Event Analysis Tutorial

Part 2: Answer Key

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***Abstract*—Event reports have been an invaluable feature in microprocessor-based relays since the initial introduction of the technology. The days of unknown root cause for an operation, lengthy outages, or unexplained test results are largely over due to this tool and the ability of engineers and technicians to use it. We must practice to become proficient at analyzing event reports. This session provides 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. We have distribution, transmission, transformer, bus, generator, and motor event examples.

In each case, we provide the following:

- A brief introduction to the application and problem.
- The event reports required to solve the problem.
- 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.

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.

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

II. Distribution Feeder Fault

This event occurred on a distribution collector at a wind farm. For practical purposes, faults on the collector behave like faults on a radial feeder fed from a Dy1 transformer. The wind turbines do not contribute any significant fault current. The location and connection of the potential transformers (PTs) are not known at the time of publication.

Lightning arresters, one per phase, are positioned on the top of the steel support structure. Each arrester is connected by a jumper to the phase conductor. A bird caused a fault near one lightning arrester, which caused its jumper to blow loose and contact other phases.

Open the event report titled **2 – Distribution Feeder Fault 351S-6.cev** to analyze this case. See Fig. 1 for a screen capture from this event.

The relay involved was an SEL-351S-6. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

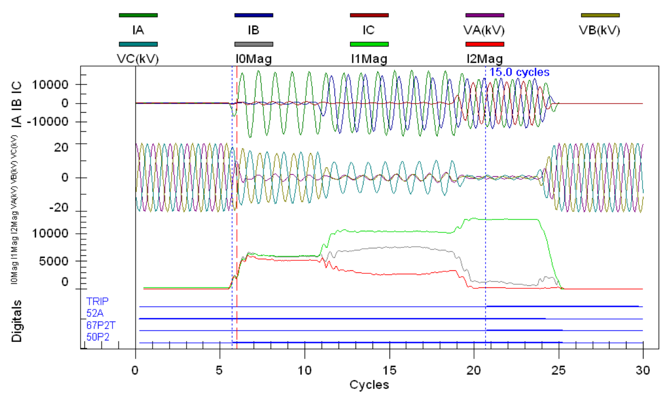


Fig. 1. Distribution Feeder Fault (2 – Distribution Feeder Fault 351S-6.cev)

Questions:

II-a Before the fault, in what direction is power flowing?
Power is INTO the bus or in the reverse direction.

II-b What is the system phase rotation?
ABC.

II-c What type of fault occurred?
This is an evolving fault on the feeder (forward direction). It starts as an AG fault, evolves to an ABG fault, and then finally evolves to a three-phase fault.

II-d What protection element within the relay caused the trip?
67P2T—a nondirectional phase overcurrent definite-time delay element.

II-e How long did it take for the relay to operate?
15 cycles.

II-f How long did the breaker take to clear the fault?
About 3.5 cycles.

II-g Did the relay and protection system operate correctly and as expected?
Yes.

Another event report from a different system is provided for comparison. Open the event report titled **2 – Distribution Feeder Fault 351A.cev** to analyze that case. See Fig. 2 for a screen capture from this event. The relay involved was an SEL-351A. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

Note in Fig. 1that the phase fault current is largest during the single-line-to-ground fault period. In Fig. 2, the phase fault current is largest during the three-phase fault period.

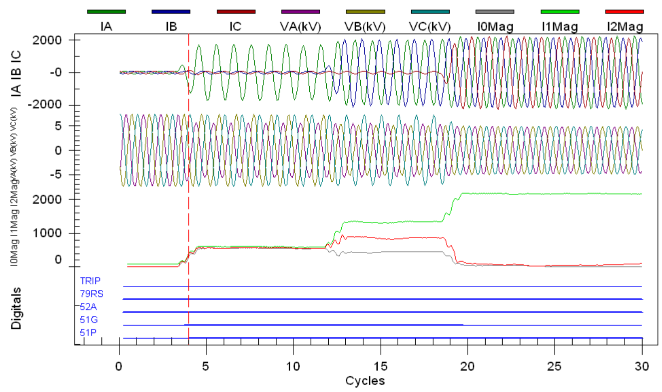
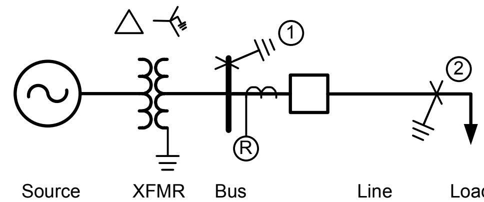


Fig. 2. Distribution Feeder Fault (2 – Distribution Feeder Fault 351A.cev)

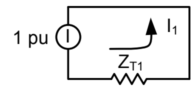
Question:

II-h On a radial distribution feeder, what type of fault do you expect to produce the largest phase fault current?
This depends on fault location and transformer type.
Does the type of transformer used as a source matter?
Yes. Core-type transformers can have lower zero-sequence impedances, which can make the phase current for a close-in LG fault larger than that of a three-phase fault.
Does the fault location make a difference?
Yes. As the fault moves out on the line, for LG faults, the zero-sequence impedance (which is typically larger than the line positive-sequence impedance) begins to dominate and make the LG fault current less than that of a three-phase fault.
Can you provide an explanation for the fault type current magnitudes in these two event reports?
See the following derivations.

II-h Derivation 1

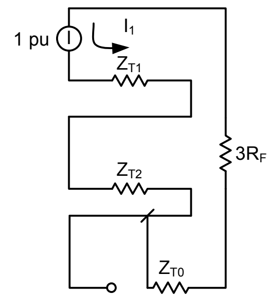


Three-Phase Fault (3PH) at Bus 1 (Assume Infinite Source)



$I_1 = \frac{1}{Z_{T1}}$ $\quad I_A = I_1$

LG at Bus 1 (Assume Infinite Source)



$$I_1 = \frac{1}{Z_{T1} + Z_{T2} + Z_{T0} + 3_{RF}}$$

Assume $Z_{T0} = Z_{T1}$, and $3_{RF} = 0$

$$I_1 = \frac{1}{3Z_{T1}} = I_2 = I_0$$

$$I_A = I_1 + I_2 + I_0 = \frac{1}{Z_{T1}}$$

If XMFR is a core-type transformer, because of its lower exciting impedance, the zero-sequence impedance can be 85 to 100 percent of its positive-sequence impedance [1].

Assume $Z_0 = 0.85\ Z_{T1}$

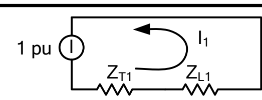
$$I_1 = \frac{1}{Z_{T1} + Z_{T2} + Z_{T0}} = \frac{1}{2.85\ Z_{T1}} = I_2 = I_0$$

$$I_A = I_1 + I_2 + I_0 = \frac{3}{2.85\ Z_{T1}} \cong \frac{1.05}{Z_{T1}}$$

(i.e., I_A for an LG larger than I_A for 3PH for 1 with certain XFMRs)

II-h Derivation 2

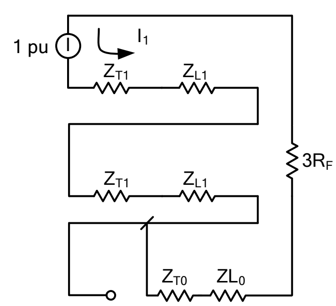
3PH at Line 2 (Assume Infinite Source)



$I_1 = \frac{1}{Z_{T1} + Z_{L1}}$

$I_A = I_1$

LG at Line 1 (Assume Infinite Source)



$$I_1 = \frac{1}{3Z_{T1} + 5Z_{L1}}$$

Assume:

$Z_{T0} = Z_{T1} = Z_{T2}$

$Z_{L0} = 3Z_{L1}$

$Z_{L1} = Z_{L2}$

$3R_F = 0$

Rearranging,

$$I_1 = \frac{1}{3(Z_{T1} + Z_{L1}) + 2Z_{L1}} = I_2 = I_0$$

$$I_A = I_1 + I_2 + I_0 = 3I_1$$

$$I_A = \frac{1}{Z_{T1} + Z_{L1} + \frac{2}{3}Z_{L1}}$$

(i.e., I_A for an LG smaller than I_A for a 3PH for 2)

The SEL University classes PROT 301: Protecting Power Systems for Technicians and PROT 401: Protecting Power Systems for Engineers review necessary symmetrical components and fault analysis fundamentals. Register for these classes and more at www.selinc.com.

III. Underfrequency Load-Shedding Test

These events were recorded from laboratory tests. An SEL-451-5 was being applied for underfrequency load shedding. Laboratory tests were conducted to prove the protection scheme would perform as intended.

The scheme was designed to trip groups of 7 kV feeders at various underfrequency set points. The first group of feeders should have tripped at 58.7 Hz. A different group of feeders would have tripped at different frequencies. Therefore, frequency elements were programmed directly into individual output contacts. All frequency elements were originally connected by OR gates in the trip logic only to provide a local trip light-emitting diode (LED) indication; the trip logic was not used by any output contacts.

The feeders were on the low side of a 66 kV/7 kV transformer. The relay voltage inputs were fed from the 66 kV bus PTs.

A standard test set applied secondary voltages. The frequency of VA was lowered in steps, rather than using a ramp. Trip unlatch (TULO) was set for Option 3. With no current applied and no breaker status simulated during the test (see Page A.1.14 of the SEL-451-5 Instruction Manual), the trip will unlatch when trip conditions expire or after a minimum time of 12 cycles (TDUR3D).

