Advanced Event Analysis Tutorial

Part 2: Answer Key

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***Abstract*—Event reports continue to be an invaluable feature in microprocessor-based relays. Some events are relatively straightforward to analyze, and others require experience and considerable knowledge of the power system and protective relay system in order to find root cause. This session provides several advanced real-world event examples, time to evaluate them, and solutions.**

I. Introduction

The event reports provided in this session are from real-world applications. They have been edited only to the extent that the owner involved is not revealed. They provide us the opportunity to learn and improve our power system. We want to thank the engineers and technicians who share information and what they know for the benefit of our industry.

We provide a number of example case studies. These come from a wide variety of power system and protection applications and include distribution, transmission, transformer, and bus event examples.

In each case, we provide some or all of the following:

- A brief introduction to the application and problem.
- The event reports required to solve the problem.
- The instruction manual for the product involved.
- References for future reading and further instruction.

Students are required to use their own personal computer with SEL Compass®, ACSELERATOR QuickSet® SEL-5030 Software, and ACSELERATOR Analytic Assistant® SEL-5601 Software installed. These programs are available for download at no cost from www.selinc.com. It will also be helpful to have the instruction manuals available for the relays being applied in the example events.

Students are invited to answer the questions asked in this document. These questions are intended to guide analysis, keep the class efforts focused in the same direction, and highlight the main lesson points. Please document the solution to each case study in the format of a Microsoft® Word document with appropriate software screen captures and notes.

Some of the events highlight the need to capture certain event formats. For example, it is always recommended that users capture a filtered compressed format and unfiltered compressed or COMTRADE format for each event. In some cases, a traveling wave COMTRADE is required.

Finally, instructors are available to answer questions, share tips, and highlight lessons learned. Have fun!

II. Directional Element Operates for Reverse Fault

This event occurred on a 230 kV line protected with an SEL-311C Transmission Protection System. Direct tripping and a permissive overreaching transfer trip (POTT) scheme were employed with phase and ground protection elements. The relay produced a trip for an apparent reverse fault, as shown in Fig. 1.

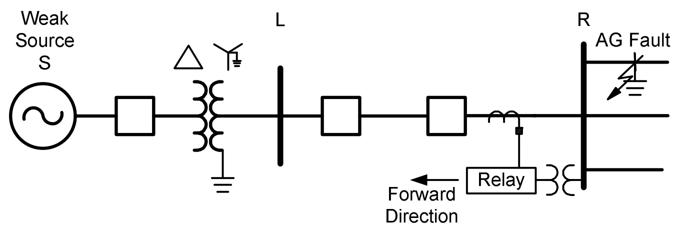


Fig. 1. One-line diagram of example system

First, consider the expected operation. For an external fault (reverse fault from the R terminal), no tripping would be expected. The L relays would likely detect a forward fault and send a permissive trip signal to the R terminal. The only possibility for a trip is if there were a protection or breaker failure to clear the fault from the protected line. However, what actually occurred is a trip at the R terminal.

Open the event labeled **2_EXAMPLE 2_311C.cev**. Also, in order to analyze the relay settings and logic, some familiarity with the relay and protection scheme is necessary.

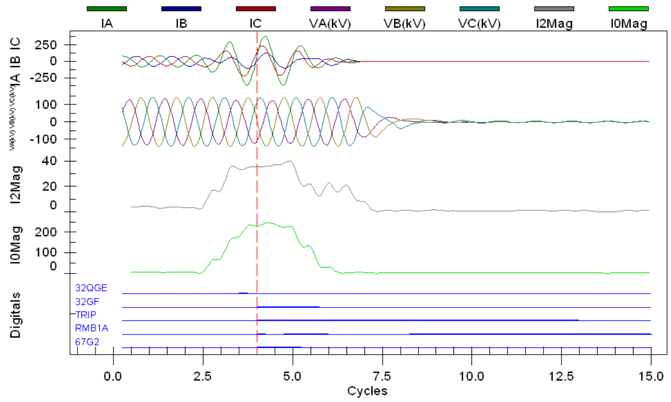
II-a What relay elements are programmed to trip, and what tripping schemes are applied?

This protection system uses the following POTT scheme logic with MIRRORED BITS® communications, direct tripping, and switch-onto-fault logic.

```
ECOMM = POTT

TR    =M1P + Z1G + Z2T + 51GT
TRCOMM=M2P + Z2G + 67G2

TRSOTF=M1P + M2P + Z1G + Z2G + 50P1 * 3P27


PT1   =RMB1A
```

II-b What relay element or elements actually produced the trip condition?

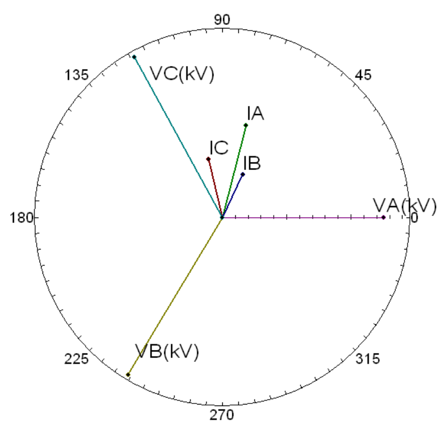
The following screen capture of the event report from ACSELERATOR Analytic Assistant shows element 67G2 asserted with a received PT1 input to produce a POTT trip.



II-c What type of fault occurred? Was the fault forward or reverse? Did the relay elements operate correctly?

This appears to be a low-level reverse AG fault, based on the relative position of VA and IA. Thus, 67G2 misoperated.

Also, this appears to be a sole zero-sequence source with very little positive- or negative-sequence contribution because all three currents (IA, IB, and IC) were nearly in phase, as shown in the following screen capture.

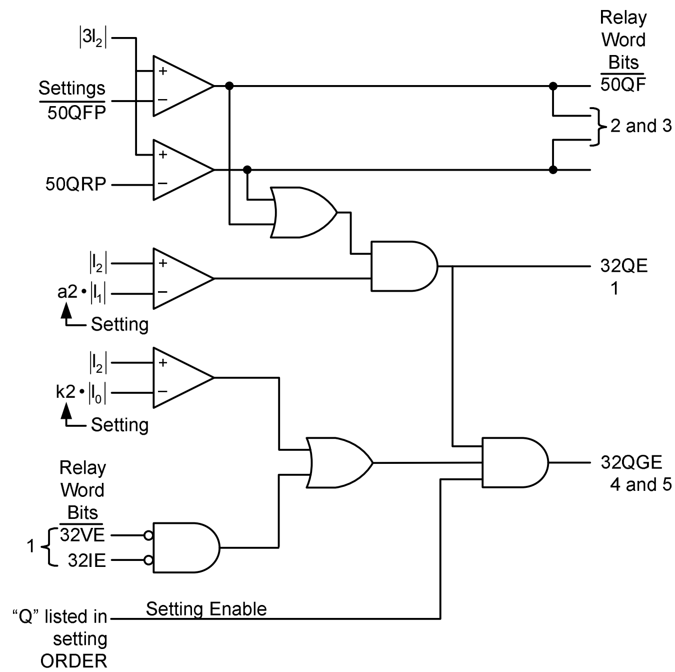


II-d How was the directional element set? Did the relay use negative sequence, zero sequence, or both?

The following screen capture shows the settings related to the directional elements. Refer to the SEL-311C Instruction Manual for specific details.

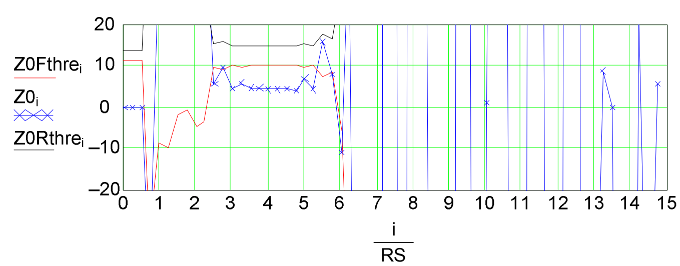
```
CTR    = 400

CTRP   = 1          PTR    = 2000.00


E32    = Y

ORDER  = QV
Z2F    = 3.30       Z2R    = 6.60     50QFP  = 0.50     50QRP  = 0.25
a2     = 0.10       k2     = 0.20
50GFP  = 0.50       50GRP  = 0.25     a0     = 0.10

ZOF    = 9.00       ZOR    = 18.00
```

The 32 element ORDER setting (QV) is set to use the negative sequence (Q) and then switch to zero sequence (V) if the operating quantities dictate, indicated by element 32QGE dropping out. The following figure displays a logic diagram from the SEL-311C Instruction Manual (Figure 4.8) that shows the internal enables used in ORDER switching logic.



There were about 40 A of I2 and 200 A of I0. The settings 50QFP and 50QRP are based on 3 • I2, and 50GFP and 50GRP are based on 3 • I0. Thus, there were 120/400 = 0.3 A of 3 • I2, greater than 50QRP. But the k2 ratio, I2/I0, is slightly less than the 0.2 setting. Thus, the relay switched from Q to V, as indicated by the 32QGE bit dropping out.

Once the relay switched to zero-sequence quantities, the relay compared the measured Z0 (V0/I0) against the threshold settings Z0F and Z0R. Using a Mathcad® or Microsoft Excel® spreadsheet to model the directional element can be helpful in these cases. As we can see in the following Mathcad screen capture, the measured Z0 element ($Z0_i$ declared a forward fault based on the Z0F and Z0R settings ($Z0_i$ plot below the Z0 forward and reverse thresholds).



