Fault Analysis Using Protective Relay Digital Fault Records From the Big Rivers Electric Corporation 161 kV System

By

Elmo Price
ABB Inc.
Alpharetta, Georgia

Bob Warren
Big Rivers Electric Corporation
Henderson, Kentucky

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Abstract: Fault analysis using digital and oscillographic fault data recorded in microprocessor relays has become commonplace with the application of this technology. The fault information provided has made short work of the fault analysis task that was once complicated and arduous. This paper reviews the analysis of two interesting faults on the Big Rivers Electric Corporation system that resulted in both correct and undesired operations. The analysis correlates the recorded fault data of two events with the system operation to provide a better understanding of the protection operation and identify appropriate system or protection improvements.

Big Rivers: Big Rivers Electric Corporation is a generation and transmission cooperative located in western Kentucky and headquartered in Henderson. It has 1,459 MW of generating capacity and a 1,200-mile 161 kV transmission system serving the surrounding rural electric cooperatives.

Fault #1

System Configuration

Figure 1 shows the basic line and bus configuration needed for analysis. The Henderson-Reid-HMP&L 161 kV line is protected by a three terminal POTT scheme utilizing a microprocessor system relay at each terminal and pilot communications over microwave. The motor operated disconnect on the transformer high voltage at Henderson accidentally closed into a three phase ground chain. The relays at all terminals tripped.

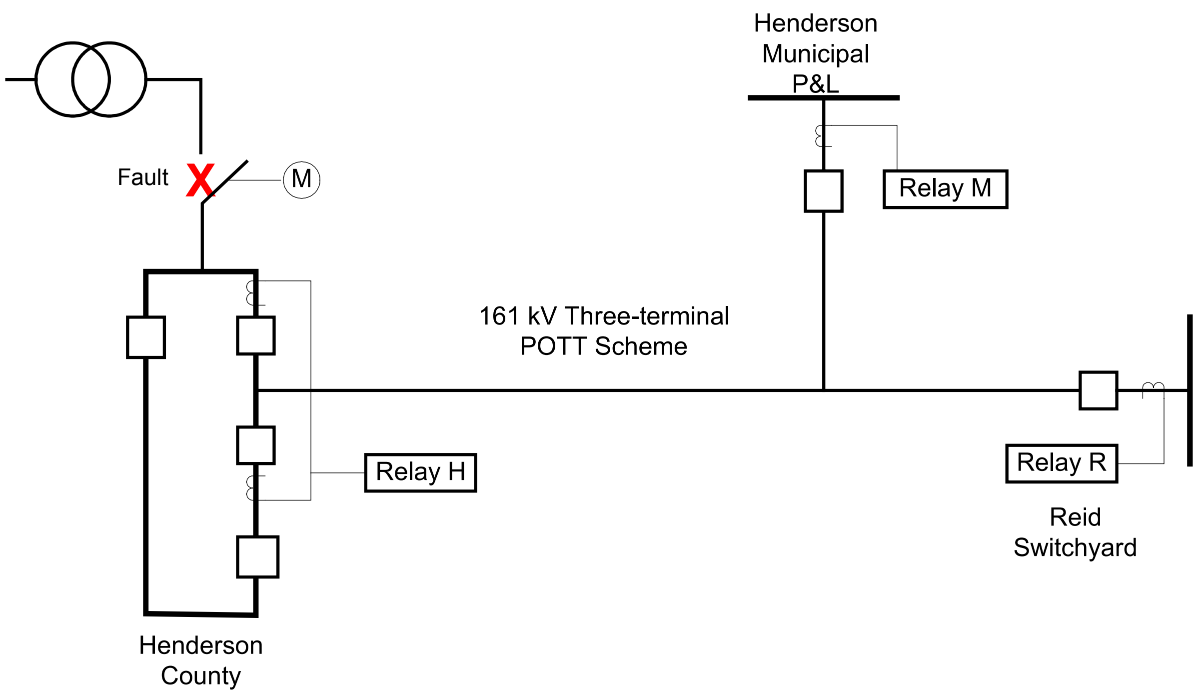


Figure 1. Henderson-Reid-HMP&L Three-terminal Line

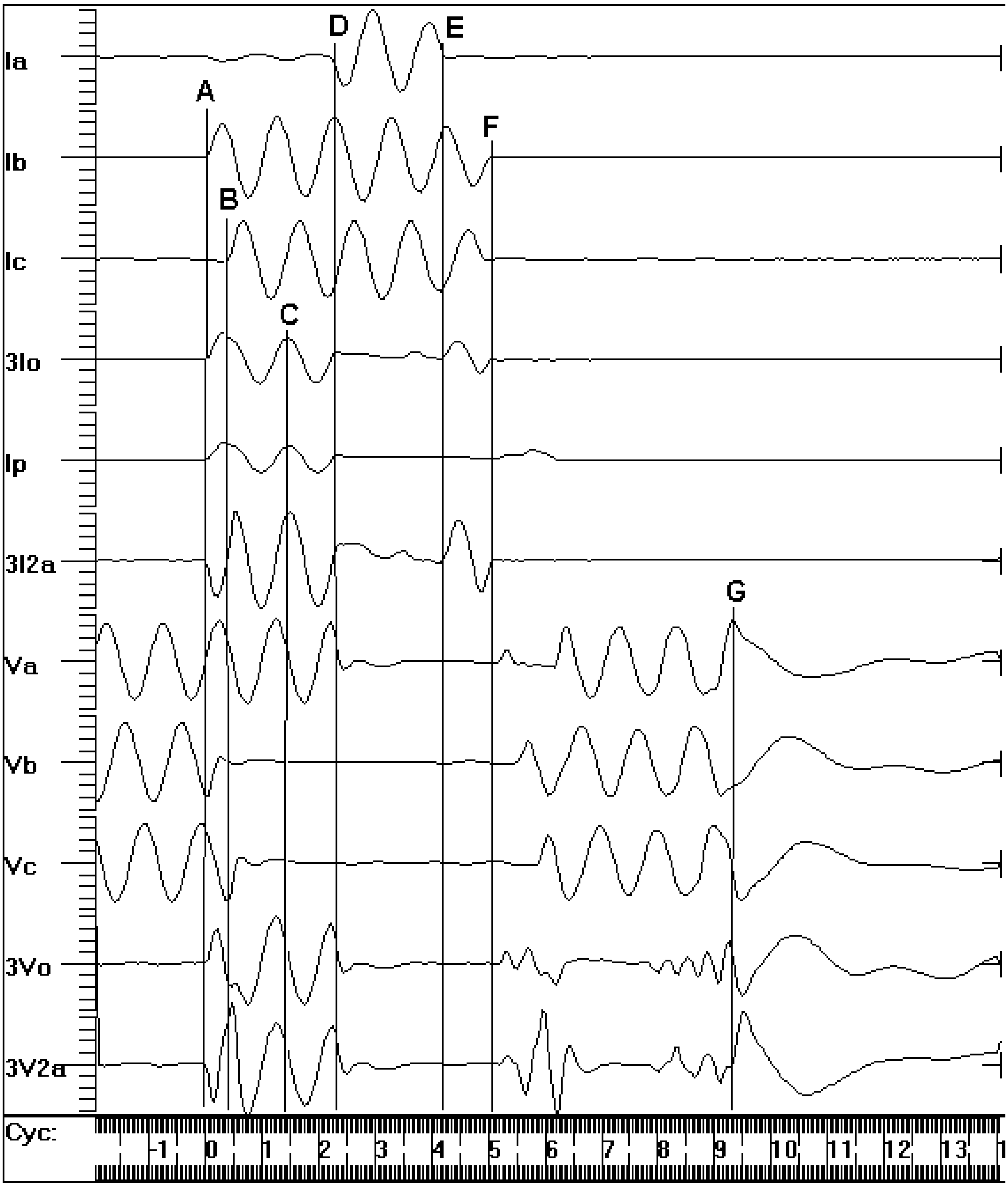


Figure 2. Relay H Reverse Fault Analog Data

Figure 2 shows the oscillographic analog data recorded by Relay H at Henderson for the reverse fault. There are 7 points or regions of interest. These are:

A. Fault inception starts with the fault on phase B-to-ground.
B. The fault evolves to phase C creating a two-phase-to-ground fault.
C. It is observed that $3I_0$ (zero sequence current measured – $3I_0=I_A+I_B+I_C$) and I_P (transformer polarizing current input) are in phase. For a reverse these quantities should be out of phase. A large negative sequence current, 3I2a, is also observed.
D. The fault evolves to phase A creating a three-phase fault. The negative sequence (3I2a) and zero sequence (3Io) currents diminish.
E Phase A clears (goes to zero). The negative (3I2a) and zero (3Io) sequence currents return
F. Phases B and C clear.
G. The voltage source is removed from the relay.

