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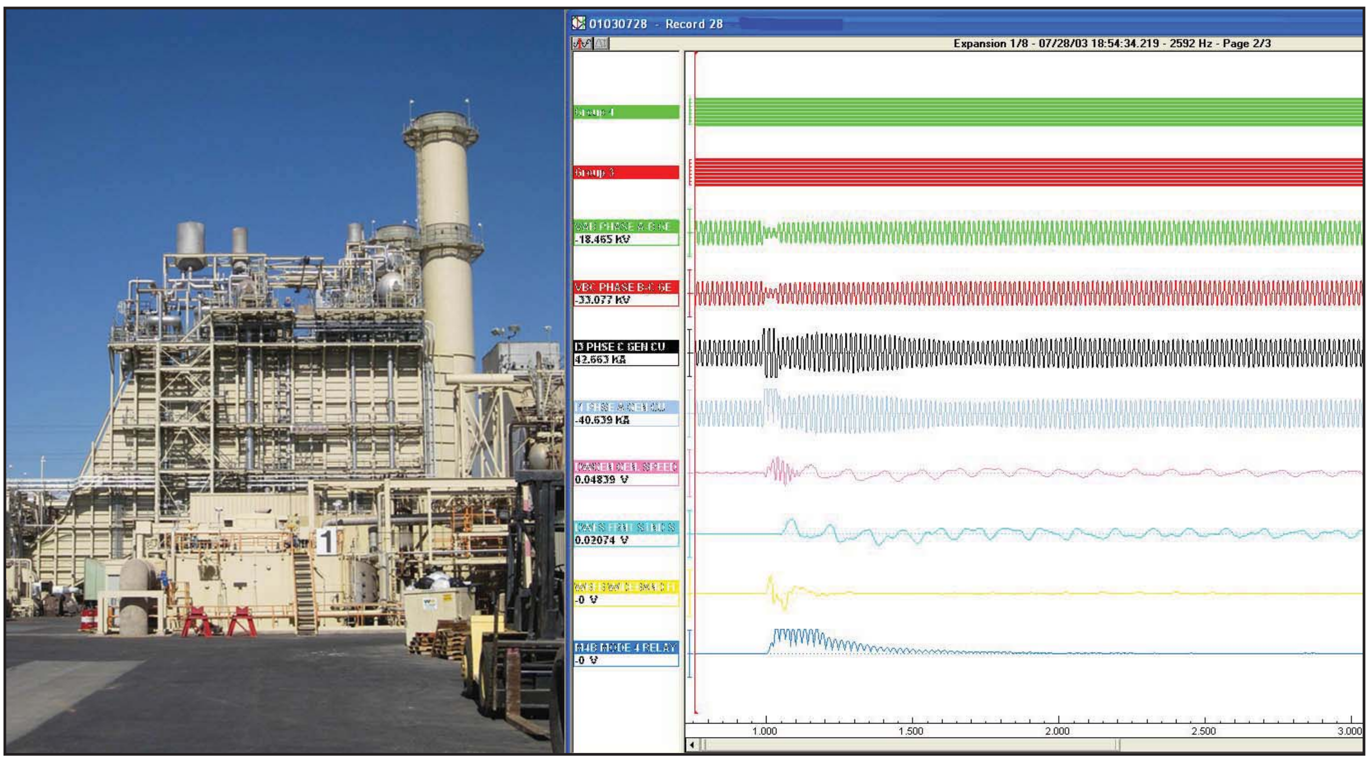
Digital Fault Recorders in Power Plant Applications



Digital Fault Recorders in Power Plant Applications

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PRODUCT DESCRIPTION

This report educates power plant operators on the use of information captured by digital fault recorders (DFRs) in power plant applications.

Background

Since their introduction in the 1980s, digital fault recorders have had a significant role in monitoring the bulk electric power system. As digital monitoring technology continues to evolve, DFR capabilities are being incorporated in devices that have historically performed other functions. By eliminating the need for dedicated monitoring equipment and contributing to a reduction of manpower, these new applications can provide significant cost advantages while helping power plant personnel improve their abilities to identify and diagnose power plant problems.

Objectives

- To provide practical guidance in installing, monitoring, and maintaining digital fault recorders in power plant environments.
- To promote new applications for data captured by DFRs that benefit power producers and electric utilities.

Approach

The project team addresses general capabilities and uses of data captured with fault recording technology to illustrate different approaches for obtaining and applying the technology. While the team discusses different types of technology, their primary focus is on conventional standalone fault recorders; principles and processes the team highlights can be applied to different digital fault recording and disturbance monitoring technologies. The team also presents case studies of how to use fault recorder data in unique ways with the goal of promoting new applications.

Results

The report provides a brief background on the evolution of digital fault recorder technology and a discussion of the different factors involved when installing DFR. In addition to the benefits gained from monitoring with DFRs, regulatory requirements are discussed in terms of the justification for installing monitoring systems. Existing and proposed industry and North American Electric Reliability Corporation (NERC) standards commonly used with DFR captured records are outlined. Data access and interpretation also are covered. Included in the report are case studies highlighting the benefits of monitoring power plants using DFRs.

EPRI Perspective

Generator owners and operators who install dedicated standalone digital fault recorders have the capability to monitor and maintain their plants at a level not available to those who don't have the monitoring capability. As generator operators and owners learn how to make best use of the data available to them, increased operating efficiencies will be realized and improved plant operations will result.

Keywords

Fault recorder
Digital recorder
Transients
Plant monitoring

ABSTRACT

Digital fault recorders (DFRs) have had a significant role in monitoring the bulk electric power system since the 1980s, and evolving DFR capabilities are being incorporated in devices that have historically performed other functions. By eliminating the need for dedicated monitoring equipment and contributing to a reduction in manpower, these new applications can provide significant cost advantages while helping power plant personnel improve their abilities to identify and diagnose power plant problems and comply with some North American Electric Reliability Corporation (NERC) standards. This report provides practical guidance in installing, monitoring, and maintaining digital fault recorders in power plant environments and promotes new and unique applications for data captured by DFRs through documented case studies.

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INTRODUCTION

Background

Cost effective monitoring of the electric power system has long been a sought after goal for electric utilities. While electric power generation, transmission, and distribution is by requirement analog in nature, the digital revolution has had significant impact on the analog world that electricity providers live in. Digital technology has enabled many new capabilities that allow accurate monitoring of the analog electrical system and rapid transmission of these quantities for fast dissemination and interpretation of information. Digital Fault Recorders (DFRs) evolved in the 1980s and were quickly adopted as a significant tool in monitoring the bulk electric power system. Despite this quick and early adoption of DFR technology by the electric utility industry, the technology has primarily been applied to utility transmission systems in monitoring key substation and transmission lines. Other applications of the technology have seen use but not on as wide a scale as seen in the transmission business. In particular, the application of fault recorders in power plants for monitoring of generators is practiced by some utilities but it is not as widely implemented as transmission substation applications. Utilities that apply DFRs to generators for monitoring have seen that digital monitoring of generators can have a significant benefit in the form of improved availability, rapid restoration of generation following an outage, identification of developing problems, and post event analysis following major faults or generator outages.

As digital monitoring technology continues to evolve, digital fault recording capabilities are being incorporated in devices that have historically performed other functions. The expansion of the technology into digital protective relays has spread the coverage of fault recording to many more levels not previously covered by conventional fault recorders. The need for generator fault monitoring is evidenced by the quick adoption of digital fault recording technology to digital multi-function generator protective relays. As generator voltage regulators and exciter controls have gone digital, fault recording capabilities have been incorporated in the new digital devices for the purpose of improving the visibility of what is happening with the generator excitation system. As previously unavailable data has become available to power plant operators, new uses for the information have been developed and have been put to use for monitoring and decision making. These new applications can have significant cost advantages in the form of eliminating the need for dedicated monitoring equipment and a reduction of manpower.

Generator owners and operators are now in a position where they may possess digital fault recording capability without realizing they have it. Those who install dedicated stand alone digital fault recorders have the capability to monitor and maintain their plants at a level not available to those who don't have the monitoring capability. As generator operators and owners better learn how to make use of the data available to them, increased operating efficiencies will be realized and improved plant operations will result.

Objectives of This Project

The primary objective of this project is to provide practical guidance in the installation, monitoring, and maintenance of digital fault recorders in power plant environments. In addition, the use of the information provided by digital fault recorders is addressed for the purpose of helping power plant personnel improve their abilities of identifying and diagnosing power plant problems, educate power plant operators on what data is available, how to use the data, and inspire new applications. Case studies of how to use fault recorder data in unique ways provide insights on not only what has been done to date to improve plant performance and monitoring capabilities, but will hopefully promote thoughtful new applications of analyzing data for the benefit of the power producer and electric utilities.

As with all progress, rapid continuous advances in technology create an ever changing and elusive target when trying to describe the "state of the art". No attempt is made here to characterize what constitutes the most recent technological capability, but general capabilities and uses of the data captured are addressed. Different types of fault recording technology are discussed with the purpose of illustrating that many different approaches can be made to obtaining and applying fault recorder technology. While these different types of technology are discussed, the primary focus of this document is on the application and use of conventional stand alone fault recorders. Principles and processes discussed here can be applied to all of the different digital fault recording and disturbance monitoring technologies.

Report Structure

The structure of the remainder of this report is as follows:

- Section 2, "Digital Fault Recorder Technology": In this section a brief background of the evolution of Digital Fault Recorder technology is provided along with a description of what constitutes a DFR. Advances in the technology are discussed with the present technology state of the art. A comparison of the different technologies that are available is given.
- Section 3, "Installation Requirements": In this section the different factors involved with the installation of a DFR are discussed. Physical installation requirements are discussed as well as the electrical interface requirements including the communication requirements. Various maintenance issues associated with DFRs are discussed.
- Section 4, "Monitoring Using DFRs": In this section, the justification for installing DFRs in power plant environments is presented. In addition to the benefits accrued from monitoring with DFRs the regulatory requirements are discussed in terms of the justification for installation of the monitoring. With the many different signals available for monitoring, the most critical signals are itemized along with other monitoring issues such as where and when the monitoring should take place. Data access and interpretation are also a part of this section.

- Section 5, "Regulatory Requirements and Standards": This section discusses the existing and proposed industry and North American Electric Reliability Corporation standards. Increasing regulation of the electric power industry by regulating authorities create system monitoring requirements that are met through the use of DFRs. In addition to regulator requirements, the various industry standards that commonly used with DFR captured records are outlined.
- Section 6, "Case Studies": This section includes examples of the benefits of monitoring power plants using DFRs by presenting case studies of how information captured by DFRs is used in real operating scenarios. Unique applications of the data are demonstrated including shaft torque monitoring, generator field winding monitoring using flux probes, and the analysis of typical generator fault events.
- Section 7, "References": This section provides a list of references used throughout this document.
- Section 8, "Glossary": This section provides a glossary of terms and abbreviations used in this document.
- Appendix A, "Power Calculations": This appendix details various methods that can be used to calculate generator and transmission line real and reactive power from the measured quantities. These are the most commonly calculated quantities and methods to calculate them are presented.
- Appendix B, "Vendor List". This appendix contains a list of vendors supplying DFR equipment and other equipment commonly used in DFR installations.

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DIGITAL FAULT RECORDER TECHNOLOGY

What is a DFR?

A simple definition of a Digital Fault Recorder would be any device that digitizes and records oscillographic type fault records as well as sequence of event type event records. The fact that the oscillographic type fault records have been digitized and saved in digital files would provide for the capability of transporting these files electronically from one location to another such that a person remote from the recording location can view and analyze the file. Since the purpose of the recorder is to record faults, the capability to record data at speeds adequate to capture faults is required.

Historical Overview of DFR technology

To fully understand the structure and power of a digital fault recorder it is necessary to get an overview of the preceding technology. Analog Fault Recorders (AFRs) devices were the predecessors to Digital Fault Recorders (DFRs). Some AFRs stored between 8 and 32 channels of analog data on magnetic tape. Once a record was captured, the tapes had to be retrieved from the remote location of recording and transported to a central playback and analysis facility. The taped records would then be plotted on strip chart paper. A power system engineer or technician would then manually scale the traces back to primary voltage and current quantities. Other AFRs employed light beam pens driven by analog vacuum tube amplifiers and galvanometers to write traces on photosensitive paper at the recording site. Regardless of their operational mechanisms, AFRs suffered from a litany of problems including calibration drift, low reliability, poor signal to noise ratios, limited dynamic range and high cost of installation and maintenance. To make matters worse, AFR records from remote locations took several days to a week for data retrieval and playback to a plot suitable for analysis. AFRs rarely provided information in a timely enough manner to resolve operational issues. Instead, they provided information that might be useful for post event documentation and verification of engineering calculations, protective relay settings, etc. AFR recording times and trigger capabilities were severely limited and no post processing functionality was possible. A typical magnetic tape based analog fault recorder is shown in Figure 2-1. At best, the analog recorders provided very limited insight into the transient behavior of the power systems they monitored. Consequently, AFRs were installed on only the most critical substations and generating facilities. Only those sites could justify the high cost of acquiring a limited record of power system transient behavior. AFRs provided too little data too late to be of use for most power system problem solving issues. Until a reliable electronics platform with improved triggering, data storage and transmission capabilities was available, the importance of AFRs to power system diagnostics was limited.

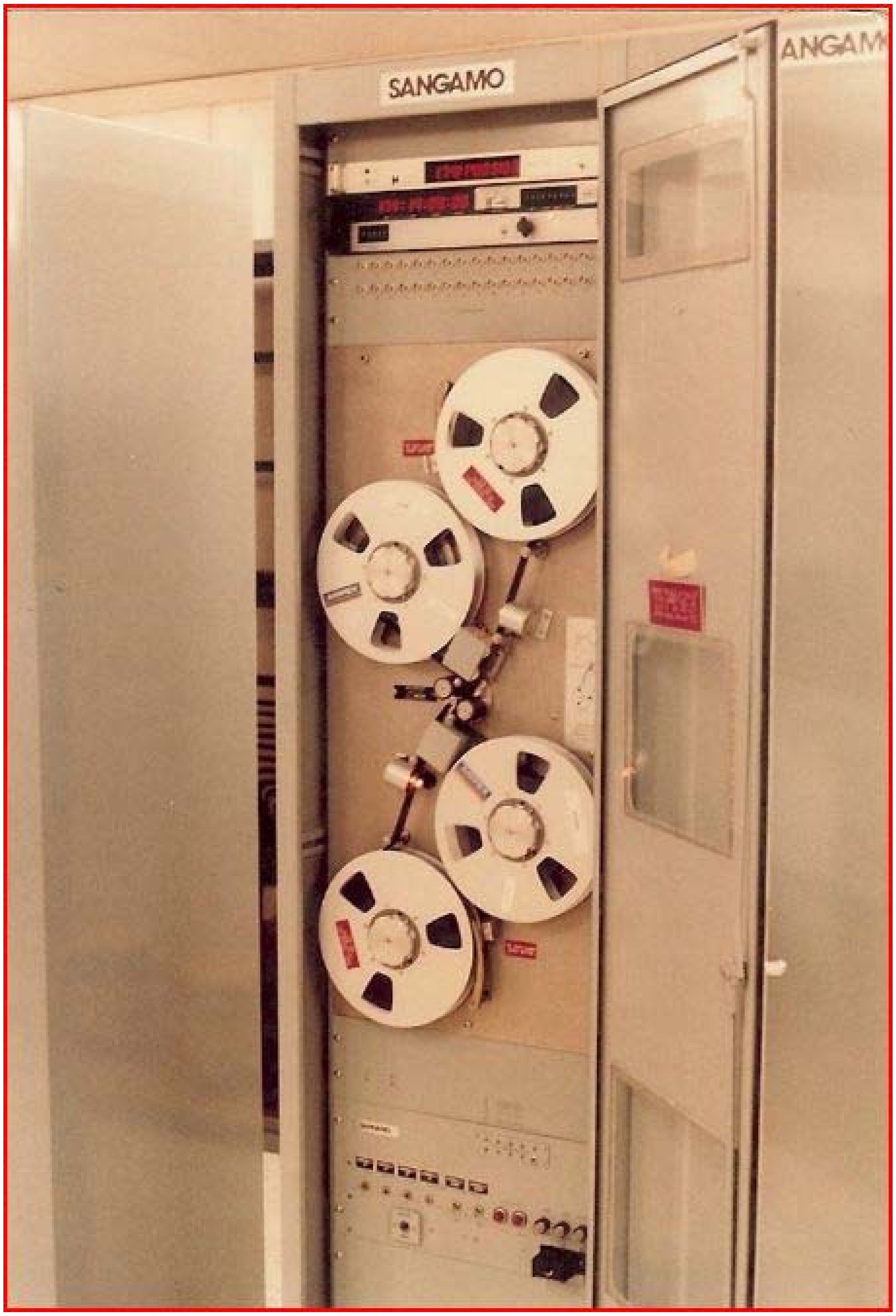

Figure 2-1
Magnetic Tape Based Analog Fault Recorder

A digital fault recorder provides a means to sample, store and transmit several power system analog and digital quantities to a central master station for analysis. It is the functional replacement for the analog fault recorder. In contrast to the AFR, the DFR converts analog voltages, currents and digital event inputs from the power system into a digitized data stream. The digitized data stream is handled by the elements described next. The DFR accomplishes this functionality by employing digital technology including a dedicated central processing unit

(CPU), analog to digital converter (A/D), digital record storage, and a communication system to a personal computer (PC). The PC, often referred to as a master station (MS) runs specialized software for point-on-wave display, analysis and storage of the analog waveforms and digital events captured by the DFR.

A First Generation DFR

DFRs originated in the early 1980's from the merger of small digital computer platforms and improved analog to digital converter technology. At that time, analog to digital converter technology with 10 bit or greater resolution was available at prices low enough to make an 8 or 16 analog channel DFR a viable product. They offered reasonable dynamic range and recording times as well as greatly improved record retrieval speeds as compared to their analog predecessors.

First generation DFRs were typically configured as 8 or 16 analog channel instruments with 16 or 32 digital event channels. They often mimicked the form and function of the AFRs they replaced. Larger DFR installations were built from multiple DFR instruments either being slaved together or by population of additional analog and digital input slots in the DFR main cabinet. A typical functional block diagram for a first generation DFR is presented in Figure 2-2.

Analog DFR inputs such as generator PT voltage and voltages proportional to generator current are input to the DFR analog front end via dedicated isolation devices (1) for each channel. The isolation devices are necessary to avoid problems associated with mixing grounds, electronic commons, neutral points, introduction of ground loops, etc among the analog input data set. Isolation was necessary for protection of the solid state low voltage circuitry in the analog to digital converters and the downstream multiplexor and digital computer. Isolation is typically specified for at least 1500 Vrms. This level of isolation is obtained in either of two common methods: an isolation transformer or an isolation amplifier. Isolation transformers are relatively inexpensive and usually are adequate for waveforms with no DC component. Isolation amplifiers are the more costly but the preferred means of obtaining isolation. DC isolation amplifiers not only handle DC offsets, but are able to provide accurate representation of the complex waveforms encountered in monitoring silicon controlled rectifier (SCR) based excitation systems. Isolation amplifiers good for 1500 Vrms isolation with flat frequency response to 10 KHz have been available even in first generation DFRs. Digital input isolation is also required for DFR event inputs (2). An event input is simply an indication of a change of state (i.e. contact open to contact closed). Consequently digital input isolation is readily obtained from either a relay contact or an opto-isolator. Once the analog and digital inputs have been isolated they are sampled via a multiplexor (3) circuit. A multiplexor may be thought of as a precision high speed electronic switch. The switch is sequentially connected to the analog isolation devices for each DFR input channel. With the typical first generation configuration shown in Figure 2-2, the sample rate of the DFR is defined by the number of multiplexor switches per second divided by the number of channels monitored. The multiplexor provides an analog voltage representative of each input channel to the analog to digital (A/D) converter (4). Initially, 10 bit A/D converter resolution (one part in 1024) was typical. Good engineering practice would dictate that an anti-aliasing filter should be installed upstream of the multiplexor to eliminate all high frequency components of the input signal. This was not always the case. Some first generation DFRs completely ignored the issue of signal aliasing. Anti-aliasing filters consist of a low pass filter with a corner frequency of less than half the A/D converter's sampling rate. In any case, the A/D converter's output is a binary data stream for each analog and event channel. This data is continually written to a circular buffer in the DFR computer (5). A complement of trigger circuits employing analog level detectors and analog signal processing are represented in Block 6 of Figure 2-2. Typical analog triggers were available for over current, under/over voltage, over/under frequency, and negative and zero sequence currents. Event triggers were possible as well for a simple contact change of state. Typical DFR event triggers (Block 1B) include exciter start or generator breaker close or open. When trigger conditions are met, the digitized data stream is written to local memory in the DFR computer. Data storage may either be in local RAM or on a hard drive.

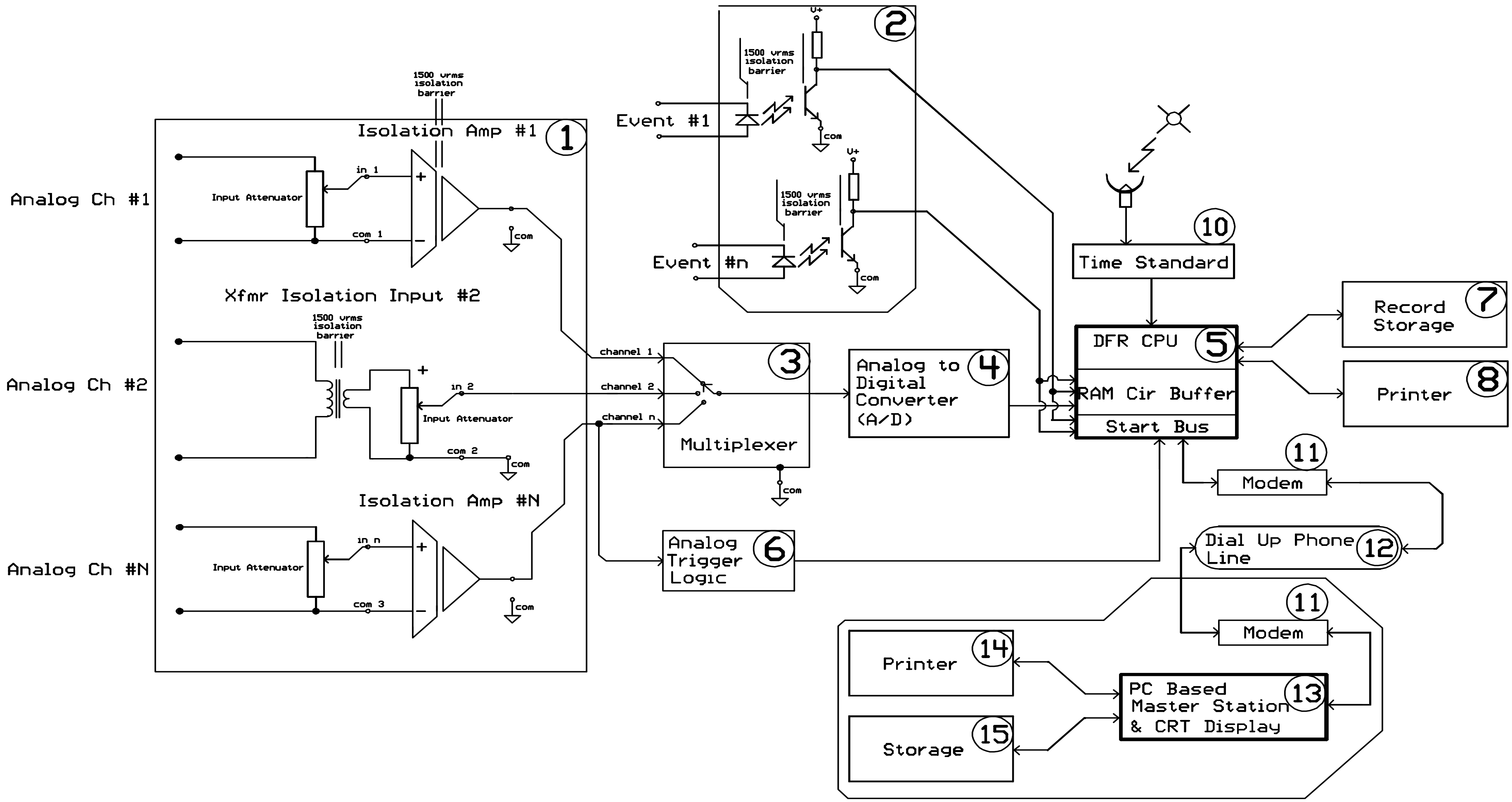

Figure 2-2
First Generation DFR Functional Block Diagram

DFR trigger conditions are developed by either of two means. In first generation DFRs, the trigger logic function (6) was often derived from analog level detectors, timers and filters – a throwback to analog fault recorders. Later, trigger logic based upon digital signal processors (DSP) greatly enhanced triggering capabilities. Simple triggers would consist of analog level detector settings for generator over current and generator over and/or under-voltage conditions. The length of the saved DFR record depended upon how the unit was configured, the available memory and how long the triggering condition persisted. Record lengths from a few tenths of a second to several seconds were common for first generation DFRs. The DFR CPU software also handled administrative tasks such as assigning record numbers, file names, and date and time stamps. Time stamp information was typically obtained from one of two sources. The first is an internal free running clock and the second is an external time standard. Radio time standards such as WWV or WWVB were the first available for time synchronization and were suitable for synchronization to a few tenths of a second. True precision time synchronization was attained with the advent of satellite clocks. They typically produced an "IRIG B[1]" format time signal. In the early 1980's the defacto time standard was the Geostationary Orbit Earth Satellite (GOES) system with an accuracy of approximately 1 millisecond. Modern Global Positioning Satellite (GPS) receivers have now replaced GOES receivers with accuracies in the 10 microsecond range. This level of precision is sufficient to allow synchrophasor measurement across the entire power system.

Once a DFR record has been created, it needs to get from the location at which it was recorded to the location where it can be analyzed. The DFR master station computer runs communications software that drives a modem (10) connected to a voice grade phone line (11). The DFR end modem dials the DFR master station (MS) phone number, establishes communication and tells the master station it has a record in memory. It then hangs up and waits for the master station to call back and retrieve the record from the DFR memory or hard drive. First generation DFR communication ran at data rates as low as 1200 baud, with 9600 baud and eventually 19,200 baud becoming common. Transmission times for a record could take well over an hour for DFR records of several seconds duration. Although extremely slow by present standards, modem transmission of generator DFR records was a great step forward compared to the days of shipping an analog tape back to a central location for playback onto a paper plot. DFR master stations were initially IBM PC-XTs with a 5 to 10 megabyte hard drive (8). A first generation MS allowed for record storage, printing and analysis functionality consisting of little more than peak or rms magnitude readout, and time between events resolution. As the personal computer evolved so did the analytical power of the DFR MS and that process remains in continual evolution and expansion. First generation MS machines typically ran DOS operating systems or variants such as Concurrent DOS which allowed for multitasking capabilities in several DOS windows. Important records were analyzed on the MS, manually annotated, copied and then incorporated into permanent documentation of significant events.

[1] **I**nter **R**ange **I**nstrumentation **G**roup – IRIG time coding was developed at the White Sands Missile range for the time synchronization of recording instrumentation. The B format time code consisted of a 1000 Hz audio tone amplitude modulated to convey time information encoded as binary one and zero values at either 50% or 100% amplitude modulation. The 1000 Hz tone is easily distributed to multiple devices in the power plant over either a phone circuit or coaxial cable.

Present Technology

A present technology DFR is perhaps three or four generations removed from the first embodiment of the concept. In terms of a functional block diagram, a state of the art DFR does not look significantly different from a first generation recorder, however a great deal more functionality and computational power is contained within. Figure 2-3 is a functional block diagram of a typical state of the art DFR in both a distributed and local format. Note that the DFR CPU (3) is still central to the functional block diagram, but if required the actual analog and digital input modules (1) and (2) can be located much closer to the points of origin for the analog and event points to be monitored. When a distributed DFR is not the preferred configuration, the dashed line encircling elements (1), (3), (4), and (5) define the conventional configuration. For example, a distributed DFR installation may be preferred at a new plant to monitor all four generators at a plant from a single CPU that supervises 64 analog inputs and 128 event inputs. The input sub-modules ((1) and (2)) communicate to the DFR CPU via a single fiber optic connection. This connection is much simpler and less costly to establish rather than pulling generator CT and PT cables many hundreds of feet around a plant to a central CPU location. Note that the input sub-modules are each much more powerful than a first generation stand alone DFR. Each sub-module contains all the functionality required for analog input isolation (a), anti-aliasing low pass filtering (b), A/D conversion (c), a CPU and DSP for triggering (d), event input isolation (e), and communication via a bi-directional data stream between the input modules and the DFR CPU (3). Several gigabytes or more of non-volatile storage (4) are commonly configured with the CPU. Some systems may be configured with hundreds of gigabytes of storage on an industrial grade hard drive. Local storage for the data processed by the CPU is not as an important factor as in the past thanks to the high speed network connection (5) to the DFR MS via the owner's 10Base T or 100 Base T network (7). The network connection typically ensures that the DFR records are available at the MS (8) within minutes. As with first generation DFRs, the time synchronization is provided via an external precision clock. The standard now is a GPS clock (6) typically with 1 microsecond accuracy or better. Accurate time synchronization allows for another level of functionality to be built into the DFR platform – synchrophasor measurements. Data display (9) and storage (10) are easily handled these days by a variety of options only limited by the user's imagination. Note that for monitoring of a single generator, a distributed system may not be the best solution. Several manufacturers produce compact 16 analog / 32 event channel machines that are easily installed in or adjacent to a generator control panel that contains most of the DFR input quantities. This is particularly true in new packaged simple combustion turbine applications and retrofits in pre-1980s fossil plants. It is possible to configure a state of the art DFR to function as a high performance fault recorder, long term disturbance monitor and synchrophasor monitor. The value of each of these functions is discussed elsewhere in this document.

The performance and flexibility of a state of the art device is remarkable. A new DFR can sample as fast as 15 KHz per channel with 16 bit resolution – 64 times better than the typical first generation instruments. Modern DFRs may be configured out to hundreds of analog channels and event channels. Multiple highly sophisticated digitally configured DSP based triggers are available on each analog channel. A state of the art DFR is also capable of calculating virtual channels derived from actual channels. Calculated generator real and reactive power and negative sequence generator current are examples of virtual channels. A virtual channel may also be used with trigger algorithms to capture records. Complex triggering logic based upon a user defined map is typically available as well. Figure 2-4 depicts a typical DFR installation in a free standing cabinet. Note the separate satellite clock at the top of the cabinet. Figure 2-5 shows a picture of the back of this cabinet.

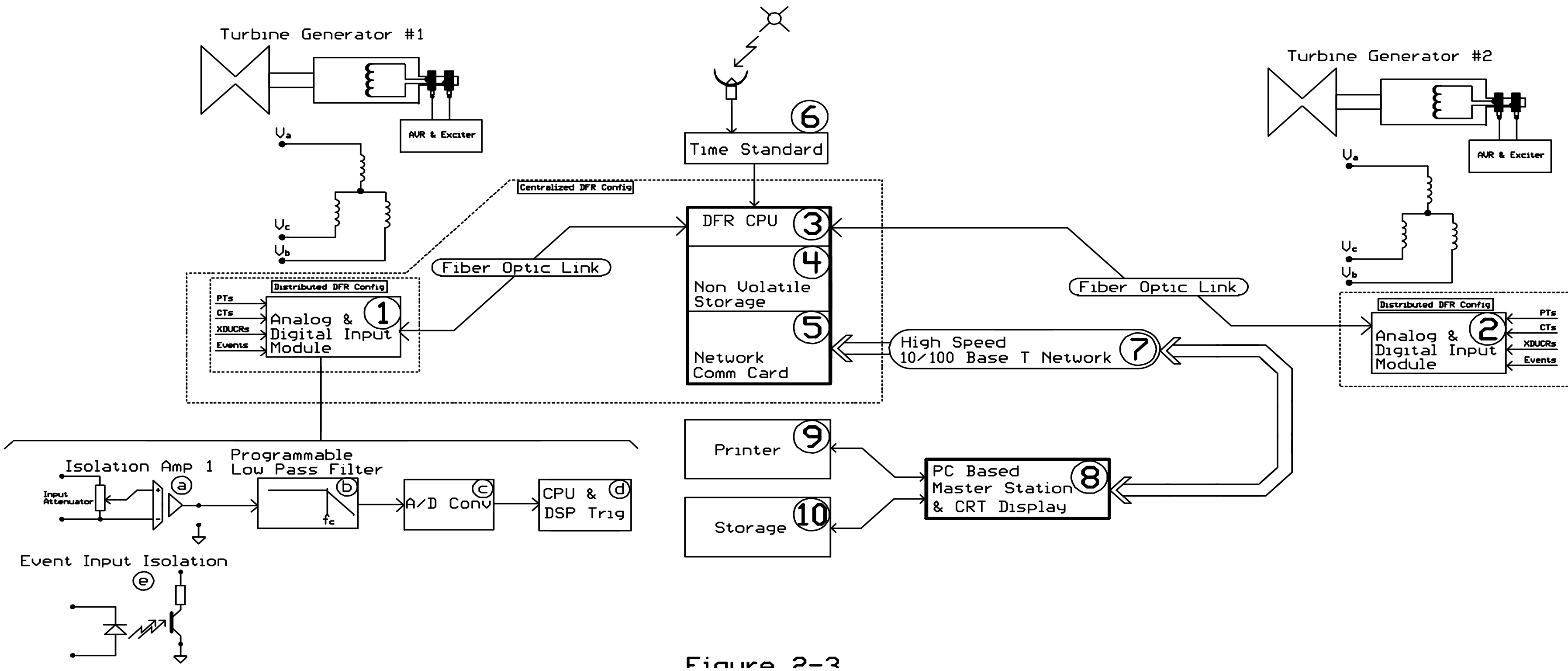

Figure 2-3
Modern DFR Functional Block Diagram

Figure 2-4
DFR Installed in Stand Alone Cabinet

Figure 2-5
Rear Apron view of DFR in Cabinet

Complementary Technologies

As defined in Section 2.1, a Digital Fault Recorder is defined as any device that digitizes and records oscillographic type fault records. The digital fault recording/oscillography technology has advanced to the point that the technology is now incorporated within many different devices and systems and not only within stand alone devices. The different systems and devices that use this technology have different targeted functions and therefore are mostly complementary of each other as opposed to being competitive with each other. Some of the technologies that use digital recording technology within the power plant environment include the following:

- Distributed Control Systems (DCS) and Process Integration (PI) Systems – These technologies generally gather and archive large volumes of data that are available in the power plant. Because of the broad brush nature of the data collection, the sample rates are on the order of seconds so high speed events are not captured. These systems are useful in the identification of long term trends.
- Sequence of Event Recorders – These devices record digital changes of state so as to be able to determine the sequence of the events that occur within the power plant. No analog quantities are available so waveform analysis is not provided but alarm and contact closures are sequenced.
- Phasor Measurement Units (PMU) – This technology uses time synchronized sampling of voltages and currents to calculate synchronized phasors. The benefit of this technology is that phasor magnitudes and angles are calculated and time synchronized with any other phasor measured using the same technology. The phasor snapshot of the state of a power system may be used in the assessment of system stability and security. Consequently, one cannot dismiss the importance of including PMU functionality in new DFR installations. Significant research is being done throughout the industry on applications of this technology.
- Embedded Oscillography – This technology embeds digital fault recording technology in devices that are primarily designed to provide another function such as digital relay protection, or excitation controls associated with a synchronous generator's field winding. Embedded digital oscillography used in such systems is limited in the sample rate, file size, and number of files that may be captured. In addition, the quantities that are recorded are limited to those required for the device to function as designed. Despite these limitations, these embedded oscillographic functions can be valuable tools in troubleshooting generator problems, especially problems related to the devices containing these embedded systems.
- Stand Alone Digital Recorders – Small PC based digital recorders are available that can be used to record both analog and digital signals via isolated inputs that avoid issues involved with inadvertent mixing of electronic common, station ground, and neutral points. A typical device provides high resolution recording with some limited triggering capabilities. These digital recorders can be thought of as digital strip chart recorders that are very useful for trouble shooting systems that don't have permanent recording capabilities. The portability and ease of use of these systems combined with their high sample rates are their major advantages. They can be set up and running in a few minutes time.
- Portable DFRs – Some manufacturers have developed the full power of a DFR in a smaller portable unit that can be applied in temporary configurations. These units can be very useful for application to systems and devices where periodic problems are being diagnosed and unattended triggering is needed to capture the problem. The prices for these devices are generally higher than for dedicated permanent installations.