II-e Were the settings correctly applied?

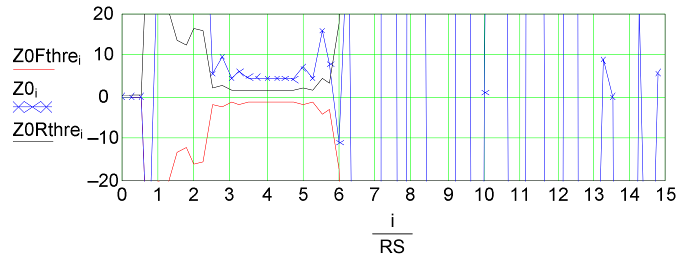
As in many applications, settings can be an art and a science, so there can be many correct solutions. Reference [1] provides directional element design and application background to the following guidelines from Page 4.31 of the SEL-311C-1 Instruction Manual:

> **Setting Guidelines for ORDER and Negative-Sequence Impedance Directional Thresholds**
>
> For most systems, select ORDER = Q. This enables only the 32QGE negative-sequence directional element for ground faults.
>
> If single contingency (loss-of-line or generator) can cause the loss of the negative-sequence source and no zero-sequence mutual coupling is present, set ORDER = QV to use the Best Choice Ground Directional® logic to automatically switch to the zero-sequence voltage-polarized directional element. Avoid selecting an ORDER setting with "V" on lines with zero-sequence mutual coupling, because this creates the risk of false declaration of the 32VE element.
>
> When using "I" in the ORDER setting to apply current polarizing (e.g., "QVI" or "QI"), analyze system faults to verify that the current polarizing source is reliable for all fault types and locations.
>
> If the relay is applied in a communications-assisted trip scheme (e.g., POTT or DCB), use the same ORDER setting at both ends of the line.
>
> If the strongest source (smallest Z2 equivalent impedance behind the relay) is less than 0.5 ohms secondary, set E32 = AUTO to automatically center the Z2F and Z2R threshold settings around one-half of the positive-sequence line impedance based on the line parameter settings, Z1MAG and Z1ANG. The line parameter settings, Z1MAG and Z1ANG, must accurately represent the secondary line impedance as seen by the relay.
>
> If the strongest source is greater than 0.5 ohms secondary, set E32 = Y and set Z2F and Z2R thresholds centered around the origin (e.g., Z2F = –0.3, Z2R = +0.3). In this case, the negative-sequence directional element still requires a valid setting for Z1ANG.

Thus, the ORDER setting of QV appears to be correct because the source can be strong or weak.

The root cause of the problem is that the Z0F and Z0R settings are biased too far in the forward direction.

In the following figure, the Z0 element simulation correctly declared reverse after the Z0F and Z0R settings have been changed to –0.3 and +0.3, respectively. As we can see, $Z0_i$ plots above the Z0F and Z0R thresholds.



III. High-Speed Zone 1 Trip for 345 kV Line Fault

In this example, an SEL-421 Protection, Automation, and Control System tripped at high speed for a line fault. The utilities involved considered this to be a correct operation. However, here we take the opportunity to analyze the event reports. What can we learn from a correct operation? The one-line diagram is shown in Fig. 2.

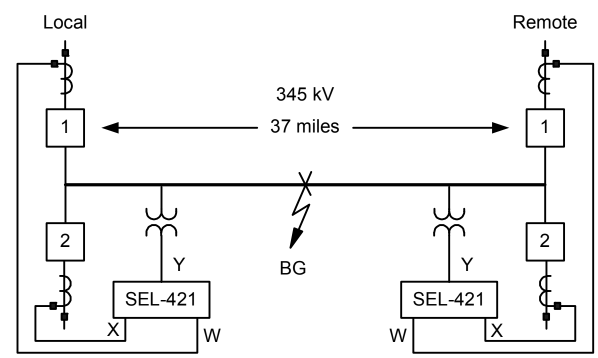


Fig. 2. One-line diagram of example system

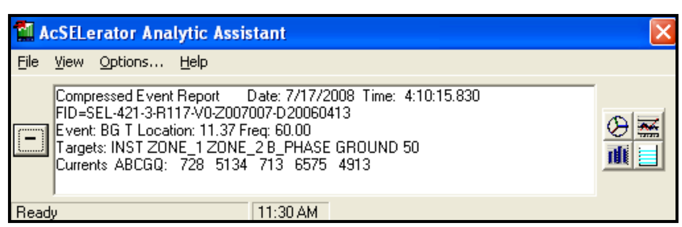
In this section, we have the following three events:

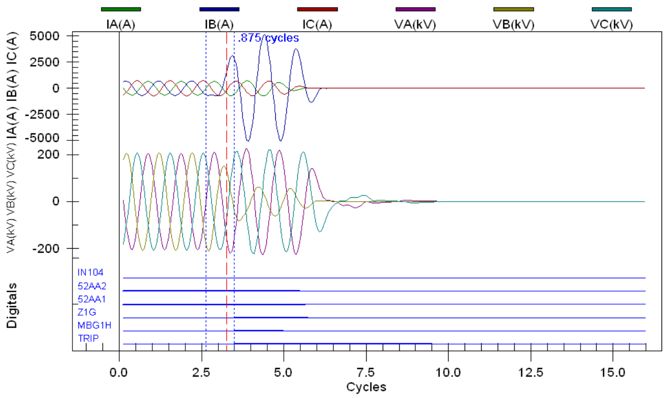
- Local SEL-421 compressed filtered event at 8 samples per cycle.
- Local SEL-421 COMTRADE unfiltered event.
- Remote SEL-421 filtered event at 4 samples per second (not compatible with ACSELERATOR Analytic Assistant).

Each event has useful data that we can use to evaluate the protection system performance. First, open the local compressed filtered event **3_421_LOCAL.CEV**.

III-a What type of fault occurred?

This was a BG fault. The following screen captures of a local filtered event show a high-speed Zone 1 trip.





III-b What protection schemes does the relay apply?

The relay was set to produce direct tripping using phase and ground distance mho elements and several other elements, switch-onto-fault tripping, and pilot protection using directional comparison blocking (DCB), as shown in the following screen capture.

```
ECOMM   := DCB

BT      := IN104

Trip Logic
TR      := M1P OR Z1G OR M2PT OR Z2GT OR M4PT OR Z4GT
OR 67G1 OR \
           51S1T OR PCT01Q OR PCT02Q
TRCOMM  := Z2PGS
TRSOTF  := M2P OR Z2G OR (50P1 AND (VAYM <= 46.000000
AND VBYM <= 46.000000 AND VCYM <= 46.000000))
```

III-c What element within the relay caused the trip? How long did it take for the relay to operate? How long did the breaker(s) take to clear the fault?

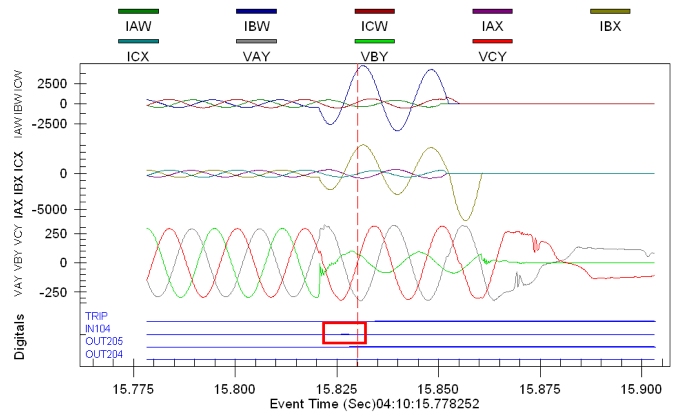
Element Z1G produced the TRIP condition. From the initial change in current to TRIP was 0.875 cycles. From the initial change in current to both breakers opening was 3.0 cycles.

III-d Did the relay and protection system operate correctly and as expected?

Based on the event report and field reports, the protection system operated correctly.

III-e Open the local COMTRADE event **HR_10003_421_LOCAL.DAT**. Evaluate the unfiltered currents and voltages before, during, and after the fault. What observations can we make, and are there any concerns?

The currents were slightly offset and interrupted, as expected. The voltages demonstrate significant capacitive ringdown voltage that lasted almost 6 cycles. Based on the line voltage (345 kV), it is not unusual to see this, and the shunt capacitance was further increased by the use of capacitor voltage transformers (CVTs). However, it is noteworthy, and time delays for automatic reclosing should take this into account. The following screen capture of the local COMTRADE event shows ringdown and momentary block trip (BT) input assertion, as denoted by input IN104.



III-f Evaluate the DCB scheme. What inputs and outputs were assigned for the DCB scheme? Did the local inputs and outputs assert as expected?

The DCB scheme at the local SEL-421 used OUT204 and OUT205 for START and STOP. START was programmed for directional start. In the previous screen capture, we see that OUT204 correctly did not assert and OUT205 asserted, as expected. The settings are shown in the following screen capture.

```
"OUT204","DSTRT OR 67G3 OR M3P OR Z3G # DCB START"
"OUT205","STOP OR M2P OR Z2G OR 3PT # DCB STOP"
"BT","IN104"
```

However, in the previous event report screen capture, we observe the BT input asserted momentarily on the COMTRADE event, which is not seen in the filtered event. This could have been produced by a remote block or a noise burst seen by the carrier receiver (somewhere from 60 to 250 kHz) and created by the fault transient. In order to be sure, we must evaluate the remote relay.

