Case Study: Analysis of a 138 kV Intercircuit Fault

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***Abstract*—Lower Colorado River Authority (LCRA) is a public utility that operates in central Texas to manage the water supply in the lower Colorado River basin and both generate and supply electric power. LCRA Transmission Services Corporation (TSC) owns and operates more than 5,150 miles of transmission lines and 180 substations. LCRA TSC routinely analyzes event report data retrieved from the protective relays applied on their system to verify correct response to system events.**

This paper provides a discussion of event analysis and complex faults, along with a few key characteristics to assist in analyzing event report data generated by a complex fault. Finally, an in-depth analysis of a complex intercircuit fault that occurred on the LCRA TSC 138 kV system is provided.

I. Introduction

Lower Colorado River Authority (LCRA) is a nonprofit public utility that operates in central Texas to manage the water supply in the lower Colorado River basin and both generate and supply electric power. The LCRA Transmission Services Corporation (TSC) is a nonprofit transmission service provider within the Electric Reliability Council of Texas (ERCOT) region. The LCRA TSC network includes 5,150 miles of 345 kV, 138 kV, and 69 kV transmission lines and 180 substations. This network supplies the electric loads of more than 40 transmission customers in the ERCOT region.

On June 30, 2013, LCRA TSC experienced a simultaneous trip of two 138 kV lines that share the same tower structure. Severe thunderstorms were reported in the area at the time of the trip. Some breakers automatically reclosed successfully, while others tripped to lockout, requiring manual closing. As per the LCRA TSC protocol, the event was analyzed to verify correct operation. This paper covers the analysis that was performed and the lessons that were learned through the analysis.

II. Event Analysis Procedure

Before looking in detail at the fault that occurred on the LCRA TSC system, it is important to review the procedure to follow for analyzing fault data.

Often when a fault occurs on the power system, there is a temptation to immediately dive into the generated event report data. This urge is often further aggravated by the pressure applied by operators and management who want to restore service quickly. Although this approach may work for a simple case, it will often lead to frustration in analyzing more complex faults.

Instead, following a methodical approach provides a better foundation for event analysis. This approach is based upon an understanding of the expected operation of the protection system. The logic programmed in the relay provides a road map that leads to the element(s) that operated [1]. A comparison between the expected operation and the resulting data will confirm whether the system operated as desired or not. Deviations from the desired results must be addressed, and solutions must then be developed and tested. All of these details should be documented. Fig. 1 summarizes this process. Reference [2] provides a thorough discussion of event analysis procedures.

III. Complex Power System Faults

Simple power system faults include three-phase, line-to-line (LL), line-to-line-to-ground (LLG), and line-to-ground (LG) faults. The phase and sequence component relationships for these fault types are well understood. Although a detailed analysis of these relationships is beyond the scope of this paper, it is useful to review the sequence component relationships for unbalanced faults, as they vary based on the phases involved. These relationships are shown in Fig. 2 through Fig. 4 and are derived in [3].

A variety of complex faults can occur on the power system. Several publications discuss these faults. However, there are no standard definitions for the various complex fault types. Reference [4] divides these faults into two categories: intercircuit and cross-country. An intercircuit fault is one that occurs at a single geographic location and involves a fault connection between two or more circuits on a multicircuit line. Note that more than one phase on each line as well as ground may be involved. In contrast, cross-country faults involve two or more faults that occur at different geographic locations on the system.

Analysis of complex faults, intercircuit or cross-country, is typically more complicated than analysis of the simple faults mentioned previously. Instead of only ten fault types, there are in excess of 100 possible fault-type combinations [5]. Calculating the expected values for various fault types is beyond the scope of this paper, but is covered in detail in [3] and [6]. In addition, standard fault simulation software packages provide the capability to simulate these complex faults. This paper focuses on complex faults on parallel lines with a common bus at one or both ends.

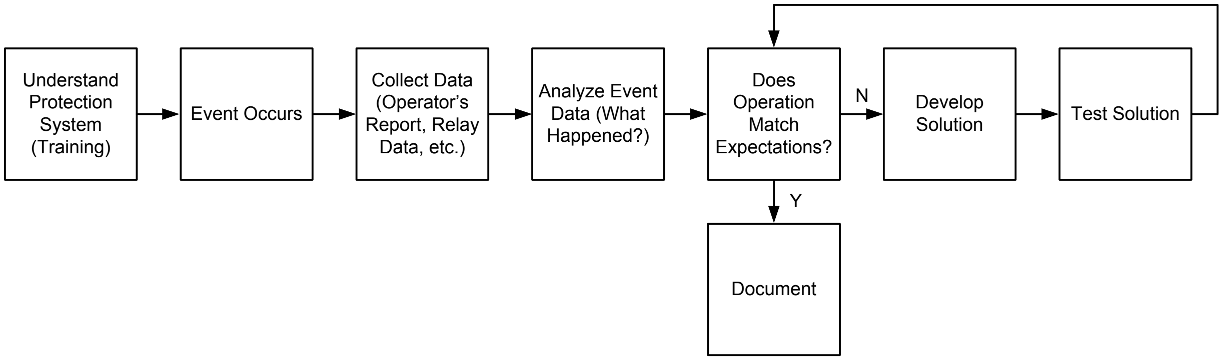

Fig. 1. Event analysis procedure

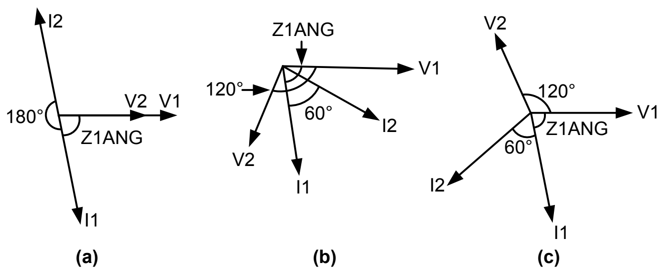

Fig. 2. Sequence component relationships for BC (a), AB (b), and CA (c)

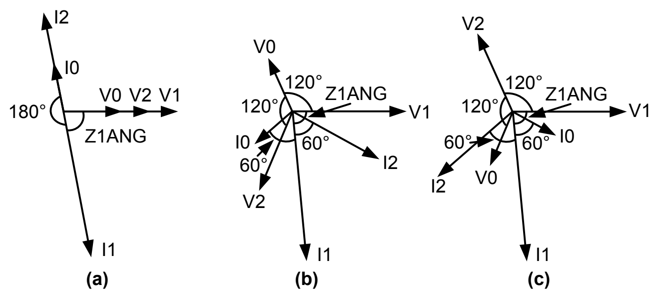

Fig. 3. Sequence component relationships for BCG (a), ABG (b), and CAG (c)

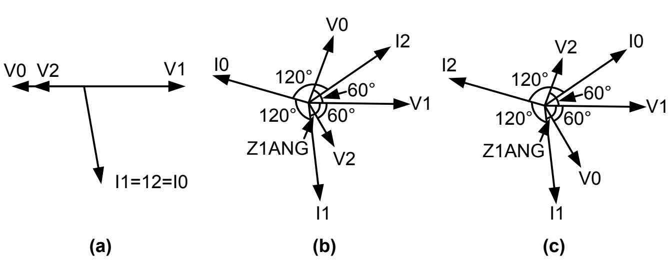

Fig. 4. Sequence component relationships for AG (a), BG (b), and CG (c)

A. Procedure to Determine Complex Fault Type

When looking at fault data captured by relays during a complex fault on the system, it is important to understand that the data captured by the relay will not contain the full fault data. The voltages will contain the complete fault data and reflect the fault from a system perspective. In contrast, the current data will only contain the portion of the fault data related to the faulted phases on that specific line.

1) Determine the System Fault Type

When multicircuit lines share a common bus, an equivalent source can be created by summing the currents from the two (or more) faulted lines. The bus voltage provides the equivalent source voltage. It is essential that the data be time-aligned to give an accurate representation of the equivalent source currents. The voltage signals in each relay are reliable references to use to confirm that the signals are time-aligned.

Based on this equivalent source, the phase and sequence component quantities can be analyzed to study the system fault. In the case of some complex faults, the equivalent source phase quantities will provide a clear indication of the system fault type.

However, in other complex faults, the phase quantities may not clearly reflect the system fault type. In these cases, analyzing the equivalent source sequence components may provide a clearer indication of the system fault type.

When analyzing the sequence components, it is important to compare the negative-sequence quantities with respect to the positive-sequence quantities. This comparison should be performed separate from the zero-sequence quantities, which should also be compared to the positive-sequence quantities.

The reason for this separation is that because complex faults are a combination of simple faults, the resulting sequence components may not resemble only one simple fault type. An example will help illustrate this point.

