Understanding and Analyzing Event Report Information

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INTRODUCTION

Event reporting is a standard feature in most microprocessor-based protective relays. The data and information saved in these reports are valuable for testing, measuring performance, analyzing problems, and identifying deficiencies before they cause future misoperations. The ability to quickly and accurately analyze event data can save money.

This paper emphasizes the usefulness of event report data and shows practical analysis methods and simple tools. Analysis of event reports captured from actual installations demonstrates solutions to a variety of problems.

Event reports indicate whether the protective relay operated as expected. In addition, analysis identifies whether all associated components of the protection system were installed and operated correctly. Power system models, settings, wiring, auxiliary relays, circuit breakers, current and potential transformers, communications equipment, the dc battery system, and connected loads can all be measured and monitored by analyzing event report data.

Modern digital relays can record and store a great deal of information in a variety of reports, from brief summary messages to oscillograph and phasor data. The analog information in event reports is available in many formats: varying amounts of pre-fault, fault, and post-fault data captured, length of data capture, number of samples per cycle, and whether the data are digitally filtered. Each format addresses a specific analysis purpose. This paper describes the data formats appropriate for different types of analysis.

Regulatory agencies require the installation of disturbance monitoring equipment. Relays with event reporting meet these requirements.

Every time the power system faults and relays capture data, we have ready-made test reports. By analyzing actual relay and system performance, many utilities are saving money by extending or eliminating traditional routine tests. This paper supports this effort through examples that clearly show the tools needed to turn the data into useful information.

WHAT IS AN EVENT REPORT?

When faults or other system events occur, protective relays record sampled analog currents and voltages, the status of optoisolated inputs and output contacts, the state of all relay elements and programmable logic, and the relay settings. The result is an event report, a stored record of what the relay saw and how it responded. With readily available information from product instruction manuals, the user is provided with all the necessary tools to determine if the response of the relay and the protection system was correct for the given system conditions.

Event reports are formatted ASCII text files that are read vertically. Time increments as we read down the page, and data are displayed in columns. Each horizontal row represents a particular point in time. Figure 1 displays an example event report from a distribution relay.[1]

```
FEEDER 1                          Date: 02/11/97    Time: 09:52:14.881
STATION A                                                                 Firmware identifier

FID=SEL-351-X111-Vf-D970128       CID=1F00                                Firmware checksum identifier

                                                                    Out    In
      Currents (Amps Pri)           Voltages (kV Pri)               135791 1357
    IA    IB    IC    IN    IG     VA     VB     VC     VS Vdc Freq  24680A 2468
[1]
   188  -291   102     0    -1    8.0  -11.8    3.8    0.0 126 60.00 ...... b...
   226    50  -278     0    -2    9.0    2.5  -11.5   -0.0 126 60.00 ...... b...   One cycle of data
  -189   290  -102    -1    -1   -8.0   11.8   -3.8   -0.0 126 60.00 ...... b...
  -227   -51   277    -1    -1   -9.0   -2.5   11.5    0.0 126 60.00 ...... b...

           [Cycles 2 and 3 not shown in this example]                             > Arrow indicates trigger row
[4]                                                                               corresponding to the date and
   190  -290   100     0    -1    8.1  -11.8    3.7    0.0 126 60.00 ...... b...  time stamp above
   225    52  -279     0    -2    9.0    2.6  -11.5   -0.0 126 60.00 ...... b...
   437   269   -84    -1   622   -7.6   11.7   -3.8    0.0 126 60.00 ...... b...
  -914   -52   251     0  -716   -7.7   -3.1   11.0    0.0 126 60.00>...... b...
[5]                                                                               Trip by inst phase o/c
 -1228  -227    68     0 -1387    5.8  -11.0    4.2    0.0 126 59.72 ...... b...  element, OUT1 closes
  1985    47  -211    -1  1821    6.0    3.8  -10.3    0.0 126 59.72 1..... b...
  1390   205   -71    -1  1524   -4.5   10.5   -4.7   -0.0 125 59.72 1..... b...
 -2369   -43   196     0 -2216   -5.7   -4.0   10.2    0.0 124 59.72 1..... b...

           [Cycle 6 not shown in this example]
[7]
 -1382  -206    70     0 -1519    4.5  -10.4    4.6    0.0 120 60.02 1..... b...
  2373    43  -197     0  2219    5.7    4.0  -10.2   -0.0 120 60.02 1..... b...
  1379   205   -70    -1  1514   -4.5   10.4   -4.6    0.0 120 60.00 1..... b...
 -2376   -44   196     0 -2224   -5.7   -4.0   10.2    0.0 120 60.00 1..... b...  See Figure 2 and 3 for details
[8]                                                                               on one cycle of phase A
 -1375  -206    69     0 -1511    4.5  -10.4    4.6   -0.0 120 60.00 1..... b...  (channel IA) current
  2380    44  -197     0  2226    5.6    4.1  -10.2    0.0 120 60.00 1..... b...
  1367   205   -69    -1  1503   -4.6   10.4   -4.6   -0.0 120 60.00 1..... b...
 -2385   -45   197    -1 -2233   -5.6   -4.1   10.2    0.0 120 60.00 1..... b...
[9]                                                                               * Star indicates maximum
 -1358  -205    68     0 -1495    4.6  -10.4    4.5    0.0 120 60.00 1..... b...  phase current row for
  2391    45  -198     0  2238    5.6    4.1  -10.2   -0.0 121 60.00*1..... b...  summary below
   737   150   -28    -1   859   -5.1   10.6   -4.4    0.0 122 60.00 1..... b...
 -1592   -37   130    -1 -1499   -6.9   -3.7   10.8    0.0 123 60.00 1..... b...
[10]
   -62   -48    -6     0  -116    7.0  -11.2    3.8    0.0 124 60.32 1..... b...
   394    14   -32     0   376    8.4    3.0  -11.5   -0.0 125 60.32 1..... b...
     0    -1    -1    -1    -1   -8.4   11.8   -3.4   -0.0 126 60.32 1..... 2...  IN1 deasserts indicating the
    -1    -1    -1    -1    -2   -8.7   -2.9   11.6   -0.0 126 60.32 1..... 2...  breaker has opened

           [Cycles 11 through 15 not shown in this example]
```

```
Protection and Control Elements

51     50 32 67   Dm 27 59     25  81   TS     Lcl Rem  Ltch SELogic
                          V   5   2     ih ZLV               Variable
        P PN      PN  P  P1   9S  7135 7mo lOd 13571357O1357
ABCPNGQPP QG PNGQ QG PPSPPQNS VFA B246 9et dPc 24682468C2468 1234567890123456
[1]
......... .. .... .. ........ ... .... R.0 ... ............. ................
......... .. .... .. ........ ... .... R.0 ... ............. ................
......... .. .... .. ........ ... .... R.0 ... ............. ................
......... .. .... .. ........ ... .... R.0 ... ............. ................

           [Cycles 2 and 3 not shown in this example]
[4]
......... .. .... .. ........ ... .... R.0 ... ............. ................
......... .. .... .. ........ ... .... R.0 ... ............. ................
.....p... .. .... .. ........ ... .... R.0 ... ............. ................
...p.p... .. .... .. ........ ... .... R.0 ... ............. ................>
[5]
...p.p... .. .... .. ........ ... .... R.0 ... ............. ................
...p.p.A. .. 1... .. ........ ... .... C.0 ... ............. p...............
...p.p.A. .. 1... .. ........ ... .... Cr0 ... ............. p...............
...p.p.A. .. 1... .. ........ ... .... Cr0 ... ............. p...............
```

Overcurrent elements asserting; reclosing element changes from reset to cycle

```
           [Cycles 6 through 15 not shown in this example]

Communication Elements

 S  PZ EE   ZDNS  TMB  RMB  TMB  RMB  RRCL PWR
3O  T3KKCWU 3SSTB A    A    B    B    OBBB A B C
PT PRREETFB XTTOT 1357 1357 1357 1357 KAAO 131313
OF TXBYYTCB TRRPX 2468 2468 2468 2468  DDK 242424
[1]
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......
[2]
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......
.. ........ ..... .... .... .... .... b... ......

           [Cycles 3 through 15 not shown in this example]

Event: AG T  Location:    2.41  Shot: 0  Frequency:  60.00
Targets: INST 50
Currents (A Pri), ABCNGQ:   2749   210   209     0  2690  2688
```

Summary information, includes phases involved, front-panel targets, fault location, and maximum currents

```
Group 1

Group Settings:
```

Event data are followed by relay settings

```
RID   =FEEDER 1                      TID   =STATION A
CTR   = 120      CTRN  = 120      PTR   = 180      PTRS  = 180
Z1MAG = 2.14     Z1ANG = 68.86
Z0MAG = 6.38     Z0ANG = 72.47    LL    = 4.84
E50P  = 1        E50N  = N        E50G  = N        E50Q  = N
E51P  = 1        E51N  = N        E51G  = Y        E51Q  = N
E32   = N        ELOAD = N        ESOTF = N        EVOLT = N
E25   = N        EFLOC = Y        ELOP  = Y        ECOMM = N
E81   = 1        E79   = 2        ESV   = 1        EDEM  = THM

           [Remainder of settings not shown in this example]
```

```
SELogic group 1

SELogic Control Equations:
TR    =51PT + 51GT + 81D1T + LB3 + 50P1 * SH0 + OC
TRCOMM=0
TRSOTF=0
DTT   =0
ULTR  =!(51P + 51G)

          [Remainder of logic settings not shown in this example]
```

Settings are followed by Boolean logic programmable equations

Figure 1 Example Event Report

The analog data in Figure 1 are reported every quarter-cycle or 90 electrical degrees. This makes it simple to take one sample, the oldest or previous, as the y-component and the next sample, the newest or present, as the x-component of a phasor current or voltage. Modern relays, including the one that generated the event report in Figure 1, are capable of sampling much faster, as much as 16 to 64 samples per cycle, for better resolution and oscillography. However, the relays continue to offer the analyst a choice of display rates: 16 samples per cycle for generating detailed oscillography or 4 samples per cycle for quick visual analysis.

View ASCII event report files with a personal computer using any standard terminal emulation program, such as Microsoft Windows® HyperTerminal™, and using ASCII character commands. Basic analysis of event reports does not require special software. Event reports can be saved to a diskette or file by using the capture text option of the terminal emulation program.

The number and type of analog channels monitored and captured in an event report will vary by relay model. Simple nondirectional overcurrent relays will record three phase currents and calculated quantities, such as residual current (IG = calculated $3I_O$ = IA + IB + IC). More advanced distance and directional overcurrent relays will record as many as four phase voltages and four currents, as well as system frequency, dc battery voltage, and calculated quantities such as residual current and positive-sequence memory voltage. Relays intended for closing and reclosing applications may monitor up to six phase voltages, while relays intended for multi-terminal current differential applications can monitor up to 12 phase currents. One line current differential relay records both local and remote phase currents in one event report. Similarly, the number and type of relay elements monitored and captured in an event report will vary by relay model. Product instruction manuals define the acronyms and relay element names used as column labels in the event report, as well as the symbols used to display relay element operating states.

Figure 2 shows how the event report ac current column data relate to the actual sampled waveform and root-mean-square (RMS) values. Note that any two rows of data, taken one quarter-cycle apart, can be used to calculate RMS values. If an event report is displayed in a 16-sample per cycle format, every fourth row of data could be used to calculate RMS values. Figure 3 shows how to convert the event report current column data to phasor RMS values. Process voltages similarly.

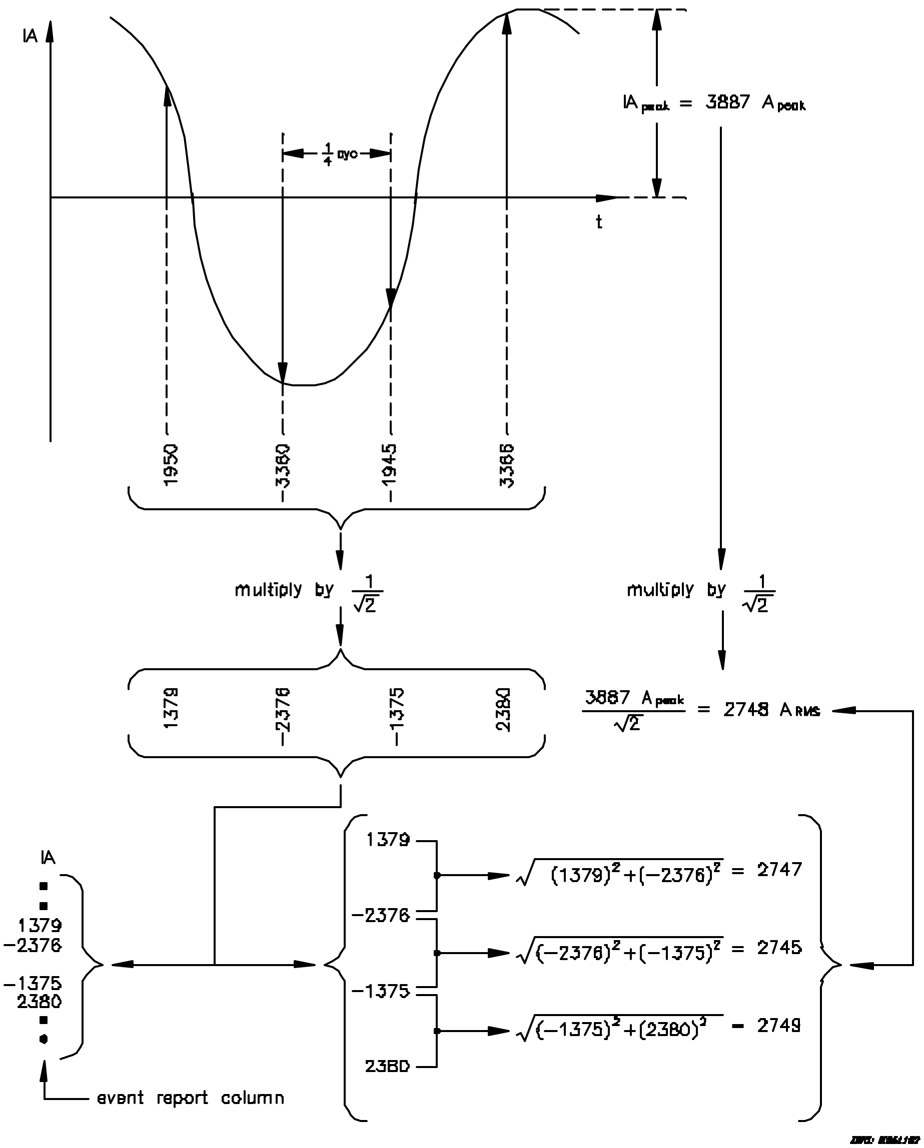

Figure 2 Derivation of Current and RMS Current Values From Sampled Waveform

Event report analysis can reveal problems with power system models, settings, breakers and auxiliary contacts, instrument transformers, and more. In the past, these problems would go undetected until they were either caught during routine maintenance or more serious consequences occurred. It is a good practice to examine every event report to see if the operation was normal or exceptional.

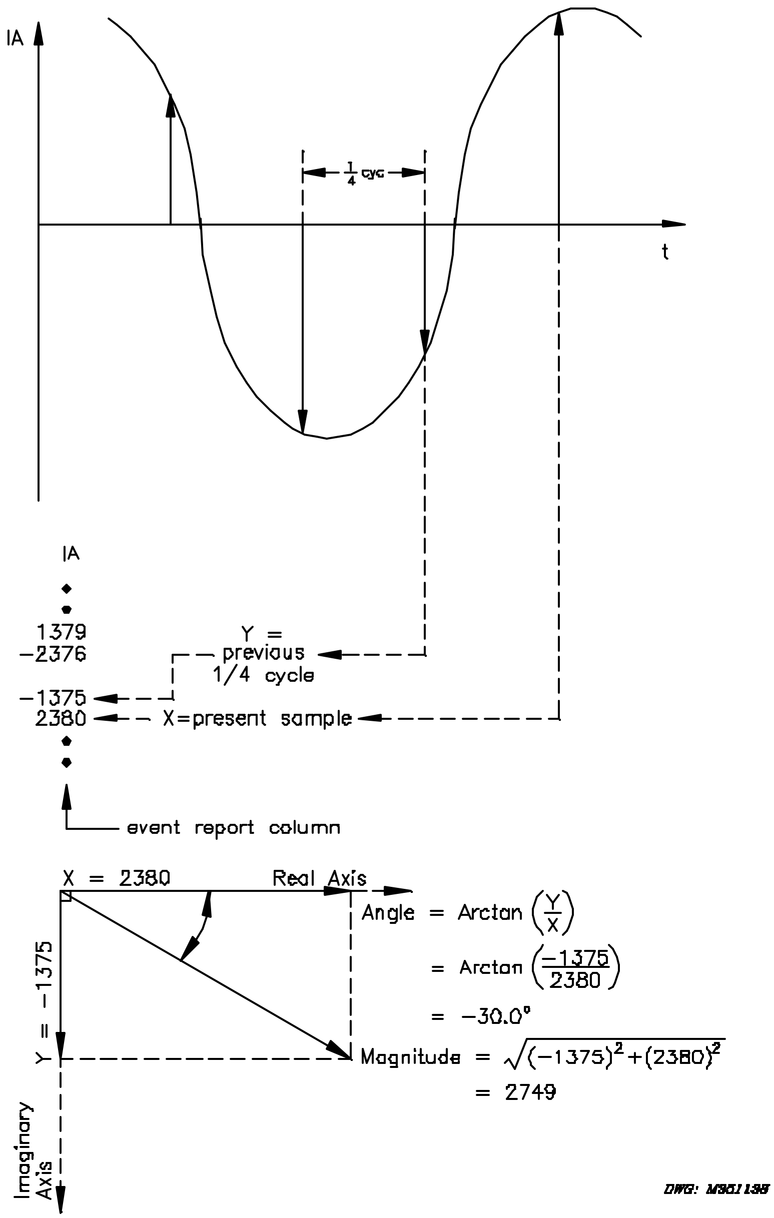

Figure 3 Derivation of Phasor RMS Current Values From Sampled Waveform

VARIETY OF REPORTS

Microprocessor-based relays are capable of generating a large variety of reports, each for a specific purpose. A brief review of some of the common types of reports is given so that they can be contrasted with detailed event reports.

History Report

Historical reports provide an overall picture of what has happened at a location. The relay adds a new entry to the history every time an event report is generated. An example is shown below.

The history is displayed from newest event, Event 1, to oldest event, Event 6. Each entry provides basic information, referred to as a short event summary, which generally includes the date and time of the event, type of fault, and fault location. The most common use for the history report is to quickly determine which events require further analysis using the detailed event reports.

```
=>HISTORY

PBL 21/112A, CITY OF PBL PLANT LINE       Date: 9/20/0     Time: 08:26:56

#   DATE        TIME       TYPE  DIST   DUR   CURR
1  9/19/0    17:38:43.375  2ABC  50.62  4.25  825.7
2  9/19/0    17:28:46.387  2ABC  48.95  5.25  674.4
3  9/19/0    17:27:39.166  2ABC  47.07  7.00  970.8
4  9/19/0    17:06:06.791  1CA   3.06   5.00  4332.2
5  9/19/0    17:06:05.241  3CA   43.19  5.00  887.4
6  9/19/0    17:06:04.491  1CA   3.09   5.00  4364.4
```

Event 6 in the history above corresponds to the initial trip from a primary transmission line relay. Event 5 was generated by inrush current during the reclose operation. Event 4 was a second trip just after the reclose. Over 21 minutes later, after a tree was cleared from the line, Events 1 through 3 were generated by inrush and unbalance during the manual close operations.

