Analysis of Event Reports

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INTRODUCTION

Because microprocessor-based relays save event reports during faults, protection engineers can now analyze event reports to gain a better understanding of faults and disturbances on transmission line systems. This analysis frequently leads to better line parameters, more accurate fault locating for complex faults, and improved understanding of system operations. The event reports also help determine fault resistance and explain otherwise inexplicable events.

This paper reviews the manual and automated techniques used to analyze ten microprocessor relay event reports. These event reports cover:

Incorrect wiring
2. High impedance ground fault
3. Blocking carrier coordinating time
4. Zero-sequence voltage reversal
5. Evolving fault
6. Closing a generator breaker out-of-synchronism
7. Excessive tertiary current
8. Sequential clearing
9. Zero-sequence current flow verification
10. Cross country fault

The event reports used in this paper are field data supplied by utilities using microprocessor relays.

EVENT REPORT RECORDING EQUIPMENT

Data stored before, during, and after a system disturbance or fault must provide the protection engineer with sufficient information to investigate and/or recreate the event. The following data storage methods, some of which have existed for many years, are presently available to the protection engineer:

1 Digital Oscillographs - These are typically installed in larger substations where a large number of lines are monitored. Data recorded from an event may be stored on disk or printed on paper. An experienced operator must interpret the oscillograms. While this method shows the traditional sine waves on the printouts, accurately determining the phase angle relationships between the voltages and currents may be difficult. Where large current magnitude differences exist between faults at the bus and the remote end of the line, scaling requirements may make it hard to unravel load from fault quantities.

2. Light Beam Oscillographs - These are typically used the same way as the digital oscillographs. Data from an event are stored only on light-sensitive paper as traces which fade with time. A skilled operator must read the printouts. In older light beam oscillographs, the paper drum does not begin to move until after a start sensor detects the disturbance; thus, no prefault information is available.

3. Microprocessor relays - Typically installed in single terminal applications, these devices perform protective functions for the transmission line. All SEL relays produce and save event reports when faults or other triggering events occur. These relays report voltages, currents, relay elements and contact I/O in an easy-to-use, compact status format.

    1. Date and time of the fault or disturbance
    2. Prefault, fault, and post-fault voltages and currents
    3. Relay input and output contact status
    4. Relay element status
    5. Calculated fault location in miles or kilometers
    6. Relay settings at the time of the fault or disturbance

   Reporting by relays has several advantages over oscillograph recordings:

    1. Oscillographs are too expensive for most stations.
    2. Relay event reports are more compact and easier to read, making retrieval and interpretation faster.
    3. If the station oscillograph is out of service, data are not recorded at that station. On the other hand, it is virtually impossible to lose all relays.

VOLTAGE AND CURRENT INPUT DATA FORMAT

In our relays, the voltage and current inputs shown in event reports are determined using the low pass and digitally filtered secondary voltage and current quantities. The low pass filters remove frequencies above 85 Hz, and the digital filter removes the dc and/or decaying exponential component of the incoming signals.

The digital filter output data are scaled into primary quantities for the event report. Scaling is accomplished using the current and potential transformer ratios entered in the relay settings. Because the samples are recorded every ¼ cycle, the adjacent data have the 90 degree relationship required to create phasor diagrams. Therefore, with respect to the present output, the previous value was taken one-quarter cycle earlier and leads the present value by 90 degrees.

The filter output values shown in the event reports represent the voltages and currents as phasors:

The PRESENT value of the output is the X-component of the phasor.
The PREVIOUS value of the output is the Y-component of the phasor.

On Cartesian coordinates, the lower row (more recent value) is plotted as the X-component and the upper row (older value) is plotted as the Y-component. To convert the Cartesian coordinate data to polar coordinate data, use the simple equations below:

$$\text{Magnitude} = (X^2 + Y^2)^{1/2} \qquad [1]$$

$$\text{Angle} = \text{Arctan}\,(Y/X) \qquad [2]$$

The complete phasor diagram may be rotated to a reference angle. Typically VA is used as a reference by rotating its phasor to zero degrees by either adding or subtracting degrees from the calculated angle.

After the protection engineer recognizes the amount of information and data stored in the event reports, the reports can become indispensable.

EVENT REPORT EXAMPLES

Example 1: Incorrect AC Wiring

This example event report shows how engineers used the event report from a microprocessor relay to determine that voltage and current inputs to the relay were incorrectly wired.

The correct phase rotation required to match the utility system phase rotation was ACB.

Figure 1 shows the first four rows of the event report.

```
QUINCY SUB                                Date: 6/7/89     Time: 13:25:30.587

FID=SEL-121-2-R101-V651mpacp21cc-D881004

                  Currents                Voltages       MHO   +Seq -Seq Outs     Ins
                  (amps)                  (kV)
                                                        ABCABC iIv  ivV3 TCTTTTA DTBD5E
  /K*RES     A       B       C       A       B       C  GGGBCA          2 PLTABCL TTTC2T

       0   -60       3      63   -40.0     3.2    36.7  ...... ...  ***. ....... ....*.
       0   -25      65     -43   -19.4    44.3   -25.0  ...... ...  ***. ....... ....*.
       0    60      -3     -65    40.0    -3.2   -36.6  ...... ...  ***. ....... ....*.
       0    25     -65      43    19.4   -44.3    25.0              ***              *
```

Figure 1. One Cycle of Event Report Data Showing Incorrect Wiring

Notice in the event report that the negative-sequence current and voltage elements in the "-Seq" column were picked up on balanced three-phase load. This was the first indicator that the phase rotation was opposite that of the power system.

The voltage and current phasor diagrams in Figure 2 confirm the phase rotation to be ABC instead of ACB.

Plotting phasors from event reports can also be used to verify the direction and polarity of the microprocessor relays when commissioning. Or use the microprocessor relay METER command to obtain the megawatt and megavar readings. These readings define the angle of the current flow relative to the voltages.

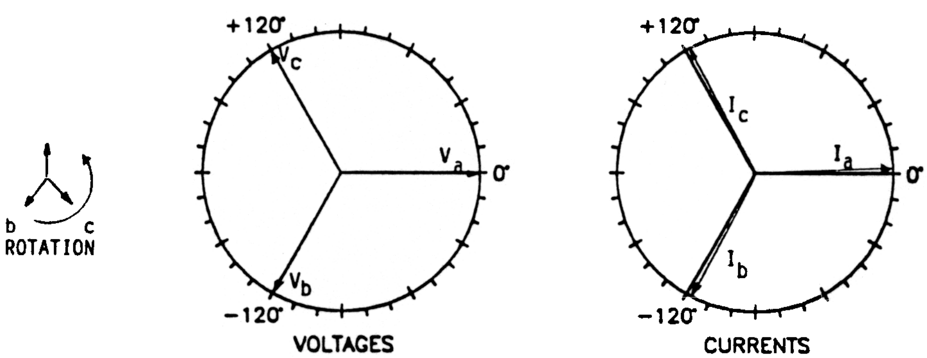
It is interesting to note how the microprocessor relay sampled the sinusoidal waveforms. Notice, for example, that every other sample in each column has the same magnitude, but opposite sign. The reason for the sign change is evident from the graph of the Aϕ current in Figure 3.

STATION QUINCY SUBSTATION DATE: 6/ 7/ 89 TESTED BY ____________
SWITCH NO. ____________ EQUIPMENT ____________
INSTALLATION ______ ROUTINE ______ OTHER EVENT REPORT INVESTIGATION
(REVERSE ROTATION CONNECTION)

LOAD CONDITIONS:
STATION READINGS: MW (OUT)(IN) MVAR (OUT)(IN) ______ VOLTS ______ AMPS
SEL READINGS: MW (+)(−) MVAR (+)(−)

AS SEEN ON SCREEN	Ia	Ib	Ic	Va	Vb	Vc	
COMPANY NOTATION	I(a)	I(c)	I(b)	V(a)	V(c)	V(b)	
1st LINE CHOSEN (Y COMPONENT)	-60	3	63	-40.0	3.2	36.7	
2nd LINE CHOSEN (X COMPONENT)	-25	65	-43	-19.4	44.3	-25.0	
CALCULATED MAGNITUDE $\sqrt{X^2+Y^2}$	65	65.07	76.28	44.46	44.42	44.41	ROW 1
ANGLE IN DEGREES ARCTAN Y/X	-112.62	2.64	124.32	-115.87	4.13	124.26	
VALUE OF Va DEGREES TO SUBTRACT TO OBTAIN Va DEGREES = 0	-244.13	-244.13	-244.13	-244.13	-244.13	-244.13	
@ Va DEGREES = 0, ANGLE USED TO DRAW PHASOR DIAGRAM	+3.25	-241.49	-119.81	0	-240.0	-119.87	ROW 2

USE THE VALUES IN ROWS 1 AND 2 ABOVE TO DRAW PHASOR DIAGRAMS BELOW



DWG. NO. A7-0446
DATE: 12-07-88

Figure 2. Incorrect Wiring Direction and Polarity Check Worksheet

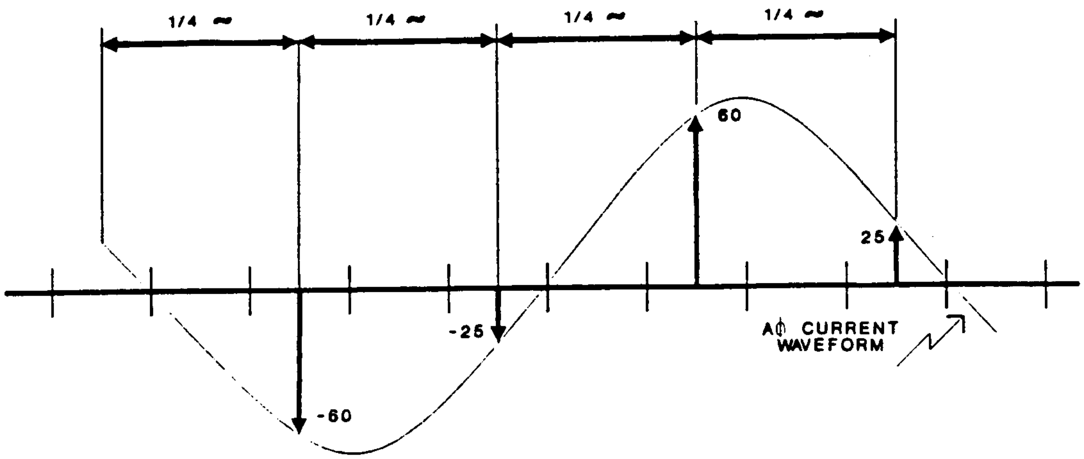


Figure 3. First Cycle of Aϕ Current Samples, Incorrect Wiring Event Report

Example 2. High Impedance Ground Fault

On January 26, 1989, Lea County Electric Cooperative, Inc. experienced an Aϕ-ground fault on their 69kV system where the conductor contacted a support arm. The microprocessor relay was performing as a fault locator on OCB 19 at the time of the fault. The Zone 1, 2, and 3 elements were set for 100%, 300%, and 700% of the line length respectively.

Due to a fault location reading of 4.05 miles (80% of Zone 1 reach) with only a Zone 2 ground distance element operation, engineers immediately suspected a high impedance fault. The Zone 1 ground distance element did not assert during the fault. Field patrols verified the fault location as approximately 4.02 miles from OCB 19 on the 5.10 mile line. This gave credibility to the line parameters modeled in the relay settings.

The full event report for this fault is shown in Figure 4.

The event report was entered into the SEL-PROFILE TRANSMISSION LINE FAULT ANALYSIS PROGRAM to verify fault location. Results from the fault analysis program using the Takagi method yielded a fault location of 4.02 miles. These results agreed with the fault location from the microprocessor relay. Based on the simple reactance method, both manual and fault analysis program calculations yielded a fault location of 3.36 miles. The results for the Takagi and reactance methods differ because the reactance method ignores fault resistance.

In addition to recalculating the fault location, the fault analysis program also computed voltage and current at the fault location for each phase.

