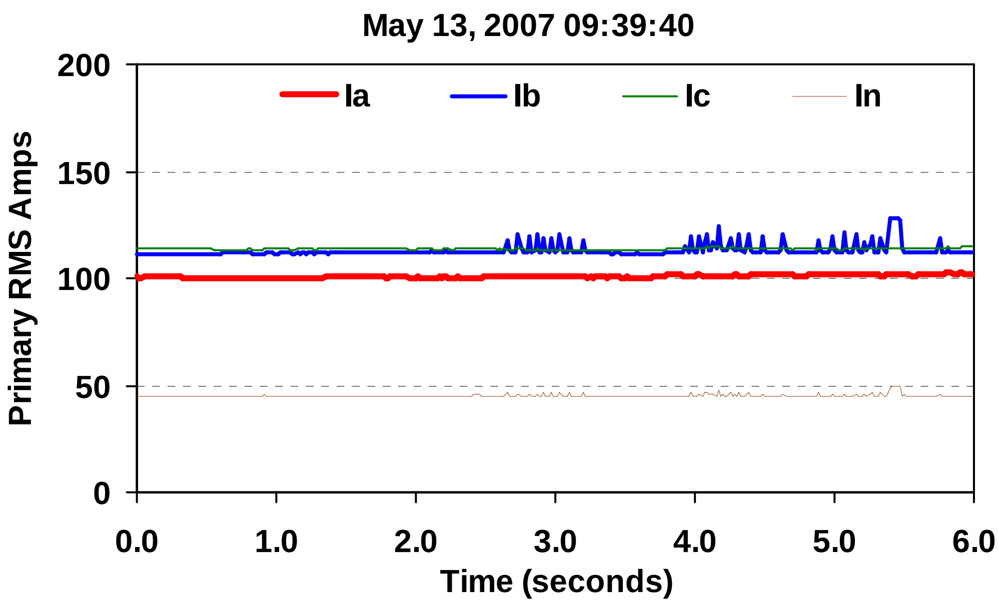

Figure 3-20
Precursor Signals Immediately Prior to Initial Customer Outage (RMS)

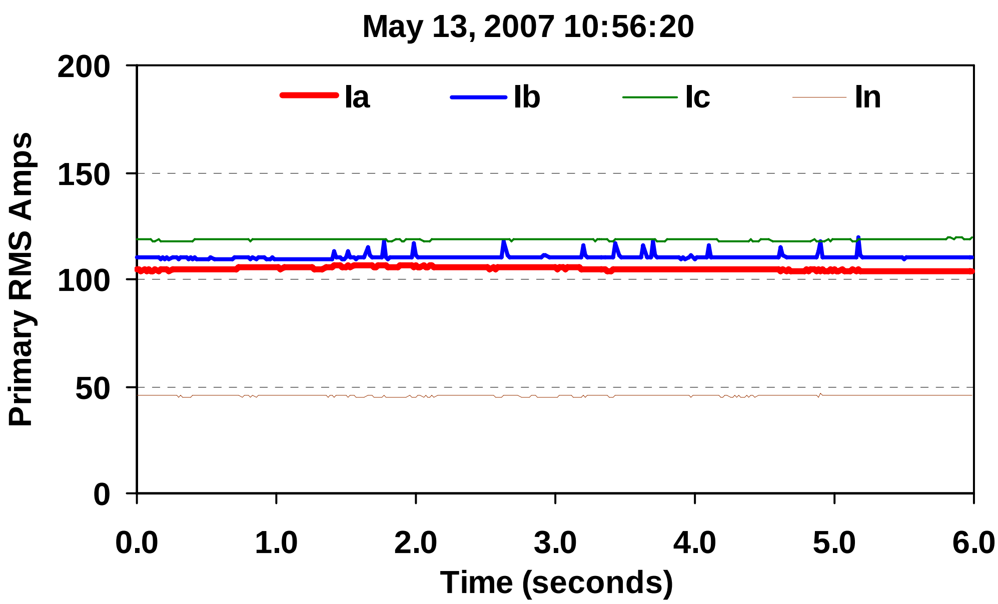

Figure 3-21
Precursor Signals 30 Minutes After Crew Reset Transformer (RMS)

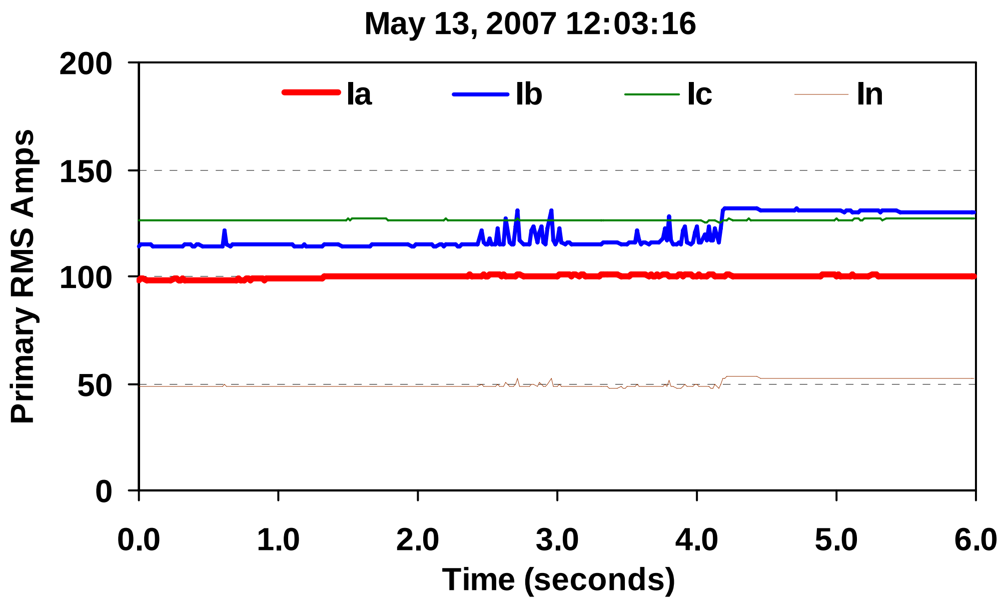

Figure 3-22
Precursor Signals Preceding Second Trip (RMS)

Case Study: Internal Failure of Transformer Primary Bushing

A DFA prototype registered a one-cycle fault that tripped the feeder breaker. The breaker reclosed 45 cycles later and no sustained outage resulted. Figure 3-23 illustrates this fault. Five hours later there was a second fault, similar to the first. As before the breaker tripped and reclosed and no sustained outage resulted. Figure 3-24 illustrates the second episode.

