

Distribution Fault Anticipator

Phase II: Field Data Collection and Algorithm Development

Technical Report

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Phase II: Field Data Collection and
Algorithm Development

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PRODUCT DESCRIPTION

Utility companies perform preventive maintenance based on schedules they have developed over long periods of time. Analysis of the historical performance of certain types of equipment provides statistical information about “safe” maintenance intervals. By observing these intervals, utilities reduce the likelihood of certain types of potentially catastrophic failures. When determining maintenance intervals, the primary focus has been on maintaining service, with only secondary attention to cost. Obviously, performing maintenance on all equipment of a given type, at an interval short enough to ensure an acceptably low rate of failure, means that much of the equipment will be maintained more often than necessary. The utility company faces a conundrum: How does the company target limited resources to significantly reduce O&M expenses, while identifying critical problems on circuits before they cause service disruptions? This project has sought a solution to just that problem in the form of the Distribution Fault Anticipator (DFA).

Results & Findings

DFA prototypes have been designed, constructed, and installed in electric power utility distribution substations. These systems have collected approximately 1500 circuit-months of data from numerous utility companies with diverse operating conditions and philosophies. Over this period of time, they have collected thousands of high-fidelity waveform capture files. The vast majority of these files have represented normal system events such as capacitors switching, motors starting, etc. This has been by design. The characteristics of most events of interest are, by definition, not known before they have been recorded and researchers have had an opportunity to analyze and characterize them. Therefore, collection of a large number of normal events and even “nonevents” has been necessary to minimize the likelihood of missing the infrequent, but very important events of real interest.

The library of recorded events includes a significant number of abnormal system events and this library continues to grow with the passage of additional monitoring time. Many of these events have been diagnosed and documented by utility companies, providing the basis for Texas A&M’s research team to develop and test algorithms for classifying them.

Challenges & Objective(s)

EPRI and the Texas A&M University (TAMU) Power System Automation Laboratory have a long and productive history in the area of applying advanced technologies to challenging power system problems. TAMU and EPRI postulated that it might be possible to detect and use changes in electrical parameters to “anticipate” when failures and faults were likely to occur. They conducted proof-of-concept research, which confirmed that various types of failing apparatus produce measurable changes to electrical parameters. The proof-of-concept phase successfully

demonstrated the potential to measure electrical changes that accompany deteriorating distribution system apparatus. The goals of this project have been to broaden the base of measurements for both normal system events and incipient failures, while exploring methods for using these measurements to improve system reliability. Subsequent chapters in this report provide more detail about methods employed and results obtained from field installations.

Applications, Values & Use

A tool that could provide information on impending circuit failures would enable fundamental changes in operating and maintenance philosophies. Certain types of expensive, low-return activities, formerly necessary to maintain an adequate level of service quality and reliability, could be reduced or eliminated. Such a tool has the potential to allow utilities to improve reliability while reducing operation and maintenance costs.

EPRI Perspective

Today's competition-driven electric utility company must determine system reliability in innovative ways that go beyond standard preventive maintenance activities. Historical practices that have been used to "keep the lights on" may still be effective, but often are too inefficient and costly for today's market. In addition, reliability indices are becoming increasingly important drivers in this competitive environment. DFA technology offers the potential to operate and maintain distribution circuits in a manner such that utilities can know that circuit equipment is deteriorating and, if left untreated, will disrupt service in the near future.

Approach

Earlier EPRI-sponsored efforts at Texas A&M University proved the concept of using sensitive monitoring to provide early warnings of impending failures. The current DFA project has built on that success by involving more utilities, substations, and circuits in the next phase of the technology's development. The goal of the project has been to advance DFA technology and demonstrate its potential in day-to-day operations. To that end, researchers designed a more robust prototype hardware and software platform. Eleven utilities have participated by installing these prototypes on their circuits and by serving as the hands-on operators of these prototypes. The extensive monitoring program is providing a database of measurements for a wider variety of failure modes, complete with detailed documentation by utility participants. In addition, the research team has devised methods to automate data analysis in order to convert measured data into information useful to operating utilities, thereby making the technology more practical. Commercialization efforts have begun and will provide utilities with the benefit of DFA technology's current capabilities. At the same time, significant potential remains to be tapped and efforts to discover and develop additional DFA capabilities continue.

Keywords

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- Exelon
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- Southern Company/Alabama Power Company
- Tennessee Valley Authority/Pickwick Electric Cooperative
- TXU Electric Delivery

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1

INTRODUCTION

Historical Market Perspective

The electric utility of today is not what it was ten years ago. The coming decade promises further change, as deregulation and competition become the norm. Electric utilities must adapt to the changing marketplace if they are to survive and prosper.

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.

Utility companies perform preventative maintenance on periodic schedules that they have developed over long periods of time. Analysis of the historical performance of certain types of equipment provided statistical information about “safe” maintenance intervals. By observing these intervals, utilities reduced the likelihood of certain types of potentially catastrophic failures. When determining maintenance intervals, the primary focus was on maintaining service, with only secondary attention to cost. Obviously, performing maintenance on all equipment of a given type, at an interval short enough to ensure an acceptably low rate of failure, means that much of the equipment will be maintained more often than necessary.

Today, there are ever-increasing demands to lower electricity rates to attract and retain customers. At the same time, utility companies must operate profitably or go out of business. An obvious solution is to reduce expenses, both capital and operating. Because of its sheer size, the operating and maintenance (O&M) budget is a tempting target.

Breakers are maintained for a reason. Trees are trimmed for a reason. Patrols are conducted for a reason. When evaluating the reduction or even elimination of certain maintenance activities and expenditures, one must consider that each of these activities has a purpose and that capriciously reducing or eliminating it will affect the reliability of the system.

The utility company faces a conundrum: How do I target my limited resources so that I significantly reduce O&M expenses, while also identifying critical problems on my circuits before they cause service disruptions? This project has sought a solution to just that problem.

Project Background

EPRI and Texas A&M University's (TAMU's) Power System Automation Laboratory have a long and productive history in the area of applying advanced technologies to challenging power system problems. Much of the early work focused on the development of patented technology that now is commercially available to utility companies for the detection and discrimination of high-impedance, arcing faults.

During the course of their field evaluation of high-impedance fault detection technology, researchers noted numerous instances of changes in certain electrical parameters that were followed some time later by failures on the power system. For example, they observed instances of signals indicative of arcing that preceded faults on the system hours or days later, sometimes during fair weather. As another example, they noted a correlation between increased arcing activity and insulator contamination levels.

Based in part upon this work, TAMU and EPRI postulated that it might be possible to detect and use changes in electrical parameters to "anticipate" when failures and faults were likely to occur. They conducted proof-of-concept research in which they confirmed that various types of failing apparatus produce measurable changes to various electrical parameters. They recorded instances of electrical changes indicative of problems developing in several types of apparatus, including a failing lightning arrestor, a failing substation voltage regulator and a chattering capacitor bank switch. In addition, they were able to recognize intermittent overcurrents that caused numerous voltage sags and momentary interruptions to downstream customers [1].

In short, the proof-of-concept phase successfully demonstrated the potential to measure electrical changes that accompany deteriorating distribution system apparatus. During the process, the research team developed considerable expertise in the diagnosis of measured events. They noted that most were normal events (e.g., capacitor banks switching, load tap changers stepping, motors starting, etc.). Diagnosis of large numbers of such events is tedious and time-consuming, but critical to the identification of the relatively small number of events of real interest, i.e., those that represent incipient faults.

In summary, conclusions of the proof-of-concept phase were as follows:

- Deteriorating or contaminated apparatus often produce electrical changes.
- These electrical changes often are measurable and can be used to recognize the deteriorating conditions.
- Anticipating faults has the potential to allow utility companies to reduce expenses while maintaining or enhancing service quality and reliability.
- Electrical changes that deteriorating apparatus produce often are very subtle and require high-fidelity conditioning and signal processing for their measurement and analysis.
- Normal system events and incipient faults both cause changes to some of the same parameters, but detailed analysis of these changes provides the basis for differentiating them.
- Manual processing of event data is tedious and time-consuming, making it impractical to use this process on a widespread basis. However, it should be possible to automate much of the process through the proper use of technologies such as signal processing, pattern recognition, artificial intelligence, etc.

Based upon these observations and conclusions, TAMU and EPRI began the current project. The goals of this project have been to broaden the base of measurements for both normal system events and for incipient failures, and to explore methods for using these measurements to improve system reliability. Subsequent chapters in this report provide more detail about methodologies employed and results obtained from field installations.

Reference

1. *Distribution Fault Anticipator, Phase I Final Report*. EPRI, Palo Alto, CA: 2001. 1001879.

2

GOALS

The overall goal of this project has been to document and more fully develop the use of measured electrical signals that indicate deterioration and incipient failure of power system apparatus. This would enable utility companies to anticipate faults and take corrective action to prevent adverse consequences to the system and to customers. Ultimately, this has the potential to enhance service quality and reliability, while reducing the need for routine maintenance activities and the large expense associated with them. The following sections detail the project's main tasks and how they have contributed to this goal.

Expand Database of Incipient Events

During the proof-of-concept phase ("Phase I") of the project, the research team designed and constructed a small number of pre-prototype data collection devices. Where possible, they used off-the-shelf components, in an effort to minimize design time and cost, with relatively little attention given to the per-unit cost of the equipment. They built and installed four pre-prototypes at utility companies across the United States. Each pre-prototype monitored one circuit.

Over a period of approximately two years, these four pre-prototypes recorded the following types of events:

- Normal system events (capacitors switching, load tap changers operating, etc.)
- Conventional overcurrent faults
- Lightning arrestor deteriorating and finally failing catastrophically
- Capacitor bank switch "bouncing" or "chattering"
- Substation voltage regulator failing

In addition, the four pre-prototypes recorded two examples of situations in which intermittent short circuits caused repetitive overcurrent faults. One case was diagnosed as an intermittent contact between the overhead primary and a ground point and the other case remained unresolved.

These measured events provided a vivid demonstration of the types of events that cause electrical changes that could enable fault anticipation. However, the database of events recorded in Phase I did not, in general, contain a multiplicity of instances of the different types of failures. Specifically, the database contained one instance of a failing lightning arrestor, one instance of a bouncing switch and one instance of a failing voltage regulator. Obviously, it would not be prudent to base any diagnostic system on such a small sample of recorded events. A central focus of the present project, therefore, has been to expand the database of recorded events significantly, both in number and in variety.

The research team designed a new prototype platform and delivered fourteen prototypes to eleven utility companies for installation in substations in various locations in the continental United States and Canada. Each prototype can monitor from one to eight circuits in a given substation. Participating utilities ordered and installed prototypes configured with the number of circuits they desired, based upon the substations in which they planned to install them. In total, sixty circuits have been monitored during the project. For various reasons internal to participating utility companies, installation of the prototypes proceeded at various rates, with several installed in early 2003 and the last unit installed in late 2004.

The larger number of prototypes and monitored circuits has increased the variety and number of events in the database significantly. The diverse set of participating utilities has exposed the prototypes to a wide variety of operating philosophies and practices. In addition to operational diversity, geographical diversity has provided further variations in operating conditions. All of this has been good for development of robust analysis and classification methods.

This project has expanded the variety of recorded events in the database in at least three ways:

- ***Types of apparatus*** – Phase I recorded instances of deterioration and failure for several types of apparatus, but certainly not for all types. For example, the original database contained measurements from a failing lightning arrester, but not from a failing secondary service cable. The present effort has added this latter type of event, and others, to the database.
- ***Failure mechanisms*** – A given type of apparatus may have multiple failure mechanisms. For example, a porcelain insulator might fail because of mechanical damage (e.g., from natural causes or vandalism). However, it also might fail because of contaminant buildup (e.g., salt spray, sand, or chemicals). The expanded number of monitored circuits has increased the likelihood of measuring signals from multiple failure mechanisms for given types of apparatus. This is important because different failure mechanisms may affect monitored parameters in different ways and, thus, may require different recognition techniques.
- ***Quantity of events*** – The database from Phase I contained several types of apparatus failure, but in general, it did not contain multiplicities of given types of failures. The larger number of monitored circuits has increased the likelihood of experiencing multiple instances of specific types of apparatus failures and their underlying failure mechanisms. In addition, it is important to experience a large number of normal system events in diverse operating environments. This is important in the design of recognition methods, so that the methods can be robust enough to ignore minor variations between power systems and between individual apparatus.

Enhance Quality of Database of Incipient Events

During Phase I, participating utilities installed pre-prototype systems in their substations. They also provided information about events on their systems when the research team at Texas A&M made specific inquiries. However, the utility companies had no day-to-day responsibility for formally investigating and documenting events on their systems.

In the current project, participating utility engineers have borne primary responsibility for day-to-day operations. Each utility has been responsible for allocating a significant portion of an engineer's time and effort for the duration of this project. The engineer has been responsible for routinely checking the prototype for newly recorded events; for investigating and determining the cause of each event; for documenting the underlying cause of the event; and for adding this information to the database. Obviously, having large numbers of recorded events in the database would be of limited value if the relatively few events of real interest did not have thorough investigation, identification, and documentation.

Automate Data Management

During Phase I, the research team periodically (i.e., several times per week) initiated contact with each pre-prototype from a master computer at Texas A&M headquarters. They did this via dial-up modem. They then retrieved new data from the pre-prototypes. This process was tedious and time-consuming, but for the limited number of pre-prototypes in the proof-of-concept phase, it was satisfactory.

With more than a dozen prototype systems in the field recording large volumes of data from sixty circuits, the amount of human intervention necessary to retrieve field data has to be kept to a minimum in the current project. Also, during Phase I, TAMU had been the sole repository for collected data, but in the current phase, utility engineers have needed direct access to the data from their prototypes to enable them to fulfill their analysis, investigation, and documentation responsibilities.

The prototype systems have utilized the following technologies to automate data collection:

- ***Reliable high-speed communications*** – Master Station computers at TAMU and at utility engineers' offices communicate with the corresponding Field Units via high-speed Internet, utilizing industry-standard TCP/IP Sockets communications.
- ***Automated polling*** – Each Master Station is configured to poll the Field Units periodically and to collect from them any information recorded since the last polling cycle. This occurs with no human intervention.
- ***Integration of classification results with data captures*** – The large number of recorded events, most of which represent normal system switching events, makes it important to have means to integrate the results of manual and automatic classifications with the data records themselves. The Master Station software allows specific classification information to be tied to each recorded event. During automated polling cycles, the results of utility classification efforts are shared with TAMU, and vice versa.

Automate Data Analysis

During Phase I, the research team's emphasis was on demonstrating the concept of recognizing signatures of failing equipment. The team became proficient at recognizing a large number of normal system events and certain characteristics of incipient failures. The bulk of their analysis consisted of visual examination of waveforms and extracted parameters in a custom data-viewing

program that they developed. This provided them with the ability to view the behavior of a large variety of data over time, including current and voltage waveforms, computed power values, and various spectral components. The team performed more detailed analyses from time to time, but they generally used generic third-party tools (e.g., spreadsheets, MATLAB™, etc.) for these purposes. They did not attempt to automate the analysis process.

The manual analysis approach was appropriate for the proof-of-concept goals of Phase I. However, it was time-consuming and required the development of a high level of expertise, making it infeasible for widespread application by utility companies. The amount of time to develop the expertise would be considerable and, more importantly, the amount of time needed to perform the analyses on a day-to-day basis would be prohibitive in the long run.

For these reasons, one of the central goals of the current project has been to automate as much of the analysis process as possible. The research team has developed algorithms for automatically classifying normal and abnormal events.

3

WORK SUMMARY

Work performed during this project has consisted of three main tasks: producing and deploying prototype systems at host utility substations, assisting utility engineers in the analysis of collected events, and developing automated analysis routines. The following paragraphs discuss these activities in more detail.

DFA Prototype Design and Production

Design Overview

The initial task of the project was the design and production of the prototype systems for collecting, storing, and analyzing field data. Where practical in terms of both time and cost, the design team used commercially available, off-the-shelf components as building blocks. The reason was that development of the data collection platform was a means to an end, not the end in itself. With this in mind, however, certain specialized components were not available as off-the-shelf components. In these cases, the design team did the required low-level design and production.

The following subsections describe the two components of each DFA prototype system: the DFA Prototype Field Unit and the DFA Prototype Master Station. In order to avoid excess verbosity, here and elsewhere in this document, the term DFA Prototype Field Unit often is shortened to Field Unit and the term DFA Prototype Master Station often is shortened to Master Station.

DFA Prototype Field Unit

Each Field Unit resides in a 19" rack-mount chassis with nine card slots. One slot is reserved for a Master CPU card, which consists of an off-the-shelf single-board computer (SBC) with onboard RAM (random access memory) and a hard disk for storage of configuration information and long-term data. In addition, the Master CPU card provides for communication with an off-the-shelf weather station that is a peripheral to each Field Unit. Other peripherals include commercial-grade monitor, keyboard, mouse, and UPS (Uninterruptible Power Supply).

Each of the other eight slots is available for insertion of a feeder module. Each feeder module is designed to monitor the current and voltage signals for one feeder. Each feeder module provides four current inputs (five-amp nominal) and three voltage inputs (120-volt nominal), for connection to the secondary windings of conventional current and potential transformers (CTs and PTs). Each feeder module consists of two main components. The first is a custom-designed signal-conditioning module that interfaces with the CT and PT inputs, provides

appropriate signal conditioning, and converts the input signals to digital format at a rate of 15,360 samples per channel per second (i.e., 256 samples per cycle at 60 Hertz). The second is a single-board computer (SBC) with onboard RAM. The feeder module's SBC communicates with its signal-conditioning module via PC-104 bus. This allows the feeder module's SBC to adjust various settings on the signal-conditioning module and allows the signal-conditioning module to send its digitized samples to the feeder module's SBC. The feeder module's SBC performs various numerical functions on the data, including computation of standard power system quantities, frequency components, etc. It also monitors the levels of various parameters and triggers high-speed data captures when real-time values cross configurable thresholds. Finally, the feeder module's SBC is responsible for calculating various statistical values that it periodically records to long-term storage.

The main functions of the Master CPU card are to coordinate the activities of the multiple feeder modules, manage long-term data storage, and communicate with the outside world. The feeder module CPUs communicate with the Master CPU via an Ethernet hub inside the Field Unit's chassis. When a feeder module needs to store information in long-term storage, it notifies the Master CPU of this and then sends the data to the Master CPU, which in turn carries out the actual storage operation.