Open the event report titled **3 – Frequency Load Shed Test One 451-5.cev** to analyze the first test. See Fig. 3 for a screen capture from that event. The relay involved was an SEL-451-5. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

Three problems were noted by technicians. First, the output contact used by the underfrequency element 81D1T chattered continuously after the frequency was lowered below the set point, and it would not stop until the frequency was returned to normal. Second, the trip time for the underfrequency event was slightly longer than expected. Third, the frequency metering stopped tracking at 58.0 Hz, despite the test set being lowered below this level.

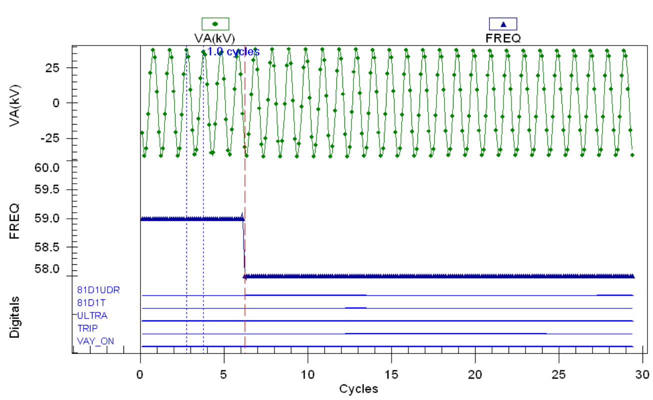


Fig. 3. Frequency Test 1 (3 – Frequency Load Shed Test One 451-5.cev)

Open the event report titled **3 – Frequency Load Shed Test Two 451-5.cev** to analyze the second test. See Fig. 4 for a screen capture from this event. The trip logic was changed for the second test, setting TR equal to NA. The only other change made for this test was the addition of the FREQOK (frequency tracking okay) and FREQFZ (freeze frequency tracking) Relay Word bits to the digital elements recorded with event reports.

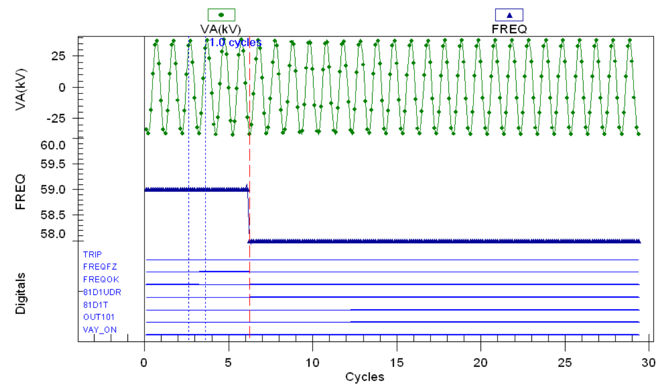


Fig. 4. Frequency Test 2 (3 – Frequency Load Shed Test Two 451-5.cev)

Questions:

III-a Using event data, can you determine if the voltage magnitude applied is correct for this application?

The applied voltage is 110 V secondary line-to-neutral (LN). The nominal voltage setting, line-to-line (LL), is VNOM = 199 V. So the relay expects 199 V LL/115 V LN, and 110 V is applied. While it would be best if the test set voltage magnitude matched the expected nominal voltage (115 V LN), this is close enough and should not create a problem.

III-b At what point in the event data did the test set actually change frequency?

Just before Cycle 3 in Fig. 3, the frequency of the applied voltage begins to change. We can determine this because samples begin to hit the steady-state waveform at different points on the curve. There is always a slight lag in frequency tracking in a digital relay and the actual frequency of the input signals. Frequency tracking, in most relays, determines sampling rates. So when the sample points start moving to different points on the curve or when *x* samples per cycle do not get us back to the same point on the waveform we know the input signal frequency is changing, and the frequency tracking and sampling rate of the relay are drifting slightly.

III-c Is a step change in frequency an appropriate test method for an underfrequency load-shedding application?

No. In a real power system, frequency changes ramp but do not step change. In some relays, frequency tracking algorithms have a maximum slew rate, above which the algorithm suspends frequency tracking. In a step change test, it is likely that the maximum slew rate will be exceeded. In Fig. 4, we can see the FREQOK bit drop out and the FREQFZ assert right at the point where sample rates are changing, indicating the test set stepped to a new frequency value. This is where the SEL-451-5 froze or suspended its frequency tracking.

III-d Does the frequency element time delay match the expected scheme settings?
A test set timer, measuring the difference in time between the state change and the assertion of 81D1T, would measure 3 to 4 cycles longer than the 6-cycle delay expected. This is due to the suspension of frequency tracking, which, in turn, disables frequency elements (according to the instruction manual Figure R.1.58).

III-e In the first test, the frequency element can be seen asserting and then deasserting. What element do you suspect turned the frequency element off?
Within 1 cycle of the trip asserting, the frequency elements deassert. Within 3 cycles of the trip deasserting, the frequency elements pick up again. It appears the trip logic affects frequency elements from these test results. In the second test, the trip equation is set to NA, and the frequency elements do not cycle. In fact, frequency tracking in the SEL-451-5 is suspended during faults as determined by the trip equation—when TR is a logical 1, FREQOK is driven to a logical 0. This disables the frequency elements.

III-f In an SEL-451-5, can frequency elements be included directly in the trip equation?
It depends. If only one level of frequency load shedding was implemented, then yes, a single 81U element can be programmed along with other tripping elements in the TR equation. If an 81U operation occurred, the relay would trip correctly. If, as in this case, the relay is used as a station underfrequency load-shedding device tripping multiple feeders at various frequency levels, then the TR equation should not be used by 81U elements. Instead, front-panel LED indication and remote supervisory control and data acquisition (SCADA) notification can be accomplished using SELOGIC® control equations rather than using the trip logic, and 81U elements (including minimum trip or output contact closure times and seal-in) can be programmed directly into separate output contact logic.

The technical paper “Frequency Tracking Fundamentals, Challenges, and Solutions” is available at www.selinc.com and is recommended reading for more information on this subject.

IV. Directional Overcurrent Operation

SEL-351A Relays are used as main breaker relays in an industrial plant main-tie-main scheme. The instruction manual is provided as part of the class material and is available at www.selinc.com.

A one-line diagram is provided in Fig. 5. The industrial plant is a radial load. The SEL-351A provides the 67P function. Forward direction for this relay is into the industrial bus; reverse is into the utility. Reverse power flow, due to odd breaker status combinations, through either transformer is not desired or allowed.

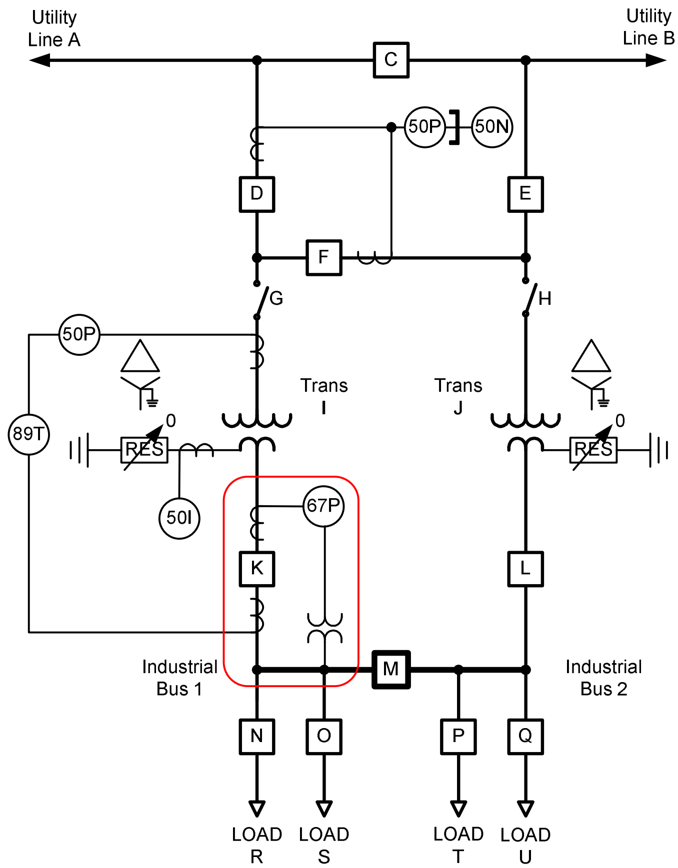


Fig. 5. One-Line Diagram for Directional Element Operation

The utility had a lightning arrester failure at a customer-owned substation several terminals away from this plant. The 67P relay tripped for this fault.

Open the event report titled **4 – Main Breaker Directional Element 351A.cev** to analyze the event. See Fig. 6 for a screen capture from this event.

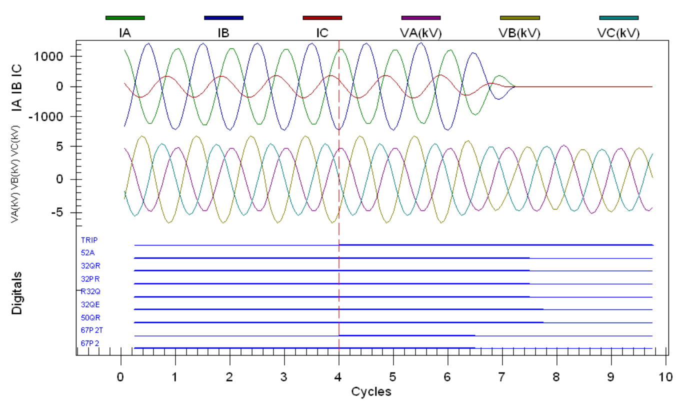


Fig. 6. Main Breaker Data (4 – Main Breaker Directional Element 351A.cev)

Questions:

IV-a The phasors and oscillography during the event do not indicate an obvious fault type. Can you explain why?
There is a fault, in the reverse direction to this relay, many line sections away. This creates phase voltage unbalance and negative-sequence current and voltage at the relay location. There is no generation source on the industrial bus. However, negative-sequence current flow is coming from the plant through the motor and other load impedances. This limits the 3I2 magnitude but does not eliminate it. At the same time, load or power flow into the plant is superimposed in the forward direction.

IV-b What relay element tripped?
The 67P2T, which is a reverse direction phase overcurrent element with a definite-time delay.

IV-c From the settings and your experience, what is the purpose for this relay?
The relay is set as a reverse power or reverse current element. If significant power flowed from the industrial bus to the utility, it would be because the industrial bus tie breaker was closed and the utility ties were open. This is neither desired nor allowed.

IV-d Is this relay tripping response expected or a misoperation?
There was a fault on the utility system (which is a reverse fault to this relay). So, technically, the relay did as it was told: see the reverse phase or ground faults and trip. However, it was intended to trip after a fair time delay for reverse power flow or as backup for a high-side fault when the utility high-side breakers were open. The utility had a failure to clear the fault at high speed, so the prolonged fault time exposed this problem. It is safe to say no one intended this relay to be so sensitive and to see an LG fault several line sections away.

IV-e What is the root cause?
The problem for this application is the relay directional element sensitivity. An electromechanical phase relay directional element operates like a power meter. With high load INTO the plant during an external fault, the high load overpowers the reverse fault sensing, so the overall decision is forward. In SEL-351 Relays, the phase overcurrent element has two distinct areas of logic. First, high forward load into the plant exceeds the phase overcurrent magnitude pickup. Second, a separate directional element looks for the fault location. For unbalanced faults, the relay uses negative-sequence quantities, which are provided by unbalanced current flow through motors and other loads in the plant. In other words, forward load into the plant picked up the phase overcurrent element (magnitude sensor) and the reverse negative-sequence element saw the fault location as reverse. The solution is to make the phase overcurrent element be supervised by the positive-sequence directional logic ONLY, so the phase overcurrent only sees three-phase faults or power flow in the reverse direction. For high-side unbalanced faults, we enable a negative-sequence overcurrent element and supervise it with a negative-sequence directional element. The referenced technical paper and application guide go into more detail.

The technical paper "Use of Directional Elements at the Utility-Industrial Interface" is available at www.selinc.com and is recommended reading for more information on this subject. The SEL Application Guide AG2009-17 "Enabling Sensitive Directional Tripping for Non-Line Protection Applications With SEL-351 Series Relays" provides settings recommendations and is also available at www.selinc.com.

V. Transformer Differential Operation

A 10.5 MVA, 115 kV/13.2 kV transformer is protected by an SEL-387A. The instruction manual is provided as part of the class material and is also available at www.selinc.com. A fault occurred on the system, and the transformer differential element tripped. The transformer serves radial loads.

The transformer application is configured as shown in Fig. 7. This high-voltage terminal is delta-connected and labeled Winding 1(W1). The low-voltage terminal is wye-connected and labeled Winding 2 (W2).

The transformer is an ANSI standard, where the polarity of H1 is connected to the nonpolarity of H2. The system phase rotation is ABC. C-phase is connected to H1, B-phase is connected to H2, and A-phase is connected to H3.

Open the event reports titled **5 – Transformer Differential Report 387A.cev** and **5 – Transformer Filtered Report 387A.cev** to analyze this event. See Fig. 8 and Fig. 9.

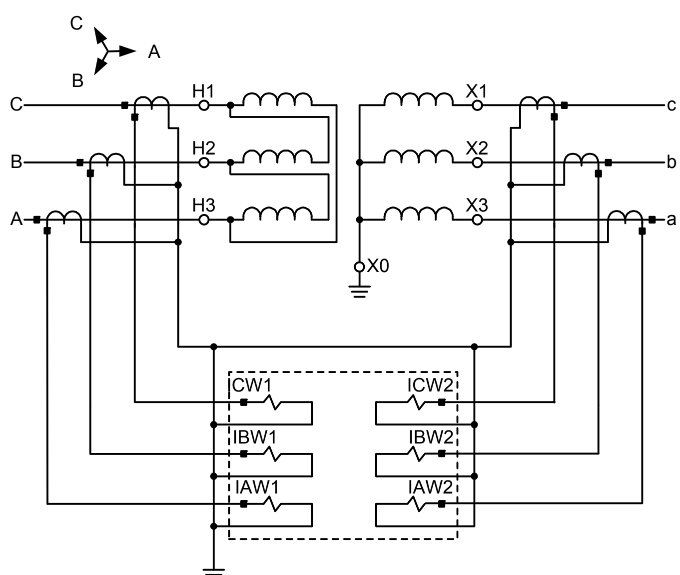


Fig. 7. Transformer Application

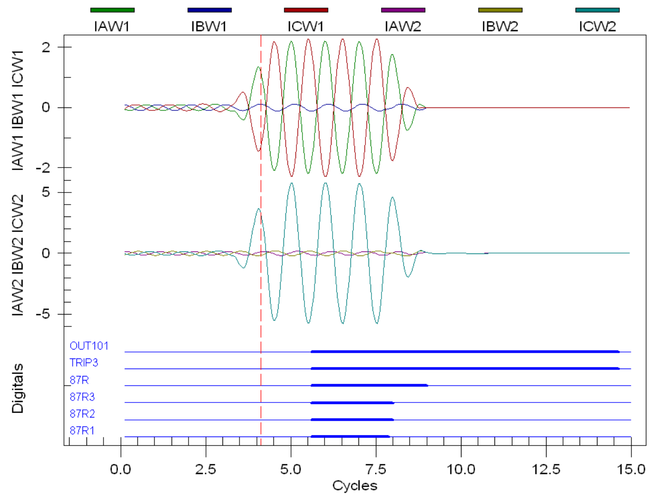


Fig. 8. Phase Currents (5 – Transformer Filtered Event 387A.cev)

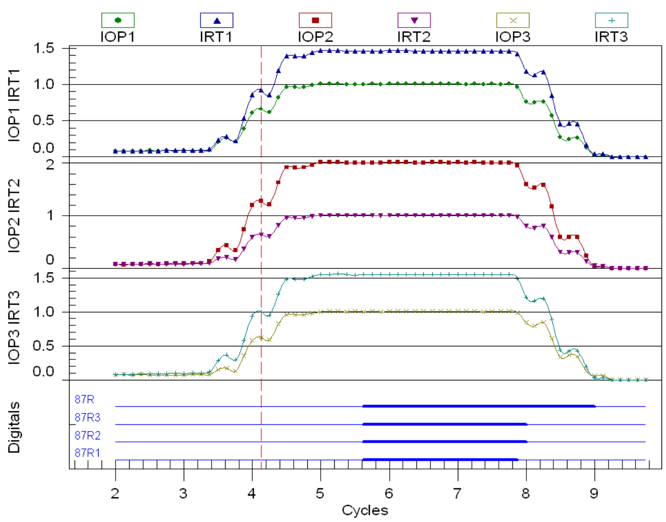


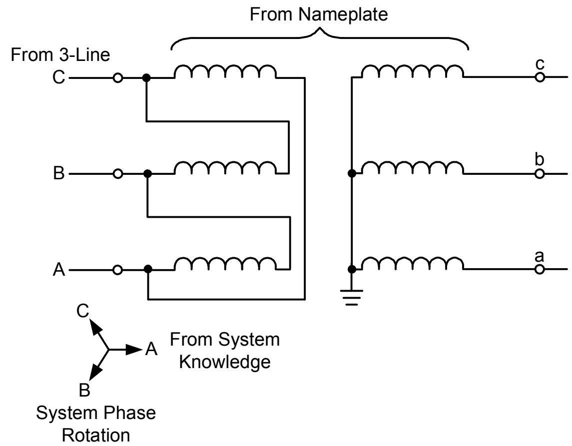
Fig. 9. Differential Signals (5 – Transformer Differential Report 387A.cev)

Questions:

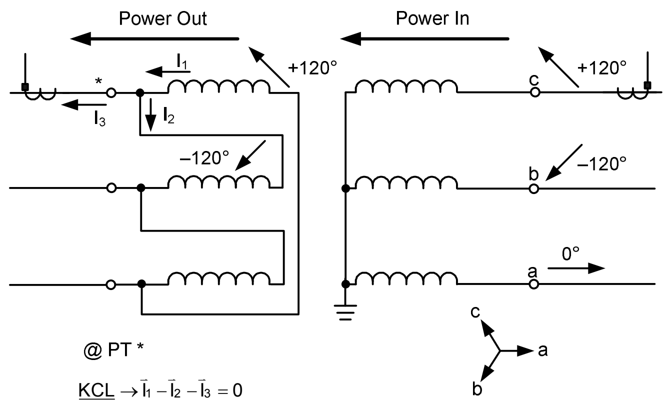
V-a Using the prefault phasors, can you confirm the system phase rotation?
ABC.

V-b Given the information about the system and the diagram shown in Fig. 7, can you determine the expected phase angle relationship across the transformer?
See the derivations that follows. The high side will lag the low side by 30 degrees.