Nothing further occurred until six days later, when a third fault occurred. Figure 3-25 shows the current measured at the substation during this episode. In this episode fault current increased over a period of about two cycles, finally reaching a magnitude of several thousand amperes. The breaker tripped and reclosed, but the fuse on a transformer on the feeder operated before the breaker opened, and a localized outage resulted.

The utility responded to the resulting outage and found a failed transformer with a blown fuse. They subsequently had the transformer torn down and inspected. Figure 3-26 shows that the internal bushing had failed catastrophically. Findings can be summarized as follows:

- There was almost no oil in the transformer.
- When refilled with oil, a hole was identified where a tack weld on a cooling fin had failed.
- The secondary bushings were loose and could be moved by hand.
- The inside of the transformer was damp and corrosion was found in several places.
- The internal bushing that failed had a “rivulet” that the testing company believes to be either a manufacturing defect or the result of leakage and fault current over time.

This is another example of a type of precursor and failure first documented during the most recent twelve months of the project.

As an aside, there was some question about the response of the overcurrent protection. In each episode the fault current ceased one-half to two-and-one-half cycles before the substation breaker opened. A protection engineer for the utility confirmed that the relaying scheme is designed and configured such that all faults result in an instantaneous trip of the breaker. If a fuse or other downstream device operates before the breaker trips, the breaker trips anyway but the fault does not resume when the breaker recloses and no further action is required. This was confirmed to be in conformance with the substation protection scheme implemented by the utility.