Fig. 3 and Fig. 4 show that I2 and I0 are 180 degrees out of phase for BG and CAG faults. If a BG fault occurs on one line and a CAG fault occurs on a parallel line, depending on the relative magnitude of I2 and I0 on each line, it is possible for the angle between I2 and I1 of the equivalent source to reflect a BG fault, while the angle between I0 and I1 reflects a CAG fault, or vice versa.

In addition, I2 and I0 of the equivalent source will be smaller than the respective line sequence quantities, because they will be subtractive. Therefore, the magnitudes of the source I1, I2, and I0 will not match the expected relationship for simple fault types.

Another consideration is whether the source has zero-sequence quantities. There will only be zero-sequence voltage and current at the equivalent source if the source is grounded and the fault involves ground. This is true despite the fact that intercircuit faults not involving ground will have zero-sequence current flowing on the lines.

2) Complete the Picture Using Line Quantities

Once the system fault type has been determined, the line quantities can then be analyzed in the light of the overall picture. Analyzing the phase currents captured by the line relays will provide an indication of the faulted phases on each line.

Additionally, I0 on Line 1 should be compared to I0 on Line 2. An out-of-phase relationship, as shown later in Fig. 7, indicates an intercircuit connection between the two lines. Note that the intercircuit connection can be through ground as well. However, when this is the case, the magnitude of I0 will not be the same on each line and V0 will not be zero.

It is important to note that if fault resistance is neglected, more than one fault combination can produce the same results. Therefore, once the picture has been completed from the line data, it is helpful to simulate the assumed fault combination to verify the results.

B. Example Fault Analysis

As an illustration, the intercircuit fault shown in Fig. 5 was simulated in ASPEN OneLiner™ to determine the resulting line and equivalent source quantities.

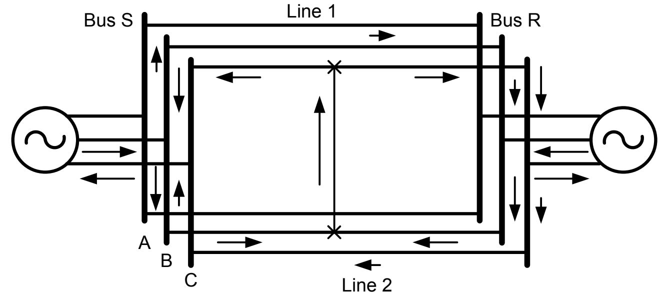

Fig. 5. BC intercircuit fault currents

Fig. 6 depicts a single-line diagram of the Fig. 5 system that shows the phasor diagrams of the quantities measured by the relays and of the quantities of the equivalent sources. Fig. 7 provides the sequence components for the same system.

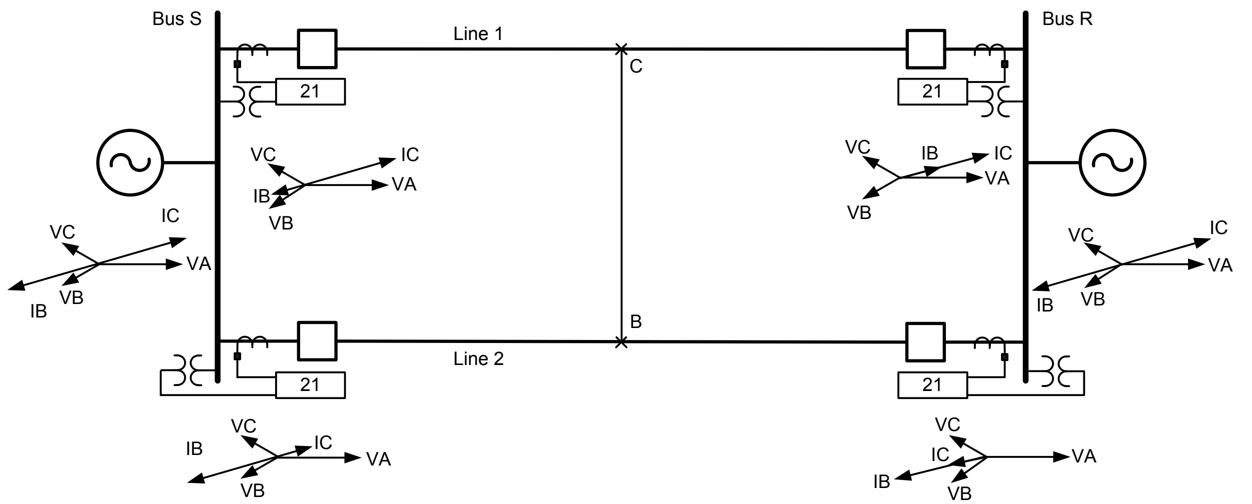

Fig. 6. BC intercircuit fault phase voltages and current phasors

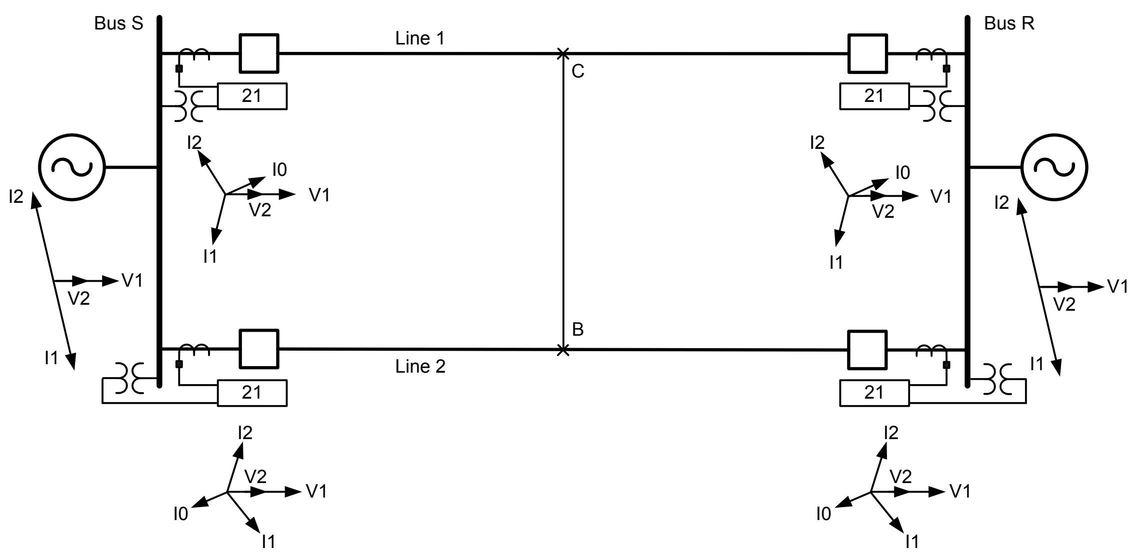

Fig. 7. BC intercircuit fault sequence voltages and current phasors

In this example, the magnitude and angle of the phase and sequence component quantities of the equivalent sources at both ends of the line correspond to a BC fault. Therefore, the system fault type is BC.

In addition, the sources have no zero-sequence quantities. This condition agrees with the observed system fault type.

By analyzing the line phase quantities, we conclude that the C-phase is faulted in Line 1 and the B-phase is faulted in Line 2. We also observe that the B-phase on Line 1 and the C-phase on Line 2 have currents that are 180 degrees out of phase at the ends of their respective lines. This phase shift indicates that these currents are through currents, which means that these phases are not faulted on the corresponding lines. Note that the current seen on the unfaulted phases shown in Fig. 6 may or may not be seen for this fault connection, depending on the system configuration.

Comparing the zero-sequence current on these two lines further confirms the expected fault type. I0 on Line 1 is equal and opposite to I0 on Line 2, indicating an intercircuit fault that does not involve ground.

Combining all of the parts of this analysis together completes the picture: the C-phase of Line 1 is faulted to the B-phase of Line 2 (an intercircuit fault). In a real-world case, this fault could be modeled to confirm the suspected fault type.

C. Distance Element Behavior for Complex Faults

In addition to understanding the expected phasor relationships, it is important to understand the expected performance of distance elements for complex faults. As with any fault on the system, prefault load flow and fault resistance will affect the measured impedance.

Mutual coupling also has an effect on the values measured. In multicircuit lines, the positive- and negative-sequence mutual coupling is very low, resulting in a mutual impedance of 5 to 7 percent of the line zero-sequence impedance [7]. Zero-sequence mutual coupling, on the other hand, can be quite large on multicircuit lines, reaching up to 70 percent of the zero-sequence impedance [7]. Mutual coupling is a significant source of error in the impedance measured by ground distance elements. Reference [8] discusses in detail the factors that influence the error that mutual coupling causes in ground distance elements. These factors include source strength and fault location.