Figure 5 shows the system voltage and current display from the SEL-PROFILE FAULT ANALYSIS PROGRAM for this event.

```
*** OCB 19 *** SEL 121                              Date: 1/26/89     Time: 05:50:05.904

FID=SEL-121-R101-V656mpacp21c-D880404

                  Currents                   Voltages      MHO +Seq -Seq Outs    Ins
                  (amps)                      (kV)
                                                         ABCABC ilv  ivV3 TCTTTTA DTBD5E
 /K*RES     A       B       C       A       B       C   GGGBCA         2 PLTABCL TTTC2T

     0    -41       3      40   -38.3     9.0    29.5 ...... *.* .... ....... ......
     0     20     -47      24    11.6   -39.2    27.6 ...... *.* .... ....... ......
     0     41      -3     -40    38.3    -9.0   -29.5 ...... *.* .... ....... ......
     0    -20      47     -23   -11.6    39.2   -27.6 ...... *.* .... ....... ......

     0    -41       3      40   -38.3     9.0    29.5 ...... *.* .... ....... ......
     0     20     -47      23    11.6   -39.2    27.6 ...... *.* .... ....... ......
     0     41      -3     -40    38.3    -9.0   -29.5 ...... *.* .... ....... ......
     0    -20      47     -23   -11.6    39.2   -27.6 ...... *.* .... ....... ......

     0    -41       3      40   -38.3     9.0    29.5 ...... *.* .... ....... ......
     0     20     -47      23    11.6   -39.2    27.6 ...... *.* .... ....... ......
     0     41      -3      40    38.3    -9.0   -29.5 ...... *.* .... ....... ......
   -46    -24      47     -24   -11.6    38.2   -27.6 ...... *.* .... ....... ......

  -381   -322      -3      36   -35.5     8.5    28.9 ...... *.* .*.. ....... ......
   -39   -271     -52      27     9.3   -39.5    27.3 ...... *.* **.. ....... ......
  1309    983      18     -22    27.7    -6.8   -26.9 ...... *.* **.. ....... ......
   405    978      68     -30    -2.6    39.3   -27.4 2..... *.* **.* ....... ......

 -1975  -1440     -27      12   -21.9     5.7    25.1 2..... *.* **** ....... ......
  -707  -1479     -87      35    -2.6   -38.8    27.8 2..3.. *.* **** ....... ......
  2085   1502      21     -11    20.9    -5.8   -24.5 2..3.. *.* **** ....... ......
   776   1574      98     -44     3.5    38.6   -27.9 2..3.. *.* **** ....... ......

 -2064  -1484     -12      13   -20.6     6.1    24.2 2..3.. *.* **** ....... ......
  -780  -1574    -102      53    -3.7   -38.5    27.9 2..3.. *.* **** ....... ......
  2041   1471       4     -12    20.6    -6.2   -24.0 2..3.. *.* **** ....... ......
   769   1560     104     -62     3.7    38.3   -27.9 2..3.. *.* **** ....... ......

 -2027  -1468       1      10   -20.7     6.3    23.9 2..3.. *.* **** ....... ......
  -761  -1552    -104      67    -3.7   -38.2    27.9 2..3.. *.* **** ....... ......
  2027   1470      -5      -9    20.6    -6.4   -23.8 2..3.. *.* **** ....... ......
   771   1563     105     -70     3.7    38.1   -27.9 2..3.. *.* **** ....... ......

 -2005  -1455       8       8   -20.5     6.4    23.7 2..3.. *.* **** ....... ......
  -754  -1545    -104      74    -3.9   -37.9    27.9 2..3.. *.* **** ....... ......
  1981   1448     -12      -7    20.8    -6.5   -23.6 2..3.. *.* **** ....... ......
   714   1505     101     -74     4.0    37.8   -28.0 2..3.. *.* **** ....... ......

 -1962  -1449      14       7   -21.2     6.6    23.6 2..3.. *.* **** ....... ......
  -670  -1459     -97      74    -4.1   -37.7    28.1 2..3.. *.* **** ....... ......
  1950   1454     -17      -3    21.7    -6.6   -23.7 2..3.. *.* **** ....... ......
   638   1423      87     -60     4.1    37.7   -28.2 2..3.. *.* **** ....... ......

 -1973  -1475      20       0   -21.8     6.4    24.0 2..3.. *.* **** ....... ......
  -660  -1441     -67      31    -4.0   -37.8    28.2 2..3.. *.* **** ....... ......
  1978   1479     -25      -2    21.5    -6.1   -24.2 2..3.. *.* **** ....... ......
   747   1476      40     -14     4.3    37.8   -28.2 2..3.. *.* **** ....... ......

 -1540  -1127      19       3   -25.2     6.6    25.1 2..3.. *.* **** ....... ......
  -650  -1155     -19       8    -0.7   -37.8    28.1 2..3.. *.* **** ....... ......
   631    419      -8      -1    32.8    -8.2   -27.1 2..... *.* **.* ....... ......
    50    476      20      -2    -6.5    38.2   -27.7 ...... *.* **.. ....... ......

Event   : 2AG     Location   : 4.05   mi  0.29   ohms sec
Duration: 7.00    Flt Current: 2122

R1  = 3.60   X1  = 4.23   R0  = 5.94   X0  = 14.09  LL  = 5.10
CTR = 40     PTR = 600    MTA = 49.61  79OI= 30.00  79RS= 60.00
Z1% = 100.00 Z2% = 300.00 Z2DG= 10.00  Z2DL= 15.00
Z3% = 700.00 Z3DG= 60.00  Z3DL= 45.00  50FD= 300    46PH= 1000   TTI = 1
Z1E = Y      Z2E = Y      Z3E = Y      32QE= Y      GSE = Y      BPFE= Y
```

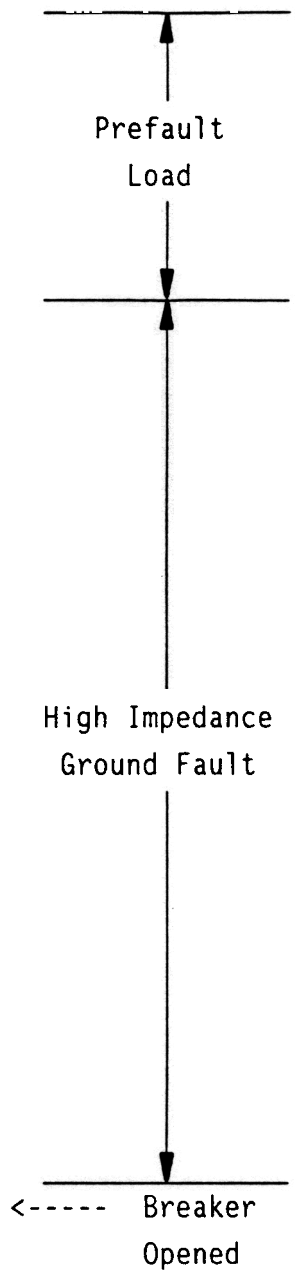


Figure 4. High Impedance Ground Fault Event Report

SYSTEM VOLTAGE/CURRENT PROFILE

FAULT AT ‹4.02› MI/KM FROM ‹···OCB 19··· SEL 121›

		BUS	LINE	FAULT
VA	(kV)	20.93	20.93	9.37
	(deg)	/-27.03	/-27.03	/-65.09
VB	(kV)	38.73	38.73	42.34
	(deg)	/-116.36	/-27.03	/-65.09
VC	(kV)	36.67	36.67	37.92
	(deg)	/+113.62	/+113.62	/+122.02
IA	(amps)	2137.66	2137.66	2137.66
	(deg)	/-63.40	/-63.40	/-63.40
IB	(amps)	104.12	104.12	104.12
	(deg)	/-109.60	/-109.60	/-109.60
IC	(amps)	67.60	67.60	67.60
	(deg)	/+80.80	/+80.80	/+80.80

Figure 5. System Voltage/Current Profile Printout

The Aϕ voltage at the fault divided by the Aϕ current at the fault equals the line-ground fault resistance as shown below:

$$R_f = VA_f/IA_f = \frac{9.37\text{kV } /{-65.09°}}{2137.66\text{A } /{-63.04°}} = (4.40 - j0.22)\Omega.$$

Thus, the fault contained 4.40Ω of fault resistance. Hand calculations of the fault resistance also yielded 4.40Ω (See APPENDIX A).

Figure 6 shows the effect of the impedance in the fault on the mho distance characteristics.

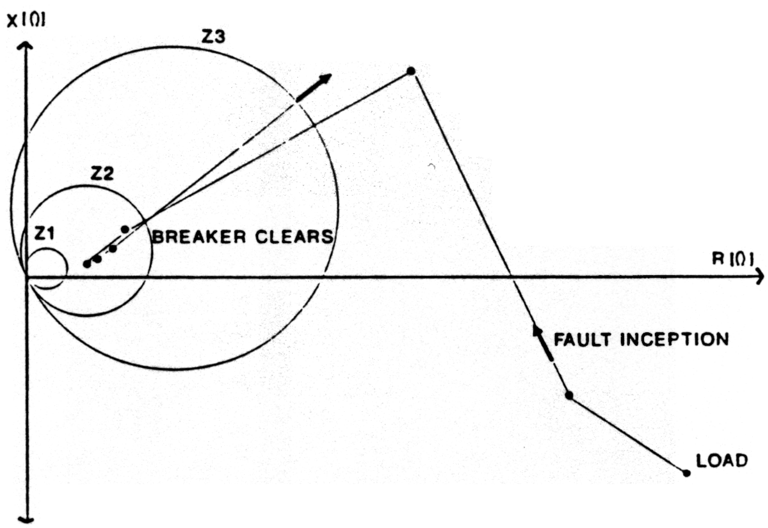


Figure 6. Lea County Electric Event Report R-X Diagram

Example 3. Blocking Carrier Coordinating Time

On May 4, 1989, Grand River Dam Authority (GRDA) experienced a misoperation of the directional comparison blocking scheme on the MAID-HUNT 115kV transmission line. The event report saved by the microprocessor relay indicated a fault within the Zone 2 ground overcurrent element zone of protection. Trouble occurred for this event because the blocking signal did not arrive in time to block the Zone 2 carrier ground element from tripping the breaker.

The portion of the event report shown in Figure 7 recorded the time relationship between Zone 2 ground overcurrent element assertion and the arrival of the blocking carrier signal. The Zone 2 carrier coordinating time interval was set to 0.75 cycles but the block signal arrived after the Zone 2 carrier ground overcurrent element asserted; hence, the MAID-FDR 91 breaker tripped. After reviewing the data saved in the event report below, GRDA engineers determined that the carrier propagation delay for the MAID-HUNT transmission line was longer than expected. GRDA engineers lengthened the carrier coordinating time of the Zone 2 elements to avoid any future trouble. Had there not been an event report to show the relationship of the carrier elements, it would have been very difficult to determine the cause of the misoperation.