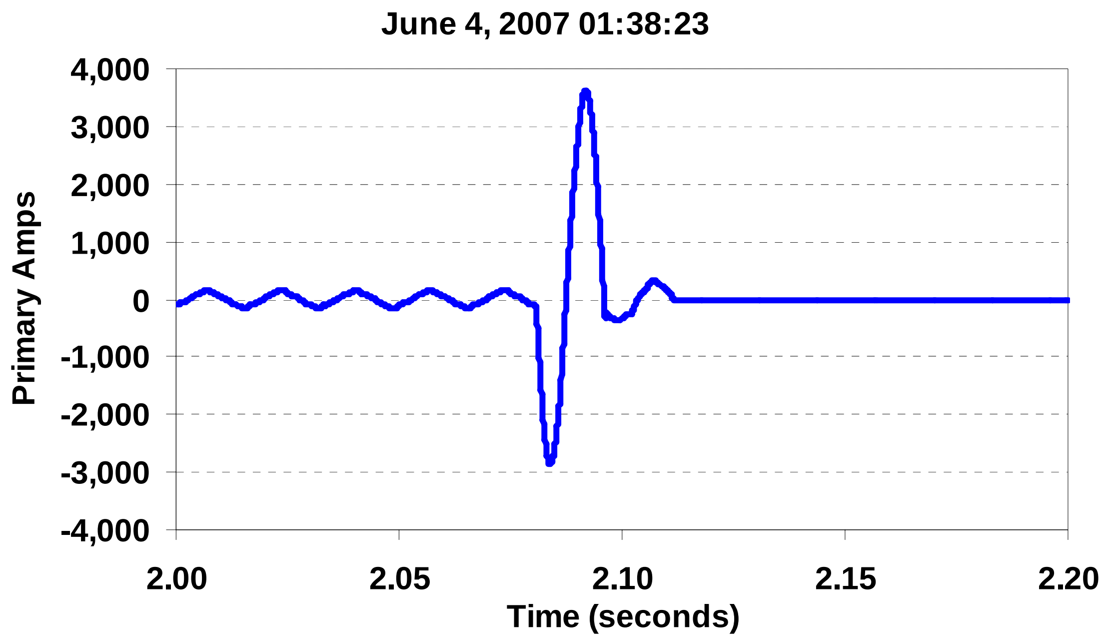

Figure 3-23
First Internal Flashover of Transformer Primary Bushing

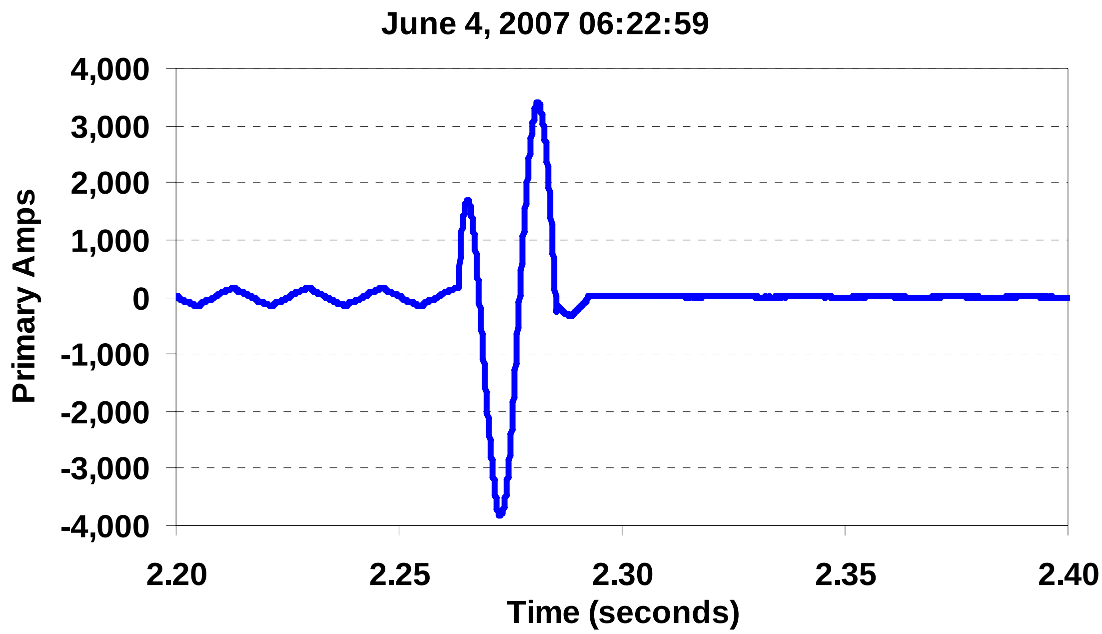

Figure 3-24
Second Internal Flashover of Transformer Primary Bushing

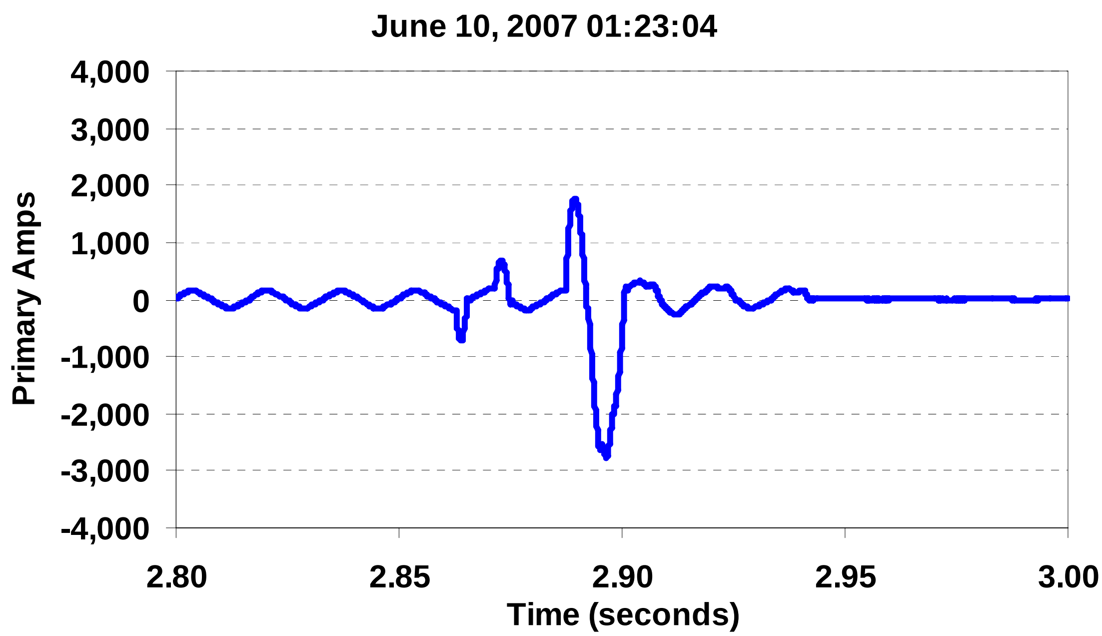

Figure 3-25
Final Internal Flashover and Failure of Transformer Primary Bushing

Figure 3-26
Failed Internal Transformer Bushing

Case Study: Capacitor Controller Malfunction (Extreme Case)

DFA prototypes have documented numerous cases in which capacitor controllers have malfunctioned in such a way that they operate dozens or even hundreds of times per day, instead of the normal one or two times per day. Causes for such malfunctions have included electronic failures and incorrect settings. To study the natural progression caused by this kind of malfunction, one utility allowed such a problem to persist for a period of two months after learning that the problem existed from their DFA prototype. The capacitor operated more than 3,000 times over this 60-day period. The capacitor bank's switches were rated for only 1,500 operations and the excessive wear and tear resulted in internal failure of one of the switches. Prolonged arcing in the failing switch contacts caused significant, near-continuous transients for several days and resulted in failures not only in the subject capacitor bank but also in capacitor banks on the same feeder and even on another feeder connected to the same substation bus. Other utilities have taken the approach of using the DFA prototype to actively correct problems and they have identified and fixed similar problems within days of inception, thereby avoiding escalation of the problem and other failures.

Figure 3-27illustrates the reactive power flow as a capacitor switched on a DFA-monitored feeder. There are two distinct items of interest here. First only phase A shows a step change in reactive power, despite the fact that all capacitor banks on this feeder are configured to operate as balanced three-phase banks. This indicates a problem with the bank, such as blown fuses or failed switches or control circuitry on phases B and C. This type of problems represents suboptimal operation and needs to be addressed by the utility, but the need is not urgent. Rather it is the type of problem that likely should be reported on a daily or weekly list of capacitor problems, to be investigated and remedied in due course.

The second item is more interesting and more troubling. Prior to the time period illustrated in the figure, the capacitor had been energized continuously since switching ON earlier that day. At the illustrated time the bank switched OFF, which is indicated by a precipitous increase in reactive power on phase A. This is normal and can be caused by multiple control parameters, such as time-of-day, temperature, VAR flow, or line voltage level at the bank. It is not normal, however, that the bank switched bank ON a few seconds later. It then proceeded to cycle OFF and ON periodically at intervals of approximately six seconds. It continued to cycle in this manner for the next 36 minutes, during which time it cycled OFF and ON approximately 350 times!

A touch of irony occurred several hours later, when a power supply in the prototype DFA monitoring equipment failed. This equipment had been in service in this location for several years. The fact that its power supply failed a few hours after the capacitor bank cycled 350 times is a good indicator that the hundreds of proximate transients caused failure of the power supply.

The repetitive switching stopped abruptly 36 minutes after it began. A cursory examination of the feeder did not reveal the problem, although a more thorough search might identify the culprit. There are at least two possible causes for a capacitor switching ON and OFF in this way. The switch itself could have mechanical failure, in which faulty contacts allow intermittent contact and conduction. Past experience in more than one instance has shown that this type of failure causes multiple transients per second, as sparking and low-level arcing occur between stationary contacts. The other is a malfunction of the controller logic or circuitry. The timing of the switching operations at precise, consistent six-second intervals makes this seem the far more likely cause in the present case.