III-g Open the remote event **3_421_REMOTE.txt**. Did the remote SEL-421 send a block signal? What could have caused the local SEL-421 BT input to assert?

The remote event is only in text format, as shown in the following screen capture, and the digitals are not readily available. OUT207 and OUT208 cannot be viewed directly. However, we can view the reverse distance elements (M3P, Z3G) and observe that these elements do not assert.

```
OUT207  := DSTRT OR M3P OR Z3G #FOR CARRIER START
OUT208  := STOP #FOR CARRIER STOP

                                                                      22 B B
                                                             C        55 F F
                      VZ             S      66     66   55    O BBBBBB AA T T
         MMM      ZZZ PL        3333 05 666 77 666 77 511  Z M KKKKKK 11 RFRF
TTT MMMM 234 ZZZZ 234 OOL OO 3S 2222 TO 777 GG 777 QQ 1SS  3KP 121212 BB IBIB
PPP 1234 PPP 1234 GGG LAO SS PP QQGG FP GGG 23 QQQ 23 S11 PRER RRLLCC KK PFPF
ABC PPPP TTT GGGG TTT VDP BT OO FRFR T1 123 TT 123 TT 1TR TBYM SSOOLL 12 1122

[1]
... .... ... .... ... *.. .. .. .... .. ... .. ... .. ..* .... **.... ** ....
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... .... ... .... ... *.. .. .. *.*. .. ... .. ... .. ..* .... **.... ** ....
[7]
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*** .... ... .*.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* **.... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
[8]
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
[9]
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. **. .. ... .. *.. ...* ...... .. ....
*** .... ... **.* ... *.. .. .. *.*. .. .*. .. ... .. *.. ...* ...... .. ....
*** .... ... .... ... *.. .. *. *.*. .. .*. .. ... .. *.. .... ...... .. ....
```

So the momentary assertion of IN104 was likely caused by the carrier receiver responding to a high-frequency transient produced by the fault itself.

Finally, this section highlights the good practice of collecting relay event reports in filtered compressed and unfiltered compressed (e.g., in SEL-300 series relays) or COMTRADE (e.g., in SEL-400 series relays) formats, as described in SEL Application Guide AG2007-12, available at www.selinc.com.

IV. Traveling Wave Fault Location

The SEL-411L Advanced Line Differential Protection, Automation, and Control System now has the ability to provide traveling wave (TW) fault location, which measures the time that high-frequency transients produced by faults are sensed at each end of the line. The TW-based fault locating function uses the internal protection elements, the communications channel to the remote terminal, and Global Positioning System-based (GPS-based) time synchronization. The TW fault locator uses conventional current transformer (CT) measurements.

Although the fault location estimate can be provided automatically from each end, it is useful to be able to evaluate and calculate the estimate using event reports.

For this example, we examine an actual BG fault on a 72.77-mile 161 kV line in an area of rough terrain in the western part of the United States. The actual line data, event information, and traveling wave calculation details are described in [2]. The basic formula for calculating fault location is shown in (1).

$$\mathrm{TWFL} = \frac{\mathrm{LL} + \left(\mathrm{TwaveA} - \mathrm{TwaveB}\right) \bullet \mathrm{c} \bullet \mathrm{LPVEL}}{2} \qquad (1)$$

where:

TWFL is the TW-based fault location from local Terminal A.

LL is the line length.

TwaveA is the TW arrival time recorded at Terminal A.

TwaveB is the TW arrival time recorded at Terminal B.

c is the speed of light.

LPVEL is the propagation velocity of the TW in per unit (pu) of the speed of light.

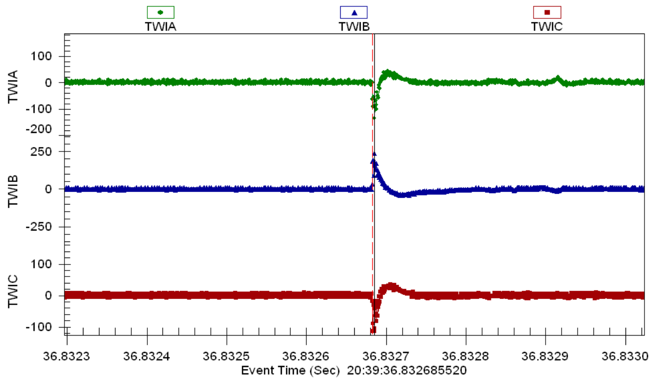
From [2], the TW propagation velocity is a key parameter in the fault location calculation and is typically obtained from line parameter estimation programs. We can also estimate propagation velocity using TW measurements with the following:

- Local TW information recorded during line or reactor energization tests.
- Local and remote TW information recorded during external faults.

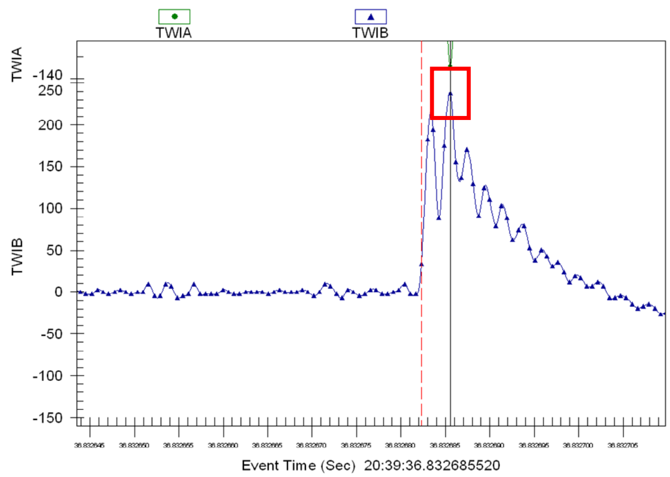
Open the event reports titled **4_TW_10002_LOCAL.DAT** and **4_TW_10002_REMOTE.DAT** to find the precise time of the transient of the fault. Using the zoom-in feature of ACSELERATOR Analytic Assistant and selecting **Line and Points** in the **Style** selection, we can view the peak of the local and remote waveforms. We can select the peak point on the given phase to give us the time stamp.

IV-a What is the time stamp for each event?

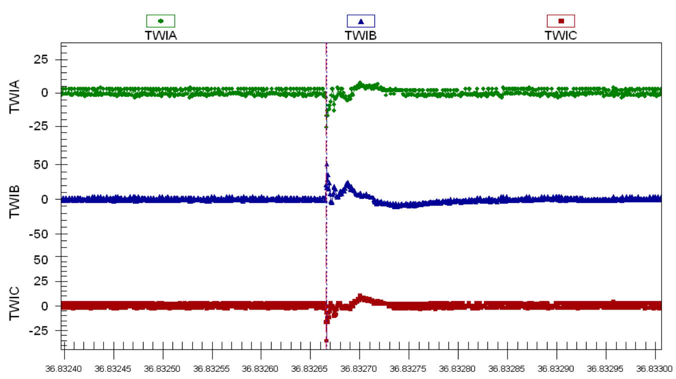
For the local event, the time stamp is 20:39:36.832685520. The following screen capture of the local TW COMTRADE event gives accurate time stamps for TW fault location.



The following screen capture shows the zoomed-in view of the selected point.



For the remote event, the time stamp is 20:39:36.832666040. The following is a screen capture of the remote TW COMTRADE event.



IV-b Calculate TWFL using the observed times and remaining parameters, which are the following:

- LPVEL = 0.98821 (setting determined from system test).
- c = 186282.39705 miles per second.
- LL = 72.77 miles.

Using (1), we perform the calculation using the following parameters:

LPVEL = 0.98821
c = 186282.39705 miles per second
LL = 72.77 miles
TwaveA = 36.832685520
TwaveB = 36.832666040
TWFL (from LOCAL) = 38.18 miles

The customer reported that a broken insulator was found at a distance of 38.16 miles.

V. Transformer Differential Operation

A fault on a distribution feeder produced an undesired operation on a transformer differential relay. Fig. 3 shows the system one-line diagram.

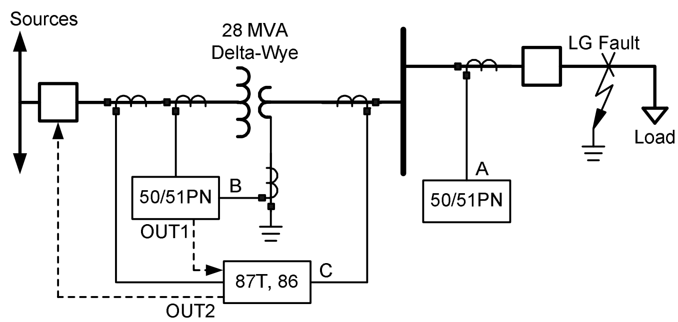


Fig. 3. System one-line diagram

In order to analyze this event, it is first important to understand the following expected operation:

- The recloser (A) should operate first.
- The transformer backup overcurrent relay (B) should operate second.
  - The relay protects the transformer based on the damage curve.
  - The relay coordinates with the downstream recloser control.
  - The output from B is connected as an input on Relay C, which acts as a lockout relay.
- The transformer differential relay (C) 87T should restrain.