MAID-FDR 91 Date: 3/04/89 Time: 15:24:42.791

FID=SEL-121G-R102-V656mptr12-D881024

		Currents (amps)				Voltages (kV)		Relays	Outputs	Inputs
								52265L	TCAAAAA	DPBD5E
IPOL	IR	IA	IB	IC	VA	VB	VC	011710	PL1234L	TTTC2T
								P3PNNP		A
-8	3	96	-204	108	16.2	-39.9	23.5	L.....	....	....*.
-3	0	186	-18	-169	36.8	-4.5	-32.2	L.....	....	....*.
10	-7	-96	204	-108	-16.2	39.9	-23.6	L.....	....	....*.
0	0	-186	18	169	-36.8	4.5	32.2	L.....	....	....*.
-10	7	96	-204	108	16.2	-39.9	23.6	L.....	....	....*.
0	0	186	-18	-169	36.8	-4.5	-32.2	L.....	....	....*.
8	-7	-96	204	-108	-16.2	39.9	-23.6	L.....	....	....*.
3	0	-186	18	169	-36.8	4.5	32.2	L.....	....	....*.
-8	3	96	-204	108	1[illegible]2	-39.[illegible]	23.6	L.....	....	....*.
-3	3	186	-18	-169	3[illegible]8	-4.[illegible]	-32.2	L.....	....	....*.
8	-3	-96	204	-108	-1[illegible]5	40.[illegible]	-23.4	L.....	....	....*.
3	-3	-186	18	169	-3[illegible]5	4.[illegible]	31.8	L.....	....	....*.
189	-51	30	-206	118	17.3	-39.9	23.0	L.....	....	....*.
-1085	318	418	13	-108	27.9	-2.5	-29.2	L.....	....	....*.
-1440	482	372	239	-126	-12.7	38.6	-23.9	L.....	....	....*.
2683	-729	-690	-60	15	-20.1	0.6	26.0	L...P.	....	....*.
3038	-992	-810	-287	103	6.8	-37.0	25.5	L...P.	....	....*.
-2952	749	685	60	8	18.4	-0.1	-24.9	L..2P.	*......	....*.
-3431	1095	886	305	-93	-6.3	36.7	-25.7	L..2P.	*......	..*.*.
2824	-712	-677	-43	5	-18.3	0.1	24.8	L..2P.	*......	..*.*.
3395	-1091	-896	-300	106	6.4	-36.6	25.8	L..2P.	*......	..*.*.
-2844	715	687	33	-5	18.6	-0.1	-24.7	L..2P.	*......	..*.*.
-3451	1105	906	297	-101	-6.0	36.6	-26.2	L..2P.	*......	..*.*.
2799	-712	-677	-30	0	-18.7	-0.0	25.1	L..2P.	*......	..*.*.

Zone 2 Ground Element Asserted

Arrival of Block Signal

Figure 7. Six Cycles of the Blocking Carrier Coordinating Time Event Report

Example 4. Zero-Sequence Voltage Reversal

On January 30, 1989, B.C. Hydro experienced a misoperation of the permissive overreaching transfer trip scheme (POTT) of the 2L2 line. The initiating cause of the misoperation was the 500kV breaker at Cheekye (CKY) reclosing into a permanent fault on 5L42.

Figure 8 shows the single line diagram of this system.

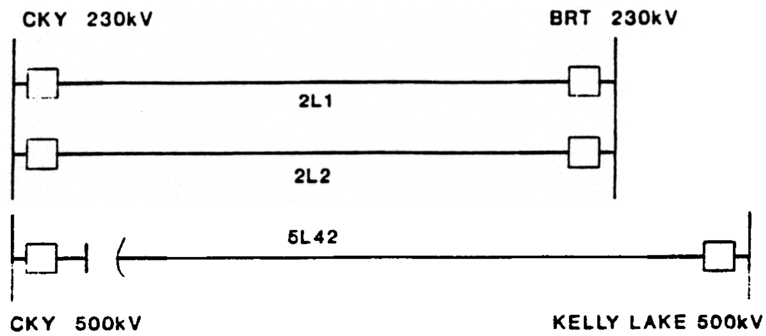


Figure 8. CKY, BRT, and Kelly Lake System Diagram

Analysis of the event reports determined that zero-sequence mutual coupling from the 500kV transmission line to the parallel 230kV lines created the misoperation of the 2L2 protective scheme. This zero-sequence mutual coupling inverted the zero-sequence voltage at the CKY 230kV terminal. Thus, the CKY 230kV terminal declared the actual reverse fault as a forward fault, allowing its Zone 2 ground overcurrent element to assert and give trip permission to the Bridge River Terminal (BRT). The fault was actually in the forward direction for the BRT terminal, so its Zone 2 ground overcurrent element also asserted. The result was that both 2L2 terminals gave permission to trip.

Zero-sequence voltage polarized schemes declare a fault as forward when the zero-sequence current leads the zero-sequence voltage plus or minus 90 degrees from the maximum torque angle (Figure 9).

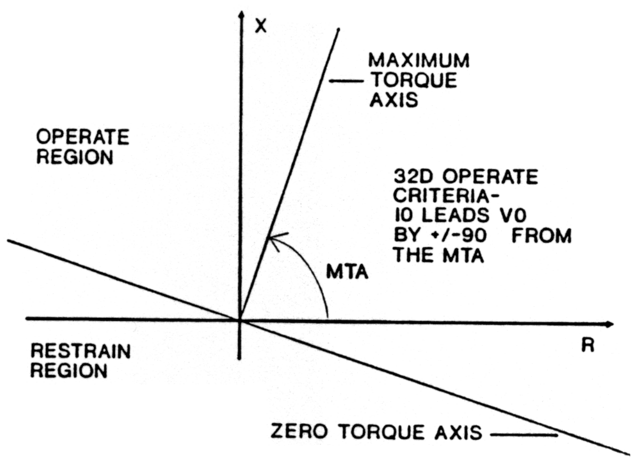


Figure 9. Operate and Restrain Regions of Zero-Sequence Directional Element

The graphs in Figures 10 and 11 show the relationship of the zero-sequence voltage and currents prior to, during, and after the CKY terminal tripped. The phase angular relationship of V0 and I0 were easily obtained by converting consecutive rows of data in the event report from rectangular coordinates to polar using the fault analysis program.

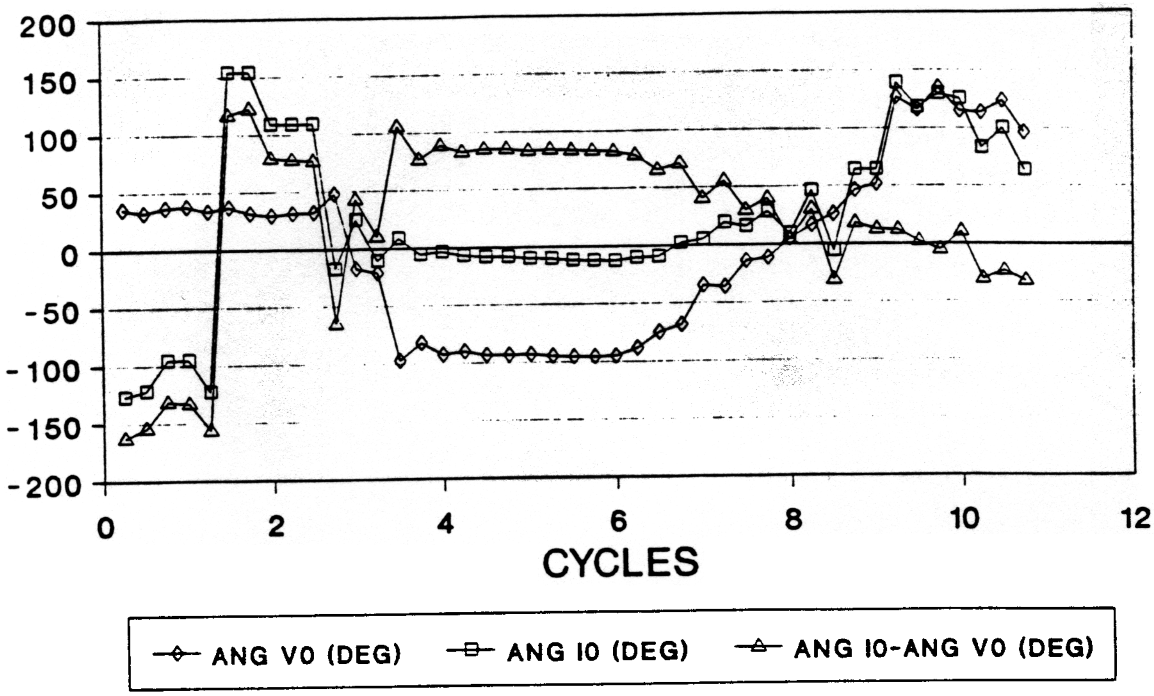


Figure 10. I0 vs V0 for CKY 230kV Terminal

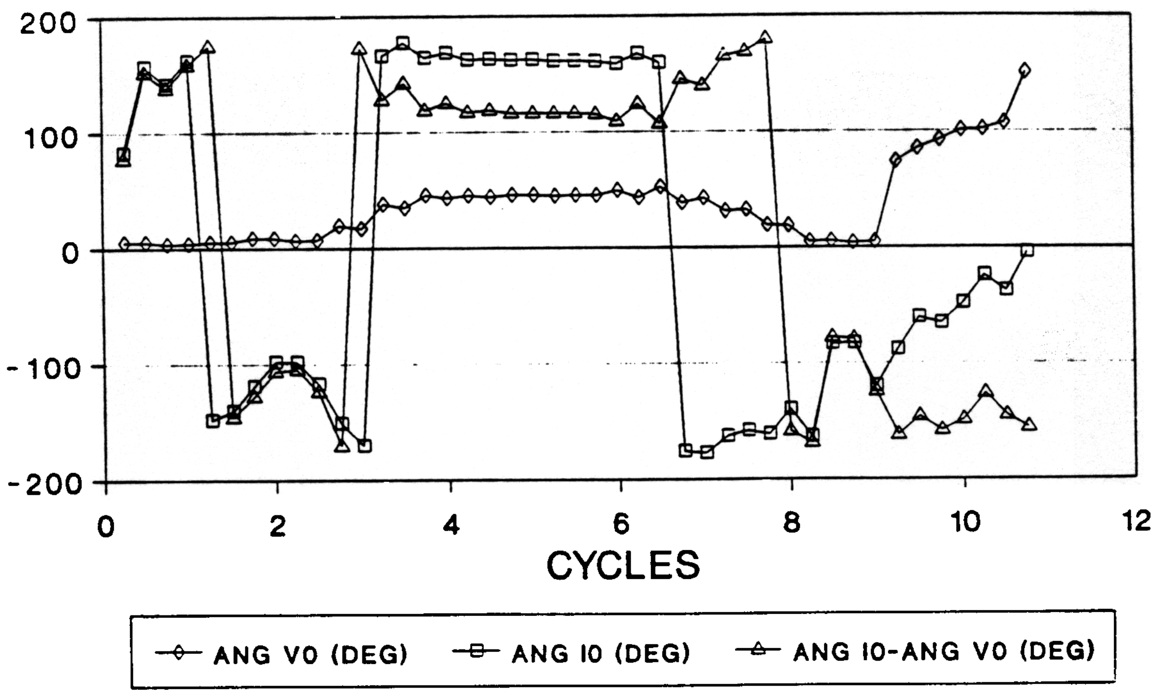


Figure 11. I0 vs V0 for BRT 230kV Terminal

Notice in the CKY graph that the zero-sequence voltage is inverted to what was expected for a normal reverse fault, as shown by the zero-sequence current (I0) leading the zero-sequence voltage (V0). Thus, the CKY terminal declared the actual reverse fault as a forward fault. The BRT graph of the V0 and I0 relationship shows I0 leading V0 for the same fault, as expected for a forward fault.

The graph in Figure 12 compares the angle of the negative-sequence voltage and currents to the angle of the zero-sequence voltage and currents for the same event at the CKY 230kV terminal. Had the ground overcurrent relay at CKY been negative-sequence polarized, the fault would have been declared a reverse fault and the POTT scheme would not have misoperated.

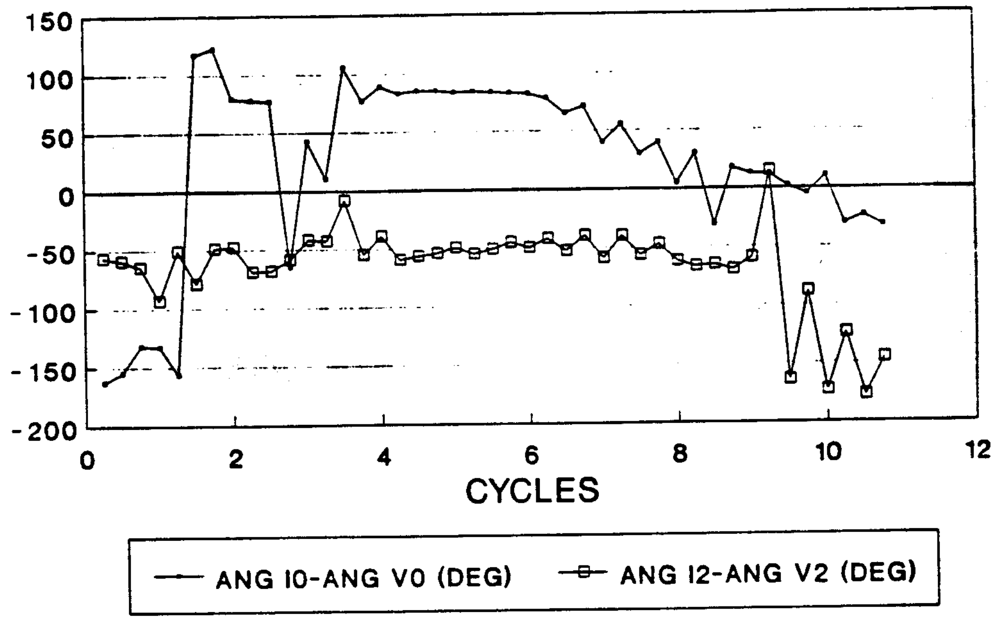


Figure 12. I2 vs V2 Comparison with I0 vs V0 at the CKY Terminal

As a solution, B.C. Hydro engineers recommended the ground directional element be changed to negative-sequence at the CKY and BRT 230kV terminals. They accomplished this change with a simple setting modification.