A summary comparison of these different digital recording technologies is given in Table 2-1. Experience has shown that each of the digital recording technologies fills a specific need and that these different technologies complement each other to provide thorough coverage of the monitoring needs of the power plant.

Summary

In this section a historical overview of how digital fault recording technology has evolved over the years. Different generations of technology are presented together with a discussion of the improvements and benefits accrued with the advances in technology. A definition of a digital fault recorder is presented along with block diagrams of the different functional parts that make up the recorder. In addition, a listing of complementary technologies that can be used for data capture and analysis is present. This list of technologies includes mature as well as evolving technologies and each occupies an important place in the overall scheme of providing monitoring in the power plant environment.

Table 2-1
Comparison of Typical Capabilities for Different Digital Recording Technologies

	Digital Fault Recorder	Sequence of Events Recorder	DCS or PI System	Embedded Oscillography	Stand Alone Recorders	Portable DFR	Phasor Measurement Units
Sample Rate / Time Resolution	Variable up to 15,000 Hz	1 ms resolution	1 sec or slower	960 Hz	Variable up to 200,000 Hz	Variable up to 15,000 Hz	Up to 60 Hz
Number of Records	Thousands, only limited by storage media	Continuous System	Continuous System	1 to 16	Thousands, only limited by storage media	Thousands, only limited by storage media	Thousands, only limited by storage media. Typically set to continuous recording
Record size	Only limited by storage media	Continuous System	Continuous System	Varies	Only limited by storage media	Only limited by storage media	Continuous recording typically
Captured Quantities	Any analog and/or digital	Digital only	Analog and digital	Analog and digital but only those signals associated with device	Any analog and/or digital	Any analog and/or digital	Phasor magnitude and angle – voltage and current, also digital inputs available
Triggering capability	Under/Over, rate of change, Pendling, edge, level, boolean logic available	Change of state	No triggering, continuous recording	Trigger on quantities associated with device.	Triggering is limited, typically used similarly to strip chart recorder	Same as DFR	Over/Under, rate of change, frequency
Record file format	Proprietary and COMTRADE	ASCII table format	ASCII table format	Proprietary, sometimes COMTRADE is available	Various, typically no COMTRADE	Proprietary and COMTRADE	Various possible, typically not COMTRADE

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INSTALLATION REQUIREMENTS

Thorough, concise planning of a power plant DFR installation has significant benefits. This section presents an overview of the authors' experience over their careers of working with AFRs and DFRs in power plant environments. What is presented here is not the only way to configure an installation, but is a method that has proven to be adequate and thorough through the years. Installation of stand alone DFRs is primarily addressed.

Equipment Requirements and Capabilities

A DFR applied in power plant environments should meet the following general requirements:

- Power input received from the station battery and/or an uninterruptable AC source
- 14 bit A/D converter resolution or better
- Sample rate to 10KHz per channel or better
- 10Base T/ 100 Base T network communications available. Modem capability also desirable as backup communication method.
- Operating range[2] 10 to 50 degree C
- Analog input isolation to at least 1500 Vrms. Isolation amplifiers preferred over transformers.
- Event input isolation via opto-couplers preferred to at least 1500 Vrms
- 16 analog and 16 event channel minimum configuration
- Solid state nonvolatile data storage to 1 gigabyte or better. Hard drives storage is acceptable but not preferred.
- Comprehensive support and analysis software with COMTRADE capability
- Functionality as a Synchrophasor device and dynamic disturbance recorder (DDR) if desired
- Current sensors[3] that can withstand 10 times rated current for 10 seconds

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[2] It is recommended to locate the DFR acquisition electronics in an environmentally controlled room. Should environmental controls fail, the DFR will still function as intended. It is also desirable to select DFRs without moving rotational components such as cooling fans or hard drives. As the technology evolves, this is becoming an increasingly easier criterion to meet.

Physical Installation Requirements

The cabinet room or freestanding 19 inch rack-mount space allocated for a power plant DFR installation should be as generous as possible. An enclosed cabinet with front and rear door access is preferred over a freestanding rack-mount unit. Reduced dust contamination and potential for unintentional contact with the wiring is the driver for this preference. With either mounting choice, experience has shown that an external set of input test switches should be mounted within the DFR cabinet or on a rack-mount panel. The test switches serve multiple functions. First, they allow for complete isolation of the DFR from the generation they monitor. This allows for safe and efficient troubleshooting of the DFR problems without the risk of opening up a CT circuit or grounding a PT circuit which could trip an operating unit. Second, it provides convenient signal pickup points for generator testing, exciter and PSS testing and general troubleshooting. Figure 3-1 documents a typical DFR cabinet installation with test switches configured on either side of the DFR's rear apron. Last, an unfortunate design constraint exists for most DFR manufacturers - the space available on the rear apron to land analog input connections. The DFR terminal connectors used are small and require light gauge wires to terminate reliably in the connector's small jaws. The test switches provide a convenient transition point from the utility world of large gauge cables that can be securely pulled through conduit and the electronics world of miniscule fragile connectors. This is particularly true for CT circuit connections. Opening a CT circuit can have fatal consequences and using a CT shorting switch in the DFR cabinet provides safer and more secure connections than directly wiring the CT circuits into the DFR input jaws.

The preferred location for the DFR cabinet or rack-mount is the room containing the generator protective relaying. Depending on the vintage of the generation, the protective relaying could be an array of many electromechanical relays or a redundant set of digital generator protection relays (GPR). Many of the quantities that are inputs to the GPRs are also DFR inputs. This commonality can greatly simplify wiring[4]. Other critical generator inputs (such as generator field voltage and field current), are easily run as transduced[5] outputs to the GPR room from their points of origin at the exciter cubicle.

Another important consideration for DFR installation is whether the DFR is to be dedicated to a single generating unit or is part of a plant wide installation. For example, in a new combined

[3] Current input may be either from a conventional shunt or a split-core current transformer with a built-in internal burden. Shunts generally can meet this requirement. A temporary split-core CT with internal burden may have significantly less overload capability.

[4] It should be noted that some company policy may be structured so as to preclude using the same PTs and CTs for protection and monitoring. The contrarian point of view is that monitoring GPR inputs allows evaluation of GPR performance.

[5] The philosophy here is to never run high energy dc circuits to the DFR. Instead use a wide bandwidth transducer that faithfully converts the actual field voltage waveform into a ± 10 volt output replica of the high energy quantity waveform. Applied to generator field quantities, this philosophy also eliminates the possibility of inadvertently introducing a ground on the exciter field circuit. In some companies a field ground will result in a protective relay tripping the generator. Others issue a high priority alarm. In either case use of a transducer precludes the DFR from causing a problem rather than solving one.

cycle plant with several "2 by 1" combustion turbine / steam turbine generating units, a plant wide installation approach might be best. A DFR configurable as a number of analog/digital input modules connected to a central controller would be favored. Input module(s) are assigned to each generator and installed in their respective GPR rooms. The modules are connected to the DFR CPU module via fiber optic cables. A single network connection ties the plant wide DFR to the corporate network and the master station. This approach is much less costly than assigning and installing multiple stand alone DFRs at each combustion and steam turbine generator location. Lastly, experience has shown that although architect-engineers (AE) are very good at designing and building power plants, they are novices at integrating DFRs into them. Having an AE integrate a DFR into a new plant design may not be the best approach. A better plan may be to request the AE to reserve and install an empty cabinet in each generator's GPR area. After taking delivery of the plant, perform the installation and commissioning of the DFR with company staff who have a vested interest in the success of the project. The only downside to this approach is that the DFR is not available for plant startup[6].

[6] It may be possible to establish a temporary DFR installation or other related data acquisition equipment to assist troubleshooting a new plant startup.

Figure 3-1
Rear apron view of a DFR In Cabinet Installation

Interface Requirements

Interfacing a DFR to a new or existing plant does not have to be a daunting task – if proper planning has been a key part of the process. DFR interfacing issues that must be addressed include:

- DFR location / allocation of floor space
- Additional power drain imposed upon critical dc and or ac resources
- Connection to the corporate network

- Location of isolation transducers and provision for secure power for the devices
- Provision for an isolated dc source for contact wetting voltage. An isolated wetting voltage supply avoids grounding or disruption of station battery power from malfunctioning DFR hardware or attending staff errors.
- Allocation of the manpower and materials to pull cables, cut cabinet panels, install test switches, GPS clock antennas, etc. This includes a technical and economic evaluation of installation of a distributed or localized DFR configuration.
- Plant training to assure staff that the DFR is being installed to help them – not act as a telltale on operational errors.
- Allocations of resources to field check factory analog channel calibrations both with test signals and live generator quantities.

Experience has shown that the total cost of an installed DFR is two to three times the cost of the DFR itself. Keep in mind that one averted generator incident (through close DFR monitoring of the unit) will pay for the installation many times over.

Maintenance Issues

Modern DFR technology is a quantum leap ahead of the AFR technology they superceded in terms of the maintenance they require. Analog circuitry contained in AFRs is for the most part not self checking whereas digital systems can be designed to perform self diagnostics. Analog devices use potentiometers to establish trigger set points. Pots can drift in value or open circuit[7]. The Digital Signal Processors (DSPs) used to trigger modern DFRs don't drift and can be configured to inform the CPU of a failure. Consequently, the difference in maintenance from an AFR to a DFR may be characterized as from "frequent" to "rare".

Although modern digital fault recorders require significantly less maintenance than their predecessors, various situations may require maintenance and testing for the following reasons:

- Failure of an internal DFR component or circuit card
- Firmware updates from the DFR manufacturer
- Communication problems located either within the DFR box (rare) or in the communications network (more likely)
- Clock synchronization problems
- Regulatory body mandated maintenance and testing
- Noticed misbehavior or mis-calibration of the DFR channels

Detection of a gross failure internal to a DFR is usually easily accomplished since the DFR either stops functioning or the data captured by the DFR is grossly in error. In order to help flag problems, DFR manufacturers have incorporated self testing algorithms and watchdog timer

[7] In areas of elevated vibration it is not uncommon to find open circuited pot wiper arms after a few years of service.

circuits which test whether critical or non-critical errors have occurred internally. Most digital fault recorders employ a set of output contacts that are user defined and may be assigned to operate for different conditions. These may include general operation conditions such as the triggering of a record or they may include problems that the DFR is experiencing such as loss of time synchronization, excessive temperature in the DFR cabinet, or failure of the self diagnostic check. Often these output relays can be configured by the user to pick up its contacts for the specific problem condition desired by the user. Wiring these output contacts to the plant distributed control system (DCS) provides immediate notification to plant personnel of a DFR maintenance issue that needs to be resolved. Table 3 - 1 gives a listing of the different maintenance issues that can be assigned to the output contacts for plant DCS monitoring.

Table 3-1
List of Maintenance Issues Reported by DFR

Loss of network communication	Loss of power supply	Loss of clock signal
Loss of sub-module communication (for distributed configuration)	CPU failure	High cabinet temperature

In addition to the monitoring of the DFR output contacts, other methods can be employed to verify proper operation of the recorder. In effect, a DFR reports a self diagnostic of its condition each time it calls the master station. When calling the master station, the DFR not only reports any records that have been triggered, but as a part of this process alarm logs are generally reported to the master station. The alarm logs contain detailed DFR diagnostic information. These features give the operator of a DFR fleet information on the status of the fleet in real time. If desired, a DFR can be set to automatically trigger itself at regular intervals. This ensures that alarm logs and problems are reported regularly without needing to rely on system events to trigger fault records and so initiate contact between the DFR and the master station. This action verifies the proper function of the entire data acquisition, storage and data transmission path.

In addition to verifying the communication path and checking the fault logs of the DFR, programming the DFR to trigger itself at regular intervals can also uncover other maintenance issues. Some utilities have used the scheduled triggering capability of DFRs to form the backbone of their maintenance and integrity checks for their DFRs. Sophisticated analyses of the captured waveforms can be performed to verify not only the integrity of the DFR, but also to spot problems with other connections on the electrical system. These analyses can be automated and programmed to see loose connections, faulty potential transformers, shorted field turns, unbalance issues, harmonic issues, phasing problems, and other issues that can not only affect DFR maintenance, but other high power equipment maintenance. [Ref 1]

In recent years, regulators have written standards that apply to application of disturbance monitors both on the transmission side and generation side of the business. Digital Fault Recorders can qualify as disturbance monitors and in so doing fall under the regulation of the written standards. With regard to maintenance of disturbance monitors, the present standards require the disturbance monitor owner to have a maintenance and test plan and to abide by it. The standard does not presently define what the maintenance plan is or with what frequency maintenance should occur. However, future changes to these standards are likely and it is possible that both the frequency and extent of the maintenance and testing could be specified.

Last, the issue of calibration checks must be addressed. DFR manufacturers often encourage calibration checks once a year. This could be accomplished by opening the test switches and injecting test voltages and currents from a generator relay test set. In the real world, with resources spread thin, yearly calibration checks are difficult to justify and a complete calibration at the time of DFR commissioning may be all that is justified until a reason is seen to re-calibrate the unit. When a calibration test appears prudent, it is best done by opening the analog input test switches to isolate the DFR from the generator PT and CT circuits. Simulated generator PT and CT inputs from a relay test set are connected to the DFR side of the test switches. Testing of CT inputs should involve running a calibrated (or measured) current through the current shunt being used. Other inputs such as field voltage and current may be checked from the open test switches and a precision 10 Vdc source used to simulate full scale transducer output. Conversely, an end to end check of the transduced quantities to DFR recorded levels can be done with a millivolt calibrator and a low current several hundred volt dc source[8]. The field current path is checked by lifting and taping the millivolt current shunt input to the transducer and introducing a simulated full scale shunt input (typically 50 or 100 millivolts) to the current transducer. The full scale output of the current transducer (typically 10 Vdc) may be verified along with the full scale output of the DFR field current channel in amps DC. Similarly, the field voltage transducer calibration may be checked by lifting and taping the field voltage input, attaching the high voltage dc source and setting it to at least 20% of the transducer rating. The transducer output should then be 20% of 10 volts = 2 volts. The DFR primary calibration value may then be verified as 20% of the transducer rating.

Summary

In this section the installation requirements for digital fault recorders is outlined. Although they change with time, typical DFR equipment capabilities and specifications are reviewed. The physical installation requirements are presented including preferred locations and configurations. The distributed versus centralized DFR arrangement is compared and maintenance issues are addressed.

[8] Recommended test equipment for this work is the Fluke Model 744 or 707 process calibrator and the Agilent model 3612a Power Supply.

4
MONITORING USING DFRs

Why Monitor

The application of DFRs to the monitoring of turbine-generators can be justified based on one or more of the following benefits: Post Event Analysis of major events, improved and more efficient maintenance strategies, replacement of other less cost effective equipment, generator performance monitoring, and regulatory requirements. In each of these areas, significant cost savings can often be seen through the use of data captured by a fault recorder.

Post Event Analysis

The data captured by digital fault recorders is most often used as part of the post event analysis process for significant events affecting the generator being monitored. The post event analysis process is important following significant events in that it is the method whereby events are explained and root causes of failures are identified. While human perception is subjective, digital oscillograph recordings provide unbiased evidence of what happened and when it happened. Post event analysis often can be broken down into immediate short term analysis and longer term more detailed analysis and documentation. Until a root cause is understood and corrected, significant events have the potential to recur. Root cause analysis is usually a process that takes significant time and effort to ensure correct results. While root cause analysis is of interest and importance to power plant managers, the short term post event analysis that occurs within the first 30 – 60 minutes following an event is often of more immediate concern. If the immediate analysis of available data can help bring a generator back on line faster than it otherwise could, significant cost savings can be realized through reduced replacement energy costs by bringing a unit back on line as quickly as possible. Many time Digital Fault Recorders can be instrumental in quick identification and resolution of problems enabling fast restarts of generators. As an example, in 2003 a 52 MVA steam generator in a combined cycle plant tripped on main transformer protection. Because the unit trip occurred during peak load, replacement energy costs were high. Of most immediate concern was determining whether any equipment was damaged. If the generator step-up transformer had failed, the long replacement/repair time would not only affect the steam unit that tripped, but also the gas turbine that is part of the same combined cycle plant. Within 30 minutes of the unit trip, engineers began looking at DFR records to determine what had occurred. Generator DFR fault records failed to show any fault currents and it was quickly determined that neither the transformer nor the generator had sustained any damage. Shortly thereafter, plant management had the unit back up and running thus minimizing replacement energy costs. Subsequent investigation identified inappropriate relay settings on the main transformer ground fault circuit that allowed the transformer to trip due to a fault on the auxiliary system.

A similar example demonstrates how multiple sources of fault recording technology can assist plant management. On February 13, 2009 a 321 MVA base load unit at a coal plant tripped on generator differential protection. The fault record from the DFR (see Figure 4-1) was immediately reviewed but showed no generator fault currents. Note the following about Figure 4-1:

1. The vertical red line denotes the point in time that the DFR trigger occurred.
2. The event triggers at the top of the record show that the first indication of a trip is recorded by the pickup of the 86G lockout relay. This relay was tripped by a protective relay that picked up on the generator differential function.
3. The bottom three traces are the three generator currents. Note that there is no indication of any fault. All three currents show normal magnitude and phasing. Based on this observation, one can be confident that the generator has not been damaged by whatever event tripped the unit. It is also unlikely that an internal generator fault (as implied by the differential relay operation) occurred.

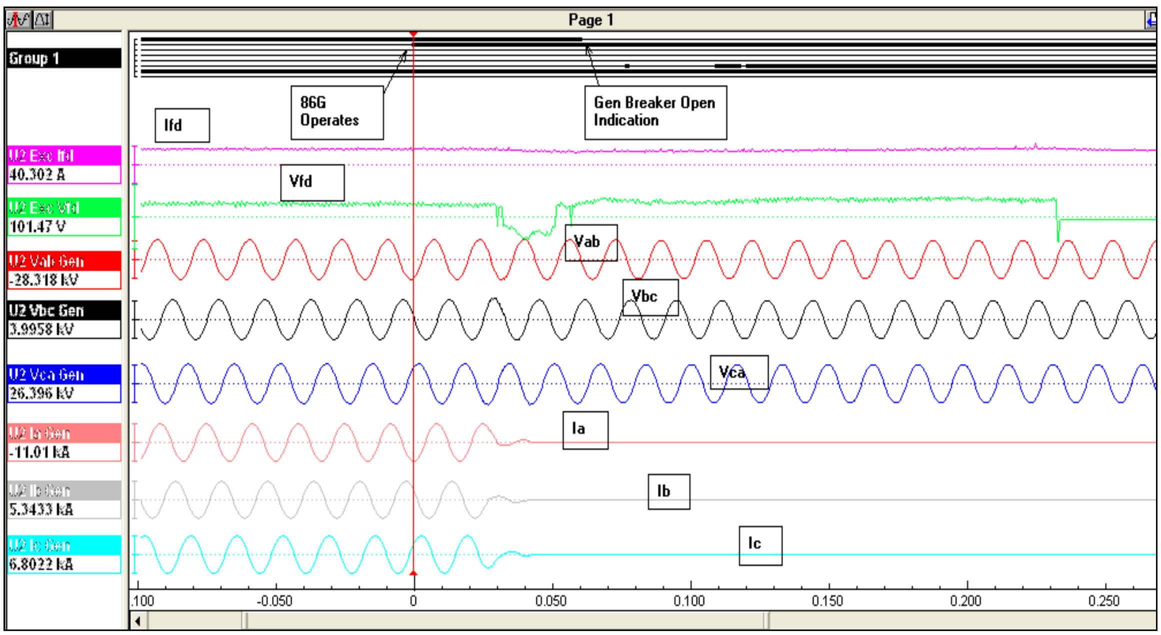

Figure 4-1
DFR Record for Full Load Unit Trip

This initial analysis indicated that the unit had not suffered an internal fault but it was still unclear if the trip was valid, and if so why it happened. Fortunately, the protective relay that tripped the unit also provides some digital fault recording functions. Obtaining these records required that someone physically plug a computer into the relay and download the records. When these records were obtained and examined, the trip cause became clear. Figure 4-2 shows the relay captured digital oscillograph record for the event. The top three waveforms are the currents measured on the system side of the generator and the bottom three waveforms are the currents on the neutral side of the generator. Because the relay monitors both sets of currents and the DFR only monitors one set of currents, the relay fault record is able to diagnose the problem when the stand alone DFR could only determine that the generator did not experience a damaging fault. Note in Figure 4-2 that the Phase C current on the system side of the generator has several abnormal cycles just prior to the trip. These abnormal cycles would explain the differential trip so plant attention was focused on the particular CT that showed the abnormal waveforms. Investigation of these particular CT connections revealed a frayed CT wire which likely made contact with ground causing the differential operation. The trip cause and correction of the problem was accomplished within a few hours of the unit trip allowing a quick re-start of the plant. The initial determination that no generator problem existed was accomplished using the main generator DFR but since the DFR only monitored one CT circuit, additional information from the relay digital fault records was required to definitively identify the problem.

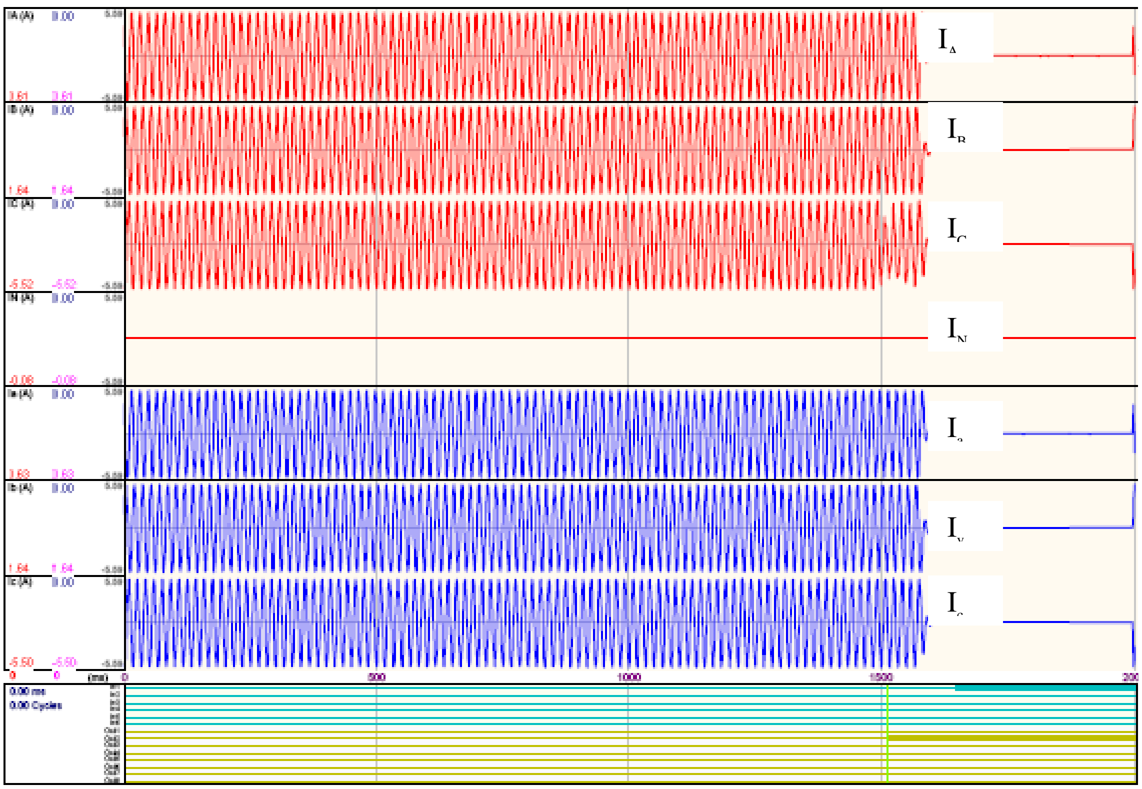

Figure 4-2
Multi-Function Digital Relay Oscillograph Record – 3/13/09 Event

The need for accurately time stamped fault recordings during major system events is perhaps most vividly depicted by the August 14, 2003 Eastern area blackout. This blackout event affected over 50 million people and resulted in just under 62,000 MW of lost generation. Estimated cost of the outage was between 4 and 10 billion dollars in the US and over 2 billion dollars in Canada [Ref 2]. One of the challenges facing the investigators trying to determine the cause of the outage was the lack of accurate and time stamped records with which to piece together the sequence of events. This lack of data hindered the investigation and ultimately led to three of the resulting 46 recommendations specifically addressing the need for accurate data and time stamped system information. The pertinent recommendations from the final NERC report are as follows [Ref 2]:

> 11) "Establish requirements for collection and reporting of data needed for post-blackout analyses. FERC and appropriate authorities in Canada should require generators, transmission owners, and other relevant entities to collect and report data that may be needed for analysis of blackouts and other grid-related disturbances."
>
> 24) "Improve quality of system modeling data and data exchange practices. NERC's requirements of February 10, 2004 direct that within one year the regional councils are to establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance… The task force supports these requirements strongly."
>
> 28) "Require use of time-synchronized data recorders. In its requirements of February 10, 2004, NERC directed the regional councils to define within one year regional criteria for the application of synchronized recording devices in key power plants and substations. The Task Force supports the intent of this requirement strongly, but recommends a broader approach."

Because digital fault records provide detailed, precisely time stamped information, they are valuable for use as post event documentation in determining sequence of events and in formal reports. This is most useful when formal event documentation is required either by the utility, a regional coordinating council, or a national entity. Nuclear power plants in particular have stringent documentation requirements and post event analysis is facilitated with the strong documentation that DFR records provide.

Cost Reduction

Specialized analysis of data monitored by a fault recorder can enable plant management to track and monitor generator status in unique ways that can either replace expensive dedicated monitoring systems or reduce maintenance costs. The ability to monitor any signal allows one to see if and when problems occur. Ideally a problem can be spotted prior to the situation deteriorating to a post event analysis situation. In certain cases, automation of the data collection and analysis process can have significant cost savings. In general, it is less expensive to implement a software solution to a problem than a hardware or personnel solution so the information that a digital fault recorder captures can be valuable in reducing or minimizing costs.

Two examples of the utilization of DFRs to reduce costs (hardware and/or personnel) are given. The first example involves the monitoring and tracking of turbine-generator shaft integrity for significant system disturbances involving torsional oscillations. The second example explains how a digital fault recorder can be used to automate the monitoring of generator field winding health and eliminating the need for attended data collection and monitoring. While these two examples are specific to unique needs of specific power plants, the main point illustrated is that many unique problems can be addressed using the capabilities of a DFR.

Shaft Torque Monitoring

Western high voltage electrical systems often employ series capacitors in transmission lines to enable greater power flows on transmission paths. These series capacitors interact with the inductance of the transmission lines and generators to create electrical resonances at frequencies in the sub 60 Hz frequency range. A subsynchronous resonance on the electrical system can interact with a turbine-generator spring-mass system and cause rotor oscillations at the natural frequencies of the mechanical shaft system. Should this happen, growing shaft oscillations can cause fatigue in the turbine-generator shaft ultimately resulting in shaft fracture. For those generators that are susceptible to subsynchronous resonance issues, torsional shaft monitors can be applied to calculate the shaft torque magnitudes and durations and thereby calculate the fatigue life of the shaft expended during an oscillation event. Dedicated torsional shaft monitors are very expensive and similar shaft torque monitoring can be accomplished with a fault recorder, appropriate input signals, and specialized software to make the shaft torque and fatigue life expenditure calculations. Even without the specialized software to make the shaft torque calculations, fault recorder signals can be used as input to freely available industry simulation software such as the Electromagnetic Transient Program (EMTP) to perform these calculations. A generator that is not susceptible to subsynchronous resonance oscillations may still experience significant torsional stress events for close-in faults, full load rejections, and bad synchronization events so shaft torque monitoring may be desirable even for turbine-generators without an SSR problem.

Figure 4-3 shows a typical fault recorder system setup for use as a turbine-generator torsional shaft monitoring system. The minimum required analog monitoring quantities for shaft torque monitoring are generator voltages and generator currents. If toothed wheel speed deviation signals are available from the ends of the turbine-generator shaft system, these demodulated signals should be input to the recorder as well. Figure 4-3 depicts additional signals that are often recorded including field voltage, field current, neutral ground resistor voltage, digital event signals such as field breaker status, generator breaker status, and any other status indicator desired.

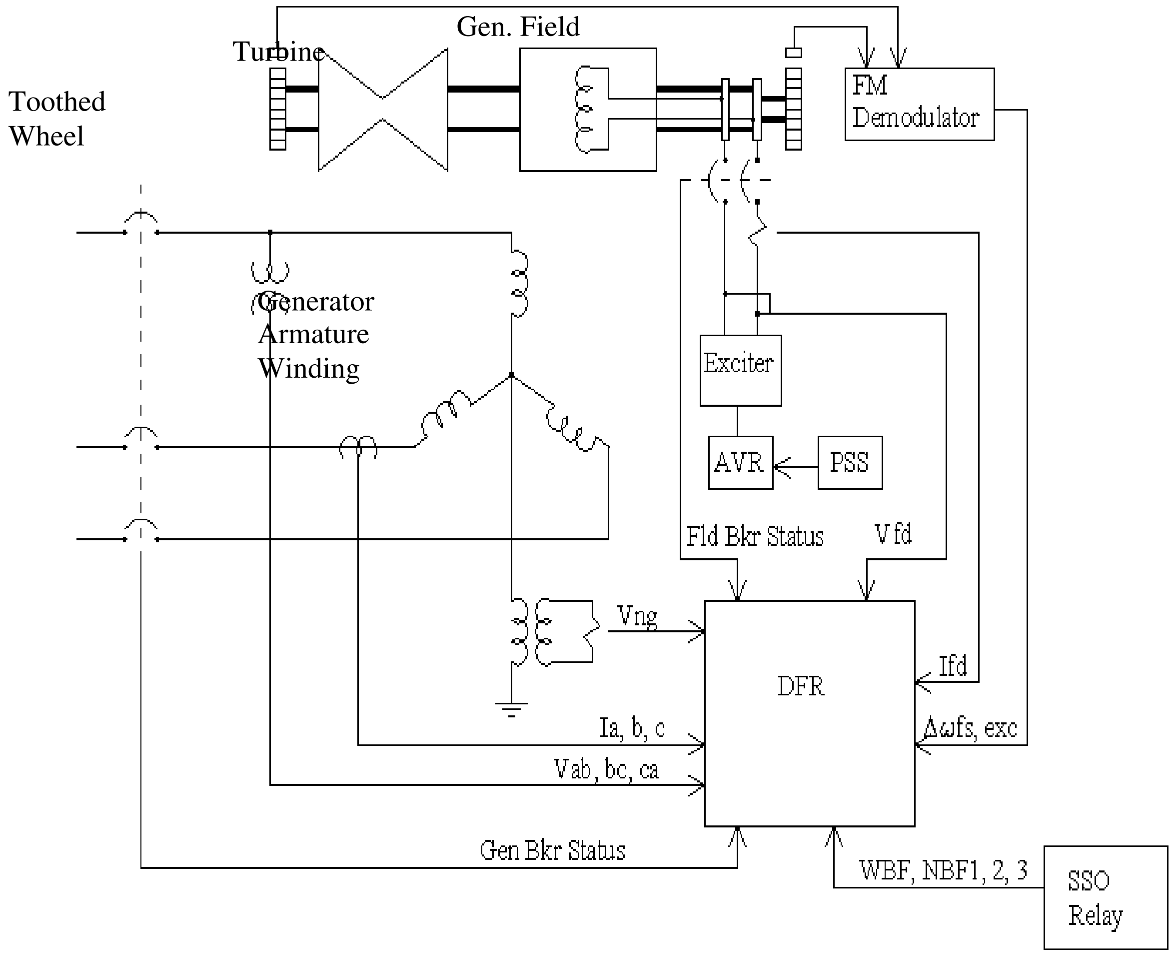

Figure 4-3
Torsional Monitoring Setup

Figure 4-4 illustrates a typical model of a turbine-generator spring-mass system. While the actual turbine-generator shaft system is a continuous system composed of many masses connected by the generator shafts, a low order simplified model usually can be used to represent the system with 3 or 4 masses connected with a shaft system. Each mass in the model represents either a turbine section, a coupling mass, the generator mass, or the exciter mass. These masses are connected to each other by a torsional spring which in actuality is the shaft system of the turbine-generator. Torsional oscillations will cause these masses to move relative to each other and cause a twisting of the generator shaft. Excessive twisting causes fatigue in the shaft section which can lead to shaft cracking and failure.

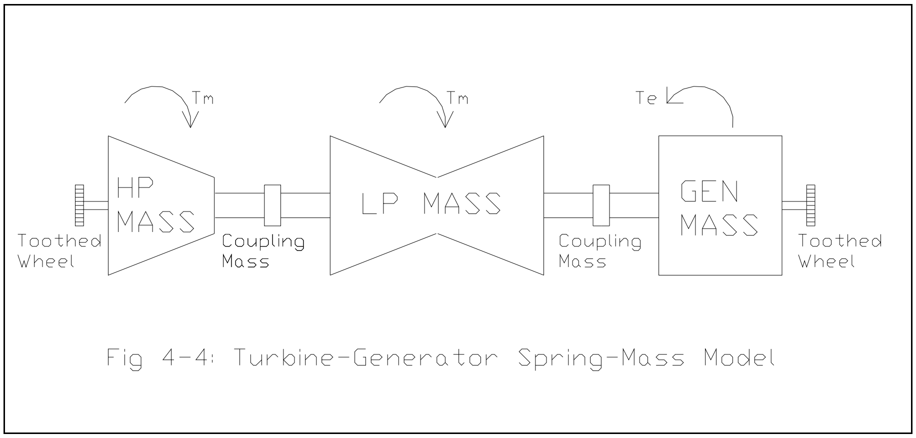

Figure 4-4
Turbine-Generator Spring-Mass Model

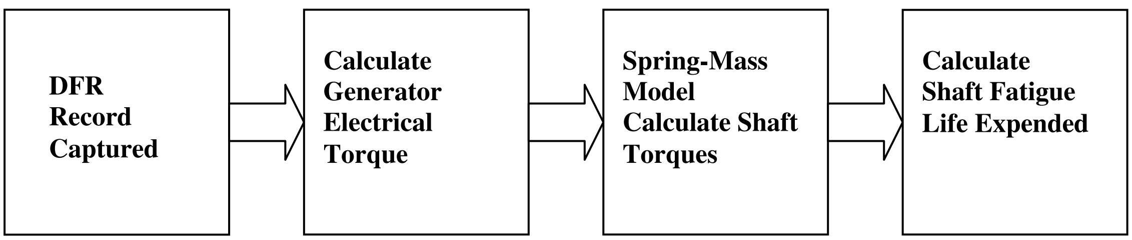

Figure 4-5
Torsional Calculation Block Diagram

Figure 4-5 shows the overall method used by a DFR based torsional monitoring system in the calculation process. This calculation process involves the following steps:

1. Capture of fault recorder data for the desired event. This data is usually triggered by an overcurrent or undervoltage sensor (for a fault type event), or a breaker opening (for a unit trip type event).
2. Conversion of fault recorder data to actual system quantities. This is generally done in COMTRADE format but can also be a simple ASCII file where generator voltages and currents in scaled quantities are available.
3. Calculate the generator power for the system event. This calculated generator power is per unitized based on the machine base quantities and is equivalent to the generator electrical torque applied to the machine.
4. Input the per unit generator torque to a spring-mass system model and calculate the shaft torques in each section of the turbine-generator shaft system.
5. Plot and analyze the resulting shaft torques and calculate the fatigue life expended in the shaft system for the event.