The following actually occurred:

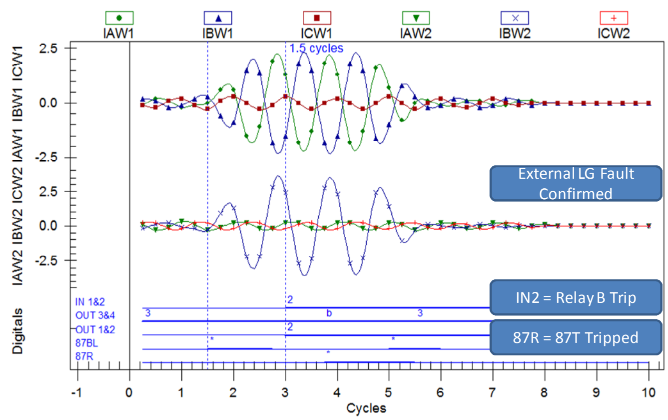
- A line-to-ground fault occurred on the feeder.
- Recloser A did not trip.
- The high-side circuit switcher did trip.
- The substation and all load were de-energized.

In order to find root cause, we will analyze the event reports. Open the events **5_YELLOW Event Files 587 2-4-12.CEV** and **5_YELLOW Event Files 551 2-4-12.CEV**.

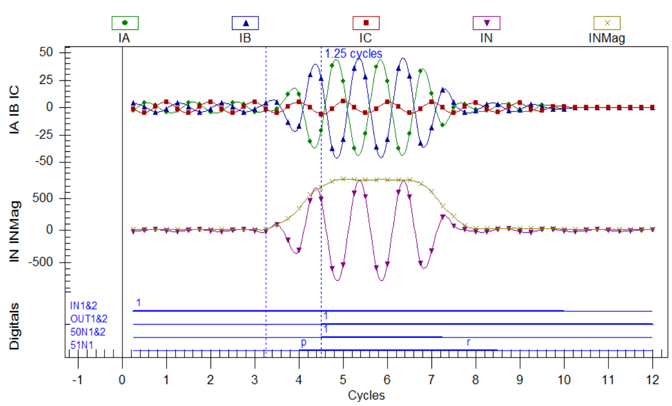
V-a Where was the fault (internal to the transformer or external to the protection zone)? Did Relay B operate? Based solely on the event reports and the one-line diagram, what observations can we make?

Because both windings show current flowing with a single-phase current flowing on the grounded-wye side, we can confirm that it was an external fault.

Yes, Relay B operated, which is shown both in the Relay B event report and from input IN2 to Relay C. The following transformer differential event report confirms the external fault, undesired 87R trip, and undesired Relay B trip.



The following neutral overcurrent relay event shows the trip.



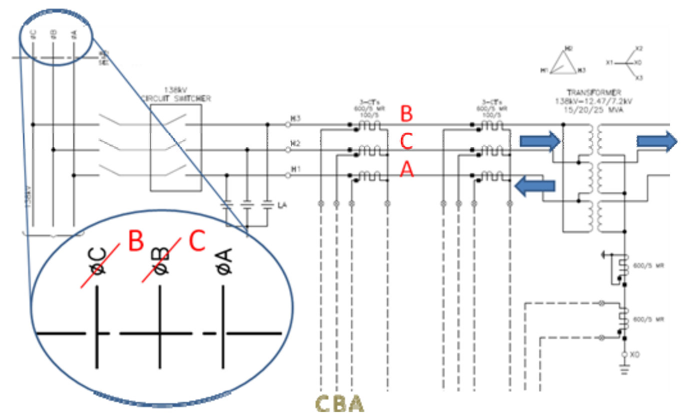
So our observations are the following:

- The fault was an external fault.
- The fault was a BG fault on the distribution side.
- The transformer backup (B) tripped instantly (1.5 cycles).
- 87T (C) would have tripped even without miscoordination.

The remainder of this event we will analyze together.

V-b What problems, settings, wiring, testing, and so on contributed to these misoperations?

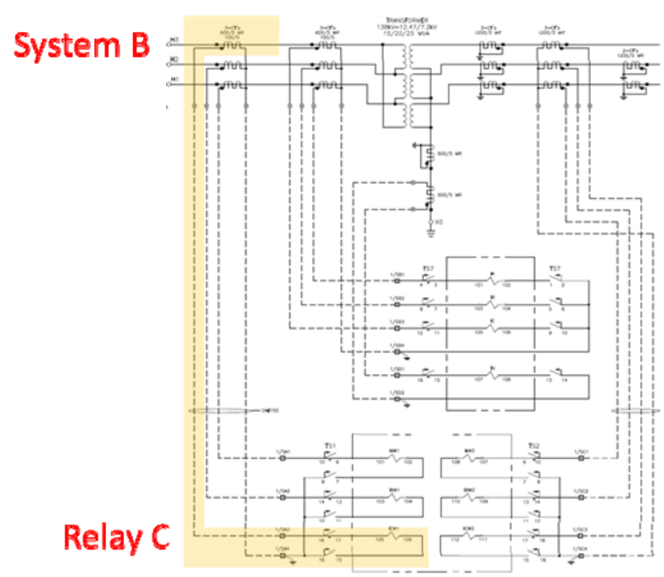
Problem #1: The as-built prints did not match the phase wiring in the field. The following three-line diagram shows primary B and C phases rolled in the field.



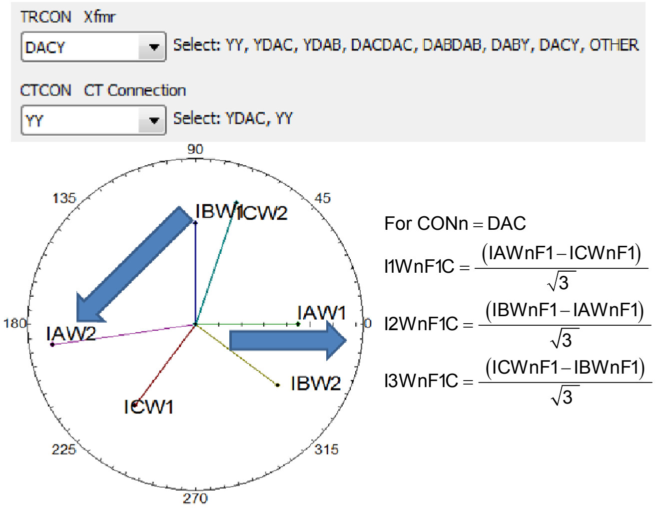
Additional problems introduced by the incorrect prints include the following:

- The original prints showed DABY or Dy1, and the as-built print showed DACY or Dy11.
- The CT-to-relay phasing rolled System B to Relay C and System C to Relay B.
- The relay phase rotation did not match the system phase rotation.
- The CG system fault looked like a BG fault at the relay.
- The 87T transformer and CT compensation settings were incorrect.

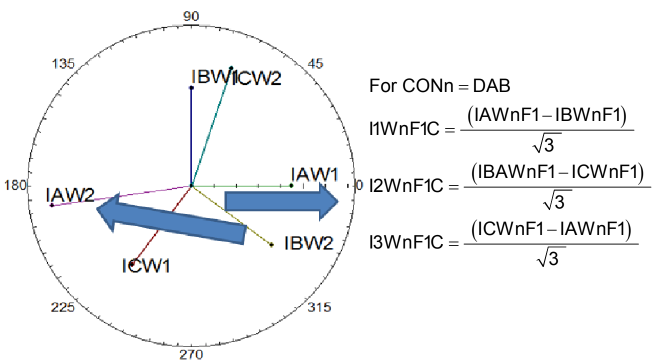
Problem #2: The wiring between the CTs and the relays was incorrect, as shown in the following print.



The following screen capture shows the settings based on incorrect information.

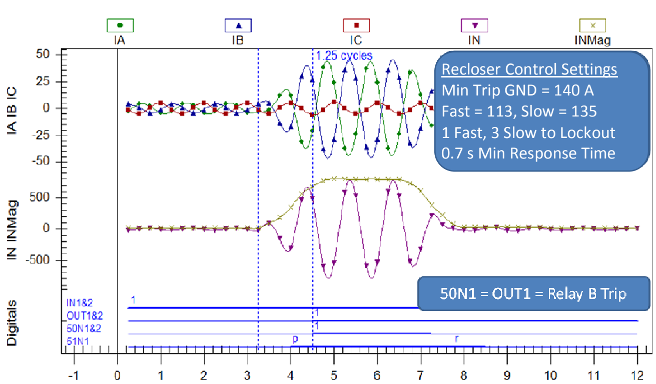


Can we correct the 87T setting by changing to DABY? The following screen capture shows current phasors with the TRCON = DABY setting.

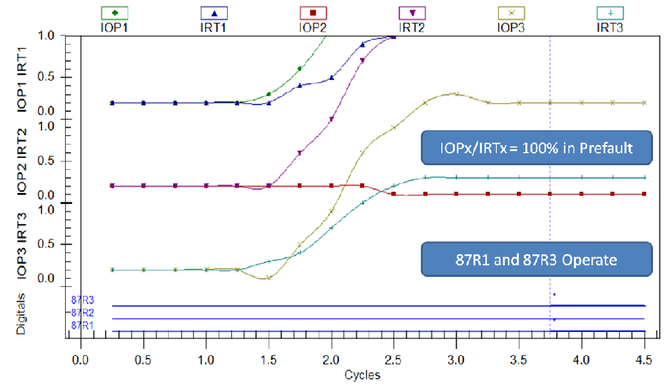


The answer is yes, but the system phases and phase rotation will not match the relay. The solution is to fix the wiring.