In addition to these errors, complex faults have the potential to introduce error into the distance measurement. Distance relays are designed for optimal operation in response to simple faults. Furthermore, fault identification logic is used to identify the simple fault type that is seen and enable the corresponding distance element.

As discussed previously, when a complex fault occurs, the line relay will see voltage that represents the entire system fault, but current that contains only a portion of the fault data. In some cases, this partial information will contain sufficient data for the relay to enable the correct distance element and accurately measure the distance to the fault. However, there are other complex fault types that can introduce errors into the fault identification decision, the measured impedance, or both.

The resulting effect of the errors introduced by complex faults may add to or subtract from the other errors mentioned previously, causing a distance element to either overreach or underreach. Note that it is possible for the same element to overreach for one fault type while underreaching for another. Furthermore, an element can overreach for one system configuration and underreach for another configuration when presented with the same fault [8] [9] [10].

D. Example Distance Element Underreach

There are too many variations of complex faults to cover each in detail. Instead, the example in Section III, Subsection B will be used to illustrate the effect of complex faults on distance elements.

For Line 2, only the B-phase is faulted. Therefore, the fault identification logic will enable the BG distance element. Remember that the BG element is designed to measure the impedance for a BG fault. As such, the relay is expecting to see B-phase voltage reduced in magnitude, B-phase current magnitude increased, and B-phase current lagging the B-phase voltage by the positive-sequence impedance angle of the line.

Instead, the relay reads the quantities shown in Fig. 6. The phase voltages resemble a BC fault, while the B-phase current contains only a portion of the fault data. As such, the B-phase current lags the phase-to-phase voltage VBC by the positive-sequence impedance angle of the line. The result is that the angle that the B-phase current lags the B-phase voltage may be significantly less than the positive-sequence impedance angle of the line. Fig. 8 illustrates the difference between the B-phase quantities measured by the relay for these two fault types.

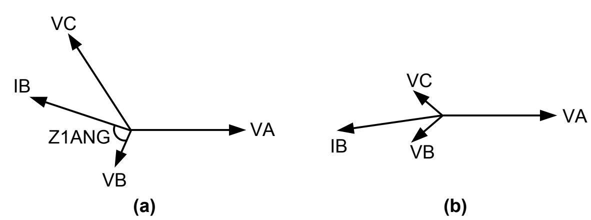

Fig. 8. B-phase voltage and current measured for a BG fault (a) and a BC intercircuit fault (b)

When applied to the same impedance calculation, the two sets of voltage and current quantities shown in Fig. 8 will yield different results. The variations are not limited to angle only. The resulting magnitudes may not be equal, as well.

This is only one complex fault type. It is intended to illustrate one possible effect that a complex fault can have on traditional distance elements. Other fault types can produce varying results that can cause a distance element to overreach or underreach.

IV. LCRA TSC System Description

In addition to understanding applicable power system theory, event analysis requires knowledge of the system network of interest and its protection system design.

A. System Configuration

The system that experienced this case study fault was part of the LCRA TSC 138 kV network. Fig. 9 shows a simplified one-line diagram of the system section of interest.

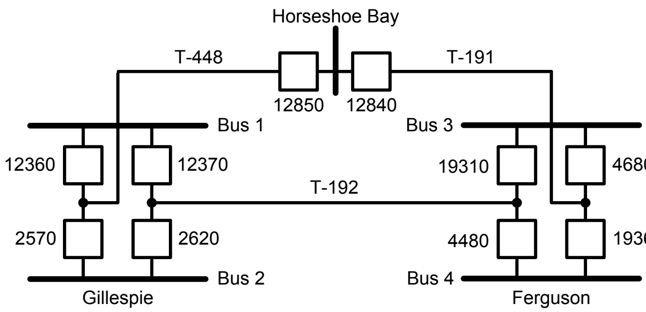

Fig. 9. System one-line diagram

The T-448 line connecting the Gillespie substation to the Horseshoe Bay substation is 36.43 miles long. The T-191 line connecting the Horseshoe Bay substation to the Ferguson substation is 2.68 miles in length. The T-192 line connects the Gillespie substation to the Ferguson substation (a distance of 39.11 miles). The T-192 line shares the same tower structure as the T-448 line from Gillespie to Horseshoe Bay. Then, from Horseshoe Bay to Ferguson, the T-192 and T-191 lines share the same tower structures. Fig. 10 depicts the tower structure and phasing of the T-192 and T-448 lines.

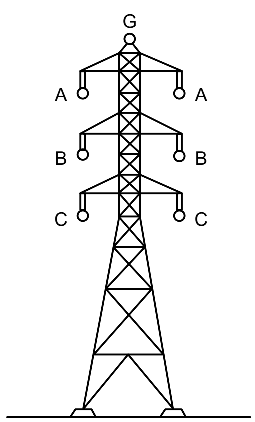

Fig. 10. Tower configuration

The impedances of each line are provided in Table I in per unit (pu) on a 100 MVA base.

LCRA engineers assumed Z1 = Z2 for these lines in their system model. However, these lines are not transposed. Therefore, some unbalance is expected for balanced load and three-phase fault conditions. In particular, the authors of this paper expected to see some differences between the actual event report data and simulation results. A discussion of the source and magnitude of these errors is beyond the scope of this paper. References [11] and [12] provide more information on this topic.

TABLE I
LINE IMPEDANCES

Line	Z1 (pu)	Z0 (pu)
T-448	0.1451∠79.45°	0.4877∠77.44°
T-192	0.1560∠79.45°	0.5180∠77.33°
T-191	0.0107∠79.42°	0.0310∠77.77°

B. Protection System

The protection system of the two lines involved in the fault under study uses primary and secondary relays at both ends of each line. The protection system design is identical on both the T-448 and T-192 lines. All relays have a step-distance scheme that includes three zones of phase and ground mho distance elements. The first two zones are set to reach in the forward direction, while the third zone is set in the reverse direction. The phase Zone 1 reach is set to 85 percent of the positive-sequence line impedance, while the phase Zone 2 element is set to 120 percent. The reverse-looking Zone 3 elements are set to reach beyond the remote-terminal Zone 2 element reach. The ground mho elements are set similarly, except for the Zone 1 element, which is set to 75 percent of the positive-sequence line impedance for added security.

The phase and ground Zone 1 elements have no time delay. The Zone 2 elements have a 43-cycle delay to coordinate with the Zone 1 elements on the adjacent lines. The Zone 3 elements have a delay of 90 cycles to coordinate with the Zone 2 elements. A common timer has been enabled for the phase and ground Zone 2 and Zone 3 elements. Therefore, if a fault asserts either the phase or ground element and then evolves such that the other element type asserts before the timer expires, the relay will not reset the timer, but rather continue timing.

All of these elements are included in the relay trip equations. However, in addition to the mho distance elements, the relays are also programmed to trip on ground directional overcurrent elements. A high-set instantaneous element is included, as well as a sensitively set inverse-time overcurrent element. Both elements are only enabled for faults in the forward direction.

In addition to the step-distance scheme described previously, which will result in delayed clearing of faults near the ends of the lines, the primary relays use communications to implement a directional comparison blocking (DCB) scheme via a transfer trip module over a multiplexed network. If the Zone 2 phase or ground distance element or the Level 2 directional ground overcurrent element asserts and a blocking signal is not received in the specified short time delay (2 cycles for distance elements and 10 cycles for the overcurrent element), the relay will trip rather than wait for the full Zone 2 timer to expire. Note that the secondary relays do not have any communications-assisted tripping schemes applied.

The final tripping mode is through a switch-on-to-fault (SOTF) scheme. The relays at the Gillespie substation use bus potential transformers (PTs), while the relays at both the Horseshoe Bay and Ferguson substations use line-side coupling capacitor voltage transformers (CCVTs). The use of a line-side voltage source requires the use of SOTF logic to ensure dependability if the line is closed into a close-in three-phase fault. The SOTF logic allows the relay to trip without delay if the Level 1 phase overcurrent or Zone 2 phase or ground mho elements assert within 10 cycles of closing the breaker.

The primary relays are programmed to automatically reclose after a set open interval once the fault has been cleared. For the T-192 line, the Gillespie relay is set with an open interval of 30 cycles, while the relay at Ferguson has an open interval of 600 cycles. Therefore, the line will be re-energized and tested from the Gillespie terminal. As shown in Fig. 9, both of these substations use a double-bus, double-breaker configuration. With this configuration, one breaker is selected as the leader (CB-12370) and will close first. If the reclose is successful, the follower breaker (CB-2620) will also reclose. The same configuration is used at the Ferguson end of the line, with CB-19310 designated as the leader and CB-4480 programmed as the follower. Additionally, because the Gillespie end will have energized the line for several seconds once the Ferguson relay open-interval timer expires, the reclose of the Ferguson breakers is supervised with a synchronism-check element. Note that the secondary relays on this line do not have reclosing or synchronism-check elements enabled.