The other component of the Field Unit is a weather station. The weather station is a commercially available, off-the-shelf component. It provides a suite of weather sensors that connect to a weather station console residing in the substation control house. This console provides a serial connection that allows the Field Unit's Master CPU to poll it for real-time weather values. Measured weather parameters include temperature, relative humidity, wind speed and direction, and rainfall.

Figure 3-1 illustrates the interconnection of the various components of each Field Unit.

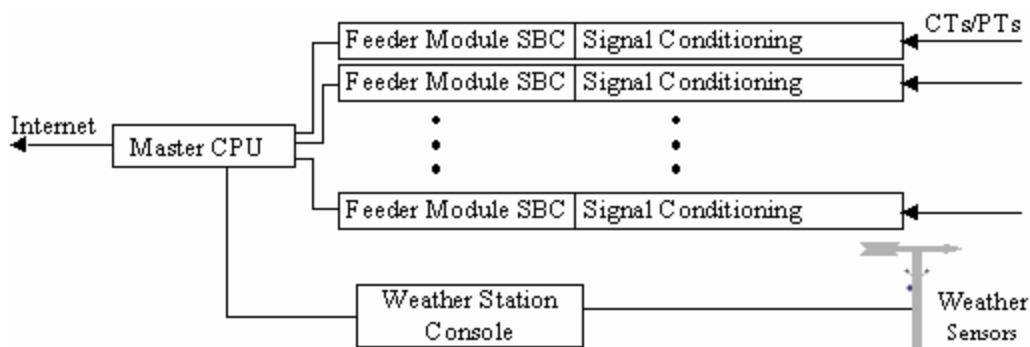


Figure 3-1
DFA Prototype Field Unit Functional Block Diagram

DFA Prototype System Data Storage

Each Field Unit continuously conditions, digitizes, and analyzes multiple channels of incoming data from each of its feeder modules. Obviously, it is not practical to record all incoming data on a continuous basis. Therefore, the Field Units store two types of data:

- **Statistical data** – The Field Unit continuously calculates numerous parameters from the incoming voltage and current signals. Depending on the particular parameter, it calculates these values at intervals ranging from a fraction of a cycle to multiple cycles. At the end of each configurable interval, nominally 15 minutes in length, each feeder module CPU calculates several statistics from each of these parametric data streams. The Field Unit then stores each feeder module's statistical values in its database, for long-term storage, retrieval, and analysis.
- **Data captures** – The Field Unit also stores high-speed waveform data when appropriate. Each feeder module determines the need to store this high-speed data when any one of the monitored parameters crosses one of its configurable thresholds. When this occurs, the feeder module records high-speed waveforms to long-term storage for several seconds.

DFA Prototype Master Station

Each Field Unit records a significant amount of information each day. The Master Station retrieves this information and provides the user with a straightforward way to analyze and manage it. Conceptually, the Master Station is the user's window to the Field Units.

The Master Station hardware consists of a high-end personal computer (PC) running Microsoft Windows 2000 Professional™ or Windows XP Professional™. The Master Station software consists of two components:

- **Synchronization program** – The synchronization component of the Master Station software is intended to run automatically without user intervention. Its purpose is to connect to the user's Field Unit(s) automatically on a configurable time interval. Each time it does so, it retrieves any new information that the Field Units have collected. For example, the user may configure his Master Station to run the synchronization program at midnight every night so that any information collected on a given day will be available on the Master Station the next morning when he comes to his office. Because the synchronization program is not normally intended for human interaction, its interface is a simple console that generates text progress messages as it retrieves information from the Field Units. The purpose of the automatic synchronization program is to relieve the user of the burden of manually connecting to Field Units, determining what information has not been collected yet, and going through the tedious process of specifying and retrieving this new information.
- **Graphical User Interface (GUI)** – The graphical user interface, or GUI, component of the Master Station software provides the user with tools to view and analyze the data that the Field Units collect. It also allows the user to communicate with the Field Unit in real-time, in order to view real-time readings and to view and modify settings on the Field Unit.

The GUI organizes information hierarchically by utility, substation, bus, and feeder. At the feeder level, it then provides means to filter data captures by date and by cause (e.g., capacitor bank, arcing, overcurrent, etc.). The GUI simplifies visual analysis of data captures by allowing the user to simply double-click on a data capture's icon to open it and display it in the GUI's chart window.

Figure 3-2 illustrates the look and feel of the GUI when viewing one parameter in a data capture. The icon next to the data capture entry in the tree indicates that this particular data capture has been classified as an overcurrent event. Figure 3-3 illustrates the viewing of statistical data, providing a high-level view of the performance of a particular feeder over an extended period of time (e.g., a week, a month, etc.). Note that these screen captures were taken from TAMU's Master Station GUI. Therefore, the hierarchical trees show multiple utility companies and substations. By contrast, each participating utility company's Master Station communicates only with that company's Field Unit(s), and utility Master Station GUI's only have single Utility entries in their GUI trees.

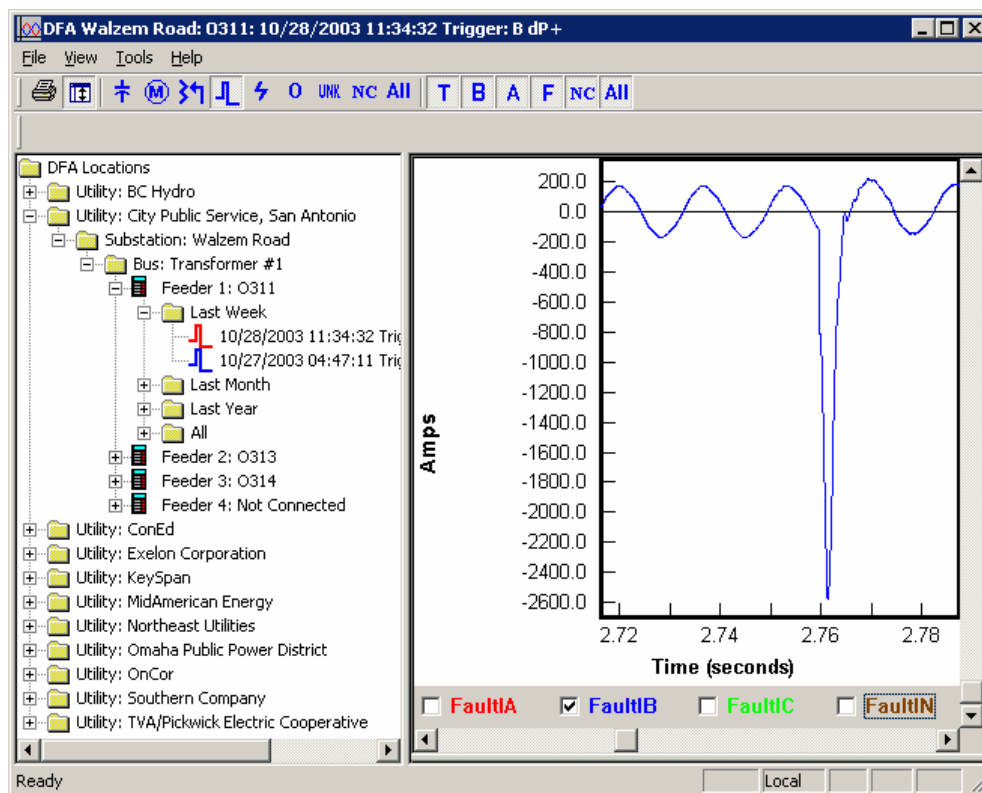


Figure 3-2
Data Capture Viewed in DFA Prototype Master Station GUI

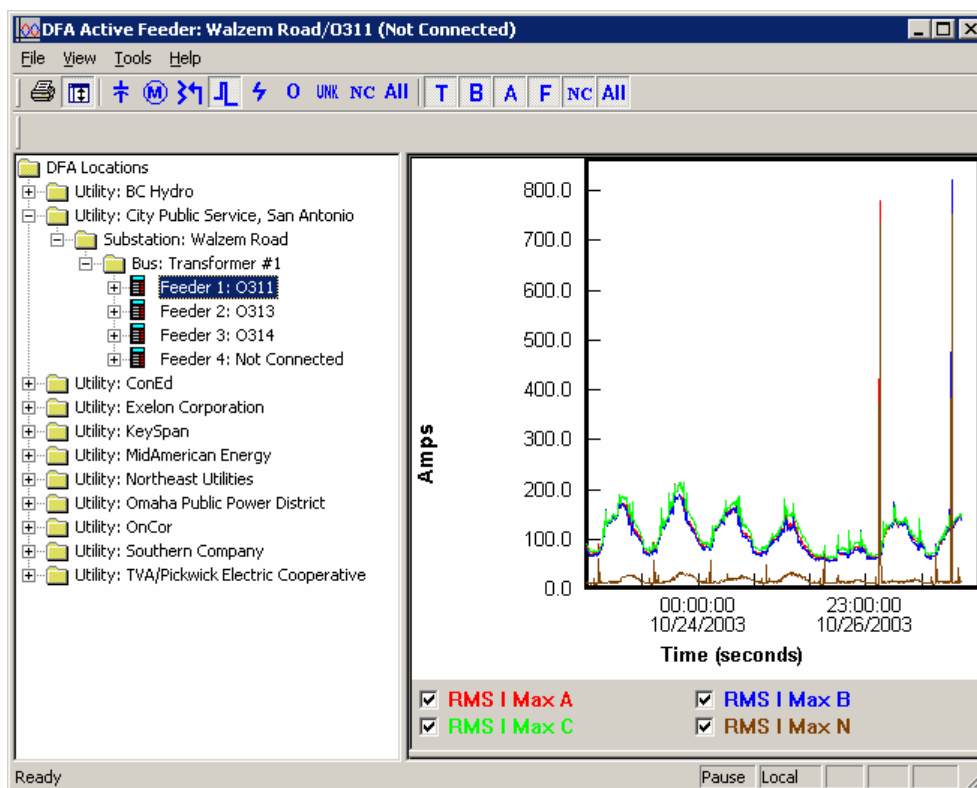


Figure 3-3
Statistical Data Viewed in DFA Prototype Master Station GUI

Users Group Meetings

Active participation by host utility members has been critical to this project. Participants have been responsible for day-to-day operation of the DFA prototypes at their respective utility companies. They also have been responsible for investigating and documenting events that occur on their circuits.

It has been beneficial for the utility users to interact with one another. In this way, each has learned from the experiences of others. Through trial and error, one utility company may conceive a useful method for diagnosing certain types of problems. By sharing this experience with other project participants, all members build on and benefit from a common body of knowledge.

To facilitate this interaction, EPRI has hosted Users Group meetings approximately every six months for the duration of the project. The project has held seven Users Group meetings:

1. July 10-11, 2002, Texas A&M University, College Station, Texas
2. March 26-27, 2003, Alabama Power Company, Birmingham, Alabama
3. October 15-16, 2003, BC Hydro, Vancouver, British Columbia, Canada
4. March 24-25, 2004, CPS Energy, San Antonio, Texas

5. September 9-10, 2004, Exelon, Chicago, Illinois
6. March 2-3, 2005, Tennessee Valley Authority, Knoxville, Tennessee
7. October 20, 2005, BC Hydro, Vancouver, British Columbia, Canada

These Users Group meetings have provided a forum for the various participants to become familiar with each other's installations and experiences and have been quite valuable. Most participants have attended meetings in person, although some of the participating utilities have had budgetary and other constraints that limited their attendance. In these instances, some have participated by telephone conferences and WebEx™ conferences. Clearly this type of participation is less beneficial than in-person participation, but it does have value if the only alternative is non-participation.

The first meeting in College Station, Texas was an introductory meeting. TAMU personnel introduced the participants to the project's goals and gave them an opportunity to see an installed Field Unit first-hand. They also introduced the users to the look-and-feel of the GUI.

By the time the second meeting was held in Birmingham, Alabama, TAMU had shipped Field Units to all of the initial utility participants and approximately half of these units had been installed. TAMU provided additional training in the use of the GUI at this meeting.

The third and subsequent meetings have shifted the focus from issues related to production and initial installations to the experiences that users have had with their Field Units and Master Stations. TAMU has provided regular updates on recent significant events and on advances in the analysis and ability to recognize various patterns in measured waveforms. TAMU also has provided guidance on how to differentiate the causes of various types of measured signals and on the use of the Master Station software, particularly new features that have been implemented over time.

Recent meetings have continued to discuss newly documented field events and measurements. In addition, attention has turned to transferring the technology into the commercial domain. It has been recognized that the platform and technology continue to have unrealized potential that will require additional work to tap. However, the utility users, EPRI, and TAMU have reached the consensus that the technology has demonstrated significant benefit that can be of current use to utility companies, while research continues in parallel, to investigate additional functionality and value.

Automatic Classification System

Many of the events of interest in this project produce electrical signals with small amplitudes, often of the same order of magnitude as many loads. For example, a damaged lightning arrester that is beginning to fail, but that has not reached the point of catastrophic failure, may draw current similar in amplitude to that of a medium-sized motor. Because the amplitudes are similar, Field Units record both phenomena and allow subsequent analysis to differentiate between them.

Most circuits record a significant number of events each day. To analyze all of these events manually would be a daunting task, even if one had sufficient time to do so. The reality is that no one has the time necessary to do this. Therefore, one of the key tasks of this project has been the development of techniques for automating the recognition of captured data waveforms. Ultimately, the goal is to automate this to the point that the system would not only recognize what particular captures represent, but also be able to decide which ones are “important” and should be brought to the attention of the user.

TAMU has developed and tested algorithms for automatically classifying a large majority of the data captures. To allow individual utility users to benefit from this automatic classification, they have put in place a system for automatically sending the results of these classifications to the individual utility users. This system also retrieves any classification results that the users have entered into their Master Stations manually.

Conceptually, the automatic classification system consists of two parts: the classification algorithms themselves, and an automated system that retrieves captures, classifies them, and propagates the results to users. The following subsections discuss each of these parts in more detail.

Classification Algorithms

As soon as Field Units began to be put in place in substations, they started generating a significant volume of data. Normal system operations, such as capacitors and motors switching, are common events, and as expected, they began generating a steady stream of data captures from day one. Because fault and incipient fault conditions have not been staged or otherwise created, faults and fault precursors have not occurred with great frequency. Therefore, as expected, acquisition of these captures has occurred relatively slowly as compared to the rate for normal events.

When TAMU began to design algorithms for automating the recognition of data captures, they considered these realities and focused on developing algorithms for normal system events first. There were two complementary reasons for doing this:

- The volume of data captures representing normal system events soon became sufficiently large to support development and testing of robust algorithms, much more quickly than the volume of data captures representing abnormal events did so. As an example, most circuits have at least one capacitor bank that switches at least twice per day (once turning ON and once turning OFF). This alone generates 3,600 ($= 30 \text{ days/month} \times 60 \text{ circuits} \times 2 \text{ operations/day/circuit}$) captures per month. By contrast, load tap changers (LTCs) seldom fail, so the probability of experiencing even a single LTC failure in a given month (or year, for that matter) is very small.
- One of the responsibilities taken on by each user was the classification of each data capture, by analyzing the waveforms and entering the appropriate classification information into the database via the Master Station software. After gaining experience and proficiency in doing this, users could accomplish the classification of individual normal system captures very quickly. However, the cumulative amount of time to classify a large number of classifications was significant, particularly for those users with a large number of monitored circuits or with particularly active circuits in terms of the frequency of normal events.

When a classification algorithm is first developed, it is normal for there to be some number of incorrect results. Therefore, whenever a new classification algorithm is ready for initial testing, TAMU begins allowing it to classify new data captures as they occur and are retrieved, but they do not immediately allow the results of these classifications to be propagated to the users. Over a period of time, they compare the results of the algorithm classifications with those manually entered both by utility users and by TAMU personnel. They use this feedback mechanism to assess strengths and weaknesses of the algorithm, and then use this assessment to refine the algorithm. The algorithm's accuracy generally becomes high enough within the first few weeks of this kind of testing to allow the results to be propagated to the users. Naturally, the accuracy and robustness of a given algorithm correlate to the volume of data available for testing it. For example, a method for classifying capacitor operations achieves a high level of reliability much more quickly than, say, a method for recognizing the failure of a line switch.

Automated Classification System

Throughout the project, the central processing location has been a server at TAMU headquarters in College Station, Texas. The automated classification system performs several tasks to make the system work together, without human intervention. To do this, it coordinates the following activities:

1. Retrieve new data captures from Field Units.
2. Retrieve user classifications from Field Units.
3. Classify each new data capture, either manually, automatically, or both.
4. Resolve discrepancies between manual user classifications, manual TAMU classifications, and automatic TAMU classifications.
5. Propagate appropriate classifications to the Field Units and ultimately to the utility users' Master Stations.

The TAMU team has designed appropriate automation on their Master Station to accomplish these tasks. This system has been in place and working satisfactorily for over a year.

4

FIELD RESULTS

Field Units have collected data for significant periods of time at the participating utility companies. At the time of this writing, they had accumulated an average of approximately two years of installed service.

The following sections provide a detailed series of case studies that give a sense of the types of incidents that the Field Units have recorded. The proof-of-concept project that provided the basis for the current project involved a small number of single-feeder pre-prototype units, some of which continued to collect pertinent information during the early months of the current project. Some case studies include information from these units as well.

Most of the cases cited below have been resolved by finding and making repairs to the underlying problems on the affected circuits. Others have remained unresolved or remain under investigation. Incipient events often take considerable time to develop and progress to final failures and outages. Therefore, a long period of time sometimes elapses between initial recognition that something is wrong and final determination and documentation of the problem.

As often happens in research projects that involve collection of field data, some of the collected information represents interesting events that are somewhat tangential to the initial focus of the project, but that represent additional opportunities to use DFA-like monitoring to enhance reliability and operational efficiency. The following case studies include several such examples.

Data Collection Philosophy

A primary goal of this project has been to characterize early warning signs that may accompany failing apparatus. Because no one ever collected this type of information before, there was no way to know beforehand what form these precursor signals might take. Further, the number of apparatus failures per year on a given circuit is small. Neither the research team nor the participating utility companies cause these failures to occur: they happen when they happen and you'd better catch them when they do!