Problem #3: The SEL-551 Overcurrent/Reclosing Relay X0 bushing 50N element was not coordinated with the feeder. As shown in the following screen capture, Relay B (SEL-551) was set to trip instantaneously, and the feeder (Relay A) minimum trip time was 0.7 seconds.



Problem #4: Standing differential operate current in prefault current means the transformer differential system was not sufficiently tested. In the following screen capture, differential current in the prefault data shows that 87T was not properly commissioned.



To summarize this event, multiple issues were discovered. The following is a list of problems and solutions:

- Incorrect phasing—improve test procedures or use synchrophasors, if available.
- Incorrect drawings—use peer review and document controls and revisions.
- Incorrect CT wiring from the system to the relay—use primary injection for commissioning testing.
- Poor coordination—test protection schemes in the laboratory.
- Incorrect transformer differential settings—use primary injection and commissioning checklists.
- Insufficient testing—commit to allowing adequate time and budget for proper testing, test plan creation, and reviews.

VI. Bus Differential Relay Application

Fig. 4 shows the one-line diagram of a 138 kV bus protected by a high-impedance bus differential scheme. The bus has two line sources, two transformers feeding radial load, a surge arrester, and a capacitor bank. The capacitor bank is manually controlled (energized and de-energized) by system operators to adjust the system voltage.

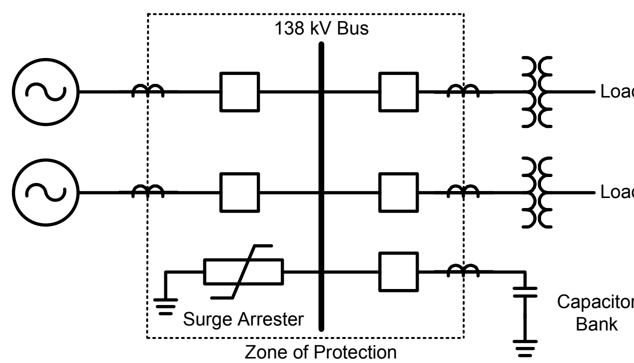


Fig. 4. One-line diagram of bus differential zone of protection

In a high-impedance bus differential scheme, the paralleled output of all of the CTs is connected through a large resistor (2,000 ohms in the SEL-587Z High-Impedance Differential Relay). The CTs are selected to be the same ratio (in this case, all CTs are 2000:5). If an unbalance current flows, such as for an internal fault, a voltage is developed across that resistor and the relay compares the voltage to a predefined threshold. The threshold is typically set to withstand an external fault if one CT completely saturates.

On one occasion, the high-impedance bus differential operated when the capacitor bank was de-energized. To evaluate this event, open the event files **6_SEL_587Z FILTERED.CEV** and **6_SEL_587Z RAW.CEV**.

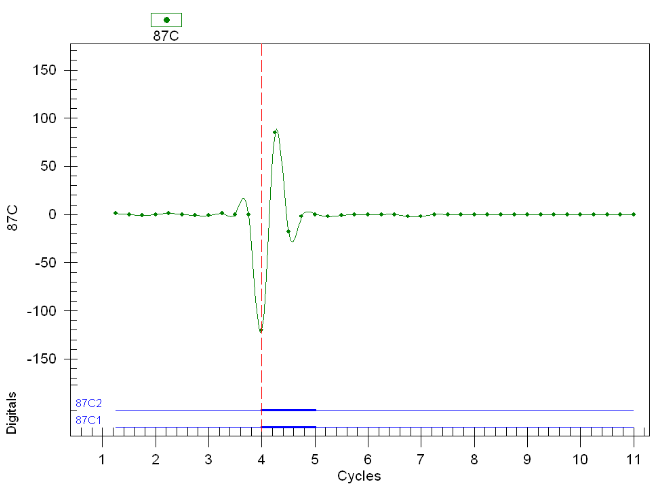
See [3] for more background on this event.

VI-a What element produced the trip? How was the element set?

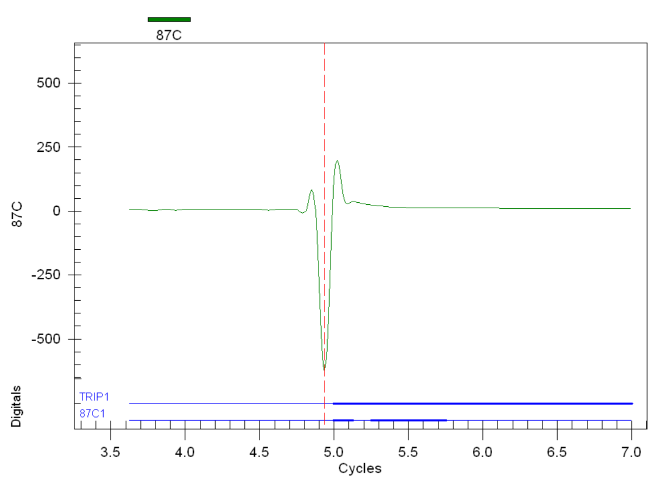
The following screen capture shows the settings and the trip equation.

```
87A1P = 75        87A2P = 75        87B1P = 75
87B2P = 75
87C1P = 75        87C2P = 75
.
.
TR1    =87A1 + 87B1 + 87C1
```

This was a trip by the 87C1 element. The pickup was set for 75 V. The following screen capture of the local filtered event shows a high-speed Zone 1 trip.

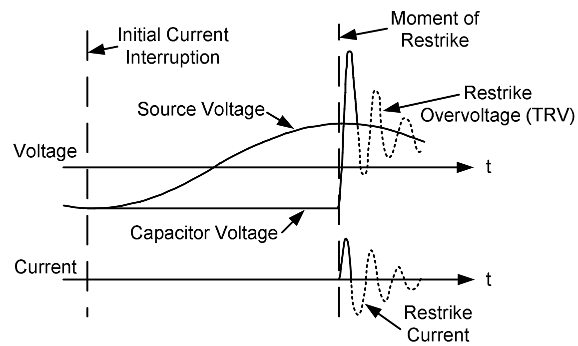


The following screen capture of the local unfiltered event shows a high-speed Zone 1 trip.



VI-b There were no other faults on the system at the time of the trip. The trip was directly related to the de-energization of the capacitor bank. What is the possible cause of the trip?

The following figure shows a likely possibility. In this scenario, when the capacitor bank was de-energized, it was followed by a circuit breaker restrike. The current was interrupted at the zero crossing, and at that instant, the system voltage and the capacitor voltage were at negative maximum value. The capacitor voltage stayed at the negative maximum value due to the trapped charge left on the capacitor. One-half cycle after the interruption, the system voltage reached its positive maximum value, resulting in twice the maximum voltage value appearing across the circuit breaker. The high-voltage potential across the contacts exceeded the dielectric strength of the gap at that moment. The breakdown of the dielectric strength resulted in an arc that reestablished current flow (i.e., a restrike).



The surge arrester then started conducting because of the 2 pu nominal voltage. In this case, the arrester was rated to conduct at 1.75 pu of system voltage. The surge arrester current was enough to produce the bus differential operation.

VI-c If the root cause is the conduction of the surge arrester, what protection measures can be taken?

It is likely that a future operation could occur because it is dependent on unpredictable voltage zero crossings. Because the operators require the flexibility of switching the capacitor banks, the best solution might be to add a short time delay (e.g., 1 cycle) to ride through the transient if the arrester should conduct.

VII. Restricted Earth Fault (REF) Element Trip

A large manufacturing facility experienced two critical transformer trips, which caused a loss of production while the trips were being investigated. The transformers were actually three single-phase, three-winding transformers connected in wye-wye-delta. A simplified three-line diagram is shown in Fig. 5. Fig. 6 shows a more detailed wiring diagram where we can see a spare transformer.

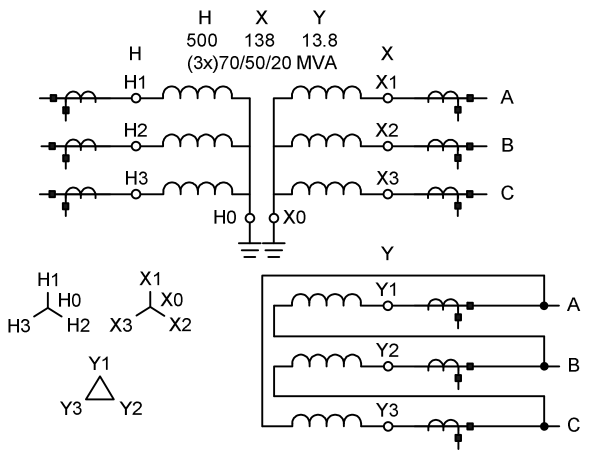


Fig. 5. Simplified three-line diagram

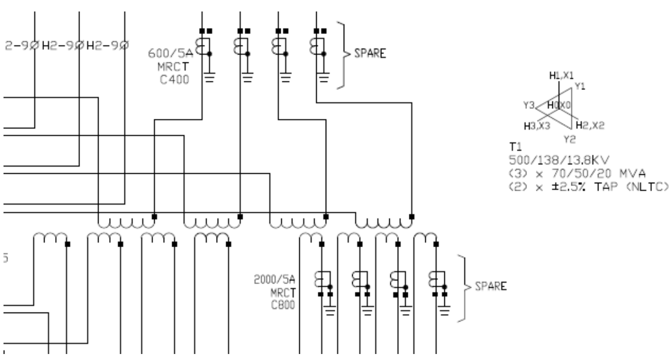


Fig. 6. Detailed screen capture shows single-phase transformers connected wye-wye-delta with spare transformer

The questions and discussion in this section follow a sequence of events that allow us to determine root cause. Open the event **7_CEV_S4_L30_1 initial trip.CEV**.