V-b Derivation 1



V-b Derivation 2



@ PT *

KCL $\rightarrow \vec{I}_1 - \vec{I}_2 - \vec{I}_3 = 0$

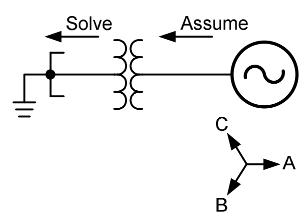
$\vec{I}_3 = \vec{I}_1 - \vec{I}_2$

$= \frac{\vec{I}_c}{n} - \frac{\vec{I}_b}{n} = \frac{|I_c|\angle +120°}{n} - \frac{|I_b|\angle -120°}{n}$

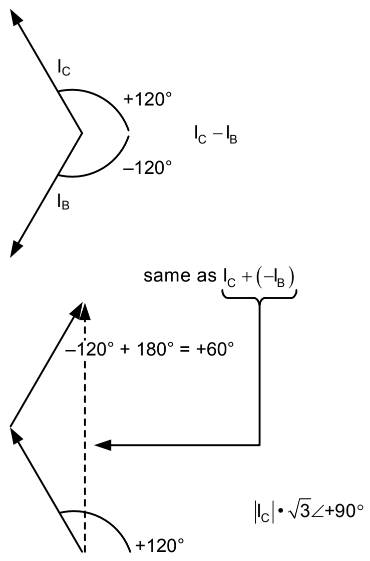
$= \frac{|I_c|}{n} \bullet \sqrt{3}\angle +90°$

V-b Derivation 3

To determine phase shift, assume generator/source on wye side and solve for the currents (i.e., short-circuit impedance test):



V-b Derivation 4



V-c Using the prefault phasors, does the actual system match your expected phase angle relationship from question V-b?
Yes.

V-d Where was the fault (internal to the transformer or external to the protection zone)?
This is a radial system, and both high- and low-side current transformers (CTs) measured fault current. The phase angle relationships during the low-side LG fault correspond to the drawing in Fig. 7 and prove that the wiring is as expected.

V-e Was the transformer differential operation correct or incorrect for the fault location?
The 87R element should not respond to an external fault. This indicates some problem exists with the application (CT ratio [CTR] tap, setting, wiring, and so on).

V-f Is the relay set correctly?
No. The WxCTC settings are incorrect. W1CTC should be changed to 0 or 12 (from 11), and W2CTC should be changed to 11 (from 12).

V-g Using the differential report data, was there any indication before the fault that a problem existed?
Yes. The operate current is too high, as a percentage of restraint current. If IOP/IRT > 10 percent, this indicates a problem with a transformer application.

The technical paper “Proper Testing of Protection Systems Ensures Against False Tripping and Unnecessary Outages” is available at www.selinc.com and is recommended reading for more information on this subject.

VI. Restricted Earth Fault Operation

Restricted earth fault (REF) protection in an SEL-387-6 was enabled on a 25 MVA transformer to provide a sensitive ground current differential zone of protection for the grounded-wye winding and low-side bus. See Fig. 10.

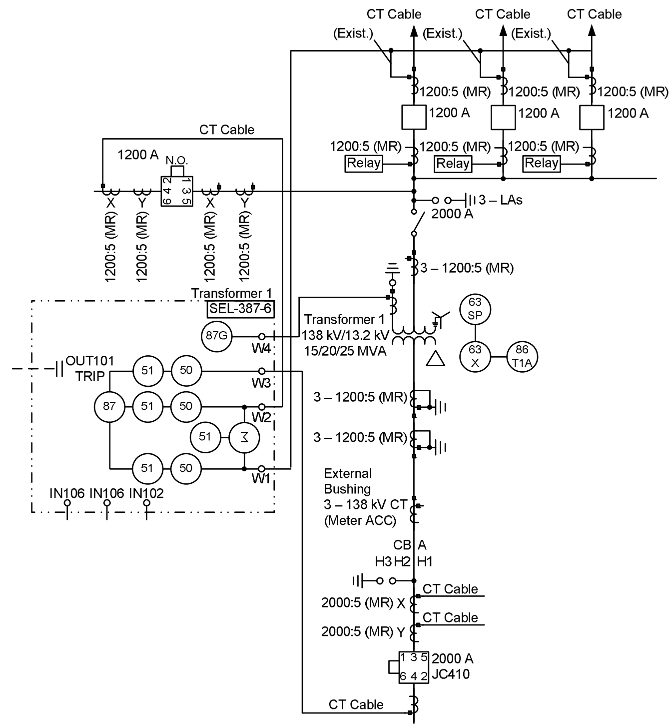


Fig. 10. REF Application

The SEL-387-6 Instruction Manual is provided as part of the class material and is available at www.selinc.com. Open the event report titled **6 – Transformer REF 387-6.cev** to analyze this event. See Fig. 11. Winding 1 feeders are radial loads.

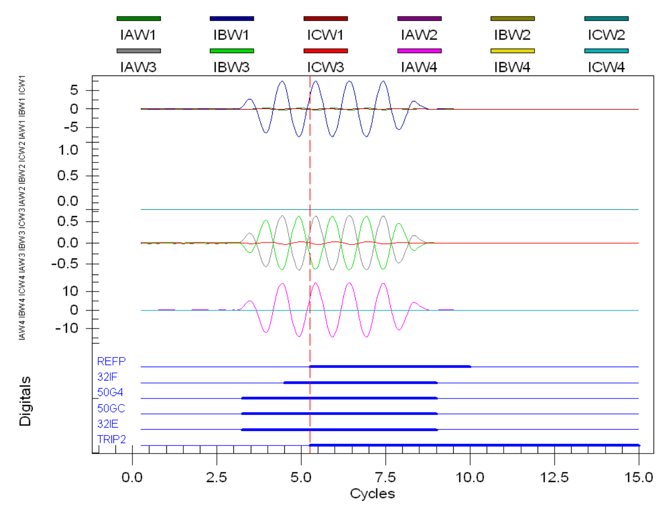


Fig. 11. REF Application (6 – Transformer REF 387-6.cev)

Questions:

VI-a Where was the fault (internal to the transformer or external to the protection zone)?
The fault was external. The X0 bushing and Winding 1 (W1) both saw current for an LG fault. Because the loads were radial, the fault must be external to the REF zone.

VI-b Was the tie breaker open or closed at the time of the event?
The bus tie was open, as indicated by no Winding 2 (W2) currents.

VI-c What element operated to trip the transformer?
The REF element operated to trip the transformer offline.

VI-d Was the transformer relay operation correct or incorrect for the fault location?
The REF element should not respond or trip for system ground faults, so the operation was incorrect. This indicates a problem (i.e., settings, wiring, and so on).

VI-e For an external ground fault, what phase angle relationship do you expect between the Winding 1 and Winding 4 currents?
The primary X0 bushing CT ground current should be equal and out of phase with the primary 3I0 ground current exiting the feeder CTs. In this case, the feeder W1 3I0 current is in phase with the X0 ground CT current. This indicates that one of the CTs has incorrect polarity.

VI-f Why is the ground current magnitude on Winding 1 different than Winding 4?
The W4 and W1 CT ratios are different, and the SEL-387-6 event data are provided in A secondary. Therefore, for the same primary fault current, the secondary currents will be different. This is correct.

VI-g A CT wiring problem is suspected. Can you prove which winding has the error?
We know that the W1 feeder CT that experienced the external fault is connected correctly because the IB current on W1 is out of phase with the IB current on W3, the transformer high-side CT. That means the X0 bushing CT is connected backward or with incorrect polarity. The drawing in Fig. 10 is correct, so the error is in field wiring or the CT in the transformer tank is installed backward. Three recommended ways to ensure that the REF CTs are installed correctly are primary injection testing, standard CT polarity testing, or leaving the REF tripping disabled until the first system fault record can verify proper connections.

The technical paper "Analysis of an Autotransformer Restricted Earth Fault Application" is available at www.selinc.com and is recommended reading for more information on this subject.

VII. Transformer Differential Commissioning Test

Engineers and technicians were on-site to witness the energization of a new 138 kV/12.47 kV substation. After putting some load on the distribution feeders, they noticed that the differential current measured by the SEL-587 was quite high, as a percentage of restraint. The load was very small, and there was some debate as to whether the transformer was ready to be put into service.

See Fig. 12. Two 1200:5 MRCTs, tapped at 900:5, are paralleled and connected to the Winding 1 inputs of the relay. A single 1200:5 MRCT, tapped at 1200:5, is connected to the Winding 2 inputs of the relay. The transformer is rated 12/16/20 MVA and 138 kV/12.47 kV. From Fig. 12, the polarity of H1 is connected to the nonpolarity of H2. A-phase is connected to H1, B-phase is connected to H2, and C-phase is connected to H3. The system phase rotation is ABC.

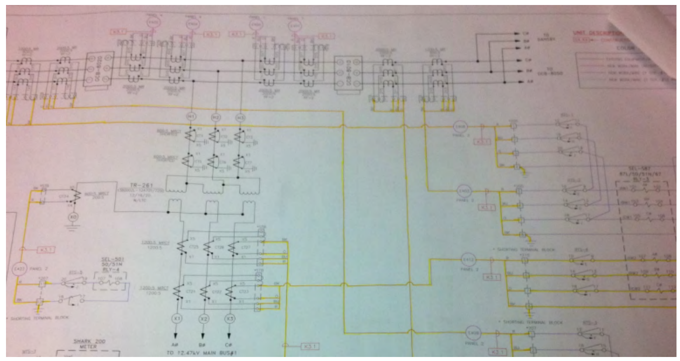


Fig. 12. Commissioning Example

The SEL-587 Instruction Manual is provided as part of the class material and is also available at www.selinc.com. Open the event report titled **7 – Transformer Commissioning 587.cev** and the settings file titled **7 – Transformer Commissioning Settings 587.pdf** to analyze this event.