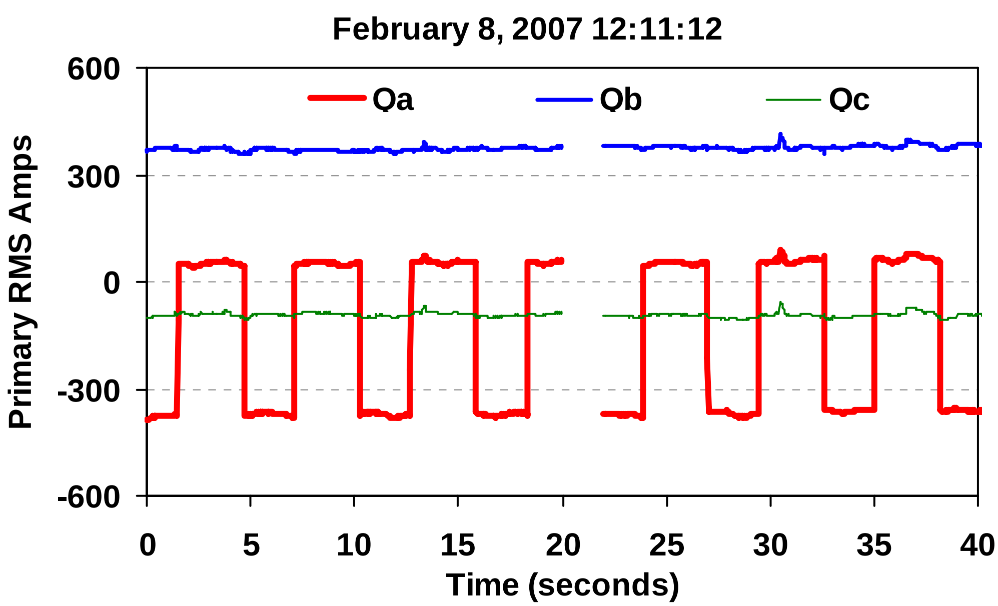

Figure 3-27
Malfunctioning Controller Cycling Capacitor Every Six Seconds

Concluding Remarks

Researchers continue to take advantage of the network of prototype DFA monitoring systems put in place during Phase II of this project. They continue to capture high-fidelity recordings of waveforms from normal and abnormal events on 60 feeders at 14 substations across North America.

The monitoring systems provide additional examples of apparatus failure modes that already exist in the DFA database. These provide the opportunity to further assess characterization algorithms and to improve them when improper or suboptimal behavior is discovered. This results in more robust algorithms. The monitoring systems also have documented failure modes that previously did not exist in the DFA database, offering opportunities to assess these new failures and implement or improve algorithms.

Case studies documented in this chapter provide multiple examples of the types of failures that the DFA detects. None of the utilities involved in these cases had information regarding the subject failures, except from the DFA. Utilities are discovering potential and value in the anticipation of faults and failures. They also are discovering myriad uses for the data outside the initial purpose of anticipating faults.

The database now contains multiple examples of many common failure modes on distribution feeders. Ongoing data collection efforts continue to take advantage of the existing system of monitors to gather data about additional failure modes that are statistically less common. It is important to note that failure modes that are statistically infrequent may have significant impact on system reliability when they do occur. The case study about the substation cable failure provides a dramatic illustration.

It also is important to reiterate the value that has been provided by the extended period of monitoring. Three specific cases (i.e., substation cable failure, internal transformer winding failure, and internal transformer bushing failure) represent failure modes that had not been documented by this project prior to the most recent one-year period. These prototype systems have been in place for several years, but these three examples would not have been documented in the signature library if monitoring efforts had stopped twelve months ago. As time goes on, the rate at which new failure modes are recorded and added to the signature library will decrease. However the present rate of three or four new failure modes per year continues to represent a significant rate of advance in the science and ability to recognize problems.

4 COMPLEMENTARY PROJECTS AND ACTIVITIES

EPRI supports the basic research behind Distribution Fault Anticipation (DFA) technology. This has been the primary means of demonstrating basic concepts, developing system integration concepts, and creating a library of waveform signatures related to a wide variety of apparatus failures, failure precursors, and malfunctions. Texas A&M has been and continues to be involved in parallel projects that are complementary to the ultimate objective of making DFA technology commercially viable and available. It is beyond the scope of this current report to provide detailed information about these parallel efforts, but it is appropriate and instructive to give the reader a cursory overview to provide a better overall picture surrounding the status and future of the technology.

Sensor Characterization

DFA prototype monitoring equipment uses conventional current and potential transformers (CTs and PTs) to derive its inputs from the power system. This is appropriate and in line with early direction to avoid expensive, specialized sensing or active sensing that injects signals onto the power system.

The Sensing section of Chapter 2 discusses the desirability of using non conventional sensors for DFA deployments in substations and in distributed feeder locations. The primary motivation is to achieve a total installed cost that makes widespread deployment more economically feasible than possible with conventional CTs and PTs. This need applies to application of DFA technology and to present and future application of other advanced monitoring functions.

The Power Systems Engineering Research Center (PSERC) has agreed to fund a project to perform comparative characterization of multiple non conventional types of sensors. Texas A&M University leads this effort. The project will install multiple types of non conventional sensors electrically in parallel with conventional CTs and PTs. It will use DFA equipment that has been modified to accept low-energy inputs to monitor the outputs of the various non conventional sensors. An unmodified DFA unit will monitor the conventional CTs and PTs to provide a basis for comparison.

Waveform data will be collected when normal and abnormal events occur naturally on the subject feeder. The data will be retrieved and analyzed. The result will be a comparative characterization of the various non conventional sensors and conclusions about their ability to provide appropriate sensing for sensitive, advanced functions.

Pilot Demonstrations

The United States Department of Energy (DOE) is funding a project to perform pilot installations of systems based on DFA technology. The pilot installations are to begin in the first quarter of 2008.

Under this project the DFA prototype designed, implemented, and deployed in the Phase II EPRI project is being adapted into a commercial beta system. This involves making hardware components for field installation more modular and rugged. It also involves moving a substantial portion of the data processing responsibility from a centralized server to the field devices, making the system more scalable for widespread deployment and relieving communications and centralized storage burdens.

This project involves closer interaction with utility personnel responsible for engineering, operations, and maintenance. The intent is to study how to adapt the technology to make it most useful in a utility's daily operations. Diverse "stakeholders" have diverse uses for data and information made available by the DFA. There are many unanswered questions about how to make the right information available, to the right people, in the right form, in the right timeframe. This present report contains case studies about transformer failures, cable failures, and recurrent faults that illustrate specific examples of information capable of enhancing reliability, but the information must be targeted to the right groups within a utility, in the right form and in the right timeframe, to make it useful in real operations.

Texas A&M leads this effort. Oncor Electric Delivery and Southern Company have committed to serving as installation sites for this project. Oncor also leads a focus group that was formed to provide project guidance. This group has identified multiple stakeholders and started to map which stakeholders need access to which types of information from DFA systems.

The DOE-funded pilot demonstration project and the current EPRI-funded effort are highly complementary to one another. The EPRI project provides conceptual guidance on system requirements and also continues to grow and refine the library of documented failure signatures, while the DOE effort is producing a hardware and software system capable of implementing and exercising system concepts and algorithms and determining how to make results available and useful to end users in day-to-day operations.

Distributed Application

All efforts to date have been directed toward acquiring and processing signals and other information at the whole-feeder level. These efforts have documented measurements related to failures and precursors to failures of apparatus on the feeder and all measurements have been from substation-based CTs and PTs.

There are multiple potential benefits to applying DFA technology on a distributed basis, using a topology such as the one illustrated in Figure 4-1.

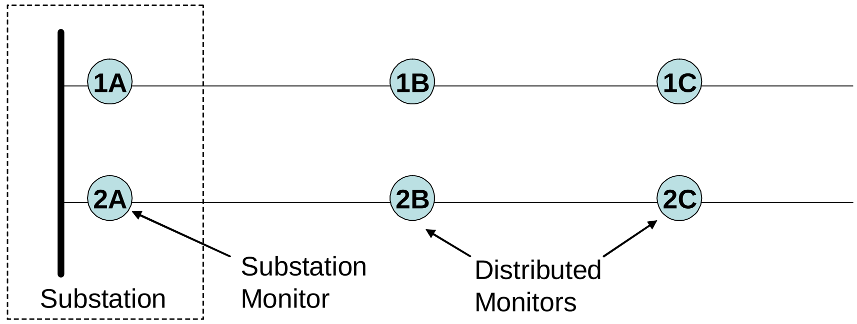

Figure 4-1
Distributed Application of DFA Monitoring

The most obvious potential benefits are in the areas of sensitivity and location. By definition substation-based devices measure total feeder current, which combines normal loads, transients, etc. with anomalous signals of interest. Measurements at a point downstream of the substation also contain the signals of interest for those anomalies that are downstream of that point, but less of the normal load signal. For instance a failing transformer near the far end of feeder 2 in Figure 4-1 will be seen in the currents measured at points 2A, 2B, and 2C, but measurements at points 2A and 2B will contain more load current than the measurement at point 2C. Because failure precursors may be very subtle, lesser amounts of load current should make detection and characterization more reliable.

It also seems likely that distributed application of DFA technology may help better estimate the location of faults, failures, and failure precursors. A case study presented earlier in this report involved precursors to a failure involving an internal transformer winding. This knowledge would have helped repair crews properly diagnose the problem after the first outage occurred. Before such an outage occurs, however, if one simply knows that a transformer on a particular phase of a particular feeder is beginning to fail, it can be quite challenging to find which one of the numerous transformers on the same phase of the same feeder is the culprit.

Problem detection and location techniques like thermal monitoring and radio-frequency (RF) scans are greatly hampered by the fact that failure precursors tend to be very intermittent. In the cited example, numerous individual precursors were recorded, but there also were long periods of time during which no precursors were recorded. RF scans likely would fail to identify the failing transformer unless that transformer happened to be scanned at the precise moment a precursor occurred. The periods of active precursors constituted a small fraction of one percent of the total time during that one-week period, making discovery by RF scan a low probability event. Further the magnitude of the precursors was limited to a few amperes. In some cases this might be enough to raise the temperature of a small service transformer sufficiently to be detected with thermal imaging. Temperature rise is a function of instantaneous power integrated over time, so the temperature rise will be significant only if the activity persists for a substantial period of time. Precursors in this and many other cases, however, consist of a small number of small-magnitude bursts, each a few cycles in duration. This would not be likely to raise the temperature noticeably, certainly not enough to differentiate the temperature of the subject transformer from other transformers with different levels of normal, long-term load.

Distributed application of DFA technology may provide better information about the location of these and other types of failures and incipient failures. A failing transformer at the remote end of feeder 2 in Figure 4-1 should produce signals measurable at points 2A, 2B, and 2C. This could allow the search area to be narrowed to that section of the feeder that is downstream of point 2C. By contrast a failing transformer located between points 2B and 2C should produce signals measurable at 2A and 2B, but not at 2C.

These and other benefits may be realized by using DFA technology to monitor at distributed points. The DOE-funded pilot project will instrument two feeders just as shown in Figure 4-1. This will provide for a first-ever investigation of the use of distributed signals to enhance sensitivity, location, and perhaps other aspects.

The chief limitation of this effort is that its scope is limited to a total of four distributed points on two feeders from one substation. This effort will have significant scientific merit because it is the first-ever evaluation of distributed data collection and analysis with data of this sensitivity and fidelity. However a larger number of more diverse sites clearly would be more desirable. Several EPRI members have expressed a desire to participate and serve as additional sites to collect data and evaluate potential benefits of distributed application of DFA technology. EPRI continues to explore possibilities with them.