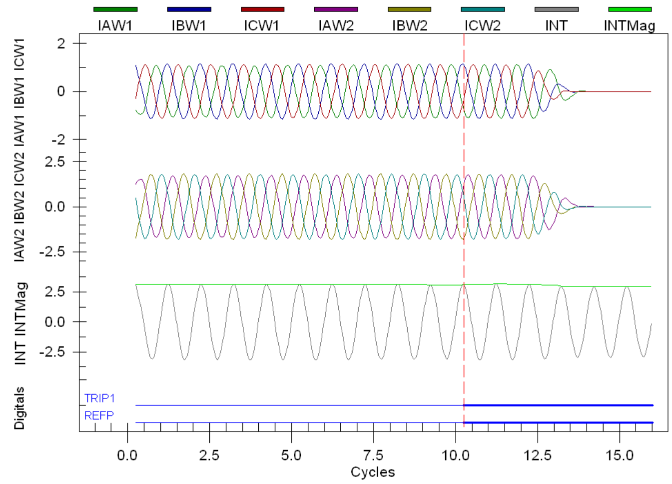
VII-a What elements were set to trip, and what element produced the first trip? How was the element set?

Windings 1, 2, and 3 produced the differential zone, and Winding 4 was used as the neutral input for the REF element. The first trip was produced by the REF element.

The settings were as shown in the following screen capture.

```
TR1      =50P11T + 51P1T + REFP
.
32IOP = 1     a0 = 0.05     50GP  = 0.85
```

In the following screen capture, the initial trip indicates an REF trip.

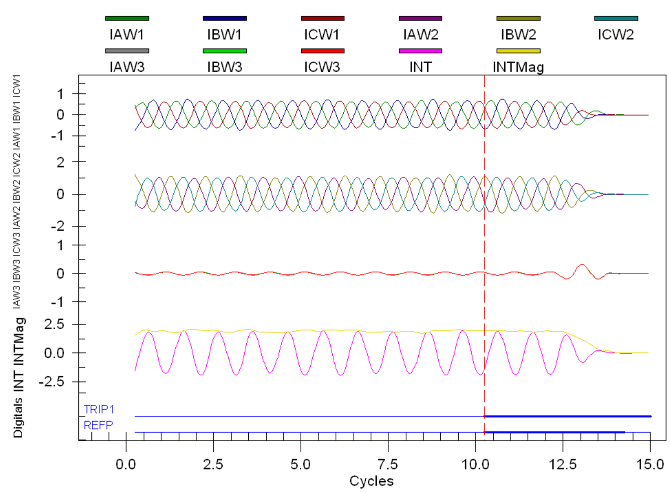


The relay user noticed a setting problem on the first trip where Winding 1 was designated as the REF winding. However, the physical neutral connection was on Winding 2 (the X winding).

So the user changed the 32IOP setting to 2. After the setting change, the transformer tripped again under load conditions.

VII-b Open the event **7_CEV_S4_L15_1-trip after load.CEV**. What element produced the second trip?

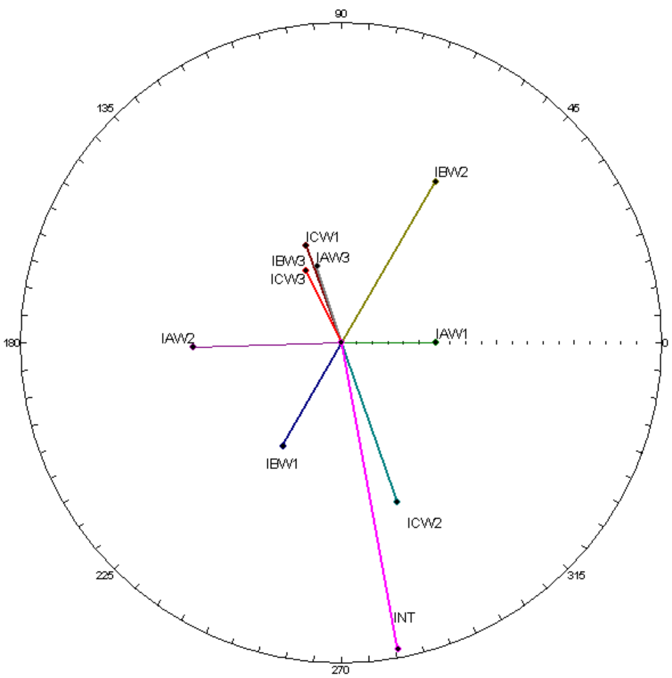
After the setting change, the transformer was energized with the same result—a trip produced by the REFP element. The following screen capture shows the second trip also caused by the REF element.



VII-c What could have caused the trip?

The following screen capture shows the phasors during the second event.

Channel	Mag	Angle	Scale	Show	Ref
IAW1	0.6	0.0	1	1	1
IBW1	0.8	240.3	1	1	0
ICW1	0.7	110.0	1	1	0
IAW2	0.9	181.6	1	1	0
IBW2	1.2	59.7	1	1	0
ICW2	1.1	289.5	1	1	0
IAW3	0.1	107.6	1	1	0
IBW3	0.1	115.7	1	1	0
ICW3	0.1	115.7	1	1	0
INT	2.0	280.5	1	1	0



A review of the event data reveals only slightly unbalanced phase currents, but unusually high neutral current (INT).

The internally calculated TAP settings were as shown in the following screen capture.

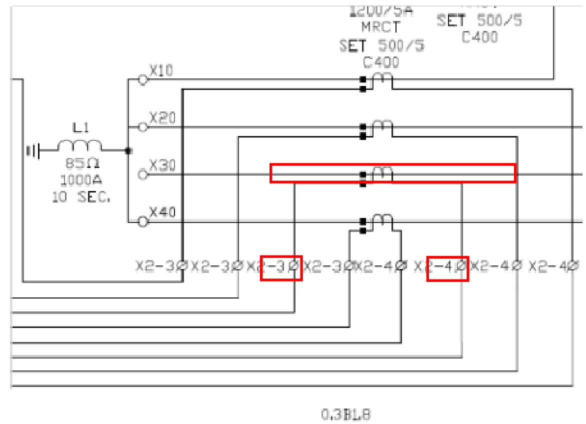
```
TAP1 = 2.42    TAP2 = 3.66    TAP3 = 14.64
```

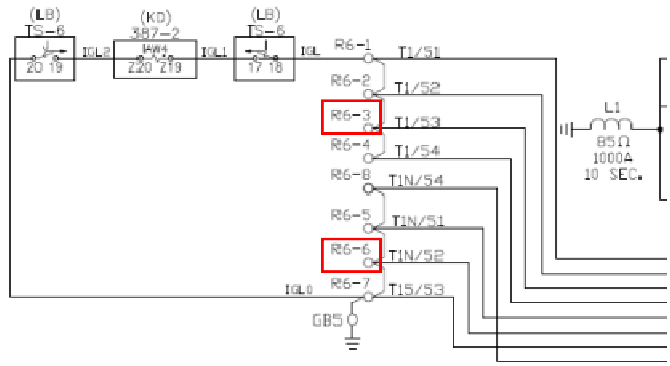
We can see that the secondary phase currents on Winding 2 were about 1.5 times the Winding 1 currents. This matches the expected currents for a given load. All of the winding currents were relatively low, indicating there was no fault condition. Thus, we suspect the wiring in the CT neutral circuit.

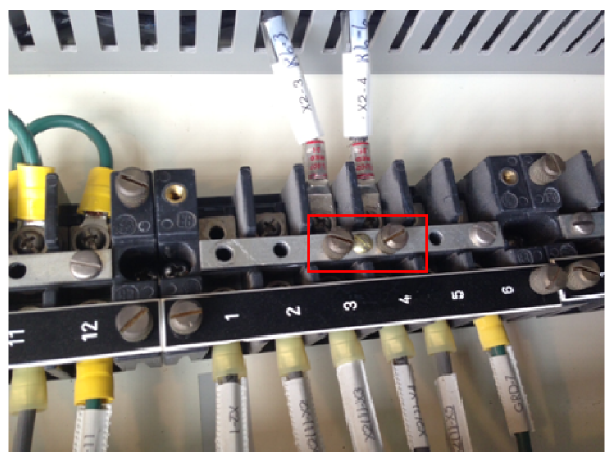
As stated previously, the transformers are three single-phase transformers connected as a three-phase transformer. Therefore, each neutral has a CT, and the CT secondaries are tied together to sum the currents.

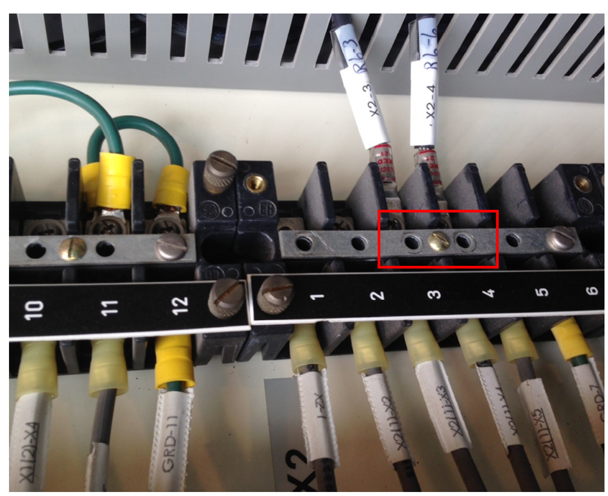
The user was instructed to measure the neutral current at the relay and the neutral current in each neutral conductor. It was noticed that the current in one neutral CT was low.