This shaft torque calculation and fatigue life expenditure calculation is usually performed in a single computer program specifically designed for the characteristics of the machine being monitored. If a generic program such as EMTP is used for these calculations, the calculation of the electrical torque from the DFR record is performed first and then the resulting electrical torque is used as an input to the EMTP program which then calculates the resulting turbine-generator shaft torques. A detailed example of the shaft monitoring steps is given as a case study in Section 6. Of significance here, is that large expenditures for turbine-generator shaft monitoring systems can be eliminated using the Digital Fault Recorder and some specialized software. The process of calculating possible shaft damage requires interaction of an engineer or technician to take the fault record information and input it to the torsional oscillation program but the effort is minimal.

Automation of Flux Probe Data Capture

Generator field windings consist of multiple windings on the generator rotor with each winding consisting of multiple turns. Direct current flows in the windings to produce the magnetic field needed for conversion of the energy stored in the mechanical rotation of the generator field to electrical energy produced in the machine's stator winding. Voltages applied to the field winding are relatively low and consequently the insulation between field winding turns is relatively thin. As machine insulation systems age, shorts between individual turns in the field winding can occur. These shorted turns can have the following negative consequences on the machine:

1. Higher field current is required to maintain a given electrical load.
2. Heating in the field winding can cause thermal unbalances in the field rotor causing vibration problems.
3. Shorted field turns can cause localized heating in the field winding incurring further damage to the insulation system. Another possibility is that over time, the localized heating may compromise the retaining ring insulation and cause a field ground.
4. Lower generator capabilities may result.

Industry standard methods of detecting shorted field turns with the unit in service involve installation of a flux probe in the stator winding slot in the air gap. This flux probe is sensitive to radial flux density magnitudes and the flux waveforms that are detected by these flux probes can identify individual shorts in the rotor windings. An excellent description of how this is done is found in [Ref 3].

In order to most accurately detect shorted turns using flux probe technology, the data for a given winding must be taken at an operating point where the air-gap flux density waveform is zero directly over the slot winding being investigated. Consequently, in order to get valid flux-probe data for the entire field winding data must be taken at various loading levels of the generator from zero load to full load. Originally, acquisition of flux probe data required a technician to monitor generator loading throughout the entire generator startup. If the generator startup occurred on a weekend or if delays occurred in the unit startup, technician overtime pay was required to retrieve the flux probe data at the appropriate load levels. In the case of a nuclear unit, startup from zero load to full load could take several days, further compounding the difficulty of recording the full range of load point measurements required. One method of automating the data collection of flux probe data was implemented using existing digital fault recorders to trigger high speed records at given MW load levels as a generator came on-line. This allowed unattended data collection thus eliminating the need to tie up a plant technician over extended time periods during unit startups. Details of how this was implemented using a digital fault recorder is given as a case study in Section 6.

Although use of flux probes is the most accurate method of identifying shorted turns in field windings, fault recorders can also give indication of shorted turns in generator rotors without requiring a flux probe. A typical fault recorder implementation on a generator will include monitoring of generator field current and field voltage. Measurement of the DC field voltage and field current allows one to perform the simple calculation of generator field resistance with a simple division of the field voltage by the field current. Tracking the calculated generator field resistance over a period of time can identify when generator shorted turns occur. While this would not necessarily be recommended for a normal healthy generator field, it is very helpful for generators with existing shorted field turns because additional developing shorted turns can be seen without having to run the generator through its entire operating range as needed using flux probe data.

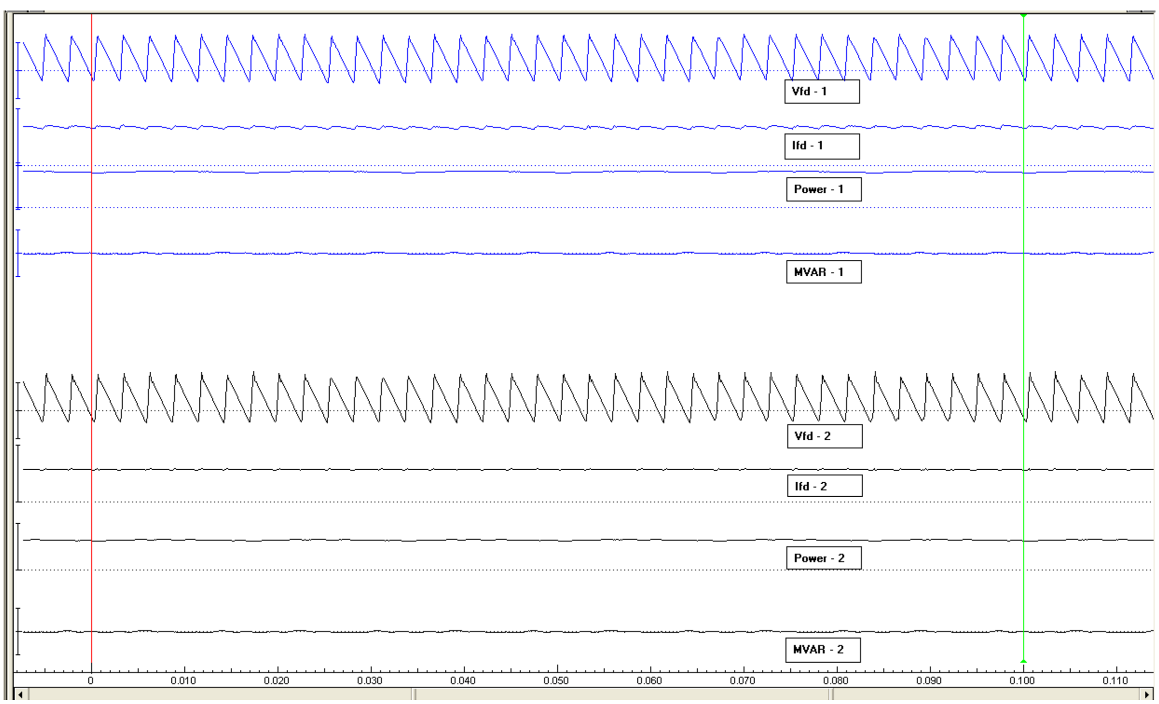

Figure 4-6
DFR Record Used to Calculate Generator Field Resistance

Figure 4-6 shows a set of generator data used for tracking shorted field turns. Blue traces are for one generator and black traces are for a second generating unit. For each generator, traces from top to bottom in Figure 4-6 are Generator Field Voltage, Generator Field Current, Generator MW, and Generator MVAR. Note that while the generator field current, MW, and MVAR traces show as a DC quantity, the generator field voltage is far from being a DC quantity. The field voltage waveform is a sawtooth shaped waveform which is classic for a three phase SCR bridge output. In order to make a field resistance calculation, the average value of the field voltage must be determined and divided by the average value of the field current. This is easily done in a number of ways with software functions available from the DFR master station software. One method is to make a harmonic calculation of each trace and pick the 0^{th} harmonic (which is the DC value). Once the DC values are determined the field resistance is calculated as the field voltage divided by the field current. By tracking the calculated field resistance over time, changes in the field resistance due to shorted turns can be identified and maintenance decisions can be made based on the observed field resistance. Because field winding resistance is a function of temperature, some variation in calculated field resistance will occur for different loading levels and to some extent for different seasons of the year. Consequently, it is important to record unit loading levels at the time the calculations are made to account for these variations. As an example of monitoring generator field windings using field winding resistance measurements Figure 4-7 shows a plot of calculated field resistance for a generator with a degrading field winding as monitored daily over a 9 month period of time. Figure 4-7 was generated by having the DFR automatically capture a record each day at the same time and then calculating the field current for each snapshot captured. Several items are of note in Figure 4-7:

1. Locations in the field resistance plot where calculated field resistance drops to zero are times when the unit is off-line.
2. Distinct changes in calculated field resistance give an indication when shorted field turns occurred.
3. Because field resistance is a function of field temperature, changes can be seen in field winding resistance that are not necessarily related to shorted field turns.
4. Increases in the number of shorted turns are usually related to when the unit has come on/off line and not to normal operating conditions. This is seen in the plot where changes to the calculated field resistance occur following a unit outage.

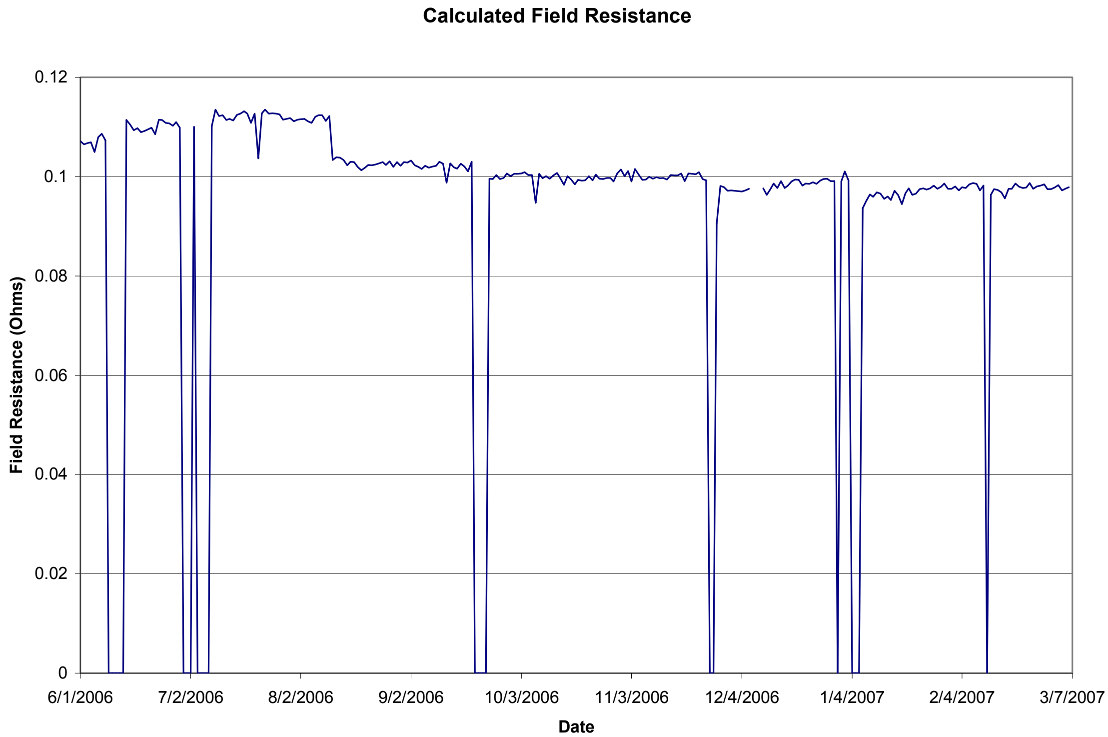

Figure 4-7
Calculated Field Resistance From Captured Digital Fault Records

In Figure 4-7 it is seen that in August 2006, a significant drop in the calculated field resistance occurred on this unit. This particular date related to an operating problem the power plant experienced but since the unit did not come off line at the time of the problem, a set of flux probe data was not obtained until the next time the unit came off line at the end of September. When this set of flux probe data was analyzed, it confirmed that several shorted turns had occurred. These shorted turns were attributed to the event back in August. Thus, daily calculation of field resistance using the DFR identified progression of the field winding problems before the flux probe data could be taken.

Power Plant Maintenance Extensions

Another potentially significant cost saving that monitoring technology can leverage in the power plant environment is the extension or delay of power plant major overhauls based on the data collected by digital monitoring technology. While the authors have not been involved in using DFR data for the purpose of extending the time periods between outages, some utilities have suggested that they consider adding an additional year to the maintenance schedule if over the course of the time between major overhauls there have been no significant events that impacted the subject unit. On the other hand, if one or more significant events have occurred during the time between overhauls, justification could be demonstrated to advance the schedule and perform an overhaul ahead of schedule to prevent possible further damage.

Similar arguments are being formulated with regard to regular maintenance of protective relays in the power plants. NERC Standard PRC-005-1 addresses the maintenance intervals on the protective system equipment in the system. Because some of this protective system equipment can only be maintained during unit outages, being able to justify longer maintenance intervals between relay maintenance would result in a cost and convenience benefit to the power plant. Some utilities are exploring the possibility of monitoring the PTs and CTs used on protective relay circuits for the purpose of demonstrating their proper operation and thereby justify extension of the relay maintenance time frames. Reference [21] is a technical reference published by the North American Electric Reliability Council that discusses the possibility of using digital oscillographic information from modern relays and digital recorders as part of the justification in a utility's relay maintenance program.

Generator Performance Verification

Power system stability studies don't always accurately model generator behavior for major power system disturbances. This became clear on July 1, 1996 and August 10, 1996 when two major system blackouts occurred on the west coast affecting people in the western United States, Canada and a portion of Mexico. Stability simulations had indicated that for the system conditions at the time of the initiating events, the system should have remained stable following the initiating events. The resulting blackouts were an indication that something was wrong with the models being used in the utility stability simulations. Eventually it was determined that the generator models being used in the program were not accurately modeling the generator behavior. Regulatory efforts were initiated to improve the generator models so transmission planners would be able to accurately predict unstable system operating points. As a consequence of the 1996 western area blackouts, the Western Electricity Coordinating Council (WECC)[9] developed a requirement for WECC member utilities to periodically test their generators and correlate their test results with stability program models to verify that the generator model accurately predicts the generator behavior. [Ref 4] Following the August 14, 2003 Northeast blackout, NERC told all the regional coordinating councils to develop similar model validation requirements.

WECC member utilities have perhaps the most experience in performing generator model validation testing. The general test requirements as specified by WECC are outlined in various WECC documents [Ref 5]. In all of these requirements the quantities measured involve quantities typically measured and recorded by DFRs applied to generators including terminal voltage, field voltage, field current, frequency, Power, and Reactive Power. Thus, for utilities that perform their own generator testing, data can often be collected for the model validation tests simply by recording the data already available on the generator DFRs. Table 4-1 gives the various tests that are typical for generator model validation. Note that all the quantities are easily obtained on a digital fault recorder.

[9] WECC is one of eight regional reliability organizations as designated by the North American Electric Reliability Corporation (NERC).

Table 4-1
Generator Test Listing

System Being Validated	Measured quantities	Validation Method
Generator Electrical Parameters	Vfd, Ifd, Vt	Compare measured and simulated quantities for Step change or unit trip at low load, underexcited in manual voltage regulator
Excitation System	Vfd, Ifd, Vt	Compare measured and simulated quantities for Step change or unit trip at low load, underexcited in automatic voltage control
Governor System	Frequency, P, Q	Compare measured and simulated frequency for unit trip at 10 – 15% load. Verify generator response to a significant system event.
Power System Stabilizer (PSS)	P, Vfd, Ifd	Compare measured and simulated power response to step change in AVR set point with and without PSS in service

To demonstrate the ability to capture staged generator model validation test data using a digital fault recorder, a comparison was made between DFR captured data and that captured by a dedicated data acquisition device typically used for generator model validation testing. Comparison data was captured for the following two different tests: generator trip test with unit on manual voltage regulator, step test with power system stabilizer out of service. Tests were performed on a 214 MVA combustion turbine with a digital static excitation system. Data was recorded on the DFR using two different sample rates: 2000 Hz and 100 Hz. The test data recorder was recording at 2000 Hz for most of the testing. Figure 4-8 shows a comparison of the pertinent model parameters and their response to the trip test on manual regulator. Note the following about the comparison of the DFR captured data versus the test recorder data.

1. Comparison of the captured terminal voltage shows the DFR and test recorder provide essentially the same results. A slight difference in the initial terminal voltage value is likely related to slight calibration differences in the data recorders. (See Figure 4-8)
2. Comparison of the generator field current for the trip test shows the DFR captured data has some noise associated with the data which is not seen in the test recorder captured data. This noise on the DFR trace is caused by aliasing of the signal. The raw field current signal has occasional notches associated with the commutation of the SCRs in the bridge circuit. The low sampling rate can correlate with the notch frequency causing this apparent noise on the field current signal. This could be filtered out of the DFR signal if desired. It is noted that the signal being recorded by the test recorder is pre-filtered with a low pass filter which accounts for its smooth appearance. (See Figure 4-9)
3. Generator field voltage comparison shows that the magnitudes of the signals compare but the DFR captured data does not show the slight decay of the field voltage during the event. This is likely due to the different bit resolution of the two recording devices. The DFR being used relies on 12 bit resolution while the test recorder is a 16 bit device. Calibration differences can also have a slight effect. (See Figure 4-9)

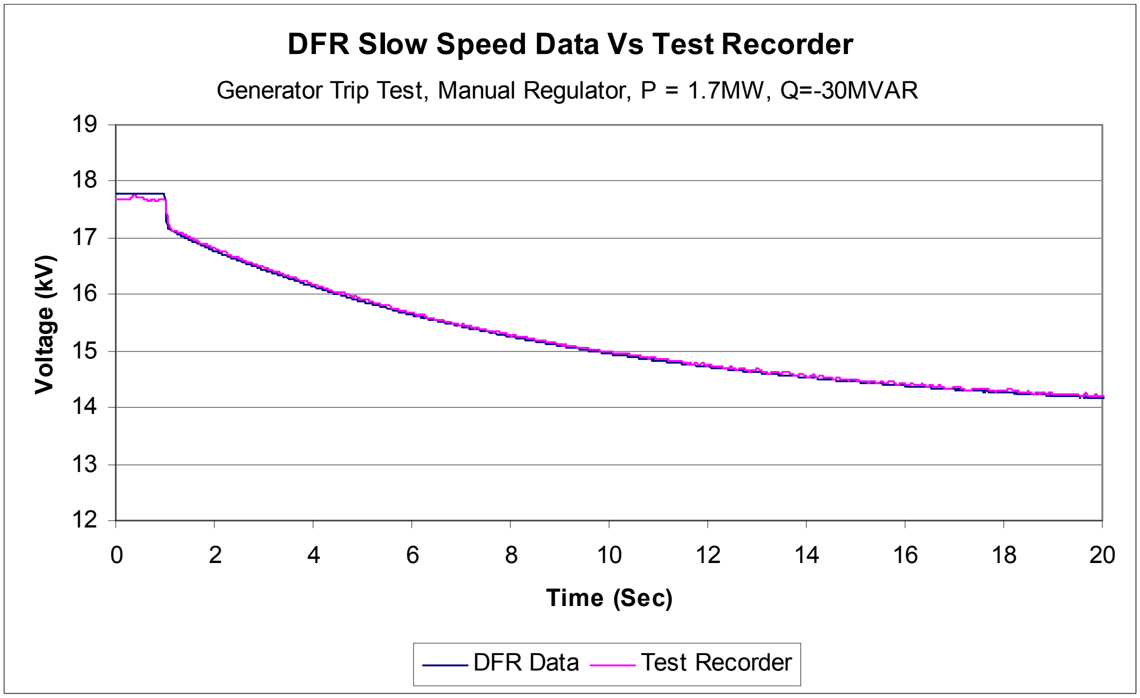

Figure 4-8
Trip Test – Comparison of Terminal Voltage Captured by DFR and Test Recorder

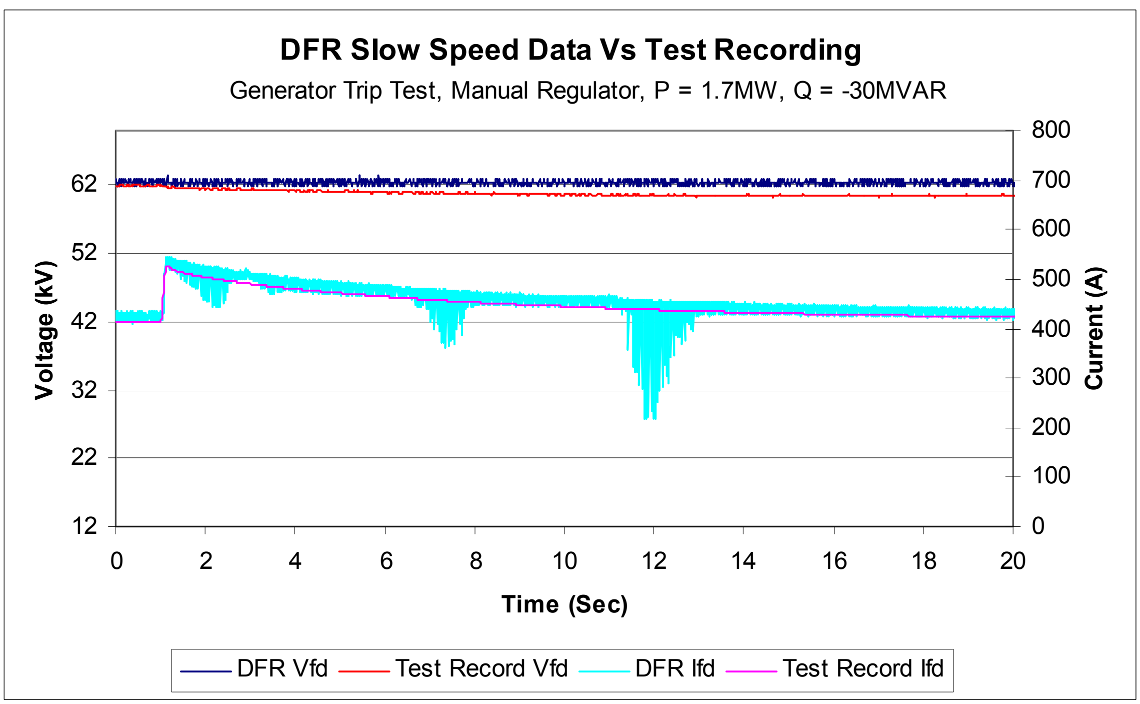

Figure 4-9
Trip Test – Comparison of Field Quantities Captured by DFR and Test Recorder

Figure 4-9 shows a DFR/test recorder comparison for a generator step test with the PSS disabled. Comparison of this data is made for both slow and fast speed data capture. Note the following points:

1. The power swings captured by the different recorders at different speeds agree quite well except for the low speed DFR captured data (Figure 4-10). The initial power swing captured by the low speed trigger on the DFR matches well but after the first cycle it appears that a negative DC offset is impressed on the signal. The reason for this is unknown and may be related to the sensor that is used to calculate power for the low speed sensor. The power signal from the high speed DFR trace is calculated after the fact and it's correlation with the test recorder results are excellent.
2. The step in voltage compares exactly between the DFR and test recorder at all sampling speeds (Figure 4-11). Post processing of the high speed DFR trace to obtain ΔVt from Vt results in some noise which isn't present on the slow speed trace or the test recorder traces. The slow speed DFR ΔVt signal is obtained using a sensor that converts to RMS before the sampling takes place.

From these examples it is clear that digital fault recorders have the capability to capture generator test data both using high speed and low speed recording. A typical generator DFR installation contains all of the monitored quantities that are used in generator testing so a digital fault recorder is a viable option for monitoring during generator testing. While being a viable option, one downside to using a digital fault recorder for generator testing is the time required for retrieving and analyzing data following each test. Use of a dedicated test recorder allows real time viewing of the generator response during the test so if any problems or unexpected behavior during the tests occur immediate action can be taken to mitigate the problem. Thus, use of a DFR for generator testing is not the preferred method, but is an acceptable one.

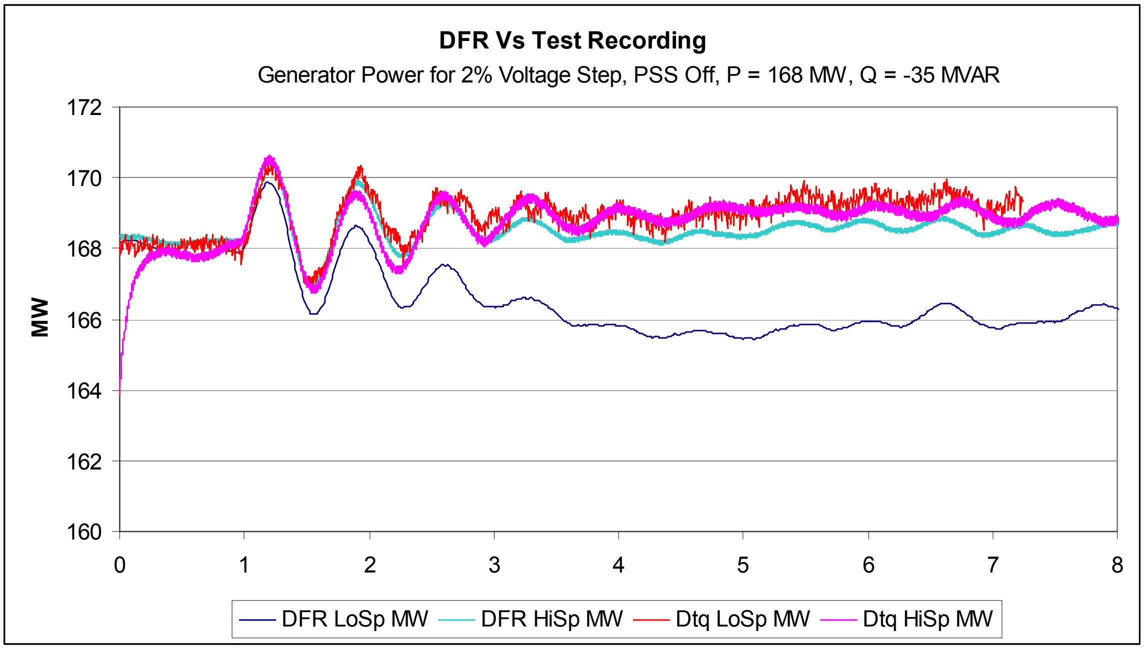

Figure 4-10
Step Test (2%) – Comparison of Power from DFR and Test Recorder

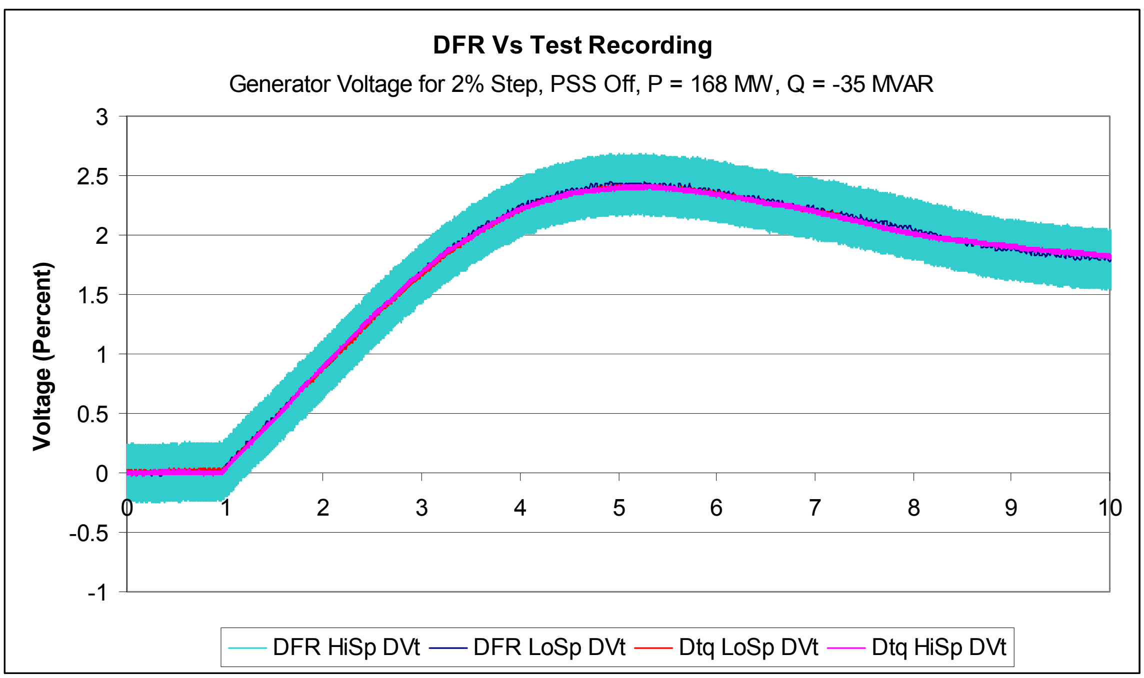

Figure 4-11
Step Test (2%) – Comparison of Terminal Voltage from DFR and Test Recorder

The model verification tests summarized in Table 4-1 are typically done by scheduled staged tests. Data is typically recorded and post processed later. Scheduling of unit tests can be complicated by the type of unit, operating schedule, and other system requirements. Nuclear units are particularly difficult to schedule for such tests because of their base load nature and their propensity for regulation and rules not seen at other types of plants. While it has been demonstrated that a DFR can be used to capture data during staged generator tests, the ideal method for verifying generator model parameters would be to use captured data from normally occurring system events to provide the needed model validation. Recent work in this area supports this approach as feasible and in fact preferred since the difficulties of scheduling dedicated tests at the plants are eliminated. Such a method of performing generator model validation is described in a recent EPRI publication titled "Automated Model Validation for Power Plants Using On-Line Disturbance Monitoring." [Ref 6] The approach is to use on-line disturbance recorded data as input to a MATLAB® based software product that uses a least squares fit algorithm to determine the appropriate generator, exciter, and governor parameters which match the recorded generator response. Significant aspects relating to the Digital Fault recorder setup to use such a model validation program include the following:

Required Signals

Minimum Required:

- Generator Terminal Voltage (RMS magnitude or three phase)
- Generator Power
- Generator Reactive Power
- Generator Terminal Bus Frequency

Extremely Desirable:

- Field voltage (exciter field voltage if brushless system)
- Field current (exciter field current if brushless system)

Additional Desired Signals:

- Generator Current (RMS magnitude or three phase)
- Generator mechanical speed
- Main control valve position (or fuel valve for gas turbines etc)
- Steam Pressure
- Steam Temperature

Required Sampling Rate

- 20 ms or better for generator and exciter parameter validation. Note that this is a fairly slow sample rate for a DFR but is easily obtained using a DFR's slow speed recording feature.
- 1 sec or better for governor parameter validation.

Record Length

- 60 to 120 seconds with at least 1 second of pre-fault data. Again this is best accomplished using the DFR's slow speed recording feature.
- For more details, refer to [Ref 6] and [Ref 7]

Test results of using this method for generator model validation show excellent results [Ref 6]. Use of fault recorders to provide input data to such generator model verification programs will become very advantageous in meeting regulatory requirements without incurring significant expense for staged generator testing.

Regulatory Requirements

A short discussion of how the east coast blackout of August 14, 2003 demonstrated the difficulty of post event analysis without quality disturbance and fault data was given in Section 4.1.1 along with the observation that the NERC report of the incident recommended multiple requirements relating to installation of time synchronized disturbance monitoring devices. As a follow up to those recommendations, the NERC Board of Trustees adopted two NERC Standards on October 2, 2006 that relate to disturbance monitoring. PRC-002 mandates that the different regional reliability organizations develop requirements for the installation of equipment to monitor disturbances on the electrical system. This standard covers the criteria for determining where disturbance monitoring equipment should be installed, what quantities should be monitored, and monitoring equipment minimum capabilities. NERC Standard PRC-018-1 specifies requirements for the generator and/or transmission owner in terms of equipment maintenance, testing, and reporting. While these present NERC standards leave it to the different regional reliability organizations to define which generation and/or transmission owners must install the disturbance monitoring equipment, work is in progress to update these standards with continent-wide standards defining who must install such equipment. The expected final outcome of this work is a consistent standard specifying which generation owners and which transmission owners must install disturbance monitoring equipment, what the minimum capabilities of that equipment must be, and what maintenance and reporting will be required for that equipment. Because the standards are enforceable with the possibility of substantial fines for non-compliance, certain generation owners will have a financial incentive to begin monitoring using fault and disturbance recorders. More details regarding the various standards associated with fault and disturbance monitoring are given in Section 5 of this document.

What to Monitor

Based upon the authors joint experience of 50+ years in DFR application to power plants, the following list of generator variables and their definitions are provided in order of their importance. Other optional DFR inputs are grouped separately and their specialized applications discussed. The expected dynamic range of DFR inputs is discussed along with any other considerations and relevant information. Refer to Figure 4-12 for an overview of variable access points – each candidate DFR input variable is enclosed by an oval or circle to indicate its pick-up point for DFR input.

Analog Inputs

1. $\mathbf{V}_{ab\ gen}$, $\mathbf{V}_{bc\ gen}$, $\mathbf{V}_{ca\ gen}$ – Generator phase to phase voltages[10]. Theses quantities are available from the generator PT inputs to either the unit's GPR or its voltage regulator. (3 analog inputs). Typically, they produce a nominal 120 Vrms, with no more than 150% of nominal = 180 Vrms possible in extreme transient conditions. Similarly, a nominal phase to neutral phase of 69vrms is typical, with no more than 150% of nominal = 103.5 Vrms.

2. $\mathbf{I}_{a\ gen}$, $\mathbf{I}_{b\ gen}$, $\mathbf{I}_{c\ gen}$ – Generator phase currents. These quantities are available from the generator CT inputs to the unit's GPR. (3 analog inputs) The dynamic range of generator current to record with saturating the channel is quite large. The maximum instantaneous generator current occurs for a fault on the low side of the generator step up transformer (GSU). Fault current amplitude is inversely proportional to the generator's subtransient reactance, $\mathbf{X''}_d$. For $\mathbf{X''}_d = 0.2$ the maximum per unit current is 1/(0.2) = 5.0 per unit. Worst case, the generator fault current could be fully offset depending on the point on wave when the fault initiates. This implies a full scale dynamic range of 10 per unit. By example, a 100 MVA, 13.8kV machine rated 1 per unit current is 4,184 amps rms or 5917 amps zero to peak. This means that the generator current channels must be configured to accept 10 times 5,917 amps = 59,170 amps zero to peak! One means to circumvent the high dynamic range requirements of generator current is to utilize two sets of current channels. The first set is calibrated for the maximum possible current. The second channel set is calibrated for only 1.5 or 2 per unit full scale. High resolution of steady state current is achieved, but at the price of three additional analog inputs.

3. $\mathbf{V}_{fd\ gen}$, $\mathbf{I}_{fd\ gen}$ – Generator main field voltage and field current (2 analog inputs). These quantities are not available on generation outfitted with brushless exciters. Route these quantities as transduced exact replicas[11] of the actual field voltage and current to the DFR from the excitation cubicle. Since the field voltage and current are supplied to the DFR via transducers with a maximum +-10 volt output, the DFR channels are configured to accept a full scale input of 10 volts. The input range of the field voltage transducer determines the maximum field voltage the DFR will accept. The value of the current shunt (i.e. "X" amps per 100 millivolts) along with the input range of the field current transducer (i.e. 50, 100 or 200 millivolts input for 10 volts output). Utilize a field voltage transducer rated at twice rated field voltage for the machine being monitored. For optimum utilization of DFR dynamic range, select a field current transducer rated for the same input voltage as the shunt (i.e. use a 100 millivolt field current transducer with a 100 millivolt shunt).