History reports provide quick answers to questions about historical trends:

- Was load interrupted? For how long?
- What settings group was enabled during the trip?
- Are faults always the same type and location?
- What is the success rate for reclosing by fault type and shot?
- Are different reclose open intervals more successful than others?
- What are the fault durations?

History reports are also useful for quickly determining element timing. A technician was using an automated test program to perform routine maintenance testing. When the program reached the ground time-overcurrent tests, it reported that the relay was out of tolerance. The program calculates three arbitrary test points at varying multiples of pickup. It then applies current and measures the response of an output contact programmed to follow the overcurrent element. The program repeats the process rapidly for test points two and three. This history report quickly identifies the actual operate times of each test as the difference between successive phase A-to-G events (pick-up) and AG T events (trip).

```
=>HIS

81-516 TO VALLIANT/HUGO                Date: 05/07/98    Time: 14:06:50.588

#    DATE      TIME       EVENT  LOCAT  GRP TARGETS

1  05/07/98 13:57:58.580 AG T  +46.29   1  TIME EN 51  <-- 8 x tap.  Actual operate time = 0.213s
2  05/07/98 13:57:58.367 AG    +46.27   1   EN
3  05/07/98 13:57:51.702 AG T  +73.62   1  TIME EN 51  <-- 5 x tap. Actual operate time = 0.362s
4  05/07/98 13:57:51.340 AG    +73.68   1   EN
5  05/07/98 13:57:44.266 AG T  +184.4   1  TIME EN 51
6  05/07/98 13:57:37.847 AG    +184.5   1   EN         <-- 2 x tap.  Actual operate time = 6.419s
```

Referring to the product instruction manual, and the relay settings (curve = very inverse, time dial = 4.70, pick up = 0.5 A secondary), we can calculate the expected operate times for each test point.[2]

$$\text{Operate Time} = (\text{Time Dial}) \cdot \left(0.0963 + \frac{3.88}{(\text{Multiples of Tap})^2 - 1} \right) \qquad \text{Equation 1}$$

Calculated Operate Times

```
Test One at 2 x tap, or M=2:  6.53 seconds

Test Two at 5 x tap, or M=5:  1.21 seconds

Test Two at 8 x tap, or M=8:  0.74 seconds
```

From the history report, the first test at 2 times tap operates as expected and within published tolerance (±4 percent and ±1.5 cycles). The second and third tests, however, operate much faster than expected. The relay has a setting that enables emulation of an induction disk ratchet and time-delayed reset characteristic. Slightly delaying the rest time between successive tests in the automated test program, as would be done when testing an electromechanical relay, easily solves the problem and allows the relay to be tested with as-set settings.

Automatic Summary Messages

Automatic summary messages are sent to serial communications ports on a relay any time it generates an event report. An example of a long event summary message is shown below.

```
SEL-311C POTT                     Date: 10/14/99    Time: 08:53:34.926
EXAMPLE: BUS B, BREAKER 3

Event: BCG T     Location:   48.84            Trip Time: 08:53:34.930
#: 00008  Shot:    Freq:  60.01  Group: 1     Close Time: --:--:--.---
Targets:                                                Breaker: Closed

PreFault:     IA     IB     IC     IP     IG    3I2       VA       VB       VC
MAG(A/kV)    199    200   201      0      2      0  131.500  131.610  131.730
ANG(DEG)   -0.04-120.27 120.04  59.15 149.15 165.15     0.00  -120.03   119.94
Fault:
MAG(A/kV)    200   2478   2480      0    212   4294  131.570  113.930  113.980
ANG(DEG)   -0.46-172.34   6.65  59.15 -11.30  94.15     0.73  -123.36   124.67

                                                 L C R     L C R
                                                 B B B R   B B B R
                                                 O A A O   O A A O
                                                 K D D K   K D D K
MB:8->1    RMBA      TMBA      RMBB      TMBB    A A A A   B B B B

  TRIG  00000000  00000000  00000000  00000000   0 0 0 0   0 0 0 0
  TRIP  00000000  00000000  00000000  00000000   0 0 0 0   0 0 0 0
```

Automatic messages are useful when doing acceptance or commissioning testing. With a personal computer plugged into a relay serial port that has automatic messages enabled, instant feedback is broadcast to the terminal emulation screen after every relay operation. This saves the user from having to access the history report, determine which event to look for, and then retrieve that event. Instead, a summary message, automatically displayed, enables quick confirmation of correct operation.

Summary messages can also automatically notify a connected communications processor that an event has occurred. Rather than having an analyst poll the relay for new event data, the relays use the automatic summary message feature to report by exception. The processor recognizes the arrival of the summary message, and critical data including fault type and fault location are immediately parsed into data registers and made available for connected SCADA systems. The summary message arrival also sets a logical bit that can initiate the automated retrieval of full event reports either by the processor itself or by an automated power system report manager, a remote software tool used to retrieve and file event reports. Productivity tools like these allow the analyst to spend more time analyzing event reports, rather than remotely dialing stations, and sorting and retrieving events via modem.[3]

Sequential Events Recorder (SER) Report

Modern digital relays include a sequential events recorder (SER) report. The relay monitors as many as 72 or more elements selected by the user (e.g., relay elements, inputs, and outputs) every quarter-cycle. If an element changes state, the relay time-tags the change and logs the event in the SER report. The relay stores the latest 512 changes of state.

SER reports are extremely useful for quickly reviewing a timing sequence, such as time-delayed tripping elements, programmable timers, and reclosing logic during testing or after an operation. For example, in the SER report below, the trip output contact OUT1 deasserts after being asserted a minimum of 9 cycles because of the minimum trip duration timer setting (time difference: 09:52:15.039 - 09:52:14.889 = 0.15 sec or 9 cycles). As soon as the trip contact, OUT1, deasserts, the first reclosing open interval begins timing on its setting of 30-cycles (time difference: 09:52:15.535 - 09:52:15.039 = 0.496 sec or 30 cycles). A close is issued via OUT2.

```
FEEDER 1                          Date: 02/11/97    Time: 13:13:09.558
STATION A

FID=SEL-351-X111-Vf-D970128       CID=1F00

#     DATE      TIME           ELEMENT           STATE

19    02/07/97  13:10:46.360    Relay newly powered up or settings changed
18    02/07/97  13:11:33.444   IN2               Asserted
17    02/07/97  13:11:38.812   LB4               Asserted
16    02/07/97  13:11:38.812   OUT2              Asserted
15    02/07/97  13:11:38.816   LB4               Deasserted
14    02/07/97  13:11:38.887   IN1               Asserted
13    02/07/97  13:11:38.887   OUT2              Deasserted
12    02/07/97  13:11:43.892   79LO              Deasserted
11    02/11/97  09:52:14.877   51G               Asserted
10    02/11/97  09:52:14.881   51P               Asserted
9     02/11/97  09:52:14.889   50P1              Asserted
8     02/11/97  09:52:14.889   79CY              Asserted
7     02/11/97  09:52:14.889   OUT1              Asserted
6     02/11/97  09:52:14.964   50P1              Deasserted
5     02/11/97  09:52:14.973   51P               Deasserted
4     02/11/97  09:52:14.977   IN1               Deasserted
3     02/11/97  09:52:14.981   51G               Deasserted
2     02/11/97  09:52:15.039   OUT1              Deasserted
1     02/11/97  09:52:15.535   OUT2              Asserted
```

Use SER reports for testing overcurrent or other time-delayed tripping elements and logic without having to program and wire output contacts to external test equipment timers.

SER reports can also be very valuable during troubleshooting. The following SER report is from a distribution recloser installation. The recloser control had operated a number of times for downstream faults on the radial line, but the recloser had never automatically reclosed as expected. Instead, it went to lockout each time. Manual and SCADA close operations worked without any problem. Analyzing the SER report made solving this problem an easy task.

In the SER report, the first event at 21:57:17.588 shows that the control tripped by time-overcurrent ground delay curve (51G2T). The reclosing cycle state asserts (79CY), while the reclosing reset state deasserts (79RS) as expected. After the TRIP output closes, an A-phase overvoltage element (59A1) deasserts. This element remains dropped out until the recloser is manually closed by control pushbutton (PB8).

```
NEFM                          Date: 12/09/98    Time: 16:26:58.623
47513

FID=SEL-351R-1-R102-V0-D980513       CID=CCE7       BCBFID=R100


#     DATE      TIME          ELEMENT           STATE
175   10/02/98  21:57:17.588  51G2T             Asserted
174   10/02/98  21:57:17.588  79CY              Asserted
173   10/02/98  21:57:17.588  79RS              Deasserted
172   10/02/98  21:57:17.588  TRIP              Asserted
171   10/02/98  21:57:17.642  59A1              Deasserted
170   10/02/98  21:57:17.667  51G2T             Deasserted
169   10/02/98  21:57:17.830  52A               Deasserted
168   10/02/98  21:57:17.830  TRIP              Deasserted
167   10/02/98  21:57:33.815  79LO              Asserted
166   10/02/98  21:57:33.815  79CY              Deasserted
165   10/02/98  21:57:33.819  SH3               Asserted
164   10/02/98  21:57:33.819  SH0               Deasserted
163   10/02/98  23:08:50.020  CLOSE             Asserted
162   10/02/98  23:08:50.020  PB8               Asserted
161   10/02/98  23:08:50.024  PB8               Deasserted
160   10/02/98  23:08:50.212  CLOSE             Deasserted
159   10/02/98  23:08:50.216  52A               Asserted
158   10/02/98  23:08:50.249  59A1              Asserted
157   10/02/98  23:09:00.213  79LO              Deasserted
156   10/02/98  23:09:00.213  79RS              Asserted
155   10/02/98  23:09:00.217  SH3               Deasserted
154   10/02/98  23:09:00.217  SH0               Asserted
```

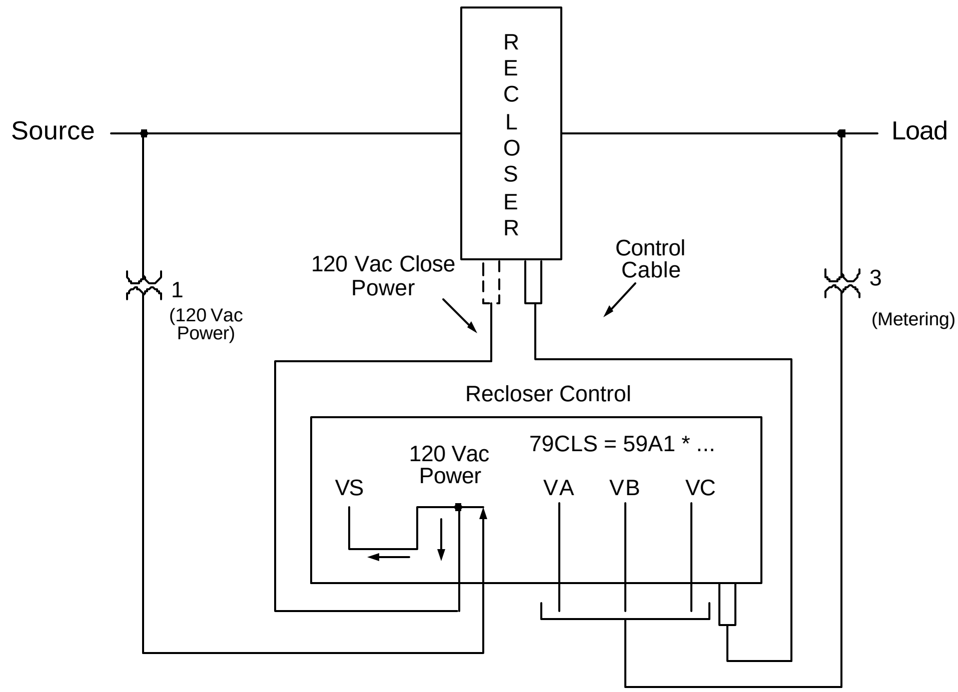

Figure 4 Nonstandard AC Voltage Connections Require Settings Change in Recloser Control

Because the recloser requires either low voltage ac or line-to-line voltage to close, the relay typically uses an overvoltage element to monitor a hot source condition. Reclosing is supervised by including the A-phase overvoltage element (59A1) in the reclosing supervision equation. However, with the A-phase metering PT mounted on the load side of the interrupting contacts on this radial line, the 59A1 voltage element drops out after every trip and prevents automatic reclosing (refer to Figure 4). This is further verified by noting that the time difference between the drop out of the TRIP and the control going to lockout (79LO asserting) is equal to the first reclosing open interval time delay (1 second or 60 cycles) plus a 15-second close power wait delay, a settable amount of time allowed for the 'source-side' ac voltage to return. The SER report shows that the manual close by pushbutton (PB8) is successful because it is not internally supervised, and the source-side voltage is present. A jumper is installed to monitor the source-side voltage with a voltage input (VS) and a corresponding overvoltage element (59S1) is set to monitor the single-phase, source-side control power. A simple setting change (79CLS = 59S1 * . . .) makes the close supervision monitor the correct voltage. The SER made this wiring and setting problem easy to diagnose.

EVENT REPORT TRIGGER CONDITIONS

Relays can generate or trigger event reports by fixed and programmable conditions. Generally, relays will automatically generate event reports for critical operations, such as a trip condition or the energizing of an external trigger input. Additionally, modern relays have the ability to program trigger conditions of choice. These may include individual relay elements, monitored optoisolated inputs that are asserted by external devices, or a change of monitored currents or voltages. By monitoring external devices such as electromechanical relays, auxiliary relays, and communications equipment, we can time coordinate their operation with the analog system quantities and the rest of the protection system.

The programmable conditions that trigger event reports must be chosen carefully. Relays have a fixed number of event reports that can be stored before older events are overwritten. Trigger conditions, such as an overcurrent element set near expected load values, should not pick up so often that the relay overwrites useful data before an analyst has a chance to download it. Alternatively, a communications processor or automated power system report manager software can retrieve and store event reports as they occur.

Event reports are triggered on the rising edge of the first element to assert in the programmable trigger equation. The relay does not generate multiple event reports when additional conditions in the programmable trigger equation pick up; only the first relay element of any continuous sequence triggers an event report. For example, the following settings were used by one utility. The relay would not generate events when the direct trip (DT) input was asserted.

```
MTU   =M1P + Z1G + M2PT + Z2GT + 51NT + 51QT + 50MF
MER   =3PT + DT + YT + LP4 + 52AA1 + LOP*52AA1
OUT1  =3PT + DT
```

When the breaker was closed, a breaker auxiliary 52a contact would energize an input and cause the 52AA1 element to assert. The rising edge of this element in the MER equation would trigger an event. As long as the breaker remained closed, no other MER element could trigger a new event report. The relay generates event reports automatically for relay trips and external triggers, but the DT element was programmed to operate the OUT1 trip contact directly and not through the internal trip logic via the unconditional trip equation (MTU). To solve this problem, the settings were changed so that the DT element trips the relay via the trip logic, which asserts the three-pole trip element (3PT). IN2 is now energized momentarily with the close coil and generates events for close operations. Other triggers can now operate because this input (and MER) does not stay asserted.

```
IN2   =LP2
MTU   =M1P + Z1G + M2PT + Z2GT + 51NT + 51QT + 50MF + DT
MER   =YT + LP4 + LP2 + LOP*52AA1
OUT1  =3PT
```

In newer digital relays, Boolean logic programming has been expanded to include rising- and falling-edge operators. In these relays, the element /52A could be used instead to cause a one processing interval pulse at the rising edge of the 52A element assertion. This would allow subsequent trigger assertions to generate events.

Because relays automatically generate event reports for trip conditions, it is common to use the programmable event trigger equation to include the pickup of time-delayed elements. This will generate one event report that captures the initial pre-fault and fault inception, and another event after element time out and trip. A distribution overcurrent relay may be set as follows.

```
TR(1246)=51T        The trip output of the time-overcurrent element.
ER(1246)=51P        The pickup of the time-overcurrent element.
```

SETTINGS STORED WITH EVENT DATA

Relay settings are stored with event data in order to indicate how the relay was set and why it responded for given conditions. In order to save storage space, older relays would append the settings to the end of the event reports; if settings were changed, the event history was cleared and event data was lost. In newer relays, if settings are changed, the event data are retained, but the settings loaded in the relay at the time of trip are lost. Following the analog and digital data, a message "`SETTINGS CHANGED SINCE EVENT`" may be displayed. This means that the current settings stored in the relay at the time the event is downloaded or displayed do not match the settings used when the event report was triggered. Therefore, it is critical for the user to either download events of interest as they happen, before they are overwritten, before power is lost, or before settings are changed. Users should also maintain accurate records of settings changes, so that the settings that were used with the relay at the time of events are known.

An example illustrates the importance of maintaining records of settings changes. The following screen capture is an excerpt from a generator relay event report. The digital element portion of the event data clearly shows that the restrained current differential element (87R) asserts at the same time the trip logic (TR1 - 4) asserts, and is the likely reason for the trip operation. However, the event report contains the message "`SETTINGS CHANGED SINCE EVENT.`"

```
Protection and Control Elements
                                              V L   R    L   D    F I
2 2 2 G 2   3 4 4  5      5    5      66 8  8 D C   E    C   E  T RON SELogic
1 4 5 E 7   2 0 6  0      1    9      04 1  7 C L   M    H   M  R ECA Variable
PPDCSAN PVPVPPZZQQ PGNHHQRGNCV PVPGQS  GG135UB  13571357 1357PN 13Q D
1212F VF 1PS121212    12        1P     12246RL  24682468 2468QG 24    12345678
                                                                              87R Asserts
[Partial event record shown in this example]
                                                                              TRIP Asserts
 [4]
...r.............r ........r.r .....b ......... ........ .3.... ..... ........
...r.............r ........r.r .....b ......... ........ .3.... ..... ........
...r.............r ........r.r .....b ......... ........ .3.... ..... ........
...r.............r ........r.r .....b ......R.. ........ .3.... bb... ..T.....>
```

The current settings stored in the relay do not even include the 87R element in the programmable trip logic. In the rush of testing and troubleshooting, settings were changed and no accurate records kept. Therefore, it is very difficult to analyze why the differential element tripped because the settings of that element at the time of the operation are lost. In the newest relays, the actual settings that were loaded in the relay at the time of the trip or event report trigger are retained in that event report, even if settings are changed before the event is downloaded. Since this benefit is only available in a few relays, it is a good general practice to download and save event reports of interest before settings are changed in a relay, so that no valuable data are lost.

EVENT REPORT LENGTH

Once triggered, the event reports will show information for a certain number of continuous cycles. Older relays stored 11 cycles of data, where the first four cycles were always pre-fault, and the remainder was fault and post-fault data. The most recent 12 events were stored in volatile memory, so a user had to take care to download and analyze critical event data before control power was removed from the relay. Other relays offer more variety in event report lengths, from 15 cycles long in current differential relays to 60 cycles long in reclosing relays.

The most modern of digital relays offer programmable amounts of pre-fault data and total event report length. In addition, the data stored by these relays are nonvolatile; the data can be cleared by command, but not by removing control power from the relay. The storage capability of these relays is often communicated by providing the total relay storage in cycles. For example, one popular relay will store the latest 240 cycles of event report data in nonvolatile memory. The length of each event report is programmable and can be set to either 15 or 30 cycles. Therefore, at least sixteen 15-cycle or eight 30-cycle reports are maintained; if more reports are triggered, the latest event report overwrites the oldest event report. Pre-fault length ranges from 1 to 29 cycles. Pre-fault is the part of the event report that precedes the triggering point.

Specialty relay models are capable of generating long event reports. One distance and directional overcurrent relay stores 300 cycles or 5 seconds of continuous data per event report. Another breaker relay has the ability to store ten 60-cycle event reports. In addition, programmable event report trigger conditions can be used to generate consecutive events. The consecutive event reports can be edited and combined using a simple text editor. In effect, the result is the creation of an event report that is longer than the relay's default capability. These extended event reports are very useful in capturing system events that take much longer than the default event report length to unfold.