The T-448 line also has a reclosing scheme, but unlike the other substations, the Horseshoe Bay substation has a single-bus, single-breaker configuration. Therefore, the primary relay at Horseshoe Bay is programmed with a short open interval of 20 cycles. At the expiration of this timer, the relay initiates an automatic reclose of CB-12850. At the Gillespie end of the T-448 line, the relay is programmed with a 30-cycle open interval. Breaker CB-12360 is the leader breaker and CB-2570 is designated as the follower breaker. Due to the short open interval, the synchronism-check elements are not used in these relays. Note that the secondary relays on this line do not have reclosing or synchronism-check elements enabled.

For both lines, there are a number of conditions that are programmed to force the reclose element into the lockout state. One of these conditions, which is applicable to the fault discussed in this paper, is a three-phase fault on the line. When all three phases are involved in a fault, the scheme is designed to prevent automatic reclosing of the line.

In addition, the primary relays are set with breaker failure elements should any of the breakers fail to interrupt fault current.

Finally, all of the relays are supplied with a high-accuracy time synchronization signal from Global Positioning System (GPS) clocks. This signal is very important for aligning data between multiple relays when analyzing fault data.

V. LCRA TSC 138 kV Fault Analysis

A. Data Collection

The first fault data typically received are in a report from system operators. This information is very valuable because it describes what was happening at the time of the event and what the operators saw occurring on the system.

In this case, the LCRA transmission operations supervisor reported that the T-448 line tripped and automatically reclosed at 07:36 central daylight time (CDT), or 12:36 Greenwich mean time (GMT). The fault was reported as a CAG fault located 29.8 miles from Gillespie and 9.28 miles from Horseshoe Bay. Also at 07:36 CDT, the T-192 line tripped, but had to be manually closed. At the time of the trip, severe thunderstorms were reported in the area.

Following the event, oscillography event reports were collected from both the primary and secondary relays for each breaker that operated. Although filtered and unfiltered data were available from each relay, only the filtered event reports were retrieved.

The operator's report included a fault type and location on the T-448 line, but not on the T-192 line. The event report data captured from the T-192 line relays included a summary with this information for the line. All relays agreed that the line experienced a BG fault. However, there were small differences in the calculated fault location between the primary and secondary relays at each end. The primary relays indicated that the fault occurred 20.42 miles from the Gillespie substation and 8.46 miles from the Ferguson substation. The secondary relays calculated a distance of 20.88 miles from Gillespie and 10.66 miles from Ferguson.

B. Fault Type

The first portion of fault analysis is focused on determining exactly what occurred on the power system. Understanding the fault(s) that the relays were required to detect will assist in analyzing the relay operation.

Because both lines tripped simultaneously, it was assumed that the system had experienced a complex fault. Determining the type of complex fault was the most difficult portion of the analysis of this system event. In contrast to the approach recommended previously, the authors originally attempted to determine the fault type by analyzing the line quantities first. Fig. 11 and Fig. 12 show the oscillography data from the T-448 line.

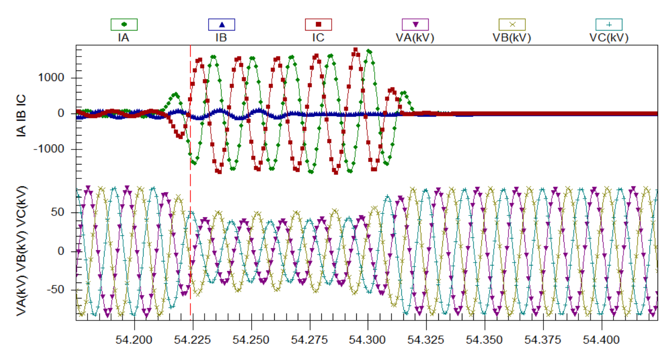

Fig. 11. Gillespie T-448 line oscillography data

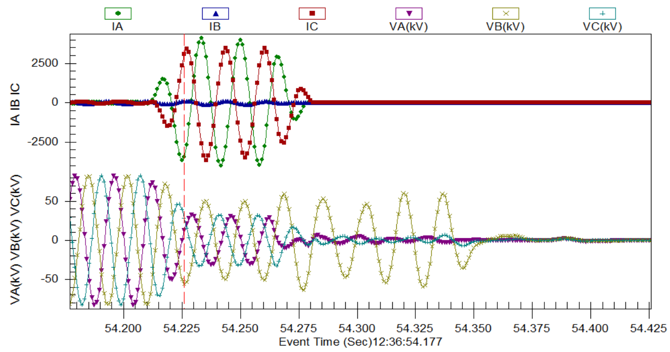

Fig. 12. Horseshoe Bay T-448 line oscillography data

Looking at the currents, we see that both ends of the line look like a CAG fault. Looking at the voltages, we see that all three phases are depressed, which looks like a three-phase fault. What kind of fault results in this combination of currents and voltages?

Fig. 13 and Fig. 14 present the oscillography data from the T-192 line.

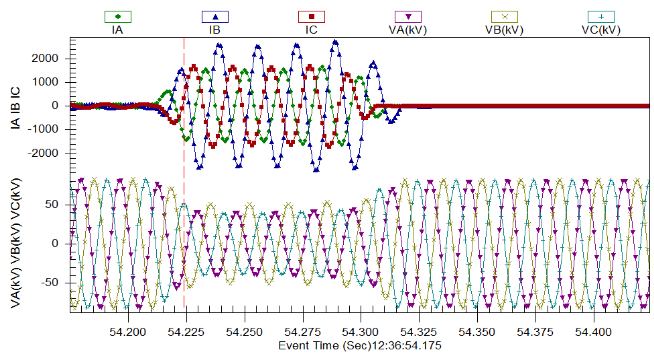

Fig. 13. Gillespie T-192 line oscillography data

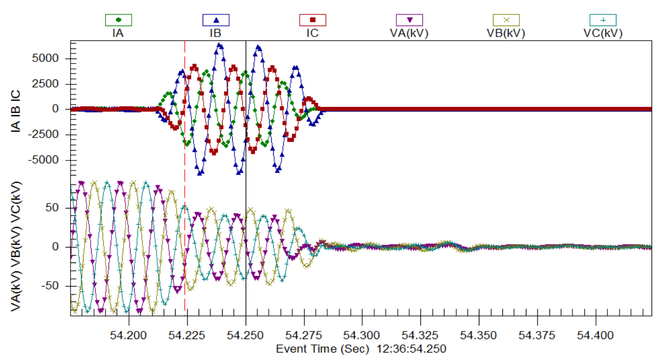

Fig. 14. Ferguson T-192 line oscillography data

The currents in Fig. 13 and Fig. 14 clearly indicate that all three phases had fault current. However, the B-phase current is significantly larger than A-phase and C-phase. How is this possible if, in fact, the line experienced a three-phase fault? The voltages again confirmed that all three phases were involved.

Combining the information from both lines, the authors noticed that the sum of the A-phase and C-phase currents on the T-448 line was out of phase with the B-phase current on the T-192 line. This led the authors to conclude that an intercircuit fault had occurred.

Despite this conclusion, doubts remained about the fault type and connection that would produce the phase values reported by the relays. This led to simulations and further research in an attempt to determine the fault type. The procedure documented in Section III, Subsection A was the result of this process.

Because the T-448 and T-192 lines share a common bus at the Gillespie substation, the procedure described in Section III, Subsection A was applied to provide clarity to the fault type. An equivalent source was created for the Gillespie substation using the common voltage measurements and the vector addition of the T-448 and T-192 currents from the Gillespie end of each line.

In order to perform the addition of the currents, the data were required to be time-aligned. This was most easily done by viewing the data with the associated time-stamp information. Also, verifying that the voltage signals were aligned provided confirmation of time alignment.

Additionally, the oscillography data from all terminals were viewed to determine a time during the fault when the quantities were stable. Fig. 11 through Fig. 14 show the oscillography data from the relays of interest.

The breakers at Ferguson and Horseshoe Bay operated first. Therefore, the phasors had to be read before these breakers opened. At 12:36:54.250 GMT, the fault data from all of the relays appeared to be relatively stable. The phase and sequence phasors calculated by each relay at 12:36:54.250 GMT are shown in Fig. 15 and Fig. 16, respectively. Additionally, the equivalent source phasors are shown as a result of the summation of the currents from the T-448 and T-192 lines. Note that voltage VA was set as the reference in each relay.

Looking first at the equivalent source quantities at the Gillespie substation, it is clear that all three phases are involved in the fault. This fault seems to be a three-phase fault. However, there are some clear differences, including the variations in magnitude and angle separation in the currents and voltages.