4. $\mathbf{V}_{fd\ exc}$, $\mathbf{I}_{fd\ exc}$ – Generator pilot exciter field voltage and field current (2 analog inputs). These quantities are available on generation outfitted with brushless exciters. Route these quantities as transduced exact replicas of the actual field voltage and current to the DFR from

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[10] Phase to neutral voltages are acceptable as well and are designated as $\mathbf{V}_{an\ gen}$, $\mathbf{V}_{bn\ gen}$, $\mathbf{V}_{cn\ gen}$.

[11] The philosophy here is that it is not prudent to route high energy dc circuits from the exciter to the DFR. Instead, wideband isolation transducers for field voltage and 100 millivolt current shunt output are installed at a point close to the excitation source, typically in the exciter cabinet or at the brush rigging and collector rings if a current shunt is nearby. The transducer outputs are selected to be +-10 volt full scale outputs. This insures that the person doing field work in the DFR cabinet will not encounter any potential inside the DFR cabinet high than the nominal 120 Vac PT circuit. It also eliminates the possibility of inadvertently grounding out the field circuit at the DFR cabinet point. The Ohio Semitronics, Inc. Model VT7 series is particularly well suited to this application.

the excitation cubicle. Since the field voltage and current are supplied to the DFR via transducers with a maximum +-10 volt output, the DFR channels are configured to accept a full scale input of 10 volts. The input range of the field voltage transducer determines the maximum field voltage the DFR will accept. The value of the current shunt (i.e. "X" amps per 100 millivolts) along with the input range of the field current transducer (i.e. 50, 100 or 200 millivolts input for 10 volts output). Plan on using a field voltage transducer rated at twice rated field voltage for the machine being monitored. Always select a field current transducer rated for the same input voltage as the shunt (i.e. use a 100 millivolt field current transducer with a 100 millivolt shunt).

5. $\mathbf{V_{ab\ sys}}$, $\mathbf{V_{bc\ sys}}$, $\mathbf{V_{ca\ sys}}$ – System side of the generator breaker phase to phase voltages[12]. Theses quantities are available from the generator breaker system (switchyard side) PT inputs to either the unit's auto-synchronizer or synchro-check relay. Recording these variables allows for a cross check of auto-synchronizer and breaker performance. It is common to have breakers configured on the low side of the generator step up transformer (GSU) on the newer combined cycle plant designs. Older plants will not have a low side breaker and the GSU will be solidly connected to the generator bushings via a bus. (3 analog inputs). Typically, they produce a nominal 120 Vrms, with no more than 150% of nominal = 180 Vrms possible. Similarly, a nominal phase to neutral phase of 69vrms is typical, with no more than 150% of nominal = 103.5 Vrms. In cases where there is no low side breaker, voltages on the high side of the GSU may be monitored.

6. $\mathbf{V_{n\ gen}}$ – Voltage developed on the resistor connected across the secondary of the generator's neutral grounding transformer. Knowing the ohmic value of the neutral grounding resistor allows scaling of this quantity to a stator current to ground. (1 analog input). The maximum neutral grounding transformer voltage is related to the ratio of the neutral grounding transformer and the generators phase to ground voltage. The secondary voltage is typically 240vrms. Consequently, the maximum generator neutral ground voltage (and current) the DFR would be expected to record is 240 Vrms @ 60Hz. The secondary side current to ground is then equal to $\mathbf{V_{n\ gen}/R_n}$, where $\mathbf{R_n}$ is the value of the neutral grounding resistor. When no ground fault is present, expect the neutral ground voltage to be a 0.5 to 10 Vrms at 180Hz under balanced conditions. A predominantly 60 Hz voltage indicates an unbalanced condition.

7. $\mathbf{V_{batt+}}$, $\mathbf{V_{batt-}}$ – Station battery voltage from the positive and negative legs to ground. (2 analog inputs) Select the dynamic range of the DFR channels for station battery voltage to be 1.5 times rated battery voltage or more. Experience has shown that oscillatory transient voltages are sometimes superimposed upon the station battery. On a nominal 125 Vdc system, plan on selecting a dynamic range of approximately 200 volts for both channels. These voltages can be superimposed upon the nominal station battery voltage. On occasion these transients have caused problems with devices powered from the dc bus. Recording the positive and negative battery voltages to ground also serves as a backup dc ground monitor. Under balanced conditions on a 125 vdc system, both battery channels measure 125/2 = 62.5 vdc to ground. As a ground to either the positive or negative bus develops, one channel voltage depresses and the other rises.

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[12] Phase to neutral voltages are acceptable as well designated as $\mathbf{V_{ab\ sys}}$, $\mathbf{V_{bc\ sys}}$, $\mathbf{V_{ca\ sys}}$.

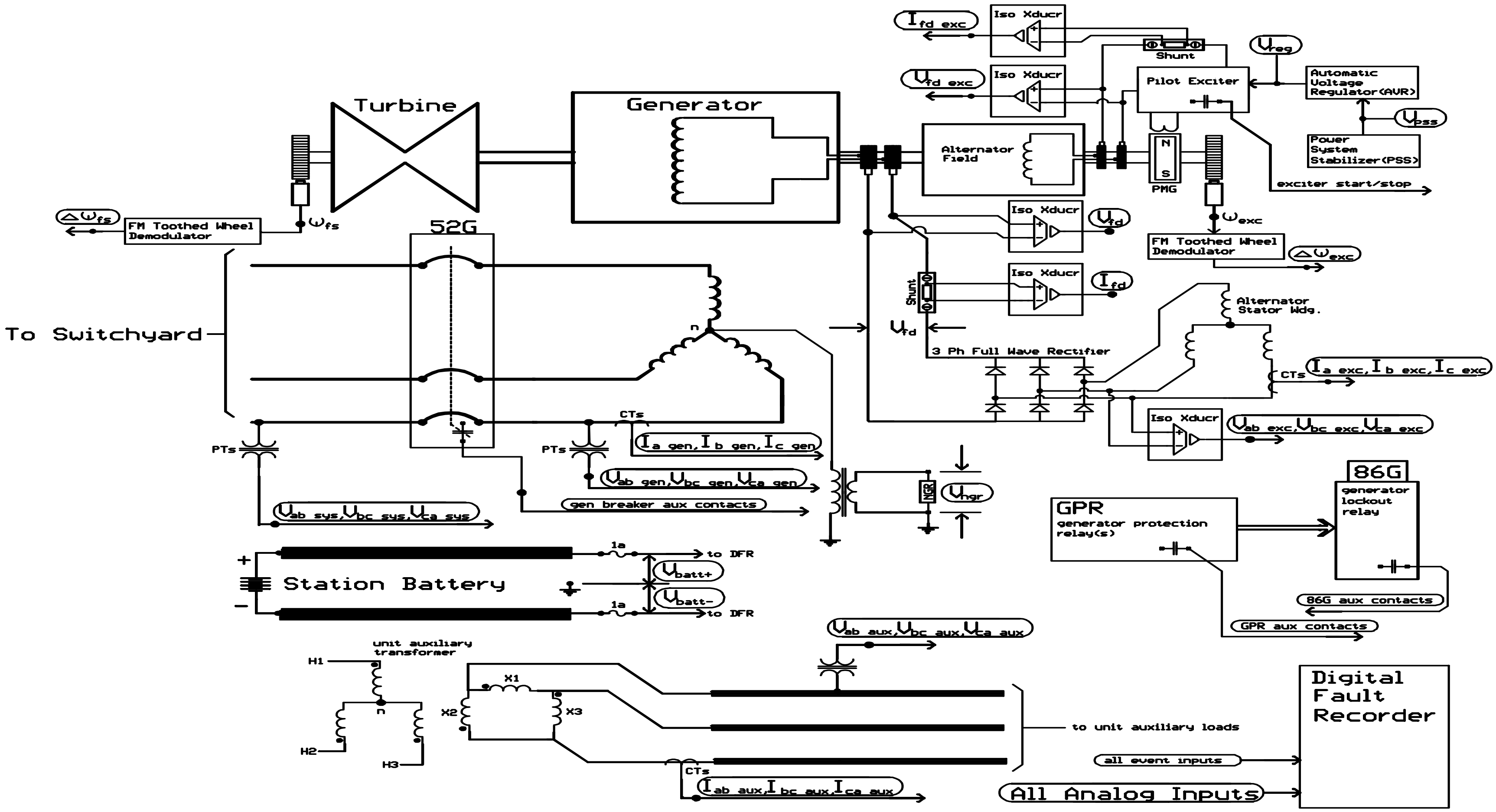

Figure 4-12
DFR Variable Access Points

Optional Analog Inputs

1. $\mathbf{V_{pss}}$ – Power System Stabilizer (PSS) output (1 channel). This is an optional DFR input of interest to those involved with the commissioning, tuning and dynamic performance of PSS. The nominal +- 10volt output of some power system stabilizers may be monitored via an analog output terminal. On some digital regulators with an integral PSS, it may require mapping to develop an output[13]. The DFR input range for V_{pss} may be coordinated with the output limiter of the monitored PSS. In no case will it ever be larger than +-10vdc.
2. $\mathbf{V_{reg}}$ – Voltage Regulator Output (1 channel). The output of the generator's automatic voltage regulator to the control circuit of the exciter. Plan on a +-10 volt dc level as a typical AVR output into the DFR. The conversion of this voltage level to meaningful engineering units is defined by the AVR manufacturer.
3. $\boldsymbol{\Delta\omega_{fs}}$, $\boldsymbol{\Delta\omega_{exc}}$ **–** Delta Omega front standard and delta omega exciter – speed signals indicating the speed deviation of the turbine front standard and exciter end from synchronous speed. $\boldsymbol{\Delta\omega_{fs}}$ and $\boldsymbol{\Delta\omega_{exc}}$ are derived from the toothed wheels, speed pickup sensors mounted at each end of the turbine generator and an FM demodulator[14] to extract $\boldsymbol{\Delta\omega_{fs}}$, $\boldsymbol{\Delta\omega_{exc}}$ from the front standard and exciter end carrier waves. This data is important to units subject to subsynchronous resonance (SSR) and torsional vibration phenomena. Record these quantities on a +-10 volt range and refer to the FM demodulator manual for conversion from volts output to radians/sec output.
4. $\mathbf{V_{ab\ exc}}$, $\mathbf{V_{bc\ exc}}$, $\mathbf{V_{ca\ exc}}$ – Exciter phase to phase ac voltages that are inputs to the SCR bridge from the excitation system power source[15].
5. $\mathbf{I_{a\ exc}}$, $\mathbf{I_{b\ exc}}$, $\mathbf{I_{c\ exc}}$ - Exciter phase currents that are inputs to the SCR bridge from the excitation system power source[16].
6. $\mathbf{V_{ab\ aux}}$, $\mathbf{V_{bc\ aux}}$, $\mathbf{V_{ca\ aux}}$ – Unit auxiliary transformer phase to phase ac voltages.
7. $\mathbf{I_{a\ aux}}$, $\mathbf{I_{b\ aux}}$, $\mathbf{I_{c\ aux}}$ – Unit auxiliary transformer phase currents.

Event Inputs

1. Generator breaker status (open / closed)
2. Exciter Start / Stop

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[13] In some cases the mapped output may only be available as a 4 to 20 milliampere signal. An external conversion device is available to transform the current loop signal into an equivalent +-10 volt level suitable for DFR input.

[14] The *EUMAC, Inc.* Model FMD-01 toothed wheel FM demodulator is a commercially available device for providing $\boldsymbol{\Delta\omega_{fs}}$, $\boldsymbol{\Delta\omega_{exc}}$ outputs.

[15] Excitation system manufacturers typically do not provide PTs for these quantities. A wideband isolation transducer is recommended to faithfully reproduce these waveforms and isolate the wiring to the DFR from the high power circuit.

[16] CTs are not typically provided. A split-core CT with internal burden is recommended to isolate the wiring to the DFR from the excitation system.

3. "86G" Generator Lockout Relay
4. Generator multi-function relay when an output is generated.

Where to Monitor

The digital revolution within the power industry has seen digital control and protection spread throughout the power plant, supplanting traditional analog devices in the areas of relay protection, automatic voltage regulator controls, and process monitoring. As digital processing power has increased, the ability to do more with less has led to many devices incorporating digital fault monitoring as an integral part of the basic product. In addition, new capabilities have not only been invented, but have been pushed into devices so that digital monitoring of equipment and processes can be made available in every nook and cranny of the power system and power plant. Many of the vendors and manufacturers of these devices that have incorporated digital oscillography into their products have incorporated the COMTRADE standard. This allows for portability of these records and common analysis program capability.

Table 4-2 provides a list of the various locations in a power plant where digital monitoring capability is available along with a list of pros and cons associated with the monitoring.

Table 4-2
Power Plant Locations With Digital Monitoring Capability

Device	Location	Pros	Cons
Digital Fault Recorder	Typically centrally located where desired monitored quantities are readily available. Other options allow remote locations which communicate with a central master device via fiber optic or other cabling.	Provides high speed and low speed monitoring of both analog and digital quantities in a single device. Strong analysis capabilities and support programs	If all analog or digital quantities are not readily available, must pull cable to location of device. Separate box for monitoring means additional cost for hardware and installation.
Sequence of Events Recorder	Centrally located where monitored quantities are readily available.	Provides accurate time tagging of digital events. Thousands of channels can be monitored. Lower cost than DFRs	Limited to only digital events.

Table 4-2 (continued)
Power Plant Locations With Digital Monitoring Capability

Device	Location	Pros	Cons
Digital Relay Oscillography	Internal to digital protective relays	Embedded in digital relays so no additional cost. Valuable in verifying proper relay function as quantities relay operates on are measured.	Monitoring limited to relay quantities Limited flexibility on modifying recording parameters. Analysis software may be difficult to use.
Phasor Measurement Units	Can be deployed as centrally located units or can be distributed in various protective relays which communicate to a central data concentrator.	Time synchronized phasor quantities Long duration disturbance records. Phase angle readily available. Future “smart grid” applications expected.	High speed sub-cycle events not captured. Data file format different from DFRs
Digital Voltage Regulator Oscillography	Internal to digital voltage regulators	Embedded in voltage regulator so no additional cost Valuable in viewing exciter and regulator parameters as many parameters not available outside the exciter are available for recording.	Recorded quantities limited to exciter and regulator parameters. Limited flexibility on modifying recorded parameters.
Digital PSS Oscillography	Digital Power System Stabilizers	Embedded in PSS so no additional cost Independent means of verifying proper PSS performance	Limited data set to record. Limited flexibility on sample rate, length, etc.
Distributed Control System (DCS) and SCADA	Part of plant control and monitoring.	Long term recording capabilities. No additional cost.	Slow speed recording on the order of one or 2 seconds per scan provides only general trending. Fault event analysis not seen due to sample rate.

Table 4-2 (continued)
Power Plant Locations With Digital Monitoring Capability

Device	Location	Pros	Cons
Portable DFRs	Applied at any location desired.	High and low speed analog and digital recording capability. Analysis software and complex triggering available. Portability allows temporary monitoring at problem spots.	Limited number of channels. Comparatively expensive
Stand alone recording instruments.	These are small portable devices that can be applied where ever monitoring is required.	High speed analog and digital recording Very portable Very compact Laptop PC controlled and data can be easily imported to standard office programs such as spreadsheets.	Limited number of channels Typically don't come with provided analysis software except for display of captured waveforms Medium to high cost device. Some may not have isolated channels.

As more and more digital products incorporate digital oscillographic capabilities, more of the power plant operation will be monitored to a degree that malfunctions or mis-operations of equipment will be easily diagnosed and understood. While incorporation of oscillography into relays and exciters provides some overlap in the digital monitoring coverage, the ability of stand alone recorders to monitor vast amounts of data and processes will continue to have an important place in power plant monitoring. Often, power plant monitoring goals are only achieved using stand alone digital fault recorders.

Centralized Schemes

Figure 4-13 gives a diagram of a centralized digital fault recording scheme. Centralized schemes bring all monitored quantities back to a single unit for monitoring. Some DFR hardware cost advantages are seen with centralized schemes because a single chassis, and common power supplies reduce the overall equipment costs. Monitoring of a single generator is often most cost effective using a centralized scheme. Sometimes, multiple units can also be monitored most efficiently using a centralized scheme when quantities for the multiple generating units are readily available in a common location. Older plants built before the distributed control system (DCS) era are good candidates for a centralized DFR. They typically have hardwired control cabinets in the operator's area. These cabinets house analog metering for generator voltage and current as well as protective relaying connections – either the original electromechanical units or retrofit digital generator protection relays. When most variables are already concentrated in a single location, the centralized DFR configuration is the logical choice.

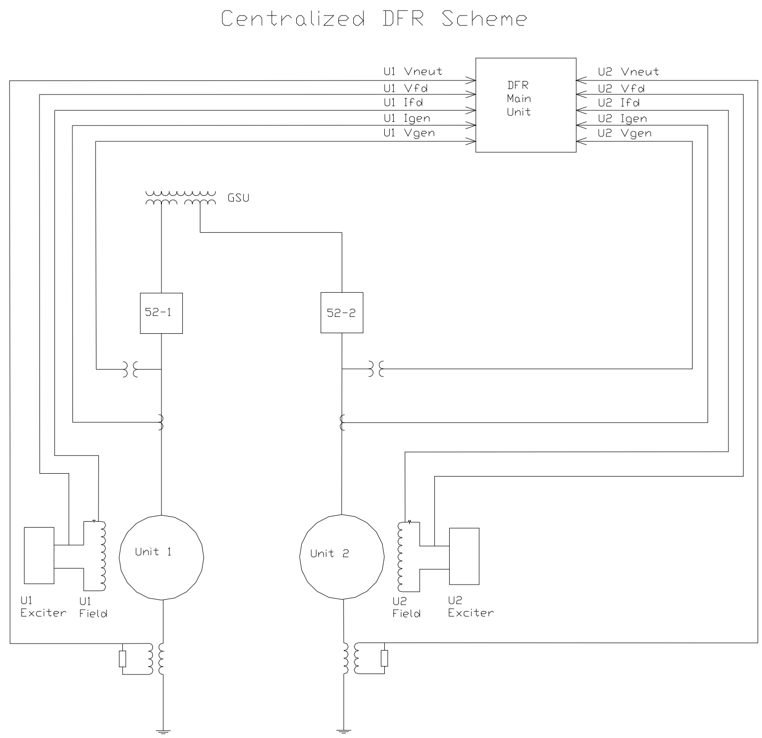

Figure 4-13
Centralized DFR Scheme

Distributed Schemes

For instances where not all quantities are in a single location, the cost of bringing each quantity being measured to the DFR can, in some cases, quickly drive up the cost of the DFR installation making a distributed application preferred. Many combined cycle power plants have separate buildings for each gas turbine and steam turbine that comprise the units. For such configurations a choice is available of applying centralized fault recording on each individual unit, or applying a distributed system where remote fault recording units provide their data to a common master unit. Figure 4-14 shows a diagram of a distributed fault recording configuration. Note that in the distributed scheme, remote units are used to monitor separate sets of analog/digital quantities with the remote units connected to a common location via fiber optic cables. The reduction in cost from eliminating the pulling of cables to a central location in most cases more than offsets the additional cost of installing separate remote hardware units. Figure 2-3 presented earlier shows a more detailed diagram of a distributed DFR monitoring scheme.

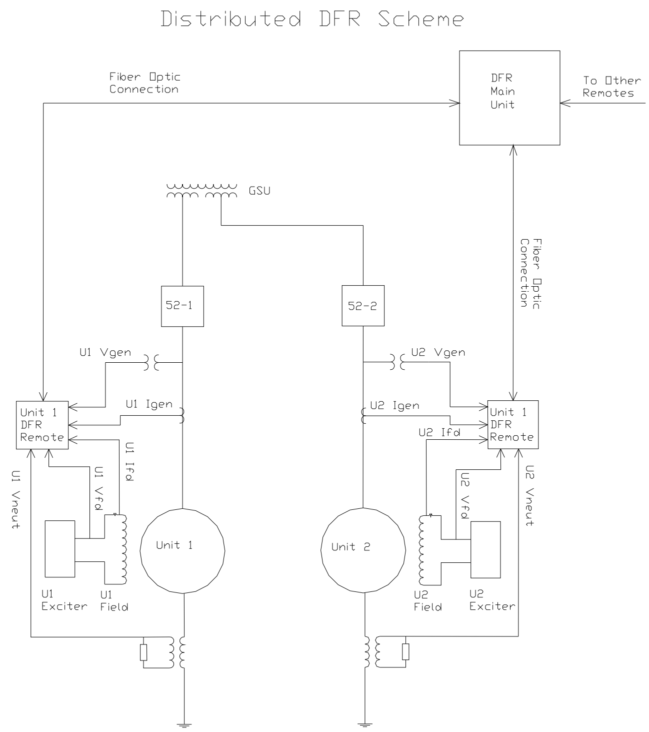

Figure 4-14
Distributed DFR Scheme

When to Monitor

Digital fault recorders are continuously monitoring each analog and digital input, but they only record and capture data when a sensor or trigger event occurs. Intelligent application of triggers and sensors are key to ensuring that critical data is captured for significant events, while avoiding a deluge of insignificant records. Triggering of the DFR is initiated by closing of a hardware contact or by the satisfying of certain criteria defined by sensor settings that are implemented in hardware or software sensors. Typical trigger settings applied to generator DFRs are listed below.

1. Operation of the generator breaker – most significant generator events result in operation of the generator breaker. High speed triggering the DFR should be set up for generator breaker opening and closing events.
2. Operation of the generator protective relays – this can either be off a contact from the generator protection relay(s) or from the generator lockout relay. Typically the triggering off these contacts is only done for contact status change in one direction, not both. High speed triggering is recommended.
3. Generator Overcurrent – A sensor is usually set to trigger the recorder for generator currents in excess of 10 – 20% of rated generator current. High speed triggering is recommended.
4. Generator Overvoltage – A sensor is set to trigger for generator terminal voltages exceeding 7 – 10% of rated generator voltage. High speed triggering is recommended.

5. Generator field current overvalue – This is a software trigger set in the range of 10 – 20 % of the full load field current. For units with digital excitation system, this sensor trigger is less important as most digital exciters have their own oscillograpy to monitor the generator field quantities.
6. Generator Frequency – This is a software trigger that is usually set for off frequency operation of the generator in the range of ±0.07 – 0.10 Hz. If the DFR has the capability, the trigger can be supervised by the status of the generator breaker so inadvertent triggers as the unit is coming on or off line are avoided. Low speed triggering may be preferred here.
7. Sequence Component Sensors – Sensors can be set to trigger fault records when a given symmetrical component type exceeds a given level. Zero sequence currents flowing in the generator can generally be detected in high impedance grounded systems by triggering a simple overvoltage sensor looking at the voltage across the grounding resistor.
8. Unbalance sensors – Because negative sequence is a method of measuring unbalance, an unbalance sensor provides little additional information that a negative sequence sensor provides.
9. Plant specific contacts – Digital inputs to the fault recorder can come from any contact that the power plant deems important to monitor. In the early days of the author's experience, one particular power plant had a rash of generator motoring events. To monitor this, the output of the anti-motoring relay's alarm and trip function was wired to the DFR event inputs. Each time an anti-motoring event occurred, the DFR output was analyzed and a report illustrating the event with undisputable facts was sent to plant management. Within a short period of time, the generator motoring events stopped at the plant.

Data Access

The issue of data access to the records captured by the fault recorder is one with various different facets including who has access to the recorders, software license issues, methods of sharing files, who has access to the recorders for maintenance purposes, etc. Access to the programming of the DFR can have regulatory issues depending on how the DFR is defined in terms of the Critical Infrastructure Protection (CIP) standards that NERC has adopted. Most of these issues are a function of the staffing levels and competency levels of power plant and central office staff. Following is a listing and brief summary of issues related to who gets direct access to the DFR and its data:

1. Software Licensing – Many of the DFR manufacturers provide company wide licensing of the master station software for use throughout the entire company by any and all people who want to use the software. A few manufacturers require individual licenses for each copy of the software installed with some provision that after a certain number of licenses are obtained a default site license for the company is obtained. With individual software licenses required, distribution of the software can be limited as a cost savings requirement. Fortunately, with the COMTRADE standard, data collected using any manufacturers equipment can be converted to a format that other viewing software and read and display.
2. Central Group versus Distributed Analysis – Typically the DFR master station will reside in the care of one particular group within a company. All DFR records are automatically sent to the master station(s) for archival and analysis. Most DFR software packages have the

capability to send data to more than one location or at least be able to allow more than one location access to the data. In the authors' experience, installing the master station software at the various power plants that are being monitored is an advantageous strategy for two reasons. First, it encourages personnel at the power plants to become actively involved in the analysis of the information provided by the fault recording technology. Second, as power plant personnel gain abilities and confidence in the analysis of fault records, fewer calls to the central analysis group will result. Unfortunately, the power plant staffing is often at a level that does not allow personnel the luxury of the time needed to obtain proficiency in data retrieval and analysis.

3. If a company has located its DFR hardware in a location that has been secured as part of a Critical Infrastructure Protection (CIP) plan (see Section 5), then access to the hardware will be restricted to a limited set of personnel. Requirements for access to equipment in CIP defined areas mean that non-cleared personnel must be escorted at all times by someone with access. Thus, those involved in the setup, calibration, and maintenance of the DFR need to have CIP clearance according to their individual company plan.
4. Access to the DFR data is readily accessible to all who need the data via the COMTRADE standard. One issue that may arise is how far inside and outside the data should be shared. Some companies consider the information contained in DFR and other disturbance records to have market value since the data may show or reveal generation levels, generation outages, etc. In these cases a company may require non-disclosure documents to be signed before sharing the data with outside entities. In addition, sometimes a company may not wish to widely circulate information from fault recorders due to other legal ramifications. Equipment failure can often have insurance ramifications and the documentation of the equipment behavior prior to, during and following the failure may be important evidence in a possible law suit or investigation. Thus, each DFR owner needs to determine how widely it disseminates information as well as for how long it will retain the information. With the exception of legal issues, the authors' experience to date has been the most benefit is obtained by sharing the information with the greatest possible audience.

Data Interpetation

Analysis of the data captured by the digital fault recorder is most often accomplished using the master station software provided by the DFR vendor. These software packages contain many tools with which an engineer can dissect, interpret, and understand the information. The tools improve the efficiency of the data analysis process providing significant benefits to the user. The following is a description of some of the tools that are used most often in the analysis of data.

1. Window Definition Capability: There are a significant number of analog and digital channels associated with power plant DFR applications. The display of these channels in a window type environment is normally set upon initial installation and set up of the DFR. However, it is often advantageous to only display those analog and digital quantities that are of interest for a particular unit or event. The window view can usually be altered to provide only those quantities desired and this view can be saved so that at any time, any record can be arranged in that view with a click of a button. Being able to look at the data needed without having to mentally sort through the extraneous data is a tremendous efficiency help in the analysis of the records.

2. User Defined and Calculated Channels: The capability of applying various transformations and mathematical functions on the captured data can provide enhanced analysis capability. Most software packages have various functions that can be applied to the data. Examples include frequency calculation, sequence calculations, RMS calculation, unbalance calculation, and phase angle calculations. In addition to these pre-defined functions, a user can apply mathematical functions to the raw data to obtain additional information that may not be available otherwise. Calculation of real and reactive power is often obtained this way (See Appendix A). Other analysis and manipulation of the data can also be done (see Section 6 for examples).
3. Harmonic and Phasor Calculations: Most DFR software packages have the capability to use advanced analysis techniques to display harmonic levels in a given signal and show voltage and current phasors in a phasor diagram mode.
4. Time Line Manipulation: For events captured during an event that spans a relatively long time, the DFR may trigger several different records that need to be time aligned for proper analysis. Software is usually included with the master station that will time align the various data records for proper sequencing of events in an easy to see graphical manner. In addition, some software will tabularize the events from different records for an easy to read table of the sequence of events. All of the software also has the capability of zooming the time scale in or out for proper viewing resolution.
5. Annotation Capability: One of the most beneficial tools available with most Master Station software is the ability to annotate a record by placing comments, observations, arrows, etc directly on the waveform records. This is of particular help when providing documentation to plant management and others not used recognizing the significant information in a fault record. These annotations can be saved in a user defined view and readily recalled by choosing the particular user view.

As time goes on, the software and analysis capabilities provided with the master station software will continue to improve. Outside software also exists with tremendous analysis capabilities.

Summary

This section has described the justification of applying dedicated digital fault and disturbance recorders to generating units and discussed various advantages to having dedicated recording devices. An overview of advantages associated with rapid post event analysis demonstrated that real monetary gains can be seen in terms of reduced outage time following unit trip events. In addition, the reduced costs associated with using DFR data and software applications to replace or eliminate the need for hardware solutions to problems can be significant. The possibility of automating processes through data collection and analysis can also reduce maintenance and personnel costs and can in some cases justify the installation of such equipment.

A compelling case was made for maintaining compliance with coming regulatory requirements by installation of DFRs. Installed DFRs not only meet mandated recording requirements, but the potential of using the data captured either during staged tests or during system disturbances was shown as being desirable for generator parameter model verification regulatory requirements.

A listing of typical analog and digital signals is suggested for power plant monitoring. These signals include generator voltages, currents and excitation system voltages and currents together with other special signals unique to power plants. A diagram showing the sources for these signals is provided. Triggering methods and signals are discussed as well as a thorough overview what to do with the data once it has been captured and who to share the data with.

5
REGULATORY REQUIREMENTS AND STANDARDS

Major system events and blackouts have a tendency to focus attention not only on the causes of the failures, but on the monitoring systems that are used to help understand why the failures occurred. This is true because the holes left by inadequate monitoring are glaringly evident under the scrutiny of post event analysis. While the electricity industry formed an informal voluntary organization for the purpose of improving coordination of the bulk electrical system in the early 1960s, it was the Great Northeast Blackout in November of 1965 that started in motion the creation of what has ultimately come to be known as the North American Electric Reliability Corporation (NERC). Early on, nine regional reliability organizations were formed under NERC with each organization overseeing a defined geographical area. These regional reliability organizations were independent overseers for their particular regions. Another major blackout in New York City in July of 1977 resulted in the first federal legislation relating to electric reliability. Initially the standards and operating policies that were formulated and accepted by NERC were general guidelines but over time and with other major system blackouts and events to occasionally refocus attention on reliability, these standards have become mandatory. Following the August 14, 2003 northeastern blackout, federal legislation as part of the U.S. Energy Policy Act of 2005 authorized the Federal Energy Regulatory Commission (FERC) to oversee NERC and require compliance with reliability standards. In June 2007, compliance with the NERC approved standards became not only mandatory in the United States but it also became enforceable with monetary penalties for non-compliance. While the vast majority of the NERC standards are not related directly to the subject of fault recording, there are some specific standards that do focus on fault and disturbance monitoring while other standards can have an effect on how fault monitoring is undertaken and/or leveraged in a utility or generating plant.

In addition to NERC requirements and standards, other entities may have standards that are related to fault and disturbance monitoring either from a regulatory standpoint or from an industry or equipment manufacturing standpoint. A discussion of the different standards associated with disturbance monitoring follows.

NERC Standards

The following NERC standards are related to fault and disturbance monitoring and may impose requirements on generation owners. Some standards may not directly impose a specific requirement, but the installation and use of digital fault recording technology may be beneficial in meeting the standard's requirements.

NERC Standard PRC-002-1:

The title of this standard is "Define Regional Disturbance Monitoring and Reporting Requirements." [Ref 8]. This particular NERC standard exists within the Protection and Control (PRC) category and requires the different regional reliability organizations to establish and define requirements for installation of fault and disturbance monitoring recording equipment at locations in there regions. There are eight regional reliability entities which cover North America as follows:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Texas Regional Entity (TRE)
- Western Electricity Coordinating Council (WECC)

Each of these different regional entities cover a different portion of North America and have the responsibility to develop the standard for their region as it relates to the requirements outlined in NERC PRC-002-1. As pertains to generating stations, the standard developed by the individual regional reliability organization fulfilling the requirements of NERC PRC 002-1 would have to specify a criterion for defining where monitoring equipment would be required. This could be defined by size of generating station, location within the reliability region, connection voltage or whatever the regional reliability group determines. In addition, this NERC standard requires each regional entity's standard to specify what must be monitored at each location, sampling speed requirements, triggering requirements, record duration requirements, and capability requirements for the instruments. The types of events that must be collected, the format of the data, file naming requirements, and time to provide data are also required to be specified. Because it is left to the eight different regional organizations to develop their own standards, differences in requirements are bound to develop between different locations throughout North America. Each generating plant owner must be familiar with the standards developed by their parent reliability organization to make sure that the appropriate equipment is installed, set up, and maintained according to the individual standard.[17] Each regional organization maintains a web site that outlines the standards its organization has developed and approved.

NERC Standard PRC-018-1:

The title of this standard is "Disturbance Monitoring Equipment Installation and Data Reporting." [Ref 9] This particular standard applies directly to the generation (or transmission) owner and basically contains requirements that the generation/transmission owners comply with

[17] See discussion of NERC Project 2007-11.

the regional reliability standards defined in PRC-002. While there are a few specific requirements relating to providing information about the recording equipment to the reliability organization, most of the requirements in this standard state that the generation/transmission owner shall meet the requirement as defined by the regional reliability organization's requirement. Thus, as with PRC-002, the generator/transmission owner must be familiar with the specifics of the standards as defined by their individual regional reliability organization.[1]

NERC Project 2007-11:

The title of this project is "Disturbance Monitoring" and is a project which involves taking NERC Standards PRC-002-1 and PRC-018-1 and combining them into a single standard that would not only incorporate all the requirements into a single standard, but also would contain requirements that would be applicable to all entities throughout North America [Ref 10]. This would eliminate the possibility of differences in standards between the different regional reliability organizations and impose the same standards on all generator/transmission owners regardless of where in the continent the generator was located. When approved this standard would become known as PRC-002-2. As presently developed this standard would apply to any generator owner with either a single generator rated 500 MVA or higher or a plant total capacity of 1500 MW or higher which connects to the transmission system at 200 kV or above. This new standard will establish requirements for Sequence of Event (SOE), Fault Recording (FR), and dynamic disturbance recording (DDR) in the applicable generating plants. Sequence of Events recorders record digital events such as breaker opening and closing status. Fault recorders measure analog quantities at data rates that give point on wave results. Dynamic Disturbance Recorders are slow speed recorders that can measure long term system events. In recent years Phasor Measurement Units (PMU) have become increasingly popular types of DDRs because of their ability to synchronously provide phasor data across the entire electrical grid. Because most modern fault recorders have the capability of providing SOE information, FR information, and DDR information, most (if not all) of the standard requirements can be met through installation of digital fault recording equipment. Pertinent requirements associated with proposed standard PRC-002 as it pertains to generating plants include the following [Ref 11]:

- Each generator circuit breaker (including low side breakers) shall have sequence of events recording.
- Time stamps must be of high enough resolution to be within 4 milliseconds of actual when recording circuit breaker change of state.
- Quantities required on fault recorders are defined including three phase voltages, currents, and neutral current of wye connected GSU high side windings
- Pre-trigger and post-trigger minimum times are defined
- A minimum recording rate of 960 Hz is defined
- Dynamic Disturbance Recording requirements indicating that voltage, current, frequency, power and reactive power must be monitored
- DDR devices installed after January 11, 2011 must be capable of continuous recording. Devices installed prior to this time that don't have continuous recording capability must meet certain triggering and recording requirements.