Capturing the slow opening of a distribution breaker is one example of the usefulness of generating consecutive events. The default event report length of one distribution relay is only 11 cycles (4 cycles of pre-fault, and 7 cycles of fault and post-fault data). The relay trip will generate an event report, but if the breaker takes longer than 7 cycles to open, we will not have any data to record the event. However, using programmable logic, we can set a timer to trigger another event report just slightly more than 7 cycles after a relay TRIP assertion.

`TZpu = 8`	Pick-up delay of programmable timer element ZT.
`TZdo = 0`	Drop-out delay of programmable timer element ZT.
`:`	
`H (34) = TRIP`	Intermediate logic variable.
`:`	
`Z (56) = H`	Z asserts at time of trip and begins TZpu timing.
`:`	
`ER(1246) = ZT + ......`	Event report is triggered 8 cycles after TRIP initiation.

With these settings, each time the relay trips, it provides two event reports with time tags exactly 11 cycles apart. The events can be captured in a text file, edited (to remove the summary and settings of the first event, and the header information of the second), and combined to make one 22-cycle event report of continuous analog and digital traces. This can be done using Microsoft Windows® Excel™. Spaces and tabs delimit the text, making it easy to parse into columns.

If events are also triggered on the pickup of overcurrent elements (ER=51P+. . .), modify this procedure. With the pickup of the overcurrent element (51P) in the event report trigger equation (ER), subsequent triggers will not occur until the current is gone. The rising-edge requirement for event triggering will prevent us from getting events other than from TRIP and external trigger (ET) conditions. One way to avoid that is to use a programmable output contact to assert the ET optoisolated input on the relay to generate an event when the ZT timer picks up. This would allow one event report to be generated at the beginning of the fault (by 51P), another at the trip initiation (by TRIP), and a third at the fault clearing (by ET, assuming the fault clears within 18 cycles of trip initiation). Some data between the beginning of the fault and the trip initiation may be lost if the trip is caused by a slow time delay. From trip initiation to fault clearing, however, the event data would be continuous. Breaker operating time can then be monitored.[4]

TIME SYNCHRONIZATION

The time and date stamp of event reports can be synchronized to a demodulated IRIG-B time-source input. Relay times are accurate to within ± 5 ms of the time-source input. The source for the relay time can be a GOES or GPS satellite clock receiver, or a local communications processor. This feature is extremely useful when analyzing and coordinating event reports from different relays within the same substation, and especially events from relays located at different substations, that were generated for the same system condition.

REGULATORY REQUIREMENTS

National and regional regulatory councils require utilities and transmission providers to install disturbance monitoring equipment and share information from that equipment. Disturbance monitoring is necessary to determine the performance of the electric system and protective relaying, to verify system models, and to determine the causes of system disturbances. Data from this equipment are compiled by independent system operators and made available to council or power pool members and the North American Electric Reliability Council (NERC).[5]

One regional council, the Electric Reliability Council of Texas (ERCOT), specifies that all power system disturbances, which include undesired trips, faults, and protective relay system (PRS) operations, be promptly analyzed by the equipment owner. Any deficiencies should be investigated and corrected. The ERCOT Operating Guide defines the following events as a misoperation:

- Failure of a PRS to trip for an in-zone fault
- Slow trip of a PRS, including correct operations, where tripping time is slower than designed
- Unnecessary or unintentional trip of a PRS for an out-of-zone fault
- Unnecessary or unintentional trip of a PRS when no system fault is present
- Failure to automatically reclose following a fault

The Operating Guide recommends that disturbance monitoring equipment be installed to the maximum practicable extent to permit analysis of system disturbances and protection system events, and that those devices be time-synchronized when possible. The equipment must be capable of triggering event reports for system voltage magnitude and current magnitude disturbances (?V and ?I) without requiring any circuit breaker operations or trip outputs from protective relay systems. Triggering by additional methods is acceptable. Triggering is adjusted to operate for faults in the area to be monitored, which should overlap into the area of coverage of adjacent fault recorders. Fault records are provided to ERCOT and NERC in IEEE ASCII COMTRADE file format, with channel identification and scaling information to allow analysis of the records.

Relays with event reporting meet these regulatory requirements for disturbance monitoring equipment. Traditionally, relays were installed for protection and control purposes, and the ancillary features like metering and event recording were added bonuses. In many cases now, relays are installed because of their data-capturing ability. In comparison to traditional digital fault recorders installed at only generation or the largest transmission substations, where data from one or many terminals away from the fault location had to be analyzed, relays now allow data at the point of the fault to be examined and time coordinated with relay elements, monitored optoisolated inputs, and other apparatus.

EVENT REPORT FORMATS

Older digital relays provided one format for displaying event reports. Much like the event report shown in Figure 1, the format was an ASCII text file with fixed sampling rate, amount of pre-fault data, overall length, and columns of displayed data. Newer digital relays provide a wide variety of formats in which to display or download event report data.

Compressed ASCII Event Reports

Compressed ASCII event reports facilitate the downloading, storage, and display of data by communications processors, spreadsheet or database programs, or analytic assistant software. The data are comma delimited and can be validated with a checksum, further enhancing this format's ability to be used by automated systems. The compressed report provides a general configuration message that defines for the external computer the data, labels, and fields to expect. The data message includes header, column label, and analog and digital data. The relay settings appear as they do in a normal event report, surrounded by commas. Because the analog and digital data are represented in hexadecimal-ASCII, and the data are not formatted in columns but run together and comma-delimited, this format of the event report is not intended for convenient visual or manual analysis.[6]

Filtered and Unfiltered Event Reports

Most modern digital relays sample the basic power measurands (ac voltage, ac current, station battery dc, and optoisolated inputs) anywhere from 4 to 64 times per power system cycle. A digital filter extracts the fundamental frequency, while an analog anti-aliasing filter rejects higher harmonics.[7,8] The relays then filter the measurands to remove transient signals. Current differential relays also extract particular signals, such as second-, fourth-, and fifth-harmonics for use in blocking, restraining, and overexcitation logic. Most relays operate on the filtered values and report them in the default event reports.

Raw or unfiltered event reports can also be selected for observation of the following events:

- Power system harmonics on current or voltage channels
- Decaying dc offset during fault conditions on current channels
- Optoisolated input contact bounce
- Transients on the station dc battery channel

The analog and digital filtering of the voltages, currents, and station battery are fixed. However, you can adjust the optoisolated input debounce via settings in many relays. Raw event reports generally display one extra cycle of data at the beginning of the report in order to populate the digital filter.

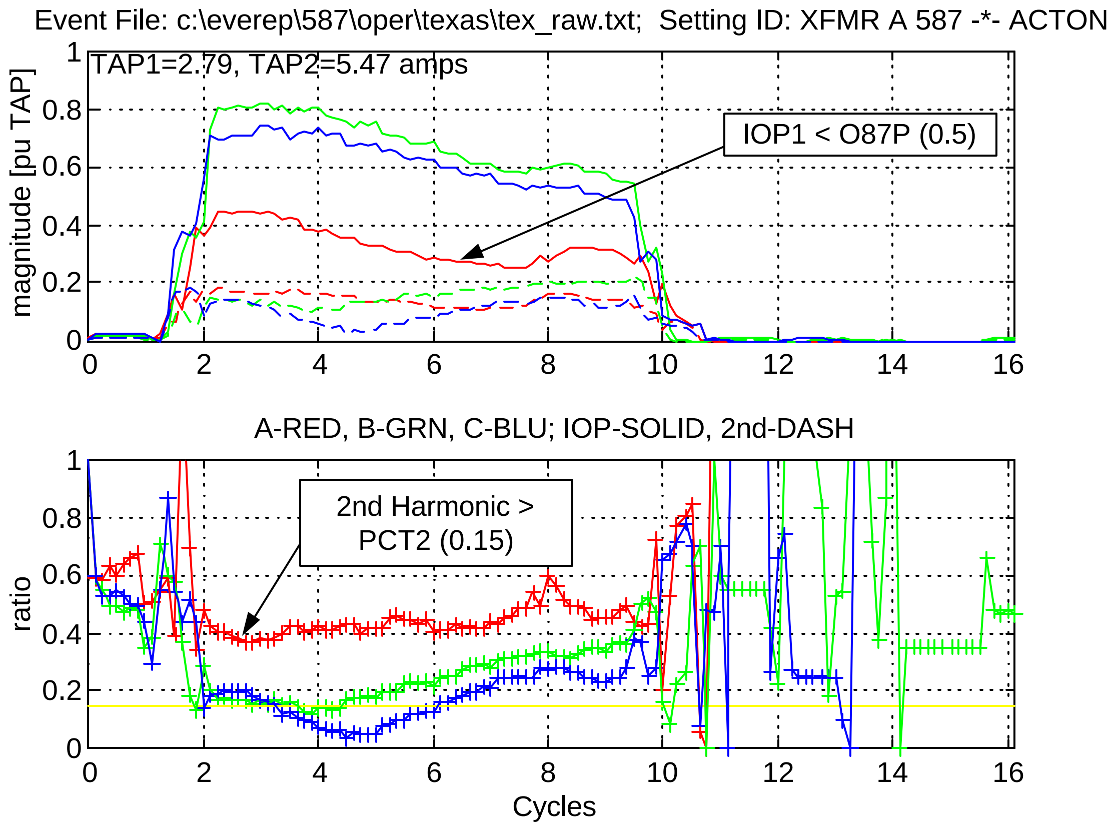

Figure 5 Mathcad® Plots from an Unfiltered Event Report from a Current Differential Relay

The following example highlights the usefulness of raw or unfiltered event reports. In most current differential relays, second-harmonic blocking is used to make the differential element secure against operation during transformer inrush. In one relay, harmonic blocking is provided if the second-harmonic content is greater than a setting, PCT2, commonly set to 15 percent of fundamental. Additionally, the relay requires that the phase quantities be sufficient by comparing each against a threshold, the minimum restrained differential element pickup (O87P). In this particular case, the minimum pickup setting was 0.5 per unit of tap. Using the raw or unfiltered event report data shown in Figures 5 and 6, we can see that while the Phase 1 second-harmonic signal is high (around 40 percent, greater than the 15 percent blocking threshold), the operate signal on that phase is very low (less than 0.3 per unit). Therefore, the Phase 1 blocking element is not enabled, and the other two phases, both of which see low harmonic content and high operate quantities, trip. Figure 5 shows the results of a Mathcad® 6.0 file. This file extracts the fundamental and second-harmonic components from the raw currents in the event report. The magnitudes of operate and second-harmonic signals per phase versus time are plotted first. The second graph shows the ratio of second-harmonic to fundamental per phase versus time.

A MATLAB® file is shown in Figure 6. This reads the raw phase currents from the differential relay event report, calculates a discrete Fourier transform for the second-harmonic signal, and applies the digital cosine filter to the raw current and extracts the fundamental signal. The file then models the relay operate, restraint, and tripping algorithms for each differential phase and plots the results. The results of two phases for this example are shown in Figure 6.

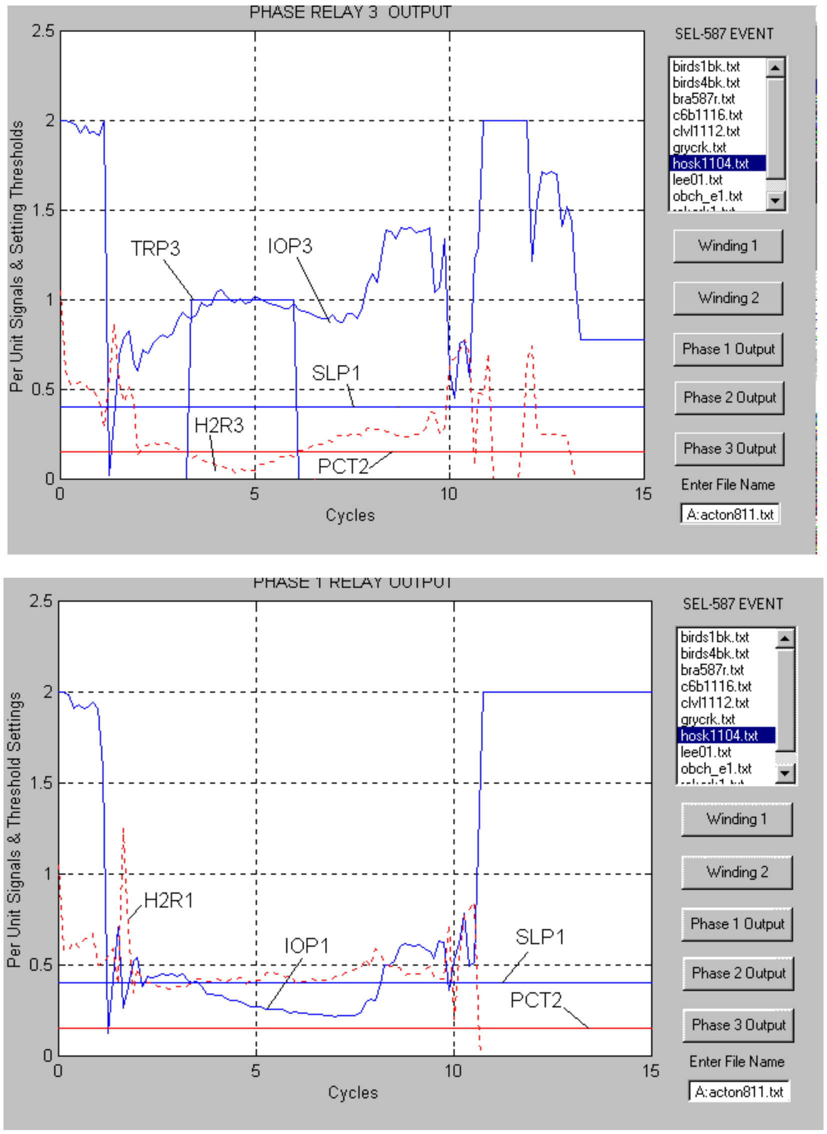

Figure 6 MATLAB® Plots from an Unfiltered Event Report from a Current Differential Relay

A new current differential relay has much-improved sensitivity for enabling the second-harmonic blocking element.[9] The harmonic threshold is equal to $(0.05 \cdot I_{NOMINAL}) / (\min(TAP1, TAP2))$. In this case, that would be $(0.05 \cdot 5) / 2.79$, or 0.089 per unit. This provides superb sensitivity for enabling blocking, while allowing the user to leave the desired minimum pickup (O87P) at 0.5 p.u. for security. With this change and the common harmonic blocking enabled, this trip would have been avoided (Phase 1 second-harmonic would have restrained). Reference 9 details some new current differential design innovations. Of particular interest here is the use of raw or unfiltered event report data in the understanding of some very rare and complex field cases, the development of new technology, and the creation of IEEE COMTRADE test files used to compare the new algorithms developed against existing designs.

SOFTWARE TOOLS

Viewing event reports as text files is very useful and easy. A personal computer and off-the-shelf terminal emulation software like Microsoft Windows® HyperTerminal™ is all that is required to display or download the information from some relays. Because many event reports are formatted ASCII files with data organized in columns, or comma-delimited in the case of compressed ASCII files, data can easily be displayed and manipulated using software tools.

One of the most readily available, off-the-shelf tools is Microsoft Windows® Excel™. Event report data are very easy to plot in a variety of formats. See Figure 7 for some examples. The event data are converted from one text field to individual columns of data. Using the built-in Chart Wizard, selected analog channels can be plotted versus time, using a smooth line chart. The Excel mathematical capability and ready-made operators automate the conversion of rectangular coordinates of the event text to polar coordinates. An x-y scatter plot with lines was chosen to graph the IA phasor below. The text data are now viewable as easy-to-analyze graphics.

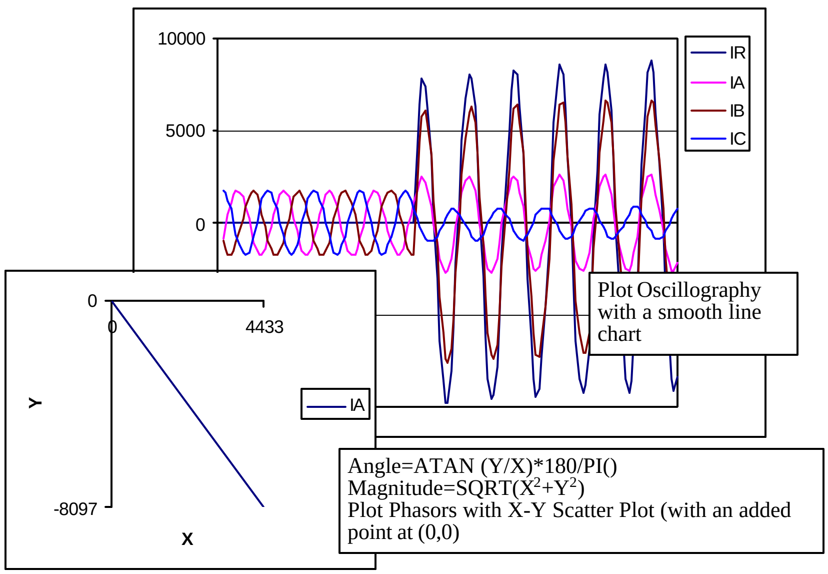

Figure 7 Microsoft Windows® Excel™ Spreadsheet Plots of Event Report Data

Relay manufacturers also provide analytic assistant software that can be used to graphically view event report data from their relays (see Figure 8). These custom software tools provide the automatic capability of reading text event reports and plotting phasor data, oscillography (analog traces and digital elements shown on one plot), calculated symmetrical components, calculated phasor magnitudes and phase angles, and harmonic analysis. The ability to add notes and labels, scale data or manipulate displayed channels and phasors, and easily export screens to other programs like Microsoft Windows® Word™ makes these tools extremely beneficial.

In two-terminal line applications, using the fault currents from each end of the line improves fault location accuracy. Software programs can be used to perform fault location using event data from multiple relays.

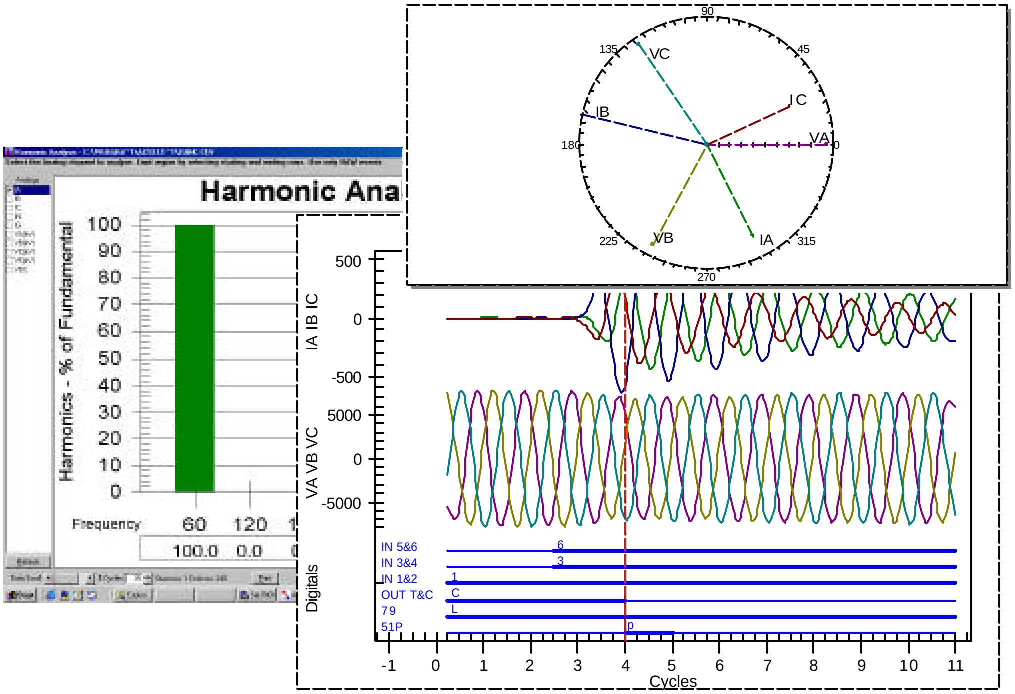

Figure 8 Analytic Assistant Software Tool Displays Event Report Data

Mathcad® 6.0 and MATLAB® are two commonly used mathematical programs. These are highly powerful tools that engineers use to calculate symmetrical components and harmonics from relay event reports, model relay algorithms, analyze relay performance for modeled inputs or for actual event report data, and plot or graph results. Refer to Figures 5 and 6 for example outputs of these programs.

Other Features

Table 1 provides a summary of the event report capabilities of a variety of microprocessor-based relays; differences aside, they all provide event reports. The table lists breaker failure relays (BF), distance relays (21), differential relays (87), overcurrent relays (51), reclosing relays (79), motor relays (MOT), and generator relays (GEN). The last column refers to what happens to the stored event reports if a settings change is performed before the event is downloaded.

Some relays have the ability to use aliases, custom names associated with digital elements and analog channels. In event reports and SER reports, these custom names are displayed in place of factory default names. This can make the data more meaningful to the analyst. For instance, aliases allow a digital element named IN101 in the SER report, or analog channel IAW1 in an event report, to be referred to as GCB12_52A and 12IA, respectively. Many relays have several options in customizing which data are displayed in retrieved event reports. Specific event report data, such as only the analog section of data, only the digital sectional of data, or only the communications and digital relay-to-relay logic portion of the event, can be downloaded or viewed with special serial port commands.

Table 1 Summary of Event Reporting Capabilities in a Variety of Relays

Type	Event Triggers	Number of History Items	Number of SER Events Stored/ Elements	Number of Aliases	Number of Events Stored	Event Storage	Event Length/ Pre-fault	Samples Per Cycle	Event Report Formats (Sample per cycle)	Raw Data	Changing Settings
BF-1	P	100	0	0	9	V His-N	60/2	4	4	No	L
BF-2	P	40	512/72	20 D	40,20,10	N	15,30,60 /1-LER-1	64	4,8,16,64	Yes	S
21-1	F	12	0	0	12	V	11/4	4	4	No	L
21-2	P	40	0	0	12	V His-N	11/4	16	4,16	Yes	S
21-3	P	40	0	0	5	V His-N	300/4	16	4,16	Yes	S
21-4	P	40,23,11	512/72	0	40,23,11	N	15,30,60 /1-LER-1	16	4,16	Yes	R
87-1	P	20	0	0	10	N	15/3	16	4,16	Yes	S
87-2	P	99	512/72	20 D 12 A	14-7	N	15,29,60 /1-LER-1	64	4,8,16,32, 64	Yes	S
87V	P	12	0	0	12	V	11/4	4	4	No	L
51-1	P	12	0	0	12	V	11/4	4	4	No	L
51-2	F	20	0	0	12	N	15/2	16	4	No	S
51-3	P	20	512/72	0	20	N	15/4	16	4,8	No	S
51-4	P	29,14	512/72	0	29,14	N	15,30 /1 - LER-1	16	4,16	Yes	S
MOT	P	14	512/96	20 D	14	N	15/4	16	4,16	Yes	S
GEN	P	30,15	512/96	40 D	30,15	N	15,30/1 - LER-1	64	4,16,64	Yes	S
79-1	P	12	0	0	12	V	60/6	4	1	No	L
79-2	P	12	0	0	12	V	48/6	4	1	No	L

Notes:

F = Fixed
P = Programmable
D = Digital
A = Analog
V = Volatile
N = Nonvolatile
His-N = History is Nonvolatile
L = Event Reports and History Lost
S = Settings Lost; History, Event Data Retained
R = All Event Data Retained

USING EVENT REPORTS FOR TESTING – COMTRADE

Use IEEE COMTRADE files to represent real-world waveforms, including dc offsets and harmonics. They can be generated by EMTP or other power system simulation programs, or from actual field event reports recorded by relays or other disturbance monitoring equipment. Once a COMTRADE file set is generated, it can be replayed into a relay through test equipment to recreate the actual or modeled system event and observe the relay response. This is very useful for documenting disturbances and testing, troubleshooting, or analyzing the response of different designs or programming for the same event.

Analytic software can automatically generate IEEE COMTRADE format files from a relay event report. Studying waveforms with dc offset or harmonics requires unfiltered high sample rate event reports. The analytic assistant software pictured in Figure 8 automatically creates a COMTRADE file set when it opens and graphs a new relay event report. The COMTRADE C37.111.1991 file sets have three files:

- Header (.hdr) – contains free-form ASCII text with details of the circumstances surrounding the events written for and to be read by analysts.
- Configuration (.cfg) – contains ASCII text for scaling, sampling, and timing data. The file is formatted so that it can be read easily by a computer. It also specifies whether the accompanying data file is in ASCII or binary form.
- Data (.dat) – contains sample numbers, time, and data values. The file is formatted so it can be read by a computer. Analysts can read ASCII data files using a text editor or word processor. To read the binary form, the analyst would need a hexadecimal file reader.

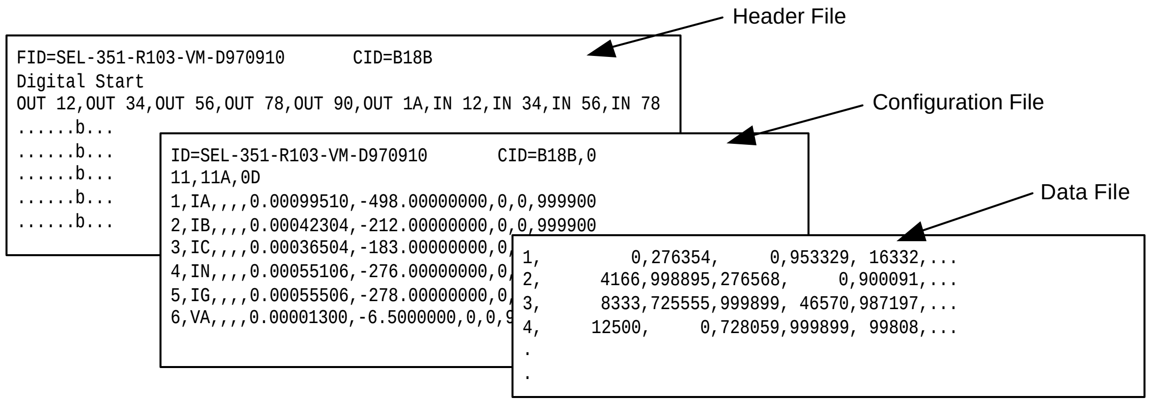

Figure 9 IEEE COMTRADE File Set

Every time a relay captures event data, ready-made test reports are available. The event reports show what the relay observed, how it responded, and provides the clues to determine that the response was correct. By analyzing actual relay and system performance, many utilities are saving money by extending or eliminating traditional routine tests. References 10 and 11 propose that traditional routine testing of microprocessor-based relays adds no value. Instead of testing every element in the relay on a periodic basis, the authors suggest that self-test alarm contacts be monitored continuously, that only items not checked by automatic self-testing be periodically tested (including optoisolated inputs, output contacts, and analog inputs), and that event reports be analyzed. Event report analysis will confirm correct operation, assist in troubleshooting problems, and identify deficiencies before they cause future problems. In addition, the three COMTRADE files can meet company and regional reliability council requirements for documentation of system events and periodic protective relay system testing. ERCOT operating guides require that protective relay systems be inspected periodically to assure reliability, that deficiencies be corrected, and that documentation of testing be maintained. An event report is documentation of the best possible test of a protective relay, an actual system fault with the user's settings installed and other system components monitored.

HOW TO ANALYZE AN EVENT REPORT

This example is provided as a step-by-step tutorial on how to analyze an event report, learn lessons, and resolve problems. Before analyzing the details of any event report, start with a basic understanding of what happened, or what should have happened. This generally involves reviewing the relay settings and logic, obtaining the relay history report, and gathering any other information that may be helpful (known fault location, targets from other relays, breaker operations, SCADA, and personnel records). Use the event report to investigate whether the actual operation matches the expected operation.

The most recent historical information was downloaded from a distribution relay that had to be manually closed after tripping to lockout. The relay controls a recloser that is mounted on a steel stand within the substation and powered from the substation dc battery. As a matter of routine, a utility employee investigates all out-of-the ordinary events, including failures to automatically reclose and lock-out events.

```
1st Event Report:
CARNALL CCT.# 2522 SN# 96143025            Date: 8/25/99     Time: 11:54:43.479
Event   : AB T    Location: 0.12      Shot:   0   Targets: INSTABQ
Currents (A pri), ABCQN:   3766   3551    239   6124     20

2nd Event Report:
CARNALL CCT.# 2522 SN# 96143025            Date: 8/25/99     Time: 11:54:44.083
Event   : CG T    Location: 0.21      Shot:   0   Targets: INSTCQN
Currents (A pri), ABCQN:      0      3   3932   3930   3931

3rd Event Report:
CARNALL CCT.# 2522 SN# 96143025            Date: 8/25/99     Time: 12:09:41.758
Event   : ABC     Location: 5.67      Shot:   2   Targets:
Currents (A pri), ABCQN:    443    654    403    478    105
```

In order to understand how the relay was expected to operate, we should immediately look to the output contact logic and determine what elements were actually used in this application. In this relay, we notice that only two elements are programmed to cause a trip (TR equation), the nondirectional phase instantaneous element (50H) and the phase time-overcurrent element (51T). The pickup of the 50H element is (30 A secondary) • (CTR=120:1), or 3600 A primary; therefore, we would expect the initial INST A B trip target for a 3766 A phase fault.

```
Partial Display of As Set Settings for CARNALL CCT.# 2522 SN# 96143025

CTR       =120.00
79OI1     =900          79OI2  =2700
79RST     =600          M79SH  =11011
50C       =99.99
50NL      =99.00
51NP      =12.00        51NTD  =15.00        51NC   =3       51NRS  =N
50L       =99.99        50H    =30.00
51P       =5.01         51TD   =2.50         51C    =4       51RS   =Y
52APU     =0            52ADO  =0            TSPU   =0       TSDO   =0
TKPU      =0            TKDO   =0            TZPU   =0       TZDO   =0
S(123)    =
A(12)     =
B(12)     =
E(34)     =
F(34)     =
K(1234)   =
L(1234)   =
A1(1234)  =
A2(1234)  =
V(56)     =
W(56)     =
X(56)     =
A3(1346)  =
A4(2346)  =TCMA
TR(1246)  =50H+51T
RC(1246)  =TF
ER(1246)  =51P
TDUR      =5            TFT    =30
IN1       =DC           IN2    =DT           IN3    =TCM     IN4    =RE
IN5       =             IN6    =52A
```

The next expected sequence for this relay would be to open the recloser, time on the first reclosing open interval, and then automatically reclose. The first reclose attempt should be after an open delay of 900 cycles, or 15 seconds (79OI1 setting). However, the second event is an instantaneous C-to-G trip only 0.604 seconds after the initial trip. What would cause a fault to occur during a recloser open period while we are timing to our first reclose attempt? The analytic software plots of the first (Figure 10) and second (Figure 12) event reports confirm our suspicion of a recloser failure and flash over inside the recloser tank.

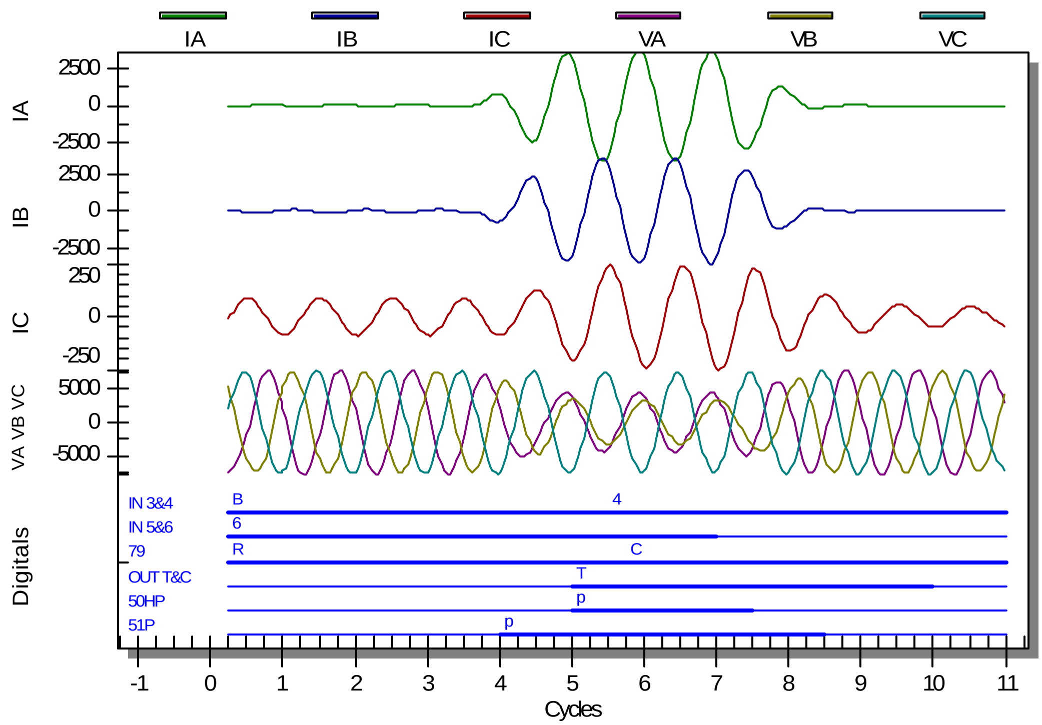

Figure 10 C-Phase Interrupter Fails to Open

In Figure 10, the initial A-to-B-phase fault is evident. The first digital element to assert is the time-overcurrent pickup (51P), the most sensitively set element. This triggers the event report as expected (ER = 51P setting). To determine what element caused the trip, find the point in time where the trip asserts (OUT T), and look for any other element transitions at that same point. The pickup of the instantaneous phase overcurrent element (50HP) asserts at the same instant that the trip output asserts, while the time-overcurrent element (51P) is picked up but still timing to trip. The reclosing element (79) prepares to time to a reclose by changing from the reset state (R) to the cycle state (C) when the relay trips. IN4 monitors a reclosing enable-disable switch.

IN6, programmed to monitor a 52a auxiliary contact, comes open 2 cycles after the trip, indicating the recloser has opened. However, after adjusting the scaling on the C-phase current channel in the analytic assistant software (Figure 10), we can easily see that the C-phase interrupter did not open fully.

The trip coil monitor (IN3) is an optoisolated input wired as a voltage divider to monitor the health of the trip coil. Refer to Figure 11. When the recloser is closed and the trip output contact is not asserted, the input allows a few milliamperes of current to flow through the trip coil. The voltage drop is across the relay input because it has a much higher impedance than the trip coil (roughly 1000 times greater). In the first five cycles of Figure 10, the input is asserted, meaning that the trip circuit was intact. At the time of trip, the IN3 deasserts, first because of the closed TRIP contact, and then because of the open 52a auxiliary in the trip circuit.

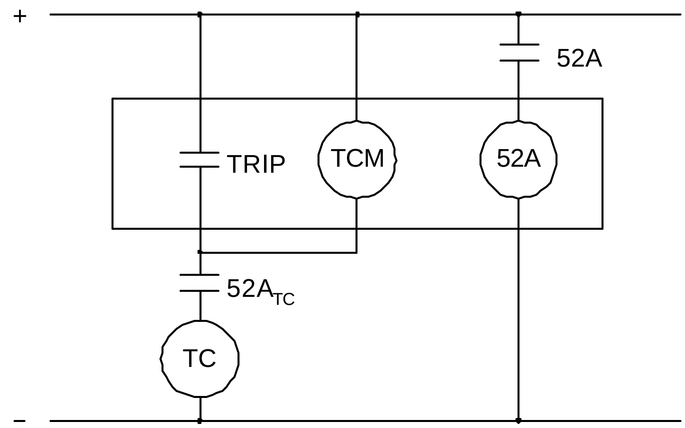

Figure 11 Trip Coil Monitor

In the second event, the failed interrupter flashes over to the recloser tank 0.604 seconds after the first trip occurred. In Figure 12, the reclosing element (79) immediately goes to lockout. The relay is designed to drive its reclosing element to lockout if a trip occurs during open interval timing. This prevents reclosing after a flash over across an open pole or internal recloser failure. Therefore, the operation of the relay was correct, and the reason for the failure to reclose was the failure of the C-phase interrupter in the recloser.

From the information in the first two events, we know that C-phase carried current for at least 0.721 seconds (the difference between the trigger times of each report, 0.604 seconds, plus 7 more cycles of fault data in Event 2). The fault current seen for the majority of this time was only around 50 A primary. Could we have used a recloser failure element to clear this fault before it developed into a more severe 4000 amp fault?

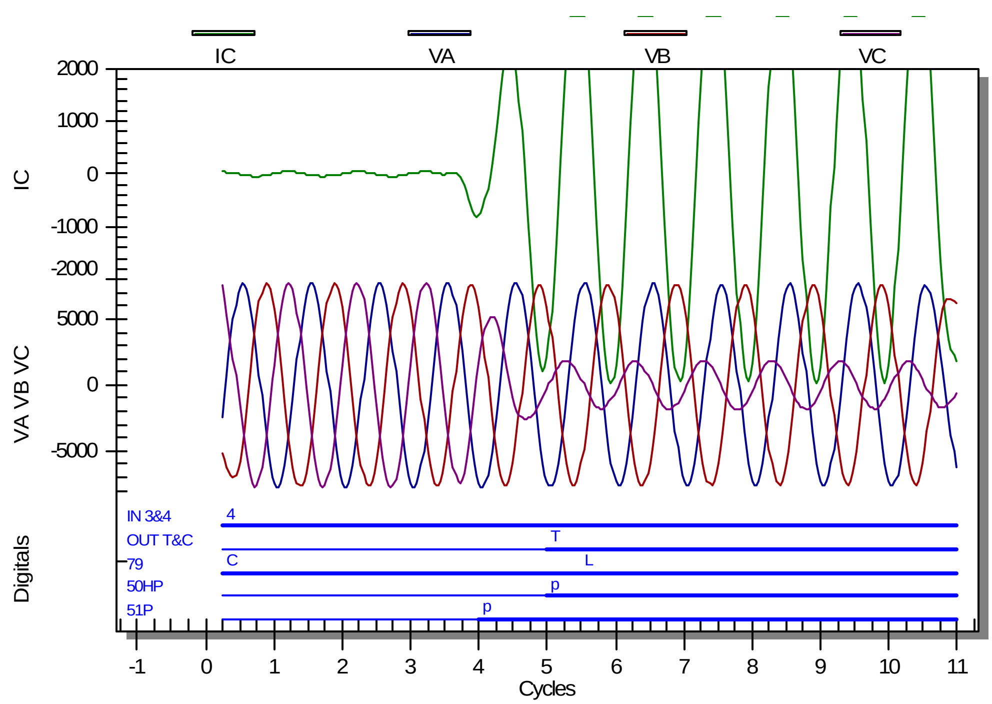

Figure 12 Failed C-Phase Interrupter Flashes to Ground

The recloser failure element, as set in this relay, is intended to cancel reclosing. The TF or trip failure bit asserts if none of the overcurrent elements in the relay (with the exception of the 50C element) have dropped out TFT cycles after a relay trip is initiated. If the overcurrent elements drop out, the trip failure element stops timing. Using the analytic assistant software, phase current and symmetrical component magnitudes are automatically calculated. At the end of the first event, the C-phase current is only 0.42 A secondary ($3I_O = Ia + Ib + Ic = 0.412$ A). The overcurrent elements that are used for tripping, and those that are not used for tripping, are set much too high to see the 0.412 A phase and residual current flowing through the failed interrupter, so the trip failure logic, as set, is ineffective.