50Q Highset Tripping

Figures 3 and 4 show the current analog and digital logic signals that explains the trips at Henderson [County], HMP&L (Henderson Municipal P&L) and Reid [Switchyard]. Tables 1,2 and 3 show the phase and sequence quantities computed from the relay sampled data for one cycle of the fault between 0.65 and 1.6 cycles. Reading the digital signals of Figure 3 we observe that both relays tripped for the HS-Q function (50Q Highset AND Forward 3V2). This is the direct tripping high set negative sequence overcurrent unit (50Q Highset) that should be set to trip for a forward phase-to-phase faults on the line, and be set above the maximum negative sequence current produced by a single phase-to-ground fault. The trip setting at Henderson and Reid was 9.0 A and 10 A, respectively, and both units were forward directionally supervised by the negative sequence directional units Forward 3V2.

At Henderson, Relay H's 50Q Highset picked up almost immediately after the fault inception. The negative sequence current (3I2) level was 33.55 A for the two-phase-to-ground fault, well above the 9 A. setting. The Reverse 3V2 directional unit also correctly picked up for the reverse fault. At about fault cycle 2.3 (point D of Figure 1) the fault evolves to three phase and the negative sequence current 50Q Highset begins to dropout and does at cycle 3.1. However, before the 50Q Highset unit drops out, the Forward 3V2 negative sequence unit picks up at cycle 2.9 due to the unbalanced fault transient of the evolving two to three-phase fault. Thus, the trip of Relay H occurred. The negative sequence directional unit operation is discussed in detail in a later section.

It is the nature of an instantaneous overcurrent unit to pickup faster and dropout slower as the fault current level increases above the pickup level. In this case the fault current was about 3 times the pickup at Henderson and the unit operated (the upper digital signal on the 50Q Highset line) in 0.35 cycles and dropped out [after a three-phase fault] in 0.8 cycles. At Reid the fault current level was about 1.3 times the setting and the unit operated (the lower digital signal on the 50Q Highset line) in 1.15 cycles and dropped out [after a three-phase fault] in 0.25 cycles.

At Reid the Forward 3V2 negative sequence directional unit (lower signal) remained operated through the fault. Tripping at Reid occurred because of an apparent low 50Q Highset setting. Similar operations occurred at the HMP&L terminal. This gives us two issues to investigate: an incorrect negative sequence directional unit operation at Henderson and larger negative sequence fault currents at HMP&L and Reid than was expected based on fault study analysis.

Current Accuracy Check

Checking the current accuracy verifies the correct ct connections, determines possible ct saturation and/or validates the use of the fault current data to check the accuracy of system parameters used in fault studies. Tables 1,2 and 3 show the phase and sequence quantities computed from the relay sampled data for one cycle of the fault between 0.65 and 1.6 cycles. These are simultaneous measurements, and therefore, the sum of the three terminal line current values for Ia, Ib, Ic, 3I0 and 3I2 will be zero [or very near] on the primary system base barring ct saturation. The ct ratios used at Henderson and HMP&L are 1200/5 and at Reid is 2000/5. For example, the sums of Ib and 3I2 are computed as follows:

$$\sum \mathrm{Ib} = 27.64\ e^{j349} + 10.87\ e^{j172}\ (2000/1200\ \ 0) + 9.42\ e^{j16}\,7 = 0.64\ e^{-j270}$$

$$\sum 3\mathrm{I2} = 33.5\ e^{j276} + 13.21\ e^{j97}\ (2000/1200\ \ 0) + 11.65\ e^{j99} = 0.62\ e^{-j8}$$

The summation shows a small error and verifies the correct ct connections and current measurement accuracy.

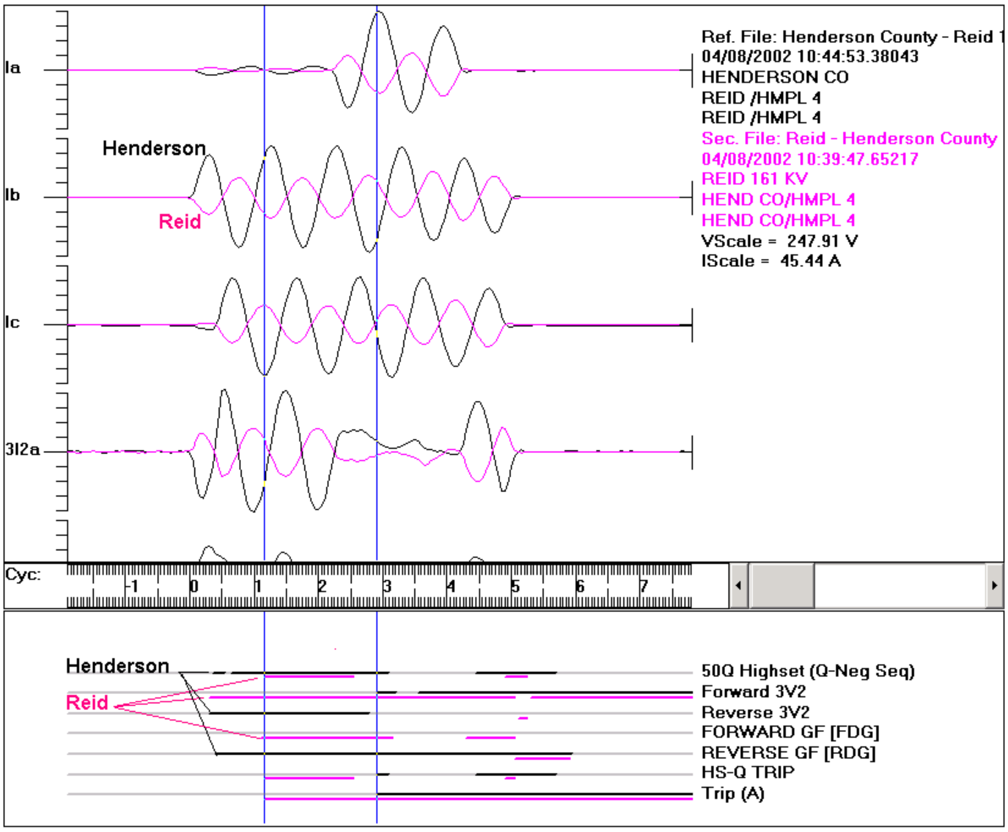


Figure 3. Analog and Digital Logic Signals Showing Trips at Henderson and Reid

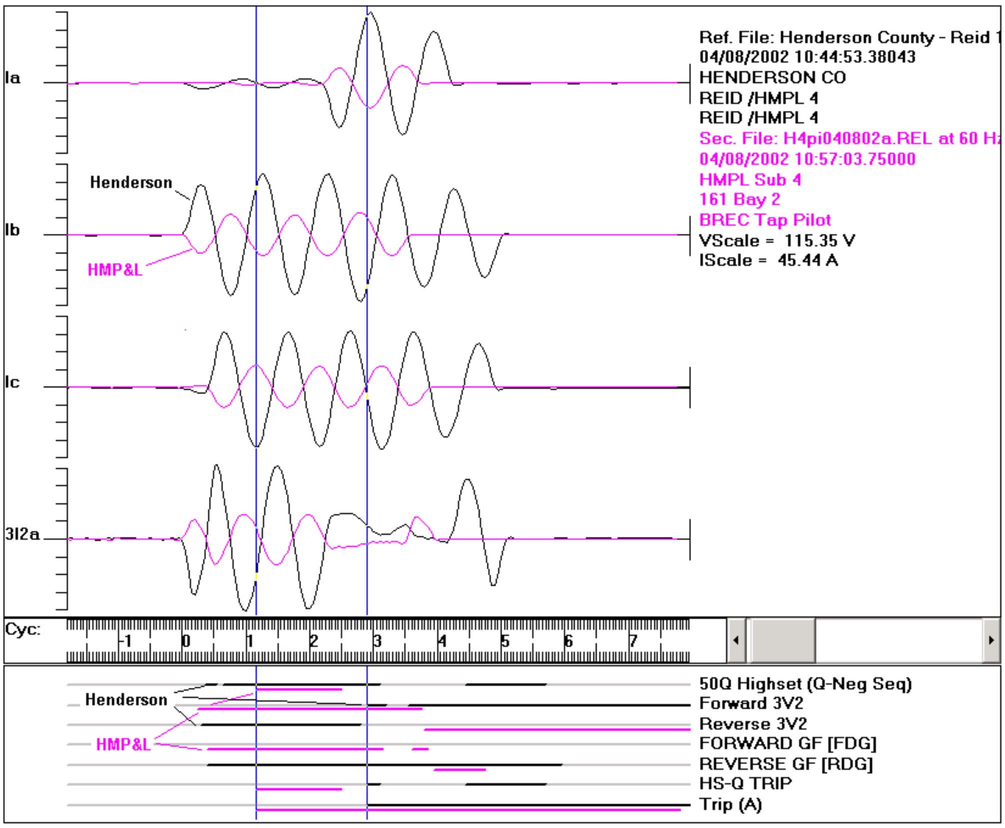


Figure 4. Analog and Digital Logic Signals Showing Trips at Henderson and HMP&L

Table 1. Relay H Fault Summary Data for Samples 53 to 72 (Cycle 0.65 to 1.6)

```
Phase Quantities
Va = 73.13 V <   0.00                        Ia =  1.99 A < 105.57
Vb =  2.43 V <  84.78                        Ib = 27.64 A < 349.09
Vc =  3.73 V < 311.70                        Ic = 26.51 A < 207.17

Sequence Quantities
3Vo= 75.84 V < 359.72                        3Io= 15.71 A < 281.08
3V2= 76.32 V <   1.60                        3I2= 33.55 A < 276.24
                                             Ip =  9.29 A < 272.82
Fault Type = BCG
Fault Impedance  = 0.11 < 105.73
Distance = 0.81 mi.
```