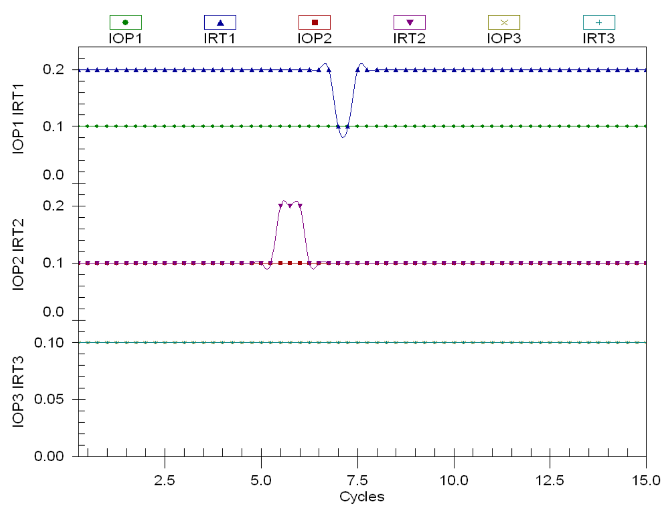


Fig. 13. IOP and IRT (7 – Transformer Commissioning Settings 587.pdf)

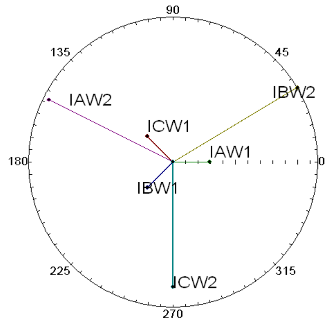


Fig. 14. Winding Currents (7 – Transformer Commissioning Settings 587.pdf)

Questions:

VII-a Based on the differential and phasor data, would you put the transformer in service?
No. IOP is too high, as a percentage of restraint. This indicates a problem.

VII-b Do the phase angle relationships match your expectations from the settings?
Yes. The drawing, settings (TRCON and CTCON), phase rotation, and phasor angles all agree.

VII-c Does the power into the transformer match the power out of the transformer?
Yes. This indicates that CT ratios are as expected in the settings.

VII-d Why would an engineer turn off the MVA setting in an SEL-587 Relay?
To manually calculate taps. Note that the relay divides the measured secondary currents by tap and uses the TRCON and CTCON compensations before processing differential calculations.

VII-e Calculate TAPx settings for this application. Do your calculations match the settings?
No!

VII-f Are your calculated TAPx settings within the range of the relay?
No. Note that the transformer voltage turns ratio is nearly 11:1, and the CTRs selected are almost the same! The TAP values chosen should then further compensate (i.e., ratio of CTRs multiplied by ratio of TAPs should match the voltage turns ratio). Remember the definition of TAP: TAP equals the CT secondary current at rated power for any particular winding. We suspect that because of the CTRs selected, the relay tried to automatically calculate TAPs, but TAPs were out of range. The TAPmax/TAPmin ratio must be no greater than 4.5 in the SEL-587. The settings engineer then turned MVA to OFF and entered TAP values that, while in range, were inappropriate and did not compensate currents correctly (i.e., they did not correspond to full load at rated power). Because of this, there was a standing error in the differential calculations.

VII-g Can you propose a solution?
Yes. We cannot explain why the high-side and low-side CTs provided are the same multiratio range. Ideally, high-side CTs would have a lower CT ratio range. A lower CTR1 would allow the relay to better meter and measure low secondary currents. However, we must ensure that selected CTRs perform the primary protection function first. In this case, we must select a lower CTR for Winding 1, change CTR1 to 400:5 or 80 (from 900:5 or 180), and leave CTR2 at 1200:5 or 240. The lower CTR1 is required to ensure that the TAPmax/TAPmin ratio is within 4.5. 400:5 is the highest that CTR1 can be set. We must change MVA from OFF to 20 and let the relay automatically calculate TAPs. The relay will calculate the full load secondary currents and use them for TAP1 and TAP2. O87P has to be set to 0.5 minimum to be within range.

The technical paper "Lessons Learned Through Commissioning and Analyzing Data From Transformer Differential Installations" is available at www.selinc.com and is recommended reading for more information on this subject.

VIII. Line Current Differential Commissioning Test

Technicians were attempting to perform a satellite-synchronized end-to-end test of a transmission line protection scheme while the line was out of service. The relays and scheme had been installed for some time and had worked correctly during previous system faults.

SEL-311L line current differential relays were used for primary and backup protection at each terminal. The SEL-311L Instruction Manual is provided as part of the class material and is also available at www.selinc.com.

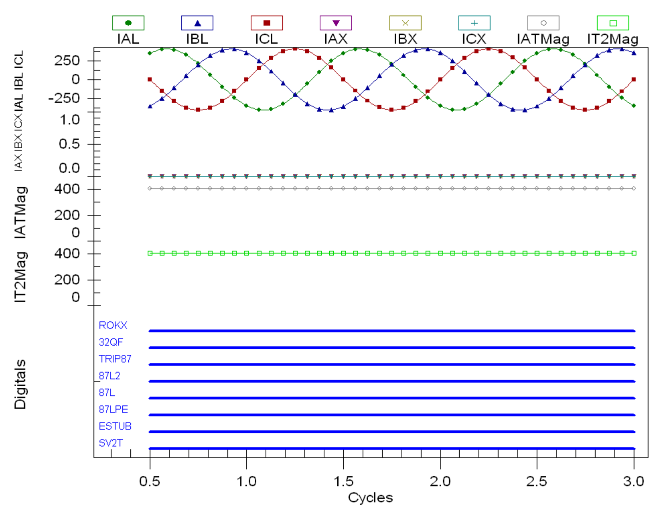


Fig. 15. Line Current Differential Commissioning (8 – Transmission Line 87L Test 311L.cev)

Open the event report titled **8 – Transmission Line 87L Test 311L.cev** to analyze this event. This event was triggered manually while local and remote currents were simultaneously applied to the relays using satellite-synchronized test sets. The event data are from Terminal A of a two-terminal line. We will refer to the remote line end as Terminal B.

During the test, several observations were made:

- The local Terminal A measures local (A) currents but does not show its remote (Terminal B) currents in metering or event data.
- The remote Terminal B measures its local (B) currents but does not show its remote (Terminal A) currents in metering or event data.
- The fiber-optic channel tests okay, and monitoring shows the channel to be in service (ROKX = 1).
- When the local Terminal A primary relay fiber is connected to itself (in loopback) or to the local Terminal A backup relay, it does not meter remote or received currents.
- When the remote Terminal B primary relay fiber is connected to itself (in loopback) or to the local Terminal B backup relay, it does meter remote or received currents.
- The local relay tripped when current was applied.

Questions:

VIII-a Do the phase angle relationships match your expectations from the settings?
No. The phase rotation setting, PHROT, is ACB, and the applied phase rotation is ABC. This will cause errors in positive- and negative-sequence calculations within the relay.

VIII-b How do you explain the trip when only 1 A balanced secondary currents are applied at each line terminal?
The 87L2 negative-sequence differential element tripped because of incorrect phase rotation. The currents applied need to match the PHROT expected phase rotation to prevent the 87L2 operation.

VIII-c Do you think it is likely that the relays have failed? Justify your answer.
We may suspect the Terminal A relay has a problem, because loopback tests work at the Remote B terminal. However, we are told that previous fault records exist that showed correct operation and that the relays have been in service for some time. We know that the self-test alarm is not asserted. We know that the channel monitor is okay, meaning the two terminals are communicating. And we are experiencing identical problems in two relays, primary and backup, at Terminal A. It is unlikely that two relays would fail identically at the same time. Because the two relays at the local end are behaving similarly, we should concentrate there.

VIII-d Can you explain why the channel monitor is healthy (ROKX = 1) but no remote currents are being metered?
We know that the local and remote relays communicate but are not exchanging currents. That clue leads us to investigate what means exist to disable transmission of current information from one relay to another. There are several things to check—test mode, stub bus, and so on. In this case, we notice that ESTUB is equal to a logical 1 in the Terminal A relays (ESTUB = !IN102, and IN102 is a zero). IN102 is probably wired to a line disconnect status switch, which is open due to the line being out of service. When the stub bus is a logical 1, the local relay stops transmitting its measured currents to the remote terminal and it does not measure or act on received currents from the remote terminal (whether connected to the channel or in loopback). If the ESTUB setting in the Terminal A relays is changed to a logical 0 during tests, everything should work correctly.

VIII-e Can you explain why the remote relays work when in loopback mode and the local relays do not work in loopback mode?
The remote relay is behaving differently when in loopback versus when connected to the channel, so we suspect that its ESTUB setting is a logical 0. When connected to the channel, the Terminal A relay does not transmit currents when in stub bus protection mode, so the remote terminal cannot receive data.

IX. Delayed Fault Clearing on Transmission Line

A crew was installing new structures for a transmission line rebuild and upgrade project. They were working in the existing right-of-way of an energized transmission line. The truck came in close enough proximity to the transmission line to cause a flashover.

The SEL-311C transmission line relays are used for primary and backup protection at each terminal. The SEL-311C Instruction Manual is provided as part of the class material and is also available at www.selinc.com.