All of these factors drove the research team's data collection philosophy: record high-fidelity data captures when small parametric changes occur, so as not to miss the rare event of true interest when it comes along. Unfortunately, many normal system events affect many of the monitored parameters. Unlike the rare incipient failure, these normal system events occur frequently. For instance, a capacitor bank or a large motor may switch OFF and ON several times per day, each time causing fluctuations in the monitored parameters and initiating a data capture. Therefore, it is predictable that perfectly normal system events represent the vast majority of data captures that have been obtained.

Summary of Failures Documented to Date

As mentioned, the data collection methodology is such that, after a Field Unit is installed, neither the researchers nor the utility participants control when failures or incipient failures occur. This process has involved a great deal of waiting for power system events of interest to occur naturally. This was expected from the beginning. It also has involved sifting through voluminous normal system data in the quest to identify these infrequent, but most important, failures and incipient failures. This also was expected.

Over time, a wide range of failure modes have been recorded and documented, including one or more instances of each of the following:

- Voltage regulator failure
- LTC controller failure
- Lightning arrestor failure
- Tree limb contacts
- OH service cable insulation failure
- URD cable failures
- Repetitive UG secondary service cable failures
- Repetitive overcurrent faults
- Tree limbs in secondary service cables
- Line switch/cutout failure
- In-line splice failure
- Substation bus capacitor bushing failure
- Customer 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

These have been in addition to numerous instances of “normal,” unpredictable overcurrents, such as wildlife on transformers, automobiles hitting poles, etc. Those events are not included in the list because they are, by definition, unpredictable.

Goals and Approaches of Utility Participants

Utility participants have diverse goals that they wish to achieve through this project. As a result, they have taken a variety of approaches to responding to information from the DFA. Some have taken an approach of using DFA information to investigate and remedy problems immediately. Others view the project as an opportunity for long-term data collection and documentation. They use the DFA to document the natural progression that problems would take without the DFA. This latter approach has the added benefit of allowing an informed estimate of the consequences that can be avoided with a tool like the DFA. A mixture of the two approaches has proven beneficial to overall project goals.

Case Studies

This section provides examples of specific problems that have occurred and been recorded by Field Units. In some instances, the Field Units have registered multiple instances of a particular variety or mode of failure. In these instances, only one example of that type of failure mode generally is presented, to avoid redundancy.

Where appropriate, some of the case studies discuss the affected utility’s use of information from the DFA, and how they might use that information further if it were integrated into their day-to-day operations.

Malfunctioning Capacitor Bank Controllers

From the outset of the project, the presumed failure modes involved mechanical failure of apparatus. However, the project also has documented failures in controls that cause the underlying apparatus to behave improperly. One of the best examples involves malfunctioning capacitor controllers. This project has documented instances of this problem at multiple utility companies. Two such instances are described and discussed below.

Malfunctioning Controller A

On August 9, 2004, a participating utility performed maintenance on the capacitor banks on a circuit monitored by a Field Unit. This was done as part of routine annual maintenance, and included testing of the capacitors and replacement of the bank’s controller. The crew completed its maintenance of the bank and left the bank in automatic switching mode shortly before noon.

When the engineer responsible for this utility’s DFA arrived at his office the next morning, he reviewed DFA records for August 9 and found that the capacitor bank in question had begun to cycle OFF and ON repetitively at 13:21 that afternoon, shortly after the crew finished its maintenance activities and left. Between then and midnight, the bank had cycled OFF and ON 22 times.

One normally would expect a capacitor bank to cycle OFF and ON once or twice per day, perhaps with a few more operations in unusual circumstances. The utility engineer recognized that 22 cycles in one afternoon clearly was improper, so he dispatched a crew to investigate. When they arrived, they found that the bank indeed had been cycling OFF and ON excessively and that it was continuing to do so. The crew adjusted one of the controller's configurable settings, which restored proper operation. In so doing, the crew remedied the problem less than 24 hours after it began. Otherwise, the problem would have persisted until either 1) it caused customers to complain, 2) the excessive operations caused failure of components, or 3) the following year's annual preventative maintenance cycle occurred.

The Research Dilemma

The utility involved in the case described above used the DFA to take corrective action. Had the DFA not been present, the controller likely would have continued to operate the bank excessively, which probably would have led to other adverse consequence. The electrical stresses from the multiplicity of operations might have damaged the individual capacitors and caused them to fail prematurely. The electrical and mechanical stresses on the bank's switches might have caused the switches to fail prematurely. The repetitive electrical transients also could have caused the phase fuses to operate.

Words such as "likely," "probably," and "might" abound in the preceding paragraph. The dilemma that researchers often face is that when a new technology is used to solve problems and avoid consequences, it often is difficult or impossible to know what would have happened had the problem been allowed to run its natural course. One knows that the behavior is not desirable and is confident that correcting the problem is beneficial, but quantifying the avoided consequences with any high degree of certainty is problematic.

This problem has been especially germane in the current project. Field Units have recorded subtle signals that indicate problems that previously were not even known to exist. The progression of events from early signs of failure to more apparent problems often is poorly understood or completely unknown. Consequently, when warning signals are used to detect and correct problems in their early stages of development, it is difficult to know the type or extent of consequences that are avoided.

The following paragraphs document another instance of a capacitor controller operating too often. Unlike the previous case, however, the utility involved in the second case used the DFA as a tool for documenting the natural sequence of events. Some of the results obtained in this case are surprising, and demonstrate the value of using the DFA as a documentation tool during this phase of the project.

Malfunctioning Controller B

This Field Unit was installed in December 2003 and TAMU began retrieving data from it in early January 2004. It was immediately obvious that a capacitor bank on one of the monitored circuits had an operational problem.

As in the previous case, this bank was cycling OFF and ON excessively. The number of operations each day varied, but most days exhibited far more operations than desirable. The following tabulation shows the number of recorded capacitor switching operations, on this one circuit, for two representative one-week periods. Each operation represents either a switch closing or a switch opening.

Date	Capacitor Switching Operations
01/01/2004	39
01/02/2004	28
01/03/2004	14
01/04/2004	27
01/05/2004	32
01/06/2004	71
<u>01/07/2004</u>	<u>34</u>
Week Total	245
	(35/day average)
02/01/2004	12
02/02/2004	36
02/03/2004	78
02/04/2004	119
02/05/2004	77
02/06/2004	82
<u>02/07/2004</u>	<u>90</u>
Week Total	494
	(70/day average)

For these representative periods, the average number of capacitor switching operations was 35 per day during the first week of January, and 70 per day during the first week of February. The number of operations each day did not increase monotonically, but there was a generally increasing trend. The worst single day was February 18, when the Field Unit recorded 373 capacitor operations on this circuit!

Figure 4-1 illustrates a phase-A capacitor short circuit on February 16, 2004. It represents a catastrophic failure of one of the capacitor “cans” that make up this bank. By this time, the DFA had registered approximately 3,000 switching operation for this capacitor in the period of approximately two-and-one-half months since the Field Unit had been installed. It is reasonable to assume that the repetitive switching transients caused or at least accelerated the failure of this capacitor and led to this short-circuit failure.

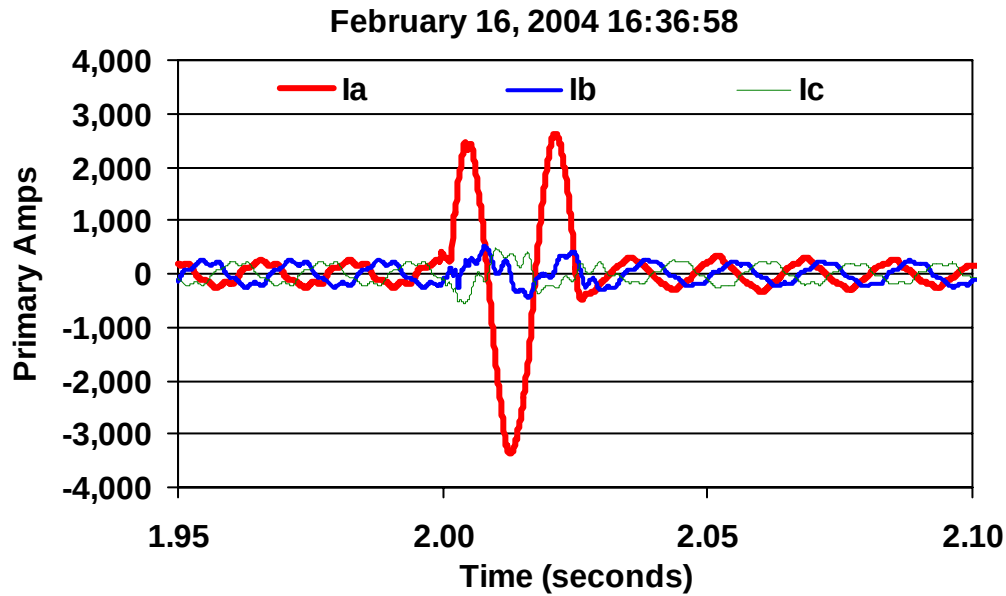


Figure 4-1
Phase Capacitor Short Circuit

After the February 16 phase-A capacitor failure, the remaining two phases continued to switch with excessive frequency for the next two weeks. Then, on February 29, the contacts of the oil switch controlling the phase-B capacitor began to arc. After switching dozens of times in the early morning hours of that day, the bank switched ON at 04:57:37. On this occasion, the contacts of the oil switch controlling the phase-B capacitor made imperfect contact, and eight seconds later, continuity of the contacts became intermittent. Figure 4-2 illustrates the RMS current signals the Field Unit measured at the substation as the switch began to fail.

Whenever a capacitor switches ON, it causes a significant voltage transient on the line and significant transient current flows from the line into the capacitor. For a single operation, the transient is time-limited and diminishes quickly as the capacitor charges to and then follows the instantaneous line voltage. The current during this period has sufficient magnitude that it would damage the capacitor, the fuse, and perhaps other apparatus if it persisted. However, the effects generally are manageable when time-limited to a few milliseconds, which is typical of normal capacitor transients.

When a capacitor switch opens, it retains the instantaneous line voltage that was present the moment the switch opened. The charge trapped on the capacitor slowly “bleeds down” so that the voltage on the capacitor is small after a few minutes. Capacitor controllers typically do not allow a capacitor to switch back ON for several minutes after it switches OFF, so that the charge will have sufficient time to bleed down. Otherwise, the resulting voltage and current transients could be more severe than normal. In the extreme, if full positive line voltage remained on the capacitor and the switch happened to close at the moment of full negative line voltage, the differential voltage and the resulting current would be twice their normal maximum values, causing excess stress on the capacitor and to other apparatus connected to the circuit.

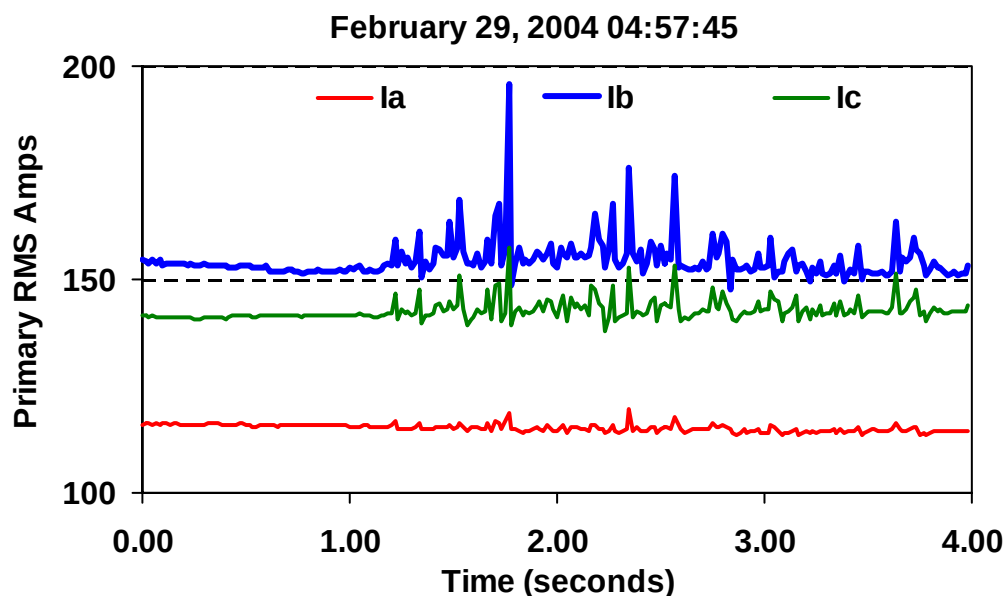


Figure 4-2
Continuity Failure in Capacitor Oil Switch Contacts

When capacitor switch contacts break and make repetitively in rapid succession, the capacitor experiences transient current similar to that which occurs when the capacitor switches ON normally, but potentially of significantly larger magnitude because of the retained charge. In addition, multiple switching transients in rapid succession result in significantly higher than normal average current. Whereas the high current associated with a single transient dies out in a few milliseconds, the current from multiple back-to-back transients maintains a high average level. These effects explain the erratic behavior of the current in Figure 4-2.

A capacitor also produces voltage transients each time a faulty switch begins to conduct. These capacitors may have higher amplitude than normal, again because of the retained charge. During this incident, the faulty switch exhibited countless cycles of losing and then reestablishing contact. As a result, the voltage experienced a nearly continuous series of back-to-back transients. Figure 4-3 shows several cycles of the phase voltage measured at the bus feeding the affected circuit. The transients are obvious.

Interestingly, the utility reported no customer complaints while these transients were occurring. If they had, this could have constituted a serious power quality problem. It should be noted that the lack of complaints may be the result of the type of customers served by this circuit. Had this circuit served customers with sensitive loads, there might well have been problems and complaints. It should be stressed that the figure illustrates the voltage at the bus, meaning that the voltage out on the circuit would be worse than that shown, and also meaning that any other circuit on this bus would be subject to the same repetitive transients.

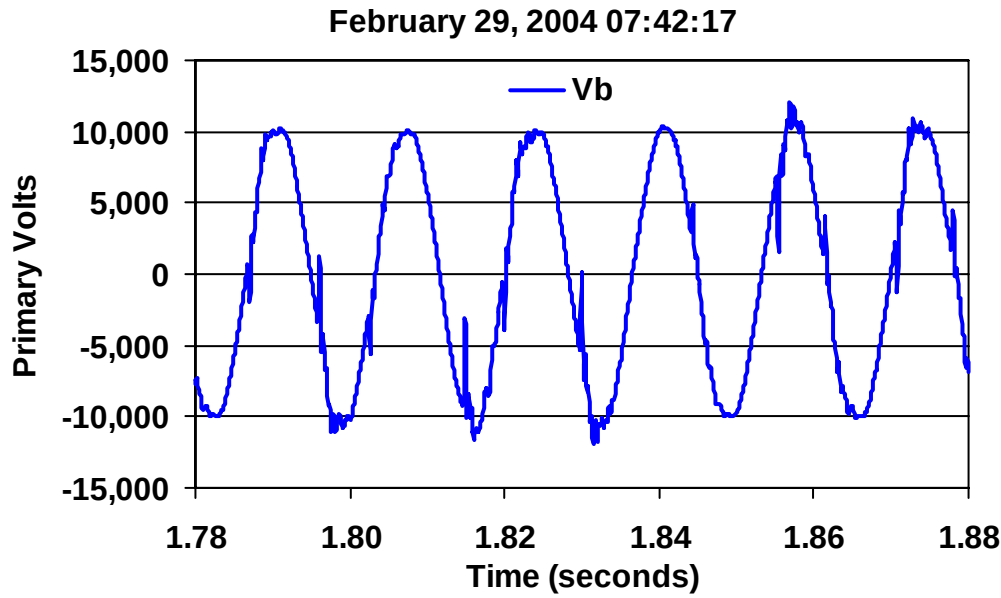


Figure 4-3
“Continuous Transients” During Capacitor Switch Failure

One might assume that this sort of intermittent making and breaking of the switch contacts would cause the contacts to degrade quickly, so that they would cease conduction altogether after a short period of time. This would leave the circuit with a VAR imbalance, which constitutes an operational inefficiency, but a relatively minor one in comparison with the severe transients that continued, intermittent conduction represents. One might assume this, but, in this case, one would be wrong. The controller continued to open and close the switch frequently for several days. Whenever the switch was in the closed position, it continued to exhibit this behavior.

Figure 4-4 illustrates the end of the sequence of failures. The intermittent current stopped flowing early on March 4, more than two months after the controller problem was recognized and nearly four days after the switch contacts began to fail. The data do not make it obvious whether the switch finally stopped conducting, or whether the phase-B capacitor or fuse finally opened in response to the constant abuse they received over the preceding days. It does not appear that the controller opened the switch at this point, because the one phase that continued to function (not shown) still had an intact bank did not register a step in VARs.

The DFA recorded multiple problems as this case developed over a course of multiple months. It first recorded and documented the excessive operations that the capacitor was experiencing. It documented the increasing frequency with which these operations were occurring. It then documented the short circuit of the phase-A capacitor on February 16 (Figure 4-1) and the initial and continuing failure of the phase-B switch contacts for four days beginning February 29.

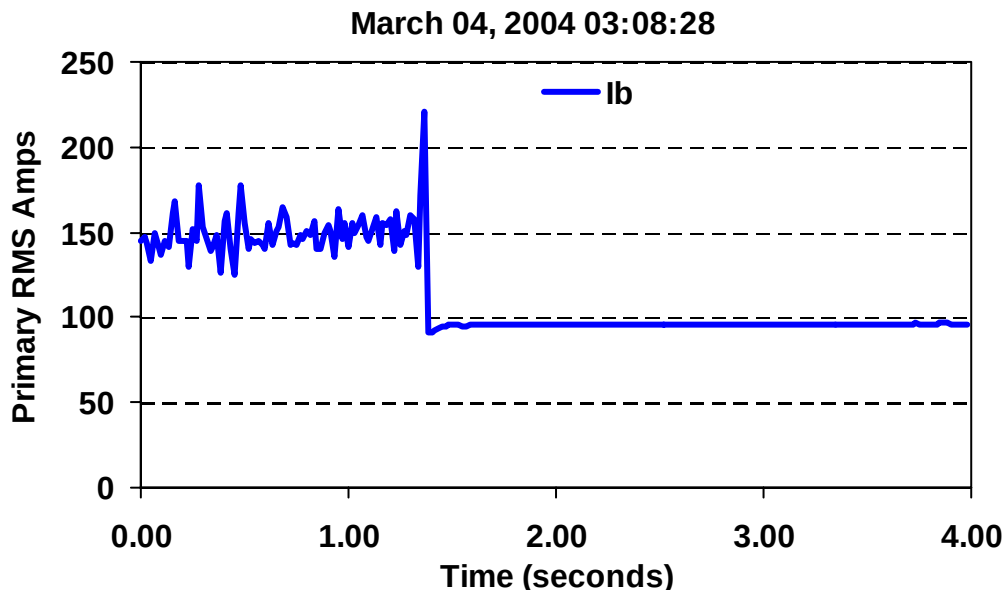


Figure 4-4
Final Failure of Capacitor Bank, After Four Days of Intermittent Connection

In retrospect, all of the above behaviors and symptoms are explainable and even somewhat predictable. If a distribution engineer were told that a capacitor was switching OFF and ON with this frequency, he probably would not be surprised to learn that a capacitor failed and a switch failed.