Example 5. Evolving Fault

On July 17, 1989, Pacific Gas and Electric's PITT-VACA 2 230kV transmission line experienced an Aϕ-ground fault which evolved into an Aϕ-Bϕ-ground fault. PG&E installed the microprocessor relay as a fault locator to assist field people in locating a suspected faulty insulator string.

The microprocessor relay detected the fault and targeted it to show the involvement of phases A, B, and ground. A digital oscillograph record of this fault trace did not show the involvement of the Bϕ current, because the Bϕ current was too small due to channel scaling requirements. However, the Bϕ current column in the microprocessor relay event report showed that the Bϕ current was indeed involved just prior to the breaker opening.

Part of the event report from this fault is shown in Figure 13.

This fault location error was of particular concern to engineers at PG&E. The relay calculated a fault location of 120.31 miles but the line length was only 107.89 miles. Primary protection at both ends of this line operated, indicating that the fault was in-section to the line.

The event report segment in Figure 13 shows that the fault involved only phase A until the last few cycles. The fault locator in this relay (SEL-121) determines the fault type from all of the elements picked up during the report, then calculates and averages the fault location for the data rows where the elements are asserted. Thus, the microprocessor relay used the line-ground fault data as input to calculate phase-phase fault location.

Using the data from the microprocessor relay and the fault analysis program (where the fault type could be declared), a corrected fault location of 45.78 miles for an Aϕ-ground fault resulted.

Notice in the event report that even while the breaker status contact is not wired into the microprocessor relay, the breaker's opening can be determined by the drop of the phase currents to zero and the voltages rising to their prefault level near the end of the event report.

```
PITT VACA 2 230 KV LINE.                    Date: 7/17/89     Time: 22:08:47.120

FID=SEL-121-R101-V656mpacp21c-D880404

                Currents                 Voltages      MHO  +Seq -Seq Outs     Ins
                 (amps)                    (kV)
                                                   ABCABC iIv  ivV3 TCTTTTA DTBD5E
/K*RES      A       B       C       A       B       C GGGBCA           2 PLTABCL TTTC2T


  -991  -1080       0      53 -117.5    21.1   104.4 1..3.3 *** **.* *.****. ......
 -1734  -1749      38      -8   42.0  -132.4    87.7 1..3.3 *** **.* *.****. ......
   875   1092    -123     -53  117.6   -21.0  -104.1 1..3.3 *** **.* *.****. ......
  1530   1769    -287      28  -41.8   132.3   -87.5 1..3.3 *** **.* *.****. ......     Aϕ-Ground
                                                                                          Fault
  -535  -1082     461      50 -118.4    21.5   103.7 1..3.3 *** **.* *.****. ......
 -1074  -1759     725     -20   41.8  -132.4    87.6 1..3.3 *** **.* *.****. ......
   231   1062    -763     -50  118.9   -22.1  -103.5 1..3.3 *** **.* *.****. ......
   747   1724    -994       3  -42.1   132.3   -88.0 1..3.3 *** **.* *.****. ......

   -20   -883     798      53 -118.9    22.0   103.3 33.1.3 *** **.* *.****. ......
  -499  -1334     838       0   41.5  -132.0    88.2 33.1.3 *** **.* *.****. ......
   -66    398    -408     -48  120.9   -21.9  -103.6 1..3.3 *** **.* *.****. ......
   218    536    -317       0  -41.9   131.9   -88.1 3..3.. *.* **.* *..***. ......     Evolution of
                                                                                        Fault to
    13    -60      35      35 -123.6    22.0   103.9 3..... *.* **.* *..***. ......     A-B-Ground
   -43    -68      18       5   43.7  -131.8    87.9 ...... *.* **.. ....... ......
     3     20       0     -15  124.2   -21.9  -103.7 ...... *.* **.. ....... ......
            5       8       0  -44.6   131.8   -87.7 ...... ..* .*.. ....... ......

Event   : 1ABG   Location   : 120.31 mi  7.39   ohms sec
Duration: 6.50   Flt Current: 2069
```

Figure 13. Evolving Fault Event Report

Example 6. Closing a Generator Breaker Out-of-Synchronism

A microprocessor relay installed as a breaker failure relay at the ANGOSTURA UNIDAD generating facility operated by the national utility of Mexico (Comision Federal De Electricidad) recorded a sequence of attempts to connect an unsynchronized 225 MVA generator with the system and the resulting trip-outs.

In addition to saving individual event reports, microprocessor relays also store a history of the recorded events. Figure 14 shows a partial listing of the event histories stored on the day the operator attempted to close the generator breaker out-of-synchronism.

```
ANGOSTURA UNIDAD 4/INT. A1040              Date: 03/31/89   Time: 14:14:44

EVENT TYPE    52A     IV-TIME   ENERGY  DATE      TIME
              (cyc)   (cyc)     (MJ)

1    TRIP3    1.75     2.75     0.00  03/22/89  06:58:16.391
2    CLOSE    7.75     0.00     0.00  03/22/89  06:10:49.008
3    TRIP3    0.00     0.00     0.00  03/22/89  06:06:34.825
4    TRIP3    1.75     3.00     0.00  03/22/89  06:06:34.012
5    TRIP3   13.25+    2.50     0.00  03/22/89  06:06:30.912
6    CLOSE    8.00     0.00     0.00  03/22/89  06:05:14.445
7    CLOSE   13.25+    0.00     0.00  03/22/89  06:03:25.654
8    TRIP3   13.25+    0.00     0.00  03/22/89  00:48:01.995
```

Figure 14. Summary of Events

The following is a synopsis of each recorded event:

- Event 8 recorded the initial fault that tripped the generator off-line.
- Event 7 recorded the operator's first attempt to parallel the generator to the system approximately 45 minutes after trip-out.
  Event 6 recorded the operator's second attempt to synchronize the generator to the system two seconds later. Figure 15 shows the A-phase current after the breaker was initially closed. Data shown in the breaker failure relay event report are not dc filtered (however, the quantities used by the microprocessor relay for protective functions are).
  Event 5 recorded external relaying tripping the generator breaker for out-of-step conditions approximately one second after Event 6.
- Events 4 and 3 recorded external relaying tripping of the generator breaker.
- Event 2 recorded the operator's final unsuccessful attempt to close the generator breaker to parallel.
  Event 1 recorded external relay tripping of the generator breaker.

This cumulative history and individual event reports from the microprocessor relay, along with external relaying targets, supplied protection engineers the information necessary to piece together the sequence of events (for cross referencing the operator's logs).

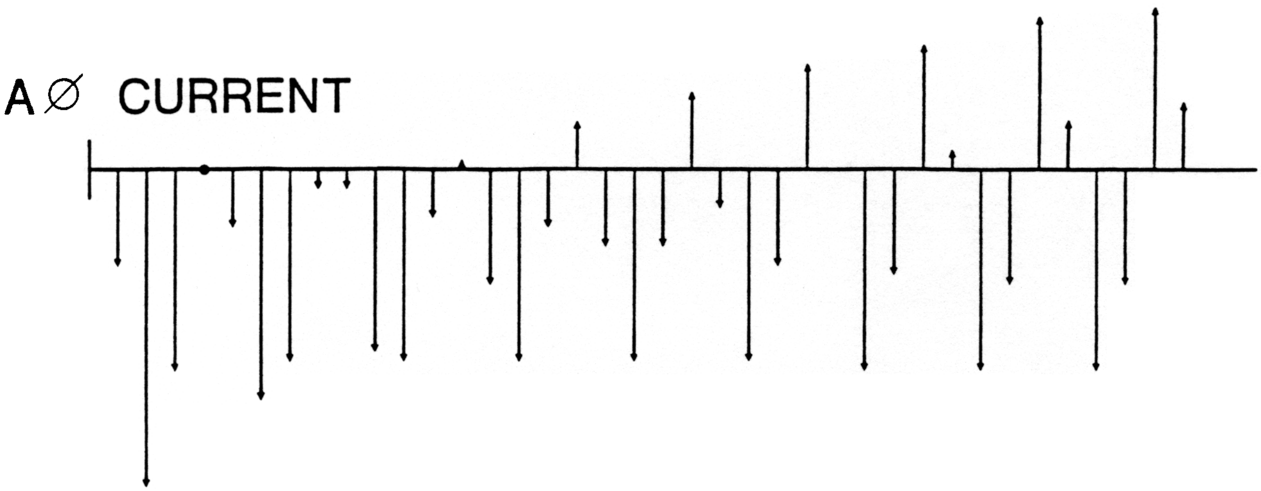


Figure 15. Aϕ Current Waveform from Event 6

Example 7. Excessive Tertiary Current

The Western Area Power Administration's Rainbow-Havre 161kV transmission line undergoes many outages during the lightning season. After a fault on July 25, 1989, WAPA engineers examined the event report and noticed that phase currents did not go to zero after the line breaker tripped. The event report shows that all three phase currents had approximately the same magnitude and phase angle after the breaker opened (52a input deassertion confirms the breaker opening). Thus, zero-sequence current flowed in each of the phase conductors after the breaker tripped. Notice that the tertiary current (monitored in the Ipol column) also increased with time after the breaker cleared the fault. Subsequent event reports saved by the microprocessor relay for later faults recorded the same phase current characteristics after the breaker opened. Figure 16 shows a single line diagram of the Rainbow-Havre system.

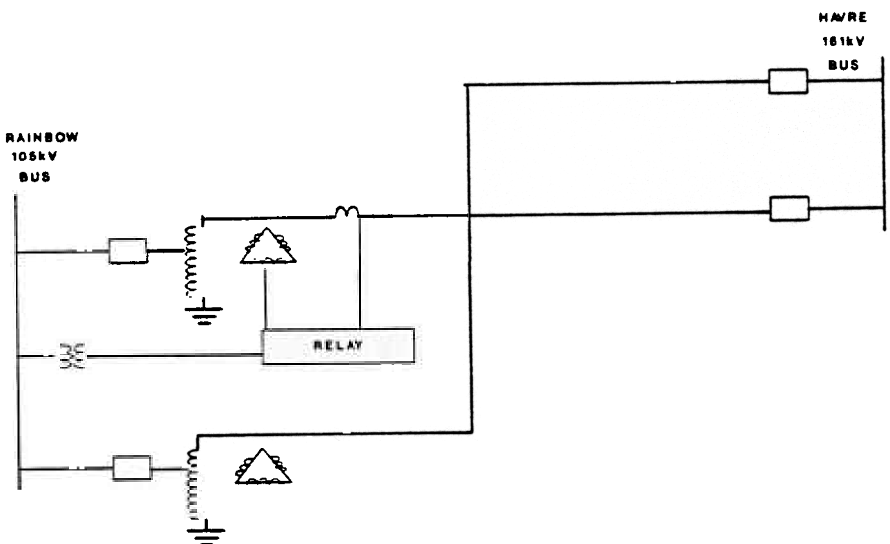


Figure 16. Rainbow-Havre Single Line Diagram

The event report from this fault appears in Figure 17 on the following page.