Substations are referenced as Terminal A and Terminal B. There are six event reports for this case study. They are named **9 – A Delayed Fault Clearing xyz Event 311C.cev** and **9 – B Delayed Fault Clearing xyz Event 311C.cev** (*xyz* represents the first, second, or third in order of when they occurred).

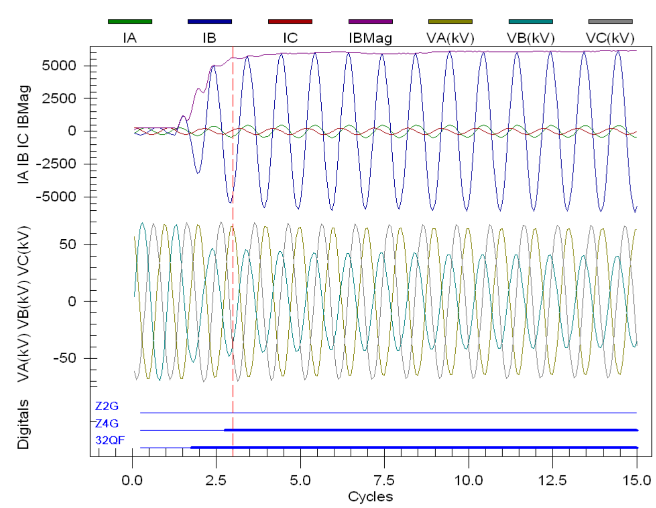


Fig. 16. First Event, Terminal A (9 – A Delayed Fault Clearing 1st Event 311C.cev)

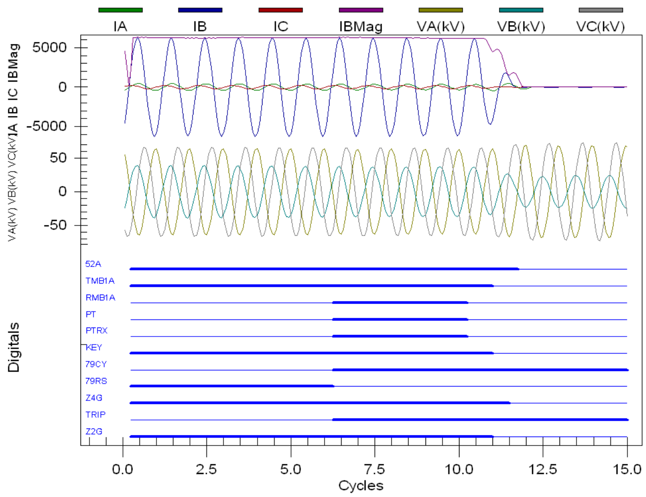


Fig. 17. Second Event, Terminal A (9 – A Delayed Fault Clearing 2nd Event 311C.cev)

Fig. 18 shows an automatic reclose. It was determined that human error caused a hot-line tag to be taken on the wrong line and not the energized line that the crew was working under. Luckily, no one was injured in this event.

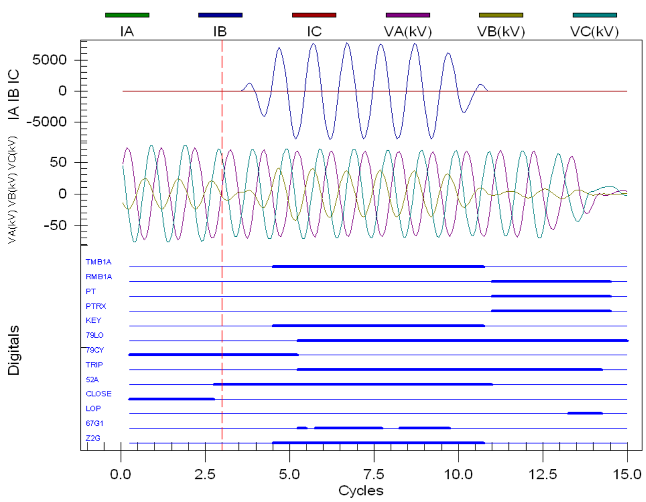


Fig. 18. Third Event, Terminal A (9 – A Delayed Fault Clearing 3rd Event 311C.cev)

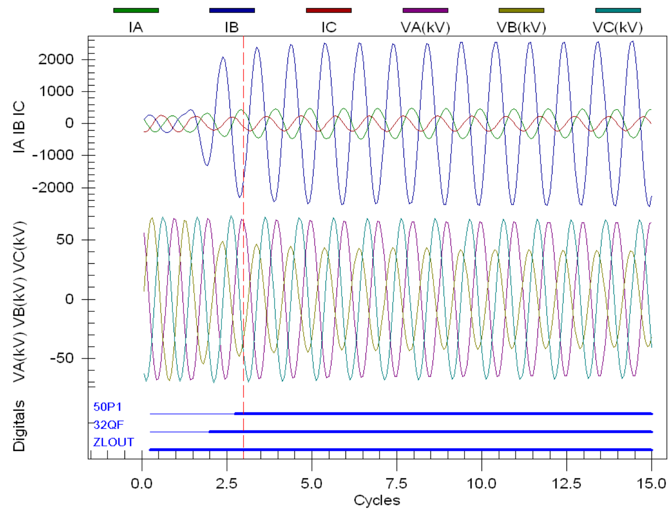


Fig. 19. First Event, Terminal B (9 – B Delayed Fault Clearing 1st Event 311C.cev)

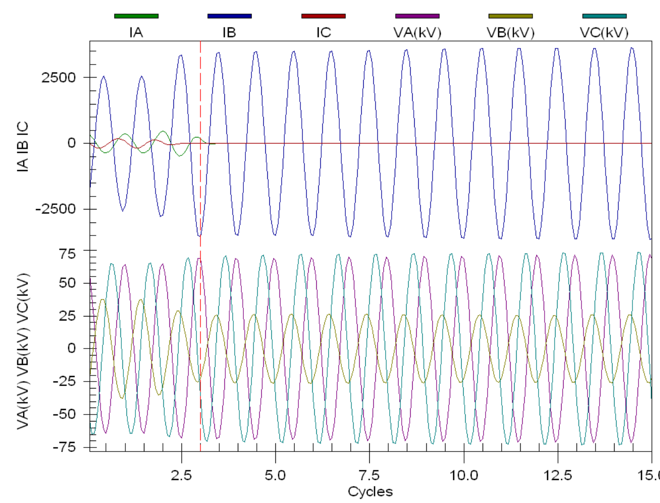


Fig. 20. Second Event, Terminal B (9 – B Delayed Fault Clearing 2nd Event 311C.cev)

Z4G picks up and starts timing. Notice the load current goes away (the remote end has opened).

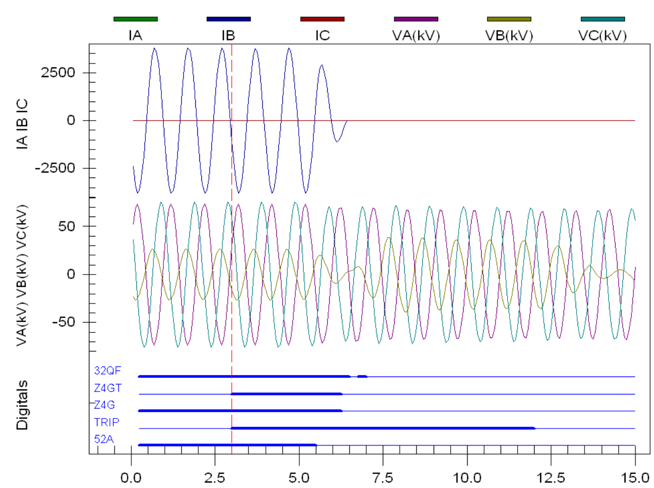


Fig. 21. Third Event, Terminal B (9 – B Delayed Fault Clearing 3rd Event 311C.cev)

Questions:

IX-a In the first event report from Terminal A, how can a fault located at 0.62 miles on a 2.96-mile-long line be in Zone 4 and not Zone 1?
This is a high-resistance fault. The Rf value pushes the measured impedance outside the mho characteristic. We can verify that this is a high-resistance fault by observing the phase angle between the faulted phase current (IB) and voltage (VB).

IX-b Using the first and second event report from Terminal A, how long did it take for Terminal A to trip?
About 22 cycles. Note that this is longer than the Zone 2 time delay, yet the relay trips by COMM target. Because of the fault resistance, Zone 2 did not immediately assert at the onset of the fault.

IX-c Terminal A trips via its permissive overreaching transfer trip (POTT) scheme logic. Can you explain why the received permission-to-trip PT signal is precisely 4.0 cycles long?
The received permissive signal is an echo key from Terminal B.

IX-d What triggered the third event report from Terminal A?
The automatic reclose and assertion of IN101, the breaker status, triggered this event.

IX-e What triggered the first event report from Terminal B?
The increase in phase current and assertion of 50P1 triggered this event.

IX-f What triggered the second event report from Terminal B?
The assertion of the Zone 4 ground distance element triggered this event.

IX-g Why do IA and IC currents go to zero in the second event report from Terminal B?
When Terminal A opened, load current was interrupted. We can see the same corresponding point in time in the second event report at Terminal A.

IX-h How long does Terminal B take to clear the fault?
Terminal B takes about 55 cycles to trip! Keep in mind, personnel were in a truck engulfed in this fault during this time.

IX-i What relay setting change can you suggest to drastically improve tripping sensitivity to high-resistance faults and therefore speed up tripping?
Include directionally supervised ground overcurrent elements in the TRCOMM and POTT logic (i.e., enable both Level 2 forward and Level 3 reverse 67G elements).