In this relay, the elements that unlatch the trip output and trip failure timing are the same elements that prevent the reclosing relay from resetting after an automatic reclose. Setting a residual overcurrent element (50NL) to 0.25 A secondary provides sensitive recloser failure supervision for unbalance faults. Check the event reports in the history of the relay to make sure normal load unbalance is not greater than (0.25 A secondary) • (CTR=120:1), or 30 A primary, so that the reclosing element may reset. With this setting, our trip failure logic would have seen the unbalance condition caused by the stuck C-phase interrupter. Programming an output contact equal to close when a trip failure is detected (TF), could trip a backup protective device (the transformer differential lock-out relay), assert an alarm to the SCADA system to initiate maintenance, and avoid a more intense fault.

Supervising the trip failure element with a phase overcurrent element is more challenging in this relay, but can still be done. The maximum pre-fault load current in the relay history of events was 130 A primary, or 1.08 A secondary. Setting any element other than 50C in this relay below load prevents our reclosing relay from resetting. The logic and wiring in Figure 13 allow a sensitive 0.5 A secondary setting for 50C to be used for phase current supervision of the trip failure logic, while not interfering with the reclosing reset logic.

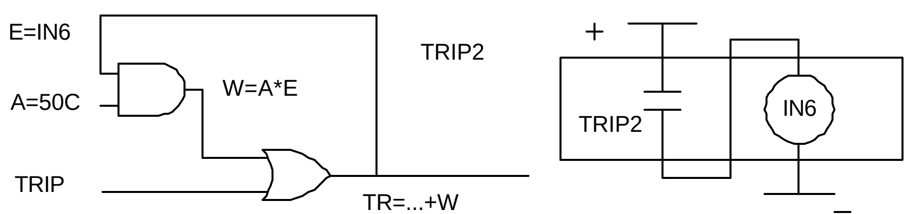

Figure 13 Recloser Trip Failure Logic for Phase Faults Below Load

We must assume that the C-phase interrupter eventually opened because no backup protective device operated, and the beginning of the third event (see Figure 14) shows that the C-phase current is zero. The dispatcher instructed a local technician to report to the substation because the SCADA system indicated the recloser was open and in lockout. About 15 minutes after the initial trip, the third event captures the manual close operation performed by the local technician. Standing at the outdoor control cabinet, directly under the failed recloser, the technician turned reclosing off and then manually closed the recloser. The recloser closed without incident.

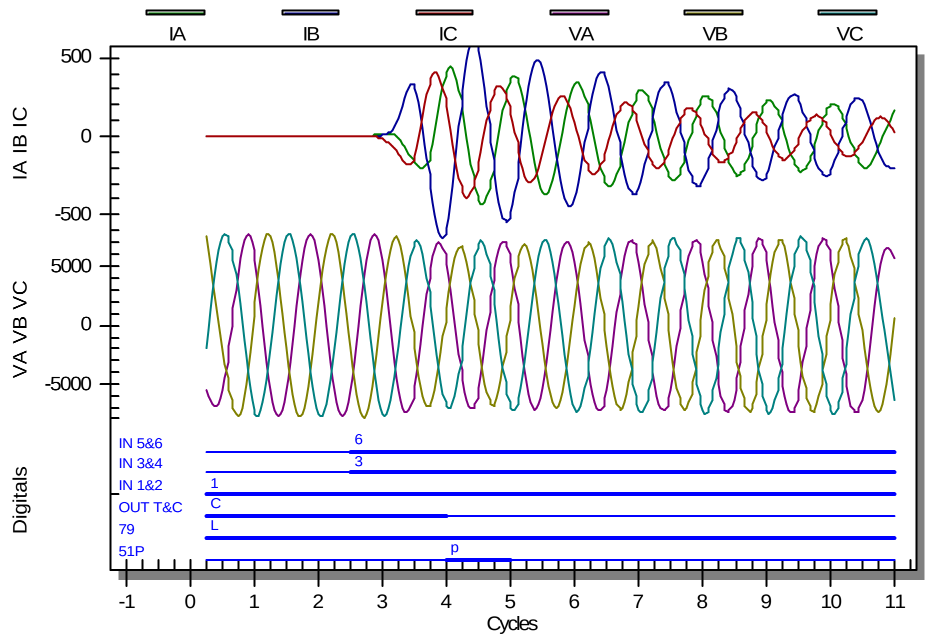

Figure 14 Manual Close of a Failed Distribution Recloser

The third event emphasizes the importance of using a manual close delay. In newer recloser controls and substation relays, front-panel operator controls are built in so that traditional control switches can be eliminated. For safety, the user may add a settable time delay to the operation of the front-panel operator controls. This delay allows an operator to initiate a manual close by pushing the CLOSE button, and then walk away to a safe distance before the close signal is actually sent by the relay to the recloser or breaker. The associated red CLOSE LED flashes as the timer counts down. This safety improvement can be made in older relays such as the one in this example by wiring the manual close switch contact to a programmable relay input, and time-delaying the close output with programmable logic as follows. See Figure 15.

`S(123)`	`= IN5`	IN5 is energized by a momentary manual close switch.
`TSPU`	`= 0`	Pickup of programmable timer ST.
`TSDO`	`= 300`	Dropout of programmable timer ST, set for 300 cycles.
`K(1234)`	`= IN5`	Programmable element K monitors the close switch.
`TKPU`	`= 0`	Pickup of programmable timer KT.
`TKDO`	`= 315`	Dropout of programmable timer KT, set for 315 cycles.
`L(1234)`	`= ST`	Programmable inverter element monitors ST.
`V(56)`	`= KT*!L`	Programmable element V asserts for overlap of KT and !L.
`A4(2346)`	`= V`	Time-delayed output from the relay to the close coil.

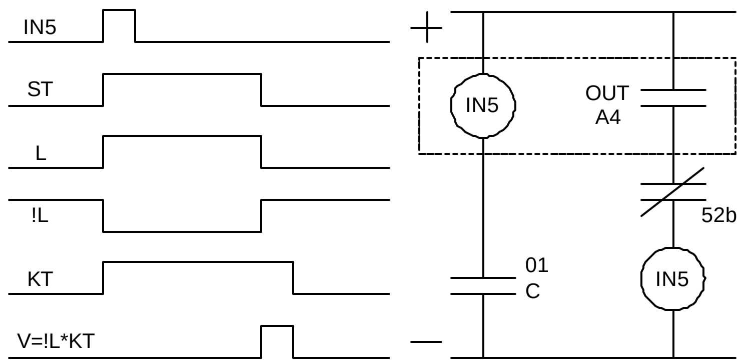

Figure 15 Delayed Manual Close Setting Option Improves Safety

Notice in Figure 14 the cold load inrush and the brief pick up of the 51P time-overcurrent element. A cold load pickup scheme can be enabled through settings that are automatically put in service when the recloser is open and locked out for a long period of time. After a successful close, the scheme automatically adjusts to original settings. When the scheme is active, the relay modifies the pickup of the phase time-overcurrent element to a higher value, while keeping the same curve and time-dial settings to maintain coordination with upstream devices[12]. See Figure 16.

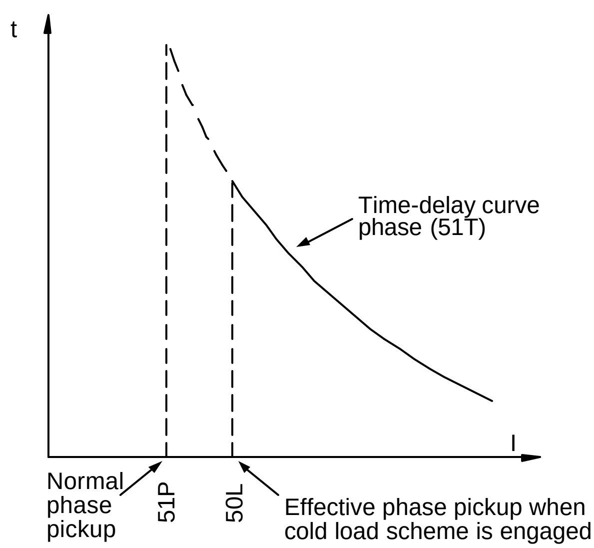

Figure 16 Cold Load Pickup Scheme Improves Security and Maintains Coordination

An element (52BT) that follows the recloser status enables the cold load pickup scheme. 52BT is the inverse of 52AT (see Figure 17). With the settings shown below, the modified pickup will be in service for a settable time (52APU) after a breaker close. After this time expires, the pickup is forced back to its original value. Another settable time delay (52ADO) is set to exceed all reclosing relay open interval time settings (79OI1, 79OI2, etc.) so the cold load pickup scheme is disabled through the reclose cycle. The cold load pickup scheme is enabled after the 52ADO time delay expires after the recloser is opened or goes to lockout. This is the loss-of-diversity time delay.

```
50L       =7.50
51P       =5.00    51TD        =2.50    51C  =4      51RS =Y
52APU     =30      52ADO       =3600
B(12)     =51T                              Normal time-overcurrent element.
C(12)     =50L                              Adjusted pickup (1.5 times tap).
F(34)     =52BT                             Asserted when cold load pickup scheme enabled.
G(34)     =52AT                             Asserted when cold load pickup scheme disabled.
X(56)     =B*C*F                            Cold load pickup scheme.
Y(56)     =B*G                              Normal trip.
TR(1246)  =X+Y                              All trip conditions.
```

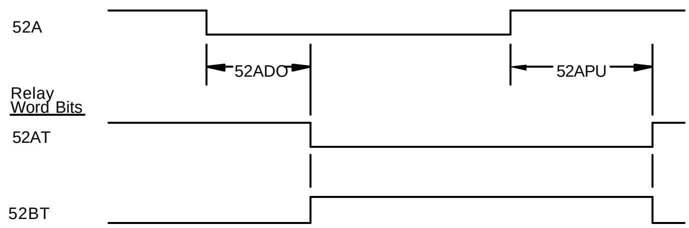

Figure 17 Effect of 52APU and 52ADO Settings on Relay Word Bits 52AT and 52BT

The relay in this example generated 10 event reports in just over 20 minutes according to the relay history. In addition to the three events reviewed, there were six event reports triggered by brief downstream B-to-G faults.

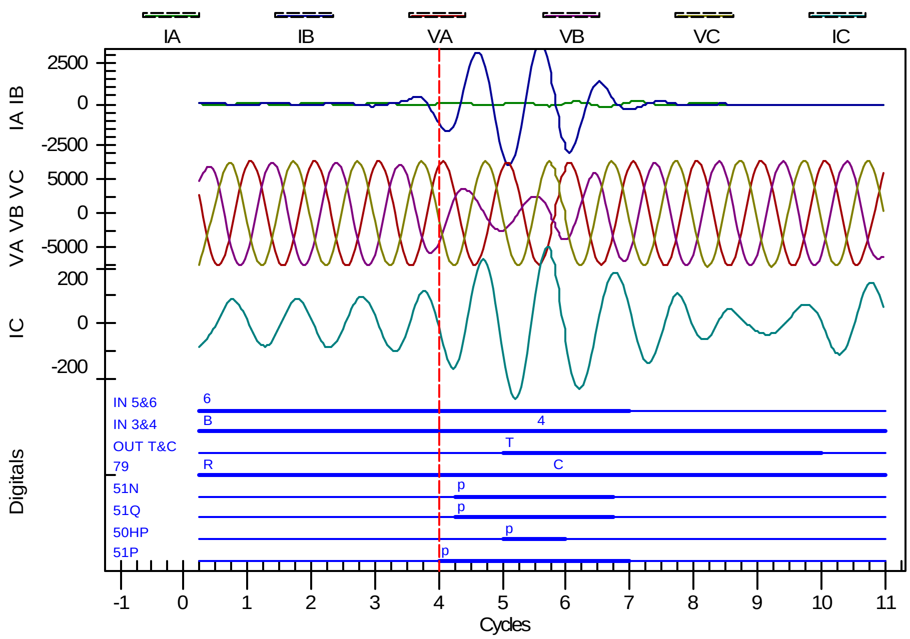

Figure 18 Another Failure of the Interrupter Recorded by Event Reports

The oldest event in the history buffer had a time stamp 11:47:33.395 (shown in Figure 18). This was a B-to-G trip. The reclose operation was successful for that fault. Had we not had a reclose failure later, we might not have investigated this first event report since it appeared at first glance to be a normal trip and reclose event. Further investigation proves that the C-phase interrupter experienced a problem during that initial trip as well. During that event, however, the reclose occurred before the fault evolved into a larger problem. Using the analytic software to calculate phase current and symmetrical component magnitudes, shows that there was more than enough current (1.3 A C-phase and $3I_O$) to assert the revised recloser failure logic.

In summary, analysis of this series of event reports:

- Reviewed the anticipated protection system behavior for a given fault
- Used simple analysis techniques and analytic software to unravel complex event details
- Verified correct operation of the relay
- Revealed a recloser failure and the need for maintenance on the C-phase interrupter
- Showed two occurrences of the interruption problem, indicating that routine event analysis can expose problems such as these before they become more extreme
- Identified a weakness in the as-set trip failure settings, and provided data to develop an improved set of settings and logic that would have identified this problem the first time, notified SCADA, and locked out the problem equipment
- Highlighted the need for safety improvements through the use of manual close operation time delays and recloser failure lockout
- Demonstrated the need for cold load pickup logic to prevent misoperation on inrush
- Illustrated the power of multifunction relays and programmable logic in developing solutions to each problem identified in the event reports

The analytic assistant software generated COMTRADE files that can be used to test the improved logic, or new relays, for this actual system fault. These files and the event records can be stored as documentation of a relay test.

The remainder of this paper briefly reviews a wide variety of actual field cases and the event reports used to analyze them.

EXAMPLE 1: BREAKER AUXILIARY CONTACT BOUNCE DEFEATS RECLOSING

This is an event report from a distribution relay that was expected to have three reclose operations and four trips before going to lockout. Instead, it went to lockout following the second trip operation. An excerpt of the second trip report is shown below. The relay is set to trip by phase time-overcurrent (51T), high-set instantaneous (50H), and low-set instantaneous element (50L) on the first trip and the last shot. The low-set first trip is for saving downstream fuses. The relay last shot is enabled at lockout and the low-set element is allowed to trip following close operations from lockout for safety. From the digital data below, we notice that the only overcurrent element asserted at the time of the trip is the low-set instantaneous element (50L). Why would that element be allowed to operate on the second trip? The 50L element is supervised by the relay shot counting bit (79SH). Notice the IN6 column that is monitoring a 52a auxiliary contact shows a one-cycle long bounce during the first reclose (close-open-close). The relay interprets this opening as a manual or SCADA trip, and drives its shot counter to last shot. When the 52a contact closes, the low-set instantaneous element is allowed to trip. The substation maintenance supervisor reported that this recloser did not have the 52a auxiliary cam adjusted for full travel. In newer relays, this breaker problem can be masked by programming a debounce time for the optoisolated input monitoring the 52a contact.

```
=>eve 2

Whiteside Cct. 950821                          Date: 8/17/97     Time: 13:11:56.500

FID=SEL-151-R414-V656rp1rqys-D951013-E2

P    Q  N   I    Out  In

555T 55 555 D 7B T13A 135
100C 10 100 E 9K &&&L &&&
 LHI     LH M  R C24R 246

.
.
.
.... .. ... . C. C... .4B
.... .. ... . C. C... .BB
.... .. ... . C. C... .BB
pT.. .. ... . C. C1.. .BB

pT.. .. ... . C. C1.. .BB
pT.. .. ... . C. .1.. .45  |  IN6 = 52a
pT.. .. ... . C. .1.. .45  |  One cycle 52a bounce increments shot
pT.. .. ... . C. .1.. .45  |  counter to last shot

PT.. .. ... . C. .1.. .B5
pT.. .. ... . C. .1.. .BB
pT.. .. ... . C. .1.. .BB
pT.. .. ... . C. .1.. .BB

pT.. .. ... . C. .1.. .BB
pT.. .. ... . C. T1.. .BB  |  TR = 50H + 51T + V
pT.. .. ... . C. T1.. .BB  |  V  = B*E*F = 50L*IN5*79SH
pT.. .. ... . C. T1.. .4B  |

PT.. .. ... . C. T1.. .4B
pT.. .. ... . L. T1.. .4B
pT.. .. ... . L. T1.. .4B
pT.. .. ... . L. T1.. .4B
```

EXAMPLE 2: LOW SUBSTATION BATTERY DC VOLTAGE DEFEATS RECLOSING

This event report is from a distribution relay that is programmed to reclose three times, but instead went to lockout during the first trip event. This relay has a programmable drive-to-lockout equation (79DTL), and one of the conditions is !IN102 (not-IN102), where IN102 is wired to a reclosing enable-disable control switch. At the beginning of the event data shown, the trip output (OUT1) is closed. Notice the optoisolated inputs, including the reclose enable, dropping out. From the second portion of the event report, the protection and control elements, we see that the reclosing element (79) goes to lockout (L) at the instant that IN102 deasserts. What made the inputs drop out during the trip? Notice the station battery voltage (Vdc) column dropping from 38 to 32 volts in just two cycles. Also, in the digital element section, note the dc undervoltage element (L in the Vdc column) asserting as the voltage drops below its 36 Vdc pickup. This indicates there is a problem with the station battery. Nominal voltage for this substation is 48 Vdc. The 48 Vdc level-sensitive inputs of this relay assert for voltages between 38.4 Vdc and 60 Vdc; the inputs turn off at lower voltages to avoid misoperation for dc ground faults. The 48 Vdc power supply is rated for 20 Vdc to 60 Vdc. About two-cycles after this breaker opens, the station battery voltage returned to around 50 Vdc.

Detecting dc grounds plays a critical role in improving performance and eliminating misoperations of the protection system. Monitor DC grounds using level-sensitive inputs on relays and event reporting.[13]

```
EASLEY S.C. DEL#3                Date: 08/26/00    Time: 17:11:01.666
CKT. GLENWOOD D3123

FID=SEL-351-R205-V0-Z001001-D19990827       CID=A28C

                                                                 Out  In
      Currents (Amps Pri)           Voltages (kV Pri)            1357 135
    IA    IB    IC    IN    IG     VA     VB     VC     VS Vdc Freq  246A 246
.
.
[3]
  -494  -164  2680  2019  2021   -0.0   -0.0   -0.0   -0.0  38 60.00 1... bb6
   652   586 -4222 -2989 -2985   -0.0   -0.0   -0.0   -0.0  38 60.00 1... bb6
   494   164 -2681 -2020 -2023    0.0    0.0    0.0    0.0  38 60.00 1... bb6
  -652  -587  4223  2989  2984    0.0    0.0    0.0    0.0  37 60.00 1... bb.
[4]
  -497  -169  2707  2038  2041   -0.0   -0.0   -0.0   -0.0  36 60.00 1... bb.
   651   586 -4224 -2990 -2987   -0.0   -0.0   -0.0   -0.0  35 60.00 1... bb.
   494   165 -2685 -2021 -2026    0.0    0.0    0.0    0.0  34 60.00 1... bb.
  -651  -586  4220  2987  2983    0.0    0.0    0.0    0.0  32 60.00 1... ...
.
.
Protection and Control Elements

51     50 32 67   Dm 27 59     25  81   TS     Lcl Rem  Ltch SELogic
                          V   5   2     ih ZLV               Variable
        P PN      PN  P  P1   9S  7135 7mo lOd 1357135701357
ABCPNGQPP QG PNGQ QG PPSPPQNS VFA B246 9et dPc 24682468C2468 12345678
.
.
[3]
...p.T... .. .... .. ........ ... *... Cr0 ... ............. ........
...p.T... .. .... .. ........ ... *... Cr0 ... ............. ........
...p.T... .. .... .. ........ ... *... Cr0 ... ............. ........
...p.T... .. .... .. ........ ... *... Cr0 ... ............. ........
[4]
...p.T... .. .... .. ........ ... *... Cr0 ..L ............. ........
...p.T... .. .... .. ........ ... *... Cr0 ..L ............. ........
...p.T... .. .... .. ........ ... *... Cr0 ..L ............. ........
...p.T... .. .... .. ........ ... *... Lr3 ..L ............. ........

SELogic Control Equations:

79DTL = OC + LB3 + !IN102

Global Settings:

DCLOP =  36     DCHIP =  60
```

EXAMPLE 3: LOOSE CT LEAD IN JUNCTION BOX CAUSES GROUND RELAY TRIP

While increasing load on a new transformer, a transformer differential relay produced a number of short duration events and then tripped by ground time-overcurrent element on Winding 1, the high side of the transformer. The transformer is delta connected on the high side, with wye-connected CTs.