After investigation, it was noticed that shorting screws were left in the CT shorting block at the transformer on one of the neutrals. One shorting screw was loose. The second shorting screw created multiple grounds in the CT circuit, resulting in the false neutral current at the relay. The following wiring diagrams and photos show shorting screws in place on one phase (B).









Note in the drawings that the X30 transformer is shown as a spare, not connected. At some point during the testing or operation, this spare transformer had been placed in service. This is likely why the shorting screws were left in place.

VIII. Ground Directional Overcurrent Operates for Remote Fault

A line protective relay tripped for a remote AG bus fault and produced a Zone 1 target, which was deemed to be a misoperation. See Fig. 7.

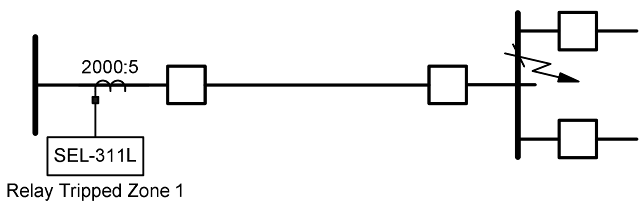


Fig. 7. One-line diagram shows Zone 1 trip for remote bus fault

The initial report from the field was that a Zone 1 distance element operated.

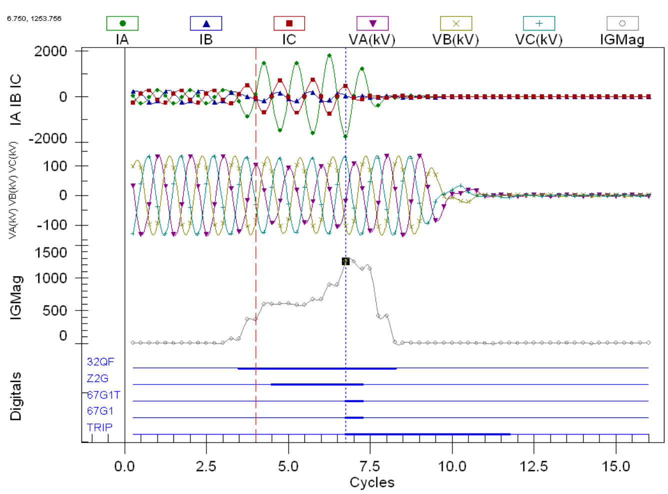
Open the event **8_311L_67G1 operation.cev**.

VIII-a What elements were set to trip, and what element produced the trip? How was the element set?

After viewing the settings, we can see from the following screen capture that numerous elements were programmed in the TR equation.

```
TR    =M1P + Z1G + M2PT + M3PT + Z2GT + Z3GT + 51GT +
67G1T + 67P3T + Z4GT
```

The following screen capture of an event report shows 67G1T assert.



The trip was produced by the 67G1T element. Furthermore, the actual trip occurred several cycles into the event. The following screen capture shows the settings associated with 67G1T.

```
CTR: = 400
 .
50G1P = 3.00
67G1D = 0.00
```

The actual fault current at the time of trigger was about 700 A. Then the current rose to 1,250 A at the time of trip.

VIII-b What could have caused the unexpected rise in current? What actions can be taken to avoid this in the future?

It is likely that there was pole scatter when the remote breaker cleared the fault. Even though this is a three-pole breaker, every breaker pole opens at a slightly different time. In this case, the time difference was long enough for the zero-sequence current to momentarily increase, which was long enough for the 67G1T element to operate.

The user had a choice—raise the pickup of the instantaneous element or consider adding a short time delay (e.g., 1 cycle) to ride through any possible pole scatter.

IX. Line Current Differential Operates on Line Charging Current

A line current differential (87L) scheme operated for an out-of-section CA fault on the negative-sequence (87L2) element on a 5.6-mile 230 kV cable with no tapped load. By definition, this is an undesired operation. Fig. 8 shows a basic one-line diagram. Note that this line is radial with only tapped load and a reactor at Station G.

Open the event **SEL-311L_STATION G_LINE GH1.cev**.

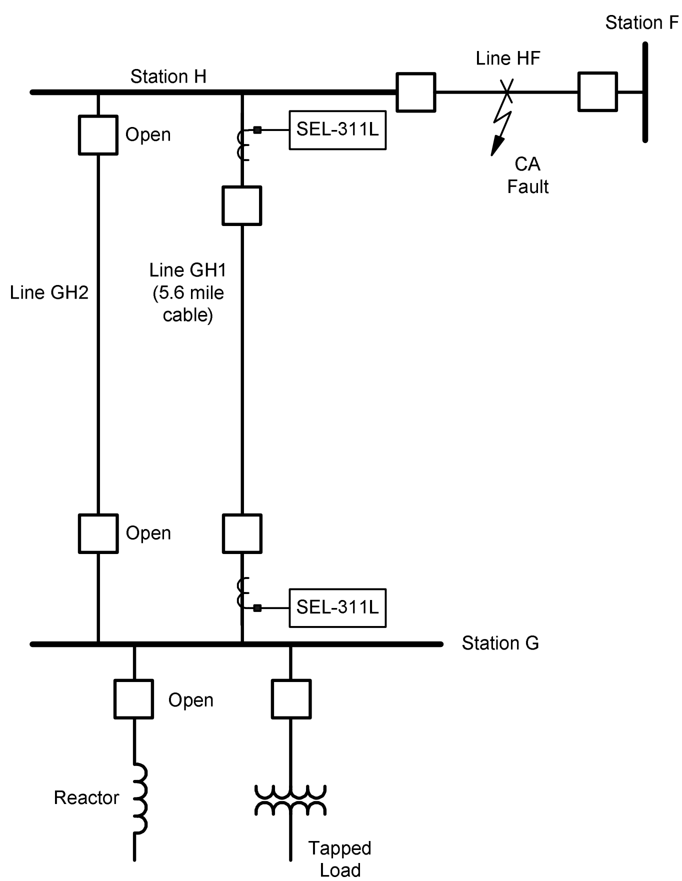
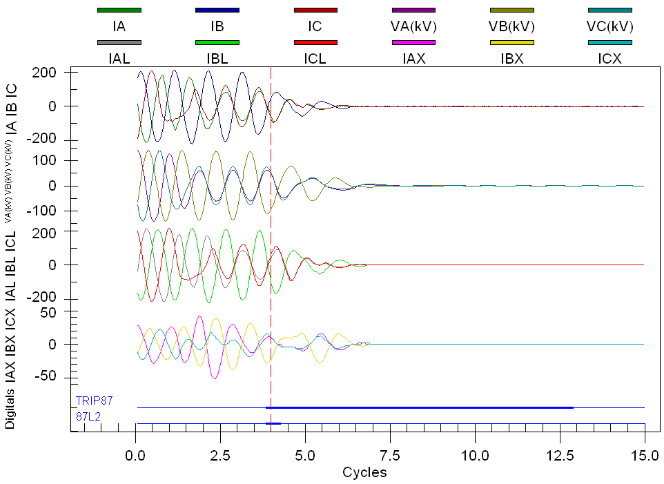


Fig. 8. Basic system one-line diagram

IX-a What elements were set to trip, and what element produced the trip? How was the element set?

The following screen capture shows 87L2 operate.



The negative-sequence differential element (87L2) asserted, as shown in the following screen capture.

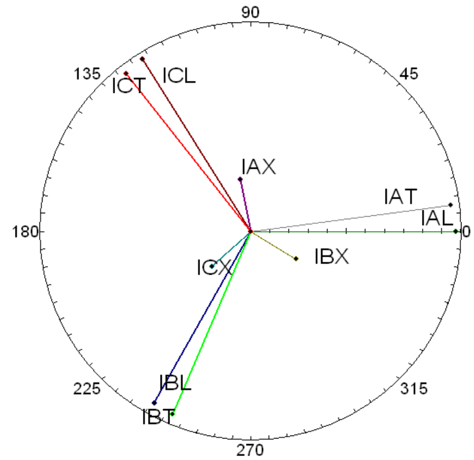
```
CTR    = 400      APP    = 311L
E87L   = 2        EHST   = 4         EHSDTT= Y
EDD    = Y        ETAP   = N         EOCTL = N
CTR_X  = 400
87LPP  = 6.00     87L2P  = 0.50      87LGP  = OFF
CTALRM= 0.50
87LR   = 6.0      87LANG= 195
CTRP   = 400      PTR    = 2000.00   PTRS   = 1155.00
.
SELOGIC Group 1
SELOGIC Control Equations:
TR     =M2PT + 51GT + TRIP87
```

IX-b Was there differential current in the prefault currents? What might have caused this?

The following screen capture shows the prefault phasor magnitudes and angles.