Table 2. Relay R Fault Summary Data for Samples 53 to 72 (Cycle 0.65 to 1.6)

```
Phase Quantities
Va = 62.83 V <   0.00                         Ia =  0.97 A < 308.40
Vb = 47.71 V < 232.89                         Ib = 10.87 A < 172.06
Vc = 48.05 V < 125.99                         Ic = 10.30 A < 28.93

Sequence Quantities
3Vo=  5.85 V <   8.08                         3Io=  5.83 A < 101.25
3V2= 24.72 V <   0.13                         3I2= 13.21 A <  96.68
                                              Ip =  3.03 A < 288.22
Fault Type = BCG
Fault Impedance = 3.82 < 79.59
Distance = 28.97 mi.
```

Table 3. Relay M Fault Summary Data for Samples 53 to 72 (Cycle 0.65 to 1.6)

```
Phase Quantities
Va =  65.31 V <   0.00                        Ia =  0.56 A < 252.65
Vb =  32.34 V < 229.74                        Ib =  9.42 A < 167.16
Vc =  32.51 V < 125.33                        Ic =  9.50 A <  27.17

Sequence Quantities
3Vo= 25.67 V < 4.12                           3Io=  5.95 A < 98.73
3V2= 40.82 V < 1.24                           3I2= 11.65 A < 98.62
                                              Ip =  0.00 A < 00.00

Fault Type = BCG
Fault Impedance = 2.88 < 80.40
Distance = 21.85 mi.
```

Negative Sequence Directional Unit Operation

Figures 5a and 5b demonstrate the operation of the forward and reverse negative sequence directional units. The forward or reverse operation is basically defined by the phase relationship of the measured negative sequence current (3I2) and voltage (3V2). 3I2 leading 3V2 is forward and 3I2 lagging 3V2 is reverse. Figure 5a shows the Reverse 3V2 directional unit is correctly operated for the reverse fault in the second fault cycle. 3I2 is lagging 3V2. Figure 5b shows that the Forward 3V2 negative sequence unit operated in the third fault cycle as a result of the fault evolving to three-phase. 3I2 is now leading 3V2. Note that the Reverse 3V0 zero sequence unit [shown in the operated logic list on the right side of the figure] operated correctly for both fault cycles. This shows the instability of negative sequence polarization relative to zero sequence polarization for this particular event.

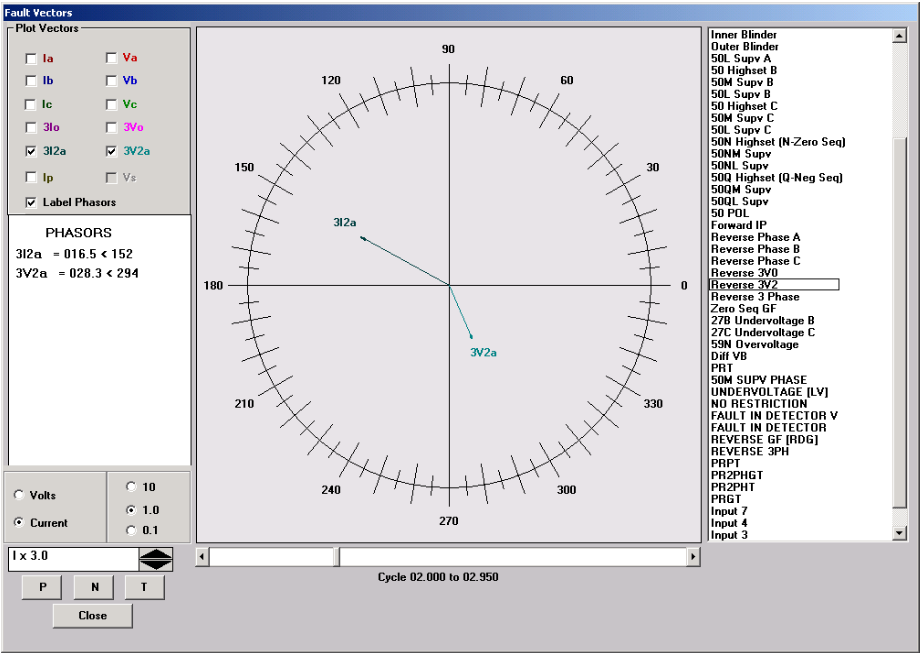


Figure 5a. Fault Cycle 2 - Reverse 3V2 Directional Unit Operated – 3I2 Lags 3V2

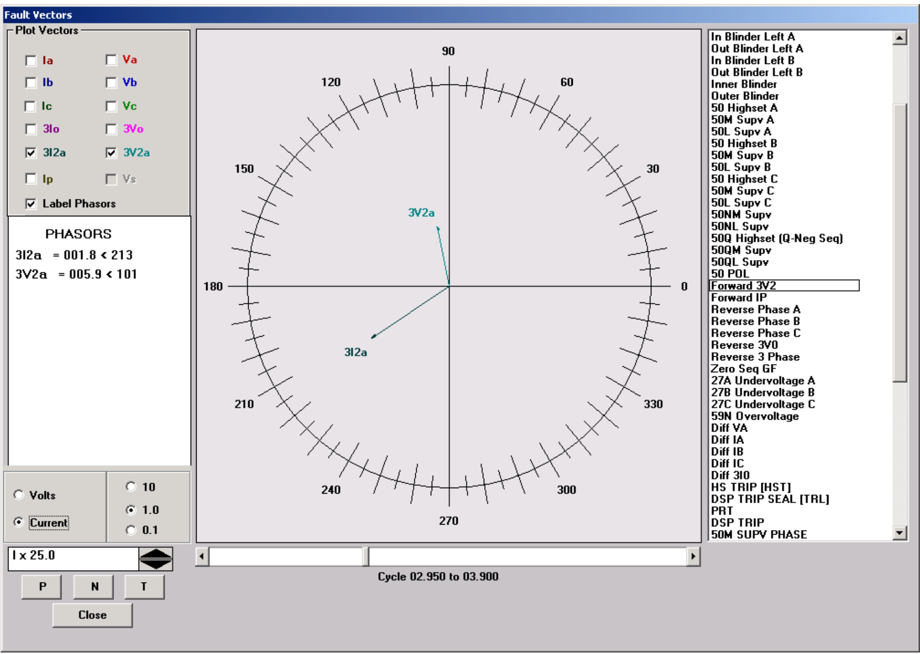


Figure 5b. Fault Cycle 3 - Forward 3V2 Directional Unit Operated – 3I2 Leads 3V2

The Polarizing Current Connection

While analyzing the fault a seemingly incorrect phase relationship was noticed with the zero sequence current computed in the relay (3Io) and the external polarizing current (Ip) measured from the transformer polarizing current transformer. Looking back at Figure 1, point C for Relay H at Henderson we can see that the quantities 3Io and Ip are in phase. This is incorrect for a reverse fault, as they should be 180^{O} out of phase. Figure 6 shows the quantities at Henderson in phase more clearly. Also at Reid, the fault as seen by Relay R is forward and 3Io and Ip should be in phase. As observed, they are about 180^{O} out of phase. This indicates a wiring problem at Reid as well.