Using analytic software to plot the waveforms, it is evident that there are several sudden drops in measured current on the Winding 1 C-phase input (see Figure 19). These correspond to increases in false residual current calculated by the relay. This event indicates a problem in the Winding 1 C-phase CT circuit and is most likely from wiring problems, including loose or high-resistance connections, temporary short circuits caused by frayed wire, or defective shorting switches. In this case, a loose lead in a junction box at the top of the transformer unit was found with evidence of arcing.

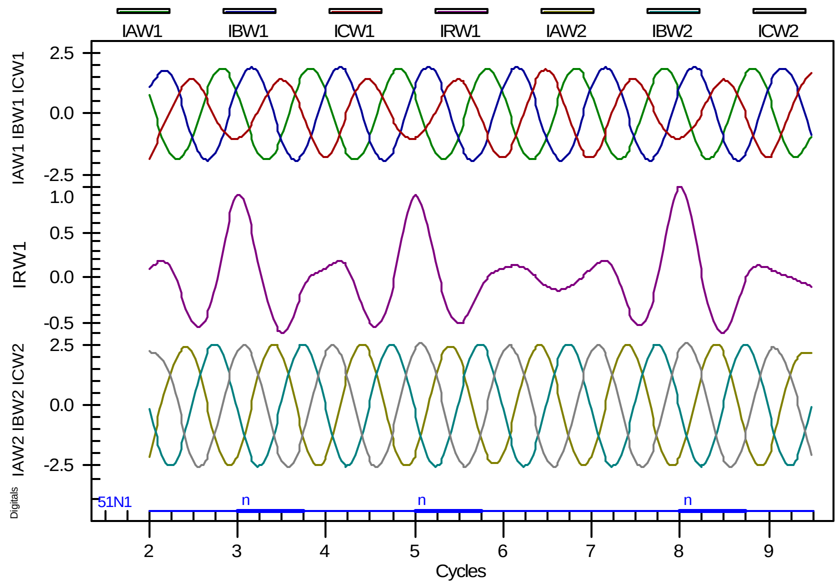

Figure 19 Sudden Drop in Measure ICW1 Causes False Residual Current

EXAMPLE 4: INCORRECT PHASE ANGLES ENTERED IN TEST SET

Event reports are commonly used to determine why a test is not working as anticipated. An example is shown below, where a technician was having trouble with a Zone 1 phase distance element and fault location test. Triggering, retrieving, and plotting an event report as either oscillograph or phasor data reveals quickly that the phase angles of VB and VC are in phase and causing the difficulty. See Figure 20.

Triggering an event report and then viewing the phasor data should be a routine part of commissioning tests, as it makes CT and PT wiring problems easy to identify. Incorrect taps, rolled phases, and opposite polarity are all readily visible.

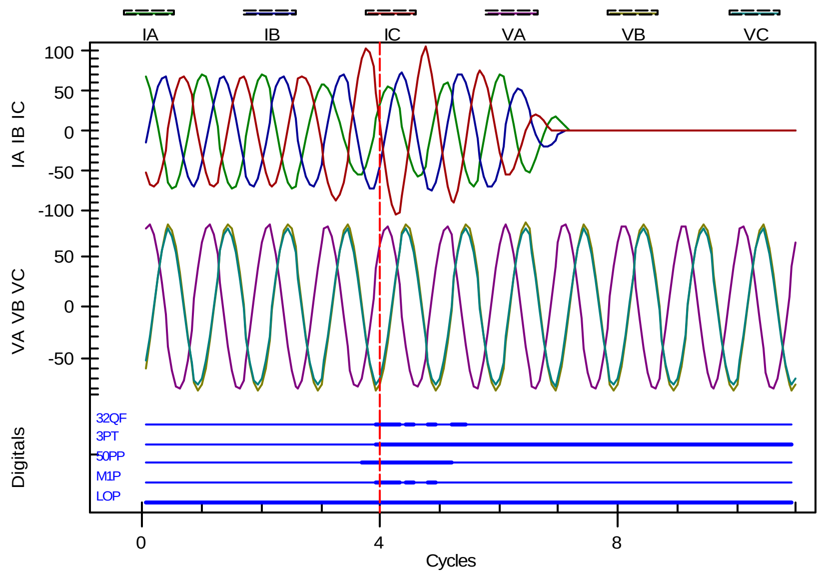

Figure 20 VB and VC Test Voltages in Phase

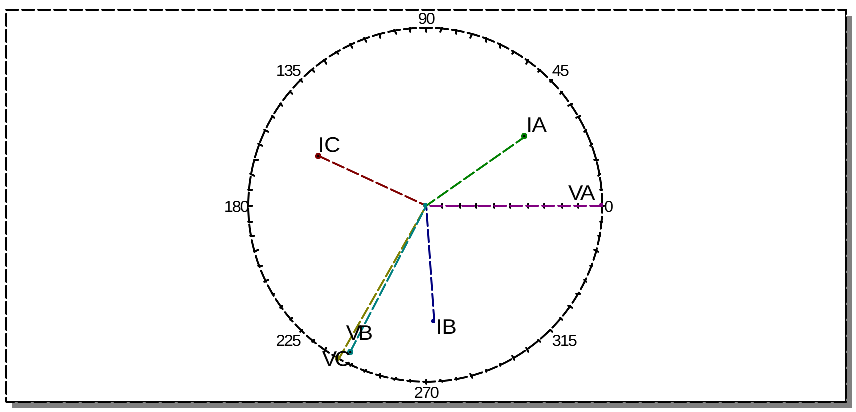

Figure 21 Phasor Plot of Test Voltages and Currents

It is evident from the phasor plot in Figure 21 that the C-phase voltage angle is set incorrectly.

EXAMPLE 5: LOOSE PT FUSE CAUSES LOSS-OF-POTENTIAL MISOPERATION

A primary and backup relay tripped and generated several event records. There was no system fault at the time of trip. The relays are different models, but are both distance relays with directional overcurrent. The primary relay is used in a directional comparison blocking (DCB) scheme and will trip if a fault in Zone 2 is detected, and no blocking signal is received. The backup relay provides step-distance protection and trips instantaneously for Zone 1 faults. The trip from both relays was from a false apparent impedance caused by a loose PT secondary fuse, as shown in Figure 22. The same secondary bus potentials serve both relays.

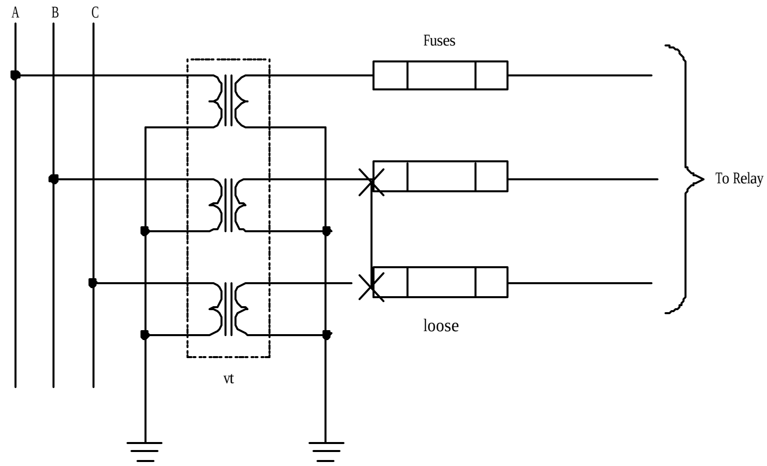

Figure 22 B-Phase and C-Phase Shorting Together

Because a blown fuse would result in a loss of polarizing inputs to the relays, detection of this condition is desirable and enabled in both relays. However, from the oscillograph data in Figure 23 and Figure 24, note that the loss-of-potential (LOP) element asserts after the phase distance element trips. There is a short delay, set to 3 cycles, before the LOP element is asserted for unbalanced conditions. In the primary relay, a loss-of-potential is detected when negative-sequence voltage (V2) is greater than 14 volts and negative-sequence current (3I2) is less than 0.5 A. In the backup relay, a loss-of-potential is detected when zero-sequence voltage (V0) is greater than 14 volts and zero-sequence current (I0) is less than 0.083 A. Once asserted, LOP is used to block distance and directional elements that rely on healthy voltage signals. This event emphasizes that early loss-of-potential logic was designed to protect distance elements from misoperating during system faults after an LOP condition was detected, while overcurrent fault detectors need to be set above load to prevent misoperation when the LOP condition first occurs.

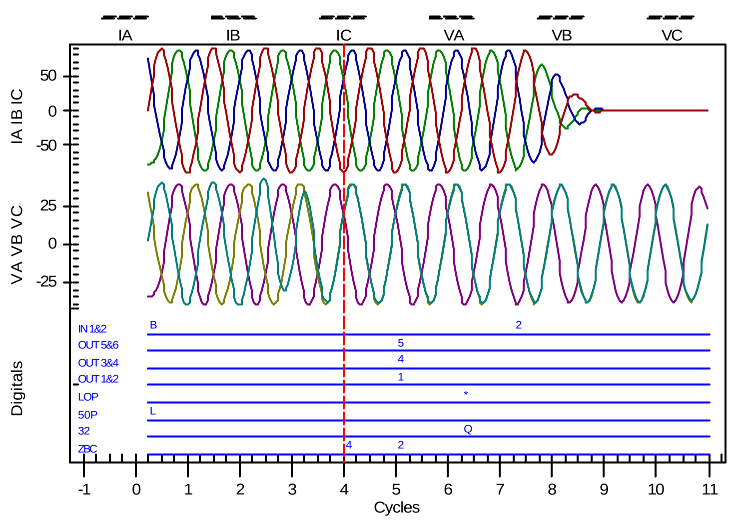

Figure 23 Loose PT Fuse Causes Misoperation of the Primary Relay

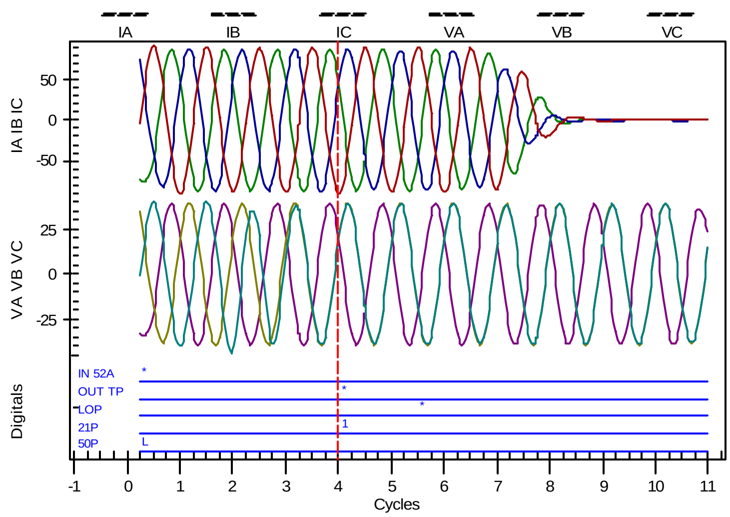

Figure 24 Loose PT Fuse Causes Misoperation of the Backup Relay

In these events, the fault detector (50L) is picked up for load current. In order for the loss-of-potential logic to prevent operation during load, the fault detector elements should be set above expected load currents (always check that the minimum overcurrent thresholds are set below minimum fault levels to ensure correct distance relay operation). New LOP logic operates in less than one-half cycle, so distance element security is much less dependent on the supervisory overcurrent elements.[14] The fault detectors may be set to their minimum pickup using this new logic.

EXAMPLE 6: INCORRECT SETTINGS CAUSE FAILURE TO TRIP

A phase-to-phase fault occurred on a 69 kV line. The primary relay did not operate, nor did it generate an event report. The fault was cleared by a backup relay at the same terminal. A status check of the relay self-testing indicates the relay is normal. An event report was manually triggered, and the first cycle of data is shown below.

```
Substation L619                                      Date: 01/01/96    Time: 09:18:50.601

FID=SEL-321-R408-V656112pb-D950323

    CURRENTS (pri)           VOLTAGES (kV pri)      RELAY ELEMENTS  OUT   IN

                                                   ZZZZZZO  555566L 1357 1357
                                                   ABCABCO 31110770 &&&& &&&&
   IR     IA     IB     IC     VA      VB      VC  BCAGGGS 2NQPPNQP 2468 2468

    -1    -12     13     -2    28.8    10.2   -39.0 ....... Q......* .... ....
    -1     -8     -7     15    28.3    39.2   -11.0 ....... Q......* .... ....
     0     12    -14      2   -28.8   -10.2    39.0 ....... Q......* .... ....
    -0      8      7    -15    28.3   -39.2    11.0 ....... Q......* .... ....
.
.
Z2F    = 0.00    50QF  = 0.50    Z2R    = 0.10    50QR  = 0.50    a2    = 0.08
.
ELOP   = Y       LOPD  = 1.00    50M    = OFF     59QL  =  0.00   59PL  =  0.00
```

When troubleshooting a problem, start at the digital relay elements and determine what is picked up and if those elements should be picked up. In this case, with the breaker open and normal bus voltages applied, the loss-of-potential element (LOP) is asserted and the negative-sequence directional element is forward. Why would the relay declare a loss-of-potential when the bus voltages appear balanced at 40 kV line-to-neutral? In this case, the settings for the LOP element are incorrect.

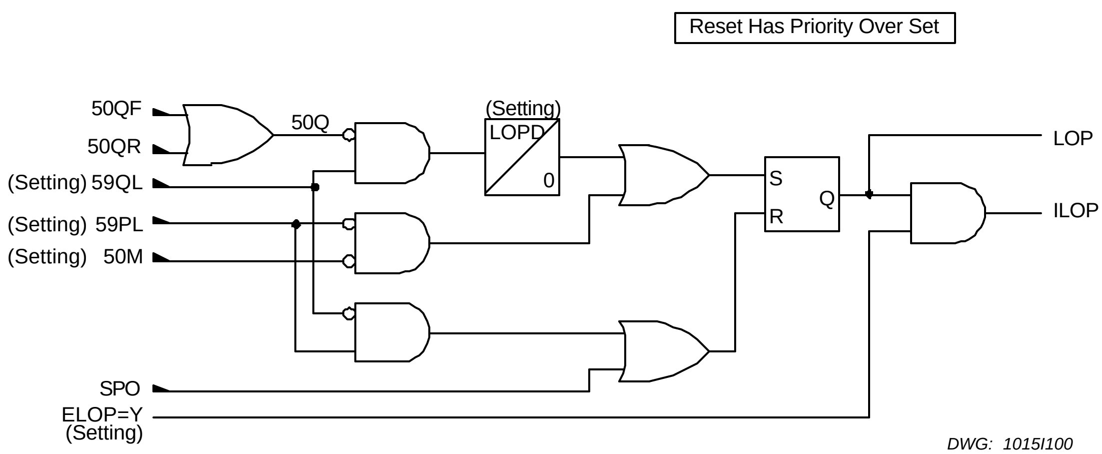

Figure 25 Loss-of-Potential Logic Diagram

Figure 25 shows that an LOP condition is declared when the negative-sequence voltage (V2) exceeds the 59QL setting and the negative-sequence current (3I2) is less than the 50QF and 50QR unbalance detectors. With 59QL set to zero, any slight system voltage unbalance is interpreted as a loss-of-potential. A typical 59QL setting is 14 V. New LOP logic requires no user settings.[14] This event emphasizes the critical role of thorough commissioning tests in finding problems such as incorrect settings prior to the relay being put into service.

EVENT 7: UNCONVENTIONAL BUS DESIGN CAUSES LOSS-OF-POTENTIAL MISOPERATION

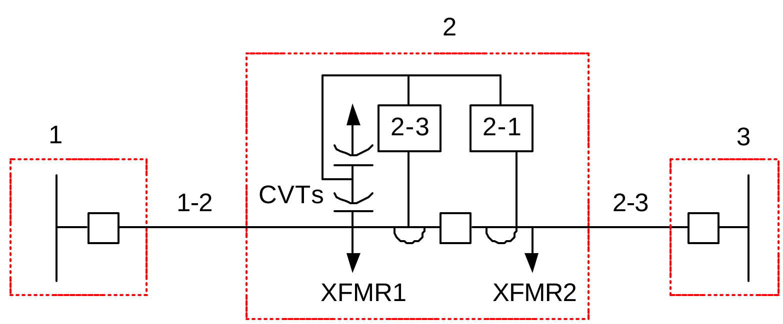

Figure 26 Relays for Two Lines Share One Set of CVTs and One Breaker

Line relays for both lines in Figure 26 use a DCB scheme. One breaker and one set of CVTs serve both line terminals at Substation 2. The most unusual thing about this configuration is that one relay has line-side potentials (2-1), while the other relay (2-3) uses bus-side potentials that go dead during the adjacent line's reclose open intervals.

A fault occurred close to Terminal 1. The relays on Line 1-2 correctly tripped, and Relay 2-3 correctly blocked the relay at Terminal 3 for the out-of-section fault. The CVTs de-energized during the reclosing open interval. The loss-of-potential logic for both relays set during the open interval and did not reset when the line closed into an unbalanced fault voltage. The result was that Relay 2-3 did not send blocking with reverse distance or directional overcurrents to Terminal 3 for the second fault, and that terminal misoperated for the out-of-section fault. In Figure 27, the 67N2 element is an overcurrent element that, because of the loss-of-potential, is nondirectional and also programmed to squelch carrier blocking.