The DFA recorded and documented other failures that were less predictable, however. One must know some of the power system topology to understand these failures. The substation in question has two transformers, each serving two circuits. Each circuit has multiple capacitors. This case involved two capacitor banks on the circuit with the problematic bank and one bank on the other circuit served by the same bus. The following discussion will designate the circuit with the misbehaving controller as Circuit A and the other as Circuit B. It will further designate the capacitor bank with the bad controller as Capacitor A-1, the other capacitor on that circuit as Capacitor A-2, and the capacitor on the other circuit as Capacitor B.

Earlier discussion outlined the method by which repetitive transient current causes elevated average current for an extended period of time, which can cause premature aging and failure of the affected capacitor. It also outlined the method by which intermittency in switch contacts causes repetitive voltage transients. As noted, Figure 4-3 illustrates the voltage of the *bus* that serves Circuits A and B. Therefore, all loads and apparatus connected to both circuits saw voltage transients similar to those in the figure. By definition, a capacitor's impedance becomes progressively smaller as frequency increases. The bus voltage of Figure 4-3 clearly contains frequencies significantly higher than the nominal 60 Hertz. The impedance of *all* capacitors on connected circuits is relatively low at these frequencies. This causes abnormally high currents to flow, not only through the capacitor with the intermittent switch connection, but also through all other connected capacitors as well.

A few hours after the phase-B switch contacts on Capacitor A-1 began to fail and arc, the sustained, increased transients caused sufficient current to blow the phase-B fuse on Capacitor A-2, the other bank on the same circuit. A distribution engineer probably would not predict this behavior, but the effect is clear enough in retrospect and demonstrates the advantage of using the DFA to record and document the normal progression of events. During a subsequent annual patrol, if a crew had found a failed phase-B switch on Capacitor A-1 and a blown phase-B fuse on Capacitor A-2, the natural assumption would be that the two events were independent of one another. Someone might wonder whether the two failures had the same cause, perhaps a lightning strike, but it is unlikely that anyone would have thought that one of the failures actually *caused* the other. Documentation from the DFA makes it quite clear that this indeed is what happened. As an aside, it should be noted that this was not the only instance of sympathetic capacitor fuse operation resulting from an arcing capacitor switch. A few months earlier, another utility participant reported an almost identical incident in which an arcing capacitor switch caused a fuse to blow on another capacitor elsewhere on its circuit.

The day after the switch began to fail, another event of interest occurred. The capacitance of Capacitor B-1 suddenly changed. This is the capacitor on the other circuit. The measured VAR flow on phase A increased suddenly, while the VAR flows on phases B and C remained unchanged. This symptom is generally consistent with a “pack failure.” Distribution capacitors typically are constructed of multiple capacitors, or “packs,” in series with one another. In a capacitor that consists of N series packs, each pack normally operates at 1/N times the line voltage. When one of these packs fails in a short circuit, the line voltage is distributed across the (N-1) remaining packs, increasing the voltage across each. Shorting of a single pack also lowers the total impedance of the series of capacitors and increases the current through the remaining packs. It is generally assumed that the increased current and increased voltage stress will accelerate the aging of the remaining healthy packs and precipitate the failure of a second pack shortly thereafter. If this results in the short circuit of a second pack, the process then rapidly deteriorates in a domino effect and results in failure of the capacitor as a whole. In this case, shortly after the phase-A VAR flow increased, the capacitor short circuited and caused a high-current failure in phase-A of Capacitor B-1.

Field Findings

After the electrical activity appeared to be over, the utility sent a crew to investigate the capacitor banks on the affected circuits and compare findings to the information the DFA provided. The crew found good agreement between the DFA’s data and their field findings. They found that the controller of Capacitor A-1 had registered in excess of 4,000 operations since being serviced during the previous summer’s annual maintenance cycle. Interestingly, another utility participant reported that oil switches are supposed to be maintained roughly every 1,500 cycles, and this switch had operated far in excess of this number since the utility last performed service (e.g., contact inspection and replacement, oil replacement) on it. They also found bad capacitors and blown fuses on Capacitors A-2 and B-1, in agreement with predictions by the DFA.

Observations and Discussion

This case represents the best documentation of the natural progression of an overactive capacitor controller known to exist anywhere. It is interesting and important for multiple reasons:

- It demonstrates the ramifications of excessive capacitor switching that one normally would anticipate, such as the blowing of a phase capacitor and the failing of switch contacts on the bank with the bad controller.
- It demonstrates ramifications that one normally would *not* anticipate, such as the failure of a fuse in another capacitor bank on the same circuit and the failure of a capacitor in another bank on another circuit connected to the same bus.
- It documents the characteristics exhibited by a failing capacitor switch over a significant period of time (days).
- It documents a case in which preventative maintenance was ineffective. Preventative maintenance was last performed some six to seven months before the problem was discovered by the DFA. The next preventative maintenance cycle was not due for several months after the problem had run its natural course and damaged or destroyed multiple pieces of equipment on multiple circuits.
- It documents the extent of the voltage distortion, at the substation bus, that accompanies the failure of switch contacts on a capacitor. Although no customers on these circuits reported problems during the course of this event, there clearly was significant, sustained, high-frequency distortion at the bus, which could cause problems for customers with sensitive loads.

In summary, this case demonstrates and documents the manner in which problems that begin innocuously can escalate into more serious failures and can even cascade to involve other equipment and apparatus.

Repetitive Overcurrent Fault

On the morning of November 2, 2004, a tree limb came into contact with both the phase conductor and the neutral conductor on an overhead single-phase line. At 06:57 that morning, it caused a high-current fault, which was cleared temporarily by a three-phase poletop recloser that tripped and reclosed one time. Figure 4-5 illustrates a second episode, which occurred just over an hour later. In this instance, the high current caused the three-phase poletop recloser to trip, at approximately 2.2 seconds into the time period illustrated in the figure. After the recloser closed back in, the tree limb continued to contact the line and draw significant current. The erratic current starting approximately 4.3 seconds into the time period shown in the figure caused the recloser to trip again at approximately 6.9 seconds. When it reclosed again, the tree limb had lost connection and stopped drawing fault current, at least for the time being.

The tree limb did not burn permanently clear of the line, however, because it started faulting again 16 hours later, at just past midnight on November 3, 2004. In total, over a period of 24 hours, this tree limb caused 17 high-current faults and recloser operations, at the times tabulated below. The line then burned down, interrupting power to 140 customers for 62 minutes.

When a crew responded to the resulting lights-out call, they found the line burned down, with a tree limb as the obvious cause. Figure 4-7 shows two clearly identifiable burn areas on the offending limb. One of the burned areas is near a fork in the tree. This fork apparently hung on the phase conductor. The weight of the limb pulled the phase conductor down to within 18 to 24 inches of the under-built neutral conductor. The second burned area, toward the right side of the picture, intermittently contacted the neutral conductor and completed the circuit for the fault.

Date	Time	Recloser Trips
11/02/2004	06:57:47	1
	07:58:33	2
11/03/2004	00:09:06	1
	00:16:48	1
	00:40:38	1
	00:40:53	1
	01:10:51	1
	01:12:37	1
	01:15:30	1
	03:24:47	1
	04:19:39	1
	04:30:36	1
	05:51:01	1
	06:19:45	3
	Total Trips	17

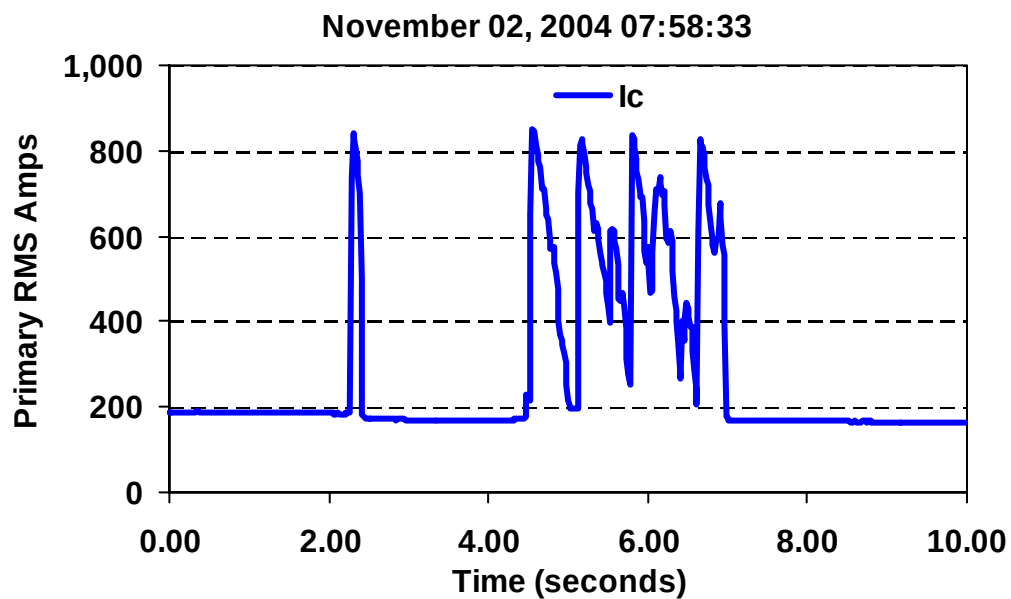


Figure 4-5
Second in Series of Overcurrent Faults from Tree Limb Contact

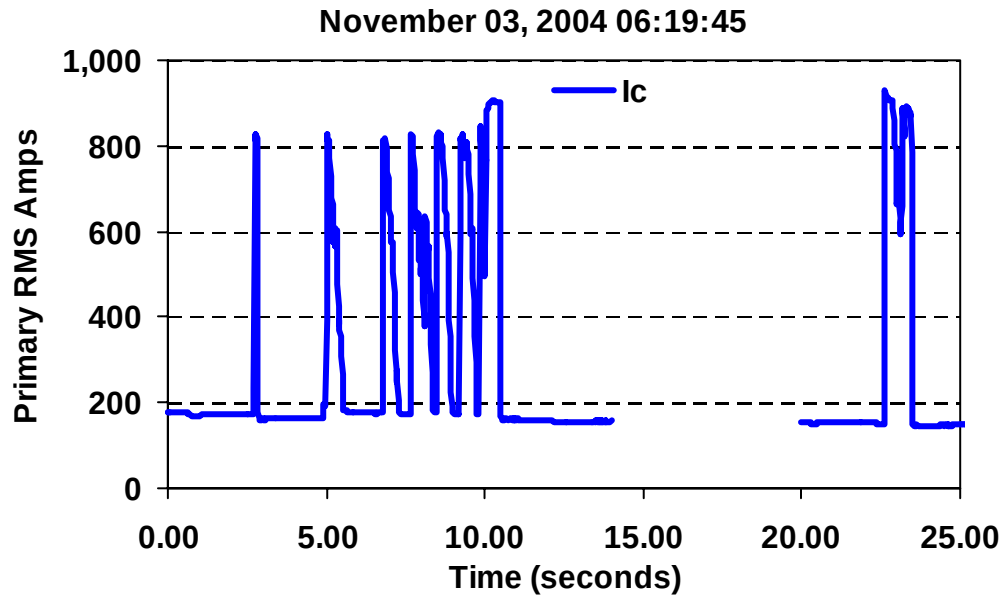


Figure 4-6
Final in Series of Overcurrent Faults from Tree Limb Contact



Figure 4-7
Tree Limb that Caused Repetitive Faults and Burned Line Down

Some might question whether this constitutes fault anticipation, since there was no anticipatory signal noted prior to the initial overcurrent, trip, and reclose. In the traditional sense of the word, there is room for debate. However, it is undeniable that this is anticipatory in the sense that some of the later episodes of faults and trips, and likely the sustained outage as well, could have been prevented. As a follow-up, TAMU asked the engineer responsible for the DFA project at this utility how he would have used this information, had he had real-time access to it. His responses are summarized as follows:

- We definitely would have dispatched a crew to investigate around 1:00 AM, given the information that the DFA provided. (Note that this was five hours before the burn down.)
- I believe it likely that the crew would have found the fault in time to prevent the line from burning down and causing the ultimate outage.
- I believe that we could have found the fault by using the following information, based upon data from the DFA Prototype: the phase of the fault, the magnitude of the fault, and the recloser's operating characteristics.

It should be noted that this case was not unique. This project has documented multiple problems that have resulted in similar series of repetitive overcurrent faults.

Long-Term, Repetitive Arcing

Several of the monitored circuits register sporadic arcing from time to time. A circuit may produce a singular arcing episode that lasts from a cycle or so to a few seconds. In some cases, the arcing never appears to recur or cause any problem. In other instances, a particular circuit produces repeated episodes of arcing. The pattern may repeat numerous times and eventually escalate to something more serious.

A Field Unit began to record episodes of relatively low-level arcing in September 2004. Figure 4-8 illustrates one early episode. Arcing begins at approximately 2.1 seconds in the figure and lasts approximately 10 cycles, during which time it adds about 100 amps of current to the existing load current on the circuit.

Over the next three months, the DFA registered similar episodes several dozen times, on the same phase of the same circuit. Each episode produced roughly the same level of current for time periods varying from a few cycles to approximately a second. In some instances, there were multiple bursts of current within a few seconds of one another. At other times, consecutive bursts of current were separated from one another by hours or even days. Figure 4-9 illustrates an episode that occurred in mid November, two months after the problem began. In this case, there were multiple bursts of arcing current over a period of a few seconds. Figure 4-10 shows the RMS current during this episode, which gives a better view of the intermittent burst nature over a period of seconds.

A previous case study discussed the decision by some utility companies to use the DFA as a data collection and documentation tool, to record the natural progression as incipient failures escalate to more severe failures. The utility in the current case did not view the DFA project that way, but circumstances led to roughly the same result. In this case, Internet service to the substation-based

Field Unit failed in early September. It was not restored for approximately two months. During this period of time, utility personnel could access the Field Unit's records only by making a trip to the substation. Not knowing that a problem was developing, they did not do this frequently. Therefore, they did not know of the problem until after their Internet service was restored in November.