Reliability Based Vegetation Management Project

Vegetation management is the largest single cost item in the maintenance budgets of many utility companies. Vegetation trimming and other maintenance typically is driven by calendar-based cycles. PSERC recently funded a project at Texas A&M in an attempt to study and better understand the relationship between reliability and electrical measurements that indicate vegetation encroachment. As part of that project, researchers staged experiments in which they used tree limbs to bridge the normal separation between a phase conductor and a neutral conductor on a 12.47/7.2-kV primary distribution system. They used high-fidelity instrumentation to record measurements from the substation serving their test facility.

These experiments created a better understanding of the electrical behavior that occurs when a tree limb bridges two primary conductors. In short these experiments found that:

- A tree limb making contact with a single phase conductor is not likely to produce high levels of fault current, because the current must pass through contact impedance and the significant impedance of the tree’s limb, trunk, and root structure to find a return path through the earth. This scenario produced only a few amperes of fault current during experimentation. There was considerable heat generated at the point where the tree contacted the primary conductor, however, which may lead to fire or weakening of the conductor, thus causing faults, outages, and safety hazards.
- A tree limb bridging two primary conductors produces an interesting sequence of events that can produce momentary interruptions, sustained outages, conductor damage, and burning vegetation. Initial contact typically does not produce significant current immediately, but scintillation does begin almost immediately at each point the limb contacts the conductors. This produces localized heating, which begins to burn and char the surface of the limb. The

charred portion of the limb becomes conductive, but the portion of the limb that is not charred continues to limit fault current to a low level. The process evolves, with the surface of the portion of the limb immediately adjacent to the already charred portion beginning to scintillate and thereby becoming charred itself (see Figure 4-2). The charring process occurs preferentially in the direction toward the limb's contact point with the other conductor. As the charred path from each end point grows longer, the length of limb that is not yet charred becomes progressively shorter. Over a period of several minutes, if no mechanical movement of the limb or conductors disturbs the process, the charred paths from the two points will meet somewhere in the middle of the portion of the limb between the conductors. This provides a continuous path of relatively low impedance and the level of current rises precipitously. The larger current may cause operation of an overcurrent device (e.g., fuse, recloser). In many cases this does not happen, however. Instead the fault current begins flowing in the low-impedance path created by the burning plasma along the surface of the limb (see Figure 4-3). The heat of the plasma causes it to rise. Much of the fault current follows this preferential low-impedance path as it rises and elongates, thereby exhibiting the well known Jacob's Ladder phenomenon shown in Figure 4-4. When the arc becomes too long to be sustained by the available voltage, it extinguishes. The char and burning plasma along the surface of the limb enable quick formation of a new arc and the process repeats. The process repeats until 1) system protection locks out, 2) the limb burns in two, 3) mechanical movement causes loss of intimate contact between the limb and one or both conductors, or 4) the limb burns off and causes loss of contact. If system protection trips but then recloses before the conductors or limb move, the charred, burning surface readily initiates a follow-on fault. However even slight movement can cause delays between bursts of fault current, as new paths must char before producing high-amplitude fault currents. Depending on fault geometry, the time for this to happen can exceed the reset time of reclosing logic, allowing a vegetation contact to cause multiple high-current events over a long period of time, without tripping protection to lockout. A DFA prototype previously recorded this exact scenario, which caused 17 recloser operations over a 24-hour period and eventually burned down a line and caused an outage to 140 customers.

The PSERC vegetation project was hampered by the fact that utilities with installed DFAs follow relatively conservative tree-trimming cycles, which has limited the number of data captures associated with vegetation contact. Experimentation efforts and ongoing monitoring have documented some cases of vegetation contacts and provide some insight into the electrical behavior caused by vegetation. Researchers continue to document such data captures when they occur and can be documented.

Figure 4-2
Carbonization, or "Char," Created When Vegetation Bridges Conductors

Figure 4-3
Arcing and Burning of Tree Limb Bridging Two Conductors

Figure 4-4
Arcing Rising With Hot Plasma and Forming Jacob's Ladder

Summary

In summary, the project that is the subject of this report has provided and continues to provide significant advancement of DFA technology. This effort is being supplemented and supported by other projects that are beginning to address ancillary topics that are important but that are beyond the scope of the fundamental EPRI project. This chapter has provided an overview of some of those activities, to give the reader a high-level perspective on the status of the technology.

5 COMMERCIALIZATION STRATEGY AND STATUS

Through all phases of the Distribution Fault Anticipation (DFA) project, a key requirement has been to focus on and develop technological solutions that can be commercialized and put to practical use by utility companies. A further requirement has been the development of a commercialization strategy that considers the features of the technology, the ultimate users of the technology, and potential manufacturers of this type of technology.

The following subsections outline user requirements, the manufacturing landscape, and the commercialization model that was developed. This model was presented to and discussed with DFA Users Group members and members of EPRI's Distribution Council on multiple occasions and was included in the 2005 final report for the previous phase of the DFA project. The model and the rational are reproduced here in their entirety for the reader's convenience, followed by comments on the current licensing status.

Utility User Requirements for Commercial Products

From the beginning of the project, the focus has been on discovering and developing techniques that will benefit utility companies by enhancing reliability, reducing operating costs, or both. Participating utility companies have consistently expressed their desire to see this technology made available in ways that will provide practical benefit to them.

Based on the stated desires and direction of EPRI and its member utilities, and based on the research team's prior experience in commercializing EPRI/Texas A&M technology, several guidelines emerged for the commercialization of fault anticipation technology. The following list gives these guidelines, along with comments about how the commercialization process can meet them.

- The technology should provide the user with useful information, not just data. Modern electronic devices (e.g., relays, power quality monitors) collect waveforms and other data from power systems. The data generally contains useful information, but utilities often cannot take full advantage of it, because they do not have the manpower to process the mountain of data that the devices collect. DFA technology should provide useful information in a way that helps the user understand and deal with problems.
- The technology should be available in a variety of platforms. Ideally, the technology should be integrated with a variety of existing and future electronic devices, such as relays, meters, etc. Some DFA functionality requires high-quality, high-capacity data flows. The quality and capacity are readily realizable in modern electronic design, but certain devices (e.g., relays) may not incorporate this level of capability, if the primary functions of those devices do not

require it. Therefore, individual devices must be evaluated to determine their ability to support DFA technology, or some subset of the technology.