RAINBOW: HAVRE 161KV LINE   Date: 7/25/89   Time: 00:50:25.637

FID=SEL-121G-R107-V656mpac11-D881024

		Currents (amps)				Voltages (kV)		Relays	Outputs	Inputs	
								52265L	TCAAAAA	DPBD5E	
IPOL	IR	IA	IB	IC	VA	VB	VC	011710	PL1234L	TTTC2T	
								P3PNNP		A	
8	-0	-38	53	-14	48.1	8.4	-56.4	L.....	....	....*.	
6	-0	-40	-13	52	-37.4	60.4	-23.3	L.....	....	....*.	
-8	0	38	-53	14	-48.1	-8.4	56.3	L.....	....	....*.	
-6	1	40	13	-52	37.3	-60.4	23.3	L.....	....	....*.	
8	-1	-38	53	-14	4 1	8.4	-56.3	L.....	....	....*.	
6	-0	-40	-13	52	-3 3	60.4	-23.3	L.....	....	....*.	
-8	0	38	-53	14	-4 1	-8.4	56.3	L.....	....	....*.	
-6	0	40	13	-52	3 3	-60.4	23.4	L.....	....	....*.	
8	0	-38	53	-14	48.1	8.3	-56.3	L.....	....	....*.	
6	-0	-40	-13	52	-37.3	60.4	-23.4	L.....	....	....*.	
-8	0	38	-53	14	-48.1	-8.3	56.3	L.....	....	....*.	
-6	0	40	13	-52	37.3	-60.4	23.4	L.....	....	....*.	
8	-0	-38	53	-14	48.1	8.4	-56.3	L.....	....	....*.	
5		-40	-11	52	-37.3	60.2	-23.6	L.....	....	....*.	
·246	201	35	150	14	-47.7	-10.4	56.8	L.....	....	....*.	Fault Inception
248	-293	36	-268	-59	36.3	-53.7	22.7	M...P.	....	....*.	
1075	-685	-22	-820	-10	47.9	9.3	-57.2	H32.P.	*...*..	....*.	Trip Contact Asserted
-528	528	-29	650	75	-35.1	45.5	-21.3	H321P.	*...*..	....*.	
-1814	1327	15	1465	9	-48.3	-5.7	56.5	H211P.	*...*..	....*.	
494	-580	25	-692	-81	34.5	-43.2	21.1	H.11P.	*...*..	....*.	
1923	-1579	-17	-1608	-13	48.5	5.0	-56.2	H211P.	*...*..	....*.	
-463	643	-26	657	79	-34.1	42.8	-21.1	H211P.	*...*..	....*.	
-1916	1567	14	1600	12	-48.6	-4.8	56.1	H.11P.	*...*..	....*.	
463	-648	26	-663	-79	34.0	-42.6	21.1	H.11P.	*...*..	....*.	
1916	-1611	-12	-1609	-12	48.5	4.7	-55.9	H.11P.	*...*..	....*.	
-462	676	-25	652	79	-33.8	42.5	-21.2	H.11P.	*...*..	....*.	
-1920	1600	12	1599	12	-48.5	-4.6	55.7	H.11P.	*...*..	....*.	Breaker Opened
496	-680	14	-658	-67	33.7	-42.6	21.3	H.11P.	*...*..	......	
1779	-1612	-15	-1588	-16	48.4	4.6	-55.6	H.11P.	*...*..	......	
-450	709	8	673	42	-33.6	42.5	-21.5	H.11P.	*...*..	......	
-1624	1585	20	1554	21	-48.4	-3.7	55.5	H.11P.	*...*..	......	
589	-671	-23	-632	-33	33.7	-44.9	21.5	H.11P.	*...*..	......	
2840	-1268	-59	-1147	-57	48.4	2	-55.0	H211P.	*...*..	......	
-1809	440	44	346	51	-33.9	5	-21.9	H221P.	*...*..	......	
-4411	733	119	493	116	-48.3	-4	54.9	M.31P.	*...*..	......	
2413	-230	-60	-102	-67	34.2	-5	22.2	M..1P.	*...*..	......	
5267	-483	-143	-193	-143	48.2	6.5	-55.1	L..1P.	*...*..	......	
-2185	212	61	80	69	-34.3	55.9	-22.2	L..1P.	*...*..	......	
-5545	446	146	153	145	-48.2	-6.8	55.2	L..1P.	*...*..	......	
2139	-214	-63	-79	-70	34.5	-56.1	22.2	L..1P.	*...*..	......	
5591	-442	-147	-147	-145	48.1	6.9	-55.2	L..1P.	*...*..	......	
-2040	213	64	78	70	-34.5	56.1	-22.2	L..1P.	*...*..	......	
-5690	442	147	146	145	-48.1	-7.0	55.3	L..1P.	*...*..	......	
2027	-210	-64	-76	-70	34.6	-56.1	22.2	L..1P.	*...*..	......	

Event   : 1BG   Location   : 21.28 mi   0.85   ohms sec
Duration: 7.25   Flt Current: 1693.0

Figure 17. Excessive Tertiary Current Event Report

Due to the placement of the current transformers on the line-side of the autotransformer, the microprocessor relay was able to monitor current flow in the phase conductors after the breaker opened.

The exact cause of the zero-sequence current flow in the phase conductors after the line breaker opened is presently under investigation by WAPA engineers. Possible causes are:

1. Slow clearing of the remote breaker
2. Mutual induction from the parallel line

<u>Example 8. Sequential Clearing</u>

Southern California Edison's CONTROL-INYOKERN 115kV transmission line experienced an Aϕ-ground fault on November 5, 1987.

Figure 18 shows the single line diagram of the faulted system.

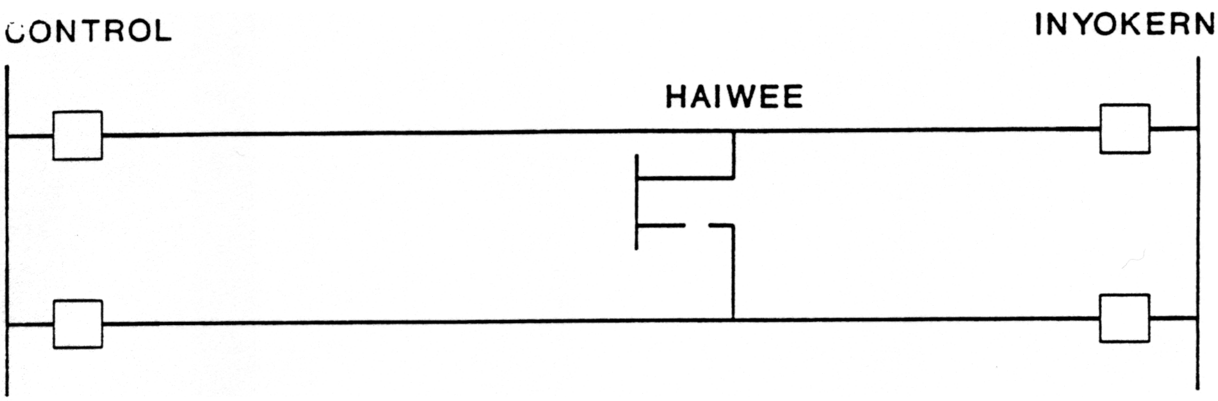


Figure 18. CONTROL - INYOKERN 115kV Transmission System Single Line

As shown in the event reports in Figures 19 and 20, the microprocessor relay at CONTROL detected the line-ground fault in Zone 2 and later in Zone 1, while the microprocessor relay at INYOKERN detected the fault in Zone 1 only. For the time that the microprocessor relay at CONTROL declared the fault to be within Zone 2, the INYOKERN terminal was feeding the fault. This infeed was the reason CONTROL did not initially declare the fault a Zone 1 fault. After the INYOKERN terminal cleared, CONTROL declared the fault in Zone 1.

By comparing the two event reports, one can see that the transition of the fault from Zone 2 to Zone 1 at CONTROL coincided with the time the Zone 1 element at INYOKERN dropped out. This would lead one to assume that the microprocessor relays at either end of the line saw the fault at approximately the same time.

From these observations, one can observe that the CONTROL-INYOKERN transmission line relayed sequentially.

CONTROL-HAIWEE #1 OR #2 115KV LINE Date:11/5/87 Time: 21:44:57

	Currents (amps)			Voltages (kV)			MHO	+Seq	-Seq	Outs	Ins
							ABCABC	ilv	ivV3	TCTTTT2	DTBD5E
/K*Res	IA	IB	IC	VA	VB	VC	GGGBCA		2	PLTABCL	TTTC2T
0	-33	57	-23	68.1	-23.9	-44.3	......	*.*	....	....	......
0	-43	-7	50	-11.6	65.0	-53.3	......	*.*	....	....	......
0	34	-57	23	-68.1	23.9	44.3	......	*.*	....	....	......
0	43	7	-50	11.6	-65.0	53.3	......	*.*	....	....	......
0	-33	57	-23	68.1	-23.9	-44.4	......	*.*	....	....	......
0	-43	-7	50	-11.6	65.0	-53.2	......	*.*	....	....	......
0	33	-57	23	-68.1	23.8	44.4	......	*.*	....	....	......
0	43	7	-50	11.6	-65.0	53.2	......	*.*	....	....	......
0	-33	57	-23	68.1	-23.8	-44.4	......	*.*	....	....	......
0	-43	-7	50	-11.6	65.0	-53.2	......	*.*	....	....	......
-12	11	-50	30	-67.8	23.8	44.3	......	*.*	....	....	......
-11	7	17	-40	12.4	-65.4	52.9	......	*.*	*...	....	......
63	81	25	-56	64.2	-22.4	-43.0	......	*.*	**..	....	......
49	120	-55	2	-11.0	64.9	-53.3	......	*.*	**..	....	......
-122	-189	5	87	-59.9	20.6	41.3	......	*.*	**..	....	......
-88	-253	95	38	8.4	-63.8	54.1	2.....	*.*	**.*	..*....	......
135	217	-16	-96	58.7	-20.2	-40.7	2.....	*.*	**.*	..*....	......
98	293	-108	-52	-8.0	63.6	-54.2	2.....	*.*	**.*	..*....	......
-131	-209	15	92	-58.4	20.1	40.5	2.....	*.*	**.*	..*....	......
-96	-292	108	52	7.9	-63.5	54.2	2.....	*.*	**.*	..*....	......
134	211	-16	-92	58.3	-20.1	-40.4	2.....	*.*	**.*	..*....	......
95	294	-108	-53	-7.9	63.4	-54.1	2.....	*.*	**.*	..*....	......
-135	-211	16	90	-58.3	20.8	40.8	2.....	*.*	**.*	..*....	......
-94	-293	107	53	7.9	-63.3	54.1	2.....	*.*	**.*	..*....	......
158	206	-4	-80	58.4	-20.2	-40.0	2.....	*.*	**.*	..*....	......
121	286	-83	-37	-7.8	63.2	-54.1	2.....	*.*	**.*	..*....	......
-220	-203	-23	57	-59.3	20.8	40.8	2.....	*.*	**.*	..*....	......
-181	-281	35	8	7.9	-63.2	54.0	2.....	*.*	**.*	..*....	......
281	216	38	-41	61.1	-21.8	-41.5	2.....	*.*	**.*	..*....	......
227	296	-7	7	-8.7	63.5	-53.7	2.....	*.*	**.*	..*....	......
-308	-234	-38	40	-62.5	22.5	42.1	2.....	*.*	**.*	..*....	......
-240	-311	3	-9	9.5	-63.9	53.4	1.....	*.*	**.*	*.**...	......
314	240	37	-40	62.8	-22.6	-42.4	1.....	*.*	**.*	*.**...	......
244	316	-3	9	-9.6	64.0	-53.3	1.....	*.*	**.*	*.**...	......
-314	-240	-38	41	-62.9	22.6	42.4	1.....	*.*	**.*	*.**...	......
-244	-316	3	-9	9.6	-64.0	53.3	1.....	*.*	**.*	*.**...	......
314	240	38	-41	63.0	-22.6	-42.5	1.....	*.*	**.*	*.**...	......
244	316	-3	9	-9.7	64.1	-53.3	1.....	*.*	**.*	*.**...	......
-315	-240	-37	41	-63.0	22.7	42.5	1.....	*.*	**.*	*.**...	......
-245	-316	3	-9	9.7	-64.1	53.3	1.....	*.*	**.*	*.**...	......
315	240	37	-40	63.0	-22.6	-42.5	1.....	*.*	**.*	*.**...	......
246	316	-1	9	-9.7	64.1	-53.3	1.....	*.*	**.*	*.**...	......
-314	-240	-37	40	-63.0	22.7	42.5	1.....	*.*	**.*	*.**...	......
-249	-315	-4	-8	9.7	-64.2	53.4	1.....	*.*	**.*	*.**...	......