- Captured SER, DFR, and DDR data must be time synchronized to within +/- 2 milliseconds of Universal Coordinated Time (UTC).
- All recorded data must be kept a minimum of 10 calendar days following a disturbance.

NERC Standard PRC-003-1:

The title of this standard is "Regional Procedure for Analysis of Mis-operations of Transmission and Generation Protection Systems." [Ref 12]. PRC-003-1 defines requirements for the regional reliability organizations to develop procedures for reviewing and analyzing mis-operation of protective relays. The result of this standard is that each regional reliability entity will have their own standards detailing how relay mis-operations are to be analyzed, documented and reported. The use of digital fault recorders and digital oscillographs for post event analysis plays a primary role in determining what happened and what the sequence of events were in a relay operation. Digital oscillography inherent in modern digital relays will take a prominent role in this type of analysis and documentation of the analysis. In addition, stand alone fault recorders will play a role because system quantities other than what are seen by the digital relays can be monitored by such devices and provide important analysis information. Locations without adequate fault recording capability may have difficulty meeting the requirements of the region should a relay mis-operation occur.

NERC Standard MOD-013-1:

The title of this standard is "Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures." [Ref 13]. This applies to facilities connected to the Eastern Interconnection, the Western Interconnection, and the ERCOT Interconnection. The standard requires the regional reliability organization in coordination with the generator owners and other planners to develop methods and standards for verifying generator and excitation system models for use in transmission planning stability studies. Because these models must be verified models, certain performance tests must be done so that the actual performance of the excitation system can be compared with the modeled behavior. The application of digital fault recorder technology on generators can assist in these performance tests in two distinct ways.

- Because digital fault recorders can capture high speed data, they can be used as data gathering devices during staged performance tests. If appropriate analog channels are being monitored, all the information needed for modeling studies can be captured by the digital fault recorder. Likewise, other digital oscillographic recorders can be used during staged tests to capture the data for analysis.
- Section 4.1.3 of this document summarizes a method whereby in-situ fault recording data captured for normal system events can be used to perform the generator performance monitoring required by this standard. This method has the advantage that specifically designed staged testing does not need to be performed in order to meet the modeling verification requirements. This is particularly beneficial for nuclear units since the data is obtained without the need for specific testing. Ref [6] gives details of this method.

Note that this particular standard is related to NERC MOD-012-1 which requires generator owners and others to provide appropriate equipment and system characteristics to comply with MOD-013-1.

NERC CIP Standards:

CIP is an acronym for "Critical Infrastructure Protection" and NERC has developed 9 standards having to do with the security and protection of generation and transmission system [Ref 14]. These standards define minimum physical security of critical assets as well as electronic security of the critical control and monitoring systems of generators, substations, control centers, etc. CIP Standard 002 requires that each responsible entity develop a process whereby critical assets are identified. Once these critical assets are identified, it further specifies a requirement that a "list of associated Critical Cyber Assets essential to the operation of the Critical Asset" be identified. Examples of these Critical Cyber Assets are called out in the standard and include systems that provide monitoring and control and are further called out as systems that have dial up access or communicate outside a given electronic security perimeter. CIP Standard 003 requires specific security management controls to protect the critical cyber assets. Other standards require access limitations on critical cyber assets by creating an electronic security perimeter as well as physical security measures. CIP Standard 009 defines recovery plans for critical cyber assets in the event of a disaster.

How these CIP standards apply to DFRs in power plants is dependant on how a generation owner defines their critical assets and their critical cyber assets. Because it is left to the individual entities to develop a risk based assessment process to define these assets, one entity may include digital fault recorders as a critical cyber asset and another may not. In general, because DFRs have no control function (only monitoring), it is arguable that they should not be included as critical assets or critical cyber assets. The DFR owner should be aware that the standard requires a yearly review of these assets so while the DFR may not be included initially, over time it may get included in the future. Because of the oscillographic capabilities of modern digital protective relays and generator exciters, access to these fault recording capabilities will most likely be limited to certain individuals as they will likely be defined as critical assets or critical cyber assets. This means that access (both physical and electronic) to the equipment and the DFR functions of these devices will be restricted to specific individuals and recovery of the data for use in analysis may be more involved than for devices that are not defined as critical assets.

Industry Standards

As digital fault recording technology has developed and matured, several standards have been developed that have benefitted both the manufacturers of the equipment and the users of the equipment. While the specific details of these standards may not be known by all users of digital fault recorders, the fact that these standards exist and apply to the industry is well known. These standards include the following.

IEEE Standard C37.111 (COMTRADE):

COMTRADE is an acronym for "The Common Format for Transient Data Exchange" and represents a standard that is used by virtually all DFR manufacturers for sharing data in a common format [Ref 15]. Most DFR software captures and encodes data in a proprietary format that only the specific vendor's software can read. In order to enable and facilitate sharing of DFR data amongst users the COMTRADE standard was developed. The original COMTRADE standard was adopted in 1991 with a modified standard published in 1999. Most software applications have the capability of writing and reading both versions of the standard although some applications are limited to the older version of the standard. This standard specifies that captured transient data be formatted into four separate files (two of which are critical) as follows:

Header File: This is a non critical file and is not really needed to share data in COMTRADE format. This file is an ASCII file that contains supplementary information about the data record. It is basically a file listing any information that is considered important about the record.

Configuration File: This file uses a three character extension (.CFG) and contains all the information that is used to configure the file – namely scale factors, data rates, number and names of channels, etc. Table 5 – 1 shows a .CFG file in the 1991 version format.. Information on the configuration of the data file is specified as follows:

- Line 1: This line contains the name of the station name, and some type of identification for the DFR (recording device). The later version of the standard added the revision year of the standard being used on this line.
- Line 2: This line specifies the total number of channels in the record and then specifies how many of the channels are analog channels and how many are digital (change of state) channels.
- Lines 3 - 11: The next set of lines contains the configuration information for each of the analog channels (as defined in Line 2 above). This information includes the analog channel number, The channel name, the channel phase information (if applicable), identification of the circuit being monitored, the channel units, a channel multiplier, a channel offset adder, the amount of time skew in the channel (in µs), the minimum possible data value, and the maximum possible data value. The 1999 version of the standard specifies a few additional items on this line. These lines are repeated for each of the analog channels.
- Lines 12 – 17: The next set of lines contains information about the digital channels including the digital channel number, the channel name, and the normal state of the digital channel (0 or 1).
- Line 18: The line frequency is specified.
- Line 19: The number of sampling rates that are used in the record. This is included since some recorders can capture data at different sample rates.
- Line 20: This line of data contains the sample rate and the sample number at the end of this sample rate.
- Line 21: This line contains the date and time stamp for the first data point in the data file.
- Line 22: This line contains the date and time stamp for the trigger point in the data file.

- Line 23: The last line in the CFG file defines what type of data is used – ASCII. Note that COMTRADE has an option for specifying binary type data but since these type files are not user readable, they are not discussed here.

Table 5-1
Listing of a COMTRADE Configuration File – 1991 Version

```
DFR677_GT3,677
15,9A,6D
1,GT3 Vab System,A,,kV,0.0011399344,0.0000000000,0,-32767,+32767
2,GT3 Vbc System,B,,kV,0.0011399344,0.0000000000,0,-32767,+32767
3,GT3 Vca System,C,,kV,0.0011399344,0.0000000000,0,-32767,+32767
4,GT3 Vab Gen,A,,kV,0.0011399344,0.0000000000,0,-32767,+32767
5,GT3 Vbc Gen,B,,kV,0.0011399344,0.0000000000,0,-32767,+32767
6,GT3 Vca Gen,C,,kV,0.0011399344,0.0000000000,0,-32767,+32767
7,GT3 Ia Gen,A,,kA,0.0010363070,0.0000000000,0,-32767,+32767
8,GT3 Ib Gen,B,,kA,0.0010363070,0.0000000000,0,-32767,+32767
9,GT3 Ic Gen,C,,kA,0.0010363070,0.0000000000,0,-32767,+32767
1,System U/V,0
2,3GT U/V Gen,0
3,3GT O/C Gen,0
4,3GT Gen Bkr,0
5,3GT Gen LO,0
6,GT3 Gen Freq,0
60
1
10000.000,5314
10/23/09,05:35:24.1318
10/23/09,05:35:24.1617
ASCII
```

Data File: The data file contains the actual digitized data for each analog and digital channel and uses the .DAT extension identifier. Each line of the data file contains the sample number, the time in microseconds from the beginning of the record, and the data values for each analog and digital channel (in the order specified in the configuration file). An example of a few lines of a .DAT file are shown in Table 5-2. Conversion of analog data from the numbers specified in the DAT file to the units specified in the CFG file is done using the following equations:

$$Ana\log Value = aD + b$$

Where AnalogValue = scaled value
a = Channel multiplier specified in the CFG file
b = Channel offset adder specified in the CFG file
D = Data value specified in the DAT file

Table 5-2
Listing of a portion of a COMTRADE Data (.DAT) File – 1991 Version

1,	0,	8320,	-17456,	9056,	-13504,	-2272,	15696,	0,	0,	-32,0,0,0,0,0,0
2,	100,	8864,	-17440,	8496,	-13104,	-2896,	15936,	0,	0,	-32,0,0,0,0,0,0
3,	200,	9408,	-17408,	7920,	-12688,	-3536,	16160,	0,	0,	-32,0,0,0,0,0,0
4,	300,	9952,	-17376,	7344,	-12240,	-4160,	16352,	0,	0,	-32,0,0,0,0,0,0
5,	400,	10480,	-17296,	6736,	-11792,	-4784,	16512,	0,	0,	-32,0,0,0,0,0,0
6,	500,	10992,	-17184,	6112,	-11328,	-5408,	16672,	0,	0,	-32,0,0,0,0,0,0
7,	600,	11504,	-17056,	5472,	-10832,	-6016,	16784,	0,	0,	-32,0,0,0,0,0,0
8,	700,	12016,	-16912,	4816,	-10320,	-6624,	16880,	0,	0,	-32,0,0,0,0,0,0
9,	800,	12512,	-16720,	4160,	-9808,	-7200,	16944,	0,	0,	-32,0,0,0,0,0,0
10,	900,	12976,	-16528,	3488,	-9280,	-7776,	16992,	0,	0,	-32,0,0,0,0,0,0
11,	1000,	13440,	-16320,	2816,	-8720,	-8336,	17024,	0,	0,	-32,0,0,0,0,0,0
12,	1100,	13872,	-16096,	2144,	-8176,	-8896,	17024,	0,	0,	-32,0,0,0,0,0,0
13,	1200,	14304,	-15840,	1472,	-7600,	-9440,	16992,	0,	0,	-32,0,0,0,0,0,0
14,	1300,	14720,	-15552,	768,	-7024,	-9968,	16928,	0,	0,	-32,0,0,0,0,0,0

Information File: This file was added in the 1999 version of the standard and is an information file using the extension .INF. This is an optional file that contains extra information about the event that may be useful to others. This file has a specific structure but since it is an optional file that is not critical to the exchange of data, not formal description of it is given here.

Most if not all DFR vendors support the COMTRADE standard for importing and exporting files. Consequently, any fault recorder captured file can be converted to the COMTRADE format and then be read and analyzed by any DFR analysis software application. Having a common format to exchange data file with is a critical development that assists not only individual users, but regional and national organizations involved with DFR analysis for significant events. Some stand alone COMTRADE software analysis products are available for those without DFR software who wish to view and analyze COMTRADE records. Some of these applications are free.

IEEE Standard C37.232-2007 (File Naming):

The IEEE Standard C37.232-2007 is named "Recommended Practice for Naming Time Sequenced Data Files" and defines a scheme for creating consistent file names that include pertinent data that is useful to anyone using the file [Ref 16]. With the advent of digital fault recorders a plethora of different schemes for naming files arose. Because the first generation fault recorders were DOS based, filenames were limited to 8 characters in the main portion of the filename and three characters for the extension. Some methods of encapsulating the date and time stamp information in the filename required use of characters that could not be distinguished except with the use of the proprietary DFR master station software. While these were unique and elegant schemes for maximizing the utilization of the 11 characters of the file name, it did not lend itself to sharing of information except through the proprietary system that could read the filenames. As operating systems developed and allowed users to use longer file names, a more standardized method of naming files was desired and developed into what is now the IEEE File

Naming Standard. The benefits of a standardized method of file naming are easily imagined when considering analysis of multiple files from multiple entities for large system disturbances.

The IEEE file naming standard defines six required components to the file name and allows for additional user defined components followed by the three character extension. The six required components to the file name are as follows:

1. Start Date (YYMMDD)
2. Start Time (HHMMSSnnn) defined to desired precision
3. Time Code
4. Station Identifier
5. Device Identifier
6. Company name

The above required values are all self-explanatory except for the time code which is a code that indicates the time zone offset from universal time. Format for this is shown in the following example: -07H30. Note that the time code begins with a sign (either + or -) followed by the number of hours and the number of minutes for the offset. The H for hours is optional. The example indicates that the time is 7 hours and 30 minutes behind universal time. Universal time (UT) is also known as Greenwich Mean Time (GMT).

The file naming standard defines that the main part of the file name consist of the required components each separated by commas, followed by any user defined optional fields also separated by commas. The main part of the file name is then followed by a period (dot) and a three character extension. The three character extension is user selectable but should conform to normal usage rules so that pre-defined extensions are not encroached on. That is, if the extension .CFG is used, ensure that the file is a COMTRADE configuration file, etc.

An example of a file name that conforms to the IEEE file naming standard is shown as follows:

091023,053524161,-7,Saguaro,Ben677_SagGT3,APS,Rcd_3420.DAT

From this example we can readily see that the file was recorded on October 23, 2009 at 05:35:24.161 which is 7 hours behind universal time. It is also seen that the record comes from the Saguaro Stations, from GT#3 which is in the APS system. An additional user field is included indicating that the record number for the file is 3420. The fact that the file extension is DAT means that this particular file is the data file from a COMTRADE format DFR file format.

Other Industry Standards:

Two other industry standards are applicable to this discussion and are mentioned for the sake of completeness. IEEE Standard 1159.3-2003 is titled "IEEE Recommended Practice for the Transfer of Power Quality Data" and defines a common file interchange format for power quality type data [Ref 17]. While it is not common for generation fault recording to utilize power quality type files, these options are available in the various digital fault recorders as well as with dedicated power quality recorders. This particular standard was developed to allow for the capability of capturing information relating to Power Quality events that were not covered by the COMTRADE standard. The IEC Standard 61850 is a set of several standards made up of 14 parts adopted by the International Electrotechnical Commission (IEC). The title of the standard is "Communication Networks and Systems in Substations" [Ref 18]. From its name it is apparent that this standard would have some say in how disturbance and fault recorders communicate and share data amongst themselves. The main thrust of this particular standard is to define the communication interfaces between substation equipment. These two standards are mentioned because there are efforts underway to combine the different aspects of these two standards together with the COMTRADE standard such that COMTRADE changes would better harmonize with these two standards [Ref 19]. Thus, changes in the COMTRADE standard may be on the horizon.

Summary

In this section of the report the various standards that apply to fault recording have been examined and discussed so that users who apply digital fault recorders in generating stations will be aware not only of the different regulatory requirements associated with the data recording equipment, but also of the different standards that improve the ability to use the data captured by the digital fault recorders. The North American Electric Reliability Corporation standards relating to digital fault recorders was addressed and it was shown that at present the different requirements relating to fault recording are left to the different regional reliability entities. However, it was also shown that there is a movement to combine several of the standards into as single standard and format that would bring consistency throughout all the different reliability regions and would directly apply to the individual generator owners. NERC standards are easily found on the NERC website (www.nerc.com).

Other industry standards were also reviewed in this section. The two most important of these standards are the COMTRADE standard (IEEE C37.111) and the file naming standard (IEEE C37.232). Together, these standards facilitate the sharing and understanding of digital fault recorder captured files.

6
CASE STUDIES

DFRs are particularly useful in understanding the abnormal and normal operation of generation connected to the grid. Some case studies are presented in this section to illustrate the point. Experience has shown that plant DFR records are of use to engineering, operations, maintenance, planning and even legal functions in the utility hierarchy. This has led to a defacto standard for documentation of DFR records. The record to be analyzed and documented is broken down into several time segments or *regions*. The regions are plainly annotated on the record(s) which characterize the event. ***Region 0*** is the recorded time before the fault or event that triggered the record. Depending on the DFR's capabilities and the end user's preferences, the prefault ***Region 0*** recording time typically ranges from 0.1 seconds (6 cycles) to 2 seconds (120 cycles). ***Region 1*** typically designates the area in which the abnormal condition persists such as the duration of generator fault current contribution and corresponding depressed generator voltage that occurs with a fault out on the transmission system. Depending on the nature of the abnormal condition, ***Region 1*** may persist for a few cycles (i.e. fault clearing time) on out to several seconds for an unstable voltage regulator. ***Region 2*** designates the recovery period after the abnormal condition has terminated. Depending upon how the DFR is configured, this region may last for a few tenths of a second out to several seconds. Other sequentially number and annotated regional sections may follow depending on the nature and complexity of the record. It has been found that whomever the end user, this system has proven useful in providing a standardized method of describing and documenting the record. The case studies presented here that are classified as system events are discussed using the regional format.

Examples of Benefits

The authors have some 50 plus years of generator monitoring experience using DFRs and other digital data recording devices. It has been our experience that in some cases the early detection of a developing problem has saved generation from catastrophic failure and paid for the DFR installation many times over with a successful avoidance of a forced outage or failure. When the cost of replacement energy is considered, the case for close generation monitoring via DFRs becomes even more compelling. Over time, digital fault recorders have allowed the discovery and remediation of many generation problems including but not limited to:

1. Evaluation of fault duty imposed upon a generator with a failing generator step-up transformer.
2. Detection of missing firing pulses in the SCR pulse generator circuits of a static excitation system.
3. Detection of stimulation of shaft torsional oscillations by a malfunctioning automatic voltage regulator and static exciter.

4. Evaluation of turbine generator transient shaft torque duty from bad synchronizations, Subsynchronous Resonance (SSR) conditions, close in faults, etc.
5. Early detection of failing PT inputs to the generator's Automatic Voltage Regulator (AVR).
6. Detection of failing generator CT circuits.
7. Detection of shorted turns on generator rotor field windings by the apparent field resistance method.
8. Malfunction and mistuning of power system stabilizers (PSS).
9. Detection of loose generator neutral connections.
10. Detection of shorted field turns by the flux probe recording method.
11. Collection of data critical to the development of turbine generator models required for connection to the grid by the Western Electricity Coordinating Council (WECC) & the Federal Energy Regulatory Commission (FERC).
12. Detection of brush lifting due to end of life wear on generators equipped with collector rings, carbon brushes & brush rigging.
13. Detection of high amplitude electrical transients superimposed upon the station battery voltage that caused malfunction of devices powered from the station battery.

It is not possible to discuss all the benefits of DFR monitoring, but a few case studies are described next.

Typical Faults

High amplitude long duration faults can be damaging to generator windings due to the mechanical forces developed by high current flow. If the fault is internal to a machine, the damage can be catastrophic. DFRs can provide valuable information as to the root cause, extent of damage and enhanced monitoring to avoid repeat failures. The following case describes an evolving stator winding end turn fault on an 18kV, 240 MVA steam turbine generator. Figure 6-1 documents the subject machine in sufficient detail to understand how the machine CT and PT instrumentation is configured and connected to the DFR. Note that the generator and system side PTs are all connected phase to ground and that the DFR is connected to its own set of CTs at the high side of the stator winding. The generator protection relays receive their generator current inputs from separate sets of CTs. This is consistent with the philosophy that segregates protective systems from monitoring systems. Also note that the generator neutral is grounded through a grounding transformer providing high impedance grounding. The entire event is documented in two separate DFR records designated as Figures 6-2, 6-3 and expansion 6-4 spanning a 20.83 second time frame.

Figure 6-2 documents the first incident of a phase B stator ground occurrence at 18:00:39.829 Hrs. The DFR record shown is comprised of eleven (11) analog traces and eight (8) event traces. Region 0 documents the pre-fault conditions for a few cycles before phase B goes to ground. As per Figure 6-1, the machine utilizes a high impedance grounding scheme that limits ground fault current to less than 10 amps. This insures that little damage due to burning and heating is incurred to the stator iron core laminations in a ground fault condition. Note that the DFR is triggered in Region 1 by the elevation in phase A & phase C voltages. A generator neutral overcurrent trigger is received almost simultaneously with the overvoltage trigger. The stator ground current component is small – less than 10 amps in the presence of several thousand amps flowing into the power system. It has no impact up the phase current waveforms plotted in Figure 6-2. The fault apparently self- extinguishes in 1.5 cycles, which defines the end of Region 1. Region 2 lasts 0.8 seconds until the DFR trigger times out. It documents that the generator has returned to normal operation for a few seconds until repeated ground faults start occurring some 20.83 seconds after the first trigger. Figure 6-3 is the second DFR record document 6.5 seconds of generator operation. Region 0 lasts over 6 seconds and documents the repeated triggering of the recorder on phase overvoltages on phase A and C, undervoltage on phase B and high generator neutral current. Note the repeated notching of the generator phase voltages as the B phase ground fault initiates and extinguishes approximately 57 times in 6 seconds. The generator protection relay function for generator neutral overcurrent/overvoltage (59N) is reset each time the fault extinguishes and thus never times out. Region 1 lasts 105 milliseconds and documents the evolution of the stator phase B to ground fault into a fully involved three phase fault. A time base expansion and current channel rescaling are required (as Figure 6-0C) to fully comprehend the failure mechanism captured in this record. Last, Region 2 documents the 550 milliseconds of time after the generator breaker opens to remove the fault current contribution[18] from the system. Fault current internal to the generator continued to flow long after the Region 2 timed out. It was not visible to the DFR since the fault was inside the machine – literally "downstream" from the location of the bushing CTs.

[18] Later, upon inspection of the machine, it was found that the fault was internal to the machine on the end turn structure. Extensive localized burning and melted copper obliterated much of the root cause failure evidence when the fault evolved into a full three phase high current fault.

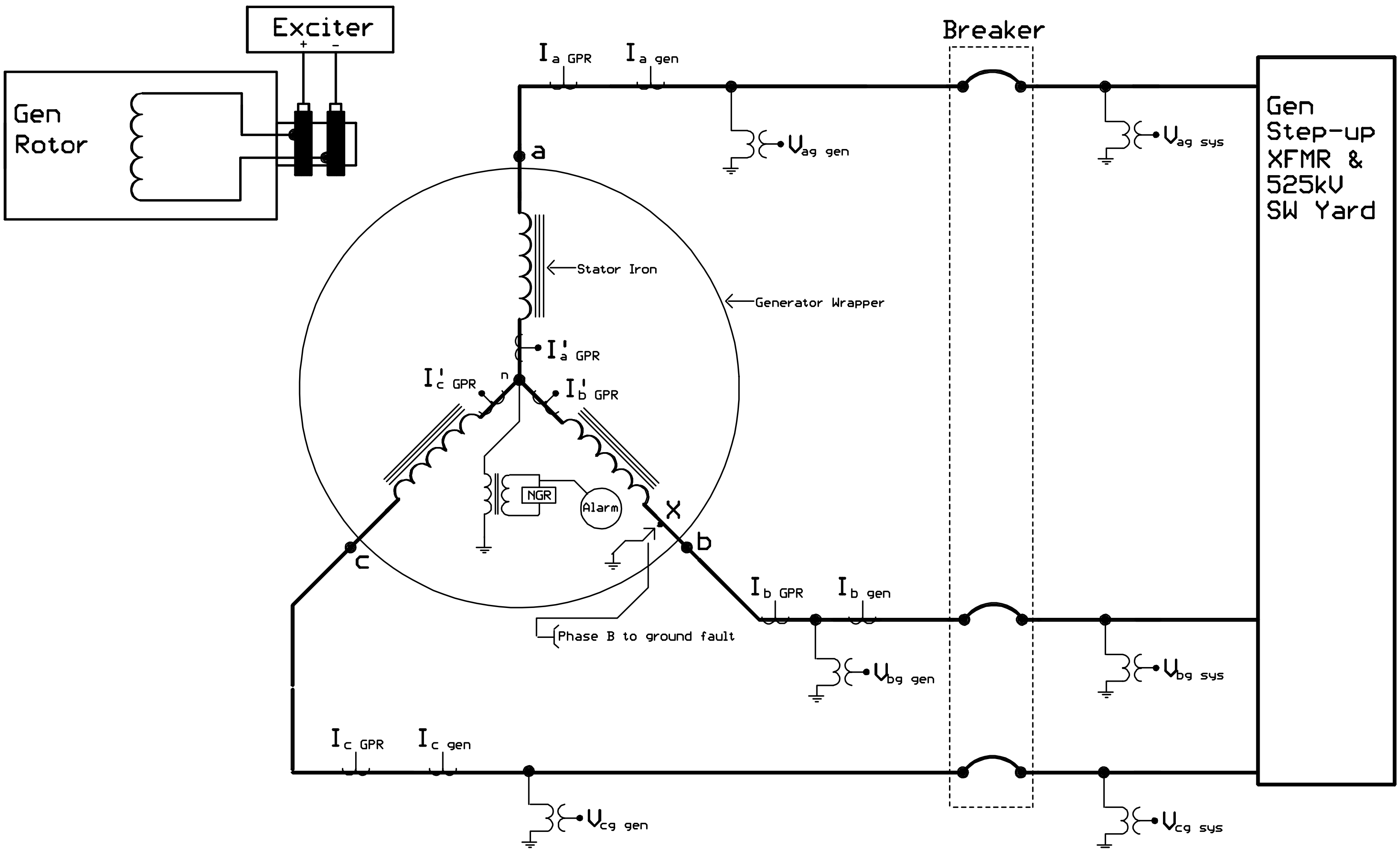

Figure 6-1
Machine Diagram

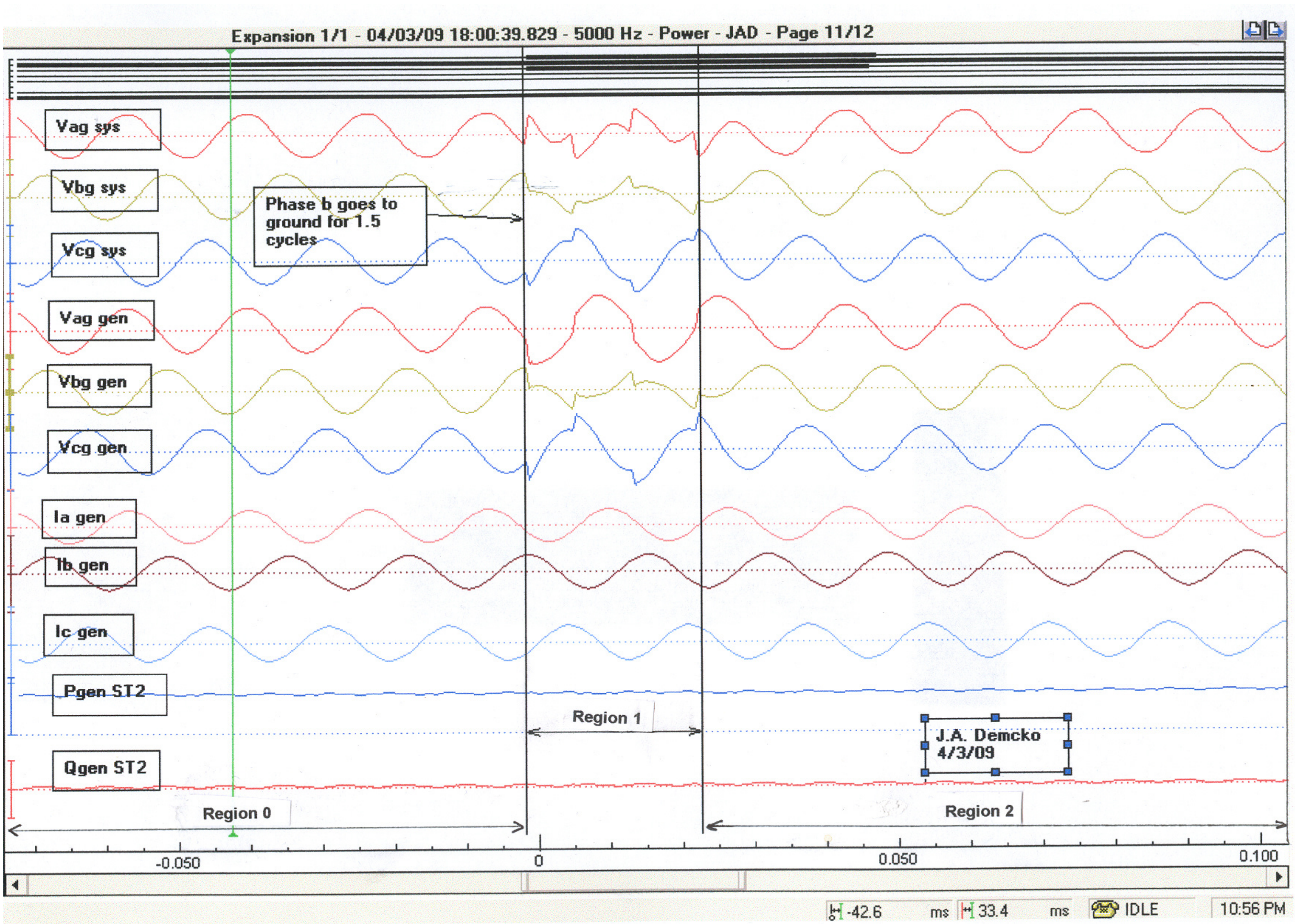

Figure 6-2
Initial Phase B to Ground Fault

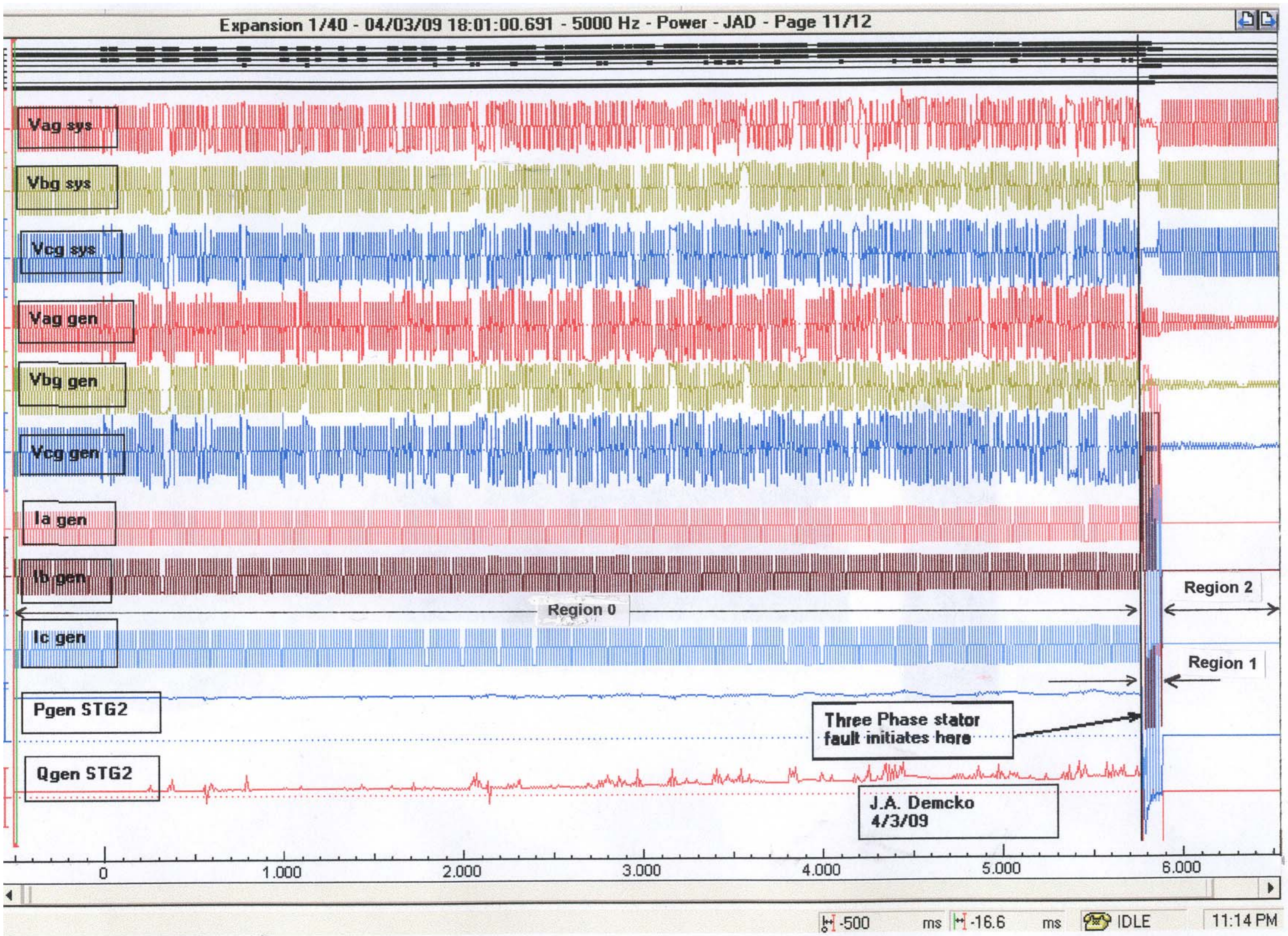

Figure 6-3
Repeating Phase B to Ground Fault

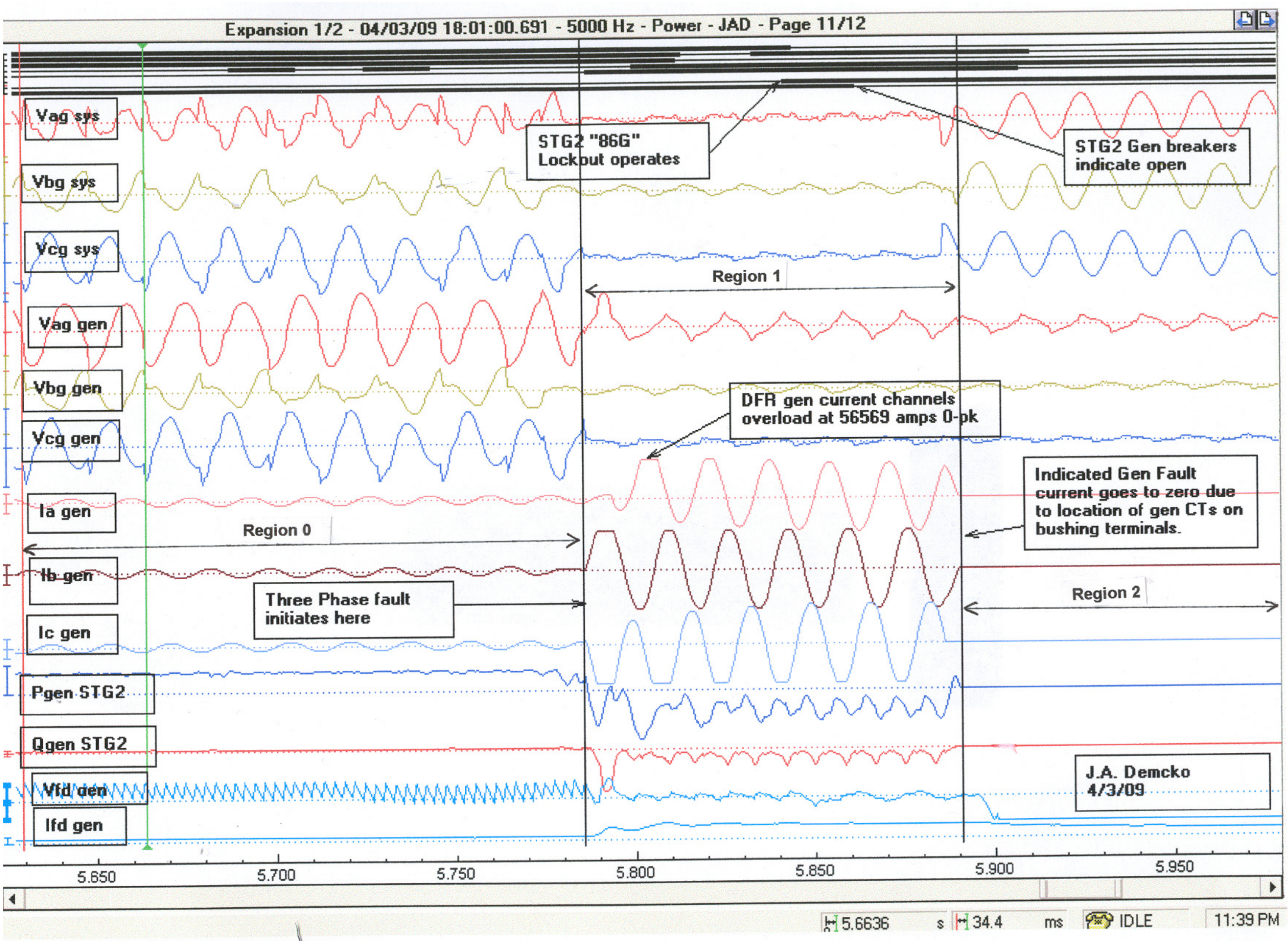

Figure 6-4
Evolution of Three Phase Fault (Expansion of Figure 6-3)

Figure 6-4 is an expansion of the previous figure 6-3. Region 0 here documents the last 0.25 seconds of operation with a ground on the generator B phase voltage. Region 1 is the same 105 millisecond span as on the previous figure, but with appropriate scaling. Note that initially in Region 1 the fault has evolved from a phase B to ground into a phase B to C fault – but only for about half a cycle when it becomes a fully involved three phase fault. Note that the DFR current channels overload at 56,569 amps zero to peak. The tradeoff on this DFR was in favor of good full load current resolution with the possibility of clipping (full scale channel capability reached) with fully dc offset close in faults. The staggering fact is that the unmeasured current contribution from the generator itself is probably larger than the measured contribution from the 525kV yard! Hence, one may expect massive internal damage from such an event. The entire stator and rotor was heavily contaminated with pyrolisis products, carbon dust and melted copper. Surprisingly, the machine was not declared a total loss. After significant cleaning and repair efforts, the machine was returned to service. It was discovered that the fault initiated from stator winding end turn vibration which compromised the phase to ground insulation system. A new end bracing and blocking structure was utilized in the stator repair and the end turn vibration levels are continuously monitored in real time by a separate dedicated data acquisition system.