The phase voltages are shifted approximately 120 degrees, with VC having the maximum deviation (5 degrees) from this balanced condition. However, the voltage magnitudes are significantly different. All three phase voltages are depressed, but VA and VC are approximately 80 percent of VB. This is a difference of 10 kV. Note that the two phases with lower voltages are those reported as faulted on the T-448 line.

The phase current angles are also very close to a balanced condition (within 2 degrees). However, similar to the voltages, IA and IC magnitudes are approximately equal but larger than IB.

The phase angles of the voltages and currents would indicate that a three-phase fault occurred on the system. If two separate faults occurred that together involved all three phases (for example, an AB fault on Line 1 and a CG fault on Line 2), all three magnitudes would indicate a three-phase fault, but the angles would not be very close to a balanced condition. However, the variations in magnitude would indicate that this is not just a simple three-phase fault, but rather some form of

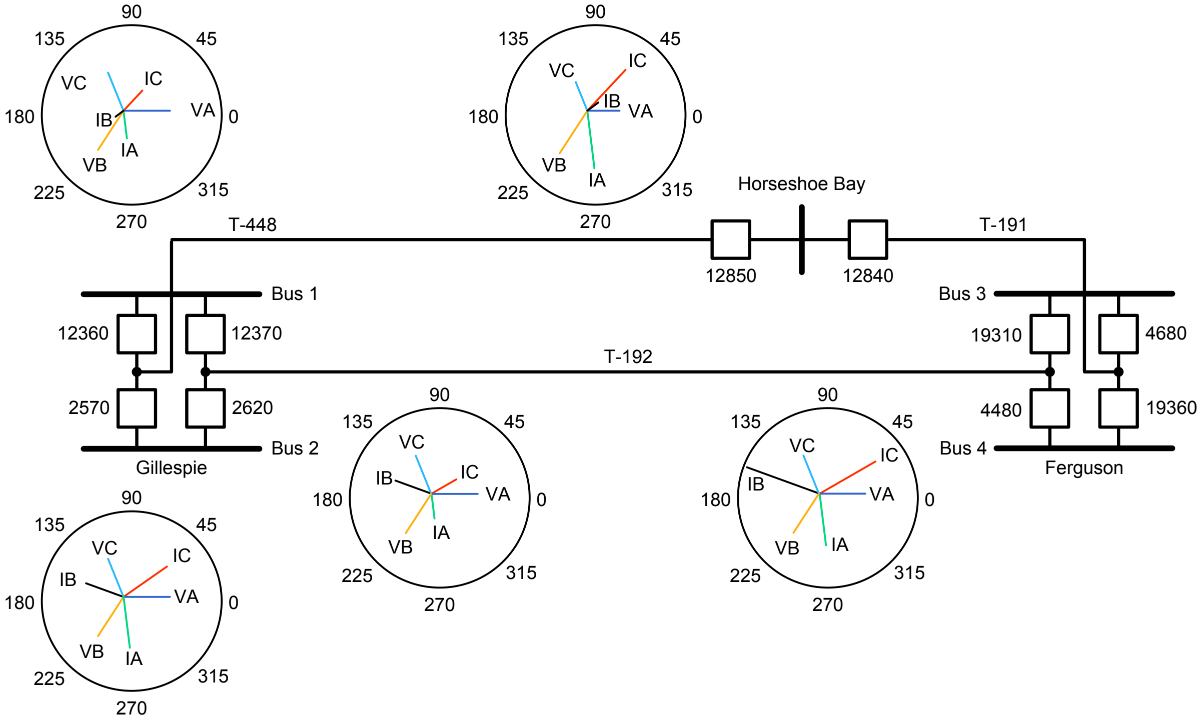

Fig. 15. Fault phase voltage and current phasors

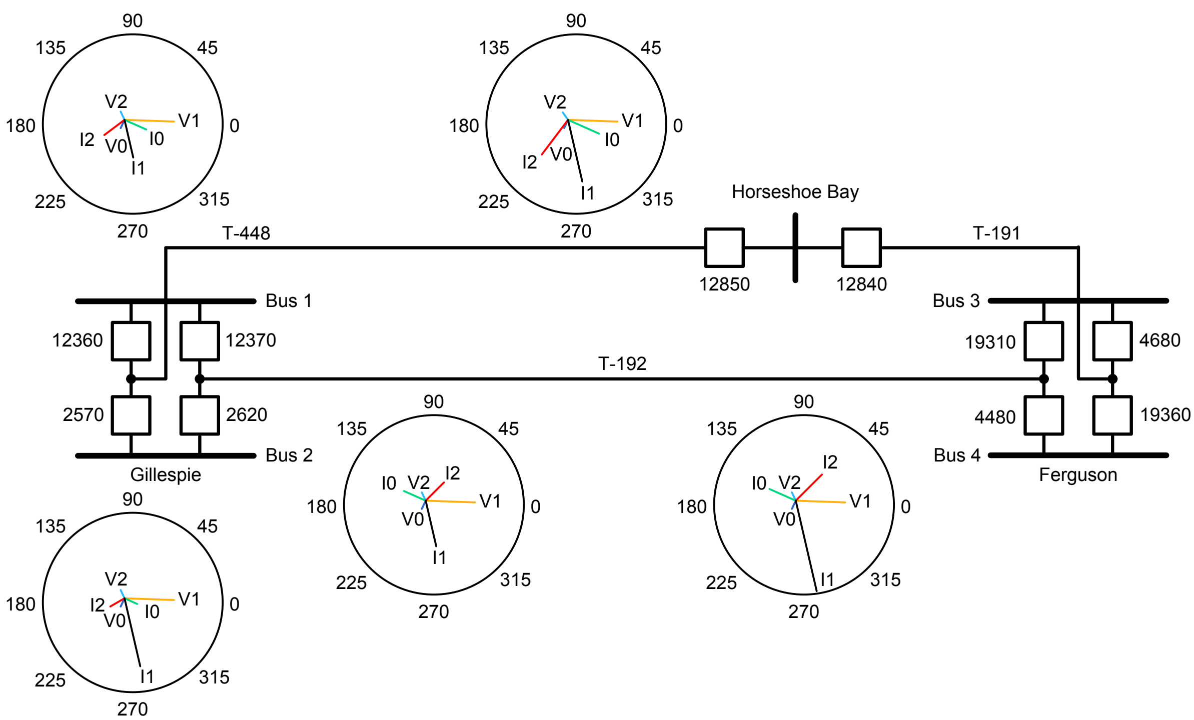

Fig. 16. Fault sequence voltage and current phasors

complex fault. This observation aligns with the fact that both lines tripped simultaneously. In this case, the A-phase and C-phase have lower voltage and higher current and were also reported as faulted on the T-448 line. Therefore, the equivalent source phase quantities and the operator's report agree.

In addition to the phase quantities, the sequence component quantities of the equivalent source can also provide useful information. Looking at the voltages first, we see that the angles resemble a CAG fault. For a CAG fault, V1 should be at 0 degrees, with V2 at 120 degrees and V0 at –120 degrees. In this case, V1 is at –2.5 degrees, V2 is at 114.6 degrees, and V0 is at 243.7, or –116.3, degrees. However, the magnitudes of V2 and V0 are quite low. All three voltages should be equal at the fault point for a pure LLG fault. Therefore, this also indicates that a CAG fault is not the only fault on the system, but rather the one primarily responsible for creating the unbalance.

The source current angles also agree with this relationship. For a CAG fault, I0 should lead I1 by 60 degrees, while I2 will lag I1 by 60 degrees. The calculated combined sequence currents are within 10 degrees of matching this expectation. However, considering magnitude and angle information, it is expected that a CAG fault will satisfy (1).

$$I1 = -\left(a^2 I2 + aI0\right) \tag{1}$$

In the case of this fault, the right-hand side of (1) equals 341.4∠96.9° A. The angle is again close to the required value, but the magnitude is only 11.5 percent of the expected value for a CAG fault. This large difference is due to the fact that the majority of the I1 current is the result of the three-phase fault previously mentioned.

Therefore, the equivalent source indicates that the fault is composed of a three-phase fault and a CAG fault. There are a number of ways to create this complex fault in this double-circuit line. At this point, it is helpful to review the line quantities to get additional information.

The phase currents of the T-448 line look similar to those of a CAG fault, except that the Horseshoe Bay relay measured a larger A-phase current. Typically, the two phase currents would be similar in magnitude for an LLG fault. The lack of transposition is not likely the cause, because the Gillespie relay on the line did not detect any significant difference between the two phase currents. However, fault resistance and prefault current could have an effect on this measured value. The sequence currents on the T-448 line also match well with a CAG fault, including satisfying (1).