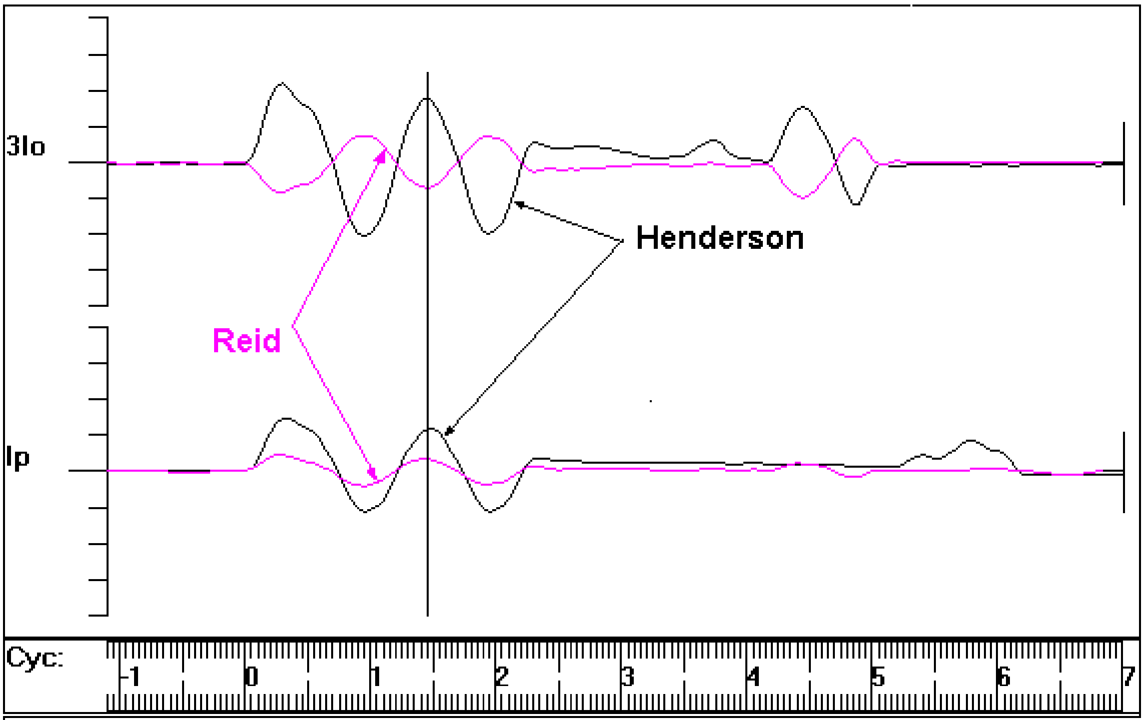


Figure 6. Phase Relationship of 3Io and Ip

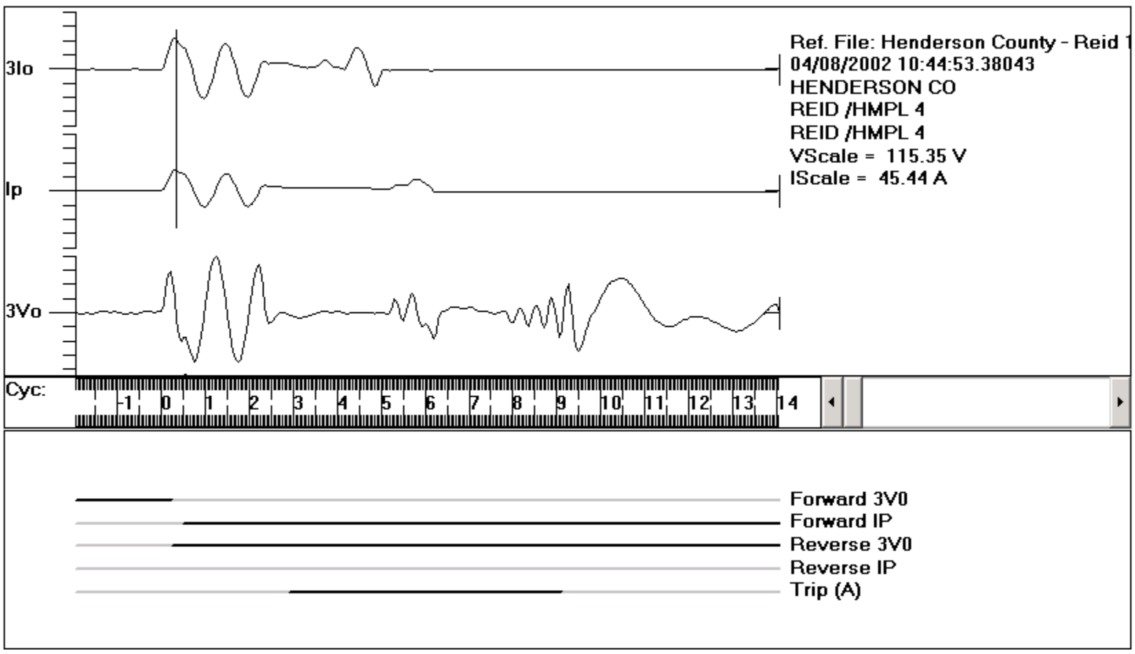


Figure 7. Directional Unit Operations

Figure 7 also confirms the incorrect polarizing current connection. The directional sensing method used by the relay is referred to as dual polarizing. The $3I_0$ measured in the relay is polarized by an external polarizing ground current from a [grounding] transformer neutral or delta winding. If Ip is less than 0.5 it is presumed that the transformer is out-of-service and the $3I_0$ measured in the relay will be polarized by the $3V_0$ measured in the relay. The operation of Forward IP and Forward 3V0 [and Reverse IP and Reverse 3V0] should agree for forward line and reverse bus faults. In this case, however, Reverse 3V0 and Forward IP are operated, indicating the connection problem. There is some operation of the Forward 3V0 unit during prefault due to system unbalances. This, however, is of no consequence.

HS 50Q Setting

The highset negative sequence overcurrent unit is provided to complement the zone-one phase-to-phase unit for faults within 80%- 90% of the line length. The setting was determined from a fault study and was selected to reach a forward phase-to-phase fault at 90% of the protected line. This was determined to be 9.0 amps secondary. A setting of 10 A for the Reid and HMP&L terminals was also determined. Table 2, however, shows that the negative sequence fault current through Relay R for a fault at 100% (the location of the remote bus) was 13.0 A, well above the 10 A setting. This would be expected to be even higher at 90% of the line length. The setting of 10.0 A at HMP&L is also observed to be to low based on the data of Table 3. The corrective recommendation is to increase the 50 Q Highset setting at all terminals to a value that would assure tripping only for a fault on the line. A setting in the order of 15 to 16 A would be more reliable.

Forward Pilot Zone Setting

For a fault at the Henderson bus it would be expected that both remote Reid and HMP&L relays' forward pilot phase zone would have operated. Figure 8 shows there was no Forward Pilot zone (mho unit) operation at HMP&L although it tripped for HS 50Q and 'trip' keyed (Start) the pilot channel.