Generator Synchronization

The effect of a mal-synchronization upon a turbine generator can be significant to both the machine and connected apparatus. The two case studies examine both a successful synchronization and the impact of a severe mal-synchronization event on a 1970's vintage 146MVA, 13.8kV, 3600 rpm turbo-generator. This particular unit is unusual in that it has paralleled breakers on the low side of the GSU sized to handle the unit's rating. For a successful synchronization, both breakers auxiliary contacts must indicate closed within a few hundred milliseconds of each other. If this does not occur, logic sends an open command to both breakers and the synchronization attempt is not successful. Figure 6-5 is a simplified schematic for the generator and switchyard. The successful synchronization DFR record is examined first. Figure 6-6 is the annotated DFR record for a successful generator synchronization. The record is comprised of 10 analog traces and a cluster of three (3) event traces. The pertinent analog traces from top to bottom are Phase a to ground voltage on the system side of the breaker ($\mathbf{V}_{ag\ sys}$), three generator phase to phase voltages ($\mathbf{V}_{ab\ gen}$, $\mathbf{V}_{bc\ gen}$, $\mathbf{V}_{ca\ gen}$), three generator phase currents ($\mathbf{I}_{a\ gen}$, $\mathbf{I}_{b\ gen}$, $\mathbf{I}_{c\ gen}$), calculated generator power (P_{gen}) and generator field voltage and current ($\mathbf{V}_{fd\ gen}$, $\mathbf{I}_{fd\ gen}$). The 3 event channels are 86G lockout relay, generator breaker A status, and generator breaker B status. The record is a simple one with only two regions to analyze. Region 0 is the pre-event portion of the record before the generator breakers are closed by an auto-synchronizer and synchrocheck permissive device. The generator voltage, speed and closing angle are adjusted by the autosynchronizer until they are within acceptable limits for breaker closure. If the synchrocheck device agrees, a permissive contact closes and the dual generator breakers are issued a close command. Another breaker control circuit verifies proper closure in that both breakers auxiliary contacts must indicate closed within a 240 millisecond window for the synchronization to be considered successful. Region 1 begins with DFR triggering from indication of closure of the "A" & "B" generator breakers once synchronization conditions were met. Since the breakers closed within 7.5 milliseconds on each other, breaker operation is deemed successful. Close examination of the time expanded record confirms that immediately prior to synchronization, the generator frequency was 60.09Hz, voltages were matched and the generator voltage waveform lagged the system voltage by 6 electrical degrees. Consequently, when the breakers closed we see generator currents start to flow and a corresponding small negative jump in the calculated generator power. The power jumps to -0.132 per unit zero to peak since the generator voltage lagged the system voltage. Since the generator frequency was greater than system frequency (59.999Hz) the prime mover has mechanical power available for conversion to electrical power at synchronous speed. The power output quickly swings positive and begins a damped oscillatory response at local mode frequency. The power output settles out to a small positive (generating) value within a couple of seconds. Since Region 2 is only 0.51 seconds in duration, the post trigger recording is not long enough to display the final steady state P_{gen} value. The preceding synchronization is considered normal event that does not impose excessive duty upon the synchronous generator, breakers or GSU. Unfortunately things don't always work so well. The following record documents a worst case scenario when the synchronization does not proceed as planned on the same 13.8kV, 146MVA machine.

The mal-synchronization occurred while attempting to resolve a missing closure indication from one of the two paralleled breakers. After several close command attempts to resolve the erroneous breaker open indication, the conventional mechanical contacts of the permissive synchro-check relay welded shut. Consequently, the synchro-check relay gave a permissive "GO" signal continuously. This allowed for the possibility that a malfunctioning autosynch circuit could issue a close command to the generator breakers across any random phase angle between the generator's terminal voltage and the system voltage. Unfortunately, this is exactly what occurred. Breaker closure occurred across an angle of approximately 70° with the generator leading the system voltage. The ensuing mal-synchronization event is presented next. Figure 6-7 is the annotated DFR plot for the entire event. Note that the entire DFR plot encompasses approximately 1.4 seconds of cycle by cycle recording. An expansion of the time scale shows that the unit is connected to the system approximately 70° ahead of the system voltage. There are five (5) designated regions in this record and they are discussed next.

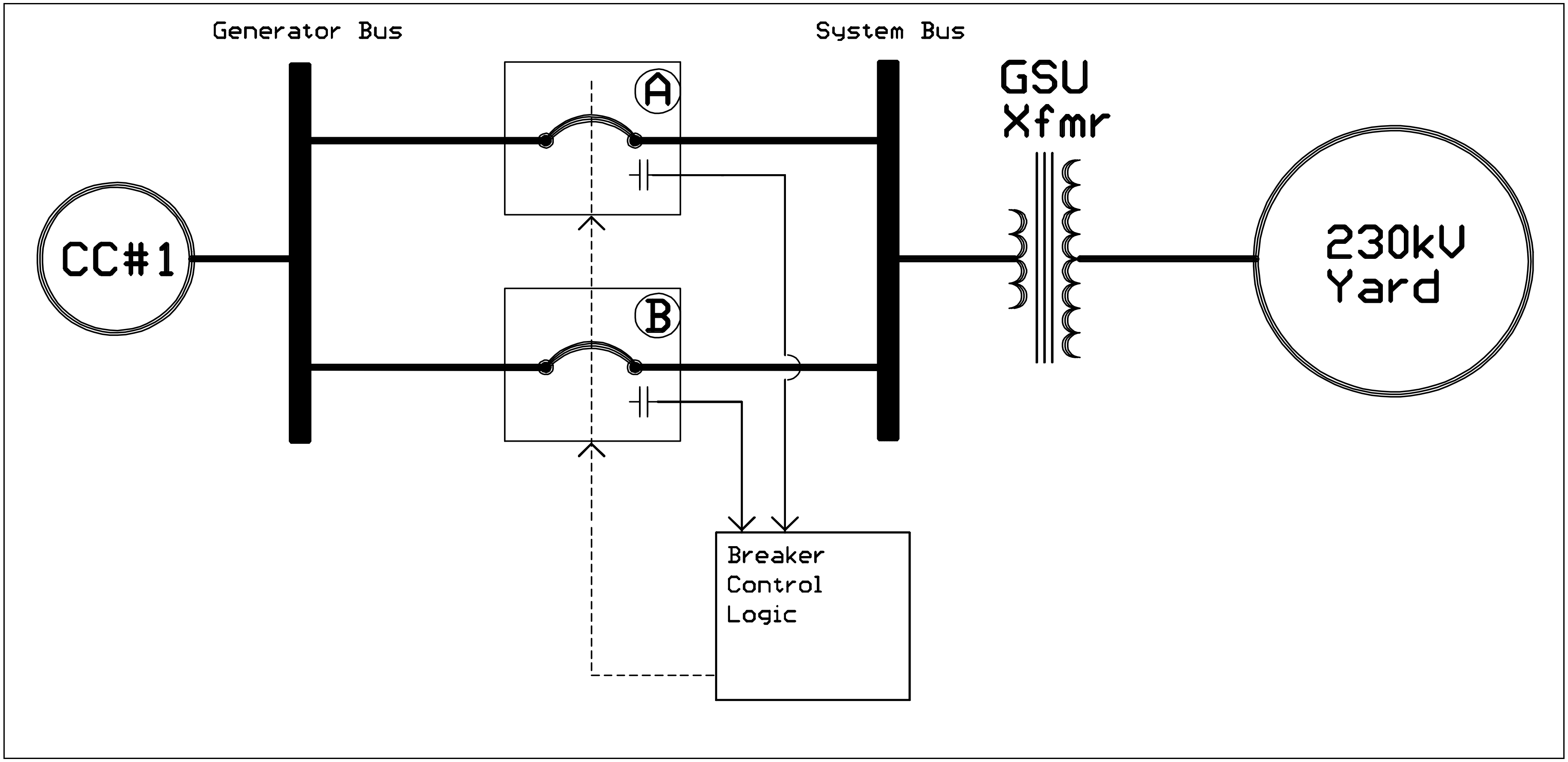

Figure 6-5
Dual Breaker Configuration on a Single Generator

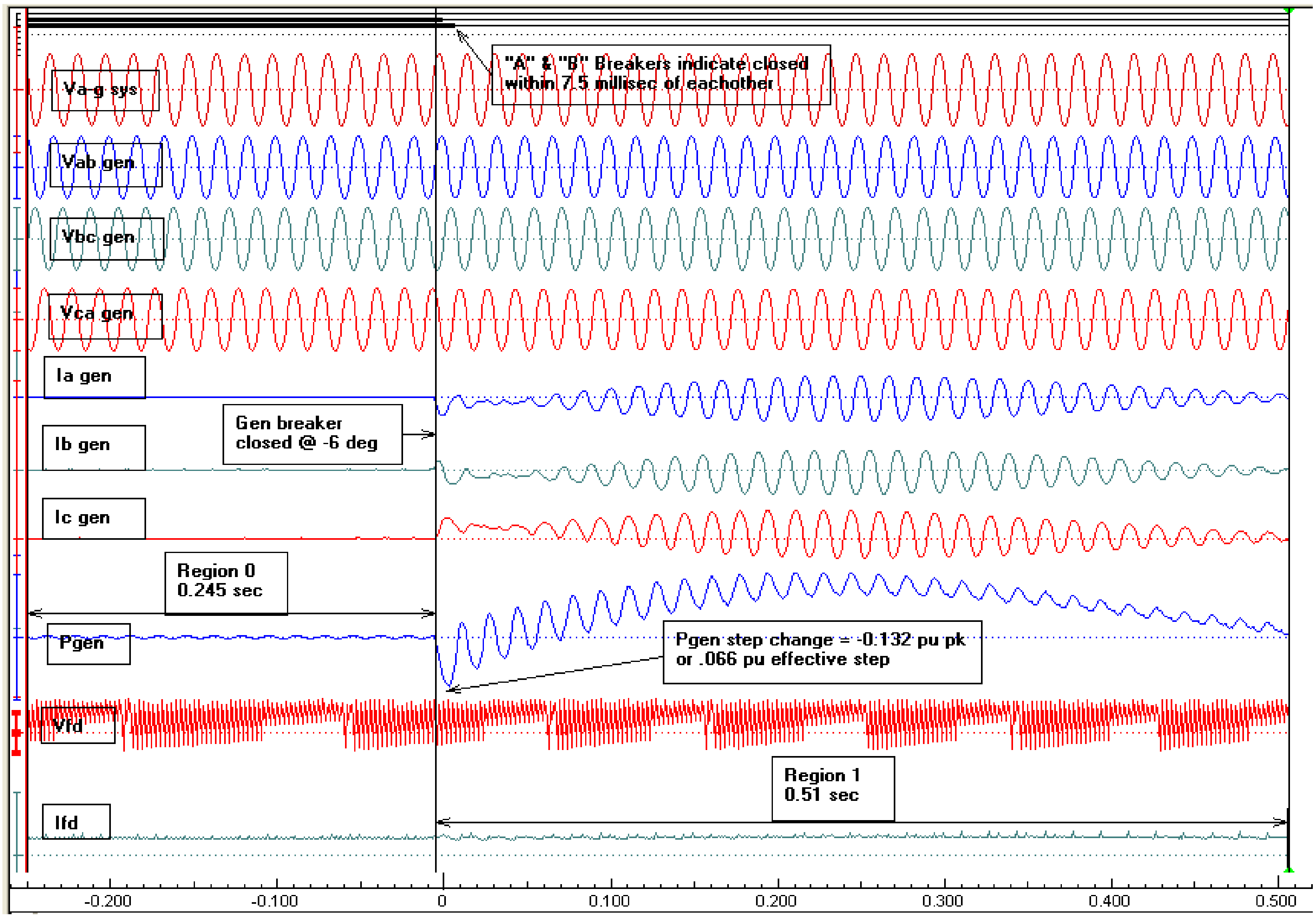

Figure 6-6
DFR Record for Normal Synchronization

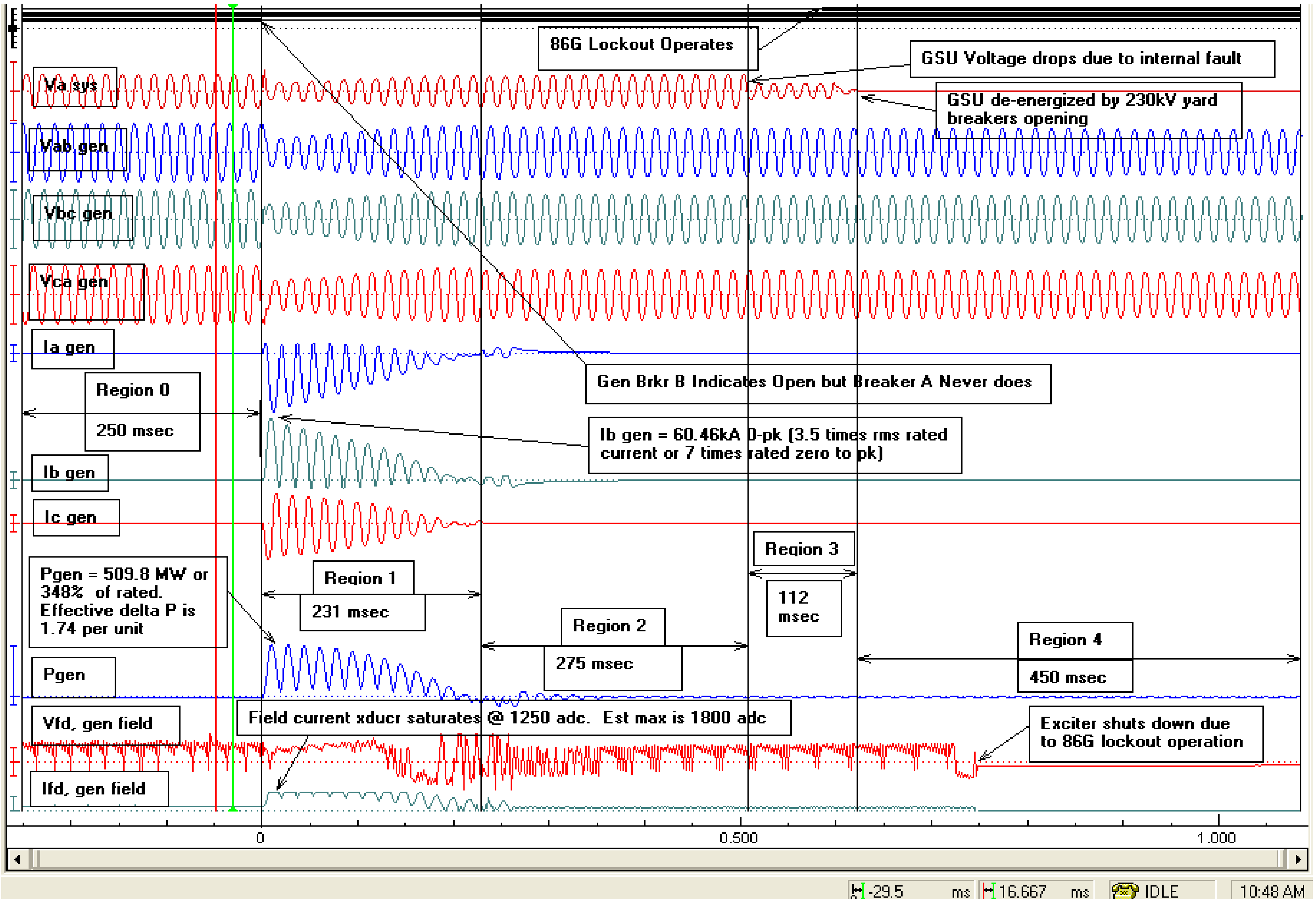

Figure 6-7
DFR Record for Generator Malsynchronization Event

Region 0 documents the pre-event operating conditions of the machine. Prior to the synchronization, the turbine-generator was operating at the nominal terminal voltage and speed in preparation for a synchronization attempt. At this point operating parameters appeared normal and the welded synchro-check relay permissive contacts were undetected. Time scale expansion of **Region 0** shows that the system voltage and generator phase voltages were approximately 70° out of phase[19] immediately prior to synchronization. **Region 0** is only 0.25 seconds in duration. Since the DFR was configured for only a quarter second of pre-fault trigger data storage. This particular record was first triggered by the Breaker B event trace indicating closed upon synchronization. It marks the start of **Region 1**. **Region 1** begins with the out of phase generator breaker closure and the ensuing electromechanical transient. Note from Figure 6-7 that the system and generator voltages immediately collapse to approximately half rated voltage. Generator phase currents are extremely high. $\mathbf{I}_{\mathbf{b\ gen}}$ reaches a value of 60,460 amps zero to peak (about 3.5 times rated generator rms current and 7 times zero to peak), with a full dc offset of the sinusoidal waveform. The mechanical forces on the generator windings are proportional to the square of current, consequently the expected impact loading[20] of the windings will be over 12 times the steady state winding forces. This is particularly stressing of the stator winding end turn structure. Note that $\mathbf{P}_{\mathbf{gen}}$ also appears as a positive 509.8MW zero to peak step level in power output with a large 60Hz oscillatory component. It can be shown that the effective value of the step change in power is equal to half the zero to peak value or 1.75 times rated MVA. ANSI synchronous machine standards call for a generator to handle a 0.5 per unit rated step change in power without mechanical or electrical damage to the machine. Consequently, the potential for damage to this machine is a high. Knowing the magnitude of the step change in power to which the machine was subjected, an inspection of the stator end turn structure and turbine-generator coupling bolts is warranted. Generator vibration reads before during and after the event (when it was deemed safe to spin the unit back up to speed after a comprehensive mechanical and electrical inspection) were compared. The remaining two analog traces for $\mathbf{V}_{\mathbf{fd}}$ and $\mathbf{I}_{\mathbf{fd}}$ indicate that this unit's high performance static exciter performed as expected. When the generator voltage dropped upon synchronization, the static exciter voltage immediately went to ceiling[21] and the generator field current rose accordingly. The $\mathbf{I}_{\mathbf{fd}}$ trace confirms that the significantly higher field voltage drives field current towards ceiling. The field current transducer saturates at a maximum value of 1250 amps dc for approximately 0.16 seconds. Note that the saturated value appears "notched" at a 16.67 msec repeat rate. This effect is due to the dc offset of the stator currents being reflected back into the generator field current as a 60Hz waveform. It is estimated that maximum field current experienced by the transient was approximately 1,800 amps. This $\mathbf{I}_{\mathbf{fd}}$ level exceeds the static exciter rating by 80%. A thorough inspection and functional test may be in order before declaring the exciter operational. **Region 1** ends 231

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[19] After accounting for the fact that $\mathbf{V}_{\mathbf{ab\ gen}}$ phase voltage leads $\mathbf{V}_{\mathbf{ag\ sys}}$ by 30°.

[20] A separate section of this document addresses using DFR data to calculate the torsional duty imposed on the turbine generator for severe electrical transients.

[21] This is indicated by the absence of the familiar 360Hz sawtooth pattern in $\mathbf{V}_{\mathbf{fd}}$ indicating that the SCR bridge has turned full on to apply maximum available dc voltage. The level does not rise on the plot as much as one might expect since the voltage available to the SCR bridge from the static exciter's power potential transformer (PPT) is about halved during the transient. The average value of the pre-synch $\mathbf{V}_{\mathbf{fd}}$ sawtooth waveform is much less than the SCR full on level.

milliseconds after it started when generator breaker A fails to give a closed indication from its auxiliary contacts. At this point, control logic commands both generator breakers to open thereby disconnecting the unit from the generator step up transformer (GSU) and the grid. Note that the unit appears to have electrically survived the gross mal-synchronization in that generator voltages, currents, and calculated power have returned to typical normal post synchronization values. Field voltage and current are trending towards normal values but have yet attained those levels. **Region 2** spans the next 275 milliseconds of operation. It documents the unit's offline behavior and the GSU's phase A voltage to ground. Note that the synchronous machine is running at approximately 3600 rpm off-line with the exciter on and holding rated voltage. It appears to have survived the mal-synchronization event. Likewise, the GSU secondary is producing rated voltage on the system side of the generator breakers. For this brief interval, it appears that the generator and GSU may have dodged the mal-synchronization bullet.

Region 3 begins with the collapse of $\mathbf{V}_{\mathbf{a\ sys}}$ to less than half of nominal and ends with the 230kV switchyard beakers opening[22] to clear an internal fault in the GSU some 117 msec (i.e. 7 cycles) later. **Region 3** also documents the operation of the "**86G**" generator lockout devices on event trace 1 in an adjunct to isolate the failed GSU from the switchyard. Rolling the 86G lockout initiates excitation system shutdown. The effects of that shutdown command appear in **Region 4**. **Region 4** spans the remaining 0.45 seconds of the DFR record. Proper shutdown of the excitation system is documented here and provides confidence that the exciter's power components and controls survived the event intact. Note that the three phase full wave SCR bridge voltage, $\mathbf{V}_{\mathbf{fd}}$, in the exciter reverses output polarity to expedite forcing the field current towards zero before the field breaker opens.

The power of the DFR lies in that 1.4 seconds of monitoring the correct variables at the right time yielded sufficient information to diagnose and comprehend the severity of the event. The results of that analysis were transmitted to plant management within 90 minutes of the event. This allowed the timely mobilization of crews to inspect the autosynchronizer circuit, inspect the machine, inspect & test the exciter, draw transformer oil, perform transformer testing and plan for the outage required to return the machine to service. Although the turbine-generator survived the mal-synchronization event, the generator step-up transformer suffered a complete failure.

Excitation System Performance Monitoring With A Stand alone Recorder

The stand alone recorder is a recent addition to the array of generator monitoring possibilities. It is particularly attractive option when monitoring is only required for a few hours or days since a standalone system can be configured and operating in a few minutes time. This case study underscores the effectiveness of utilizing a standalone recorder to evaluate the effectiveness of a power system stabilizer (PSS) on a retrofitted static excitation system. PSS are utilized to damp out generator rotor oscillations in the 0.2 to 2Hz frequency range. They are required equipment in some North American regional operating areas. When properly tuned PSS are extremely effective but PSS tuning requires a skilled technical staff to acquire the data required to develop settings. Once the settings are entered into the PSS a means to stimulate and measure the

[22] Opening of the 230kV yard breakers was confirmed from a separate DFR event record on the switchyard DFR and does not appear on the generator DFR.

generator rotor's oscillatory response is required. The standalone recorder, along with a data processing spreadsheet, is an ideal means to quickly assess PSS performance. Figure 6-8 is a functional block diagram of the standalone recorder connections necessary for this work. Generator voltage, current and terminal voltage deviation are the inputs required to the standalone recorder.

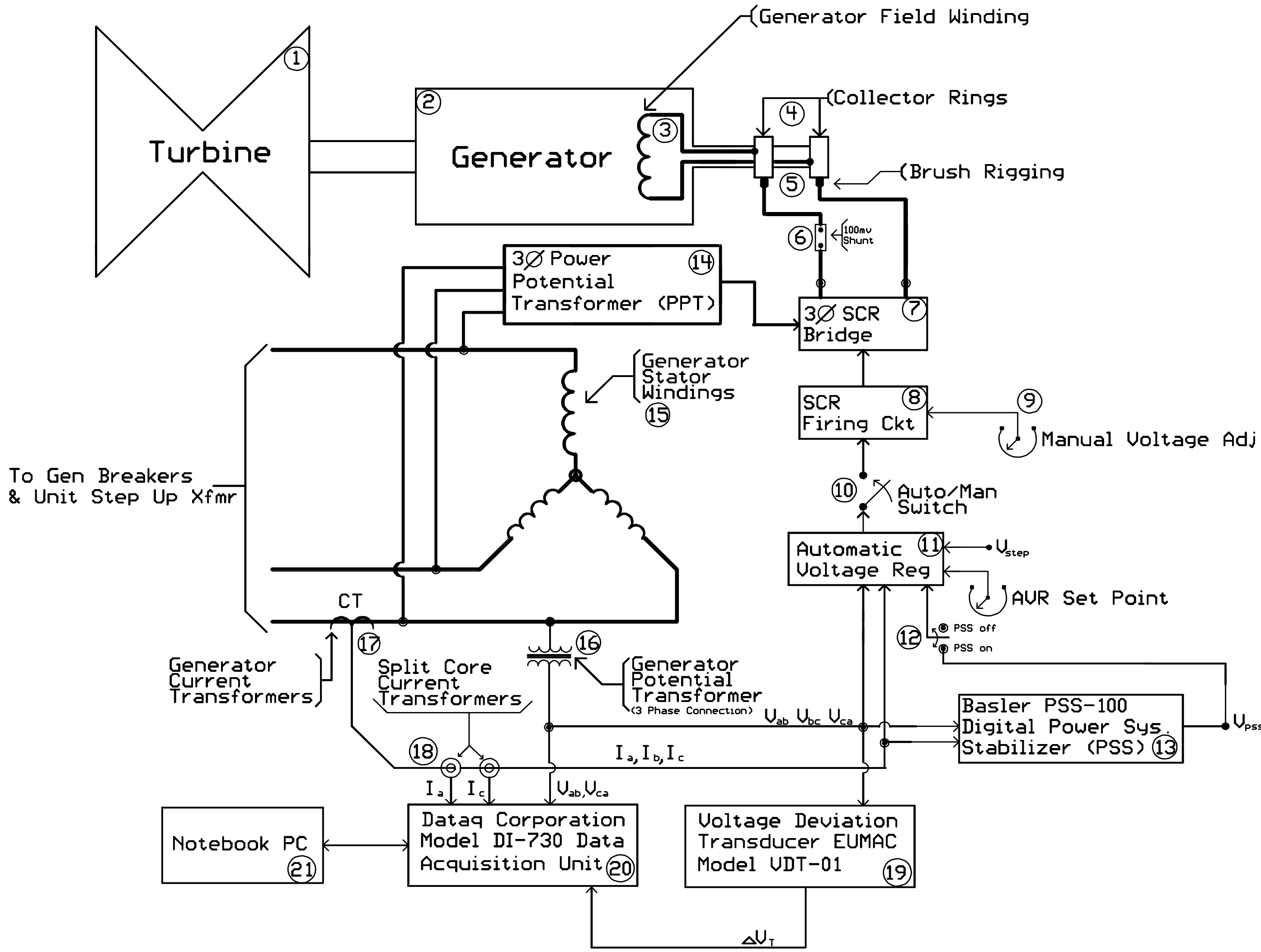

Figure 6-8
PSS Local Mode Damping Verification with Stand Alone Recorder

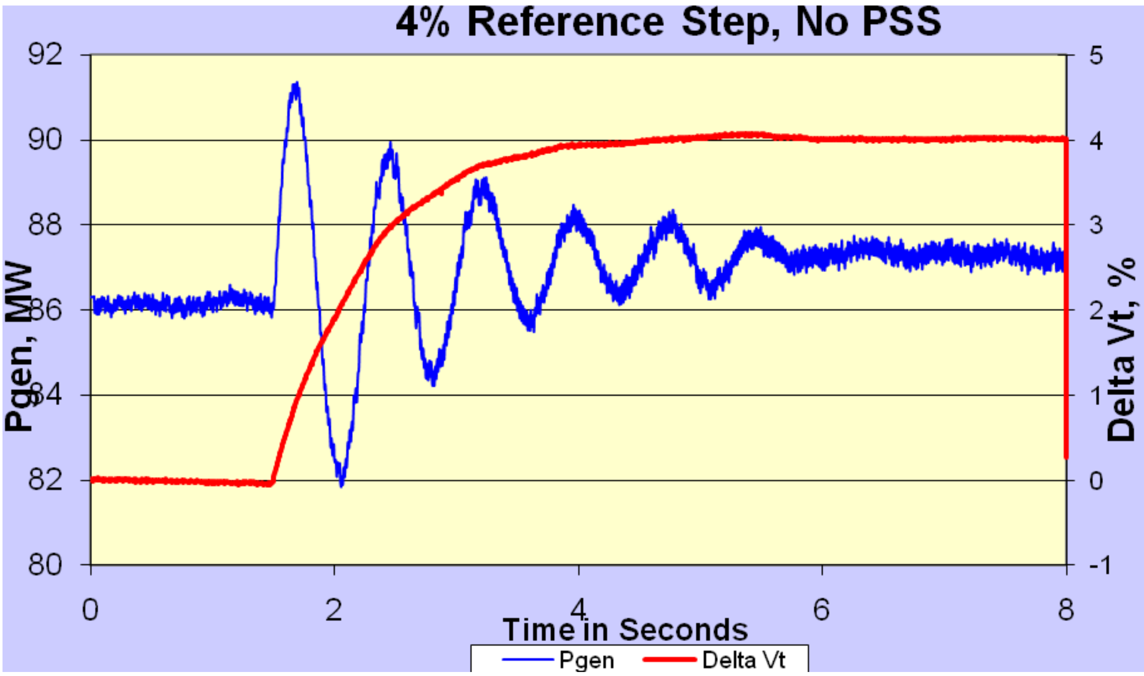

Figure 6-9
Generator Local mode Power Oscillation Without PSS In Service

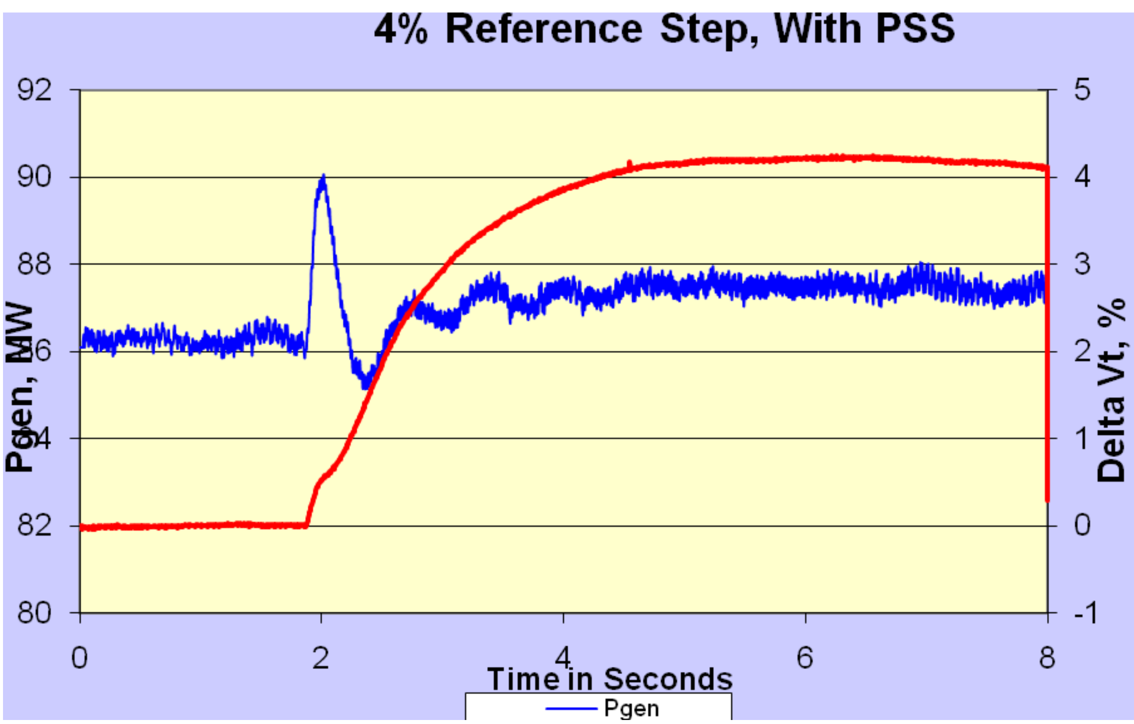

Figure 6-10
Generator Local Mode Power Oscillation With PSS In Service

The standalone recorder used for this case allows for continual display of up to 8 analog channel inputs on the notebook PC that supervises the recorder via a USB connection and Windows based display and acquisition software. Once the recorder is displaying the monitored channels a direct data link to an EXCEL spreadsheet provides real time importation of the recorder's digitized channels for a length of time specified by the user. In this case, a time series record 8 seconds in length is sufficient to assess PSS performance. Early on in the 8 second acquisition, a step of reference is inputted to the unit's automatic voltage regulator (AVR). Depending on the regulator's vintage, the step may be an actual low frequency voltage (.05Hz or lower) square wave into the physical summing junction of an analog voltage regulator or it may be a computer software generated step into the virtual summing junction of a digital regulator. In either case the result is the same. On an instantaneous basis, the electrical power output is perturbed. For an increase in reference voltage, the machine's output power swings upward and then returns to its original value in a damped sinusoidal response. The frequency is determined by the machines inertia constant and the inductive reactance between the machine and local high voltage bus. The response frequency is referred to as the local mode frequency. For most utility scale machines connected to a transmission system, local mode frequency falls between 1 and 2 Hz. Local mode damping is determined by a myriad of factors including AVR settings, machine and network parameters. It can be shown[23] that a properly tuned PSS damps out local mode oscillations as well as lower frequency inter-area oscillations that are problematic to long distance bulk power transmission. Consequently, the standalone recorder and associated EXCEL spreadsheet will be used to evaluate PSS performance by comparing local mode power swings created by a 4% AVR step of reference both without and with the PSS in service. Power is calculated by the two wattmeter method from the equations in Appendix A as $\mathbf{P_{gen} = V_{ab\ gen}{*}I_{a\ gen} - V_{bc\ gen}{*}I_{c\ gen}}$. After the 8 second data stream is loaded into the EXCEL application, instantaneous generator power is calculated and plotted along with $\mathbf{\Delta V_t}$. The data presented here is for an aggressively tuned PSS on a high performance static excitation system. Figure 6-9 documents the local mode power swing on a 13.8kV, 146MVA machine without the PSS in service. Prior to the reference step, the machine's power output rests at a steady state value slightly over 86MW. The machine's response to the step is a lightly damped 1.33Hz sinusoid with a 9.75 MW peak to peak initial value. Note that it takes about 4.5 seconds for the oscillation to damp out. Terminal voltage deviation follows a classical response pattern for response to an instantaneous step change of reference. Figure 6-10 documents the same machine's local mode response to a 4% step with the PSS in service. The plot scaling is the same as for the previous figure so that a direct comparison can be made. Note that the local mode is essentially damped out in one swing and that the peak to peak MW swing is now only about 4.5MW. The PSS works by creating a damping torque on the generator rotor by modulating the field voltage (and therefore field current) supplied to the machine. This, in turn, does transiently impact terminal voltage deviation, $\mathbf{\Delta V_t}$**,** as can be seen in Figure 6-10. However, the overall time taken to reach the new set point remains virtually unchanged. Based upon the data presented here the PSS is properly tuned has proven to be very effective in improving local mode damping. The total time to set up the standalone recorder and conduct the testing is between 30 minutes and an hour.

It would have been possible to take similar test data to verify PSS performance using a conventional DFR, but the ability to conduct the testing in front of the regulator/exciter cabinet

[23] "Integral of Accelerating Power Type PSS Part 1 – Theory, Design & Tuning Methodology" Dr. Alexander Murdoch III et al. IEEE Paper PE-473-EC-0-12-1997.

and analyze data on the spot is a distinct advantage. This is especially true if multiple step tests are required in the course of tuning the PSS and AVR.

Figure 6-11 is a photo illustrating a laboratory setup of the standalone recorder to verify its performance in testing that utilizes a generator step of reference. On the left hand side of the photo, a standard Windows based notebook PC running vendor supplied data acquisition software controls the operation of a standalone recorder. The recorder is second from the bottom of an instrument stack on the right hand side of the photo. The bottom instrument is the voltage deviation transducer and the top device is a breakout box for distributing generator PT voltage to the recorder and the $\boldsymbol{\Delta V_t}$ transducer. Note that between the PC and the instrument lies the split-core CTs that are connected over the existing nominal 5 amp generator CT secondary circuit. Good quality split core current transformers with internal burdens are available from several manufacturers as documented in Appendix B. Only 5 of the 8 available channels are required to assess PSS performance. Occasionally field voltage, field current and PSS output voltage (to the summing AVR's junction) are added to fully document excitation system behavior with the PSS in and out of service. In the interest of safety, these quantities are isolated via transducers at the exciter cubicle and then routed to the standalone recorder via low noise coaxial cable. In the case of solid state excitation systems with high power three phase SCR bridges, the field voltage is a 360Hz "sawtooth" with even higher frequency commutation transients due to circuit capacitance and inductance. Adjacent channel cross talk may superimpose spiking artifacts on the field current as well. Depending on the end use of the field quantities an adjustable frequency unity gain low pass filter may be inserted between the transducer output and the recorder to produce a smooth waveform representative of field quantities without the risk of aliasing or corruption by high frequency switching noise. Appendix B suggests sources for appropriate low-pass filters as well.

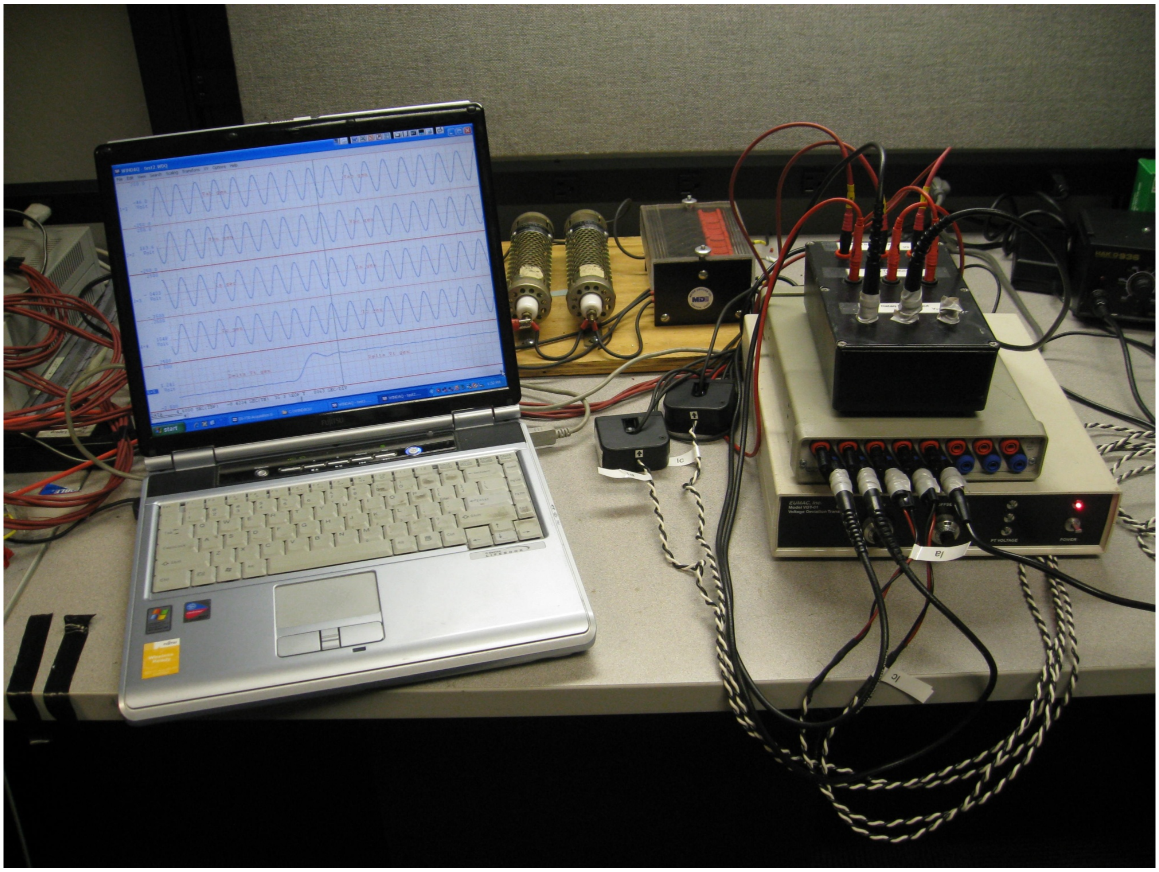

Figure 6-11
Stand Alone Recorder in Laboratory Performance Check

Shaft Torque Monitoring

Section 4 described in general terms the method of using digital fault recorders as part of a shaft torque monitoring system. Figure 4-4 shows a typical turbine-generator shaft system and is repeated here for convenience. For normal steady state operation the entire shaft system spins in unison with the HP and LP turbines providing mechanical torque (T_m) to the shaft system and the generator providing an electrical counter torque (T_e) which balances the driving toque of the turbines. At this operating point, the mechanical torque applied to the shaft system is equal to the electrical torque of the generator and the entire shaft system spins in unison at a fixed synchronous speed. If a sudden torque is applied to the shaft system, the masses on the shaft will no longer solely rotate in unison in the direction of shaft rotation, but the masses will oscillate torsionally according to the natural frequencies associated with the spring-mass system of the turbine-generator shaft system. The spring-mass system of the turbine-generator will have inherent natural frequencies and mode shape displacements that are fixed and defined by the inertia of the masses and the spring constants associated with steel shaft. Figures 6-12 and 6-13 show the mode shapes for a turbine-generator torsional system with three masses (as in Figure 4-4 if the coupling masses are neglected). These mode shapes describe the rotational displacement of the three different masses with respect to each other under a torsional oscillation event. Each individual mode will oscillate with a frequency that is unique to its specific mode.

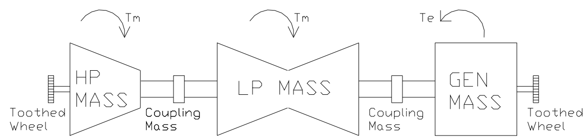

Fig 4-4: Turbine-Generator Spring-Mass Model

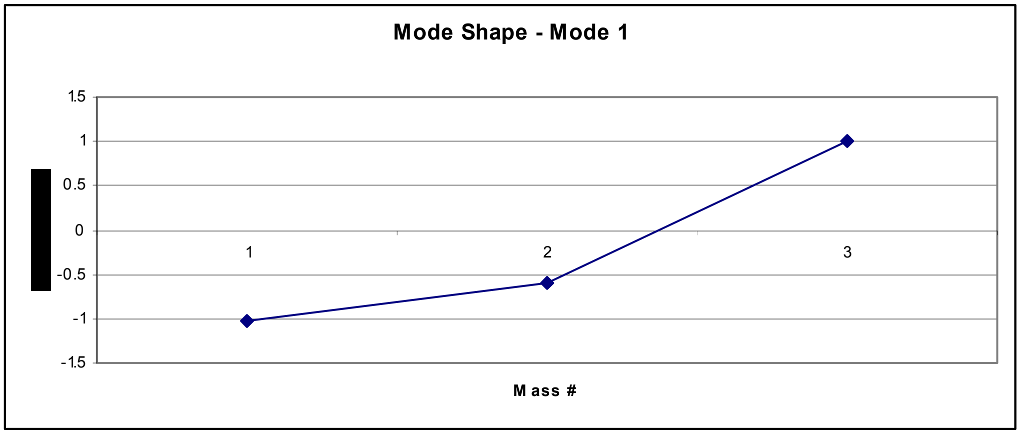

Figure 6-12
Mode shape for Mode 1

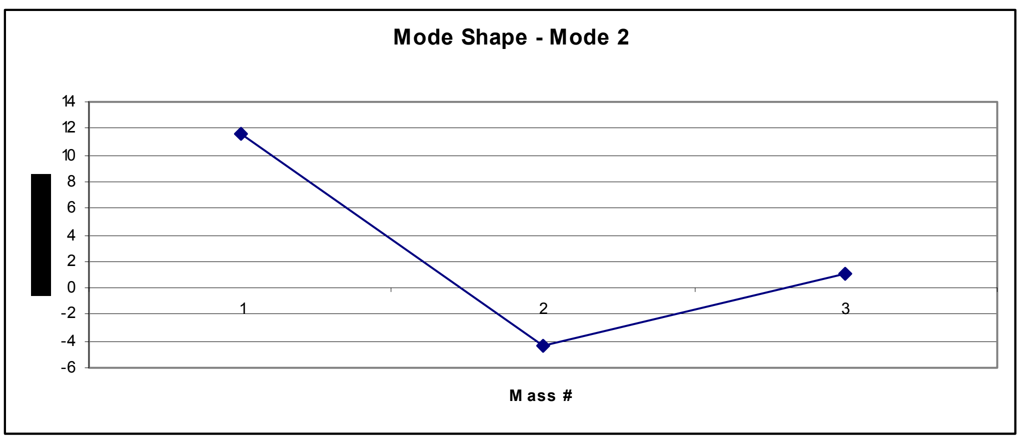

Figure 6-13
Mode shape for Mode 2

A fault near the terminals of the generator will cause the electrical torque of the generator to suddenly drop from its pre-event steady state value to near zero. This sudden change in torque acts in the same manner as the sudden application of a large torque on the spring-mass system and the turbine-generator shaft system will torsionally oscillate at its natural frequencies. These shaft oscillations will damage the shaft if the torques are large enough or if they are of sufficient duration.

A digital fault recorder can be used to monitor shaft torsional oscillations and the records captured by the DFR can be used to calculate the amount of life taken out of the shaft for significant events. The simplest form of shaft torque monitoring is to monitor the speed signal at one or both ends of the turbine-generator shaft. Toothed wheels are commonly applied to the turbine-generator shaft ends for the purpose of sensing shaft speed. Reluctance probes mounted in proximity of the teeth produce a frequency modulated signal that contains the shaft speed deviation from nominal. Passing these signals through an FM Demodulator gives signals that represent the shaft speed deviation from nominal at each end of the turbine-generator shaft system. Because a torsional event will stimulate the natural torsional frequencies, this demodulated signal can be filtered using band-pass filters to isolate the individual modal frequencies. If these signals are available, including them in the DFR analog channels will provide a measure of torsional monitoring of the generator shaft system. Triggering thresholds can be identified on the filtered waveforms so that DFR records can be captured.

While this type of torsional monitoring is of some use, the ability to calculate the amount of shaft damage during a torsional event is of more interest than just knowing that an event occurred. Unless a generator is highly vulnerable to subsynchronous resonance, most significant torsional events are associated with significant system events such as close in generator faults, mal-synchronizations, etc. For such events, other triggers will capture the DFR data associated with the torsional event and one need not rely on sensors looking at the speed pickup signals. To illustrate the process of calculating the shaft damage to a significant event, a specific case study is presented.

The general process for doing shaft torque analysis is illustrated in Figure 6-14. The steps associated with the process are as follows:

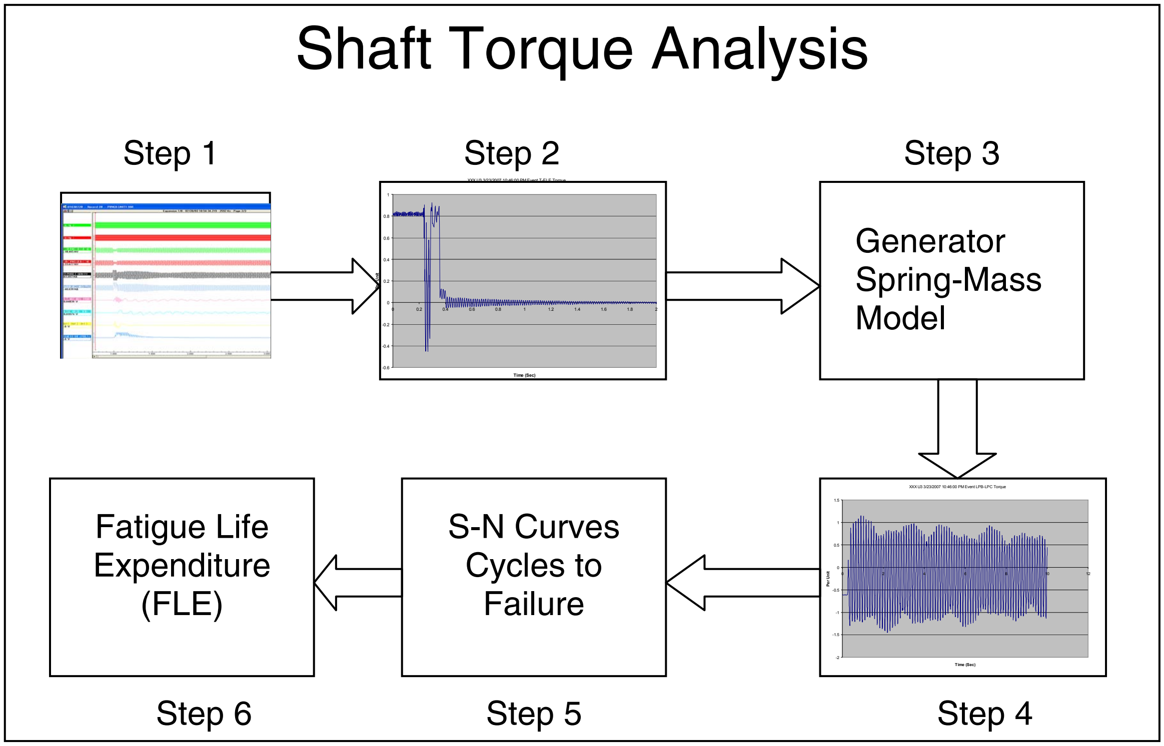

Figure 6-14
Shaft Torque Analysis Process

Step 1: Capture a digital fault record for the given event. The fault record should have at least 6 to 10 cycles of prefault data and enough post fault data to capture any significant changes in the applied torque. A 2 – 3 second record for shaft torque analysis is adequate.

Step 2: From the captured DFR record calculate the electrical torque for the event. In order to do this one needs at least two generator voltages and two generator currents if the generator is ungrounded or high impedance grounded. Otherwise, three generator voltages and three generator currents are required to calculate the electrical torque of the machine. It is noted that the calculation of the generator electrical torque is only an approximation for the air-gap torque. In most circumstances this is an adequate representation of the air-gap torque. The calculation of electrical torque is actually a calculation of the electrical power of the machine. When per unitized the electrical torque and electrical power are equivalent for a constant speed assumption. This approximation is reasonable.

Step 3: In order to calculate the shaft response to the torque stimulus, a model of the generator spring-mass system must be developed. Reference [20] describes a method of developing such a model. A state-variable representation of the system can be used with the externally applied torque on each mass making up the input vector. The total mechanical torque applied to the masses is assumed to be constant and equal to the pre-disturbance electrical torque calculated in Step 2. Thus, the electrical torque is the only changing input to the state variable system. By applying the input torque vector to the state-variable system, the torques from each shaft system are calculated (Step 4).

For those who don't have a computer program that models the state-variable representation of the spring-mass system of their turbine-generator, an alternate approach for Step 3 would be to model the generator in the Electromagnetic Transients Program (EMTP). The available machine models in EMTP allow spring-mass system of the generator to be modeled. The models do not however allow direct control of the electrical torque of the machine. To circumvent this limitation, the electrical torque signal from the DFR is operated on to create a mechanical torque signal that is input to the TACS portion of the program that results in a stimulus to the spring-mass system similar to the electrical torque stimulus. The EMTP then calculates the response of the turbine-generator spring mass system.

Step 4: The shaft torques for each shaft section are determined from the calculations done in Step 3. These shaft torques are available for plotting or for calculating the loss of shaft life for the event in Step 5.

Step 5: In order to calculate the amount of shaft life expended for a given event, the S-N curves for the generator are required. An S-N curve relates the given torsional stress on the shaft to a given number of cycles at that stress level that it will take for the shaft to fail. This information must be provided by the turbine-generator manufacturer. Given the shaft torques calculated for the given event, the cyclic stress amplitudes are counted and the percent fatigue life expenditure (FLE) is calculated for each shaft. Note that each shaft has its own characteristic S-N curve and similarly its own torque response for the given event.

Step 6: The calculated FLE is reviewed to determine the severity of the given torsional event. Since the FLE is cumulative in nature, a program of maintaining the history of the FLE is needed to determine how much fatigue life is expended over the life of the turbine-generator.

1. An example of the above calculations is given for illustration purposes. On July 28' 2003 a three-phase fault occurred on a 500 kV bus immediately in the vicinity of a plant with several large turbine-generators. The close proximity of the fault to the generator caused one of the units to trip but the others remained on line. The captured DFR record for this event is shown in Figure 6-15. In this figure the following points are noteworthy: The top two analog traces are two of the line voltages – Vab and Vbc. Note that both voltages are depressed during the fault.
2. The 3rd and 4th analog traces in the DFR plot are the line currents Ia and Ic. Note that the phase C fault current saturates the DFR trace at some of the peaks of the waveform.

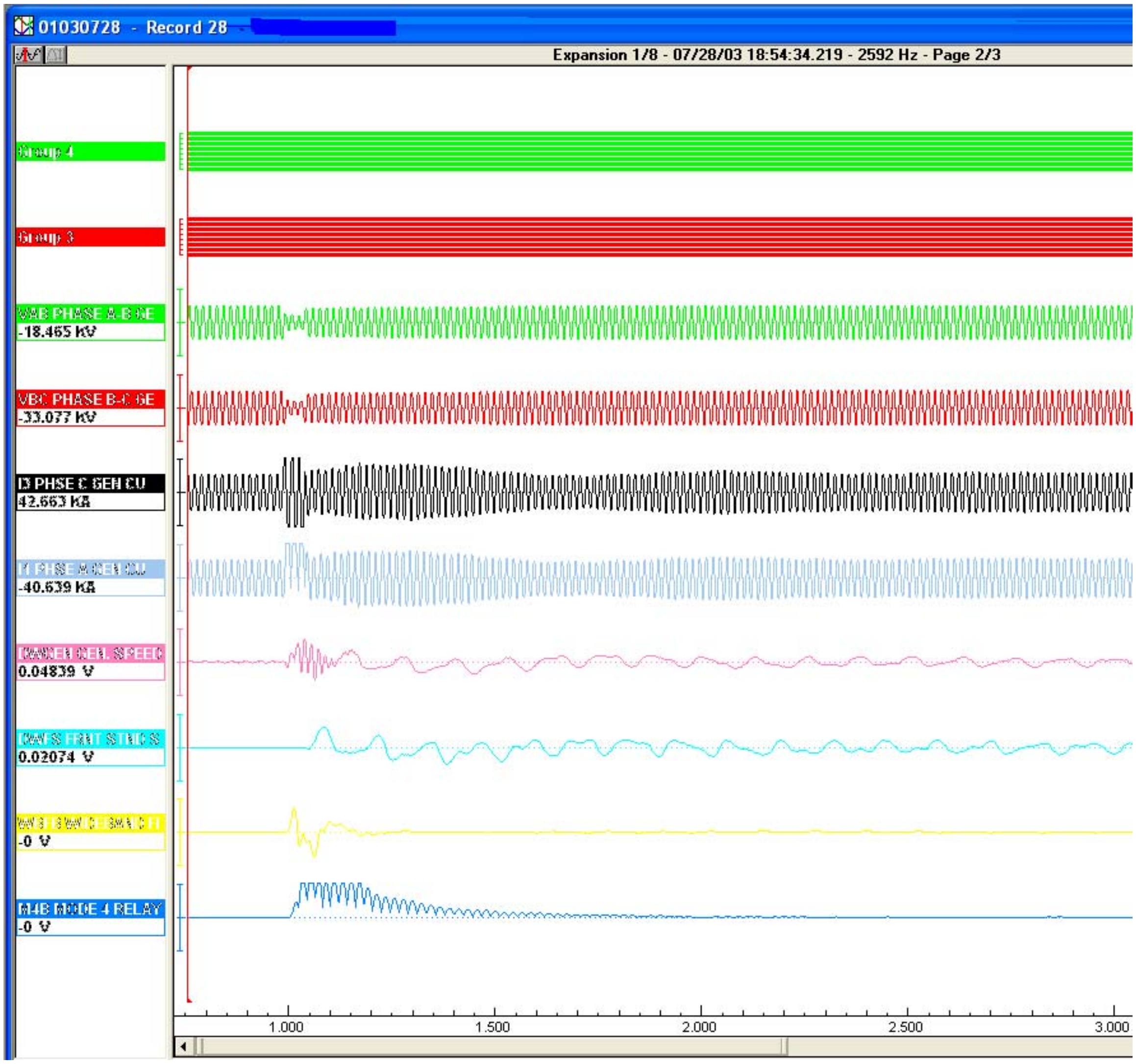

Figure 6-15
DFR Trace for 7/28/2003 Three Phase Fault Event

From the voltage and current traces the electrical torque for the event was calculated. Figure 6-16 shows the calculated electrical torque for this particular event. Note that because this particular unit trips following the event, the torque applied to the shaft system has two significant changes. The first significant torque change occurs at the time of the fault where the shaft torque drops from 0.8 pu to near zero and then back to 0.8 pu when the fault clears. The second significant torque event occurs approximately 4 cycles later when the unit trips and experiences a full load rejection. The electrical torque instantly reduces from 0.8 pu to less than 0.1 pu and then to zero. This electrical torque represents a significant transient torsional event on the turbine-generator shaft.

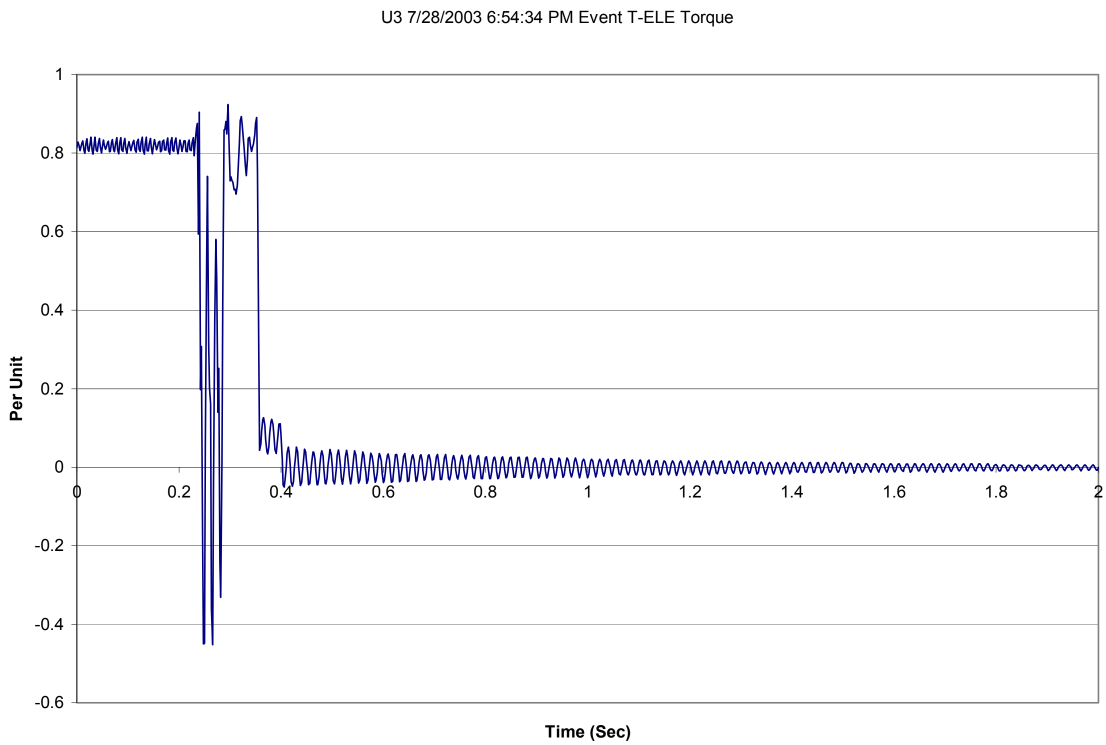

Figure 6-16
Calculated Electrical Torque for 3-phase Fault Event Followed by a Unit Trip

The electrical torque is used as an input signal to the state variable model of the generator spring-mass system and the outputs from the computer program are the shaft torques for each of the shaft sections. Figure 6-17 shows the calculated shaft torque for one of the shaft sections that experiences a significant FLE for the event. Note that the shaft torque oscillations have a peak-peak value of over 2 per unit. Since the unit trips off line, the no-load modal damping value of 0.3 rad/sec is used in the calculation. While it is apparent that the shaft torques are damped, the damping is low.

The shaft torques in Figure 6-17 are used together with the S-N curve for the shaft section to calculate the amount of fatigue life expended for the event. Figure 6-18 shows a report with the calculated FLE for each shaft section. Note that for the shaft section shown in Figure 6-17, the FLE is calculated to be in the range of 2 – 3 percent for this single event. This is very unusual as most event result in less than 0.01% shaft fatigue life expenditure.

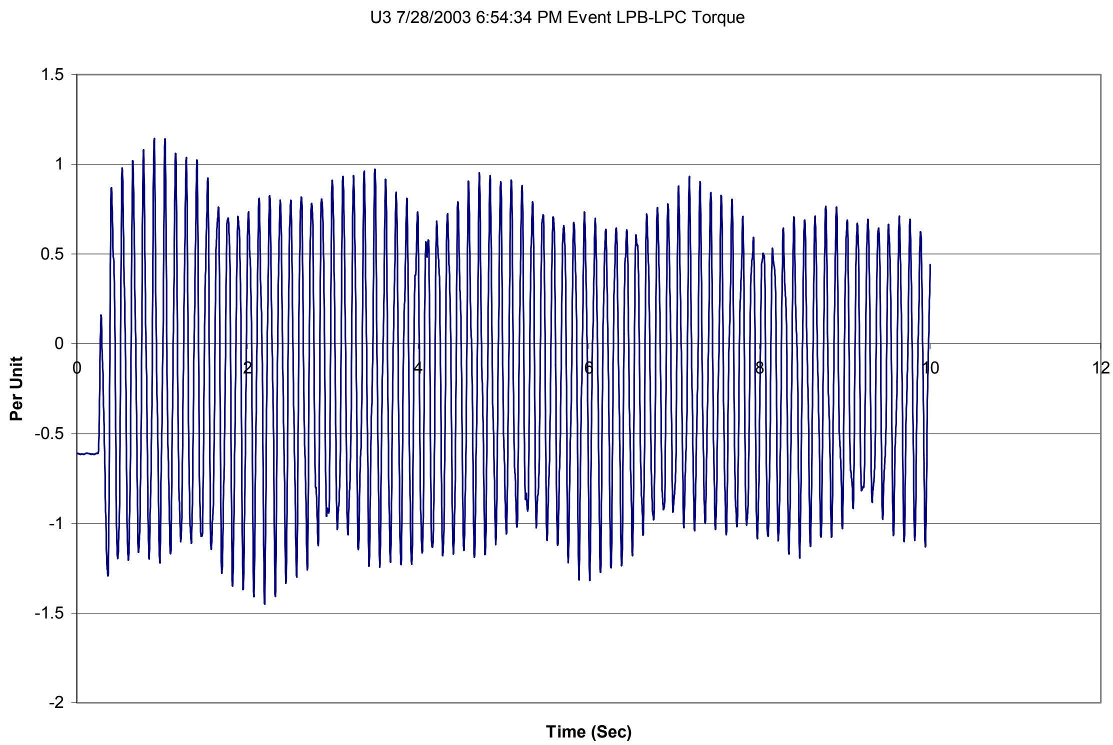

Figure 6-17
Calculate Shaft Torque for Three-Phase Fault followed by Unit Trip Event

```
***************************************************
*                   MOST REPORT                   *
*                                                 *
*                                                 *
***************************************************



------------ UNIT and EVENT Identity -------------


   SOURCEDAU,3,DESCRIPTION,UNIT3 DFR
   FAULT-DATETIME, 7/28/03  18:54:34.220



     Modal Damping Specified (rad/s) =  .03

 (FLE is based upon  10.000 seconds simulation )
 (DFR data may be available for longer interval)

***************************************************
*          SHAFT          FLE (%)                 *
*       ---------      -----------                *
*         HP-LPA         .235E-01                 *
*         LPa-LPb        .299E+01                 *
*         LPb-LPc        .204E+01                 *
*         LPc-Gen        .798E-01                 *
***************************************************
```

Figure 6-18
Calculated Fatigue Life Expenditure for Different Shaft Sections

Flux Probe Monitoring

Section 4 touched on using fault recorders to monitor the health of the generator field winding both by using flux probe data and by calculating the field resistance and trending over time. This case study shows details of how flux probe monitoring can be automated using digital fault recorders. Flux probes are coils of wire that are installed in the stator slot for the purpose of measuring the magnetic flux in the air gap of the machine. Figure 6-19 shows a picture of a flux probe in a stator slot during the installation process. The wire from the flux probe is epoxied into the slot and brought outside the generator wrapper. During normal generator operation, as the rotor spins each rotor slot passes by the flux probe and the magnetic flux detected at the flux probe location varies due to the magnetic flux produced by the field winding turns in each slot. Because the stator slots are symmetric around the rotor, by comparing the flux waveform from one pole with the waveform from the other, differences seen on a coil by coil basis can be ascribed to shorted turns in one of the coils. A sample comparison of flux probe data using a popular flux probe analysis program[24] is shown in Figure 6-20.

[24] GeneratorTech Rotor Winding Shorted Turn Detector Program from GeneratorTech Inc.

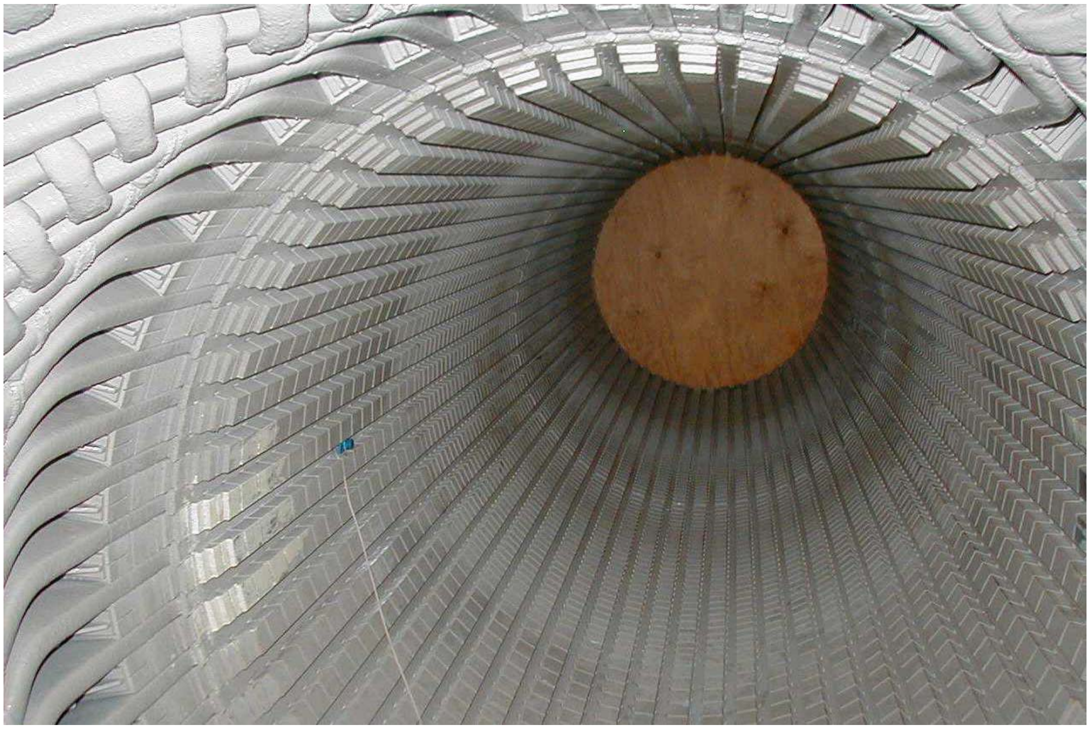

Figure 6-19
Flux Probe in Stator Slot

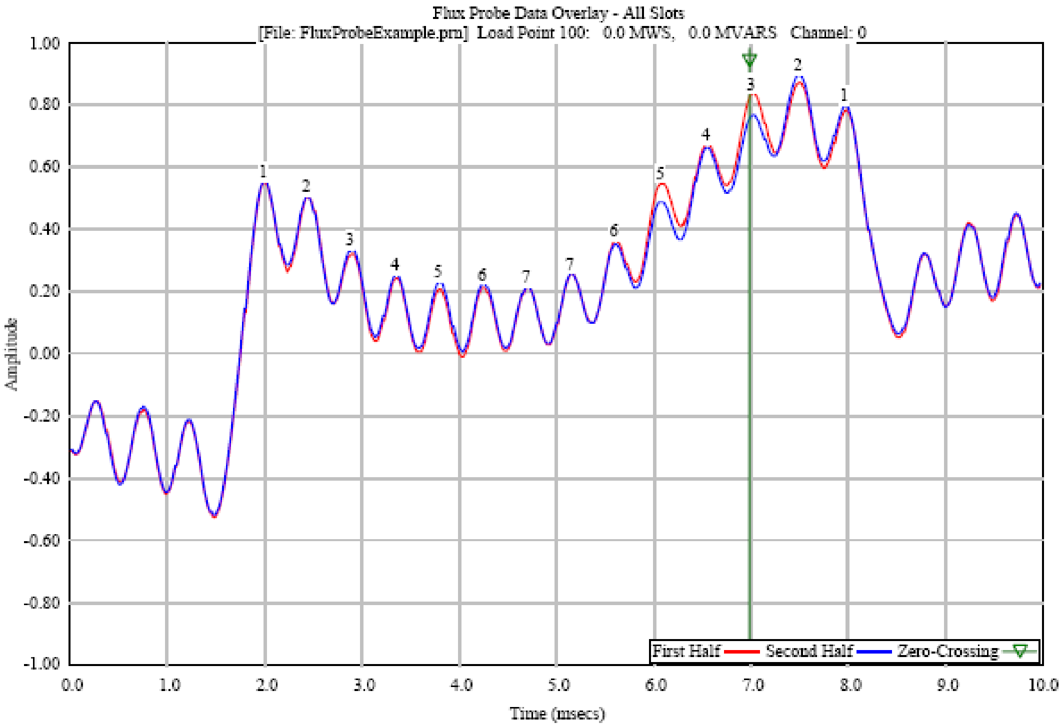

Figure 6-20
Flux Probe Analysis

Figure 6-20 shows a flux probe analysis for a generator with seven coils on each pole of the rotor. The red trace is one pole of the machine and the blue trace is the other pole. Note that Coil 3 shows a higher amplitude for the red trace than the blue trace indicating that there are shorted turns in the pole associated with the blue trace. The vertical green line indicates where the flux density zero crossing is in the air gap of the machine. It is important in flux probe analysis that the flux density zero crossing is zero at the given coil that is being analyzed. The flux density zero crossing moves from left to right on the plot as the unit loading increases from zero to full load. Figure 6-20 data is taken at nearly full load on the unit. Because the flux probe analysis is most accurate where the flux density waveform is zero, a complete set of flux probe data requires monitoring from zero load to full load on the machine. This requires a technician be on site during the entire startup sequence of the generator. When units come on over the weekend or at nighttime, this can incur overtime costs to the plant. Problems during startup exacerbate the problem as the technician must stay until the unit gets to full load. If a method of automating the capture of the flux probe data is implemented, the data can be taken without the need for a technician. Digital fault recorders can be implemented in a manner such that the flux probe data collection is automated.

Figure 6-21 is a block diagram illustrating how flux probe data capture automation can be implemented using a DFR. One of the difficulties of flux probe data capture is that the data is typically captured at very high sample rates. Typical data rates of 80 kHz or higher are used to capture the flux probe data. These high rates are required because of rotor is spinning at 3600 rpm and the waveform must be sampled at a high enough speed to capture the different coil slots as they pass by the flux probe. Unfortunately, DFRs do not have sample rates this high. How this difficulty is overcome is described next.

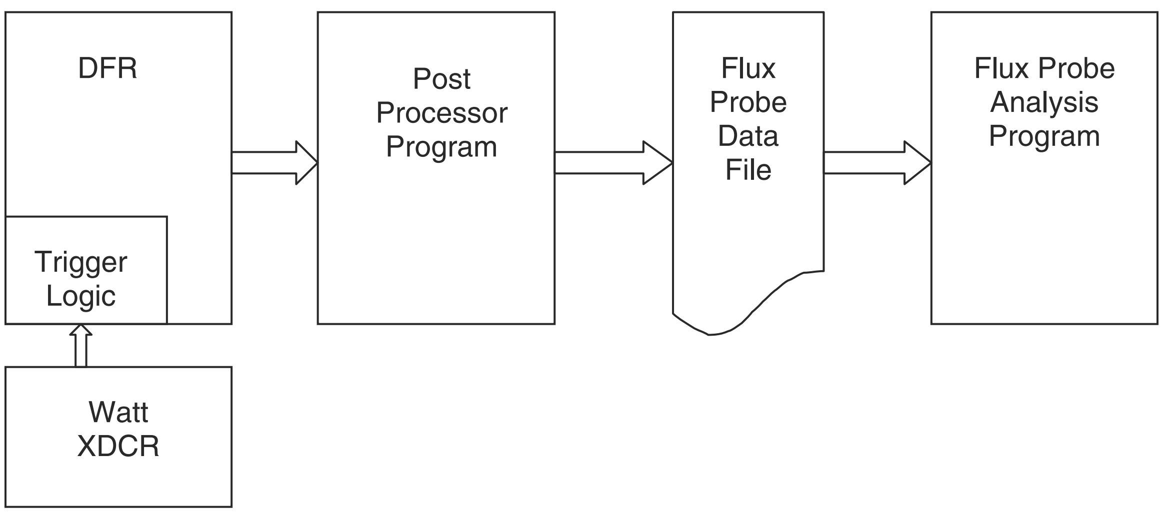

Figure 6-21
Flux Probe Data Collection Automation

The following points describe the flux probe data collection automation process as outlined in Figure 6-21:

1. The DFR must have the flux probe signal brought into one of the analog channels. The highest possible sample rate should be chosen, although it has been pointed out that by itself, the highest DFR sample rate is inadequate by itself.
2. Because the flux probe data must be collected throughout the load range of the generator, a method of automatically triggering the DFR must be developed. One method depicted in the figure is to connect the output of a watt transducer to one of the analog channels of the DFR. Because the location of the zero flux density waveform varies with unit loading, the loading points that correlate with alignment of the zero flux density waveform for each rotor coil can be identified and set as trigger values for the DFR. Prudent use of the threshold and hysteresis parameters of the triggering logic can cause the DFR to only trigger once at each desired load level when coming up from zero load. Resetting the triggers requires the unit loading to reduce to zero. DFR files should be triggered for 3 seconds or more.
3. Once the DFR has captured a record at the desired load point of the generator, the file must be post processed to get the required flux probe information for use in the analysis program. As has already been mentioned, the sample rate of the DFR is much lower than that of the normal flux probe data capture equipment. Fortunately however, each DFR record contains multiple cycles of flux probe data from which a full flux probe signal can be reconstructed. This reconstruction is done in the post processing block shown in Figure 6-21. To illustrate how this is done, refer to Figure 6-18. This is a plot of the flux probe waveform as captured by a DFR operating at 10 kHz. Figure 6-22 shows two cycles of data that are captured. It is apparent that the peaks of the waveform are not smooth like those seen in Figure 6-20. Figure 6-23 is a zoomed in picture of the data captured by the DFR. The individual points can be seen and it is apparent that the peaks and valleys are not fully captured.

   Reconstruction of the flux probe signal is possible because there are multiple cycles from which one can overlay data until all the missing points in the flux waveform are filled in. This is possible because of two aspects of the sampling. First, the sample rate of the DFR is not an exact multiple of the speed at which the rotor is spinning. That is, each time a given coil comes around to where the flux probe is, the sampling of the DFR occurs at a slightly different point on the flux probe wave. The second aspect that helps is that the rotor does not spin at exactly 3600 RPM but is always varying slightly. This ensures that the sampling does not line up and repeat points on the flux waveform. The process of reconstructing the waveform is to take a DFR record with multiple seconds of data. Then extract each individual cycle of data and superimpose it on the first cycle set of data. In Figure 6-22, one would take Cycle #2 and shift it left on top of Cycle #1. Other cycles in the series would likewise be shifted on top of Cycle #1. The zero crossing of each cycle is used as a reference point and with enough cycles superimposed on each other an adequate waveform is reconstructed. To demonstrate this, Figure 6-24 is presented. This figure is a picture of the flux probe analysis software using input data from a DFR reconstructed waveform. Note in the lower left hand plot that the flux waveforms are smooth and have captured the peaks and valleys correctly (as evidenced by the two poles matching).
4. After the DFR reconstruction program runs, the analysis of the DFR data is done using the usual analysis software. The reconstruction program writes a file in the same format that is used by the analysis software.

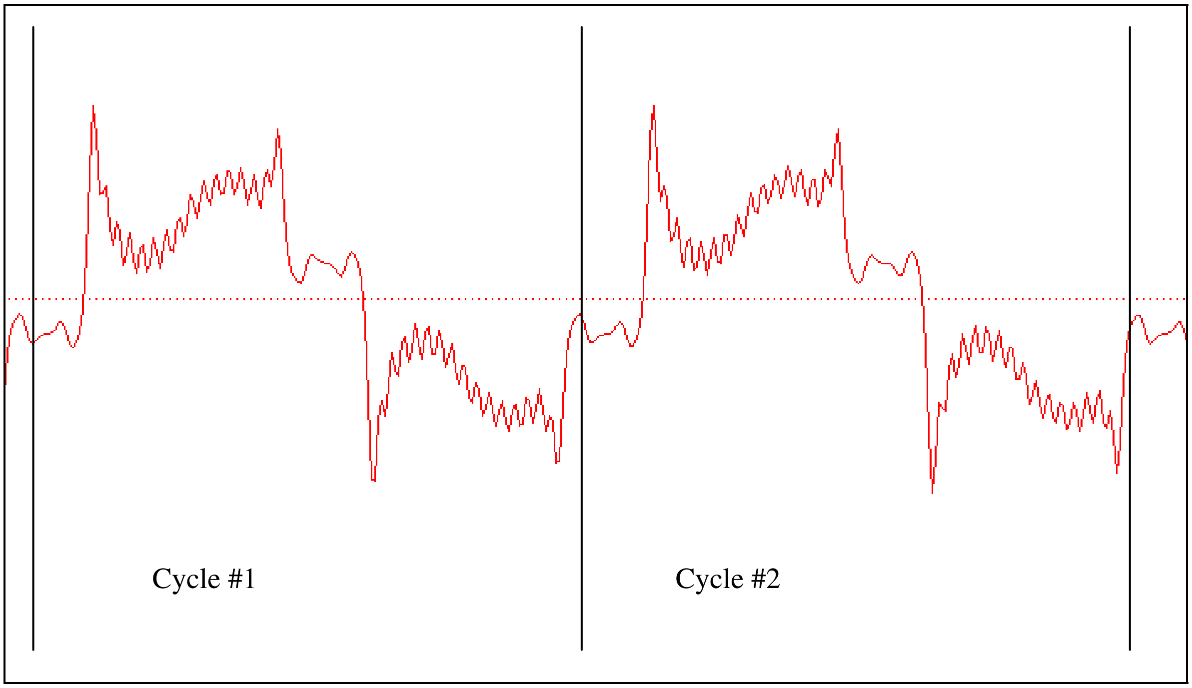

Figure 6-22
Flux Probe Signal Captured by DFR

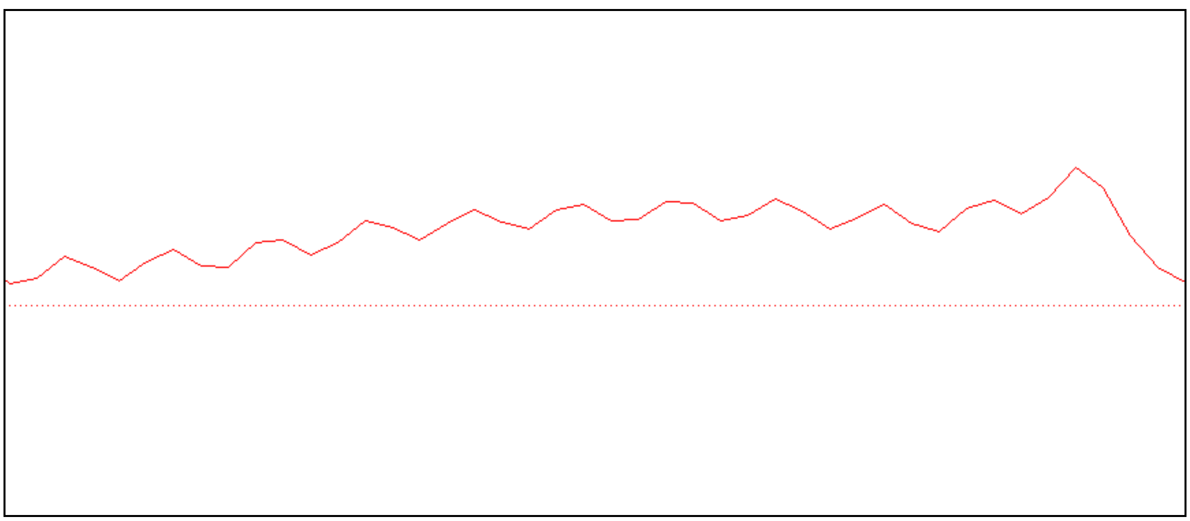

Figure 6-23
Close Up of Flux Probe Signal Captured by DFR

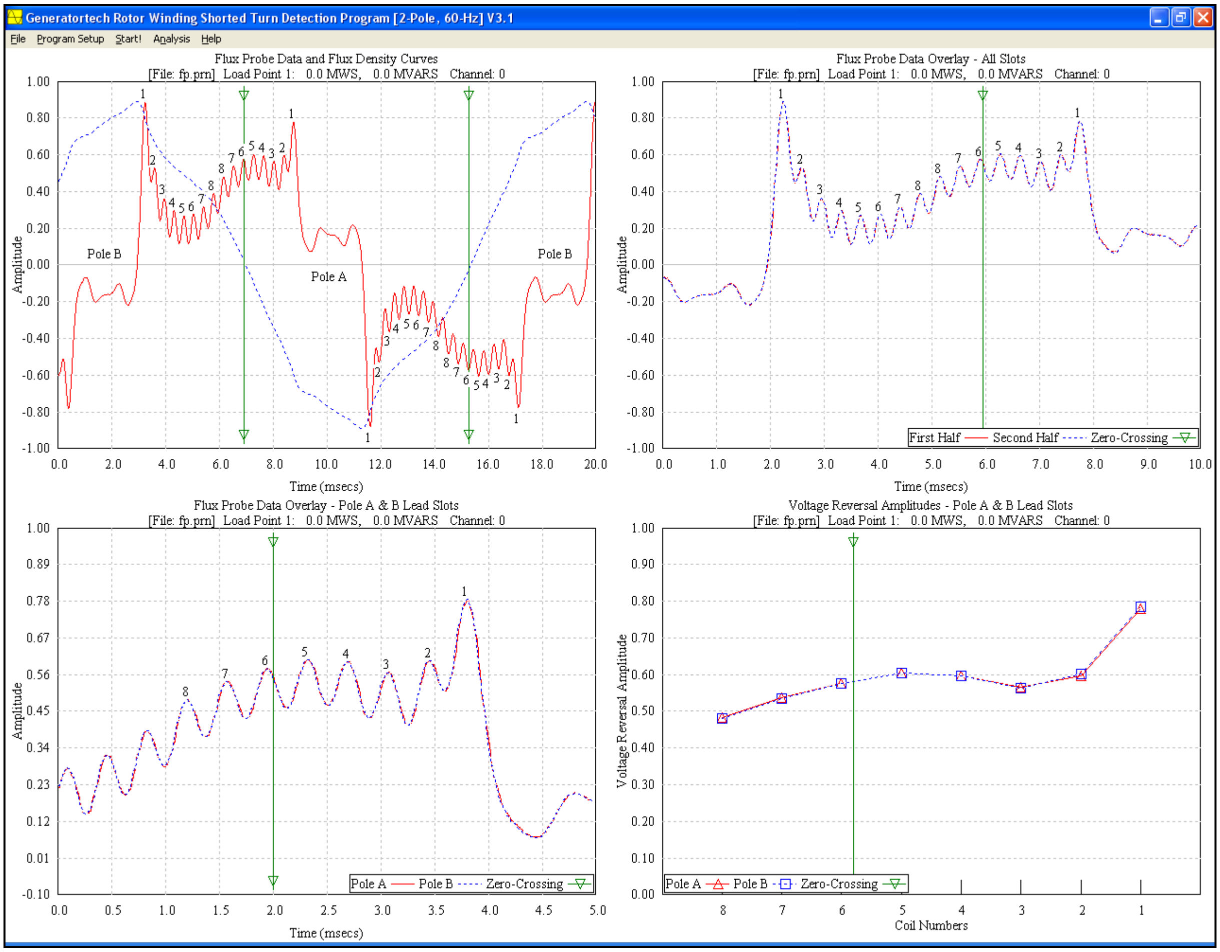

Figure 6-24
Analysis of Reconstructed Flux Probe Signal from DFR

Summary

The purpose of this section was to illustrate the myriad of uses for digital fault recorder data. Standard fault analysis is presented for some typical power plant events along with example fault recordings. In addition, unique applications are presented to show that the use of the data is only limited by a fault recorder user's imagination. A generator mal-synchronization event is presented together with a thorough analysis of the event and the issues that led up to the event. A generator stator ground fault that progressed into a full three-phase stator winding fault was analyzed and documented using the various tools available in typical analysis software packages.

Several unique applications that were presented include the use of stand alone digital recording technology to assess excitation system and power system stabilizer performance. Shaft torque monitoring technology through use of off the shelf fault recorders was presented as well as a description and example of how digital fault recorders can be used to automatically check the health of the generator field winding using flux probe technology.

All of the examples presented in this section are based on actual events that occurred and were monitored using fault recording technology. The listing of examples was not meant to be comprehensive but rather a small taste of the possibilities available in applying this technology to monitor in the power plant environment.

7
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GTTF_2005-12_Generating_Facility_Data_Requirements.pdf
GTTF_2005-12_Generating_Facility_Model_Validation_Requirements.pdf
GTTF_2005-12_Generating_Unit_Baseline_Test_Requirements.pdf
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8
GLOSSARY

A/D – Analog to Digital (converter)

ASCII -

AVR – Automatic Voltage Regulator (sometimes termed an AC regulator)

CFG – COMTRADE Configuration File Extension

CPU – Central Processing Unit

CT- Current Transformer

D/A – Digital to Analog (converter)

DAT – COMTADE Data File Extension

DFR – Digital Fault Recorder.

FCR – Field Current Regulator (sometimes termed a manual or dc regulator)

FERC – Federal Energy Regulatory Commission

FLE – Fatigue Life Expenditure

GOES – Geostationary orbit earth satellite

GPS – Global Positioning System

GSU – Generator step-up (transformer)

IEC – International Electrotechnical Commission

IEEE – Institute of Electrical and Electronics Engineers

IRIG – Inter-Range Instrumentation Group. A time code standard employed in time synchronization of DFRs, SERs, DDRs & PMUs

IRIG B – transmission of time coding information in binary form over a 1KHz amplitude modulated carrier.

MW – Megawatts

MS – Master station

MVAR - Megavars

NERC – North American Electric Reliability Corporation

PC – Personal Computer

PMU – Phasor measurement unit

PSS – Power system stabilizer

PT – Potential Transformer

PU – Per Unit

SER – Sequence of Events Recorder

A
POWER CALCULATIONS

With the significant computing power available in modern digital fault recorders, various calculations can be made both within the structure of the DFR data capturing mechanism, within the DFR display software, and externally in user developed software. One of the most often used calculations for power plant DFR applications is the calculation of both real power (P) and reactive power (Q). The method of performing these calculations differs depending on what quantities are available with which to make the calculation. This appendix documents several different approaches to making this most common of calculations. While some of the specifics mentioned in the appendix are particular to a given DFR type, the equations and methods are applicable across all types of DFRs.

Three different methods are described here as follows:

1. Multiplication of instantaneous (point-on-wave) quantities to obtain P or Q. This method is generally done either using the DFR analysis software or is done in external user written software. For this appendix, quantities v and i denote instantaneous (point-on-wave) voltage and currents. Subscripts applied to v or i would denote particular phases.
2. Use of DFR analysis software functions as provided by the DFR manufacturer as part of their master station analysis software. These functions might directly calculate P or Q, or might calculate an intermediate quantity from which P or Q are calculated such as the RMS voltage (V) or RMS current (I). For purposes of this appendix, the following functions are defined (and are generally available in DFR analysis software):

   - @P(V,I) = function that calculates real power by taking $V \times I \cos(\theta)$ where θ is the angle between the RMS quantities V and I.

   - @Q(V,I) = function that calculates reactive power by taking $V \times I \sin(\theta)$ where θ is the angle between the RMS quantities V and I.

   - @RMS(X) = function that calculates the RMS value of a signal X.

   - @Ang(X,Y) = function that calculates the angle difference between signals X and Y.
3. Use of DFR sensors to create the analog quantities upon which triggers can be set to capture data. This method is dependant on how the manufacturer has defined their trigger algorithms but can be useful at times. For purposes of this appendix, the following trigger functions are defined:

- Psens(V,I) = sensor which calculates real power by taking V × I cos(θ) and creating an analog quantity based on this calculation. Note that this sensor might be in the form of a rate of change sensor which outputs the given quantity.

- Qsens(V,I) = sensor which calculates reactive power by taking V × I sin(θ) and creating an analog quantity based on this calculation. Note that this sensor might be in the form of a rate of change sensor which outputs the given quantity.

- 3Psens(va,vb,vc,ia,ib,ic) = sensor which calculates three phase real power by multiplying phase voltages and phase currents and summing them together and extracting the DC average value and creating an analog quantity based on this calculation. Note that this sensor might be in the form of a rate of change sensor which outputs the given quantity.

- 3Qsens(va,vb,vc,ia,ib,ic) = sensor which calculates three phase reactive power based on an algorithm using phase voltages and currents. Note that this sensor might be in the form of a rate of change sensor which outputs the given quantity.

The following equations can be used to calculate real and reactive power depending on what quantities are available and what functions or sensors are available. Often in power plant applications, phase voltages are not available but instead the line-line voltages are available. Equations for both sets of available quantities are provided.

Single Phase Calculations

Given Phase Voltages

Multiplying instantaneous quantities: $v_a\, i_a = P[1 + \cos(2\omega t)] + Q\sin(2\omega t)$ where

$$P = V_{rms}\, I_{rms} \cos(\theta)$$
$$Q = V_{rms}\, I_{rms} \sin(\theta)$$

$P_{1\phi} = @P(V_a,I_a)$ *(for calculating using functions)* **Equation A-1**

$Q_{1\phi} = @Q(V_a,I_a)$ *(for calculating using functions)* **Equation A-2**

$P_{1\phi} = Psens(V_a,I_a)$ *(for calculating using sensor outputs)* **Equation A-3**

$Q_{1\phi} = Qsens(V_a,I_a)$ *(for calculating using sensor outputs)* **Equation A-4**

Given Line-Line Voltages

$$P_{1-\phi} = \frac{1}{2}\left(MWC + \frac{MVC}{\sqrt{3}}\right)$$ **Equation A-5**

$$Q_{1-\phi} = \frac{1}{2}\left(MVC - \frac{MWC}{\sqrt{3}}\right)$$ **Equation A-6**

Where
MWC = @P(V_{ab}, I_a) (using functions)
MVC = @Q(V_{ab}, I_a) (using functions)

Or

MWC = Psens(V_{ab}, I_a) (using sensor outputs)
MVC = Qsens(V_{ab}, I_a) (using sensor outputs)

Three Phase Calculations

Given Instantaneous Phase Voltages

$$P_{3\phi} = V_a I_a + V_b I_b + V_c I_c$$ **Equation A-7**

$$Q_{3\phi} = \frac{1}{\sqrt{3}}\left[V_a\left(I_c - I_b\right) + V_b\left(I_a - I_c\right) + V_c\left(I_b - I_a\right)\right]$$ **Equation A-8**

If making the calculation using software functions and phase voltages

P3ϕ = @P(Va,Ia) + @P(Vb,Ib) + @P(Vc,Ic) **Equation A-9**

Q3ϕ = @Q(Va,Ia) + @Q(Vb,Ib) + @Q(Vc,Ic) **Equation A-10**

If implementing using sensors with phase voltages

P3ϕ = (P1) + (P2) + (P3) (these individual quantities are recorded on DFR)
= Psens(Va,Ia) + Psens(Vb,Ib) + Psens(Vc,Ic) **Equation A-11**

Q3ϕ = (Q1) + (Q2) + (Q3) (these individual quantities are recorded on DFR)
= Qsens(Va,Ia) + Qsens(Vb,Ib) + Qsens(Vc,Ic) **Equation A-12**

Given Instantaneous Line Voltages

$$P_{3\phi} = V_{ab}I_a - V_{bc}I_c = V_{bc}I_b - V_{ca}I_a = V_{ca}I_c - V_{ab}I_b$$ **Equation A-13**

$$Q_{3\phi} = \frac{V_{ab}I_c + V_{bc}I_a + V_{ca}I_b}{\sqrt{3}}$$ **Equation A-14**

If calculating using software functions and Line Voltages

$P_{3\phi}$ = @P(Vab,Ia) - @P(Vbc,Ic) **Equation A-15**

$Q_{3\phi}$ = @Q(Vab,Ia) - @Q(Vbc,Ic) **Equation A-16**

If calculating using Sensors and Line Voltages

$P_{3\phi} = P1 - P2$ **Equation A-17**

Where
P1 = Psens(Vab,Ia)
P2 = Psens(Vbc,Ic)
(or other combinations as given in Equation A-15 above)

$Q_{3\phi} = Q1 - Q2$ **Equation A-18**

Where
Q1 = Qsens(Vab,Ia)
Q2 = Qsens(Vbc,Ic)
(or other combinations as given in Equation A-16 above)

Another way to calculate $Q_{3\phi}$ is to use only the Psens sensor function (instead of the Qsens sensor) and the second equation above as follows (note this method is not generally recommended – see write up below):

$$Q_{3\phi} = \frac{Q1 + Q2 + Q3}{\sqrt{3}}$$ **Equation A-19**

Where
Q1 = Psens(Vab,Ic)
Q2 = Psens(Vbc,Ia)
Q3 = Psens(Vca,Ib)

Note that the Psens sensor can be interchanged with the @P(V,I) software function. For these purposes, the function or sensor is only used to calculate the VIcos(angle) function. The sensor is used when the quantities are calculated by the DFR before the record is captured and the @P(V,I) function is used when making the calculations in DFR software.

Comments on Equations

In using the Above equations, one should understand not only how some of the sensors and functions used by the fault recorder software work but some other aspects of the equations as well. The following comments are an attempt to clarify which equations are best to use for various purposes.

In calculating real and reactive power, it should be understood that by definition, power is the multiplication of the voltage and current and as such involves both real and imaginary components. The real power (real component) has both a constant (DC) term and a term that has a zero average at double frequency. The reactive power (imaginary component) has a double frequency term only but the magnitude of this term is taken to be Q.

Calculation of single phase power and reactive power using instantaneous (point-on-wave) quantities will always result in the double frequency terms being present in the result. If instantaneous quantities are used in 3-phase power calculations, the double frequency terms add to zero for balanced system cases. However, when the system is unbalanced (during faults), a resultant double frequency term will be seen. Consequently, if power calculations are wanted without the double frequency terms included, instead of using the equations that directly multiply and add instantaneous quantities (for example – Equations A-7, A-8, A-13, and A-14), equations that use one of the software functions or sensor functions should be used (Equations A-9, A-10, A-11, A-12, A-15, A-16, A-17, A-18, A-19). An example of analysis where this would be wanted is model verification work where DFR records will be compared with stability results.

MOST type analysis would use the instantaneous multiplication type equations (A-7, A-8, A-13, A-14).

The sensors and the functions in the some DFR software use Fourier Transforms and the details of how the algorithms are developed are not completely published in the user manuals. However, it can be verified that if the RMS Voltage is multiplied by the RMS Current and Cosine (or Sine) of the phase angle between the two gives the same P or Q output as the @P(V,I) and @Q(V,I) functions.

For one particular DFR software package, the results of the various equations were calculated and compared with the following findings:

Real power using Equation A-15 is correct with the double frequency term eliminated.

Reactive Power using Equation A-16 appears to give better results than using Equation A-19. Note that Equation A-19 uses the RealPower(V,I) function to calculate reactive power. These conclusions were obtained by calculating 3-phase reactive power using single phase quantities (Equation A-10) and comparing to Equations A-16 and A-19. This is illustrated in Figure A-1 below (note bottom group of plots). Note that the red trace (Equation A-16) and the magenta trace (Q calculated using single phase quantities – Equation A-10) lie on top of each other (can't even see magenta trace as it is obscured by the red trace – results differ by about 2%). The green trace (Equation A-19) differs in magnitude from the single phase based calculation by about 19%. The yellow trace in the figure is the Q calculated using instantaneous multiplications (Equation A-14). Note the double frequency term.

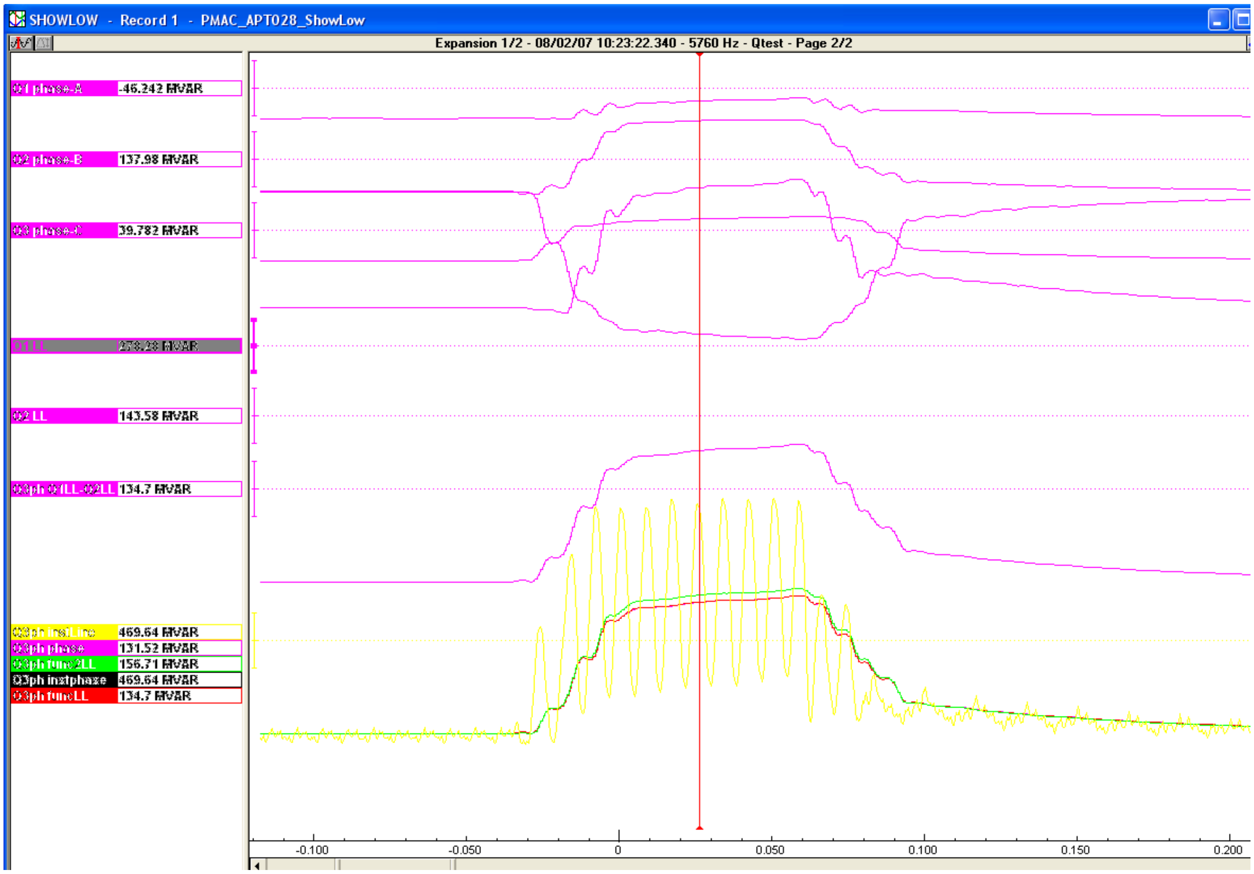

Figure A-1
3-Phase Reactive Power using Single Phase Quantities Comparison

B
VENDOR LIST

With the continuously changing electronics market it is impossible to stay current on all the available hardware associated with DFR installations. While not completely comprehensive, the following list of vendors have provided the indicated equipment associated with DFR monitoring.

Voltage & Current Isolation Transducers

CR Magnetics, Inc.
3500 Scarlet Oak Blvd
St. Louis, MO 63122
Ph. 636 343-8518
FAX: 636 343-5119
www.crmagnetics.com

Flex-Core
Division of Morlan & Associates, Inc.
6625 McVey Blvd.
Columbus, Ohio 43235
Ph. 614 889-6152
FAX: 614 876-8538
www.flex-core.com

Ohio Semitronics, Inc.
4242 Reynolds Drive
Hilliard, Ohio 43026-1264
Ph. 800 537-6732
FAX: 614 777-4511
www.ohiosemitronics.com

Voltage Deviation Transducers, FM Toothed Wheel Demodulators, Isolation Amplifiers

EUMAC, Inc.
1531 East Calavar Drive
Phoenix, AZ 85022-7504
Ph. 602 942-9168
FAX: 602 942-9168
www.eumacinc.com

Split Core Current Transducers

Flex-Core
Division of Morlan & Associates, Inc.
6625 McVey Blvd.
Columbus, Ohio 43235
Ph. 614 889-6152
FAX: 614 876-8538
www.flex-core.com

Sentran Corporation
2547 Aerial Way SE
Salem, OR 97302
Ph. 614 889-6152
FAX: 614 876-8538
www.sentrancorp.com

Power Supplies & DC/DC Converters for Contact Wetting

Acopian Technical Company
P.O. Box 638
Easton, PA 18044
Ph. 610 258-5441
FAX 610 258-2842
www.acopian.com

Digital Fault Recorders

Ametek Power Instruments
255 North Union Street
Rochester, NY 14605
Ph. 585 263-7700
FAX: 585 454-7805
www.ametekpower.com

APP Engineering, Inc.
5234 Elmwood Ave
Indianapolis, IN 46203
Ph. 317-536-5300
FAX: 317-536-5301
www.appengineering.com

Beckwith Electric Co., Inc.
6190 – 118th Avenue North
Largo, FL 33773-3724
Ph. 727 544-2326
FAX 727 546-0121
www.beckwithelectric.com

E-MAX Instruments. Inc
13 Inverness Way South
Englewood, CO 80112
Ph. 303-799-6640
www.e-maxinstruments.com

ERL Phase Power Technologies, Ltd.
74Scurfield Blvd.
Winnipeg, MB R3Y 1G4
Canada
Ph. 204 477-0591
FAX: 204 478-1697
www.erlphase.com

Mehta Tech, Inc.
208 N. 12th Ave
P.O. Box 350
Eldridge, IA 52748
Ph. 563 285-9151
FAX: 563-285-7576
www.mehtatech.com

Qualitrol Company LLC
1385 Fairport Road
Fairport, NY 14450
Ph. 585 586-1515
www.qualitrolcorp.com

Utility Systems, Inc.
8431 Castlewood Drive
Indianapolis, IN 46250
Ph. 317 842-9000
FAX: 317 849-7600
www.faultrecorder.com

Standalone Recorders

Dataq Instruments, Inc.
241 Springside Drive
Akron, OH 44333
Ph. 330 668-1444
FAX: 330 666-5434
www.dataq.com

Measurement Computing Corporation
10 Commerce Way
Norton, MA 02766
Ph. 508 946-5100
FAX: 508 946-9500
www.mccdaq.com

National Instruments
11500 N. Mopac Expwy
Austin, TX 78759-3504
Ph. 800 531-5066
FAX: 512 683-8411
www.ni.com

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