The technical paper “Very High-Resistance Fault on a 525 kV Transmission Line – Case Study” is available at www.selinc.com and is recommended reading for more information on this subject.

X. Double-Ended Fault Location

A fault occurred on an 82-mile-long 161 kV line. The left terminal (R) provided a fault location estimate of 13.95 miles (from the left). The right terminal (S) provided a fault location estimate of 56.5 miles (from the right).

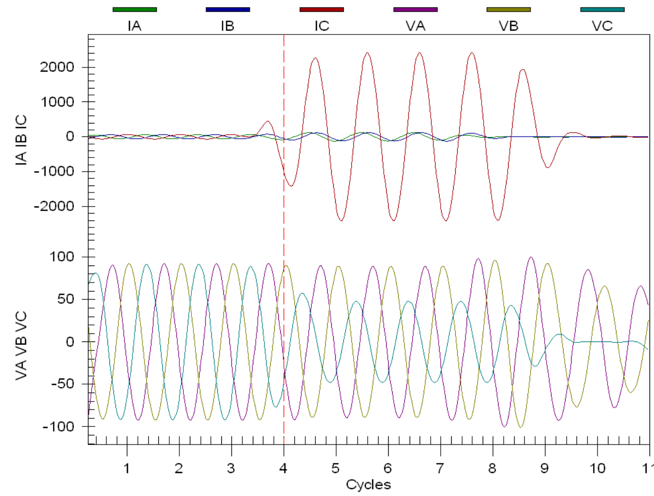


Fig. 22. LG Fault (10 – Double End Fault Location R 121G.eve)

Engineers know these estimates are in error because they do not provide a common location on the line, do not add up to 82 miles, and do not match the actual location of the fault, as determined by visual inspection and damage.

The actual location of the fault was about 17.5 miles from Terminal R.

The SEL-121G-3 and SEL-221G-3 transmission line relays are used at each terminal. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

Substations are referenced as Terminal R and Terminal S. There are two event reports for this case study. They are named **10 – Double End Fault Location R 121G.eve** and **10 – Double End Fault Location S 121G.eve**.

A Mathcad® 2000 worksheet is also provided (**10 – Two-ended_Neg-Seq_FLoc_- dac.mcd**) for those who would like to use it.

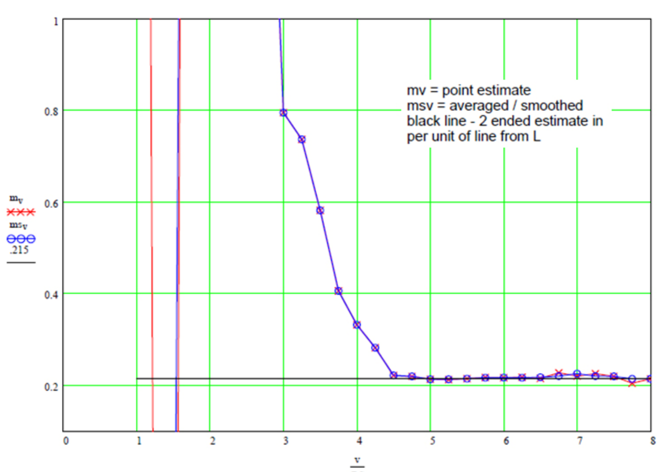
Question:

X-a Using the event data from each terminal, use the two-ended negative-sequence fault location method to determine a more accurate fault location estimate.
If you would like to solve this manually, draw the symmetrical components network diagram for an LG fault on a two-ended transmission line. Using the negative-sequence network, write the voltage drop equations from each terminal to the point of the fault. The unknowns are *m*, the distance to the fault, and Rf, the fault resistance. There are two equations and two unknowns. Use the known line impedance data from the relay settings and the negative-sequence voltage and current from the event data. We know that the negative-sequence voltage at the fault is common to both equations. Set them equal to each other using the fault voltage, and solve for *m*. Once *m* is known, solve

for Rf (if interested). The technical paper "Very High-Resistance Fault on a 525 kV Transmission Line – Case Study" provides an excellent tutorial on this method and is available at www.selinc.com.

If using a Mathcad worksheet, follow the instructions below:

- Open the left relay event report using ACSELERATOR Analytic Assistant. A temp.txt file will be created. Rename that file "left.txt" or something similar.
- Open the right relay event report using ACSELERATOR Analytic Assistant. A temp.txt file will be created (this is why it is important to rename left and right; otherwise, the original temp.txt gets overwritten with the right terminal data). Save the file as "right.txt." or something similar.
- Open the event text. Note how data are shown in the event (i.e., which analog variable is which column). Some relay events show the residual current at the left-most column, others IA, and so on. Just note how the data are originally stored in the event. The first column in the temp.txt file will be zero, the next over one, and so on.
- Enter settings CTR (CT ratio from settings), PTR (PT ratio from settings), RS (samples per cycle of event data), and Z1MAG and Z1ANG (secondary ohms and line impedance, from settings) in the worksheet.
- Import left and right data into tables.
- Edit the column reference in each of the phase calculations. For example, IAL:=Ldata < 0 > means that the worksheet is expecting the A-phase current from the left terminal to be in the Ldata table column zero. If not zero, just edit the reference.
- Finally, the black line for the fault location is adjusted manually. It does not automatically plot to the flat line. It was just added so we could manipulate the line until it lines up to where the estimate flat-lines horizontally. Just click on the number, and edit manually. The number will always be per unit from the left terminal.



The two-ended result puts the fault at 0.215 per unit of the line from the left, or at 17.6 miles from Substation R. This precisely matches the physical evidence reported by the customer.

The technical paper "Impedance-Based Fault Location Experience" is available at www.selinc.com and is recommended reading for more information on this subject.

XI. Bus Differential Operation

An engineer has applied two high-impedance bus differential relays on the same bus and connected the differential elements in series. This was done to provide backup protection against a single relay failure. The high-impedance bus protection is assumed to have two failure modes. One failure mode is a relay disabled (power supply, processor failure, and so on), but with its high impedance still in the CT circuit. The other failure mode is a metal oxide varistor (MOV) failed shorted, removing the high-impedance input of the relay.

For internal faults, the series connection limits the minimum sensitivity of the scheme. However, for solidly grounded systems, current sensitivity for bus faults is rarely a problem.

The differential element voltage setting was calculated using the standard CT plus lead resistance formula and a safety factor of two. By connecting the two voltage elements in series, a second safety factor of two is effectively applied because each relay will only see half the voltage at the junction point for an external fault.

For internal faults, the CTs will see a 4000-ohm burden instead of 2000 ohms. The CTs are 1200:5, C800. The 87 elements are set to pick up at 146 V.

SEL-587Z Relays were used in this application. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

Raw and filtered event reports from one of the series-connected SEL-587Z Relays are provided for this case study. The other relay data are identical. The events are named **11 – High Impedance Bus Trip 587Z Filtered.cev** and **11 – High Impedance Bus Trip 578Z Raw.cev**.

Lockout relay contacts were wired in parallel with the high-impedance inputs on the relays so that the inputs were shorts immediately after a trip. Overcurrent inputs were connected in series with the voltage inputs to measure the current through the high-impedance circuit.

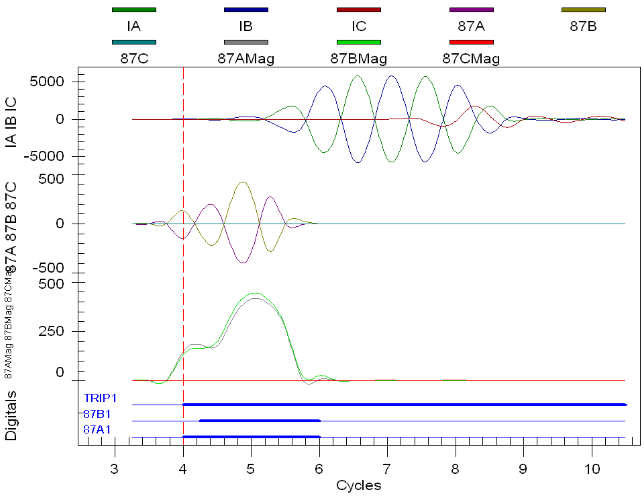


Fig. 23. Filtered Bus Differential Operation (11 – High Impedance Bus Trip 587Z Filtered.cev)

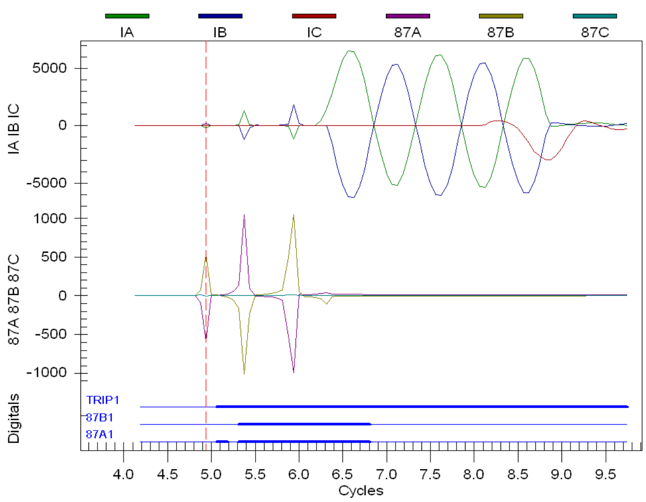


Fig. 24. Raw Bus Differential Operation (11 – High Impedance Bus Trip 587Z Raw.cev)

Questions:

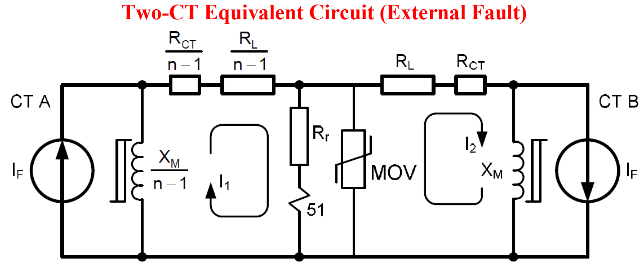
XI-a Was this an internal or external fault?
Based on the magnitude of the voltage signals, there is no question—this was definitely an internal bus fault.