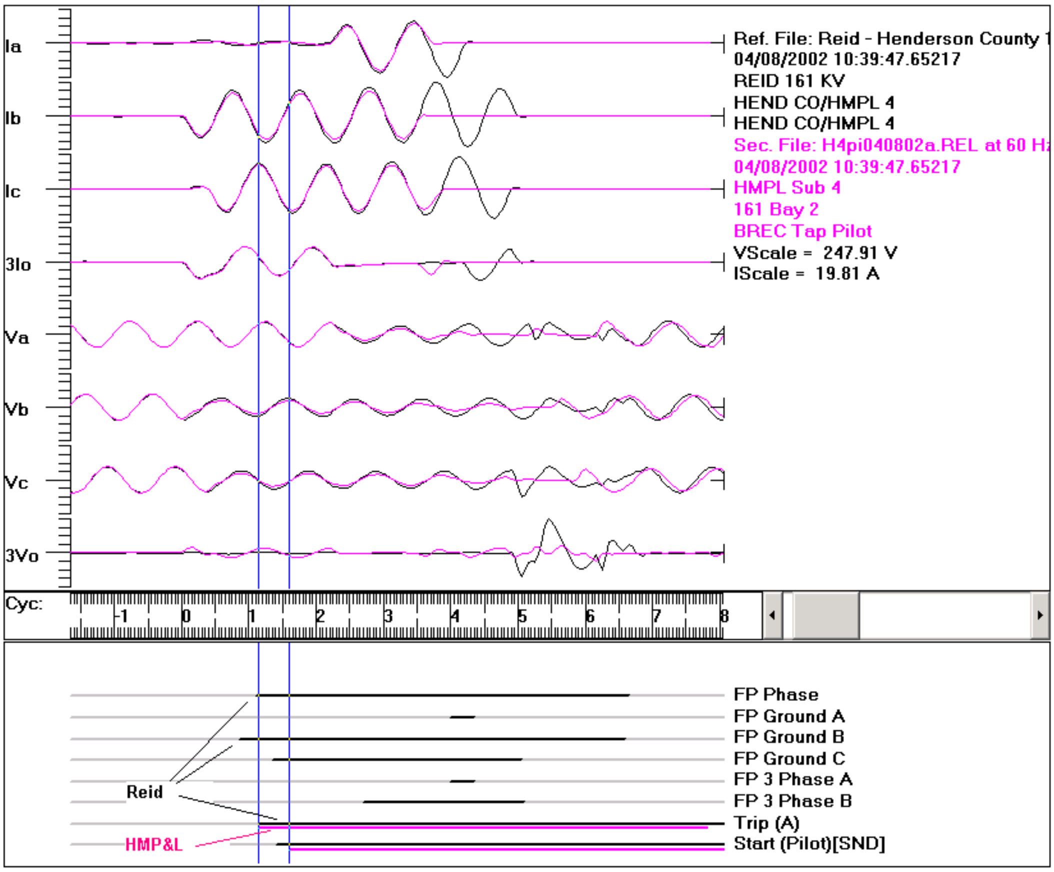


Figure 8. Forward Pilot Zone Mho Operation at Reid and HMP&L

Both relays are set for the same primary reach of 15.4 ohms, but differ in their secondary settings due to different CT ratios. The Reid unit's forward pilot phase setting is 4.48 e^{j75} ohms (CT=2000/5) and the HMP&L unit's forward pilot phase setting is 2.64 e^{j75} ohms (CT=1200/5). Tables 2 and 3 show the computed fault impedance, Z_{fBC}, from each relay. The fault impedance seen by the Reid relay is 3.82 e^{j80} and within the 4.48 ohm reach setting. Therefore it operates. The setting is about 117% of the fault [or measured line] impedance and includes the effect of infeed from HMP&L. The fault impedance seen by HMP&L is 2.88 e^{j80} and is beyond the set reach of 2.64 ohms. Therefore it does not operate. The setting is about 92% of the fault [or measured line] impedance and includes the effect of infeed from Reid. The cause of the underreach is due to the infeed from Reid and is shown by the following simple calculation. Figure 9 shows the secondary positive sequence line impedances for the three line segments and the measured phase B currents, Ib, from Tables 1, 2 and 3. Phase angles are close and are ignored for this simple calculation.

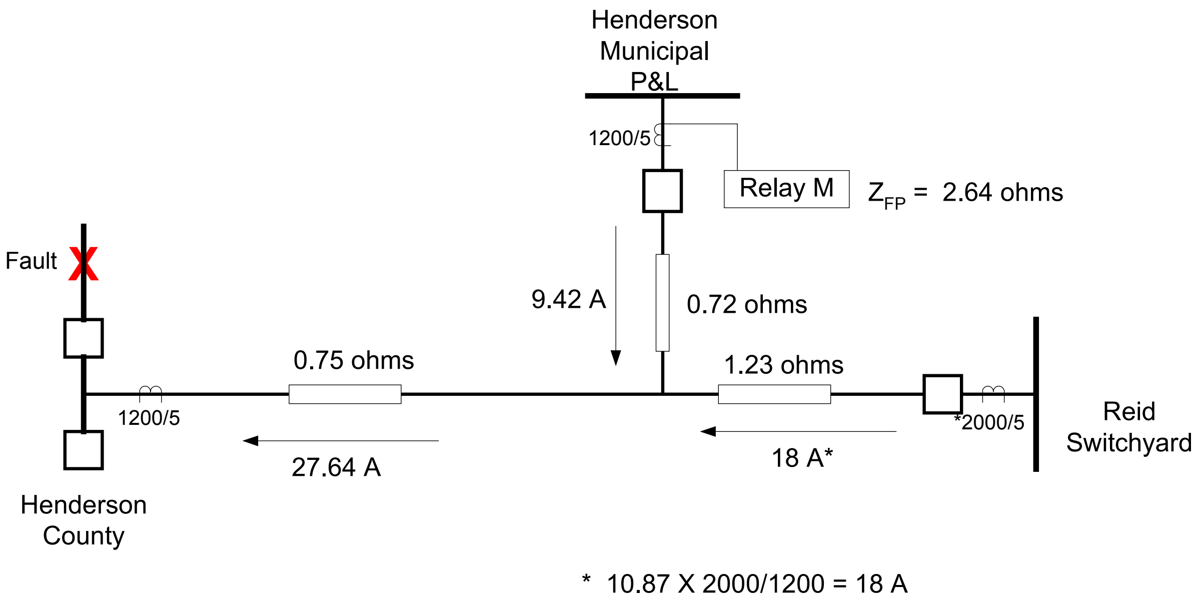


Figure 8. Calculating Relay M Underreach

The impedance between HMP&L and Henderson is 1.47 ohms and a setting at HMP&L of 2.64 ohms may appear adequate to assure overreaching of the Henderson bus. A strong infeed of 18 A. from Reid is observed and must be considered. To see the effect of the infeed, the phase B voltage drop is calculated from HMP&L to Henderson, the fault location:

$$V_B \text{ drop} = 9.42 \text{ X } 0.72 + 27.64 \text{ X } 0.75 = 27.51 \text{ V.}$$

Then the apparent impedance seen by Relay M is calculated:

$$Z_A = V_B / Ib = 27.1/9.42 = 2.92 \text{ ohms}$$

This compares reasonably with the apparent impedance of 2.88 ohms computed by Relay M shown on Table 3 and is beyond the reach setting. Therefore, the setting at HMP&L should be increased to at least 120% of the measured line [fault] impedance (1.2 X 2.88 = 3.46 ohms). To assure overreaching of the forward pilot zones at all terminals, they can be set even higher as there are no coordination issues as with a zone-2 time delayed tripping in a step-distance scheme.

Slow Clearing Breaker

Figure 10 shows the clearing of the associated Relay H breakers at Henderson. Breaker 1 clearing follows tripping by about 2.25 cycles as indicated by the dropout of the 52a-2 auxiliary contact input #3 and the simultaneous clearing of phase B and C currents. The second breaker opening of the ring bus as indicated by the dropout of the 52a-2 input #4, which follows tripping in about 6 cycles. The breakers at Reid, as shown in Figure 10, also take about 6 cycles to open. Although this may be of no consequence the discrepancy in the breakers' operating times should be investigated.