On the T-192 line, the current angles indicate a three-phase fault, similar to the equivalent source. The difference is that on the T-192 line, the B-phase current is larger than the other two currents. However, as mentioned previously, the B-phase current on the T-192 line is 180 degrees out of phase with the sum of the A-phase and C-phase currents on the T-448 line.

Further, the zero-sequence current on the T-448 line is out of phase with the zero-sequence current on the T-192 line. However, these two currents are not equal in magnitude, indicating an intercircuit fault involving ground.

Combining these observations would indicate an intercircuit fault involving all three phases on the T-192 line, A-phase and C-phase on the T-448 line, and ground.

C. Fault Location

Accurately determining the fault location is important for several reasons. First, knowing the location of the fault assists in dispatching crews to assess and repair the damage. Providing an accurate location to crews can significantly reduce outage times for permanent faults. Second, the fault location information is needed to evaluate protection scheme operation. Finally, the fault location is needed to accurately simulate the fault to verify the fault type.

The first step was to look at the fault location automatically provided by the relays. The relays used the modified Takagi method to perform a single-ended fault location calculation [13]. The fault locations were not correct because the sum of the fault distances given by the relays at both ends of each line was greater than the length of the T-448 line and less than the length of the T-192 line. The modified Takagi method uses negative-sequence quantities in order to reduce the effect of load and fault resistance on the calculation. However, in this case, the negative-sequence quantities did not represent a single fault, especially on the T-192 line, which altered the outcome of the calculation.

In an attempt to improve the calculation, the authors used the data from both ends of the T-448 line to calculate the fault location using a double-ended, negative-sequence fault location method [13]. This method provided a fault location of 32.15 miles from the Gillespie substation.

The reason for the use of the T-448 quantities was that this line closely resembled a CAG fault. It is expected that significant negative-sequence quantities will be seen for any LLG fault. Therefore, this method of calculating the fault location is applicable. In contrast, the T-192 line experienced a three-phase fault, which typically does not have sufficient negative-sequence quantities to allow for the use of this method of fault location.

D. Simulation

The calculated fault location was then applied to the LCRA TSC system model in ASPEN in an attempt to verify the fault type and location. A three-phase-to-ground fault was applied at the calculated distance on the T-192 line, along with an intercircuit fault between the A-phase of the T-448 line and the B-phase of the T-192 line. Finally, a CG fault was applied on the T-448 line at the same location. No fault resistance was added to the model for this initial simulation.

The results of the simulation were similar to the actual fault data at the Gillespie substation, but the voltages were approximately 10 kV too low at the Horseshoe Bay and Ferguson substations. In addition, the phase currents on the T-448 line at Horseshoe Bay were too high. Similarly, the phase currents on the Ferguson end of the T-192 line were higher than the measured fault data. Adding fault resistance would limit the currents at these substations, but it would also alter the Gillespie results, which were similar to the event report data. Therefore, the fault was moved toward the Gillespie substation, and the simulation was repeated.

After a few iterations, it was found that placing a bolted fault at approximately 29 miles from the Gillespie substation yielded the most accurate results. The values did not match the actual data exactly, but the current and voltage angles were very similar, and the voltage magnitude deviations were similar at either end of both lines.

Several variations were attempted to find a closer match to the actual recorded results. The authors varied the CAG fault makeup, including using a CG fault and an AG fault at different locations, as well as a variety of fault resistance combinations. The results improved at one end of the line, but became worse at the other end.

After many trials, an exact match was not obtained. In particular, the model was not able to reproduce the unbalance seen between the A-phase and C-phase on both lines. In conclusion, the authors decided to use the best results obtained with the fault located 29 miles from Gillespie for the remainder of the analysis.

As discussed previously, knowing the exact fault location is very important. A more accurate fault location method that is available uses the traveling waves generated by a fault [14] [15] Because this method does not rely on an impedance calculation, its accuracy is maintained for complex faults.

E. Relay Operation

1) T-448 Line

Based on the previous analysis, the relays on the T-448 line were required to detect a CAG fault located 29 miles from Gillespie and 7.4 miles from Horseshoe Bay. Therefore, the fault is located at 80 percent of the line length from Gillespie and should be within the Zone 1 reach of both relays. Additionally, because ground is involved, the instantaneous ground directional overcurrent element may operate if the current exceeds the pickup value. Finally, because only two phases are faulted, the line should reclose automatically following the trip. The cause of the trip for each relay is shown in Fig. 17 through Fig. 20.

As Fig. 17 and Fig. 18 indicate, the Zone 1 phase distance element (M1P) operated to cause the trip as expected. Fig. 18 shows that the M1P bit chattered. This is acceptable, because the actual fault location was within 5 percent of the reach setting. Accounting for fault resistance, instrument transformer errors, and relay tolerances results in the measured impedance being approximately equal to the reach setting.

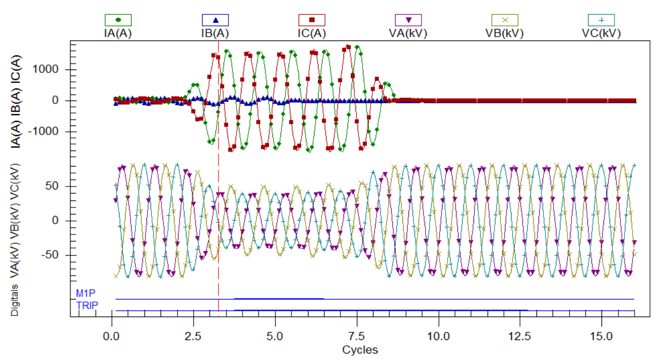

Fig. 17. Gillespie T-448 line primary relay trip output

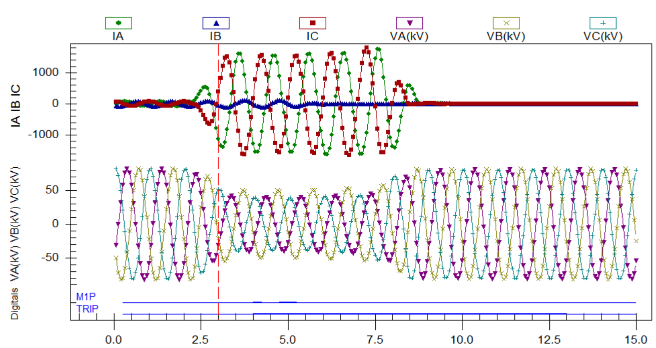

Fig. 18. Gillespie T-448 line secondary relay trip output

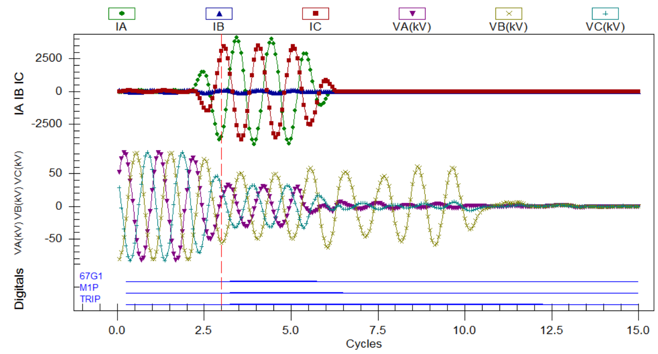

Fig. 19. Horseshoe Bay T-448 line primary relay trip output

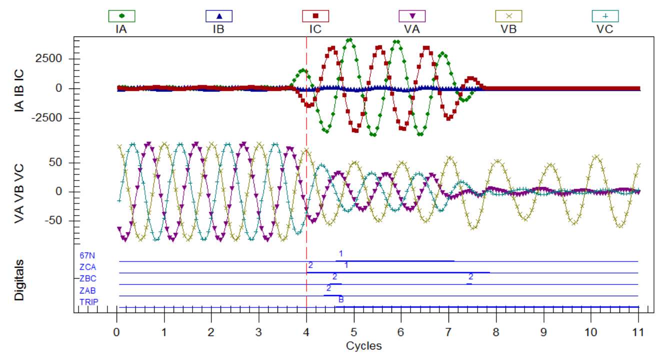

Fig. 20. Horseshoe Bay T-448 line secondary relay trip output

The fault data from the Gillespie T-448 line secondary relay were applied to a Mathcad® simulation of the relay. The simulation provided the measured impedance of the distance elements for each phase-to-phase fault loop. Only the impedance of the CA fault loop was close to the Zone 1 pickup. This impedance is labeled MCA in Fig. 21 and is compared to the Zone 1 (Z1P) and Zone 2 (Z2P) phase distance element reach thresholds.