XI-b What element caused the trip?
87A1 and 87B1 high-impedance differential elements.

XI-c In the oscillograph data, why does the current signal seemingly lag or follow the voltage?
There is current during the first 1 and 2 cycles, but it is extremely small. In the raw waveform, we can see that the secondary current signals are very distorted as well. The small magnitude is due to the 4000-ohm burden through which the CT secondary current is having to travel for an internal fault. When the relay trips the bus lockout, a contact from the lockout is used to short-circuit the high-impedance input on the relay. When this occurs, the circuit burden is drastically reduced and the secondary current through the relay increases.

XI-d Can you explain the difference in waveforms in the raw event data (sharp peaks versus smooth sinusoids)?
Consider that a C800 CT is rated so that it produces rated voltage with 20 times nominal current (5 A) flowing through a rated burden of 8 ohms. Now, consider that for an internal fault, that same CT is driving current through a burden of 4000 ohms, or 500 times greater than the rated burden. The CTs will saturate badly, and the sliver or spikes of current and voltage in the raw event are evidence of that. Nonetheless, as long as we do not use less than a C200 CT, the scheme remains secure.

Two-CT Equivalent Circuit (External Fault)



The technical paper "Application Guidelines for Microprocessor-Based High-Impedance Bus Differential Relays" is available at www.selinc.com and is recommended reading for more information on this subject.

XII. Motor Trip

This event is from an induction motor that protects a boiler water-circulating pump at a power plant. The motor was running at the time of this event. See Fig. 25.

The SEL-710 motor protection relay protects the motor. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

There is one event report for this case study. The event is named **12 – Motor Trip 710.cev**.

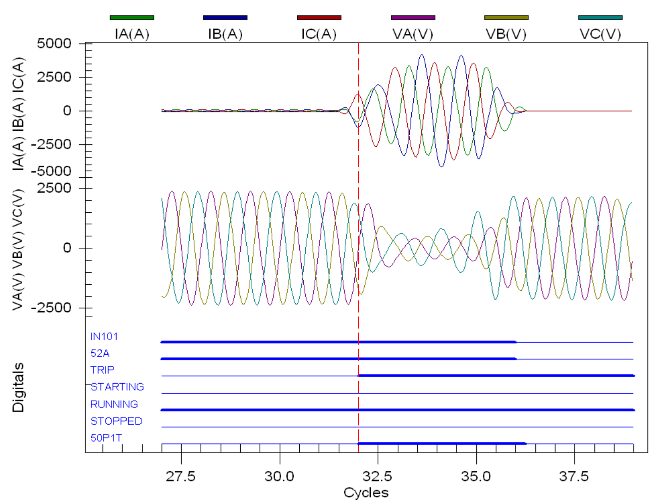


Fig. 25. Motor Trip (12 – Motor Trip 710.cev)

Questions:

XII-a What happened to the motor?
A three-phase fault occurred. The motor was running at the time of the trip. The relay saw about 3700 A primary phase current during the fault. The voltage dipped from 2380 V to about 450 V during the fault. The relay took about one-quarter of a cycle to issue a trip, and the fault lasted a little over 4 cycles.

XII-b Can you prove the event was not caused by a load jam or jammed router?
The current magnitude during the event is much greater than the motor locked rotor current (a setting) and is therefore due to a fault.

XII-c Can you prove that the motor did not stall because of low voltage?
The voltage magnitude just prior to the high-current event is at the expected nominal level (a setting).

XII-d What element caused the trip?
The 50P1T element tripped. This is based on a 50P1P pickup setting of 13 multiples of full load A, or 1235 A primary. The 50P1D delay is set to zero. Motors and their cable leads are typically protected by an instantaneous phase overcurrent element in a motor relay.

XII-e Does this application use a fused contactor or a circuit breaker?
The relay is allowed to trip for fault current that is much greater than load, so the application uses a circuit breaker. A contactor would only interrupt load current and would rely on the fuse to interrupt fault currents.

XII-f Did the tripping element operate correctly?
Yes. The 50P1P pickup is typically set around 2 multiples of the motor locked rotor current. (See the book *AC Motor Protection* by Stanley E. Zocholl for a good reference on motor protection.) This prevents the element from operating during motor starts, but the element will respond to high phase fault currents. The element was set correctly and responded appropriately to this fault.

Photo of stator winding where leads are attached.
The motor developed a three-phase fault at this location.

The textbook *AC Motor Protection* by Stanley E. Zocholl is available at www.selinc.com and is recommended reading for more information on this subject.

XIII. Generator Close

A 112 MVA steam unit was closed and generated the event shown in Fig. 26. Operators scrambled to determine if the unit tripped because of a fault or some other problem.

The SEL-300G generator relay was used to protect the unit. The instruction manual is provided as part of the class material and is also available at www.selinc.com.

There is one event report for this case study. It is named **13 – Generator Close 300G.cev**.

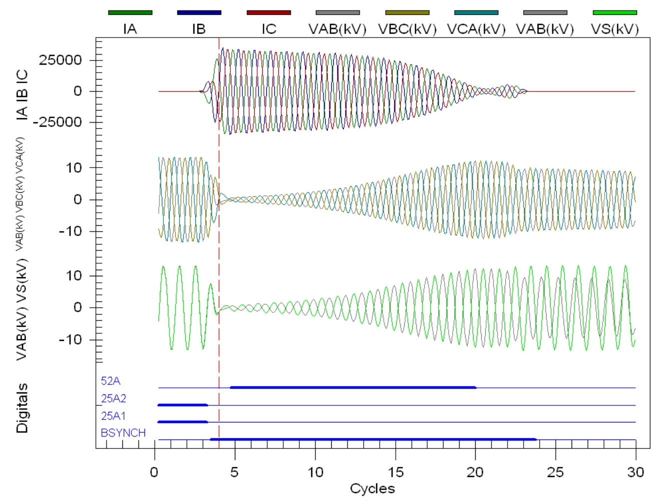


Fig. 26. Generator Close (13 – Generator Close 300G.cev)

Questions:

XIII-a What was the maximum current magnitude?
About 36,000 A primary.

XIII-b What element triggered this event report?
The 32P1 reverse power element.

XIII-c What conditions could produce this much current at the terminals of this generator?
A three-phase fault could produce high currents. However, the currents are decreasing, and voltages are increasing. A large voltage difference across the generator (and step-up transformer, in some applications) impedance caused by an out-of-synchronism close could also produce these high currents. The voltages are also returning slowly to normal, indicating the two systems are synchronizing.

XIII-d If this was a fault, what would the current magnitude look like from the generator?
For faults, we expect to see three distinct periods, which differ in current magnitude. The generator impedance changes and increases over time. The subtransient reactance period (roughly 2 cycles) produces the largest current and is followed by the transient reactance (exponential decay), which is followed finally by the steady-state or synchronous

reactance (which can be less than full load A of the generator). The current in this event does not follow that expectation, and dramatic decay occurs. Therefore, we can conclude that this was not due to a fault.

XIII-e Was the generator in synchronism with the system prior to the breaker close?
According to the synchronism-check elements (25A1 and 25A2) and the VS and VAB voltages prior to the breaker close, yes, the generator was in synchronism with the system. However, immediately after the close, it was obvious that these systems were not in phase. We expect that the power system pulled the local generator into synchronism in less than 2 cycles. The machine speed would have been increased dramatically. This corresponds to the reverse power element assertion. The SEL-300G did not issue a trip. It is possible the unit tripped because of mechanical overspeed controls and protection.

XIII-f What is the root cause of the problem?
Over time, we can see VS and VAB pull out of phase. This indicates the VS voltage was wired incorrectly (i.e., it was not actually wired to VAB on the system side of the generator breaker). VS was connected reverse polarity. Therefore, we can say that the breaker was closed with the generator and the system 180 degrees out-of-phase.

XIII-g Why did the relay out-of-step (78) function not operate for this event?
The out-of-step protection is not enabled in the relay. Even if it were, out-of-step protection monitors the trajectory of apparent impedance through blinders and timers. In this event, we did not start at an expected pre-event load far out on the right on the impedance plane (load out). It is expected that the out-of-step function would not operate for this event, even if enabled.

XIV. Reference

[1] C. F. Wagner and R. D. Evans, *Symmetrical Components*. Robert E. Krieger Publishing, Malabar, FL, 1982.

XV. Biography

David Costello graduated from Texas A&M University in 1991 with a BSEE. He worked as a system protection engineer at Central Power and Light and Central and Southwest Services in Texas and Oklahoma and served on the System Protection Task Force for ERCOT. In 1996, David joined Schweitzer Engineering Laboratories, Inc., where he has served as a field application engineer and regional service manager. He presently holds the title of senior application engineer and works in Fair Oaks Ranch, Texas. He is a senior member of the IEEE and a member of the planning committee for the Conference for Protective Relay Engineers at Texas A&M University. David was a recipient of the 2008 Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference and a contributing author to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*.

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