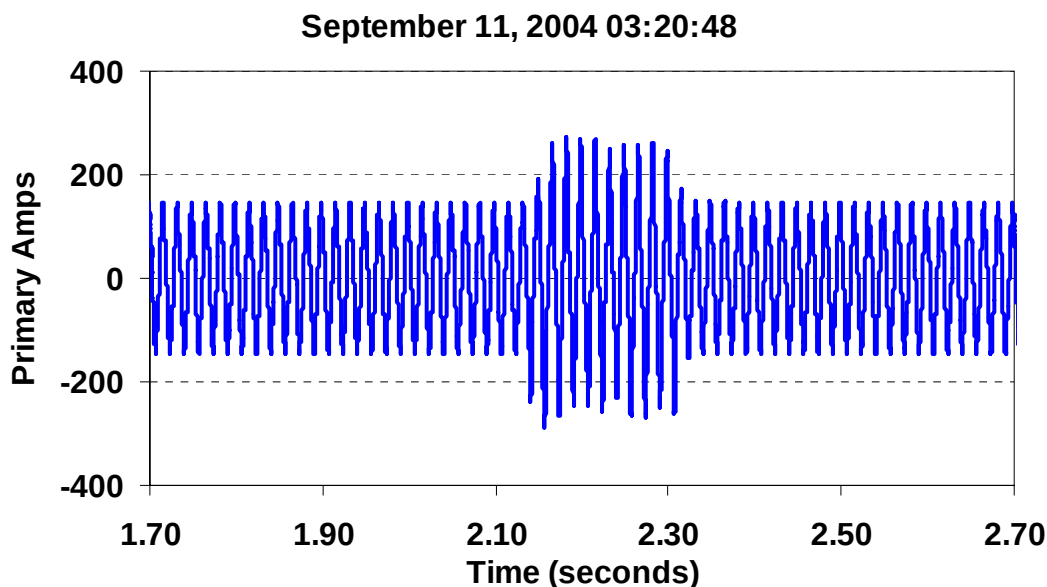


Figure 4-8
Early Episode of Repetitive, Intermittent Arcing

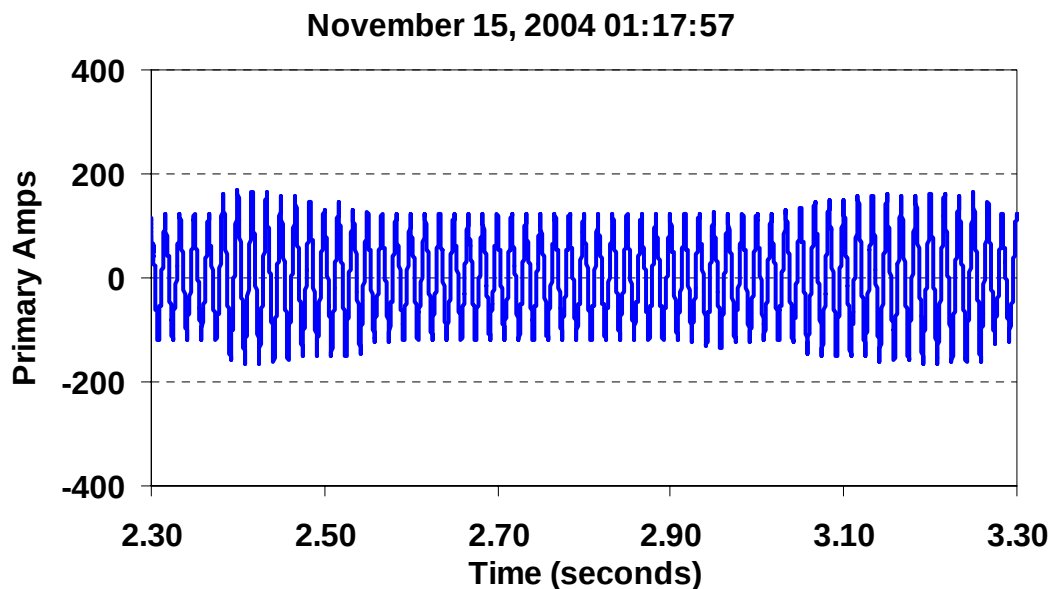


Figure 4-9
Second Episode of Repetitive, Intermittent Arcing, Two Months Later

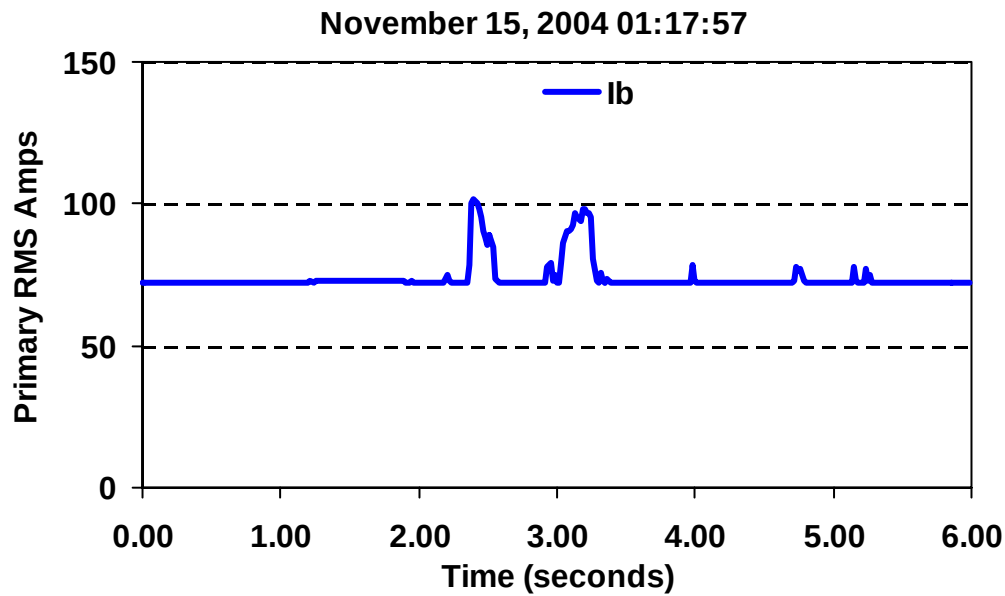


Figure 4-10
Second Episode of Repetitive, Intermittent Arcing, Two Months Later (RMS Current)

In the interim, the Field Unit recorded numerous episodes of the arcing signature. When Internet service was restored, the Master Station retrieved the backlog that the Field Unit had accumulated over the past two months. At this point, DFA data made it rather obvious that something was amiss. However, the DFA is a new type of technology that provides new types of data. As a result, the underlying problem was not immediately obvious from the data, and it took several weeks to identify the problem.

The utility had several residential customers who had experienced multiple outages during the time period in question. They received service from the same phase of the same circuit that was experiencing the repetitive arcing episodes. Each time these customers experienced an outage, they called the utility. When the utility arrived on the scene, however, they found no apparent fault. The 50 kVA CSP transformer at this location was tripped each time, but when personnel reset its breaker, full service was restored to the customers.

When DFA records became available in November, the engineer responsible for the DFA at this utility discussed the arcing episodes with operations personnel. This put them on alert that something was happening, although no one was sure exactly what it meant at the time. However, having been made aware that the DFA was indicating a problem on this circuit, when they next received a lights-out call from the customers that had the repetitive transformer trips, field personnel notified the utility engineer with access to the DFA. A check of DFA records revealed that the arcing episode of Figure 4-11 corresponded to the reported outage time, shortly after midnight on December 7.

These customers are served via direct-buried underground secondary cables that come from the CSP transformer to their meters. Based upon DFA records, personnel determined that the likely cause of the problem was in this underground service. They excavated the suspect cables and found significant deterioration of their insulation and corrosion of the conductors. Figure 4-13

shows one section of excavated cable. The two black cables are the “live” legs and the yellow is the neutral. The cables are so badly deteriorated and corroded that they do not appear capable of carrying load, but indeed they were continuing to do so, albeit with intermittent short circuits and trips of the CSP transformer. The utility found multiple locations on the cables with conditions similar to those shown.

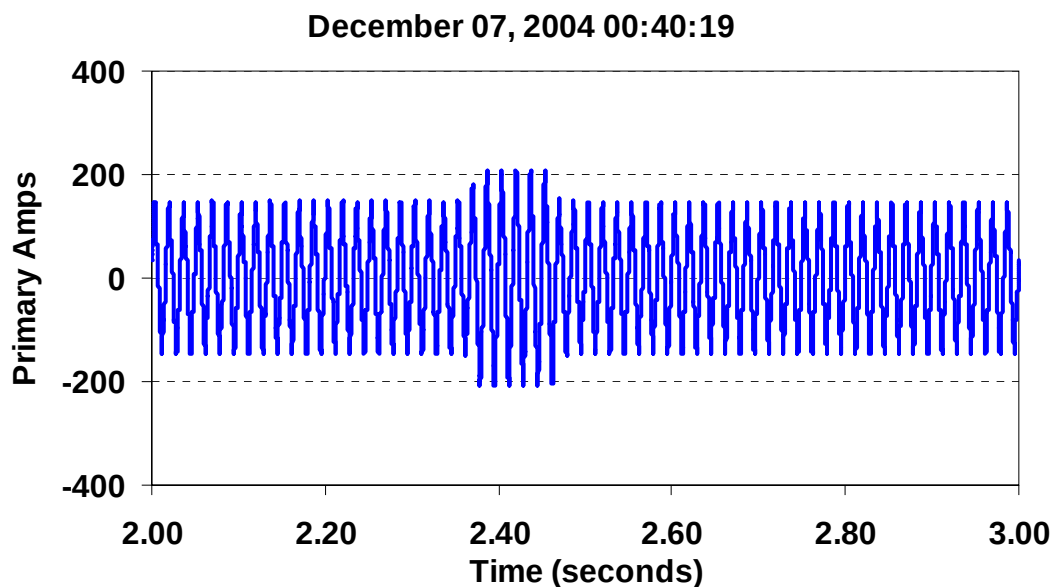


Figure 4-11
Final Episode of Repetitive, Intermittent Arcing (Three Months After First)

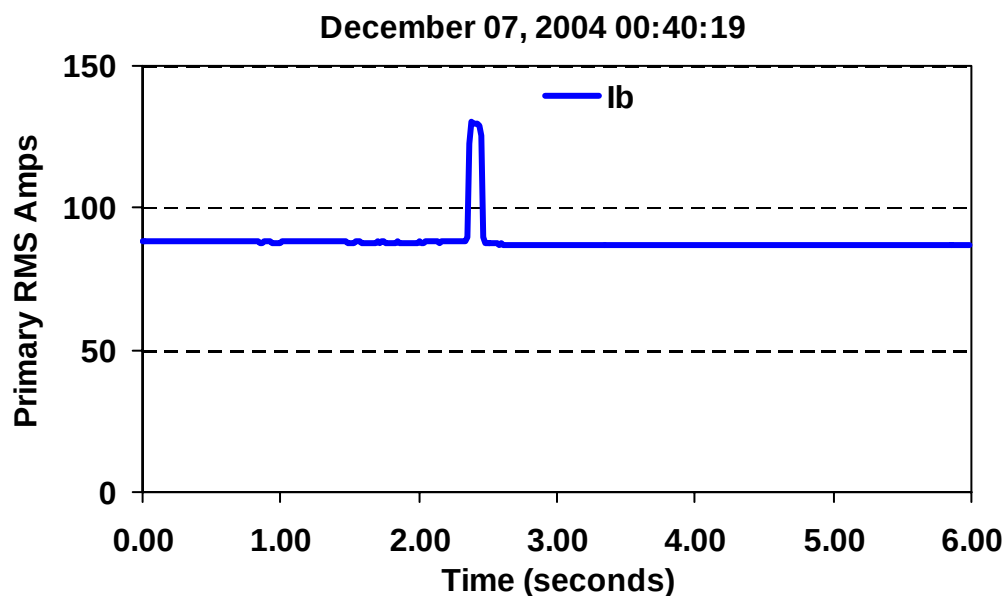


Figure 4-12
Final Episode of Repetitive, Intermittent Arcing (Three Months After First) (RMS Current)



Figure 4-13
Deteriorated and Corroded Cables Responsible for Intermittent Arcing and Outages

After this case was solved, Texas A&M asked the engineer responsible for the DFA project at this utility how he would use the information from the DFA in a future situation like this. His responses were as follows:

- “We are already using the information [from the DFA] to investigate the cause of the repetitive arcing. Phase identification is beneficial in that it reduces the number of phases that must be tracked when investigating or ‘riding’ a feeder to locate the problem. This is very beneficial on a radial overhead system. Tracking the times allows us to verify the report with other sources thereby validating the occurrence and justifying the need to determine the cause, (i.e., avoid potential outage while increasing customer satisfaction with performance).”
- “Action would have been taken sooner had we been a little more sure of what it was we were looking for. Narrowing down the possibilities of arcing allows us to more closely focus on what the problem might be. It’s much easier to look for the characteristics of tree contact than for a failing insulator or lightning arrestor. The DFA has already identified an area ... [location omitted for confidentiality] that is subject to rapid tree/vine growth and, as a result, the area is now scheduled for more timely and aggressive trimming. The inclusion of the DFA as a means of identifying possible problems and feeder outages has already been incorporated here! What we hope is the DFA will be an expandable problem solver not only able to help eliminate potential problems before they become unmanageable but a tool to help reduce costs by allowing us to put our maintenance money where it will do most good.”

Failing Switches

At 11:57 AM on March 16, 2004, a Field Unit began to register signals similar to the one shown in Figure 4-14. It recorded these signals nearly continuously for the next 42 minutes. The cause was a fused cutout that was beginning to fail.

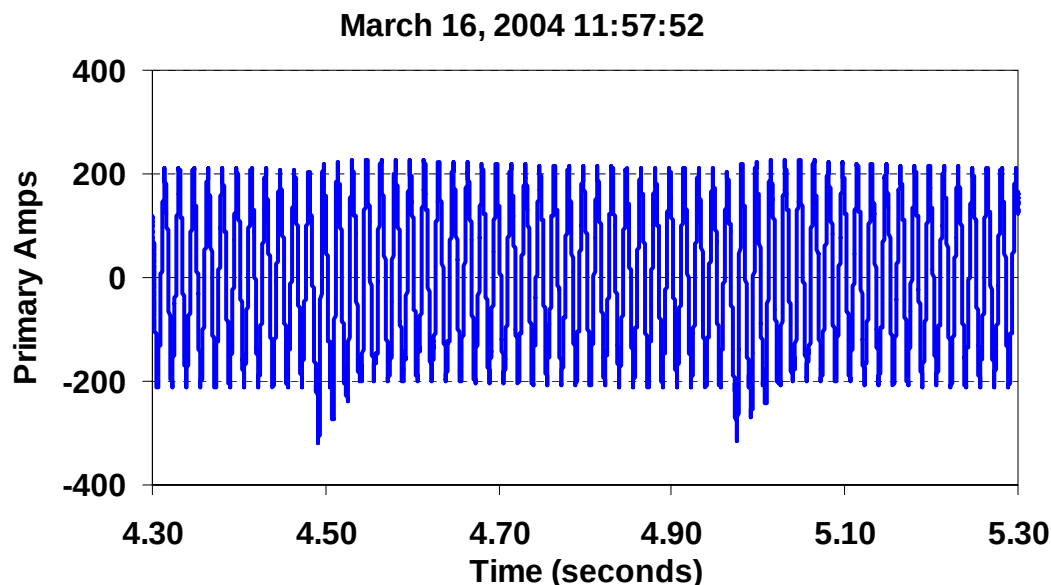


Figure 4-14
Measured Signals Produced by Failing Cutout

When a crew arrived at 12:39, the top of the pole on which the cutout was mounted was engulfed in flames. The crew manually tripped the substation breaker to isolate the fault. They switched out the affected section of line and restored service to the rest of the circuit. They then repaired the top of the pole, including replacement of the cutout, and restored full service at 2:29 PM.

This incident is of special interest, because it illustrates one of the inherent facets of a project involving field measurements. The engineer responsible for the DFA at this utility investigated the incident shortly after it happened, and the relevant data captures were labeled as being associated with a cutout failure that caused a poletop fire. However, it was not until approximately six months later that the TAMU research team identified what they believed to be a characteristic signal unique to failing switches, based upon data from another switch failure at another utility. After identifying this characteristic, they were able to review this and other “old” data captures that previously had not been fully characterized. From this review, they were able to identify four instances of apparent switch failures. They requested that the corresponding utilities perform additional reviews of their trouble records at the times of these incidents. In each identified case, they found that either a line switch or a cutout had failed. The point is that sometimes a “breakthrough” case is needed to identify a characteristic unique to a particular failure mode. When this occurs, the vast library that this project is creating allows review and validation of the findings, even if the relevant data captures were not recognized at the time they originally occurred.

Failing Service Transformer Tap

A Field Unit recorded a series of captures over a 1-1/2 hour period beginning at 22:24 on the evening of October 8, 2005. The utility had been experiencing significant rainfall for several days when this activity commenced.

Figure 4-15 illustrates the RMS current from the first such measurement. Variations in current are subtle, but the DFA was able to isolate and characterize them. The utility checked trouble reports and outage logs around the indicated time frame, but was unable to find anything that would explain the measurements.

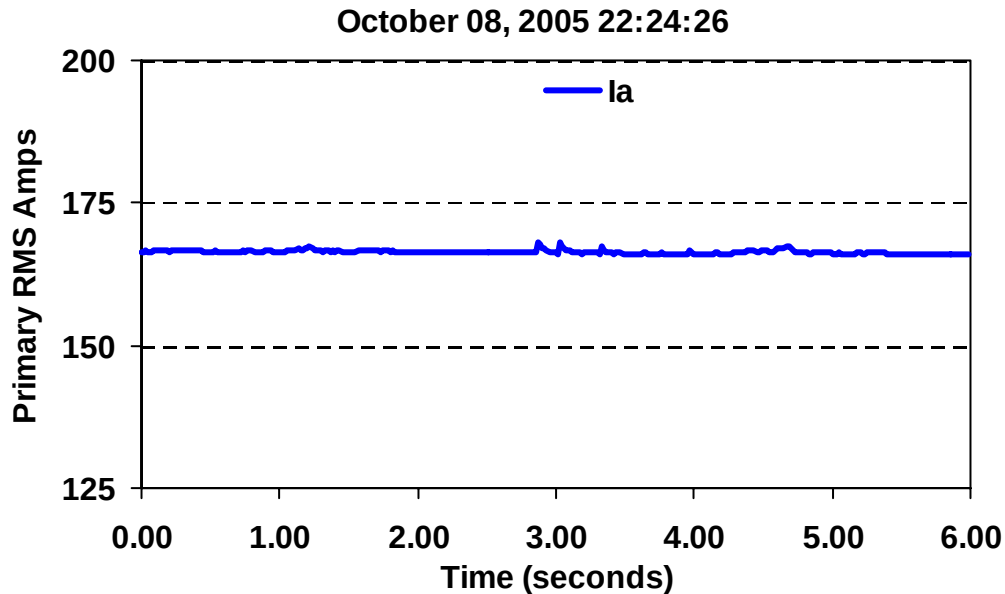


Figure 4-15
Initial Indication of Transformer Tap Failure

Several days later, at 02:01 on October 12, 2005, the DFA began recording similar captures on the same phase of the same circuit. Figure 4-16 illustrates the RMS current from the first capture on this second date. Figure 4-17 shows the corresponding current waveforms. The current shows slightly more activity than on the first date, but it still is quite small and difficult to discern or analyze.

For more than two hours, the DFA recorded this activity almost continuously. Shortly thereafter, customers reported an outage. When a line crew responded, they found burn marks around the bushings and other apparatus atop the service transformer that served these customers. Figure 4-18 shows a photograph of the transformer after it was removed and taken to a service yard. The circled area shows obvious burning of the lightning arrestor at the point at which the service tap connected it to the primary. Apparently, the connector was not tightened properly or it had a defect that caused it to fail. There also are signs of arcing on the primary bushing.

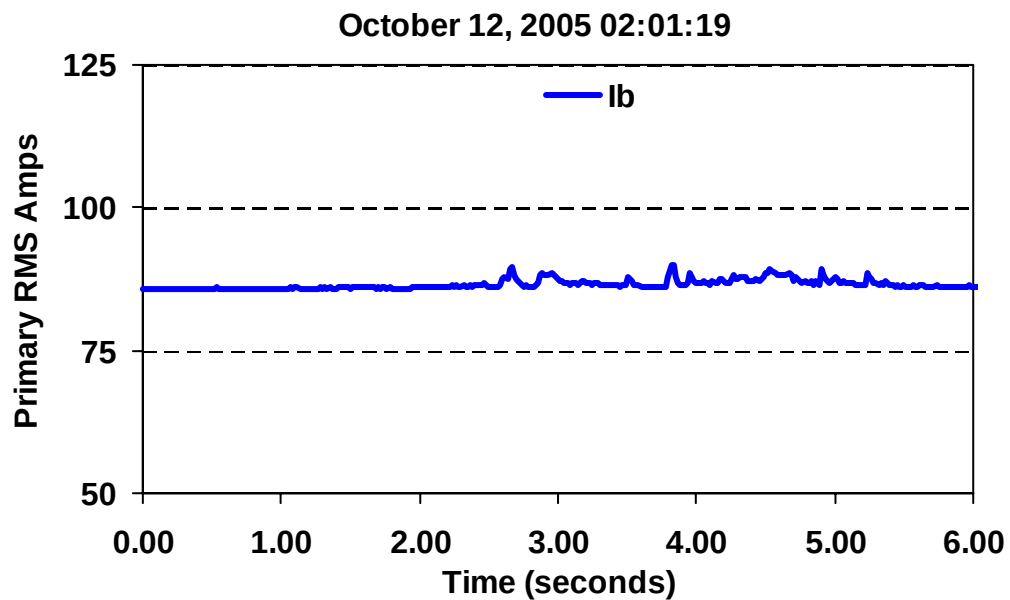


Figure 4-16
Continued Precursors to Transformer Tap Failure Days Later

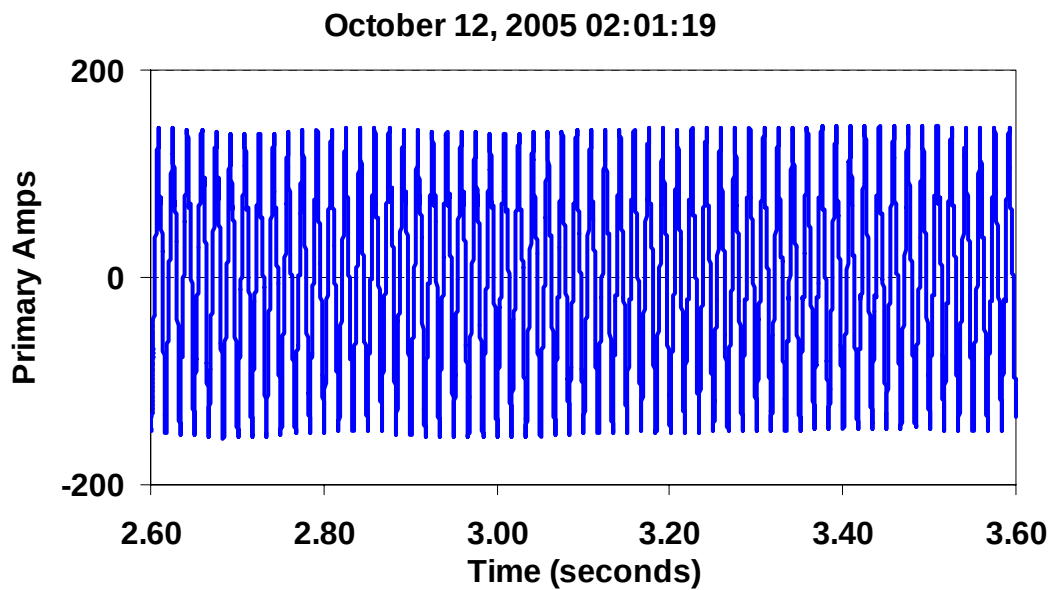


Figure 4-17
Continued Precursors to Transformer Tap Failure Days Later (Waveforms)



Figure 4-18
Transformer with Failed Tap

Substation Bus Capacitor Bushing Failure

In June 2005, a Field Unit began registering intermittent fluctuations in the phase-C voltage of several of the circuits it monitors. At this location, voltages are available on phases A and C, but not on B. The phase-C voltage showed the fluctuations, but the phase-A voltage did not. This unit monitors circuits on two busses. The voltage fluctuations were present on all circuits on one bus but not on any of the circuits on the other bus. Figure 4-19 shows the RMS voltage variations during one episode. There were many such episodes over multiple days.

The voltages for all of the affected circuits come from a common bus PT, so the utility engineer first checked the PT and the connections between it and the DFA for obvious problems. It was difficult to use voltage measurements at the PT terminals to determine whether the fluctuations actually were coming from the PT, because the fluctuations did not occur continuously and were generally unpredictable. However, the engineer did not find anything obviously wrong with the PT or with the wiring between it and the Field Unit, so he continued his investigation.

The engineer noted that the fluctuations occurred at various times of day, but many episodes seemed to cluster around 07:00 AM, the time at which a substation bus capacitor switches ON each day. He visually inspected the capacitor bank and found evidence of significant arcing on one of its phase-C bushings, as shown circled in Figure 4-20. Interestingly, the burn marks are on the capacitor's neutral bushing, not on its line bushing.

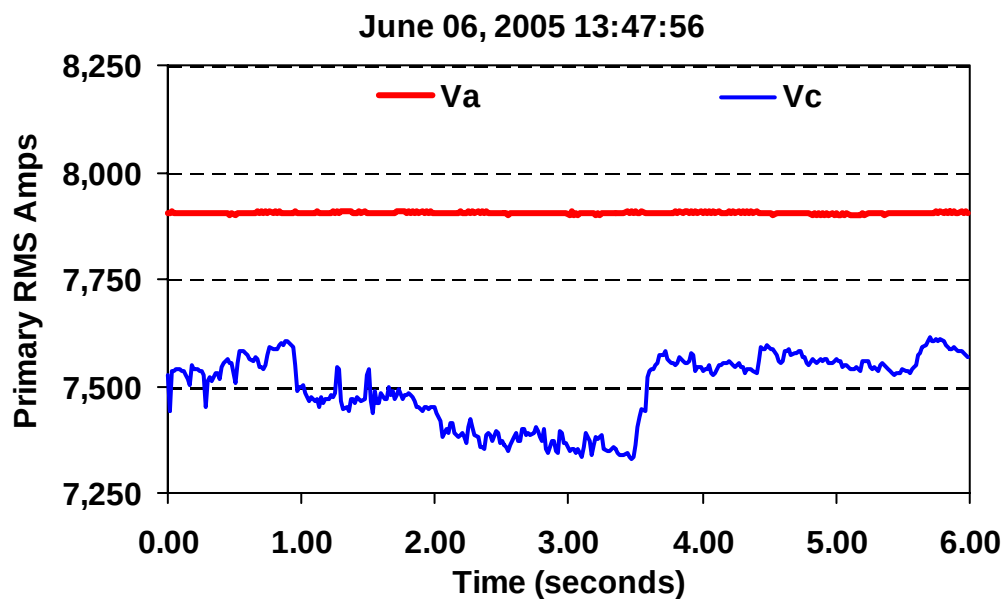


Figure 4-19
Bus Voltage Fluctuations from Failing Substation Bus Capacitor Bushing



Figure 4-20
Substation Bus Capacitor with Failing Bushing

The utility took the capacitor out of service temporarily, replaced the bad unit, and put the capacitor back in service. The voltage fluctuations ceased, confirming that the bad bushing had been the cause. It is reasonable to assume that if this condition had been allowed to persist, it would have worsened and eventually would have failed and caused a fault.

Short-Lived, High-Current Faults

It is natural to assume that, in general, a high-current fault (e.g., one with peak current in excess of 1,000 amperes) will not extinguish itself, but rather that it will persist until some outside force interrupts it. This does not mean that such a fault necessarily would result in a sustained outage, but that it would require at least momentary interruption, after which successful reclosing might be possible. Multiple measurements during this project have shown this assumption to be incorrect.

In May 2004, the research team noted the high-current event shown in Figure 4-21. The peak current during this fault, as measured at the substation, was approximately 2,400 amperes, and its duration was less than one cycle. Faults of this general magnitude and duration are fairly common, often having as their cause short circuits that clear small fuses on customer service transformers in response to, for example, animal contacts. However, in this case, the utility could find no record of any outage associated with this fault. In addition, examination of the captured data waveforms offered no evidence of a momentary interruption by a recloser. In other words, it appeared that the fault truly extinguished itself, even though this was contrary to the prior assumption that high-current events generally would not do so.

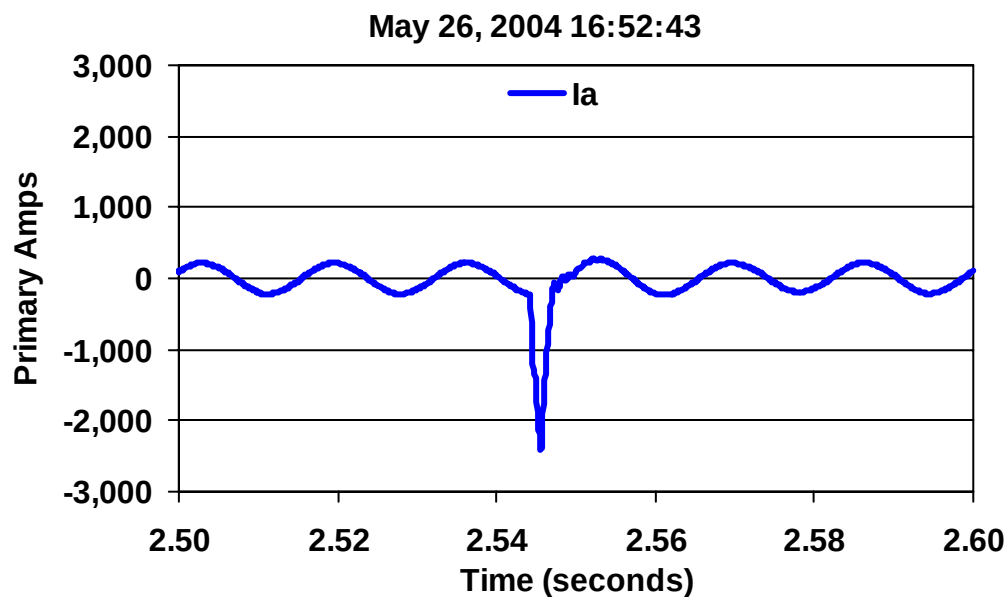


Figure 4-21
First Instance of High-Current, Short-Duration Fault

Figure 4-22 shows the current produced by a similar short-lived fault that occurred on the same circuit. The fault was very similar to the one that occurred days earlier, in that both occurred on the same phase, both had approximately the same peak magnitude, and both had approximately the same duration. In addition, neither caused an outage or even a momentary interruption.

After noting these occurrences, the research team started looking more closely for other instances of this type of behavior, both at this utility and at others. They were surprised to find that many of the utilities had significant numbers of short-lived, high-current faults for which there were no records of outages, and for which the data contained no evidence of any momentary interruption or reclosing.

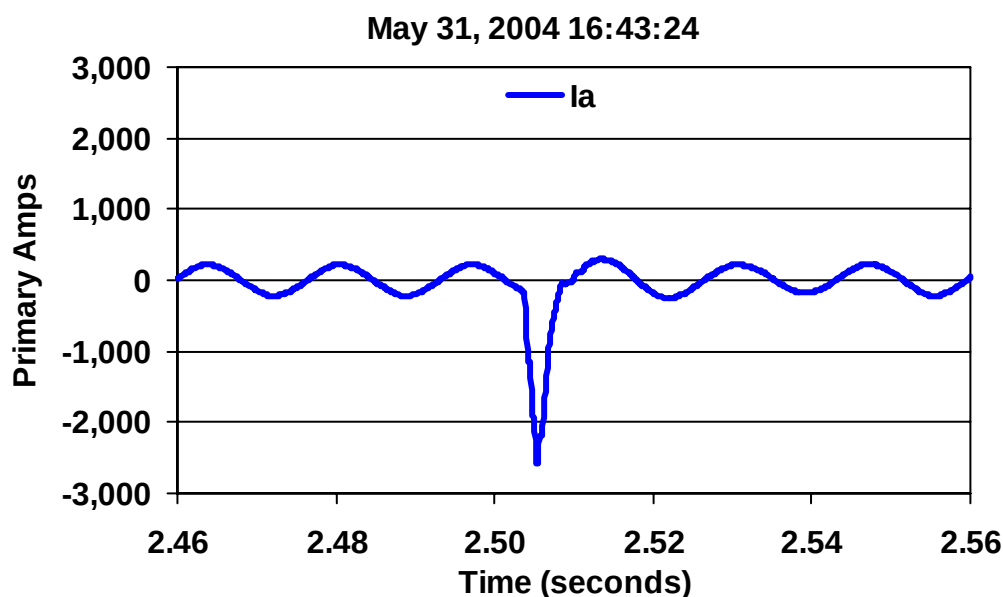


Figure 4-22
Second Instance of High-Current, Short-Duration Fault

The research team has explored and continues to explore possible explanations for these events. They also continue to monitor these types of events with special interest.

Deceptive Capacitor Fault

During the course of this project, Field Units have registered a significant number of capacitor failures of various varieties. Many involve blown fuses. Capacitor fuses can blow for several reasons. A high-current failure generally means either that the capacitor has developed an internal short circuit or that there is an external problem, perhaps a cracked bushing. Another mode of fuse operation is one in which the fuse simply opens, without any associated high-current event. This can mean that a long-term condition such as excessive harmonics has caused overheating and melting of the fuse, or it can mean that the capacitor has developed a partial internal failure that is causing it to draw more steady-state current than normal.

Figure 4-23 illustrates a high-current capacitor fuse operation on August 25, 2004. The utility confirmed that the fuse was open and dispatched a crew for repairs on September 1, 2004. The crew tested the capacitor using standard test procedures. The capacitor tested “good,” so the crew simply replaced the fuse, but replaced the old 50-amp fuse with a 60-amp fuse. When they energized the capacitor, the fuse held and the crew left it in operation.

This was odd, because it was the first instance of a Field Unit recording a high-current operation of a capacitor fuse that was not related to a permanent problem, such as a failed capacitor. Two days later, the plot thickened, when the same capacitor experienced another fuse-blowing short circuit, as shown in Figure 4-24. The only significant difference between the first and second episodes was that the second caused significantly higher fault current, possibly because the larger fuse size allowed it to conduct longer before clearing.

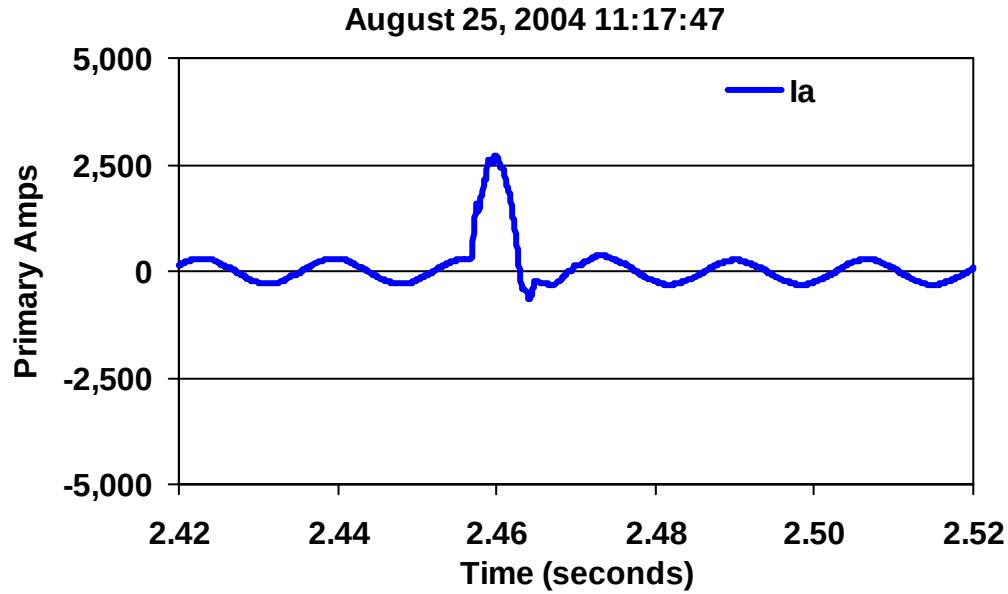


Figure 4-23
First Instance of Capacitor Fault

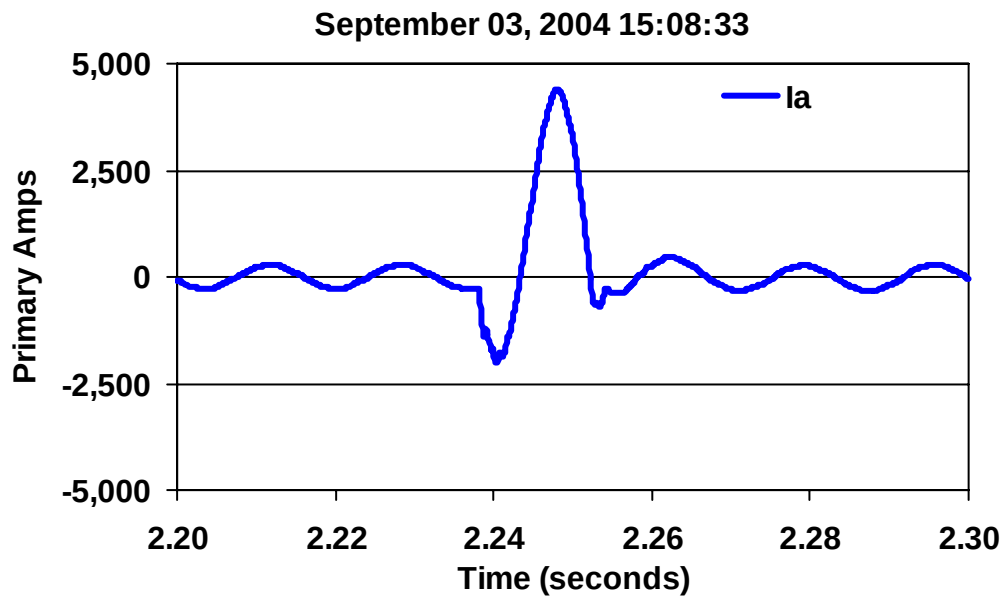


Figure 4-24
Second Instance of Fault of Same Capacitor

The utility confirmed the second fuse blowing shortly after it occurred, but did not effect a repair for two months. When the crew tested the capacitor, it again tested “good.” They placed it back in operation on November 10, 2004, this time with a 75-amp fuse. As of the writing of this report, the capacitor has continued to function with this larger fuse for nearly a year.

Of note, the second fault removed the capacitor from service a mere two days after the first fuse was replaced. Had the first blown fuse been found and replaced as part of normal annual maintenance, the second failure two days later likely would not have been discovered until crews performed maintenance again a year later. This would have left the capacitor out of service all year, despite the fact that normal annual maintenance had been performed.

Arcing on Secondary Overhead Customer Service Cable

A Field Unit measured a series of events over a period of approximately two weeks. The recorded waveforms gave very clear indications of low-current arcing. In addition, the similarities between the several recordings made it almost certain that all of the incidents had the same cause. The recorded waveforms also made it apparent that whatever was causing the arcing was not of sufficient magnitude or duration to operate conventional protection, except perhaps a very small fuse.

Figure 4-25 shows the phase current waveform recorded during one episode. Figure 4-26 shows the same time period and illustrates the high-frequency current measured, after being processed with a proprietary algorithm to remove background noise. Both figures include the phase voltage waveform as a reference.

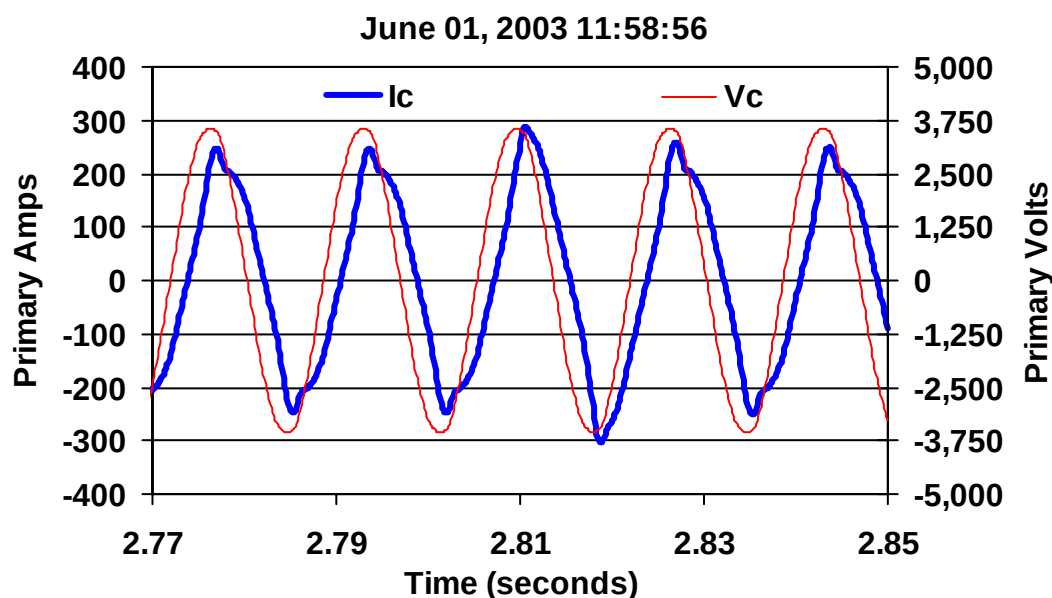


Figure 4-25
Arcing Measured on Secondary Service Cable

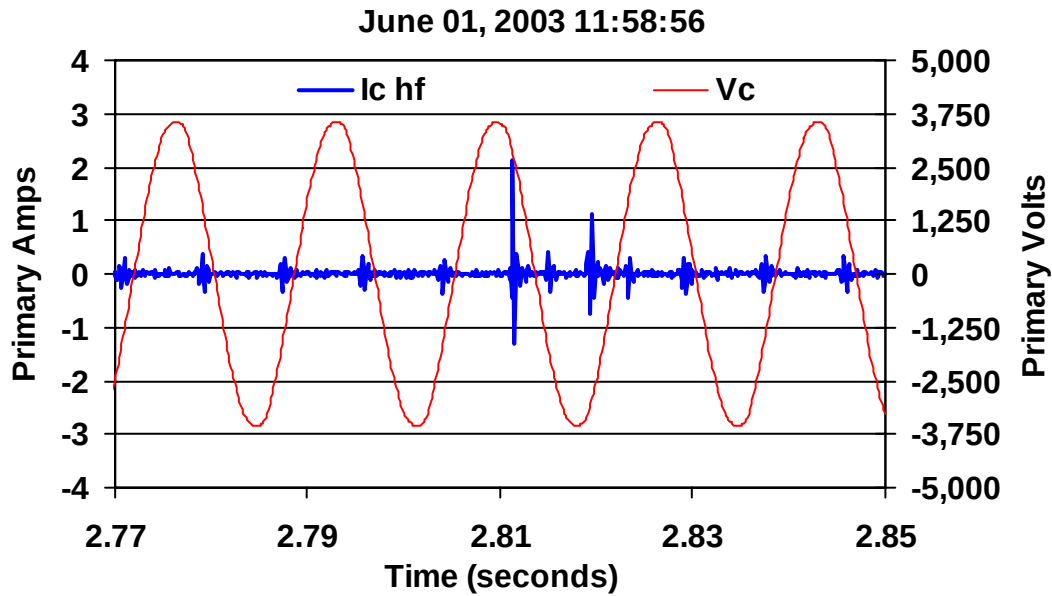


Figure 4-26
High-Frequency Current from Arcing on Secondary Service Cable

These figures illustrate but one measured episode of the event. The Field Unit measured similar episodes at each of the following times:

05/31/2003	03:00:48
	03:56:28
06/01/2003	11:58:56
	12:08:01
06/04/2003	05:00:43
06/09/2003	22:12:27
06/10/2003	13:33:04
06/14/2003	21:43:59
	21:44:06
	21:44:12
	21:44:22
	21:44:50 (fuse operation)
	22:14:36 (service restoration)

The last two episodes represent the time at which the arc current finally blew a fuse, interrupting 27 customers, and the time at which service was restored.

This event is of interest in that it represents recognition of a failure that developed over a period of two weeks, thereby providing the basis for notifying the utility of the problem while in its incipient stage.

Episodes of multiple voltage steps were recorded at each of the following times:

4-29

This list shows that this sequence of multiple steps down followed by multiple steps back up was measured intermittently over a period of approximately two months. Most of the sequences occurred in pairs, i.e., a sequence of steps down followed less than a minute later by a sequence of steps back up.

Figure 4-27 illustrates a special case in this sequence of events. At 05:56 on March 27, 2003, the bus voltage stepped down, similar to the way it had done many times before, except that the number of steps was greater than usual. In this episode, the bus voltage stepped down nine times over a period of sixteen seconds. However, unlike the previous episodes of downward steps, this time there was not a sequence of upward steps shortly thereafter. The next measured voltage steps occurred 39 minutes later, at 06:35, when the voltage took ten upward steps.

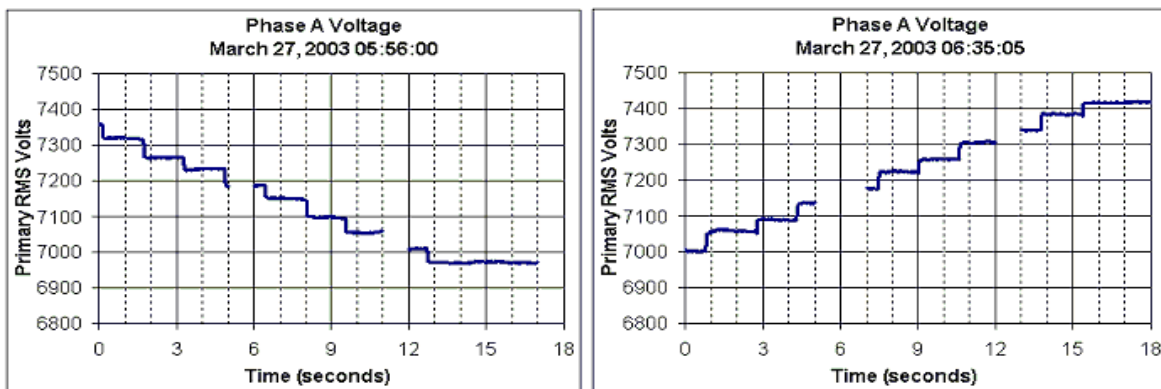


Figure 4-27
Load Tap Changer Stepping Excessively

Around 06:00 on this date, a customer reported a low-voltage condition. The utility dispatched a trouble man to investigate. He found that the circuit breaker on the LTC controller motor was tripped. Not knowing why the breaker had tripped, he reset it and the LTC stepped back up to a normal value at 06:35.

The customer call provided the utility with an indication that a problem existed, but field personnel did not have the information cited above, so they had limited means to diagnose the problem's underlying cause. When the cited information was made available to them, personnel investigated the most obvious cause of the problem: that the LTC controller was sticking. They found that the LTC controller's manufacturer had issued a service bulletin regarding the need to install an auxiliary component in the controller to keep its mechanism from sticking and causing this type of improper operation. Following the service bulletin's recommendation cured the problem.

This case illustrated the ability of DFA technology to provide information critical to the efficient diagnosis of malfunctioning equipment on distribution circuits.

Inoperative Capacitor Bank Switch

For decades, utility companies have placed fixed and switched capacitor banks on their circuits to provide voltage and VAR support. Switched banks have control algorithms that use a variety of parameters, including time-of-day, temperature, voltage, etc, to determine when the capacitor should be switched OFF and ON. Although there are some exceptions, most switched capacitor banks are operated on a balanced, three-phase basis. In other words, most banks are configured with three equally sized phase units and their controllers switch the three phases OFF and ON at the same time.

There are multiple ways in which capacitor banks fail to operate properly. One of the most common failure modes is the blowing of a single-phase fuse, often because the capacitor has developed an internal short circuit. Another is the failure of a switch to open or close properly. The result of either of these failure modes is the same: the loss of voltage and VAR support on the affected phase. In addition, single- or two-phase operations cause unbalanced voltages, elevated neutral currents, and other operational problems.

Field Units regularly record capacitors switching OFF and ON. Many of the monitored circuits record multiple such operations each day. The following series of figures illustrates two such captures, the first representing a capacitor switching ON normally and the second representing the same bank switching ON abnormally.

Figure 4-28 shows the VARs recorded when a timed capacitor bank switched ON just before 05:00 on June 28, 2003. The VARs on each phase decrease precipitously by approximately 400 kVARs per phase. The three phases do not switch at exactly the same instant, but they all switch within a second or so of one another, so the operation is considered normal.

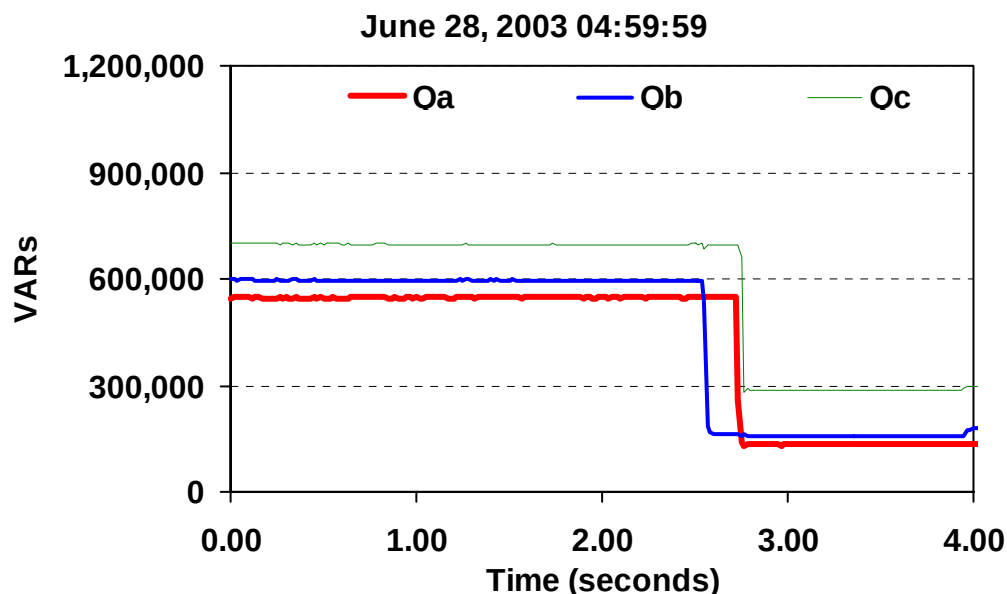


Figure 4-28
VARs Recorded when Balanced Capacitor Bank Switched ON Correctly

Figure 4-29 illustrates the same capacitor bank switching on three days later. As in the previous instance, VAR flows drop by approximately 400 kVARs per phase. However, in this case, the VARs on only two phases change, while the third does not. Project personnel noted this change in behavior beginning June 29, 2003, and reported it to utility field personnel the next day. A line crew visited a 1,200 kVAR capacitor bank on the affected circuit and found that one of the oil switches responsible for switching the capacitor bank OFF and ON was not functioning. They replaced the switch within a week of its first failure to operate, thereby restoring proper operation.

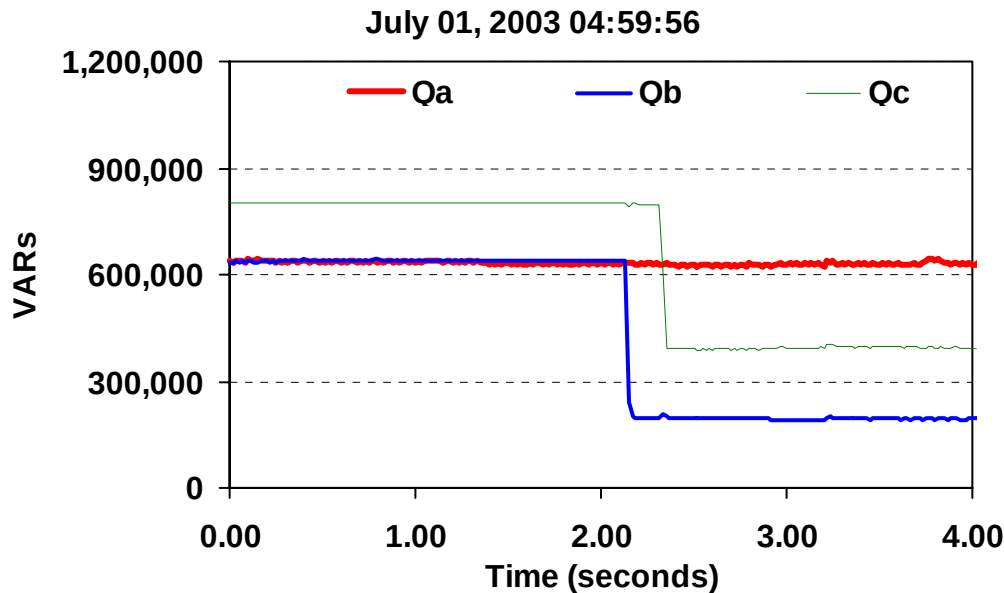


Figure 4-29
VARs Recorded when Unbalanced Capacitor Bank Switched ON Incorrectly

Figure 4-30 illustrates the RMS currents measured coincident with the VAR flows shown in Figure 4-29. Of note, the neutral current increased from a level of 18 amps before the capacitor bank switched ON to a level of 38 amps after the unbalanced switching occurred. Also of note, phase A did not enjoy the reduction in current that the other two phases experienced.

This case demonstrates the ability to recognize common capacitor bank problems very soon after they develop. Without such monitoring, the capacitor bank would have switched into this unbalanced condition daily until the utility company's next inspection cycle. Utility participants in this project indicate that most perform routine inspections and testing of capacitor banks at specific intervals, most typically once per year. Therefore, an unbalanced capacitor condition such as this statistically would remain undetected for an average of six months. For this period of time, the utility company and its customers would not enjoy the voltage and VAR support for which the utility originally purchased and installed the capacitor bank. Further, for this period of time, the unbalanced condition would cause some degree of voltage imbalance and increased neutral current.

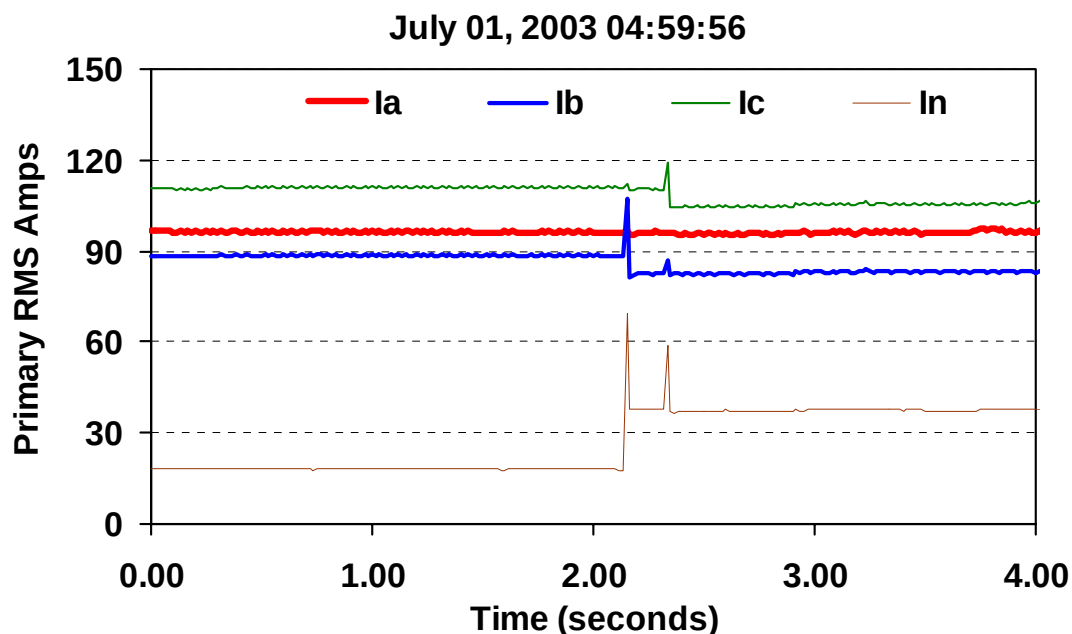


Figure 4-30
RMS Amps Recorded when Unbalanced Capacitor Bank Switched ON Incorrectly

Between 10 and 15 percent of the circuits monitored by Field Units exhibited at least one capacitor-related problem during the first few months of monitoring. Some of the problems existed when Field Units first started monitoring particular circuits, indicating that the problems had existed for unknown periods of time prior to the installations.

Temporarily Stuck Capacitor Bank Switch

This case study is interesting because it represents an intermittent condition that affects operational efficiency. Figure 4-31 illustrates the three-phase VAR flows on one of the monitored circuits for the period March 30–April 17, 2003. For the first two days of the illustrated interval, and again for the last two days of the interval, the three-phase VAR flows are fairly well balanced and they tend to track one another. However, for the period April 2–14, there is an obvious deviation from this well-behaved pattern. Specifically, on April 2, a circuit capacitor switched ON. Later in the day, it switched back OFF. When it switched OFF, however, one phase remained energized, creating a VAR imbalance of approximately 400 kVAR between phases. The bank's controller uses temperature as a control parameter and temperatures in the area were moderate in April, so the bank did not switch ON again until April 14, 2003. When it did, it restored the relative balance between the three-phase VAR flows. Later that day, the capacitor bank switched OFF again, and this time all three phases switched OFF properly.

This case is interesting because of the intermittent nature of the problem. In the previous case, once the problem developed, the failed switch consistently failed to operate. Therefore, although the next inspection and testing cycle might be months away, once it arrived it would identify the problem so that it could be repaired. The present case, however, presents a less certain outcome. If a switch only operates incorrectly some of the time, what will it do when a crew performing

routine testing operates it? It might fail, in which case the crew can fix it or replace it. On the other hand, it might operate correctly during testing, only to fail again the next time it is called upon to perform its normal function. In such a scenario, its operation likely will be intermittent until the next inspection and testing cycle, often a year later.

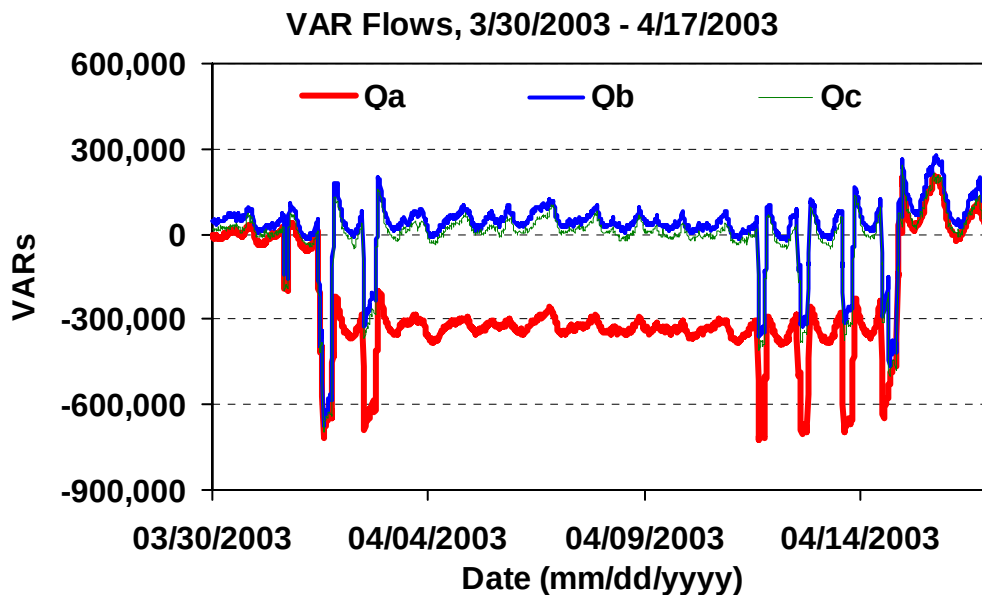


Figure 4-31
VAR Flows Caused by Intermittently Sticking Switch

Substation Voltage Anomaly

After more than a year of monitoring, a Field Unit suddenly began to record repetitive episodes of an unexplained voltage anomaly. Figure 4-32 illustrates one such episode. In this and other episodes, the anomaly exhibits the following characteristics:

- The RMS voltage on phase B dips temporarily, with the maximum deviation from steady state being about -3 percent.
- The RMS voltage on phase A rises temporarily, with the maximum deviation from steady state being about +2 percent.
- The temporary rise in RMS voltage on phase A is an inverted mirror image of the dip on phase B.
- The RMS voltage on phase C also rises temporarily, with a shape similar to that of the RMS voltage on phase A, but the maximum deviation is much smaller, rising a maximum of about +0.2 percent from steady state.
- There is an initial dip/rise period that lasts approximately 150 milliseconds, followed by another period of about 250 milliseconds during which the dip/rise has a magnitude a little less than half the size of the first.

- Following the 400-millisecond period described above, the three voltages return to near their initial values, but not exactly. The steady-state RMS voltage on phase B remains about 1/3 of one percent lower than its initial value, the steady-state RMS voltage on phase A remains less than 1/5 of one percent higher than its initial value, and the steady-state RMS voltage on phase C remains less than 1/10 of one percent higher than its initial value.

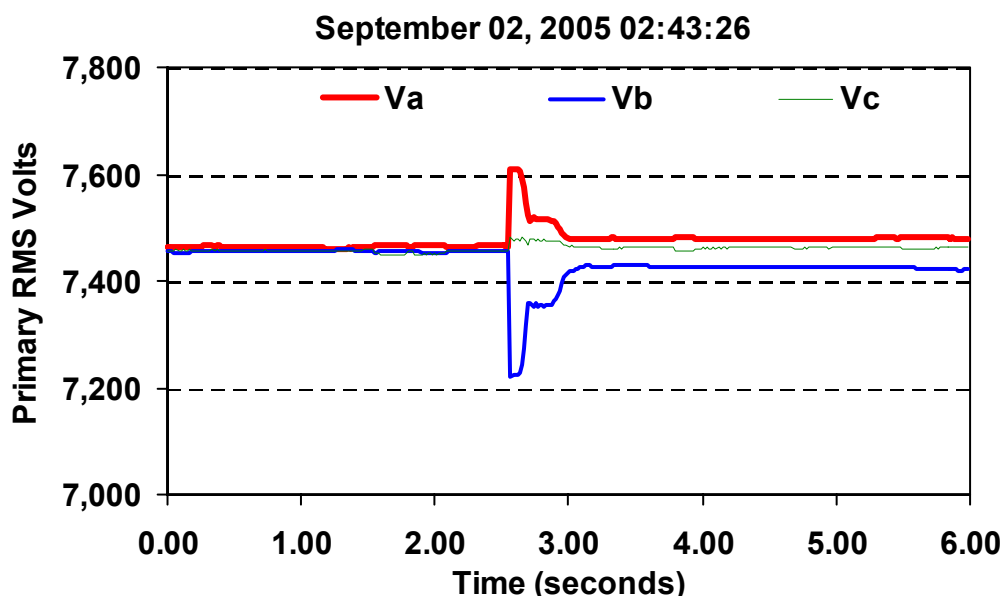


Figure 4-32
One Instance of Repetitive Bus Voltage Anomaly

Since it first began on April 4, 2005, this anomaly has occurred many times. Figure 4-33 illustrates the number of occurrences per day for the first several weeks. Through October 2005, it has occurred several thousand times.

There is no clearly discernible pattern as to the frequency or timing. The anomaly has occurred a dozen or so times per day, on average, but there is no consistent increase or decrease in frequency. Also, there is no particular time of day at which it occurs. It can occur any day of the week and at any time of day. In general, the episodes are unevenly distributed in time and tend to come in clusters. For example, there may be several episodes per hour for a period of several hours. Then, there may be no episodes for the next several hours. On occasion, an entire day passes without a single episode.

As of the writing of this report, the cause of the anomalies has not been determined, but the utility and Texas A&M have conducted considerable analysis. Discussion of the analysis requires knowledge of the substation topology, which is shown in Figure 4-34. A single transmission line feeds two substation transformers, each having a load tap changer (LTC) on its high-voltage winding. There are two circuits fed by the secondary bus of each of these transformers. The DFA monitors the currents and voltages of all four of these circuits. It monitors the currents provided by the current transformers (CTs) for each circuit. Each bus supplies two of the circuits, and the voltage inputs to the DFA come from the bus potential transformers (PTs) (i.e., Circuits A-1 and A-2 receive their voltage inputs from the bus PTs for Bus A and Circuits B-1 and B-2 receive their voltage inputs from the bus PTs for Bus B). The two busses normally are not connected to one another.

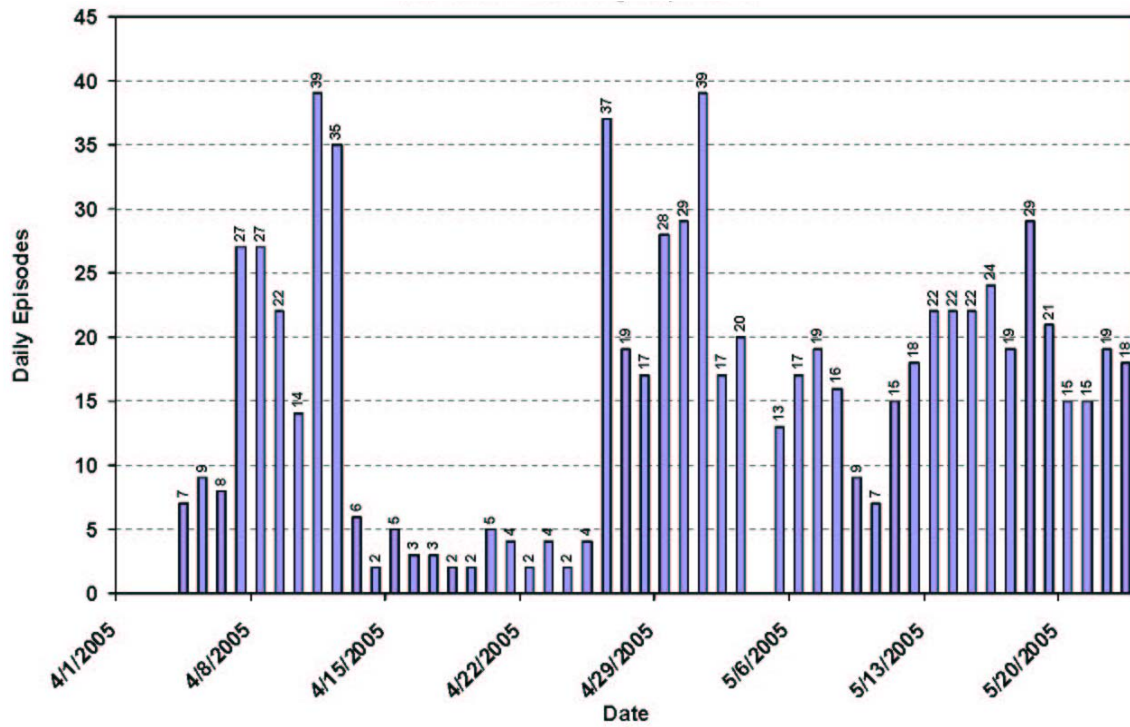


Figure 4-33
Histogram of Daily Occurrences of Repetitive Bus Voltage Anomaly

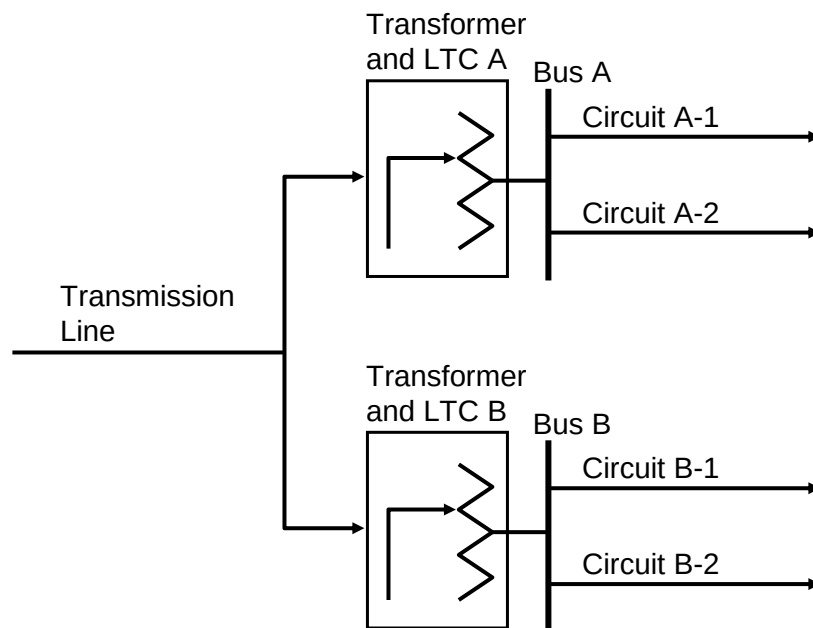


Figure 4-34
One-line Diagram of Substation with Repetitive Bus Voltage Anomaly

When the voltage anomalies occur, the DFA modules for Circuits B-1 and B-2 see and record them, but those for Circuits A-1 and A-2 do not. The most common cause of bus voltage perturbations on a single bus is a large load coming ON or other some other significant activity out on one of the circuits that the bus feeds. During the subject anomalies, however, there is no appreciable current change on either B-1 or B-2, so that is not the cause here. Because this bus does not serve any other circuits, this logically suggests that the cause is upstream of Bus B.

Faults on the transmission system often cause bus voltage perturbations. In the current case, the transmission line that serves Transformer B also serves Transformer A. Therefore, any activity on the transmission line should cause voltage activity on Bus A similar to that on Bus B, but the circuits on Bus A do not exhibit such activity.

The above discussion and analysis indicate that the most likely source of the anomalies is somewhere in Transformer B or its LTC. The utility company is scheduling inspection and testing of these substation components, but at the time of this writing, this work had not been done, so results cannot be provided here.

5

COMMERCIALIZATION STRATEGY

Commercialization and Continued Research and Development

DFA technology has demonstrated significant capability to document and diagnose problems and developing problems. Multiple utility participants have expressed their desire to take advantage of this technology by having commercial products brought to market. At the same time, all parties involved recognize that significant additional capabilities remain to be discovered and developed.

EPRI and Texas A&M seek to do both, making current DFA technology commercially available while continuing to refine the current technology and to develop new synergistic capabilities. The following sections outline user requirements, the pros and cons of traditional commercialization models, and the commercialization plan that is being pursued.

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.

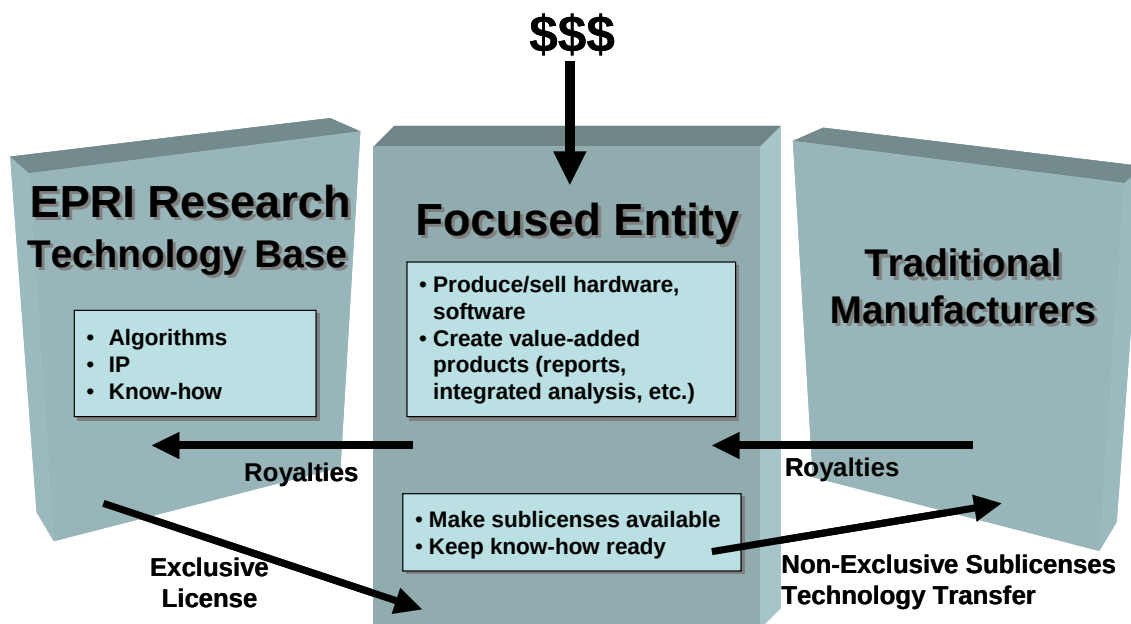


Figure 5-1
Commercialization Model for DFA Technology

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.

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

At the writing of this report, EPRI had entered into negotiations with a business entity that wishes to commercialize DFA technology according to the model discussed above. This entity has a successful track record in commercialization, having successfully commercialized the results of EPRI-sponsored research in the past. It is believed that the negotiations will be successful and will result in a license in the near future.

6

PRESENT STATUS AND FUTURE WORK

DFA Prototypes have been designed, constructed, and installed in electric power utility distribution substations. They have collected approximately 1,500 circuit-months of data from numerous utility companies with diverse operating conditions and philosophies. Over this period of time, they have collected thousands of high-fidelity waveform capture files. The vast majority of these have represented normal system events such as capacitors switching, motors starting, etc. This has been by design. The characteristics of most events of interest are, by definition, not known before they have been recorded and personnel have had an opportunity to analyze and characterize them. Therefore, collection of a large number of normal events and even “non events” has been necessary to minimize the likelihood of missing the infrequent, but very important, events of real interest.

The library of recorded events includes a significant number of abnormal system events and this library continues to grow with the passage of additional monitoring time. Many of these events have been diagnosed and documented by the utility companies, providing the basis for Texas A&M’s research team to develop and test algorithms for classifying them.

The library of captured data contains several instances of data captures that obviously represent abnormal system operations, but for which no clear explanation has been found to date. During the project, there have been instances in which these types of events have accumulated in the library, undiagnosed, until a particular utility “gets lucky” and finds the cause of one of these “breakthrough” events. Once that happens, researchers can go back to the “old” events and recognize similar characteristics in them, thereby diagnosing them long after their original collection, and enabling speedy recognition of similar events in the future. Texas A&M believes that other “breakthrough” events will continue to occur, allowing an ever-increasing number of these initially unrecognized data captures to be identified.

Texas A&M personnel have developed methods for classifying many of the captured events. Participating utility companies currently are seeing benefits from this, in that the results of these automatic classifications are being propagated to them automatically, on a daily basis, reducing their burden when manually classifying the events on their circuits, and drawing their attention to some of the events of particular interest.

Participating utility companies believe that DFA technology, in its current form, has the capability to benefit their operations. They also realize that the presence of an advanced system and platform like the DFA provides the vehicle for the discovery and development of considerable additional capability. EPRI is negotiating a license to make the current technology commercially available on a widespread, multi-source basis. At the same time, EPRI will continue to conduct research to develop additional capabilities, so that this exciting technology does not suffer the fate of others, in which advancement of the technology stops when commercialization begins.

In addition to enabling the discovery of fault anticipation functions, it has become clear that the network of advanced data collection platforms, installed under this project in a wide variety of locations across the continental United States and Canada, can be the basis for other, related areas of work in the future. It is likely that continued monitoring will suggest additional areas of exploration.

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