— Fault Inception

INYOKERN Terminal Breaker Opened

```
Event   : 1AG   Location   : 120.31 mi  7.39   ohms sec
Duration: 6.50   Flt Current: 2069

R1  = 58.32    X1  = 108.18  R0  = 109.37  X0  = 339.35  LL  = 124.76
CTR = 40       PTR = 1000    MTA = 61.70   79OI= 0.00    79RS= 60.00
Z1% = 90.00    Z2% = 120.00  Z2DG= 20.00   Z2DL= 20.00
Z3% = 150.00   Z3DG= 45.00   Z3DL= 45.00   50FD= 150     46PH= 1500   TTI = 3
Z1E = Y        Z2E = Y       Z3E = Y       32QE= N       GSE = Y      BFPE= N
```

Figure 19. CONTROL-HAIWEE Event Report

```
HAIWEE-INYOKERN #1 OR #2 115KV LINES        Date:11/5/87        Time: 21:44:17

                  Currents                      Voltages   MHO   +Seq -Seq Outs     Ins
                   (amps)                        (kV)
                                                           ABCABC iIv ivV3 TCTTTT2 DTBD5E
 /K*Res    IA      IB      IC      VA      VB       VC     GGGBCA        2 PLTABCL TTTC2T

     1    -16      24      -7   -58.4    68.0    -10.8     ...... *.* .... ....... ......
     0    -18      -3      21   -45.0   -27.6     72.5     ...... *.* .... ....... ......
    -1     16     -24       7    58.4   -68.0     10.8     ...... *.* .... ....... ......
     0     18       3     -21    45.0    27.6    -72.5     ...... *.* .... ....... ......

     1    -16      24      -7   -58.4    68.0    -10.8     ...... *.* .... ....... ......
     0    -18      -3      21   -45.0   -27.6     72.5     ...... *.* .... ....... ......
    -1     16     -24       7    58.4   -68.0     10.8     ...... *.* .... ....... ......
     0     18       3     -21    45.0    27.6    -72.5     ...... *.* .... ....... ......

     1    -16      24      -7   -58.4    68.0    -10.8     ...... *.* .... ....... ......
     0    -18      -3      21   -45.0   -27.7     72.5     ...... *.* .... ....... ......
    -1     16     -24       7    58.4   -68.0     10.8     ...... *.* .... ....... ......
     0     18       3     -21    45.0    27.7    -72.5     ...... *.* .... ....... ......

   -36    -33      23      -8   -58.4    68.0    -10.8     ...... *.* .... ....... ......    Fault
  -150   -142     -10      14   -38.6   -29.3     70.5     ...... *.* **.. ....... ......    Inception
   119     20     -23       9    49.4   -66.2     13.2     ...... *.* **.. ....... ......
   717    616      45      16    26.5    33.1    -66.2     1..... *.* **.* *.**... ......

  -116    130      28      -4   -31.6    62.3    -18.2     1..... *.* **** *.**... ......
 -1289  -1087     -87     -57   -19.7   -35.9     63.2     1..3.. *.* **** *.**... ......
    -2   -323     -38      -9    21.4   -59.5     21.0     1..3.. *.* **** *.**... ......
  1407   1173     103      72    18.4    36.3    -62.3     1..3.. *.* **** *.**... ......

    51    372      44      16   -19.9    58.8    -21.4     1..3.. *.* **** *.**... ......
 -1382  -1150    -103     -72   -18.1   -36.0     61.9     1..3.. *.* **** *.**... ......
   -36   -354     -43     -18    19.6   -58.7     21.6     1..3.. *.* **** *.**... ......
  1378   1146     104      73    18.0    35.9    -61.7     1..3.. *.* **** *.**... ......

    33    349      42      19   -19.5    58.5    -21.6     1..3.. *.* **** *.**... ......
 -1360  -1134    -104     -72   -18.0   -35.8     61.5     1..3.. *.* **** *.**... ......
   -39   -338     -45     -23    19.4   -58.3     21.6     1..3.. *.* **** *.**... ......
  1299   1120      81      55    18.2    36.0    -61.3     1..3.. *.* **** *.**... ......

   120    377      38      20   -18.7    57.5    -22.2     1..3.. *.* **** *.**... ......
  -958   -885     -30     -19   -28.7   -33.1     65.2     1..3.. *.* **** *.**... ......
  -152   -315     -14      -7    30.6   -59.7     18.3     1..3.. *.* **** *.**... ......
   378    374       1       0    40.6    28.7    -69.8     1..... *.* **** *.**... ......    Breaker
                                                                                              Opened
    68    122       1       0   -48.1    64.8    -12.6     ...... *.* **.. ....... ......
   -48    -46       0       0   -42.5   -27.7     71.0     ...... *.* **.. ....... ......
    -8    -15       0       0    53.8   -66.9     10.8     ...... *.* **.. ....... ......
     6      6       0       1    42.8    27.9    -71.5     ...... *.* **.. ....... ......

     0      1       0       0   -54.9    67.2    -10.3     ...... ..* .*.. ....... ......
     0      0      -1      -1   -42.9   -27.9     71.7     ...... ..* .*.. ....... ......
     0      0       0       0    55.2   -67.5     10.2     ...... ..* .*.. ....... ......
     0      0       1       1    43.0    28.0    -71.9     ...... ..* .*.. ....... ......

    -1     -1       0       0   -55.3    67.6    -10.2     ...... ..* .*.. ....... ......
     0      0      -1      -1   -43.1   -28.1     72.0     ...... ..* .*.. ....... ......
     1      1       0       0    55.5   -67.7     10.2     ...... ..* .*.. ....... ......
     0      0       1       1    43.1    28.2    -72.2     ...... ..* .*.. ....... ......

Event   : 1AG    Location   : 12.87 mi  0.51    ohms sec
Duration: 4.25    Flt Current: 1198

R1  = 58.32    X1  = 108.18  R0  = 109.37  X0  = 339.35  LL  = 124.76
CTR = 40       PTR = 1000    MTA = 61.70   79OI= 0.00    79RS= 60.00
Z1% = 90.00    Z2% = 120.00  Z2DG= 20.00   Z2DL= 20.00
Z3% = 150.00   Z3DG= 45.00   Z3DL= 45.00   50FD= 150     46PH= 1000   TTI = 3
Z1E = Y        Z2E = Y       Z3E = Y       32QE= N       GSE = Y      BFPE= N
```

Figure 20. HAIWEE-INYOKERN Event Report

Example 9. Zero-Sequence Current Flow Verification

Event reports from two microprocessor relays on B.C. Hydro's 1L11 115kV transmission line helped answer a long-standing engineering question:

> "Why does zero-sequence current flow in the 1L11 line for a fault on a parallel line, 1L14, after the Vancouver Island Terminal (VIT) and GTP breakers have cleared, leaving only Koksilah (KSH) feeding the fault?"

Figure 21 shows a single line diagram of the VIT and GTP system.

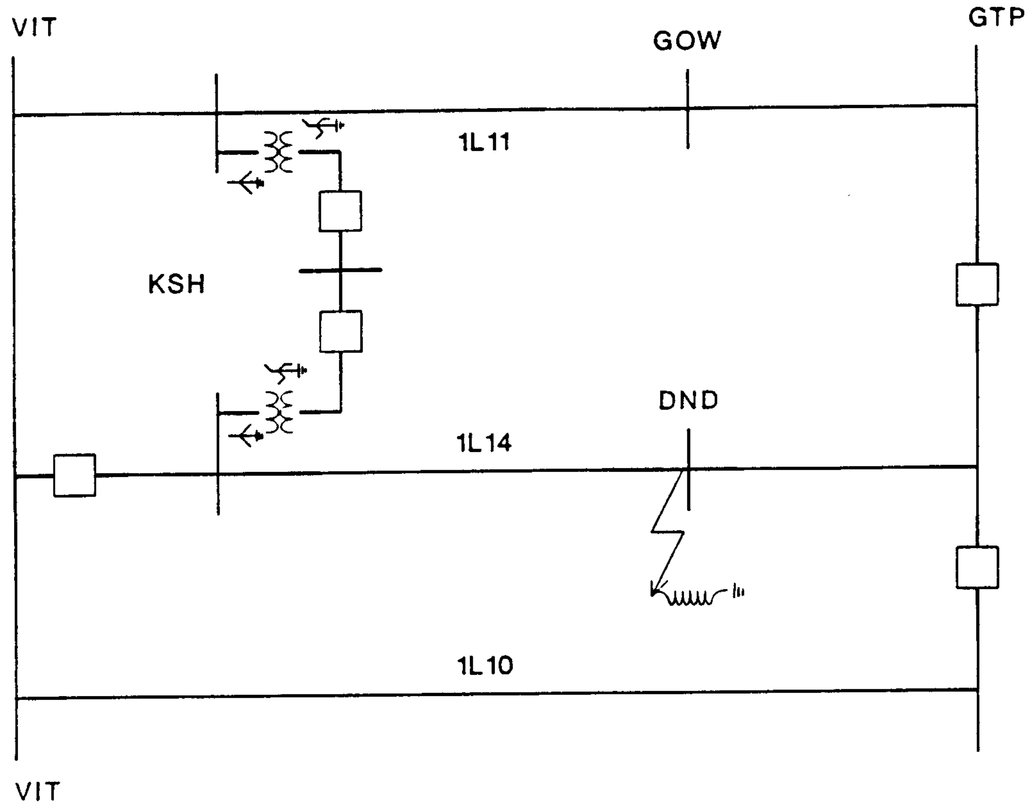


Figure 21 VIT and GTP System Single Line Diagram

The answer to this question was that zero-sequence current flowing to the fault from the KSH terminal induced a zero-sequence current in the 1L11 line. B.C. Hydro engineers suspected this answer for some time but could not determine the magnitude and phase angle of this current in 1L11 using oscillogram traces.

The data in Figures 22 and 23 (extracted from the event reports of the microprocessor relays) show that the zero-sequence current in 1L11 reversed direction and flowed into the VIT terminal after it opened. Zero-sequence current direction remained flowing into the VIT terminal after the GTP terminal breaker opened, indicating that the VIT terminal was not feeding current into the fault through the KSH transformers.