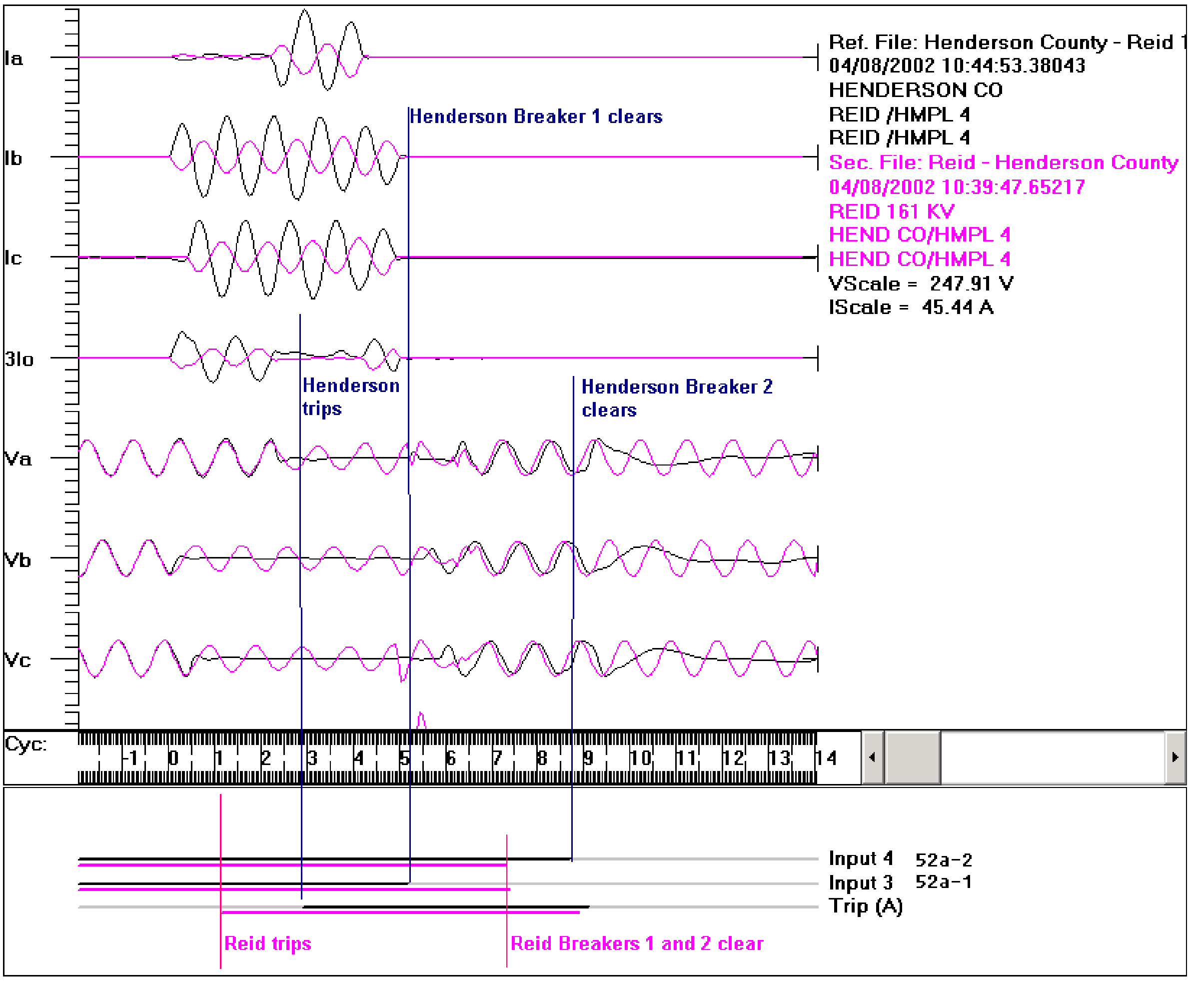


Figure 10. Breaker Clearing

Fault #2

System Configuration

A double circuit [cross-country] fault occurred May 17, 2002 outside the Bryan Road substation on the Krebs Road and Husband Roads lines. The substation and protected line configuration are shown in Figure 11. Both relays protecting the two lines correctly tripped but gave different fault locations. The fault targets of each relay are shown in Figure 12. The fault appeared as a single phase B-to-ground fault at 0.1294 miles on the Krebs Road line and as a two-phase AC-to-ground fault at 0.2428 miles on the Husbands Road Line. Figure 13 shows the line tower structure and the conductor arrangement. Following is the event analysis that shows that the event is indeed a double circuit fault, determines the correct fault location, identifies operational issues, identifies dependable tripping units and allows us to better understand this particular double-circuit fault.

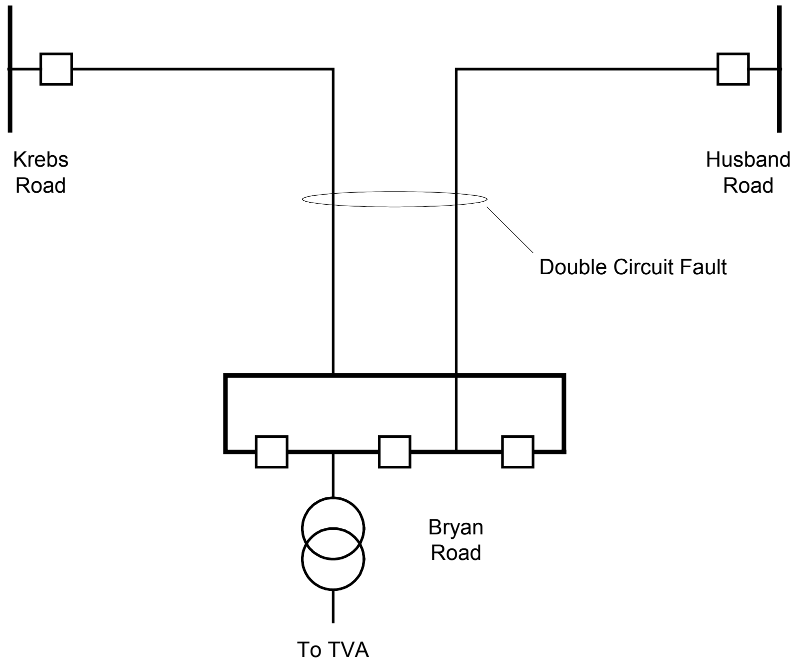
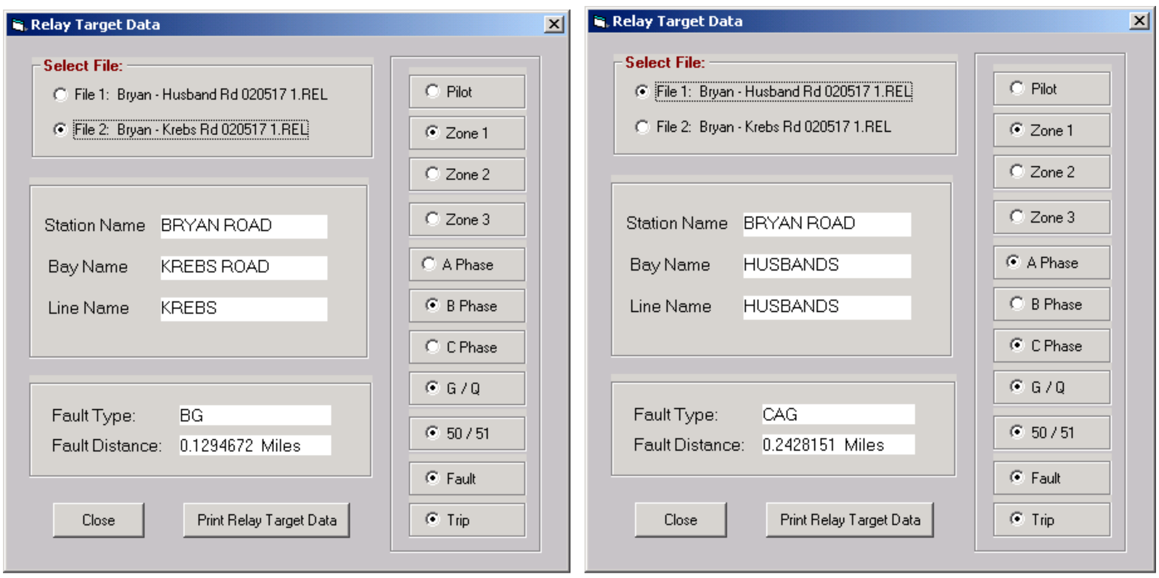


Figure 11. Bryan Substation and Krebs Road and Husband Road Lines



A. Bryan-Krebs B. Bryan-Husbands

Figure 12. Relay Fault Targets

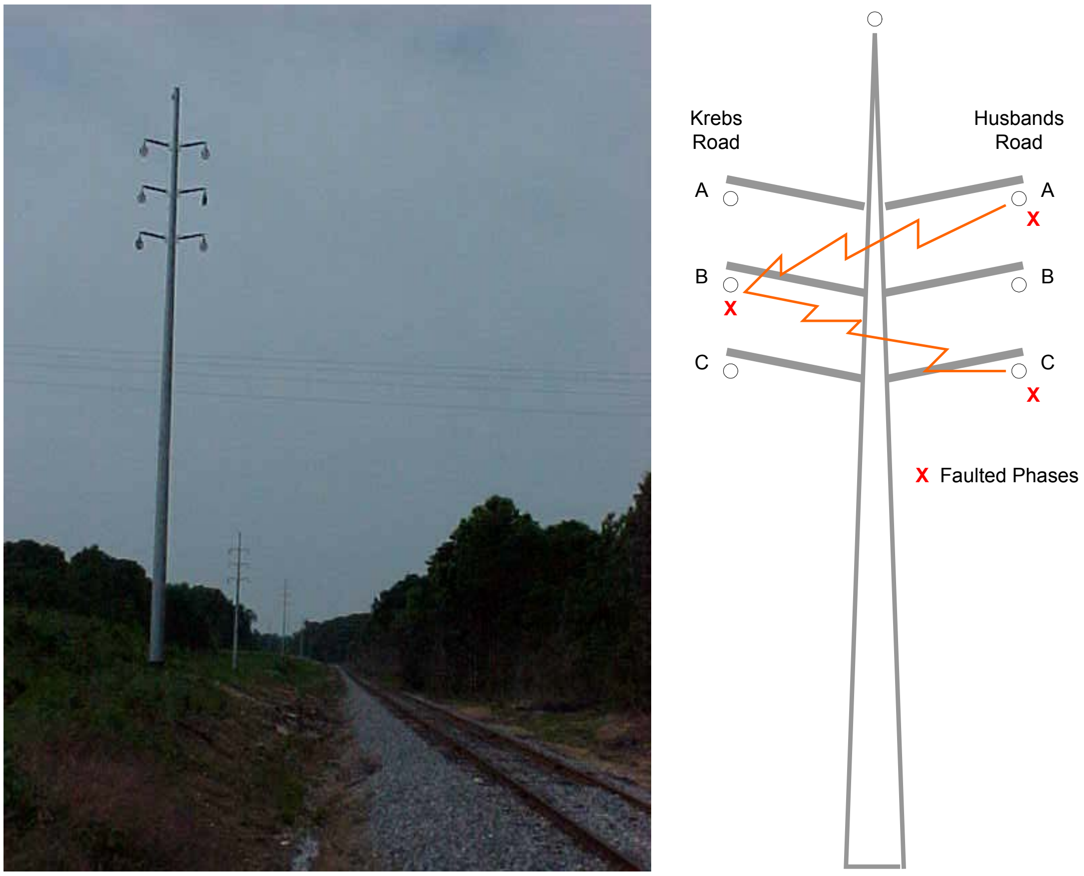


Figure 13. Double Circuit Tower and Conductor Arrangements

Bryan-Krebs Fault Record

Figure 14 shows the Bryan-Krebs relay analog fault records. The first clue to a double circuit or simultaneous fault was when both lines tripped simultaneously. The second clue lies in the nature of this fault record. We observe a B phase fault current and no appreciable current on phases A and C. The zero sequence current measured by the relay appears equal to the phase B current, but the external polarizing current, Ip, measured at the transformer at Bryan Road substation is very nearly zero during the fault except for the period of the breaker opening transient. This implies that the fault is not a ground fault. Also, the voltage has collapsed on all three phases. Superimposing the fault records in Figure 15 gives us a better picture of the fault. The phase quantities for the third fault cycle are also shown in Table 4.   Study of Figure 14 and Table 4 will lead to the conclusion that this is basically a three-phase fault involving phases A and C of one circuit and phase B of the other.