- The technology should be available from multiple manufacturers. Otherwise, a utility that does not use equipment from a given manufacturer can be “locked out” of the market if that manufacturer has exclusive access to the technology.

Traditional Commercialization Models

Texas A&M evaluated requirements and other input from EPRI and member utility companies to determine the most effective way to meet these objectives in the commercialization of the DFA technology. To this end, they evaluated traditional commercialization models to determine their applicability and their likely effectiveness.

A traditional licensing agreement is conceptually quite simple. The licensor, in this case EPRI, grants a manufacturer the right to use and sell a technology. The manufacturer develops and produces a product or a line of products and markets and sells these products to third parties, typically end users of the technology. In return, the manufacturer pays royalties to the licensor in amounts established by the license agreement.

In this type of agreement, the licensor can grant a manufacturer an exclusive license or a non exclusive license. If the license is exclusive, then the licensor cannot grant licenses to other manufacturers.

Variations are possible. For example, a license can grant a particular manufacturer the exclusive right to make and sell products using the technology in a niche area (e.g., standalone devices or embedded in relays). A license to practice in a niche area can be exclusive or non exclusive in that area, while permitting the granting of exclusive or non exclusive licenses to third parties in other niche areas.

Several problems with traditional approaches make it unlikely that they would succeed in the commercialization of DFA technology:

- An exclusive license limits access to the technology and limits future advancements of the technology. DFA technology incorporated into a specific manufacturer’s product line means that every utility would be required to adopt that manufacturer’s products in order to have DFA access. Utility participants have stated their strong aversion to such an arrangement.
- Traditional manufacturers are unlikely to invest the significant capital that will be needed to develop the technology into a product line, unless they can obtain exclusivity, at least for a considerable period of time.
- DFA technology has demonstrated that it can provide significant benefit to utility companies, but the technology currently uses research-grade algorithms in research-grade hardware. In addition, the DFA has not yet demonstrated its market viability. It will take significant effort and expense to fully develop the commercial product line and to develop a viable market. Traditional manufacturers tend to be averse to the risk associated with bridging the gap

between laboratory and marketplace, particularly if they do not have the benefits associated with an exclusive license.

- DFA technology has developed significant capabilities that are ready for commercialization. However, EPRI, Texas A&M, and utility participants recognize that significant additional benefits remain to be discovered and realized from this revolutionary technology. Past experience with the commercialization of new technologies suggests that advances cease and development stagnates in the hands of a traditional manufacturer, particularly if that manufacturer has exclusive access to the technology.
- This project has produced considerable new knowledge and know-how. Algorithms and other discovered intellectual property are being patented, and a licensee will have the right to practice the technology covered by resulting patents. However, the project also has produced knowledge and know-how that are not readily reduced to writing or patentable form. In industry, this would be known as unpatented trade secrets. Access to the patents that are expected to issue will be necessary to practice the technology, but it will not be sufficient to practice the technology successfully. Also, past experience in the commercialization of EPRI technology suggests that traditional manufacturers may not develop the high level of internal expertise necessary to fully implement, support, and advance the technology. Therefore, the commercialization plan needs to provide for keeping this expertise base intact and ready, even after the initial technology transfer to the first manufacturer(s), so that it is possible to transfer the technology to additional manufacturing partners in the years ahead. Traditional commercialization plans do not provide for this flexibility.

DFA Commercialization Plan

It is clear that there are difficulties associated with using a traditional commercialization path for DFA technology. Therefore, a non traditional plan has been developed and is being pursued. Figure 5-1 illustrates this model.

A focused entity will be responsible for commercializing DFA technology. The key word here is "focused." The commercialization entity will have a team that is focused on advancing DFA technology in the commercial domain. Commercialization of DFA technology will not just be one of many tasks for this team, but instead will be the team's central focus. It is the intent of this entity to bring this technology to the market in two distinct ways that are meant to address the previously outlined user requirements and concerns.

- The commercializing entity will develop and produce systems for practicing DFA technology. The technology likely will be provided in a standalone system that provides DFA functionality and other related functions that are natural to provide in a platform with the DFA's capability. Royalties will flow back to EPRI based upon sales.
- In addition, the commercializing entity will be responsible for maintaining the expertise and know-how necessary for practicing DFA technology. It will provide sublicenses to third-party manufacturers that wish to integrate DFA technology into existing product lines or to develop new product lines around the technology. It also will provide these third parties with the know-how needed to successfully develop products and take advantage of the technology.