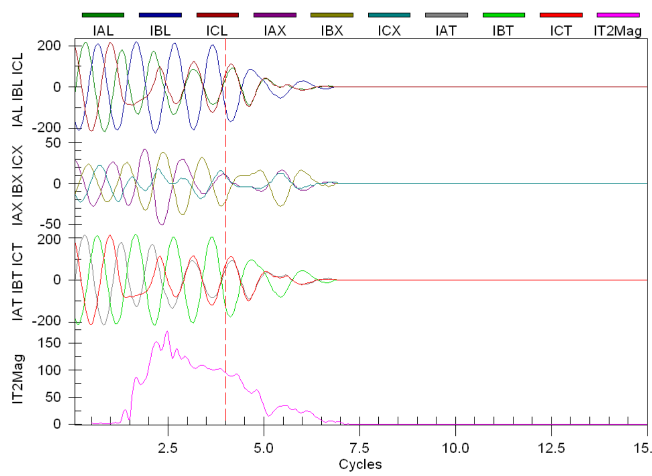
IAL	214.8	0.0	1	1	1
IBL	207.7	240.8	1	1	0
ICL	214.0	122.1	1	1	0
IAX	27.9	101.0	1	1	0
IBX	22.4	328.6	1	1	0
ICX	22.4	222.4	1	1	0
IAY	N/A	N/A	1	0	0
IBY	N/A	N/A	1	0	0
ICY	N/A	N/A	1	0	0
IAT	211.2	7.4	1	1	0
IBT	209.7	247.0	1	1	0
ICT	211.1	128.0	1	1	0

The following figure shows standing phase differential current in the prefault.



We can see significant differential current in the prefault. One of the prominent characteristics of high-voltage cables is the presence of line charging current caused by the electrical shunt capacitance. Even on short lines, this can be an issue.

If we focus on the total I2 magnitude (IT2Mag), we see an increase during the external fault, as shown in the next screen capture.



IX-c What was the line charging current? What measures can be taken to prevent future operations? The events **SEL-411L STATION G LINE GH1_REPLAY.cev** and **SEL-411L STATION G LINE GH1_REPLAY_LINE CHARGING COMPENSATION ENABLED.cev** will be necessary to complete this exercise.

Based on the event data, the line charging current was about 184.8 A per phase.

In order to avoid future operations in the SEL-311L Line Current Differential System, raise the negative-sequence differential element pickup setting. Another option is to apply the SEL-411L, which has the option of applying line charging current compensation.

To evaluate the event using the SEL-411L, we need to calculate the line susceptance.

The following is the calculation of line susceptance:

I_charging_primary = 184.8 A

CTR = 400

Per-phase voltage = 132.79 kV

V_ln_primary = 132.79 kV

PTR = 2000

The secondary charging susceptance is calculated as shown in (2).

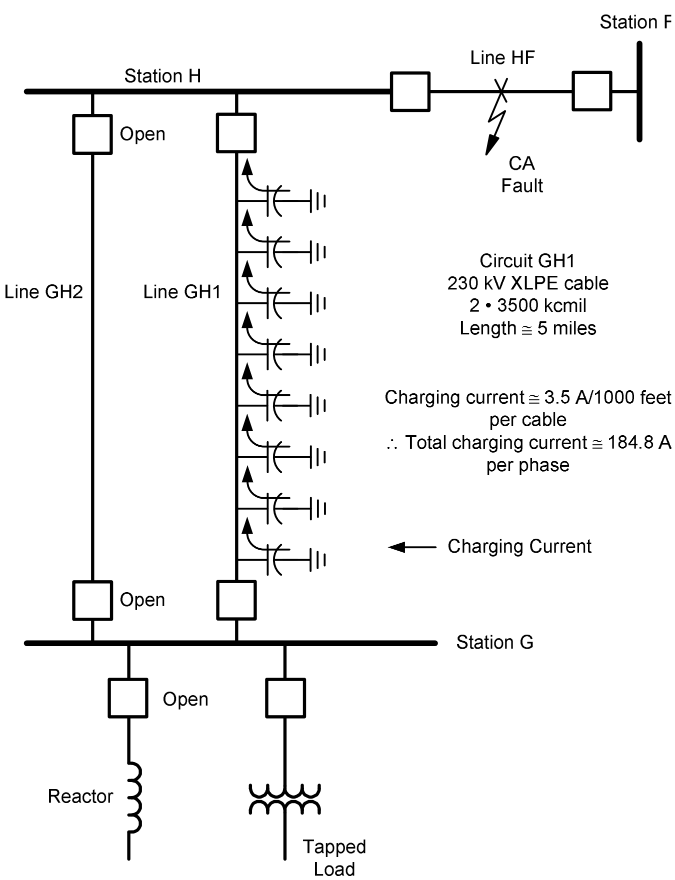
$$\mathrm{Bl} = \frac{\left(\frac{\mathrm{I\_charging}}{400}\right)}{\left(\frac{\mathrm{V\_ln}}{2000}\right)}$$

$$\mathrm{Bl} = \frac{\frac{184.8}{400}}{\frac{132.79 \bullet 10^{3}}{2000}} = 6.958 \bullet 10^{-3} \qquad (2)$$

$$\mathrm{Bl} = 7 \text{ ms}$$

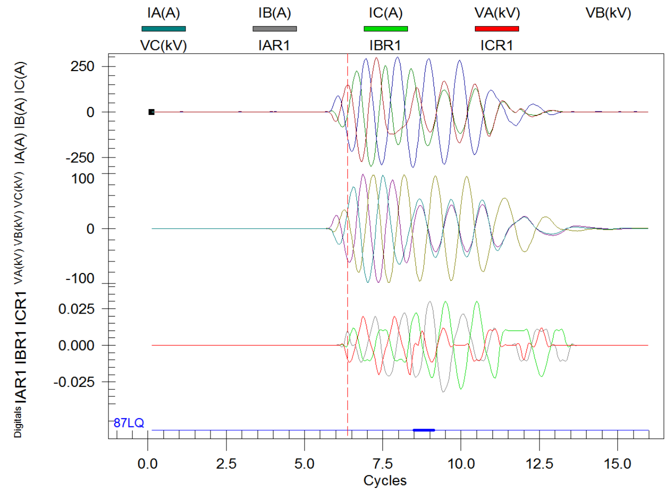
$$\mathrm{B0} = 3 \bullet \mathrm{Bl} = 21 \text{ ms}$$

The following one-line diagram shows the shunt capacitance source.

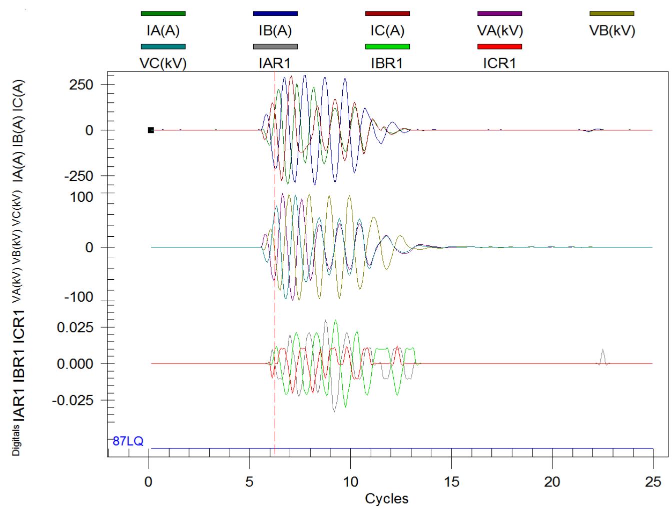


To test this, we replayed the unfiltered event through SEL-411L Relays with and without line charging compensation enabled.

We can see the 87LQ element trip. The following screen capture shows the SEL-411L 87LQ trip without line charging compensation enabled.



The following screen capture shows the SEL-411L 87LQ correctly restrain with line charging compensation enabled.



IX-d What measures can be taken to prevent future operations?

With the SEL-311L, the option is to raise the pickup of the negative-sequence differential element.

The SEL-311L Instruction Manual provides the following short caution for this type of application on Page J.5:

> As with the overhead line example, also consider the maximum voltage unbalance caused by an external unbalanced fault. This voltage unbalance can cause considerable charging current unbalance, up to the phase charging current.

A second option is to apply the SEL-411L with line charging compensation.

X. Acknowledgments

The author acknowledges the contributions of David Costello, Oskar Reynisson, Normann Fischer, Lee Underwood, Tony Lee, Bill Fleming, Mike Collum, Mangapathirao V. Mynam, and the many utility and industrial engineers who provided events and helped determine root cause of the events contained in this analysis.

XI. References

[1] K. Zimmerman and D. Costello, "Fundamentals and Improvements for Directional Relays," proceedings of the 63rd Annual Conference for Protective Relay Engineers, College Station, TX, April 2010.

[2] S. Marx, B. K. Johnson, A. Guzmán, V. Skendzic, and M. V. Mynam, "Traveling Wave Fault Location in Protective Relays: Design, Testing, and Results," proceedings of the 16th Annual Georgia Tech Fault and Disturbance Analysis Conference, Atlanta, GA, May 2013.

[3] K. Koellner, O. Reynisson, and D. Costello, "High-Impedance Bus Differential Misoperation Due to Circuit Breaker Restrikes," proceedings of the 67th Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, May 2013.

XII. Biography

Karl Zimmerman is a regional technical manager with Schweitzer Engineering Laboratories, Inc. in Fairview Heights, Illinois. His work includes providing application and product support and technical training for protective relay users. He is a senior member of the IEEE Power System Relaying Committee and chairman of Working Group D25, Distance Element Response to Distorted Waveforms. Karl received his BSEE degree at the University of Illinois at Urbana-Champaign and has over 20 years of experience in the area of system protection. He has authored over 25 papers and application guides on protective relaying and was honored to receive the 2008 Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference.