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# Requirements for a Fault Recording System

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# Requirements for a Fault Recording System

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## 1. Introduction

The traditional method for capturing fault and disturbance data in a typical substation has been to use a centralized, dedicated fault recorder, the DFR. This device typically identifies an event, then captures and stores transient data, disturbance data, and sequence of events data across the substation in an individual record for this event. Microprocessor protective relays have the ability to capture similar data for the part of the substation the relay protects, which gives rise to a debate about whether DFRs are still necessary devices. However, it is important to remember that in this context both DFRs and recording protective relays are just tools for fault recording. Fault recording has evolved to solve a common problem on the power system: what happened? Or stated more fully, using fault recording tools to understand how the power system, and especially power system equipment such as protective relays and circuit breakers, reacts during undesirable system conditions such as short circuits.

The right problem to be solved, then, is capturing the necessary information to explain system performance after an undesirable event. The goal of this paper is to take a step back, and suggest ways to think about this problem before picking the tools to use. As a way of defining the problem, this paper uses an actual event from the National Grid system. The paper then suggests answers to some questions. What is the right information to capture? What methods can be used to capture this information? What tools are available to capture this information? What is a realistic way to apply these tools and methods? What are some of the shortcomings of a solution? And what steps are there to take going forward?

Specifically, this paper will describe fault recording as a system. The paper will define the minimum required information to include in records, such as current, voltage, protection signaling, breaker status, relay operating quantities, sequence of events logs for all devices, and communications messaging. In addition, the paper will define the requirements for measurement of data, types of recording, appropriate sampling rates, and appropriate triggering methods, and give a high level view of the tools that have these capabilities. The paper will then go on to describe how to apply these tools to capture the desired information, and some challenges to recording systems.

## 2. The problem: explaining the Tewksbury event of April 2008

Power system disturbances when they occur require analysis by the protection engineer, primarily to determine if the protection system operated properly for the fault. When an event occurs which is a suspected improper operation of the protection system the engineer needs to review available data to piece together the series of related events to determine what happened. To demonstrate the data requirements an event that occurred in April of 2008 while commissioning a new 115kV circuit breaker at National Grid's Tewksbury substation will be used as an example. Figure 1 is a simplified one-line of Tewksbury substation.

At Tewksbury the J162 circuit breaker (CB) had been replaced and was ready to be test-energized. The plan was to energize the new J162 circuit breaker using the 115kV Bus 2, with the J162 line-side disconnect switch open isolating the CB from the J162 transmission line. All circuit breakers connected to Bus 2 were opened and isolated leaving all 115kV lines being fed from 115kV Bus 1. The steps to complete the test were to close the J162 circuit breaker, and then close the N140 circuit breaker to energize Bus 2 and the J162 CB. When the operator closed the N140 CB, the Y151 line tripped. The Y151 and 53-51 circuit breakers opened at Tewksbury, the 51-33 circuit breaker opened at West Methuen, the J51 circuit breaker opened at Hudson, and the 01-15 and 15-11 circuit breakers opened at North Litchfield resulting in a single-end trip of the 230kV O215 line.

The system operator at Tewksbury thought that the Y151 and 53-51 opened at the same time as the N140 circuit breaker closed. The technician on site, based on the operator account of the events, suspected that this may be an improper operation and called Protection Engineering requesting an investigation of the event. The technician explained the event informing engineering that the West Methuen and Hudson terminals on the Y151 Line had tripped and the O215 Line tripped single-ended at North Litchfield substation.

This event presented several questions that needed to be answered in order to determine what happened and what corrective actions, if any, were required:

1. Did the N-140 CB closing initiate the events that occurred?
2. Were the Y151 and O215 line operations independent or simultaneous faults?
3. Are Y151 and O215 line operations proper operations?
4. If these were improper operations, what was the cause of the operations?
5. What corrective actions are required?

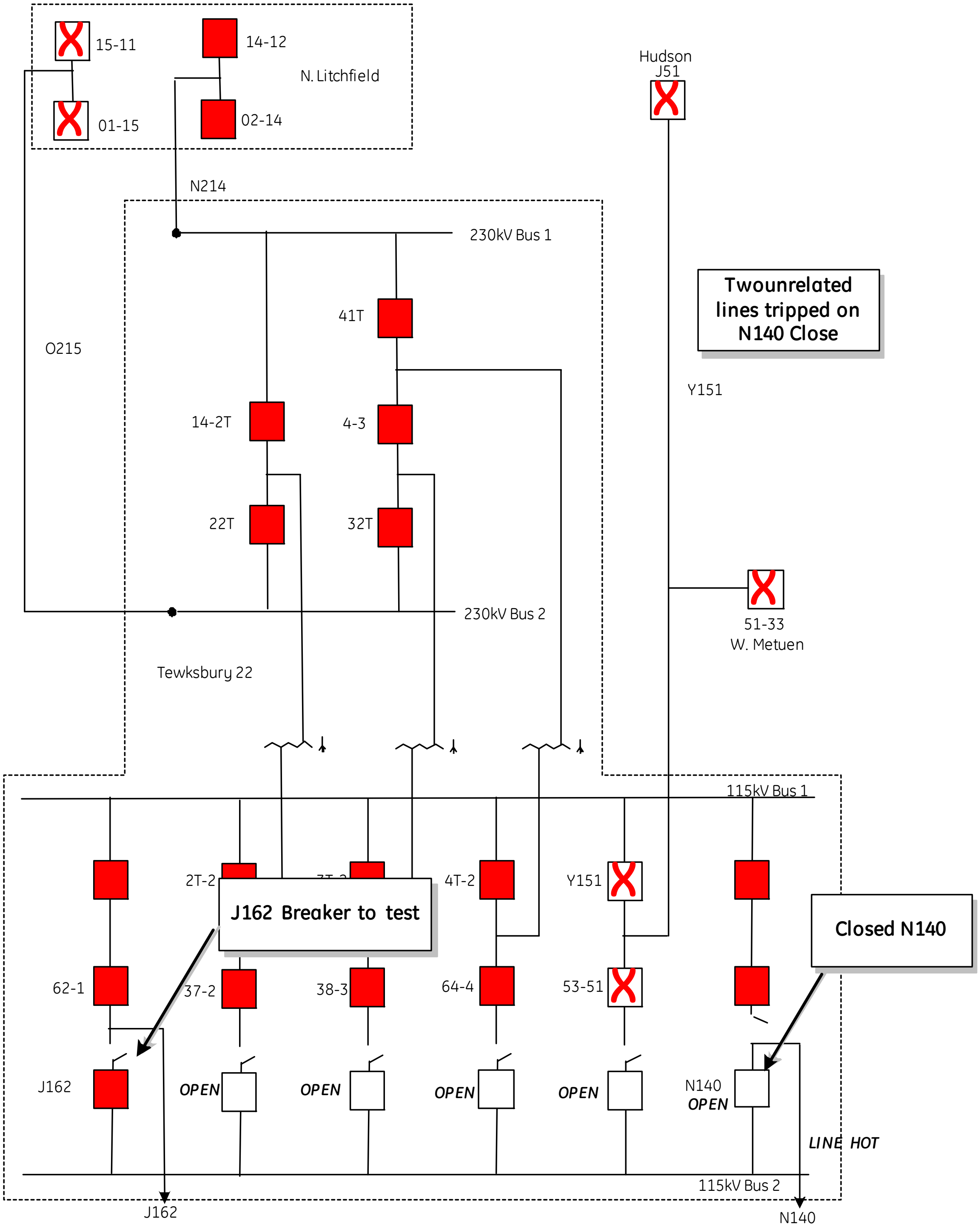


**Figure 1: Tewksbury Station**

## 3. Information needed to solve the problem

The challenge in event analysis is to determine which events require a detailed analysis and which do not. Typically a first cut analysis of the event is done to determine if further action is required. A first cut analysis typically is done with the following basic information:

a) Sequence-of-events (SOE) data, primarily circuit breaker operations, with time stamping to the millisecond.

b) Relay targets for each line and terminal affected.

For the majority of all power system faults the SOE and target information is sufficient to determine if the response and performance of power system equipment was correct and appropriate. An example of such an event would be an insulator failure on a line, where protective relay targets and circuit breaker operations from SOE data indicated the protection system operated correctly, and a line patrol found the failed insulator. However, for some fault events, such as the Tewksbury fault event, more detailed information is required to explain the operation of the protection and control system. If a more detailed analysis is needed the following additional information is required depending on the protection and control scheme:

a) Three-phase current and voltage waveforms for all impacted lines and power system equipment

b) Residual current waveforms for all impacted lines and power system equipment

c) Voltage and current sequence components for all impacted lines and power system equipment

d) Digital inputs

    a. Circuit Breaker open/close

    b. Relay protection elements pickup and trip

    c. Pilot channel inputs including

        i. Carrier start, carrier receive, carrier stop

        ii. Permissive send and receive inputs

        iii. Direct Transfer Trip send and receive

    d. Lockout relays

This information is available in DFRs and most microprocessor relays.

For this second, more detailed analysis National Grid prefers to use a DFR for the above data because:

a) All monitored current and voltage quantities are contained within on time-synchronized record.

b) The higher sampling rate, typically 64-samples/cycle, provides better resolution for analyzing events.

c) Records have a minimum of 10-cycles of pre-fault.

d) Record lengths are greater than one second allowing a display of the total event in one record.

e) The digital inputs available are:

    a. Circuit breakers

    b. Tripping relays

    c. Pilot channels

d. Lockout relays

The higher sampling rate of the DFR will capture power system transient data such as transformer inrush, CT saturation, DC offset, and circuit breaker restrikes. With the data in one synchronized record, containing all monitored analog quantities and digital inputs, an engineer gets an overall view of the power system disturbance allowing the engineer to make a determination what circuits were impacted and what protection scheme(s) operated. The DFR record's overall view of the circuits usually provides enough information to determine if the protection and control scheme operated properly for the event.

In the event a protective relay scheme is suspected to have mis-operated, the relay event records are reviewed at the third stage of the analysis. The relay event records provide three-phase voltage and current waveform data, plus residual current, the physical digital input and output status and the relay protection elements that operated.

There are DFRs at North Litchfield and Tewksbury. Also, the line protection at North Litchfield and Tewksbury consists of two systems of microprocessor relays operating in parallel, and at West Methuen consists of one system using a microprocessor relay system and the second protection system being electro-mechanical relay scheme. Table 1 summarizes the capabilities of the available recording devices at the three substations.

**Table 1: Recording equipment capabilities**

| | Digital Fault Recorder | Relay A | Relay B |
|---|---|---|---|
| Target Information | N/A | Event Type & Relay Elements | Event Type & Relay Elements |
| Sampling Frequency (Hz) | 3840 | 240 (filtered default)<br>960 (filtered long and unfiltered record) | N/A |
| Samples/Cycle | 64 | 4 (filtered default)<br>16 (filtered long and unfiltered record) | N/A |
| Prefault Cycles | 10 | 4 | Tabular Magnitude & Angle |
| Record Length in cycles | 60 | 11 | Tabular Magnitude & Angle |
| Triggers | Magnitude current & voltage, Digital change of state | Relay Elements | Trip Output |
| Data Available | Three-phase Current & Voltage all 230 & 115kV Lines, Residual Current | Three-Phase Current & Voltage of Protected Line, Residual Current<br><u>Digital Inputs/Outputs:</u> | Tabular Three-phase Current & Voltage.<br>Trip Output |

| | Digital Fault Recorder | Relay A | Relay B |
|---|---|---|---|
| | Digital Inputs:<br>Breaker Position<br>Pilot Channels<br>Lockout Relays<br>Relay Trips | Breaker Position<br>Pilot Channels<br>Relay Trip<br>Relay Elements | |
| Locations | North Litchfield, Tewksbury | North Litchfield, Tewksbury, West Methuen | North Litchfield, Tewksbury |

The O215 and Y151 line protection are both Directional Comparison Blocking schemes. It is also important to analyze and event to verify the proper operation of the protection scheme as well as to determine the root cause of an improper operation. Analyzing the operations of each system requires three-phase voltage and current, residual current, the carrier start, receive, and stop inputs and the status of the circuit breakers associated with each line. Table 2 summarizes the data that may be required to analyze the event that occurred at Tewksbury.

**Table 2: Tewksbury desirable data**

| Analog values | Digital values |
|---|---|
| J162 Line currents - phase | J162 CB status |
| J162 Line currents – ground | N140 CB status |
| Y151 Line currents – phase | N140 CB close command |
| Y151 Line currents – ground | Y151 CB Status |
| Y151 Line voltages - Phase | 53-51 CB Status |
| Y151 line polarizing quantity | 51-33 CB Status |
| | J51 CB Status |
| | Y151 Carrier Start status |
| | Y151 carrier receive status |
| | Y151 carrier stop status |
| | Y151 DCB Scheme Relay Trip status |
| | Y151 relay elements pickup, dropout (tripping elements, carrier start elements, DCB scheme logic elements) |
| O215 Line currents - phase | 22T CB status |
| O215 Line currents - ground | 32T CB status |
| O215 Line voltages - phase | 01-15 CB status |
| O215 Line polarizing quantity | 15-11 CB status |
| | O215 Carrier Start status |
| 115 kV Bus 1 voltages | O215 Carrier receive status |
| 115 kV Bus 2 voltages | O215 Carrier stop status |
| | O215 DCB Scheme Relay Trip status |
| | O215 relay elements pickup, |

| Analog values | Digital values |
|---|---|
| | dropout (tripping elements, carrier start elements, DCB scheme logic elements) |

# 4. Methods to acquire the information: fault recording

The previous section describes the data necessary to verify the performance of the protection and control system during a specific power equipment fault. The methods and tools used to capture this data are generically known as "fault recording". To identify the requirements for a fault recording system, it is necessary to set some explicit definitions of fault recording, and some criterion for fault recording capabilities.

The goal of fault recording is to provide data to engineers to analyze system performance and equipment performance after an undesirable event. Undesirable events can be loosely grouped into power equipment faults (the traditional short circuit type faults) and power system faults (such as loss of generation or loss of transmission). The data required for analysis is different in each case. Power equipment faults require analog data records of high resolution and short duration. Power system faults require longer data records, but only need a low resolution.

## *4.1. Types of recording*

The term "fault recording" actually describes 3 different functions to capture the appropriate data for all types of events.

**Transient recording**, which is capturing analog data, sample by sample, for a period of a few cycles to a few seconds. Sampling rates are typically from 16 samples per cycle to 128 samples per cycle. Required data to analyze power equipment faults, and useful data to analyze power system faults.

**Disturbance recording**, which is capturing RMS or phasor data for analog values once per cycle or once every two cycles, for a period of seconds to a few minutes. Required data to analyze power system faults, and is useful to analyze some power equipment faults.

**Sequence of events recording**, which is capturing the change in status of equipment (such as circuit breakers) and specific operating signals (such as protective relay trips and power line carrier signals) within 1 millisecond. Required to analyze both power equipment and power system faults.

## *4.2. Measuring of data*

Measuring of data is the actual implementation of the three fault recording functions. The appropriate currents, voltages, and operating signals must be physically connected to the recording system, and captured in records. Recording is initiated when a trigger condition is met. Triggers can be applied against any measured analog quantity (voltage or current), calculated analog quantity (frequency, active power, reactive power, symmetrical components, apparent impedance), or digital channels. Triggers can be based on magnitude, rate-of-change, apparent impedance, contact input, or internal logic. Different trigger criteria can initiate transient records and disturbance records. Typical triggers for transient recording include high current magnitudes, low voltage magnitudes, negative-sequence voltage, protective relay operation, and breaker operation. Typical triggers for disturbance recording includes frequency rate-of-change, active power rate-of-change, and apparent impedance.

A key consideration is that all measurements must be time synchronized to each other. This indicates that all measurements must be recorded simultaneously, and that the sampling rates and filtering methods of devices used for recording must be compensated for. Also, all necessary data in a substation should be captured for a specific event. This ensures that the impact of a fault event on all equipment in the substation can be understood.

### 4.3. *Storage of records*

Fault recordings are typically captured at the local substation level due to the large number of signals that must be collected and recorded in an individual substation. Therefore, a key piece of fault recording is the ability to store records locally in the substation until these records can be retrieved by engineering personal for use in event analysis. It is typical to transfer recordings from the substation to a central archive for more convenient use of the record. The records stored may be transient records, disturbance records, sequence of events records, or some combination of all three types. The typical requirement is the capability to store records for the previous 1 to 12 months.

### 4.4. *Meeting regulatory requirements: a North American view*

NERC has two standards relating to recording, PRC-002-1 "*Define Regional Disturbance Monitoring and Reporting Requirements*"[1] and PRC-018-1 "*Disturbance Monitoring Equipment Installation and Data Reporting*"[2]. PRC-002-1 describes the minimum measurement requirements for fault recording. These requirements include criteria for equipment location, elements to be monitored at each location, electrical quantities to record, recording length, minimum sampling rate, and triggering requirements. PRC-002-1 in practice means the Regional Coordinating Councils must define these requirements. PRC-018-1 sets the requirements for installing and maintaining recording equipment, and also requires archiving of event data for at least 3 years.

National Grid is part of the Northeast Power Coordinating Council (NPCC). NPCC explicitly defines recording requirements in NPCC Document A-15 "*Disturbance Monitoring Equipment Criteria*"[4] and NPCC Document B-26 "*Guide for Application of Disturbance Recording Equipment*"[3]. There are a few requirements from A-15 and B-26 that bear further discussion in this paper.

NPCC essentially requires redundancy of measurement for fault recording equipment to ensure data is captured for an event on the bulk power system. This requirement does not explicitly require duplicate independent measurements of each current and voltage, as it is actually intended for transient recording equipment to trigger for faults on the next bus. However, it is possible in design of recording systems to have complete redundancy of measurement of all currents and voltages, which actually exceeds the NPCC requirement.

NPCC also requires a record length for events that is a minimum of 1.0 seconds long. NPCC also suggests the minimum desirable sampling rate for transient recording is 3840 Hz, or 64 samples per cycle. NERC requirements are that records must be available locally for at least 10 days. In general, relays can only store a few recordings, so local retrieval and storage may be required. NPCC recommends keeping significant events for at least 2 years.

# 5. How to get the data: tools for fault recording

Proper analysis of the Tewksbury fault event described in this paper requires data such as voltage and current waveforms, equipment status, and the transmission and reception of communications signals to be recorded in a time-synchronized record. The building blocks of a fault recording system are the devices that actually capture the record. These devices can be divided between the centralized DFR, and distributed devices such as protective relay, phasor measurement units, and power meters.

## *5.1. Centralized DFR*

The traditional centralized DFR originally solved practical challenges for recording. Most measurement devices in a substation, such as protective relays and meters, were electro-mechanical devices without recording capabilities. And communications from the central office to the substation were non-existent, too slow, or unreliable. The DFR then grew into a stand-alone single function device to provide measuring of data and local storage of fault records, and is today a very mature device in terms of capabilities, performance, and user expectations.

The centralized DFR operates in parallel to protective relays and meters. Every analog measurement and every equipment status point must be directly wired to a measurement channel of the DFR. Therefore, DFRs require a large number of analog measurement channels and digital measurement channels, with a typically sized DFR having around 36 analog channels and 72 digital channels. In addition to directly measured analog channels, DFRs typically also capture data on calculated analog channels, typically summated currents and power channels. Analog data is not necessarily limited to DFRs providing all 3 fault recording functions: transient recording, disturbance recording, and sequence of events recording. Transient recording sampling rates are typically 64 to 128 samples per cycle. Disturbance recording has traditionally captured RMS values once per cycle or once every two cycles. Recently, DFRs have evolved to capture synchrophasor data for disturbance recording. Sequence of events is typically captured with a 1 ms resolution. Record lengths for transient recording can be from 0.5 seconds to 30 seconds. Records for disturbance recording can be 2 to 3 minutes long, with some recorders supporting continuous recording of disturbance data for up to 1 month at a time. DFRs will typically have a sequence of events recording of thousands of events.

DFRs offer a comprehensive selection of triggers for every measured, calculated, and digital channel, including magnitude and rate-of-change triggers.  Most DFRs also provide symmetrical component and logic triggers. Triggers initiate transient recording, disturbance recording, or both transient and disturbance recording. Any trigger captures a record that includes all analog channels and all digital channels. The measurements of these channels are therefore sampled at the same rate, synchronized, and included in one total record. These triggers are set on criteria different than that of protective relays, and can be used to verify protective relay operation (or non-operation). The status of every digital channel will be included in each record, as well as in a separate sequence of events log that records the status change of every digital channel.

The centralized DFR also includes significant capability to store records locally. A typical DFR can store between 30 and 1000 records in non-volatile memory for later retrieval. The size of individual record files can be as large as 5MB. Due to the amount of data, DFRs have traditionally used rotating hard drives, but flash memory is becoming more common.

To summarize, the traditional centralized DFR is a piece of equipment specifically designed to provide the measurement of data and local storage components of the fault recording system, and is appropriate for use in any substation. By using independent measurements, triggering, recording and storage, the centralized DFR is an excellent choice even when electro-mechanical relays and meters are used. Any event produces a record that includes all analog and digital measurement channels, providing a complete view of the events in a substation. All the measurement channels are inherently synchronized together, and sampled at the same rate.

### *5.2. Distributed devices*

Electro-mechanical protective relays and power meters have no recording capabilities. Microprocessor-based protective relays and meters, however, have fault recording capabilities. Fault recording is not the primary function of these devices, and capabilities for fault recording have changed significantly from the first devices to present devices. These distributed devices can be used to acquire data as part of a fault recording system.

Distributed devices, especially protective relays, are installed as the key part of the protection and control system for primary operation of the power system. Current measurements, voltage measurements, and digital status information are wired to the device as necessary for the specific protection application. The device and its intended application fix the number of analog measurement channels and digital measurement channels. A relay typically captures all directly measured analog and digital channels, and all internal element status changes. Most microprocessor devices will record relay operating quantities and protection element operations as native functions. Better devices will also capture programmable logic status points, inter-relay communications status points, and IEC61850 GOOSE message status points to record all of the protection and control system. In addition, the best devices have flexible amounts of analog and digital measurement channels to ensure all appropriate information is monitored and recorded. Devices may have as few as 4 or as many as 24 analog measurement channels, or have as many as 96 digital inputs. Therefore, for a specific application, a relay may capture more complete information than a DFR. Relays typically capture both transient records and sequence of events log, while some modern relays offer the capability for disturbance recording. Transient recording sampling rates are normally limited by the sampling rate of the relay, and are normally around 12 to 16 samples per cycle. However, some modern relays support higher sampling rates for recording of 64 to 128 samples per cycle. Also, relays may capture raw data, or they may only capture analog data filtered and processed for protection function purposes. Sequence of events logs will typically store a few hundred events, with a 1 ms resolution. Record lengths are normally just long enough to describe a protection function operation, and typically are from a few cycles to a few seconds long.

Triggering of records for protective relays is almost always based on the pickup or operation of a protection function. Therefore, a protection function must operate for data to be recorded, so an event the relay doesn't consider as a fault will not be captured. Some relays on the market have included fault recording triggers separate from protection functions, to trigger recordings on changes in currents and voltage that may indicate undesirable events the relay doesn't consider a fault.

Distributed devices typically have limited ability to store records locally. Relays typically store from 5 to 15 records, though a few devices can store as many as 64 records. Some relays have selectable sampling frequency and record length, however, the higher the sampling frequency and/or the longer the record length the fewer the number of records the relay will store. Therefore, distributed devices require a process to quickly retrieve and remove records from the device before these records are overwritten by new events. The typical file size is only 200kB to 300kB.

Distributed devices, therefore, have many of the capabilities of traditional DFRs, while providing more detail on protection element operation, control logic, and relay operating quantities for a specific piece of the protection and control system. It is important to understand, however, how each device handles sampling rates, data filtering, triggering, and record storage.

# 6. Application: using tools to capture data for the Tewksbury fault

To the experienced engineer it is obvious that the Tewksbury fault event was an unusual event that required a more detailed analysis to identify any possible system performance issues. The data required to analyze the event comes from many sources, and all sources should be used in the analysis. The engineer can start with an assumption about whether an operation is a proper or improper one. In either case, the analysis of an event should be broken into a series of steps, each more detailed than the next. A first-cut analysis of an event using the reported relay targets, breaker operation counts, and sequence-of-events data should be done to determine where a more detailed analysis is required.

## *6.1. First cut analysis*

The data for the first cut analysis of the Tewksbury event came from three sources. The first was the technician's telephone call immediately following the event. The second source of data was the System Operators report, which is logged in an on-line Interruption Disturbance Reporting System (IDS) tool. The third source of data was the SCADA database, which is the repository of all system sequence of event points collected from the Remote Terminal Units installed at the substations. This data was used because it is readily available and is the minimum amount of data required to determine what equipment and relay system operated, and the order and timing of equipment operations.

The first cut analysis involves reviewing the disturbance report with the recorded circuit breaker operations and target information.

The operation report and target information as reported by the System Control Center for this disturbance is as follows:

At Tewksbury the Y151 and 53-51 circuit breakers locked open. Y151 Line Tewksbury to Hudson locked out.

At West Methuen the 51-53 circuit breaker tripped and automatically reclosed.

At North Litchfield the 01-15 and 15-11 circuit breakers tripped simultaneously to the Y151 Line and automatically reclosed.

Prior to the event the Tewksbury 115kV Bus 2 was out-of-service resulting in loss of the A153 Line when the Y151 trip occurred.

<u>Targets reported for this event are:</u>

| | |
|---|---|
| Tewksbury: | Y151 DD/CDD/CDG System 1 Zone 4, SOTF |
| West Methuen: | Y151 DD/CDD/CDG/DG System 1 COMM Zone 2 G OC 50 |
| North Litchfield: | O215 DD/DDG/DG System 1 DEF start; |
| | O215 DD/DDG/DG System 2 Zone 2 G INST COMM |

The Sequence-of-Events (SOE) data stored in the SCADA points database for the time and date of the event was reviewed and compared to the disturbance report to determine where analysis would be required.

**Table 3: CB Sequence-of-Events**

| | | | | |
|---|---|---|---|---|
| 2008-04-11 | 13:24:17.528 | TEWKSBURY 115 | J-162 GCB | CLOSE |
| 2008-04-11 | 13:25:13.929 | W.METHUEN 115 | 51-33 OCB | OPEN |
| 2008-04-11 | 13:25:13.992 | N.LITCHFLD 230 | 15-11 GCB | OPEN |
| 2008-04-11 | 13:25:13.993 | N.LITCHFLD 230 | 01-15 GCB | OPEN |
| 2008-04-11 | 13:25:14.542 | TEWKSBURY 115 | Y-151 GCB | OPEN |
| 2008-04-11 | 13:25:14.542 | TEWKSBURY 115 | 53-51 GCB | OPEN |
| 2008-04-11 | 13:25:19.088 | N.LITCHFLD 230 | 15-11 GCB | CLOSE |
| 2008-04-11 | 13:25:19.094 | N.LITCHFLD 230 | 01-15 GCB | CLOSE |
| 2008-04-11 | 13:25:24.576 | TEWKSBURY 115 | Y-151 GCB | CLOSE |
| 2008-04-11 | 13:25:26.513 | TEWKSBURY 115 | Y-151 GCB | OPEN |

According to Table 3 it can be determined that the N140 circuit breaker was not closed when the fault occurred. The 51-53 circuit breaker on the Y151 line tripped first, followed by the 15-11 and 01-15 circuit breakers at North Litchfield on the O215 Line resulting in a single-end trip. The Y-151 and 53-51 circuit breakers at Tewksbury tripped next. The J51 tripped at Hudson during the event, however, since it is owned by a neighbor utility, the sequence of events is not readily available. Then the 15-11 and 01-15 CBs automatically reclosed at North Litchfield in five-seconds. The Y-151 CB at Tewksbury automatically reclosed after ten seconds but trips two seconds later.

Based on the SOE data it appears the Y151 fault was a proper operation and the single-ended trip of the O215 Line is an improper operation because it happened during the Y151 Line operation. The reported targets for the Y151 Line at Tewksbury indicate that the CB closed into a fault and tripped on a Switch-on-to-Fault condition. Therefore it was necessary to parse out the Event Type and Target information from the event records of created during the fault to refine the sequence-of-events for the Y151 operation. Only Relay A has the capability to capture event data, as described in Table 1. Relay A event and target data are as follows:

| | |
|---|---|
| Hudson: | 13:25:13.941 EVENT AG T, COMM ZONE 2 EN G 50 |
| Tewksbury: | 13:25:13.842 EVENT BG, INST ZONE1 EN B G |
| | 13:25:24.046 EVENT TRIP, SOTF ZONE4 EN A B C |
| W. Methuen: | 13:25:13.908 EVENT BG, COMM ZONE2 EN G 50 |

Based on the SOE data from the SCADA data base and the relay target information in the IDS report the following sequence-of-events for the Y151 Line was derived:

a) At 13:25:13.842 a B – G Fault occurred on the Y151 Line and the Y151 and 53-51 CBs trip at Tewksbury.

b) At 13:25:13.908 the 51-33 CB trips at West Methuen on COMM ZONE2 (Carrier Stop).

c) At 13:25:13.941 the J51 CB trips at Hudson on COMM ZONE2 (Carrier Stop).

d) At 13:25:24.032 the Y151 CB at Tewksbury automatically recloses, trips again and locks out.

### *6.2. Detailed analysis*

The second cut analysis of this event will use the DFR records to verify the proper operation of the Y151 Line protection including the verification of the automatically reclosing of the Y15 CB. Also, the DFR records will be reviewed to verify the O215 protection scheme did not operate properly and if possible determine the root cause of the O215 protection scheme mis-operation. The DFR records from North Litchfield and Tewksbury were used.

### *6.3. Analysis of Y151 Line operation*

The sources of data for the Y151 operation were the DFR at Tewksbury, Relay A at West Methuen and Relay A at Hudson. The DFR was used as a source because it has the three-phase current quantities, the Y151 B-phase voltage, the pilot protection channel inputs for both the DCB and the Direct Transfer Trip schemes (i.e. Carrier Start, Receive, and Stop, DTT Transmit and Receive), the relay trip outputs, and the circuit breaker status inputs. The DFR has a higher sampling frequency making it a better tool for capturing power system transient conditions. In addition using magnitude and digital triggers means a DFR is more likely to capture an auto reclose than a protective relay. Relay A was used at West Methuen because it was the only source of three-phase analog data for the Y151 Line at the substation. The neighboring utility provided a Relay A recording from the Hudson terminal because it was the only available source of three-phase analog data at that terminal. The Y151 Relay A unfiltered event record was used because it provided a record of the trip after automatic reclose. The record includes all the relay protection elements that operated in order to determine the cause of the relay operation.

The analysis of the DFR records at Tewksbury and the relay event records from West Methuen and Hudson confirmed Y151 Line protection operation for the initial fault was a proper operation. The DFR record at the time the Y151 closed was used to verify the automatically reclosing control scheme operation. The automatic reclosing conditions and times were reviewed to determine if the automatic reclosing conditions for the Y151 Line were met. The automatic reclosing conditions are as follows:

Tewksbury: Y151 CB close auto in 10 seconds on Live Bus Dead Line

West Methuen: 51-33 CB close auto in 7 seconds on Live Y151 and G133 Line in sync.

The DFR record (Figure 2) captured at Tewksbury was analyzed. The Y151 CB closed in 10 seconds as it should but tripped after three cycles. Close examination of the current waveforms showed that it was not a fault but transformer energization with some CT saturation that caused the second trip. The target information above indicates the second trip of the Y151 was a Switch-on-to-fault (SOTF) and Zone 4. The Zone 4 is a back-up zone in the forward direction. It is equivalent to a typical Zone 3 in a step distance scheme. The Zone 4 target did not make sense, as it should not have operated.

This required reviewing the Y151 Relay A waveforms and the relay settings to determine what occurred.

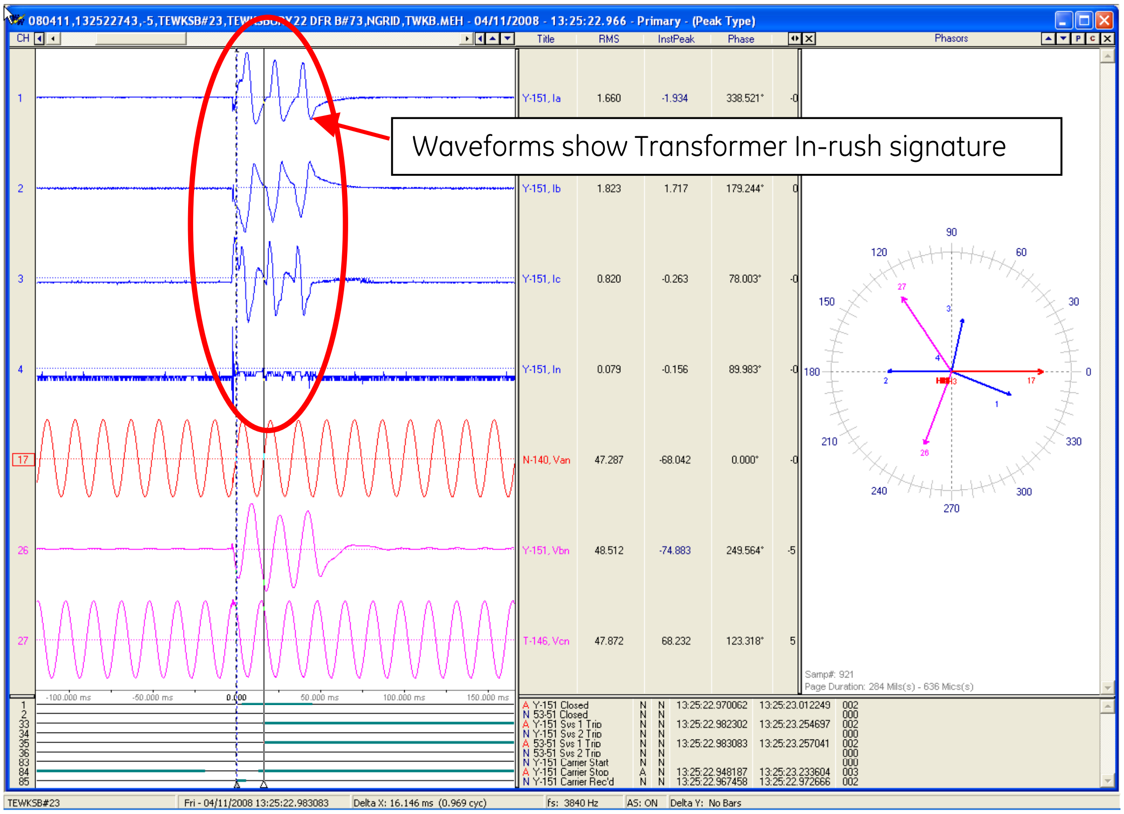


**Figure 2: Tewksbury DFR – Y151 Auto-reclose attempt**

The unfiltered waveform record of the Y151 Relay A with digital inputs and relay element operations was analyzed (Figure 3). It was determined that the Zone 4 phase element of the relay picked up at which point Output 1(Trip) of the relay closed. Review of the relay settings showed that the SOTF logic had the Zone 4 phase element pick-up as a condition to trip as part of the SOTF scheme. The manufacturer instruction manual recommends using the Zone 2 Phase element to have the SOTF function be more sensitive, not the Zone 4 phase element. However, there are five transformers tap off of the Y151 line (not shown in Figure 1) that feed distribution substations, so this is over-reaching zone is not appropriate for SOTF protection in this application.

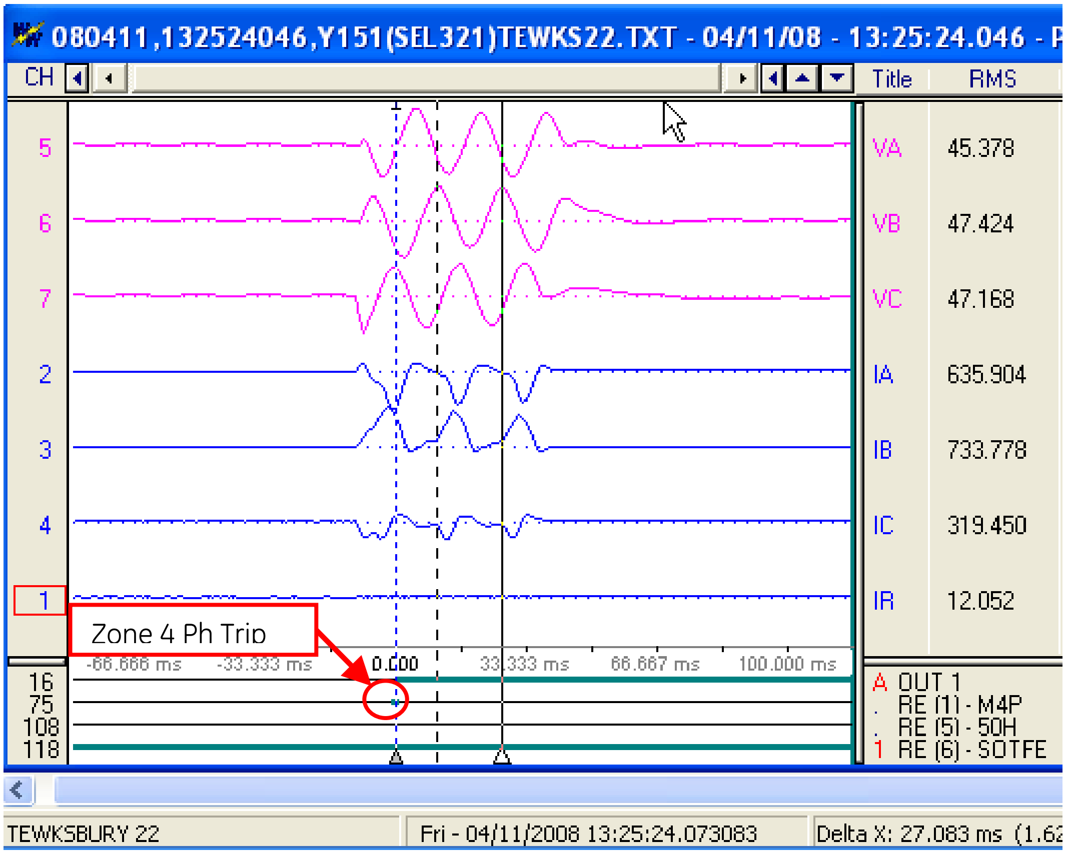


**Figure 3: Tewksbury DFR – Y151 relay event record for 2nd trip**

### *6.4. O215 Line operation*

The DFRs at Tewksbury and North Litchfield were used for the detailed analysis of the O215 Line operation because all measured quantities were in one time-synchronized record containing all measured analog circuits and digital inputs from all Pilot Protection channels for both the DCB and the Direct Transfer Trip schemes (i.e. Carrier Start, Receive, and Stop, DTT Transmit and Receive), the relay trip outputs, and the circuit breaker status inputs. The DFR has a higher sampling frequency making it a better tool for capturing power system transient conditions. The Relay A event record from North Litchfield was used when a improper operation of the DCB protection system was confirmed. However, at Tewksbury, Relay A protecting the O215 Line did not trigger, so no record was captured. Because of this the DFR record at Tewksbury was used to determine the cause of the operation, as it was the only data source for the O215 event.

Examining the fault records captured at Tewksbury (Figure 4) it can be seen that the Y151 Line cleared first and the O215 Line tripped approximately one-quarter of a cycle later. In Figure 4 the O215 Line currents appear to be symmetrical indicating that the line was not faulted. Therefore it is assumed the North Litchfield terminal O215 protective relays operated for the Y151 fault. To confirm that this was a correct determination the phasors for the Y151 and O215 (Figure 5) Lines were examined. Figure 5 shows the O215 currents to be symmetrical and approximately 180 degrees away from the phase voltage vector indicating power flow into the Tewksbury Bus confirming that the O215 line was an over trip and not a fault.

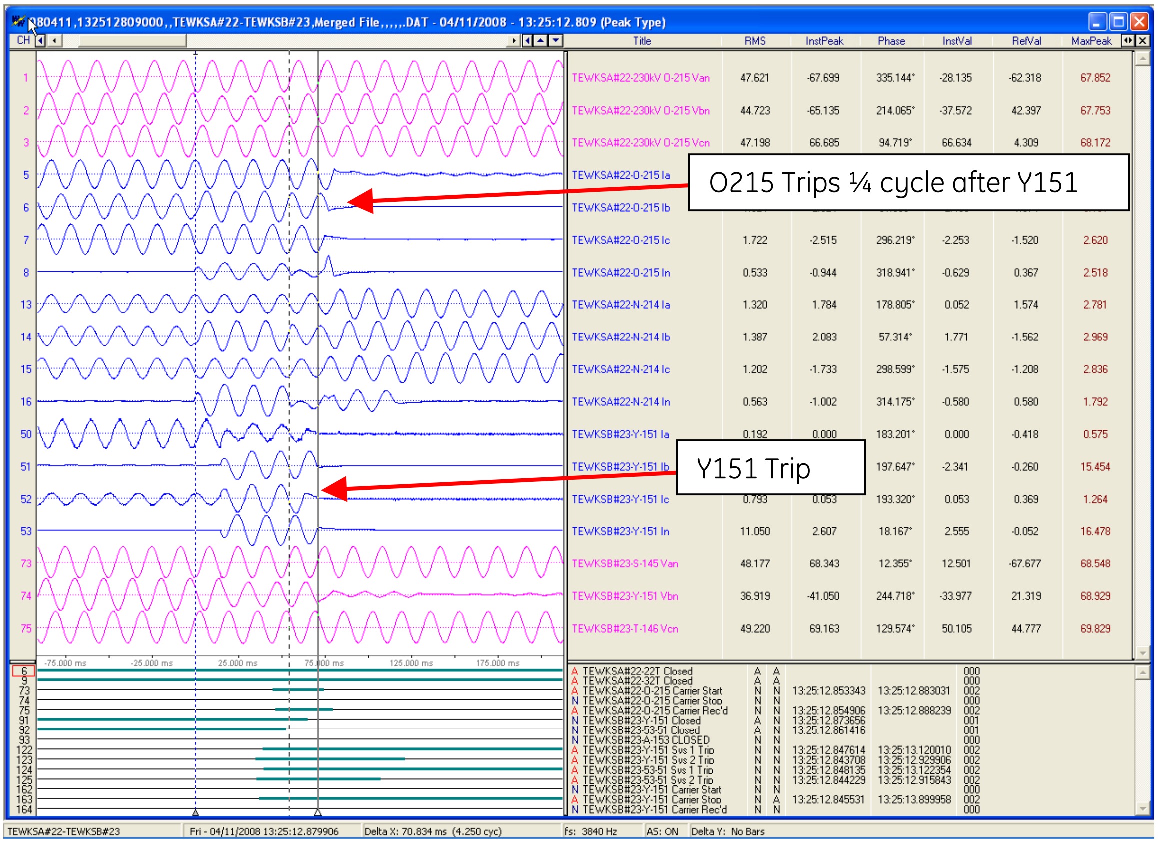


**Figure 4: Tewksbury 22 DFR - Y151, O215 Operation**

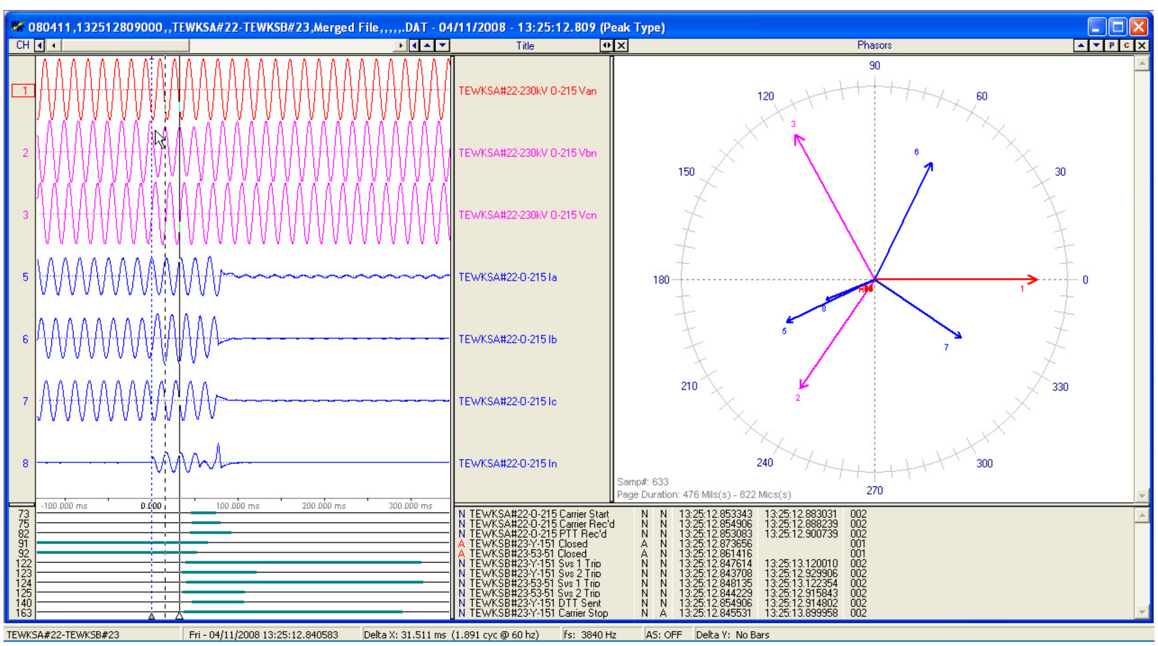

**Figure 5: Tewksbury - O215 Line Phasors – Flow towards Bus**

The O215 Line operation was determined to be an improper single-end operation of the Directional Comparison Blocking (DCB) scheme. To determine why the fault records from North Litchfield and Tewksbury were examined. It was found that during this operation the O215 DCB scheme relay at Tewksbury did not trigger for this event therefore the Tewksbury DFR record was used.

Through analysis of the fault records obtained from the DFRs at North Litchfield and Tewksbury it was observed that the Carrier Start (Block) signal was delayed in being received at North Litchfield. The delay was because the O215 Relay A did not have sufficient polarizing for the directional elements at fault inception to pick-up and initiate a Carrier Block for the external fault. Because of this delay the North Litchfield DCB scheme relay Carrier Stop (Trip) operated tripping the 01-11 and 01-15 CBs at North Litchfield. The North Litchfield CBs automatically reclosed after five-seconds.

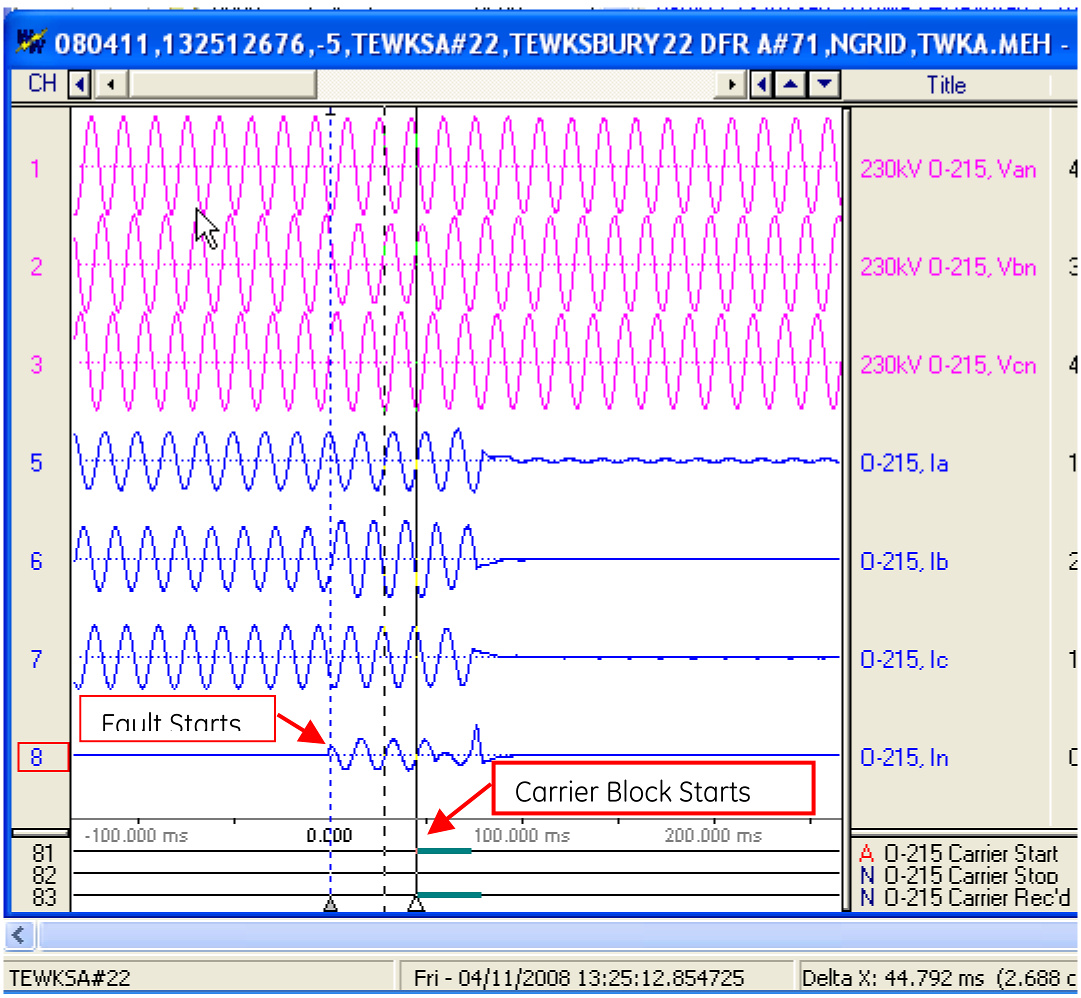


**Figure 6: Tewksbury DFR – O215 Line Waveform and Digital Inputs**

Review of the DFR record (Figure 6) shows that it took three cycles for the Carrier Start to be initiated at Tewksbury exceeding the coordination timer setting of the relay which is 1.25 cycles. The coordination timer allows time for the carrier signal to be received before allowing a trip output of the relay. With the use of the analysis tools the positive and negative sequence components on the O215 Line at the time of the Y151 fault were calculated. It was determined that at the fault inception the I2/I1 ratio was below the directional sensitivity of the relay setting of the O215 DCB relay at Tewksbury.

The ratio did rise and started Carrier approximately three-cycles into the fault, which was too late to block the North Litchfield terminal operation.

### *6.5. Actions taken*

The settings for the Y151 SOTF were changed to remove the Zone 4 phase element from the logic and the I2/I1 ratio for the O215 Line were changed in Relay A at Tewksbury and North Litchfield to increase the polarizing sensitivity. Both of these setting changes were made to correct the problems identified during the event analysis.

## 7. Meeting the requirements: one possible solution

It is clear that for the Tewksbury fault event, a DFR alone does not provide the necessary information to determine the cause of the operation of the Y151 line. Also, the protective relays on the Y151 line did not provide the necessary information. To meet the requirements for fault recording for this event, the best solution is to use a DFR in parallel with the protective relays on the line. This results in a configuration similar to Figure 7, which shows the subset of a fault recording system for the Y151 line. The system for the rest of the substation is similar in concept.

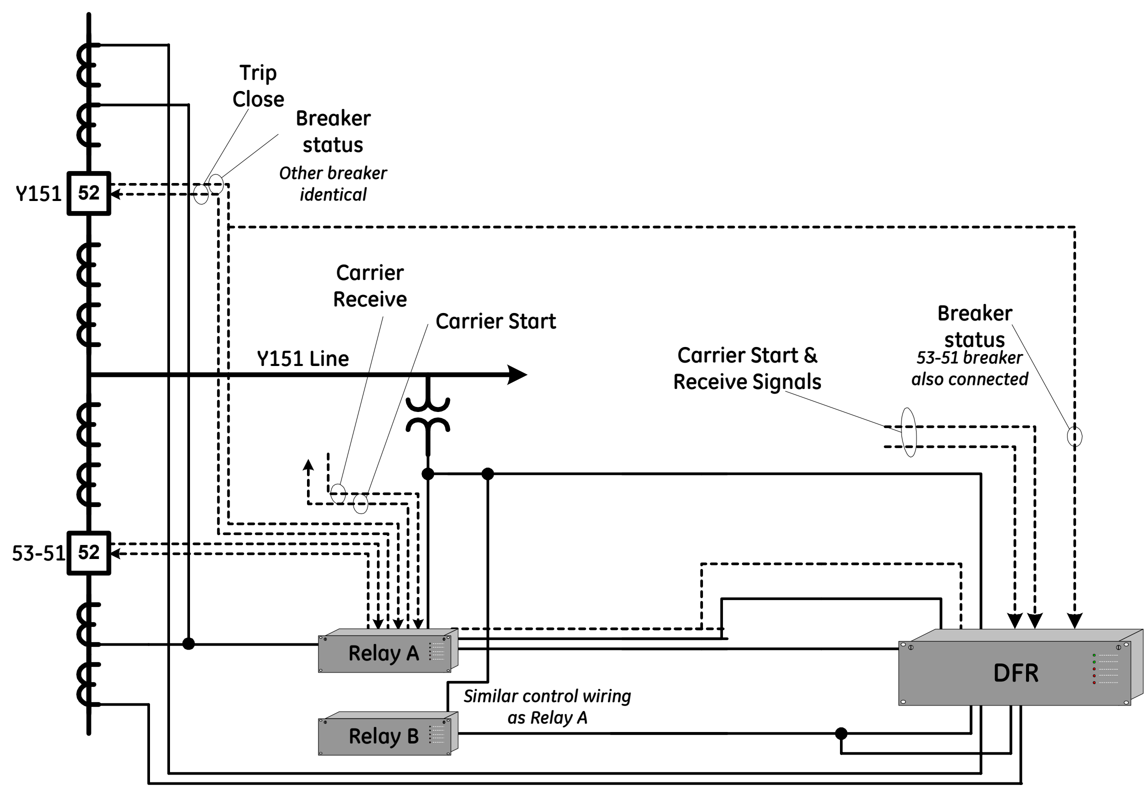


**Figure 7: Fault recording system for the Y151 Line**

This solution, using a DFR in conjunction with the standard protection relays, provides the key requirements for analysis of system performance after fault events. The DFR includes transient recording, disturbance recording, and sequence of events recording, with a high sampling rate, adequate record length, and long-term storage. DFR records are used for the first cut analysis on all events, to see if additional detail is necessary to explain the operation of the protection and control system. Relay records are used for more complex analysis situations such as the Tewksbury fault, looking at each element pickup and operation, internal logic status points, and analog protection quantities actually used by the relay. There are some points that bear further discussion.

### 7.1. Redundancy

Using a DFR in conjunction with protective relays to make a fault recording system provides redundancy of recorded data that ensures the correct data is captured even during device failure. Consider the recording system for the Y151 line:

- Line currents are captured by the DFR (as a calculated channel by summing the currents from both circuit breakers), Relay A, and Relay B.
- Breaker status and trip/close commands are captured by the DFR, Relay A, and Relay B
- Pilot protection signals (carrier start, receive, and stop) are captured by the DFR, Relay A, and Relay B

### 7.2. Detailed data

Using a combination of devices provides detailed data for analysis when necessary. DFRs capture general currents and voltages, while protective relays capture specific data used by the relay for protection decisions. Specifically, the recording system of Figure 7 provides different types of detailed data.

Individual breaker currents are captured by the DFR. Protective relays on dual breaker line terminals sum the individual breaker currents together to create the line current, and capture the line current. However, in some circumstances, this is not enough information to explain relay operations. Unequal CT saturation for external faults can cause relays to operate undesirably. Recognizing and documenting this occurrence is difficult if the individual breaker currents are not captured.

The relays capture polarizing quantities for impedance and ground elements. For applications using differential relays, the relays would capture differential and restraint currents. In addition, the sequence of events data in a relay includes every protection element pickup, operation, and dropout, every digital input and output connected to the relay, internal logic points, and relay communications signals. This information can point to an exact operating sequence of the relay, beyond what a DFR can provide.

### 7.3. Triggering

Each recording device in the substation uses its own local triggering. This can be thought of as redundancy in triggering, meaning one device should trigger for every event that occurs. However, to ensure that the *desired* information is captured for an event requires a well-thought out cross-triggering scheme. Cross-triggering can be done using contact wiring, or with intra-relay communications such as IEC 61850 GOOSE messaging.

## 8. Practical challenges to a fault recording solution

The focus of this discussion has been on meeting one specific set of performance requirements, which is that of measurement of data, to ensure the data necessary to explain an event is captured. However, capturing the right data is not the complete solution. A complete solution must focus on having this data in a usable format in front of the personnel that need to see this data. Practically, this involves retrieving, combining, storing, and presenting recording data to support and speed up analysis of events by engineering personnel. So the goal is to produce one coordinated record, containing all the appropriate information, and to store this record for 1 to 12 months in the substation. It is beyond the scope of this paper to describe the tools and methods needed to combine and retrieve data into on record, especially in regards to communications. There has been much work in the industry on this topic, as more completely described in [5] and [6]. However, when working with records created in multiple devices, it is necessary to understand some of the challenges in acquiring and comparing information from different devices.

### *8.1. Capturing the data*

One challenge relates to simply capturing the data necessary to explain a fault event. This requires that information in enough detail be recorded on all desired analog quantities and digital status points. As described previously, a DFR may not give enough detail, or relay operating quantities, while relays may simply not trigger. With multiple devices intended to capture the same event, triggering requires some consideration. The most important question to consider is: if one device triggers, should other devices be cross-triggered simultaneously? Specifically for the Tewksbury fault event, as the operator closed the N140 circuit breaker, the Y151 line tripped. To properly analyze this event, transient data and sequence of events data is needed from the relays on the N140 line and Y151 line, but the N140 relays didn't trigger.

Consider two other examples. The Set A relay protecting the Y151 line trips, the Set B relay does not. Fault recording in the relays is only triggered on protection function operation. Cross-triggering between the two relays will help determine if either relay performed correctly. The second example: a DFR triggers a disturbance recording for a power system (not power equipment) fault. Cross-triggering the appropriate distance relays will show if the apparent impedance seen by the relay came close to the operating region of overreaching impedance zones. When no DFR is present and there are only distributed devices in the substation, cross-triggering is absolutely necessary to ensure the correct data is captured for fault events.

### *8.2. Synchronizing the data*

Another challenge is in synchronizing data from various devices, whether performed manually or automatically. Synchronization loosely includes file format, time synchronization, time stamp accuracy, filtering, sampling rates, and the possibility of duplicate channels. Most devices capture data in a proprietary file format, and require proprietary software tools to retrieve and analyze recorded data. The COMTRADE standard[7] defines a common format for oscillography data. Converting files to the COMTRADE format allows engineers to compare records captured from different devices.

Time synchronization is used to ensure each device operates on a common clock, and IRIG-B signals are the common clock signals used. Care must be taken when designing the distribution network for the IRIG-B clock signals. Typically, the time delay in the time code distribution system is around 100 microseconds. However, time delays can be as high as 1 millisecond if the network is poorly designed, or communications processors are used to distribute the IRIG-B signals.[8]

Time stamp accuracy refers to the accuracy of time stamping between devices. The first piece of the time stamp is based on the actual trigger of the recording device. Devices of different designs, even when set identically, will trigger at different times for the same event, due to differences in the hardware design and software algorithms inherent to the device. The uncertainty of time stamping is also a factor, which can range from a few hundred microseconds in DFRs, and from 1 to 4 milliseconds in relays. Relays may have an even greater time stamping uncertainty on digital inputs and outputs.[8]

Filtering is another challenge to synchronizing data. The filtering method used to convert analog information to digital data inserts a time delay. This filtering time delay is based on the design of the device. Devices from two different manufacturers, triggering for the same event, will have measurement channels offset by as much as 500 microseconds, or approximately 11 electrical degrees at 60 Hz. This filtering time delay must be accounted for when combining records. In addition, the oscillography data captured by protective relays may involve additional filtering. Some relays record the analog quantities filtered, typically to the fundamental frequency, for protection processing, while other relays capture data that is only filtered for the analog to digital conversion process.

Sampling rates are another aspect of synchronizing data. Depending on the design and configuration of the device, every protective relay and meter in the substation may use a different sampling rate to record the same information. To combine these records, or to easily view records simultaneously for analysis, the data from different devices must be converted to a common sampling rate. There are well-known mathematical techniques to perform data decimation or to extrapolate data. In general, it is better to use the highest sampling rate possible to have adequate resolution to correctly identify CT saturation, DC offset, and other such phenomena.

### *8.3. Storing the data*

A final challenge to consider is that of record storage. DFRs are designed to store a large number of records for up to 12 months. Protective relays are normally only designed to store a small number of records for immediate retrieval after a fault. New fault recordings overwrite existing records, so records are rarely stored for the recommended 12 months. Protective relays therefore require a process to quickly retrieve records before new records overwrite these existing records.

## 9. Conclusions

This paper begins by defining the requirements for a fault recording system by defining the real problem to solve: capturing the right information to explain how power system equipment responded to undesirable events. To define a fault recording system, then, requires an understanding of the right data to capture, the recording devices that can capture data, how best to capture this data, and any shortcomings to a desired solution.

SCADA sequence of events logs and DFRs generally provide enough information to analyze the majority of fault events, where the system performance is clearly and easily explainable. DFRs provide one record, at a high resolution, that include much of the analog measurements and digital equipment status necessary to explain what relays responded to, and breakers operated for, faults of known and understood causes.

However, DFR records and SCADA sequence of events logs do not provide enough information to analyze the Tewksbury fault of April 2008 experience by National Grid. Microprocessor-based protective relays contain much more detailed information needed to analyze such an event, including relay operating quantities (specifically polarizing current for this event), relay element pickups and dropouts, and control system status.

So relays give the desired detail for difficult to explain events. However, relays introduce challenges related to capturing data such as triggering, synchronizing data such as file formats, time synchronization, timing accuracy, filtering offset, and sampling rates, and file storage. Relays require an engineer to be careful to design a recording system to really get the required data, to get the right data, and to really have usable data.

In the opinion of the authors, based on present recording technology, both DFRs and recording relays are needed as part of a fault recording system. A DFR provides good “first cut” data to do a quick analysis of system performance after a fault event. The high resolution and simple presentation of many measurement channels can be used to quickly explain and document the root cause of, and system performance during, most fault events. Relays provide more specific detail when necessary to explain some fault events, such as the event described in this paper, and provide redundancy of measurement. A DFR alone does not provide the detailed information necessary to analyze a complex event such as the Tewksbury fault described here. Microprocessor relays alone cannot make up a fault recording system. Besides the fact that microprocessor relays don’t have complete penetration on the system, there are other difficulties. Triggering, cross-triggering multiple devices, time synchronization, filtering issues, and record retrieval and management all must be accounted for, often on a substation by substation basis. In addition, microprocessor relays, with a few exceptions, don’t meet NPCC requirements for sampling rate and record lengths. The better solution, then, is to use microprocessor relays in conjunction with a DFR.

The wisdom of such a recording system was proven in the Tewksbury fault event. An incorrectly configured relay failed to trigger a recording for the incorrect operation of the O215 line. However, the DFR, with completely redundant measurement and triggering, did capture a recording. This data was used to identify the root cause of the incorrect operation. The biggest challenge for this type of recording system is cross-triggering of recording devices to ensure data capture, and record retrieval and storage. National Grid is actively pursuing a recording system that automatically retrieves records from various devices, converts the records to COMTRADE files, and retrieves the records via communications to a central office.

The key for the engineer at a different utility, however, is to design a recording system that meets the specific needs of that company. This requires identifying the goals of fault recording, and identifying what data, tools, and methods are required to meet those goals. This design must obviously be balanced against practical constraints, such as the capabilities of standard devices used by the company, and the cost of a possible solution. It is up to the engineer to use their best judgment to determine the final solution.

## 10. References

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[8] *NPCC SP-6 Report Synchronized Event Data Reporting*, Northeast Power Coordinating Council, New York, NY, March 31, 2005.

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