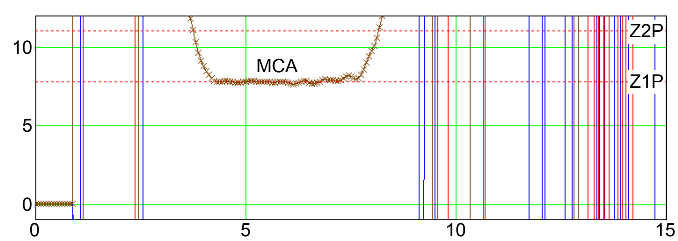

Fig. 21. Gillespie T-448 line secondary relay CA phase distance element impedance calculation

Fig. 19 and Fig. 20 show that both the Zone 1 phase distance and the instantaneous ground directional overcurrent elements asserted to cause the instantaneous trip at Horseshoe Bay.

As mentioned previously, the Zone 1 phase distance element matches the fault type and location. Verifying the instantaneous ground directional overcurrent element operation requires comparing the current magnitude with the pickup value.

The pickup setting for the 67G1 element was set to 9.07 A secondary. At the time 67G1 asserted, the relay calculated a 3I0 or IG current equal to 3,074 A primary or 12.81 A secondary. The relay directional element also correctly determined that the fault was in the forward direction, as indicated by the 32GF word bit. Fig. 22 shows all of this information.

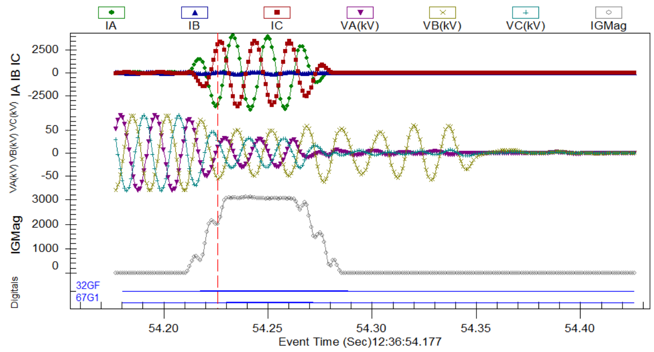

Fig. 22. Horseshoe Bay T-448 line primary relay instantaneous ground directional element

Therefore, all of the T-448 line relays correctly tripped for the fault.

In addition, the reclosing function was programmed in the primary relays at each end of the T-448 line as described in Section IV, Subsection B. In agreement with the operator's report, Fig. 23 shows that the relay correctly initiated reclosing (3PRI) and switched to the reclosing cycle state (79CY3) in the Gillespie T-448 line primary relay.

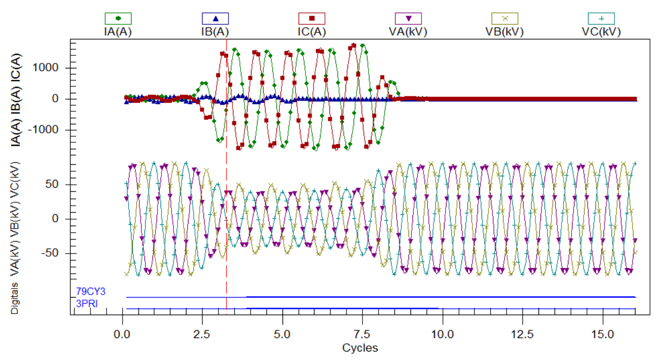

Fig. 23. Gillespie T-448 line primary relay reclose initiation

The Horseshoe Bay T-448 line primary relay also correctly initiated reclosing at the remote end of the line. Therefore, both ends of the line reclosed automatically as desired.

In summary, the T-448 line protection system correctly responded to this fault.

2) *T-192 Line*

As described previously, the T-192 line experienced a three-phase fault, which was located 29 miles from Gillespie and 10.1 miles from Horseshoe Bay. Therefore, the fault is located at 74 percent of the line length from Gillespie and should be in the Zone 1 reach of both relays. Finally, because a three-phase fault occurred on the line, the reclosing function should be forced into the lockout state following the trip. The cause of the trip for each relay is shown in Fig. 24 through Fig. 27.

Similar to the T-448 line, Fig. 24 shows that the Zone 1 phase distance element chattered. Although this relay had a slightly larger reach than the Gillespie T-448 line primary relay, the fault resistance and relay tolerances can cause this result.

Fig. 25 shows that the secondary relay operated on the Zone 1 ground distance element (Z1G). Although this is not expected for a three-phase fault, Fig. 25 also shows that the intercircuit connection resulted in the B-phase current being larger than the other two phase currents. As a result, the relay measured sufficient ground and negative-sequence current to allow the ground distance element to operate. From an overall protection system standpoint, the relay operated instantaneously as desired. Further analysis of the ground element operation is included in the following section.

Fig. 26 and Fig. 27 confirm that both Ferguson relays operated correctly on the Zone 1 phase distance elements without any intentional delay. Therefore, as desired for this internal fault, all relays operated instantaneously to clear the fault.

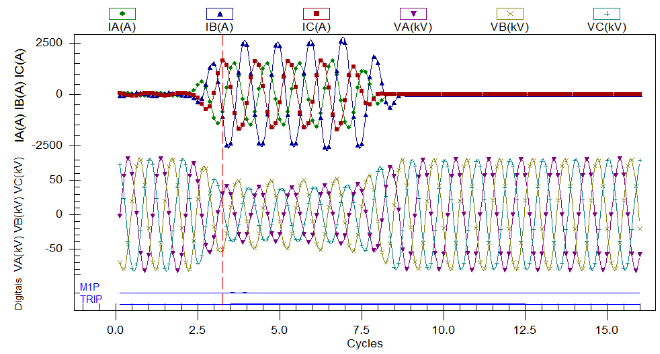

Fig. 24. Gillespie T-192 line primary relay trip output

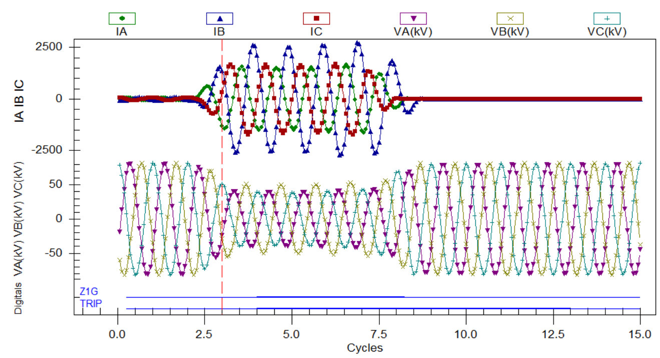

Fig. 25. Gillespie T-192 line secondary relay trip output

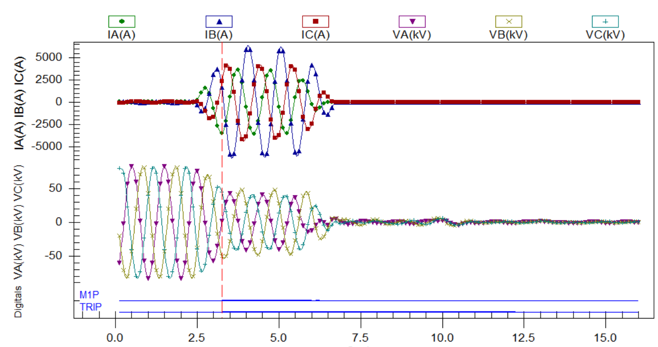

Fig. 26. Ferguson T-192 line primary relay trip output

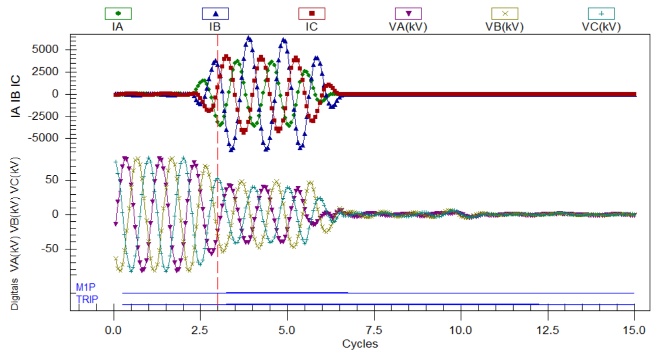

Fig. 27. Ferguson T-192 line secondary relay trip output

As mentioned previously, the primary relays are programmed to automatically reclose the line for unbalanced faults, while blocking this function for three-phase faults. In this case, both relays correctly forced the reclosing function into the lockout state. Fig. 28 shows the switch to the lockout state (BK1LO and BK2LO) following the relay trip for the Gillespie T-192 line primary relay.