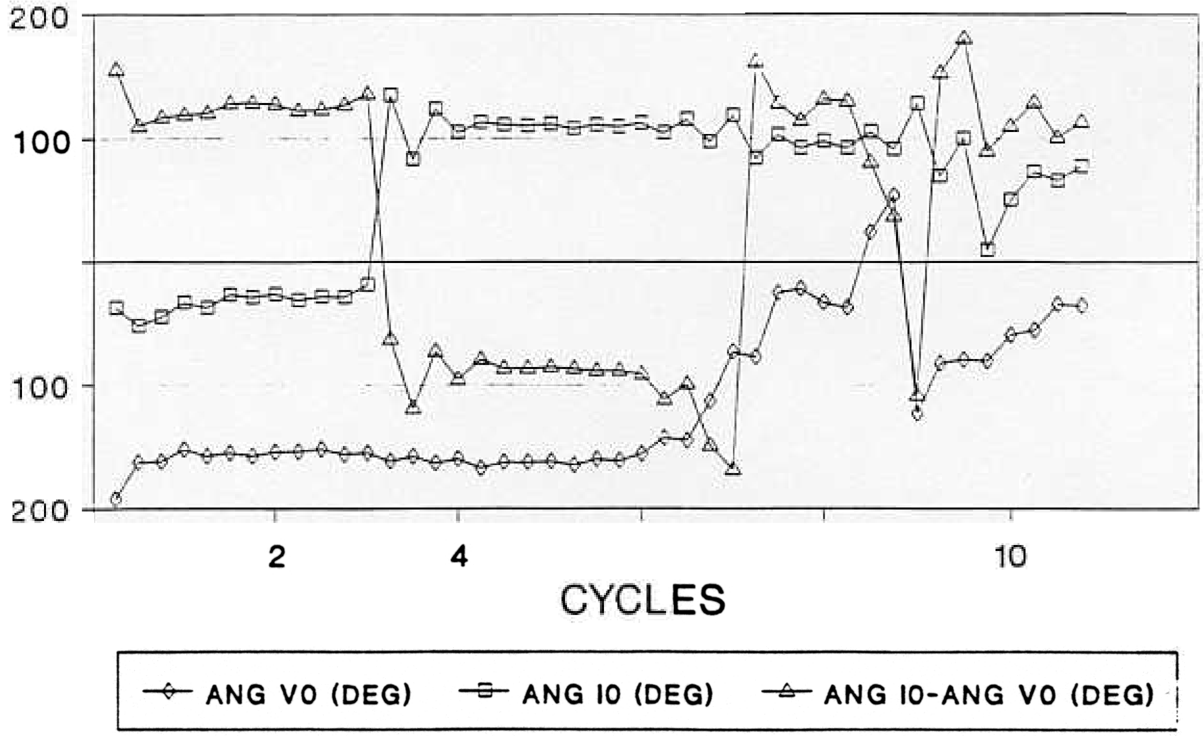


Figure VIT V0 Graph Showing Forward Reverse Fault

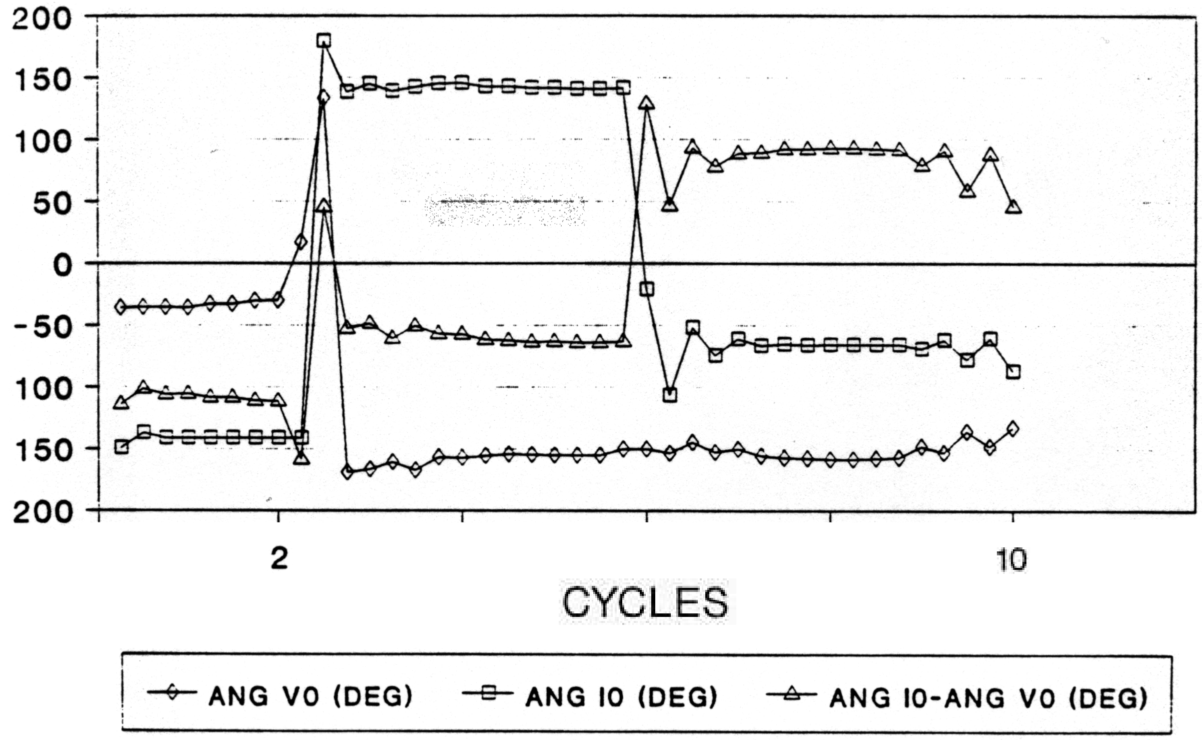


Figure GOW V0 Graph Showing Reverse Forward Fault

Example 10. Cross Country Fault

On January 20, 1989, a microprocessor relay at Chelan County P.U.D. in Washington State recorded a line-ground fault on the 115kV McKenzie-Summit transmission line.

Figure 24 shows the single line diagram of the relay placement, fault location, and the system involved in the fault.

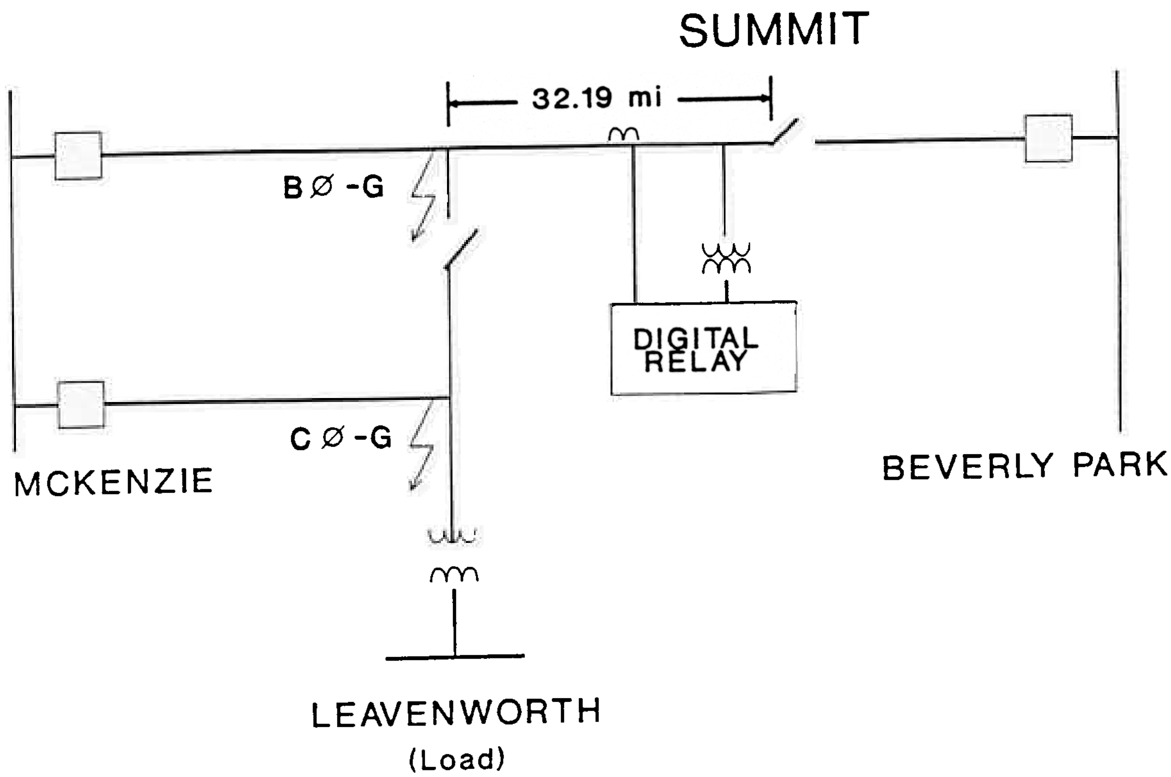


Figure 24. McKenzie-Summit Single Line Diagram

The microprocessor relay which saved the event report in Figure 25 was installed at the Summit Substation to monitor the transmission line temperature and locate faults on the McKenzie-Summit line section.

Simultaneous to the Bϕ-ground fault on the McKenzie-Summit line, relays on the McKenzie-Leavenworth line targeted a Cϕ-ground fault. Field patrols established both faults to be located 32.19 miles from the Summit Substation toward McKenzie at a switching point where the two lines crossed.

Engineers reviewing the event report triggered by the Bϕ-ground element were concerned that the fault location read negative for a fault known to be in the forward direction. Further review of the event report confirmed that the Summit-McKenzie transmission line only saw Bϕ-ground current from the fault. Oscillographs at McKenzie showed a large Cϕ current magnitude, which indicates that the McKenzie-Leavenworth transmission line saw Cϕ-ground current from the fault.

SUMMIT-McKENZIE 115 KV Date: 2/7/89 Time: 13:33:54.154

FID=SEL-49-R101-V656m-D881007

	Currents (amps)			Voltages (kV)			MHO	+Seq	-Seq	Outs	Ins
							ABCABC	ilv	ivV3	TCTTTA	DTBD5E
/K*Reff	IA	IB	C	VA	VB	VC	GGGBCA		2	PLTHLL	TTTC2T
565	35	517	-31	-51.8	30.1	-39.7	......	*.*	**..	......	....*.
148	-23	244	34	-34.8	30.6	74.8	......	*.*	**..	......	....*.
-567	-27	-521	22	53.0	-30.5	38.0	......	*.*	**..	......	....*.
-138	23	-234	-34	33.9	-29.8	-76.0	......	*.*	**..	......	....*.
572	21	527	-17	53.5	31.0	-36.7	......	*.*	**..	......	....*.
128	-21	224	35	-33.5	28.9	77.4	......	*.*	**..	......	....*.
-577	-13	-535	11	54.6	-31.3	35.0	......	*.*	**..	......	....*.
-121	20	-217	-36	32.4	-28.0	-78.4	......	*.*	**..	......	....*.
581	9	540	-7	55.4	31.3	-33.7	......	*.*	**..	......	....*.
116	-20	210	36	-31.6	27.3	79.7	......	*.*	**..	......	....*.
-583	-5	-544	3	56.4	-31.7	31.9	......	*.*	**..	......	....*.
-104	17	-197	-35	30.2	-26.6	-80.4	......	*.*	**..	......	....*.
583	0	548	1	-61.6	32.3	-30.9	......	*.*	**..	......	....*.
117	-12	200	34	-20.2	25.9	79.7	......	*.*	**..	......	....*.
-471	2	-449	-6	58.5	-20.5	26.9	......	*.*	**..	......	....*.
-102	9	-155	-21	2.6	-40.7	-59.6	.*....	*.*	**.*	......	....*.
195	0	188	2	-36.1	5.7	-24.5	......	*.*	**..	......	....*.
35	-2	53	4	9.3	62.0	30.7	......	*.*	**..	......	....*.
-6	0	-8	0	19.7	-2.8	21.3	......	*.*	**..	......	....*.
-1	0	-3	0	-16.0	-68.8	-18.9	......	*.*	**..	......	....*.
-18	0	-16	0	-17.0	3.0	-17.6	......	..*	**..	......	....*.
0	0	-2	0	17.7	69.4	18.3	......	..*	**..	......	....*.
21	0	20	0	16.9	-3.8	17.1	......	..*	**..	......	....*.
0	0	2	0	-17.4	-69.4	-18.1	......	..*	**..	......	....*.
-21	0	-19	0	-16.2	4.8	-16.5	......	..*	**..	......	....*.
0	0	-2	0	16.9	3.8	-17.1	......	..*	**..	......	....*.
21	0	19	0	16.2	-4.8	16.5	......	..*	**..	......	....*.
0	0	-2	0	-16.9	-3.8	17.1	......	..*	**..	......	....*.
-21	0	-19	0	-16.2	4.8	-16.5	......	..*	**..	......	....*.
0	0	2	0	16.9	4.9	-17.1	......	..*	**..	......	....*.
21	0	18	0	14.9	-8.3	15.0	......	..*	**..	......	....*.
0	0	2	1	-18.4	-68.8	-18.8	......	..*	**..	......	....*.
-21	0	-18	0	-14.9	8.3	-15.0	......	..*	**..	......	....*.
0	0	-2	-1	18.2	68.7	18.7	......	..*	**..	......	....*.
21	0	18	1	15.0	-7.8	15.1	......	..*	**..	......	....*.
0	0	2	0	-18.1	-68.7	-18.5	......	..*	**..	......	....*.
-21	0	-18	-1	-15.1	7.2	-15.2	......	..*	**..	......	....*.
0	0	-2	0	17.9	68.7	18.4	......	..*	**..	......	....*.
21	0	18	0	15.2	-6.6	15.3	......	..*	**..	......	....*.
0	0	2	0	-17.9	-68.7	-18.4	......	..*	**..	......	....*.
-21	0	-18	0	-15.2	6.6	-15.3	......	..*	**..	......	....*.
0	0	-2	-1	17.5	68.5	18.0	......	..*	**..	......	....*.
21	0	18	0	15.5	-4.9	15.6	......	..*	**..	......	....*.
0	0	2	1	-17.4	-68.6	-17.8	......	..*	**..	......	....*.