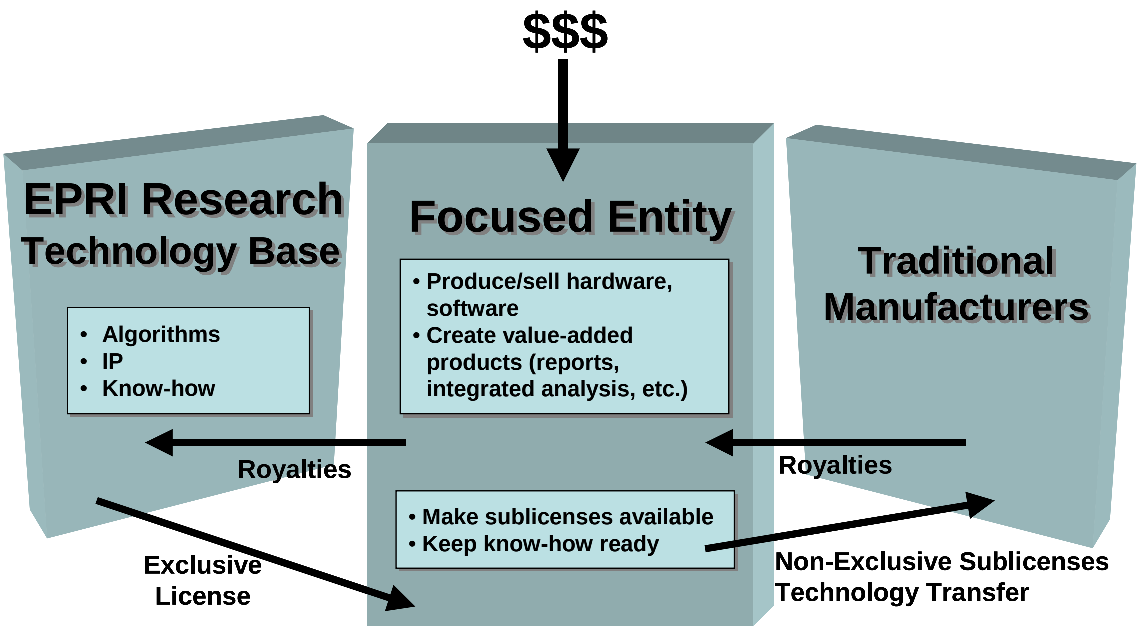

Figure 5-1
Commercialization Model for DFA Technology

Intent of Exclusive License

Figure 5-1 shows an exclusive license from EPRI to the focused commercialization entity. An exclusive license usually implies that only one manufacturer will supply the technology to end users. That is not the intent here. Rather, while the commercializing entity will have an exclusive license from EPRI, that license will carry with it a requirement that the entity make sublicenses available to third parties. The commercializing entity also will maintain the necessary expertise and know-how for practicing the technology, and provide this to third-party sublicensees to develop and provide DFA technology as part of their product lines. In short, it is not intended that the commercializing entity be the exclusive provider of the technology to end users. Rather, the commercializing entity will keep the necessary skills, know-how, and expertise intact and make them available to multiple third parties, as previously outlined. Both the license and the expertise will reside with this commercialization entity, which will in turn make them available to third-party manufacturers.

Commercialization Status

The preceding sections provide a review of the commercialization plan that was discussed with EPRI members during 2004-2005 and that was published in the 2005 report. With this model as a guide, EPRI negotiated a license with Power Solutions, Inc. to serve as the focused entity for commercializing DFA technology. These negotiations were successful and resulted in a license being issued to Power Solutions in the third quarter of 2006.

Power Solutions (PSI) has available to it key members of the research team and its leadership. Maintaining this expertise is critical to the successful development and commercialization of an advanced technology like Distribution Fault Anticipation, which by its nature is a very knowledge intensive technology. It also is apparent that DFA technology has much more potential to offer than has been discovered and exploited to date. PSI is uniquely qualified to support the technology, perform technology transfer to third-party manufacturers, and continue improving the technology in the future. Of historical note PSI holds the license to technology for detecting high-impedance arcing faults on distribution systems, which also is a technology that was developed at Texas A&M with EPRI funding and support. PSI was successful in transferring that technology to a major manufacturer, which markets the technology to the utility industry.

Power Solutions currently is in discussions with multiple third-party manufacturers about how those manufacturers might incorporate DFA technology in their product lines. Utilities are encouraged to discuss with their vendors of choice the addition of DFA technology to their product lines as well.

6 CURRENT STATUS

EPRI-funded research at Texas A&M has demonstrated the ability to use sensitive monitoring to perform a variety of functions on distribution systems. Field installation of intelligent monitoring systems has shown the ability to detecting failures and precursors to failures. The presence of intelligent monitoring systems also has proven to be an enabling technology for a wide variety of other functions, beyond the initial focus of the project. Intelligent monitoring systems enable the implementation of operations and maintenance tools to increase reliability, solve “mystery” problems, and increase the efficiency and effectiveness of certain maintenance practices.

Prior work on this project resulted in installation of prototype equipment monitoring 60 feeders in fourteen substations across North America. These devices have helped document the ability to detect the above-mentioned problems and give a flavor for the wide variety of uses for which such a system could be used in day-to-day operations.

Researchers continue to take advantage of the existing network of prototype equipment. They continue to collect vast amounts of data from these systems. This effort supplements the library with new examples of previously documented problems, thereby enabling validation and refinement of characterization techniques. The data also includes previously undocumented events. These provide new knowledge about equipment failure processes and their precursors, and suggest new functionality for the DFA.

Some failure modes are statistically infrequent and complete documentation is sometimes difficult. The past twelve months have documented three new types of failures and added the first examples of the associated waveforms to the library of failures and precursors: failure of a main substation cable, precursors seven days before failure of transformer windings, and signals six days prior to an outage from failure of an internal transformer bushing. Each of these failures was first documented in the past twelve months, not having been documented in multiple prior years of data collection. It is important to note that certain failures (e.g., main substation cable failure) are very infrequent, but singular events of this type can impact reliability indices significantly, as well as causing other problems for utility companies.

DFA prototype monitoring systems were designed to facilitate research objectives and therefore use highly centralized approaches to data management, analysis, and characterization. The system hierarchy and implementation of the prototypes are not conducive to widespread deployment by utility companies or integration into their operational and business practices. The current System Integration project is studying concepts related to making Distribution Fault Anticipation (DFA) technology useful in widespread practical application and is examining a wide variety of interrelated issues. This effort is scheduled to continue in 2008.

Complementary projects are proceeding in parallel with the EPRI-supported effort that is the subject of this report. DOE-funded pilot installations at two utility companies will test and demonstrate how DFA technology can be integrated into utility business and work practices. An effort funded by the Power System Engineering Research Center (PSERC) will perform comparative characterization of non conventional current and voltage sensors. The purpose is to evaluate sensors with lower total installed cost, to determine whether they can meet the requirements for DFA and other advanced technologies. This could lower the cost barrier that limits widespread distribution of advanced monitoring technologies in substations and particularly in distributed locations on feeders.

EPRI has licensed the DFA technology to Power Solutions, Inc. (PSI) for commercialization. PSI has available to it individuals who have had significant involvement in the research and development and that therefore have intimate familiarity with the technology. The license allows PSI to market the technology directly and to grant sublicenses to third-party manufacturers. The intent is to make the technology widely available by granting sublicenses to multiple manufacturers, so that the vast majority of individual utility companies can obtain the technology from their preferred providers, rather than being captive to a single manufacturer. PSI will offer technology transfer and support services to third-party sublicensees who desire this service.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com