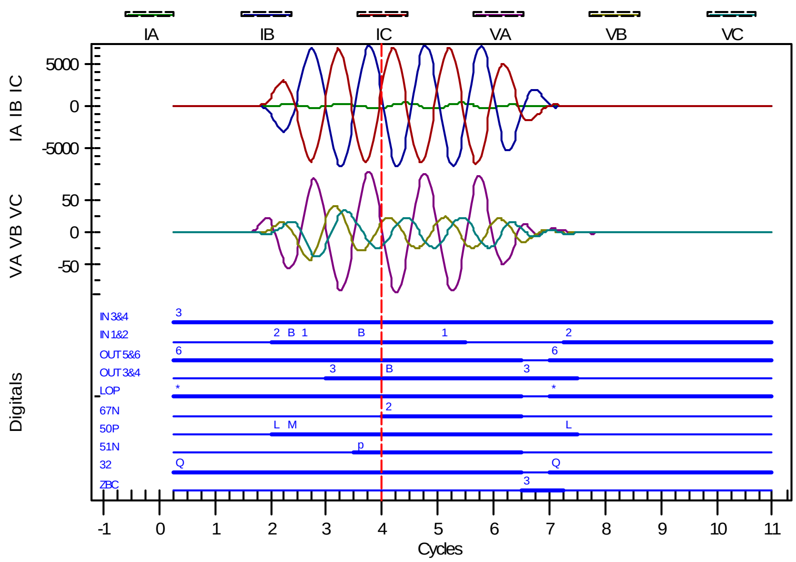

Figure 27 Loss-of-Potential Prevents the Sending of Blocking for Reverse Fault

When using unconventional designs, take special care to investigate relay logic and its correct operation for the application. Commissioning testing plays a large role in simulating real-world fault conditions to test the relay application. In this case, programmable logic in the relay could be used to ensure that the LOP logic does not assert during breaker open conditions. Additionally, new LOP logic resets during breaker open conditions, and will not set during the reclose operation.[14]

EXAMPLE 8: RADIO RETRY FEATURE CAUSES MISOPERATION

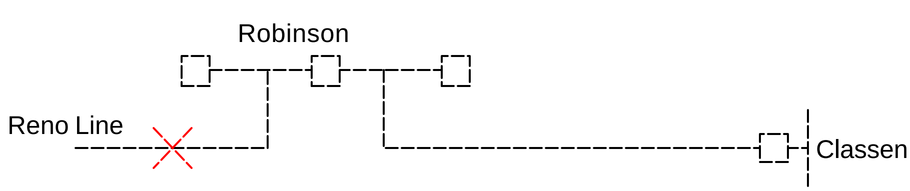

Figure 28 Robinson–to–Classen Line Uses Spread-Spectrum Radios

A fault occurred on the Robinson-to-Reno line. This is the first fault to have occurred in the vicinity of the Robinson-to-Classen line. The Classen line was using a hybrid trip scheme (combination of permissive overreaching transfer trip and DCB) with digital relay-to-relay logic and spread-spectrum radios. The fault was an out-of-section, line-to-line-to-ground fault behind the Robinson terminal. The Robinson terminal is expected to see a reverse fault and send a blocking signal to Classen. This occured, and the blocking signal arrived at Classen approximately 3.25 cycles after the fault initiation. The Classen terminal is expected to see a forward fault and send a permissive signal to Robinson. This also occured, but the permissive signal arrived approximately 0.8 seconds after it was sent by Classen. The late permissive signal is received long after the initial fault has cleared, and the Robinson line terminal trips because of a received permissive trip signal while no reverse elements are asserted (hybrid scheme logic).

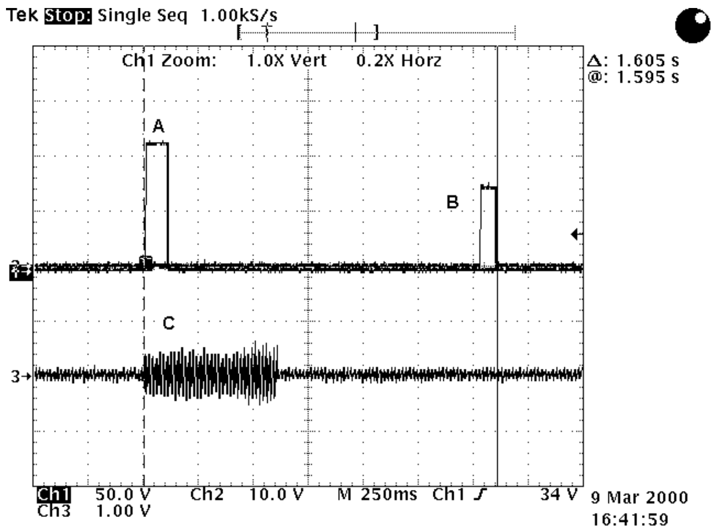

Figure 29 Radio Retry Demonstrated

The reason for the communications signal delay was a Retry Time Out setting in the spread-spectrum radio. With a setting of 255, the master radio considers a message successfully sent if it receives an acknowledgement from the slave radio for one in 255 retries. Said another way, if the master sends a packet of data and receives no acknowledgement, it will continue to resend that same message for about 2.5 seconds, since each transmission takes approximately 10 ms. While this retry feature is very useful in SCADA, metering, or other noncritical applications, it must be disabled if the radios are used with relays for pilot scheme tripping. The oscilloscope screen capture in Figure 29 depicts the keying input on Trace A, the received digital output on Trace B, and noise on Trace C. The packet resend feature is shown with an incurred delay of 1.5 seconds. Radio settings were changed to disable this retry feature, and the relay tripping scheme was changed to a pure permissive overreaching transfer trip scheme.

EXAMPLE 9: THOROUGH COMMISSIONING TESTS FIND SETTINGS ERROR

A technician is performing commissioning tests on a distance relay. No spare 52a or 52b contacts are available at the breaker, so no breaker status is wired to the relay. The breaker status relies on current only. All tests, including phase distance and ground overcurrent elements, have performed as expected. However, when the technician gets to the ground distance element (Z2G), the relay does not operate when the fault values are applied. A good way to troubleshoot a problem such as this is to find the logic diagram for the element under test (Z2G) and determine all the required supervisory conditions that must assert in order for the element to operate. By triggering an event report while test quantities are being applied to the relay, the technician was able to determine which critical element was missing.

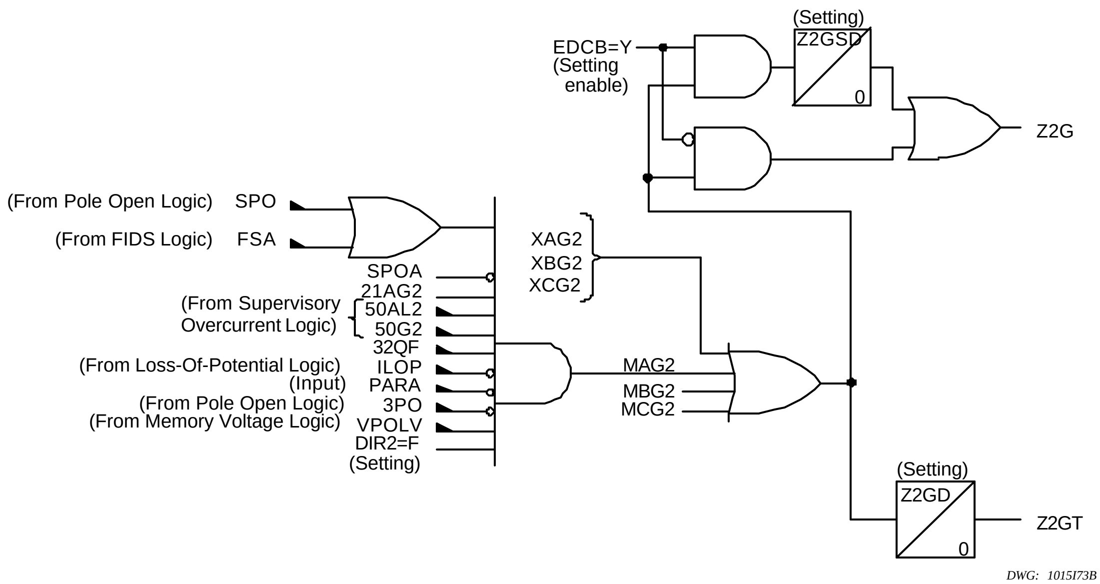

Figure 30 Zone 2 Ground Distance Element Logic Diagram

By observing the phasors using analytic software, establish whether correct phase and sequence magnitudes and angles are applied to the relay to pick up the Z2G element. Use Equation 2 to calculate whether Zone 2 will assert for the applied test quantities.[2]

$$Z_{AG} = \frac{V_A}{I_A + k0 \cdot I_R} \qquad \text{Equation 2}$$

where: Z_{AG} is the apparent impedance, I_A is the test current on the faulted phase, V_A is the test voltage on the faulted phase, I_R is the residual current, and k0 is the zero-sequence compensation factor from the settings.

Using the oscillography of the analytic assistant software, plot the active digital elements that are asserted or change state. It is evident that the one digital element preventing operation of our test is the three-pole-open (3PO) element. If significant pole scatter occurs when a circuit breaker closes, sensitive ground distance elements may operate undesirably because of the unbalanced signals applied. The relay disables the ground distance elements during 3PO condition and for a settable time after the breaker closes. The time is set by the 3POD time-delay setting. In this relay, that setting was set to 2000 cycles. Because the technician turns off the test set between tests, and the relay is looking at current only as an indication of breaker status, the 3PO element asserts. When the test is started and the current detector (50L) is exceeded, the dropout delay (3POD) begins timing; 2000 cycles later the 3PO element expires, and ground distance elements are enabled. A typical setting for 3POD is 1.5 cycles. Had this not been caught during commissioning, and the 50L element been set above load, 3PO would have been asserted until a fault occurred. This would have delayed our high-speed communications-assisted ground fault tripping by more than 2 minutes. This example emphasizes the usefulness of event reports and thorough commissioning tests.

EXAMPLE 10: EVENT REPORT IDENTIFIES CARRIER FAILURE

In a directional comparison unblocking scheme, frequency shift carrier equipment is typically used to provide communications between the two ends of the line. A guard signal is continuously transmitted on one frequency. When a fault occurs, the protective relay signals the carrier equipment to shift from the guard frequency to the permissive frequency. The receiver at the other end of the line monitors these signals. There is a short transition period in which there is no guard signal and no permissive trip signal received. If the permissive trip signal arrives momentarily, then a normal trip occurs. If the permissive trip does not arrive, then a time window is provided that allows a trip without receipt of the permissive signal if the relay sees the fault. Therefore, in a DCUB scheme, if the communications equipment at the remote terminal fails at the same time an out-of-section fault occurs that is within the reach of the forward-overreaching elements, an incorrect trip can occur. This event report displays this very problem.

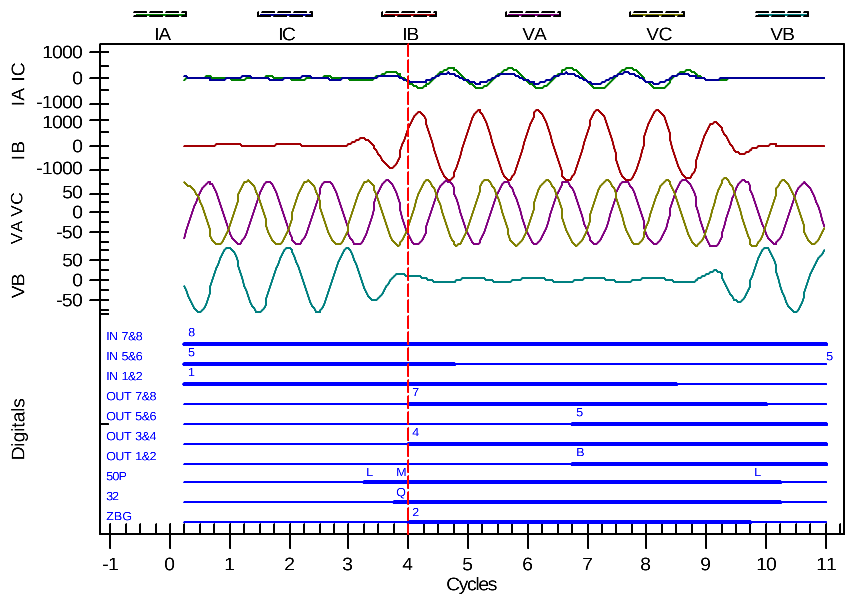

Figure 31 Failure of Communications Equipment at the Time of Fault

In the event in Figure 31, permission to trip (IN6) is never received because the fault is a remote bus fault, behind the remote line terminal. The guard frequency is monitored with an a-type contact from the carrier equipment that is wired to assert a relay input (IN5) when there is no loss-of-guard, and open or deassert IN5 upon the loss-of-guard. Around cycle 4.75, IN5 drops out.

As soon as loss-of-guard is detected, with no corresponding permission to trip received, the relay times on a security timer (set to 2 cycles in this relay). Once this expires, a window of opportunity (set to 7 cycles in this relay) allows a trip output to occur if any overreaching elements in the relay tripping equation pick up. A trip did occur because the Zone 2 ground distance element was asserted for the remote bus fault. This misoperation was caused by the loss-of-carrier guard during an out-of-section fault.

EXAMPLE 11: EVENT REPORT CAPTURES SYMPATHETIC TRIP

This is an event report from a relay that picked up and tripped on overcurrent. The overcurrent condition was not from a fault on the protected line, but from low inertia motor loads that stalled for an undervoltage condition caused by an out-of-section fault on an adjacent feeder. Reference 15 discusses the nature of sympathetic trips of distribution feeders. The authors propose two schemes to enable a microprocessor-based relay to recognize that the fault is out-of-section and then block overcurrent operation until motors can be picked up. Note that the phasor plots confirm the paper's theory. Pre-fault load shown in Figure 32 is followed by a brief reverse fault, and finally a high magnitude starting or stalled motor current.

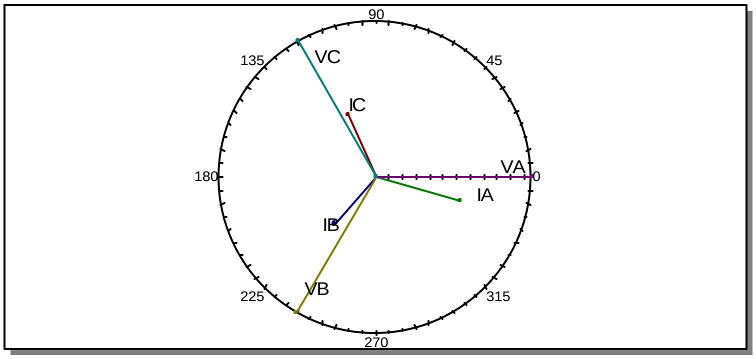

Figure 32 Pre-Fault Load on a Distribution Feeder

A directional element in the relay is used to sense the reverse fault. This directional element picks up a programmable timer with a zero pickup delay and a long dropout delay. The delayed dropout is then used to modify the tripping characteristic (increase taps as in the cold load pickup example of Figure 16) to allow the relay to be secure during higher load and unbalance current while the feeder loads restart. Once the timer expires, the relay returns to its usual, more sensitive settings.

This event, once it is read by analytic software, provides COMTRADE test files for replaying the event into relays in order to test settings solutions.

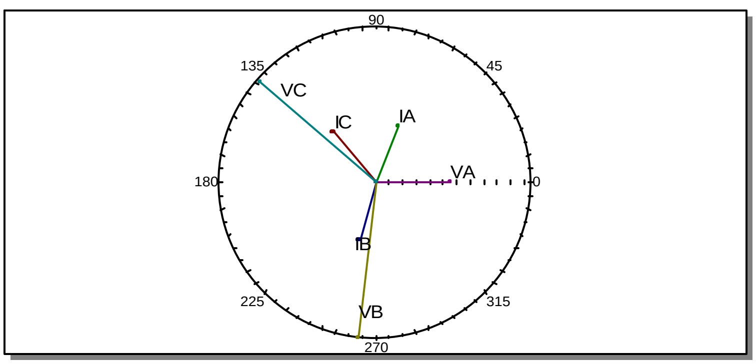

Figure 33 Momentary Reverse 1AG Fault Detected on Adjacent Feeder

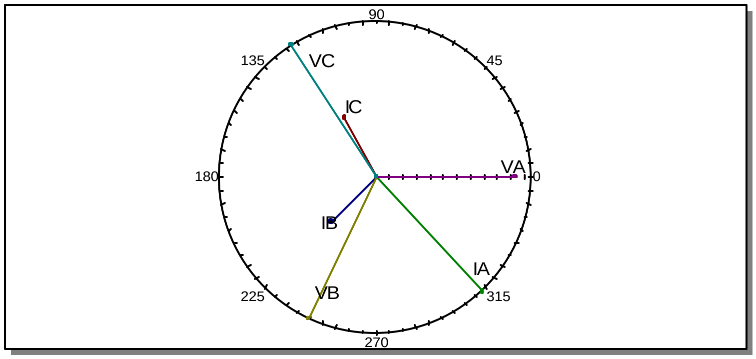

Figure 34 Phasors During Sympathetic Trip Operation

EXAMPLE 12: EVENT REPORT CAPTURES DCB SCHEME DETAILS

Monitoring carrier signals in event reports can reveal significant problems. The following event report provides examples of three DCB scheme problems.

In DCB schemes, a short carrier coordination time delay is used to prevent overreaching elements from tripping prior to the receipt of blocking for out-of-section faults. Event reports will show the receipt of blocking and can be used to judge the selection of the coordination time delay.[16] In Figure 35, carrier blocking is received (BT) at the beginning of Cycle 4. The overreaching instantaneous Zone 2 element picks up 0.75 cycle later. The carrier coordination timer delays the 21P assertion and enabling (2 in the 21P column) by an additional 1.5 cycles. Using this information, the carrier coordination timer can be reduced to improve in-section fault clearing times.

Once blocking is received by the local relay, carrier holes can cause misoperation of the overreaching elements that are already asserted. Event reports capture the momentary dropout of the carrier blocking signal, or carrier hole. Debounce timers, built-in scheme settings, or other solutions extend the received carrier blocking to ride through these momentary carrier dropouts.[17] In Figure 35, a carrier hole is seen for 0.25 cycle, just after the blocking signal is received.