Event : BG Location : -17.40 mi -0.90 ohms sec
Duration: 0.25 Flt Current: 243

Figure 25. McKENZIE-SUMMIT Event Report

The negative fault location was attributed to zero-sequence current from the McKenzie-Leavenworth transmission line inducing a voltage on the McKenzie-Summit transmission line. This microprocessor relay could not compensate for the induced voltage because of the system arrangement.

Equation 3 shows the basic inputs used to locate $B\phi$-ground faults without zero-sequence mutual coupling effects.

$$mxZ1 = \frac{VB}{IB + kxIR}, \qquad [3]$$

where

m = Per unit distance to the fault
IB = $B\phi$ current
IR = Residual current
$k = \frac{Z0 - Z1}{3xZ1}$
$Z1$ = Positive-sequence impedance of the entire transmission line
$Z0$ = Zero-sequence impedance of the entire transmission line

Equation 4 shows the equation used to locate the same $B\phi$-ground fault with zero-sequence mutual coupling included:

$$mxZ1 = \frac{VB}{\left[IB + kxIR + \frac{ZMM}{Z1}xIRM\right]} \qquad [4]$$

Definitions of Additional Variables in Equation 4

ZMM = Zero-Sequence Mutual Coupling Impedance to the offending line
IRM = Zero-Sequence Current flowing in the offending line

If the line is not mutually coupled, Equation 4 equals Equation 3.

The following steps confirmed the engineer's suspicions that induced voltage caused the negative fault location:

1. Entering the event report saved on disk in the fault analysis program.
2. Modeling the zero-sequence mutual coupling of the two circuits.
3. Entering the $C\phi$-ground current from the offending circuit assuming the same voltage at the McKenzie Bus as at the Summit Bus.
4. Performing the simple reactance method of fault locating for mutually coupled circuits.

The results of these steps yielded a positive fault location approximately 32 miles from the Summit Substation.

CONCLUSIONS

As the examples in this paper demonstrate, microprocessor relays offer protection engineers valuable help with the difficult task of analyzing transmission line faults.

The techniques required to diagnose and evaluate protective relay performance before, during, and after a fault are the same as those used by engineers in the past. However, with the essential information contained in the microprocessor relay event report, the protection engineer can quickly apply these analysis techniques to more data with less effort and achieve a high degree of accuracy.

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4. Mr. Anthony C. Eaton, Southern California Edison, System Protection Department, 2244 Walnut Grove Avenue, Rosemead, California 91770

5. Mr. Steve Miller, Western Area Power Administration, Fort Peck District Office, P.O. Box 145, Fort Peck, Montana 59223

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APPENDIX A

Lea County Electric Fault Impedance Calculations

The Takagi method determined the fault location at 4.02 miles from OCB 19. A ratio of this fault location to the total line length multiplied by the known impedances of the line resulted in the following positive-sequence line impedances to the fault:

$$R1 = (4.02/5.10)x3.60\Omega = 2.84\Omega, \quad X1 = (4.02/5.10)x4.23\Omega = 3.34\Omega.$$

The faulted phase voltage at the bus is expressed as

$$VA = Z1(IA + kxIR) + R_f xIA. \qquad [1]$$

Reduce the equation to impedance terms,

$$\frac{VA}{IA + kxIR} = Z1 + \frac{R_f xIA}{IA + kxIR}, \qquad [2]$$

calculate the apparent impedance to the fault, and subtract the known line impedance to the fault to solve for the fault impedance.

$$Z1_{measured} = \frac{VA}{IA + kxIR} \qquad [3]$$

$$\begin{aligned} VA &= 20.93kV\ /{-27.03°} \\ IA &= 2137.66A\ /{-63.40°} \\ IR &= 2155.20A\ /{-64.35°} \\ k &= 0.61\ /27.05° \end{aligned}$$

where $k = \dfrac{Z0 - Z1}{3xZ1}$

$$\begin{aligned} Z1 &= (3.60 + j4.23)\Omega \text{ for the entire line length} \\ Z0 &= (5.94 + j14.09)\Omega \text{ for the entire line length.} \end{aligned}$$

Substitute these values into Equation 3 to yield

$$Z1_{measured} = \frac{VA}{IA + kxIR} = 6.21\Omega\ /26.48° = (5.56 + j2.77)\Omega.$$

Subtract the known line impedance from $Z1_{measured}$,

$$Z1_{measured} - Z1 = (2.72 - j0.62)\Omega = 2.79\Omega\ /{-12.84°},$$

and solve for R_f

$$2.79\Omega \angle{-12.84°} = \frac{IAxR_f}{IA + kxIR},$$

which equals the right-hand term of equation 2.

$$R_f = 2.79\Omega \angle{-12.84°} \text{ x } \left|\frac{IA + kxIR}{IA}\right|$$

$$= (4.40 - j0.22)\Omega.$$

The calculated fault resistance equals 4.40Ω (the negative reactance portion of R_f can be neglected).

APPENDIX B

Zero-Sequence Compensation Derivations and Considerations

The following derivations address the zero-sequence compensation factor k and the zero-sequence mutual compensation factor kM used in some microprocessor relays. The zero-sequence compensation factor k is used in calculations for ground distance elements. The zero-sequence compensation factor kM is used in the ground distance fault locating algorithm in addition to the zero-sequence compensation factor k.

K Factor Derivation

A zero-sequence compensation factor k is used to account for the mutual induction between the faulted phase and the remaining two healthy phases of the same three-phase line for a single line-to-ground fault. Simplifying assumptions are noted throughout this derivation. For ease of computations, an Aϕ-ground fault is selected.

For an Aϕ-ground fault, the voltage seen at the relaying location is

$$VA = I1x(Z1) + I2x(Z2) + I0x(Z0). \qquad [1]$$

Note: In Equation 1, zero fault impedance is assumed and the fault voltage can be neglected.

Let Z1 = Z2, then

$$VA = Z1x(I1 + I2) + I0x(Z0). \qquad [2]$$

Note: If we further assume that the faulted line in question is not mutually coupled to another three-phase line, and that no additional sources of zero-sequence current exist between the relaying location and the fault, we can make the following statement:

$$IR = 3xI0 = IA + IB + IC. \quad [3]$$

Substitute Equation 3 into Equation 2:

$$VA = Z1x(I1 + I2) + Z0x\frac{(IA + IB + IC)}{3}. \quad [4]$$

If $IA = I1 + I2 + I0$,

then,

$$(I1 + I2) = IA - I0. \quad [5]$$

Substitute Equation 5 into Equation 4:

$$VA = Z1x(IA - I0) + Z0x\frac{(IA + IB + IC)}{3}$$

$$= Z1x\left(IA - \frac{(IA + IB + IC)}{3}\right) + Z0x\frac{(IA + IB + IC)}{3}.$$

If we let $kN = (Z0/Z1)$,

$$VA = Z1x\left[\frac{(2IA - IB - IC)}{3} + kNx\frac{(IA + IB + IC)}{3}\right],$$

$$= Z1x\left[\frac{3xIA - (IA + IB + IC) + kNx(IA + IB + IC)}{3}\right],$$

$$= Z1x\left[IA + \frac{(kN - 1)}{3}x(IA + IB + IC)\right],$$

$$VA = Z1x\left[IA + \frac{(kN - 1)}{3}xIR\right].$$

$$Z1 = \frac{VA}{IA + \frac{(kN - 1)}{3}xIR}$$

$$Z1 = \frac{VA}{IA + \frac{((Z0/Z1) - 1)}{3}xIR},$$

$$Z1 = \frac{VA}{IA + \frac{(Z0 - Z1)}{3xZ1}xIR} \quad [6]$$

Equation 6 shows that the residual current IR is compensated by the factor equal to (Z0 - Z1)/3Z1, which is referred to as k.

Now consider the case where a line is mutually coupled to a parallel (or offending) three-phase line. The fault on the line in question is an Aϕ-ground fault at a distance of m from one end and (1 - m) from the other end (See Figure A1).

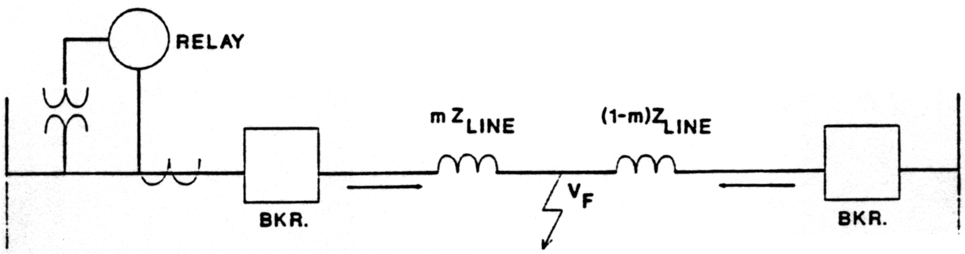

Figure A1. Aϕ-Ground Fault

Again, assuming no fault impedance, Aϕ voltage can be expressed as

$$VA = mxZSxIA + mxZMxIB + mxZMxIC + mxZMMxIRM,$$

$$= mxZSxIA - mxZMxIA + mxZMxIA + mxZMxIB + mxZMxIC + mxZMMxIRM.$$

Let IR = IA + IB + IC. Then

$$VA = mx(ZS - ZM)xIA + mxZMxIR + mxZMMxIRM,$$

$$= mxZ1xIA + mx\frac{(Z0 - Z1)}{3}xIR + mxZMMxIRM,$$

$$= mxZ1xIA + mxZ1x\frac{(Z0 - Z1)}{3xZ1}xIR + mx\frac{(ZMM)}{Z1}xZ1xIRM,$$

$$VA = mxZ1x[IA + \frac{(Z0 - Z1)}{3Z1}xIR + \frac{(ZMM)}{Z1}xIRM].$$

$$mxZ1 = \frac{VA}{[IA + \frac{(Z0 - Z1)}{3xZ1}xIR + \frac{ZMM}{Z1}xIRM]}. \qquad [7]$$

If the line is not mutually coupled, Equation 7 equals Equation 6.

Definitions of Variables in Equation 7

ZS = Self Impedance, equal to 1/3x(2xZ1 + Z0)
Z1 = Positive-Sequence Impedance of the entire line length
Z0 = Zero-Sequence Impedance of the entire line length
ZM = Zero-Sequence Impedance between the phases of the faulted line equal to 1/3x(Z0 - Z1)
ZMM = Zero-Sequence Mutual Coupling Impedance to the offending line
IRM = Zero-Sequence Current flowing in the offending line
IA = The faulted phase current
IR = The residual current of the faulted line

Factors Influencing Ground Distance Elements

1. Fault impedance causes the relay to underreach due to the current passing through the fault impedance introducing an uncompensated voltage. The ground relay overreaches by the same percentage that the ground relay on the remote end underreaches. Which end overreaches is dependent upon the zero-sequence current distribution of the power system.

2. Zero-sequence mutual compensation for ground distance relays is generally undesirable due to the possibility of overcompensation causing a ground distance relay to overreach for faults on adjacent circuits. Uncompensated ground distance relays which provide Zone 1 protection for a transmission line will have overlapping characteristics. Thus, high speed protection for the transmission line exists without the risk of overreaching for faults on adjacent transmission lines.