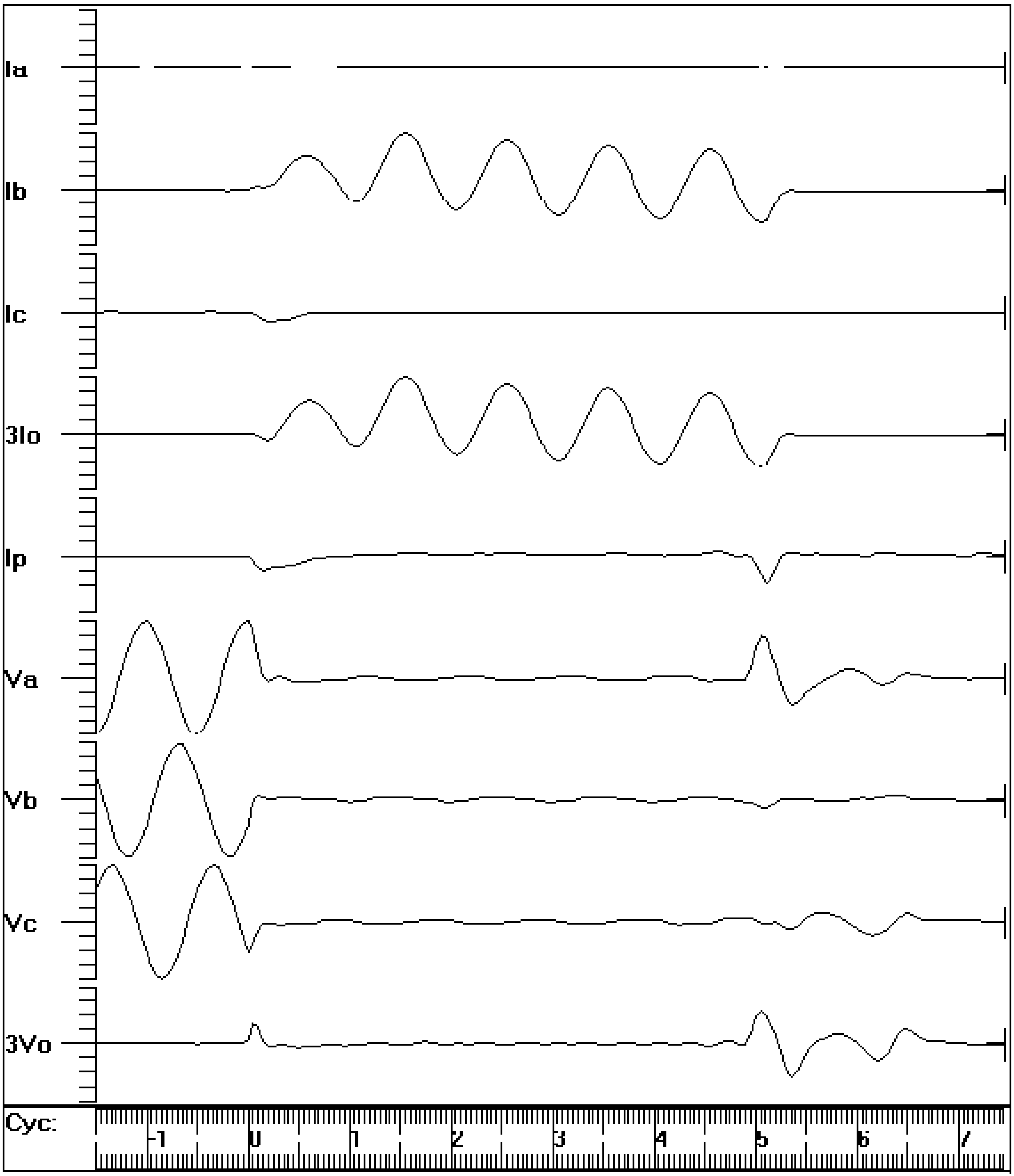


Figure 14. Bryan-Krebs Relay Fault Record

Table 4. Measured Phase Quantities for the Third fault Cycle

Secondary Values	Bryan - Krebs Line	Bryan – Husbands Line
Va	2.14 V < 0.00	2.25 V < 0.00
Vb	2.46 V < 243.50	2.26 V < 240.02
Vc	2.61 V < 115.18	2.60 V < 117.55
Ia	0	30.84 A < 335.02
Ib	30.27 A < 215.22	0
Ic	0	29.40 A < 94.49

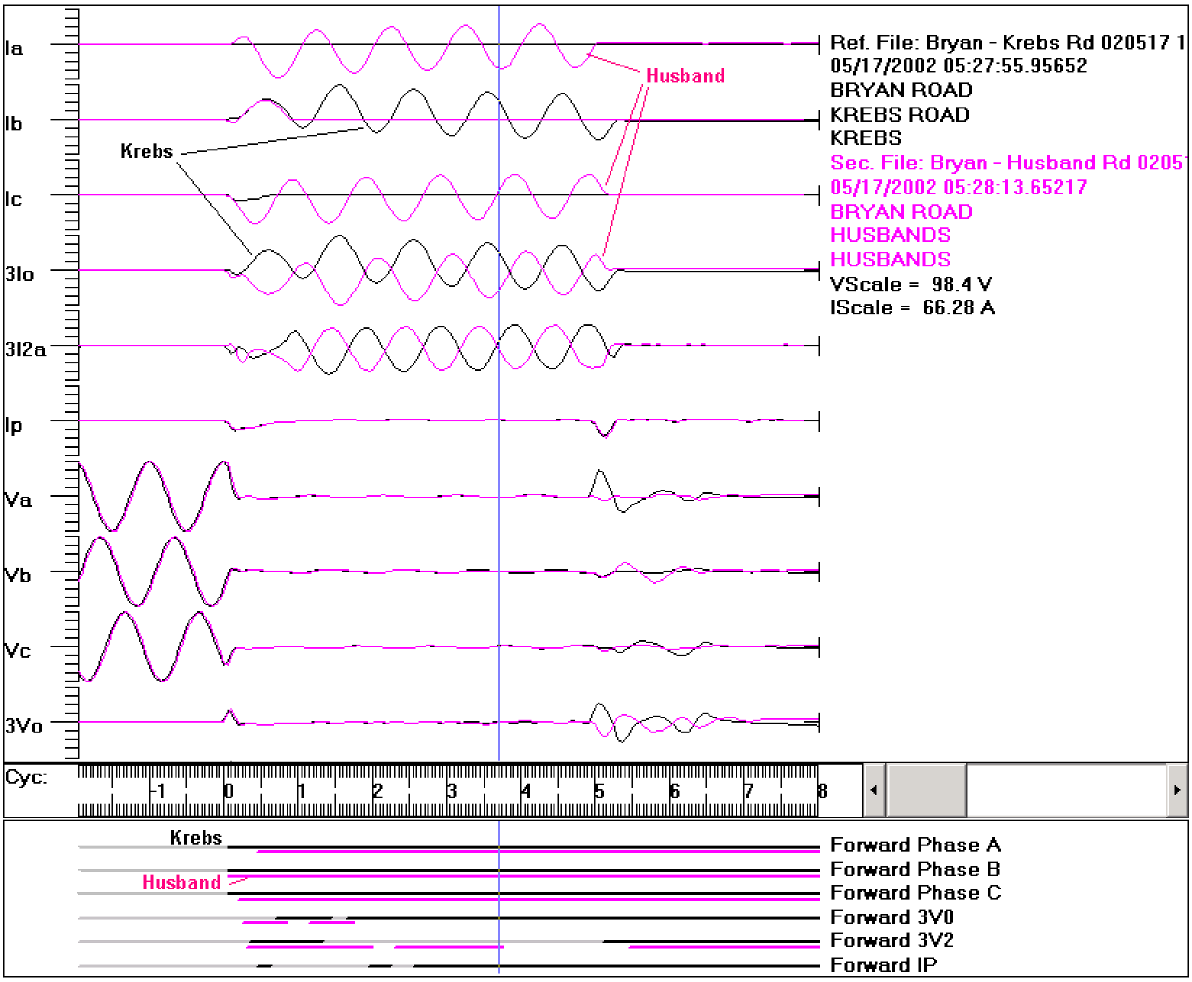


Figure 15. Bryan-Krebs and Bryan-Husband Relay Fault Records Showing Forward Directional unit Operations

Fault Location

The correct fault location was provided by the Bryan-Husbands relay because the fault location was determined as a phase-to-phase fault location computation for which the phase quantities are valid. The Bryan-Krebs fault location computation includes zero sequence compensation sensing that the fault is single phase-to-ground. Removing the zero sequence current compensation results in the correct fault location of 0.25 mile.

Directional Unit Supervision

The zone-1 and highset overcurrent-tripping units are supervised by the appropriate forward directional unit. Observing the directional unit operations of Figure 15 we see that the forward phase directional units, Forward Phase A, B and C, for both relays operated consistently through the fault. These are all correct and reliable operations. Each phase current is polarized with the cross phase-to-phase [memory] voltage (e.g. I_A polarized by V_{BC}).

The ground polarized units, Forward 3V0, Forward 3V2 and IP, operated inconsistently. This is expected. In fact, all polarizing quantities, Ip (transformer delta winding current), 3Vo (zero sequence voltage of Figure 15) and 3V2 (negative sequence voltage) are very nearly zero and cannot be relied upon for correct polarizing.

Zero Sequence Current Supervision

Zero sequence current is used to enable tripping with the ground impedance units and to block tripping of the phase-to-phase units except in the case of two phase-to-ground faults. This is done to provide secure single-pole phase selectivity. The apparent zero sequence current measured by each relay is not indicative of the actual ground [or residual] fault current flowing in the neutral or ground path. Therefore, the ground impedance units are incorrectly enabled and the phase impedance units are incorrectly blocked. Enabling the ground impedance units is of no consequence, but blocking of the phase units is not desired.

Tripping

Figure 16 shows the zone-1 phase impedance and highset overcurrent units that operated to provide a trip output. The Bryan-Krebs relay had a phase-to-phase impedance logic (Z12PHT) operation correctly providing an impedance trip while the Bryan-Husbands phase-to-phase logic did not operate. There was also a brief operation of the three-phase fault logic (Z1P3PHT), but the zero sequence current blocked it for most of the fault. The highset phase overcurrent units operated correctly on the respective faulted phases seen by both relays. This illustrates that although correct tripping may be initiated by the zone-1 phase impedance units, it is only assured with the application of the highset phase overcurrent units.

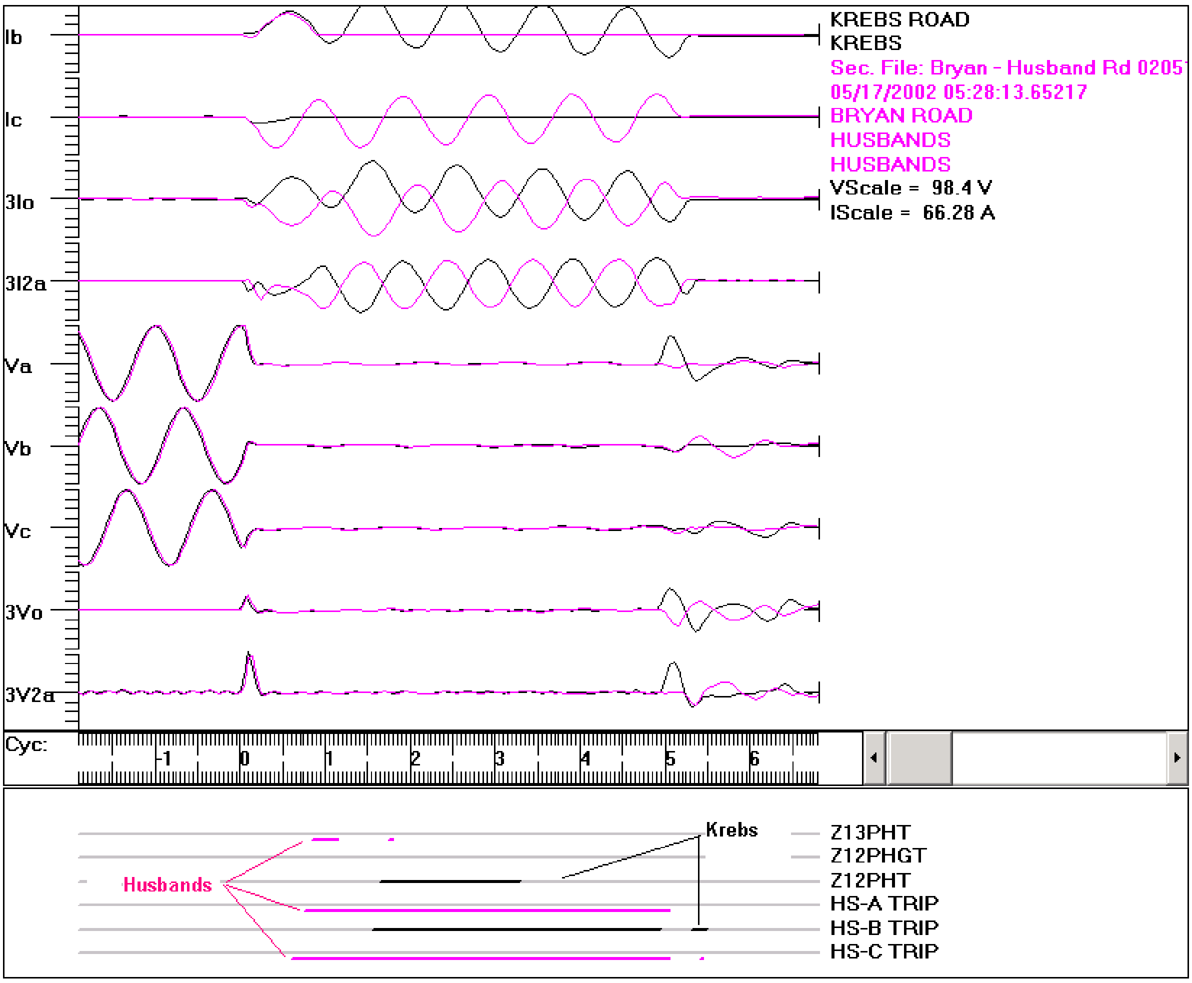


Figure 16. Bryan-Krebs and Bryan-Husband Relay Fault Records Showing Zone-1 Impedance and Highset Overcurrent Trips

Summary

The analysis of these two faults demonstrates the importance of digital fault recording in the relays and their use for fault analysis. All to often the records are not reviewed if operations appear correct, or are not looked at beyond the immediate cause of an incorrect operation. The detailed review of these records analyzed the cause of trip and pointed to several other potential problems including wiring, incorrect settings, questionable system parameters and possible breaker problems. In addition, the importance of multiple and different tripping functions to provide dependable tripping for unusual system faults was demonstrated, in particular the highset [direct tripping] overcurrent units.

It is recommended that all fault records be reviewed to verify to the extent possible those things that can improve the reliability of system operation. These include, but are not limited to:

- Correct operation or cause of incorrect operation
- Correct relay settings
- Correct instrument transformer connections and ratios
- Correct breaker (and other apparatus) operation
- Power quality
- Etc.

Biographical Sketches

Elmo Price received his BSEE degree in 1970 from Lamar University in Beaumont, Texas and his MSEE degree in Power Systems Engineering in 1978 from the University of Pittsburgh.

He began his career with Westinghouse in 1970 and worked in several engineering positions that included assignments at the Small Power Transformer Division in South Boston, VA, the Gas Turbine Systems Division in Philadelphia, and T&D Systems Engineering in Pittsburgh. He also worked as a District Engineer and an Advanced Technology Specialist located in New Orleans and supporting the South-central U.S.

With the consolidation of Westinghouse into ABB in 1988 Elmo assumed regional responsibility for product application for the Protective Relay Division. From 1992 to 2002 he has worked at both the Coral Springs and Allentown Divisions in various technical management positions responsible for product management, application support and relay schools.

Elmo is currently Regional Technical Manager for ABB in Alpharetta, Georgia supporting product sales in the southeastern U.S. Elmo is a registered professional engineer and a member of the IEEE and the PSRC Line Protection Subcommittee.

Bob Warren received his Bachelor of Science Degree in Electrical Engineering in 1982 from Purdue University and a Masters of Science Degree in Industrial Engineering in 1994 from the University of Tennessee.

His career began with a tour of duty in the US Navy as the Electrical & Auxiliaries Officer aboard the USS W.S. Sims. His first electric utility employment was with Nashville Electric Service where he served in several operations and engineering positions. Bob is now the Senior Substation Engineer at Big Rivers Electric and is a registered Professional Engineer.