When a reverse fault condition expires, DCB schemes typically extend the carrier blocking sent to the remote line terminal to provide security for current reversals. After a remote reverse fault condition is cleared, a race between the dropout of the local overreaching elements (that are armed for tripping) and the remote relay that sends carrier blocking begins. Figure 35 shows a misoperation because the remote relay stopped sending carrier blocking 0.25 cycle before the local overreaching elements dropped out. A longer carrier extension time delay at the remote relay solves this problem.

```
WORMSER->LAREDO 138KV PRI RELAY           Date: 3/1/99      Time: 21:40:21.066

FID=SEL-121G5-R411-V656mptr12syzf2-D931105-E2

              Currents                  Voltages      Relays Outputs Inputs
               (amps)                     (kV)
                                                      52265L TCAAAAA DPBD5E
  IPOL     IR     IA     IB     IC     VA     VB     VC 011710 PL1234L TTTC2T
                                                      P3PNNP              A

     3     -3    154    -96    -55   74.2  -68.8   -5.9 ...... ....... ....*.
    -3     -1     20    123   -141   36.0   47.5  -83.4 ...... ....... ....*.
     0      4   -156     98     55  -74.2   68.8    5.9 ...... ....... ....*.
     0      1    -20   -123    143  -35.9  -47.5   83.4 ...... ....... ....*.

     0     -4    156    -98    -58   74.2  -68.8   -5.9 ...... ....... ....*.
     0      0     18    123   -143   35.9   47.5  -83.4 ...... ....... ....*.
     0      3   -154     98     58  -74.2   68.8    5.9 ...... ....... ....*.
     0      0    -18   -123    143  -35.9  -47.5   83.4 ...... ....... ....*.

    -3     -2    154    -98    -58   74.2  -68.8   -5.9 ...... ....... ....*.
     3     -1     18    123   -143   35.9   47.5  -83.4 ...... ....... ....*.
     3      2   -156     98     58  -74.2   68.8    5.9 ...... ....... ....*.
    -5      1    -15   -121    143  -35.9  -47.5   83.4 ...... ....... ....*.      BT drops out
                                                                                  due to Carrier
     3     -2    156   -101    -58   76.2  -68.8   -5.9 ...... ....... ..*.*.      Hole
     3     82    126    108   -159   21.6   47.3  -83.5 L..... ...*... ..*.*.
    -3      4   -123     88     43  -57.3   70.0    7.2 ...... ...*... ....*.
     0   -358   -541    -45    227   -6.8  -48.0   81.9 H...P. ...*... ..*.*.

     0    -10     78    -76    -13   26.4  -71.0   -8.2 H...P. ...*... ..*.*.
     0    595    931    -25   -305    6.2   48.8  -79.1 H...P. ...*... ..*.*.
     0     35    -33     78    -13  -14.8   70.1    6.8 H...P. ...*... ..*.*.
     0   -615  -1004     48    337   -5.9  -48.2   77.4 H...P. ...*... ..*.*.        Zone 2 delayed
                                                                                    by carrier
     0    -46      8    -86     30   13.1  -69.0   -5.1 H...P. ...*... ..*.*.        coordination
    -3    590   1002    -55   -352    5.8   47.7  -76.1 H..2P. ...**.. ..*.*.        delay
     3     37    -10     91    -48  -12.8   68.1    4.3 H..2P. ...**.. ..*.*.
     3   -582  -1004     63    355   -5.5  -47.5   75.0 H..2P. ...**.. ..*.*.

    -3    -31      5    -91     63   12.7  -67.4   -4.3 H..2P. ...**.. ..*.*.
     0    578   1002    -70   -347    5.8   47.4  -74.2 H..2P. ...**.. ..*.*.
     0     30      0     91    -68  -12.7   66.7    4.0 H..2P. ...**.. ..*.*.     0.25 cycle
     0   -447   -818     48    317  -20.9  -47.3   74.3 H..2P. ...**.. ..*.*.     between BT
                                                                                 and Zone 2
     0    -32     28    -98     48   33.7  -65.3   -2.6 H..2P. *.***.. ....*.     drop out
     0    178    403     20   -247   34.0   46.5  -76.4 L...P. *.***.. ....*.
     0     18    -86    108    -13  -60.5   64.9    2.3 L...P. *.***.. ....*.
     0    -22   -136    -70    189  -32.7  -46.1   78.6 ...... *.*.*.. ....*.

     0     -4    113   -108     -8   67.8  -65.4   -3.7 ...... *.*.*.. ....*.
    -3      2     86     83   -169   33.1   46.4  -79.4 ...... *.*.*.. ....*.
     3      4   -121    108     18  -69.9   65.9    4.6 ...... *.*.*.. ....*.
     3     -1    -70    -91    159  -33.3  -46.7   80.0 ...... *.*.*.. ....*.
```

Figure 35 DCB Scheme Misoperation

EXAMPLE 13: EVENT REPORT IDENTIFIES INCORRECT CT TAP

A distribution relay tripped by phase instantaneous overcurrent. The upstream transformer differential relay tripped by restrained differential element (87R). The feeder relay operation was correct. The transformer relay should not have tripped for the feeder fault.

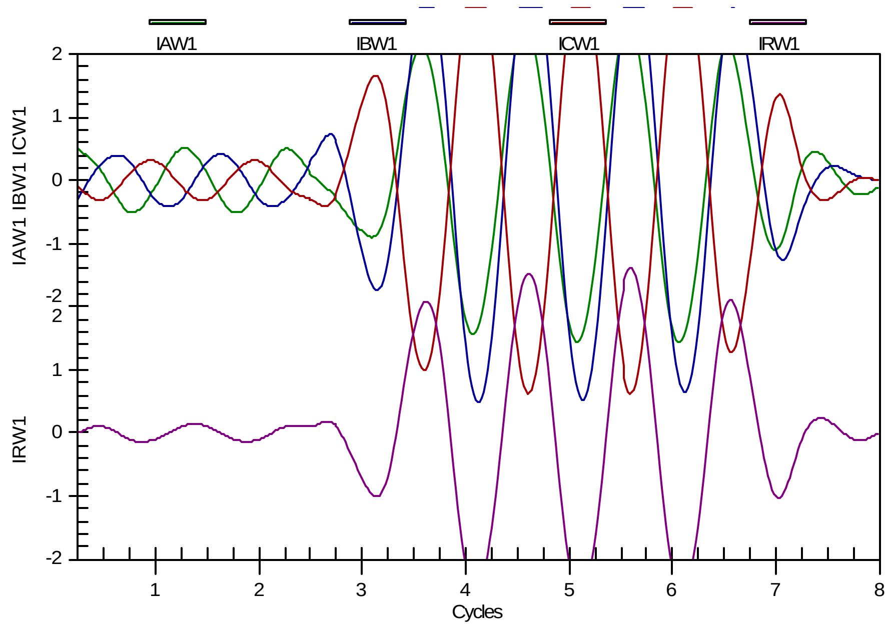

Figure 36 Incorrect CT Tap Causes Trip

Analysis of the event data, shown in Figure 36, identifies a CT problem on the high-side C-phase input (ICW1). Several clues lead to that conclusion. The pre-fault current is noticeably less on ICW1 than the other phases. The pre-fault mismatch, the ratio of operate to restraint current, is 33 percent for differential element three, while the other two elements are zero. The transformer (DABY) and CT (wye-wye) compensation settings isolate the ICW1 as the only phase input that could affect the Element 3 operate quantity and not affect the other elements. During the low-side phase A-to-C fault, residual current measured on the transformer high side is exactly 180 degrees out of phase with ICW1, which indicates the CT circuit on ICW1 was not supplying enough current and the residual compensated for it.

The relay settings indicated a CT ratio of 600/5 on the transformer high side. The C-phase high-side CT was found tapped at 1200/5. This example also emphasizes the use of triggered event reports during commissioning tests for uncovering incorrect taps, rolled phases, and opposite polarity in CT wiring.

EXAMPLE 14: EVENT REPORT SHOWS AN AUXILIARY RELAY CONTACT PROBLEM

A transformer differential relay operated and generated an event report. The only digital elements to assert in the event data were optoisolated input, IN1, and the trip output. This input was connected to an external sudden pressure relay as shown in Figure 37. Product literature for this device warns that a voltage surge can cause arcing across its normally-open output contacts.[18] The event showed that IN2 asserted for a full quarter-cycle. Programmable logic in the relay trips a transformer differential lockout for this input assertion.

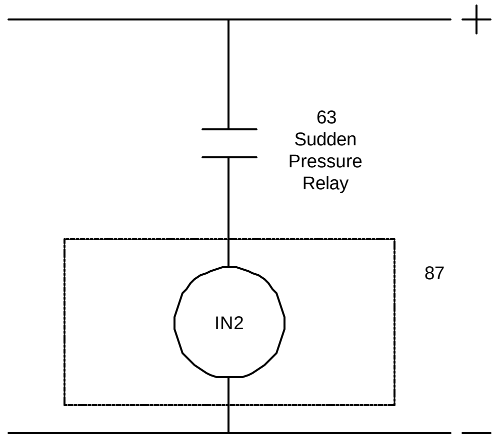

Figure 37 Voltage Surge Causes Arcing Across Sudden Pressure Relay Contact

To prevent misoperations like this from occurring, use the input debounce timers and programmable timers included in microprocessor relays to make input assertion secure for suspect circuits. Alternatively, use the manufacturer's recommended connection in addition to input debounce timers to add security. In that scheme, a normally closed contact from the sudden pressure relay is mounted in parallel with the relay input so that arcing across the normally open contact cannot assert the relay input. A current limiting resistor is installed to protect the sudden pressure relay contacts. The resistance is chosen so that it is much smaller (600 Ohms compared to 12 kOhms), so that when the sudden pressure relay does actually operate, the voltage drop is mostly across the relay input IN2.

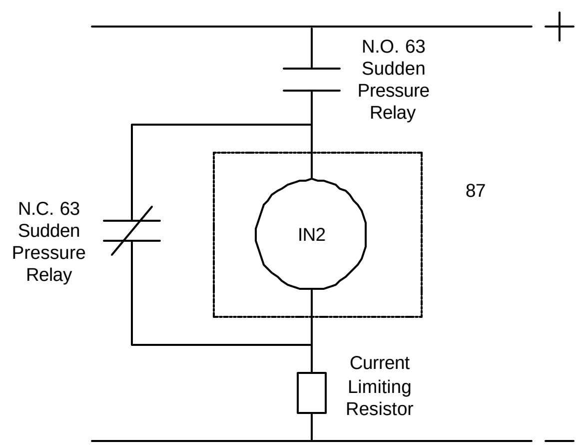

Figure 38 Circuit Modifications and Debounce Timer Add Security

EXAMPLE 15: REMOTE EVENT DATA UNCOVERS SETTING PROBLEM

A 138 kV bus fault at Buttercup substation was cleared locally by high-impedance bus differential relays. The C-phase bus surge arrestor was damaged and its failure is believed to be the source of the fault. The line relay at Whitestone misoperated for this remote bus fault. The Whitestone-to-Buttercup line uses a DCB scheme over power line carrier. See Figure 39.

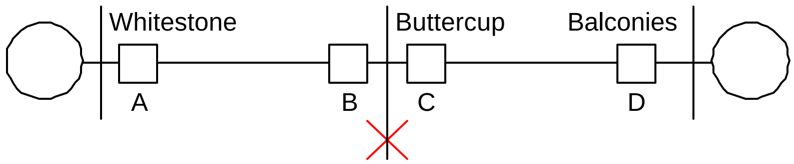

Figure 39 Whitestone-to-Buttercup Line Misoperated for Buttercup Bus Fault

The following is the event retrieved from the primary relay at Whitestone. The relay at Buttercup did not generate a corresponding event report.

```
WHITESTONE 138KV-8870                Date: 09/22/96    Time: 05:56:20.878

FID=SEL-321-R407-V656112pb-D940927

    CURRENTS (pri)            VOLTAGES (kV pri)     RELAY ELEMENTS  OUT   IN

                                                   ZZZZZZO  555566L 1357 1357
                                                   ABCABCO 31110770 &&&& &&&&
   IR     IA     IB     IC     VA      VB      VC  BCAGGGS 2NQPPNQP 2468 2468

    -3    -23     15      5    75.8   -10.1   -65.9 ....... ........ .... 13..
    -1     -6    -18     22   -32.2    82.0   -50.0 ....... ........ .... 13..
     1     22    -16     -6   -75.8    10.1    65.9 ....... ........ .... 13..
    -2      5     17    -23    32.2   -82.0    50.0 ....... ........ .... 13..

    -3    -23     15      5    75.8   -10.1   -65.9 ....... ........ .... 13..
     0     -5    -18     22   -32.2    82.0   -50.0 ....... ........ .... 13..
     2     22    -15     -6   -75.8    10.0    65.9 ....... ........ .... 13..
    -2      5     17    -23    32.3   -82.0    50.0 ....... ........ .... 13..

    -3    -23     15      5    75.8   -10.0   -65.9 ....... ........ .... 13..
    -1     -6    -18     22   -32.3    82.0   -50.0 ....... ........ .... 13..
     1     22    -16     -6   -75.8    10.0    65.9 ....... ........ .... 13..
    -1      5     17    -22    32.3   -82.1    50.0 ....... ........ .... 13..

    -4    -23     15      4    75.9   -10.0   -65.9 ....... ........ .... 13..
  -242     -9    -28   -206   -27.9    86.9   -34.2 ....... ........ ..5. 13..
  -333     12    -33   -312   -80.7     4.9    49.1 ....... ........ ..5. 13..
  1132     27     70   1035    22.0   -93.2    12.2 ....... Q...H... ..5. 13..

   743      0     53    690    89.0     4.4   -18.3 ....... Qpp.H... ..5. 13..
 -1820    -43   -110  -1667   -20.1    94.9    -5.5 ....... Qpp.H... ..5. 13..
  -854     -3    -59   -792   -92.5    -8.4     4.0 ....... Qpp.H... ..5. 13..
  1822     45    115   1662    19.7   -95.0     5.1 .....4. Qpp.H... ..5. 13..

   861      2     59    800    92.2     8.0    -3.9 .....4. Qpp.H... ..5. 13..
 -1806    -48   -117  -1642   -19.8    94.9    -5.4 .....4. Qpp.H... ..5. 13..
  -848     -3    -61   -784   -92.0    -7.9     3.9 .....4. Qpp.H... ..5. 13..
  1806     48    116   1642    19.8   -94.6     5.5 .....2. Qpp.H... 135. 13..

   842      2     62    778    91.9     7.9    -3.9 .....2. Qpp.H... 135. 13..
 -1807    -50   -116  -1642   -19.8    94.5    -5.5 .....2. Qpp.H... 135. 13.8
  -842     -3    -63   -775   -91.9    -8.0     3.9 .....2. Qpp.H... 135. 1..8
  1786     38     95   1654    20.2   -93.6     5.4 .....2. Qpp.H... 135. 1..8

   818      0     35    783    91.2     7.2    -3.7 .....2. Qpp.H... 135. 1..8
 -1435    -14    -39  -1382   -25.2    87.7   -23.6 .....2. Qpp.H... 135. 1..8
.
.
.
```

IN2, the receive carrier blocking input, never asserts. Therefore, after a short carrier coordination delay, the relay trips by overreaching ground distance element (2ZCG).

Using the voltages and currents at the time of trip, we can calculate the measured negative-sequence impedance seen by the Whitestone relay, - 4.125 Ohms. This represents the source impedance behind Whitestone for forward faults. It also represents the remote source impedance as seen by the Buttercup line terminal. To estimate the negative-sequence impedance seen by the Buttercup relay during the bus fault, we take the forward negative-sequence impedance of the Whitestone relay, reverse its sign, and add the negative-sequence line impedance to it. From the relay settings, the positive- and negative-sequence impedance is 0.25 Ohms secondary. Therefore, the negative-sequence impedance seen by Buttercup was + 4.375 Ohms. This value is compared against the relay setting thresholds of the negative-sequence impedance directional element (Z2F and Z2R).[19]

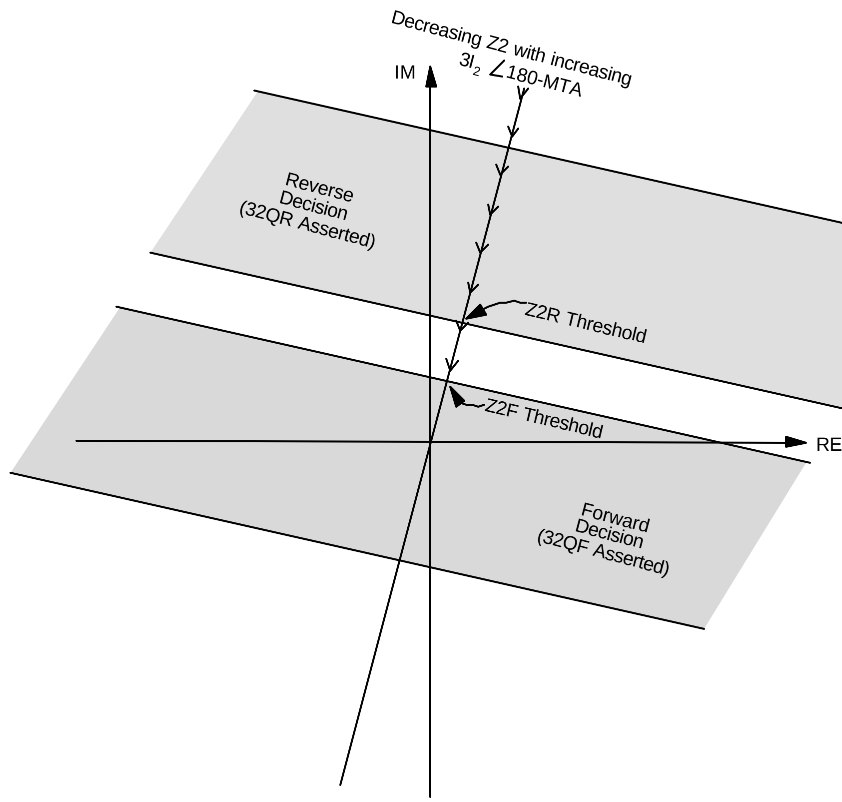

Figure 40 Negative-Sequence Impedance Directional Element Characteristic

If the measured negative-sequence impedance is more positive than the Z2R setting in the relay, the fault is determined to be reverse. If the measured impedance is more negative than the Z2F setting in the relay, the fault is determined to be forward. For fault impedances between the Z2R and Z2F settings, no directional decision is made. This is a settable security band. In the case of the Buttercup relay, Z2R is set equal to 5 Ohms, and Z2F is set equal to 1 Ohm. Therefore, the Buttercup relay failed to send blocking because its directional element never asserted due to incorrect settings. The interesting point of this event example is how remote event report data was used to determine the problem and solution for a separate relay. New relays automatically calculate directional thresholds.[20]

EXAMPLE 16: TRANSFORMER CONNECTION COMPENSATION CAUSES TRIP

A transformer differential relay operated for a distribution feeder fault. The transformer is a wye-delta power bank that uses wye-wye CTs. When conventional CT connections are not used (CTs not connected delta-wye in this case), the current inputs to the differential calculation in the microprocessor relay must be modified internally by settings to compensate for the 30 degree shift of the transformer and to extract zero-sequence current.[21] Figure 41 shows the phasors from the relay event report. For a YDAB transformer (polarity of A-phase connected to the nonpolarity of B-phase), we would expect the Winding 2 currents to lag the Winding 1 currents by 150 degrees. With the transformer connection compensation set to YDAB, the relay compares for differential operate element one IAW2 with (IAW1 – IBW1)/v3, scaled by the differential tap settings. Visually, you can determine from the phasors in Figure 41 that these two quantities will not be opposite in phase angle. In fact, the transformer connection compensation should be set to YDAC. In that case, we expect the Winding 2 currents to lead the Winding 1 currents by 150 degrees. With this setting, the relay compares for differential operate Element 1 IAW2 with (IAW1 – ICW1)/v3, scaled by the differential tap settings. Now the two quantities will be equal and out of phase, resulting in proper operation.

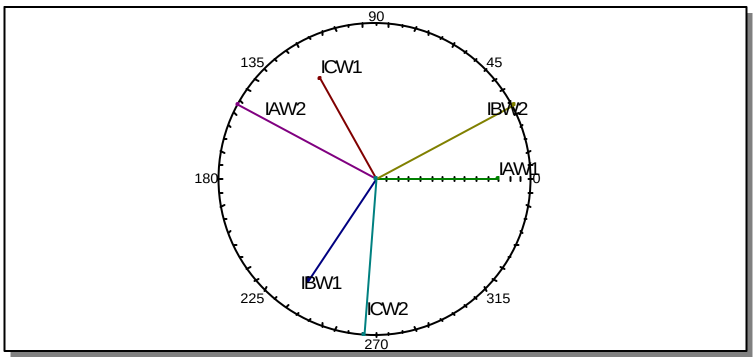

Figure 41 Phasor Data Shows Transformer Connection Compensation is Incorrect

CONCLUSIONS

1. Event reports are useful in monitoring the following protection system components: protective relays, substation batteries, dc wiring, auxiliary tripping relays, circuit breakers, trip and close coils, breaker auxiliary contacts, CTs, ac wiring, PTs, communications equipment, settings and logic, power system models, and more.
2. Event reports can document performance tests.
3. Event reports can meet disturbance monitoring equipment requirements of reliability councils.
4. COMTRADE files generated from event reports provide a powerful tool in the analysis of actual field data, the invention of new technology and solutions, and the testing of relays.
5. Event reports provide data to solve problems.

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BIOGRAPHY

David Costello has a B.S. in Electrical Engineering from Texas A&M University. From 1991 to 1994, he was employed as a System Protection Engineer for Central Power and Light. From 1994 to 1996, he was with Central and Southwest Services, Inc., where he worked as a System Protection Engineer. In 1996, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a Field Application Engineer supporting customers in Texas and Oklahoma. He currently holds the position of Regional Service Manager with SEL, and is responsible for technical support, application assistance, and training for SEL customers in the Southwest United States. He is a member of the planning committee for the Texas A&M Conference for Protective Engineers, and has presented technical papers at the Texas A&M Conference for Protective Relay Engineers.