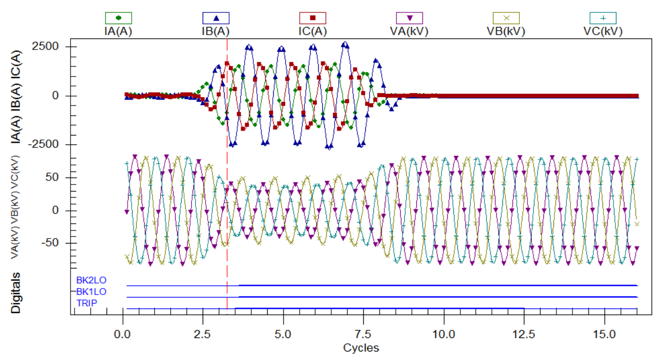

Fig. 28. Gillespie T-192 line primary relay reclose drive-to-lockout output

The Ferguson T-192 line primary relay responded the same as the Gillespie T-192 line primary relay shown in Fig. 28 and prevented the automatic reclosing of the line. This is the desired response for a three-phase fault on the line.

3) *Protection System Operation Summary*

Despite the complexity of the fault presented to the relays on the T-448 and T-192 lines, all relays, both primary and secondary, correctly tripped without delay on Zone 1. Also, the T-448 line automatically reclosed as desired, while the T-192 primary relays correctly identified a three-phase fault and blocked reclosing of the T-192 line.

VI. Lessons Learned

Although the protection system correctly responded to the complex fault on the system by simultaneously tripping the T-448 and T-192 lines without delay and reclosing only the T-448 line, further analysis of the operation revealed some additional details about the relay response and areas of potential improvement in the system design. This analysis also highlights the benefit of completely analyzing faults that occur on the system.

A. *Fault Selection Logic*

When analyzing the T-192 line relays, it was noted that the Zone 1 ground distance element operated. This was the only element that operated for the Gillespie T-192 line secondary relay, but it also asserted in addition to the Zone 1 phase distance element in the primary relays at both ends of the line.

As mentioned previously, the fault was in Zone 1 and the intercircuit connection with the T-448 line resulted in B-phase being larger than the other two phases, creating sequence components that resembled a BG fault.

However, although this produced the correct protection system result, the assertion of the BG element was analyzed in further detail. Fig. 29 shows the assertion of the phase and ground distance elements in the Gillespie T-192 line primary relay.

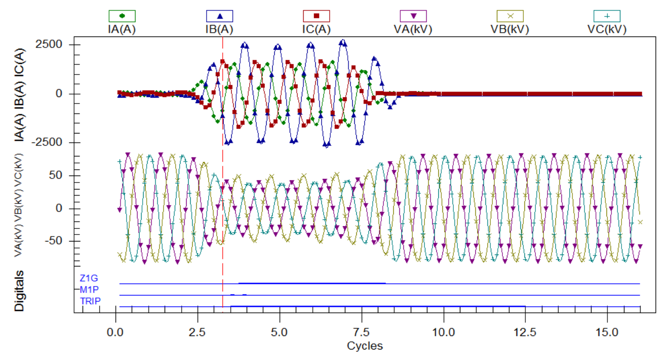

Fig. 29. Gillespie T-192 line primary relay Zone 1 distance elements

Fig. 29 confirms that M1P, the Zone 1 phase distance element, asserted first to cause the trip. However, it did not assert for the entire fault duration, but rather pulsed twice for one relay processing interval (0.125 cycle) each time. One-quarter cycle after M1P asserted, Z1G, the Zone 1 ground distance element, also asserted. However, unlike the phase element, it remained asserted until the fault was cleared. Because the ground reach is set to less than the phase reach, this result is not expected.

As discussed previously, the T-192 line experienced a three-phase fault on the line. For a simple three-phase fault, the phase distance elements are expected to operate. For a standard three-phase fault, only positive-sequence current is expected to flow. However, in reality, some small amounts of negative- and zero-sequence currents may be present. Therefore, the relay uses the ratio of the negative-sequence current magnitude to the positive-sequence current magnitude to distinguish between a three-phase fault with unbalance due to load and untransposed lines or apparent unbalance caused by current transformer (CT) saturation and a true unbalanced fault: LLG, LL, or LG. Additional checks are also used to determine if ground is involved.

In the Gillespie T-192 line primary relay, the threshold setting (a2) for this decision was set to 0.1. This means that if $|I2| \geq 0.1|I1|$, the relay would address the fault as a true unbalanced fault and proceed to determine the fault type using fault identification logic.

In the case of this fault, the complex fault also involved the T-448 line as described previously. As a result, the sum of the A-phase and C-phase currents on the T-448 line divided between the T-192 line and ground. This resultant current was in phase with the B-phase fault current on the T-192 line, resulting in it being larger than the other two phases on the line. The relay calculated the sequence components from the set of measured phase currents. The magnitudes of the resultant sequence component currents are shown in Fig. 30.

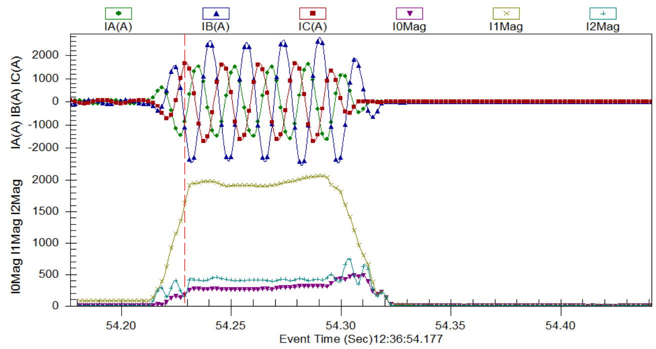

Fig. 30. Gillespie T-192 line primary relay sequence component current magnitudes

From the plot in Fig. 30, it was determined that the relay found that |I2| was as high as 23 percent of |I1| during the fault. Therefore, because this is higher than the 10 percent threshold set in the relay, the relay decided that it was not seeing a three-phase fault and proceeded to enable the fault identification logic to determine the fault type.

The fault identification selection (FIDS) logic in the relay relies on the angle relationship between I2 and I0 for the standard fault types shown in Section III. The details of the logic are described in [16]. Based on the output of this logic, the relay will enable one LG element and one LL element. The elements that are enabled are for different phases. For example, the relay would enable the AG and BC elements at the same time. As a result, only one element will operate for a given fault.

For this event, the sequence component phasors are shown in Fig. 31. From the figure, it can be seen that I0 leads I2 by approximately 120 degrees. There are two fault types that have this relationship: BG and CAG. Refer to Fig. 3 and Fig. 4 for expected phasors for each fault type. The sequence component current angle relationships shown in Fig. 31 match those of a BG fault.

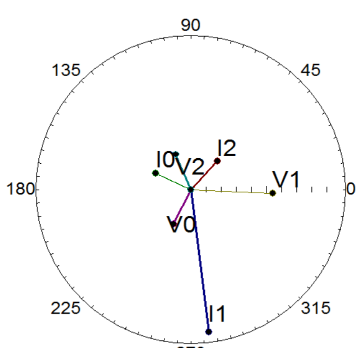

Fig. 31. Gillespie T-192 line primary relay sequence components

Based on this relationship, the relay asserted the FSB word bit to enable the BG and CAG mho elements. Fig. 32 shows the output of the FIDS logic, along with the zone distance elements that asserted.

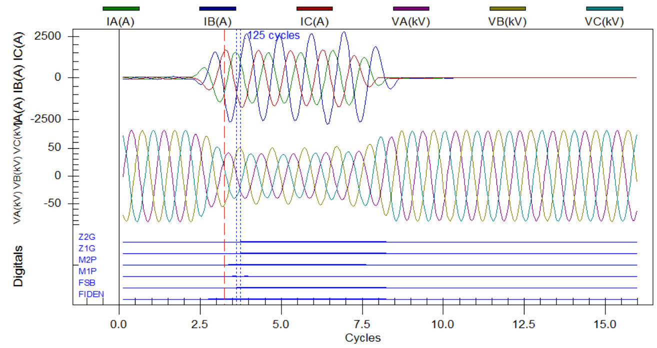

Fig. 32. Gillespie T-192 line primary relay FIDS logic output

To gain a better understanding of the apparent impedances calculated by the two enabled elements, as well as the other elements included in the relay, a Mathcad worksheet was used. The resulting distance element impedance values and the zone reach thresholds are shown for the phase elements in Fig. 33 and for the ground elements in Fig. 34.

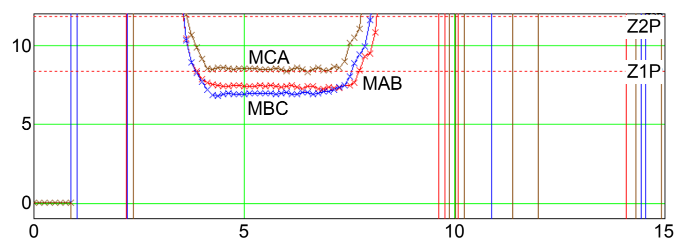

Fig. 33. Gillespie T-192 line primary relay phase distance element impedance calculations

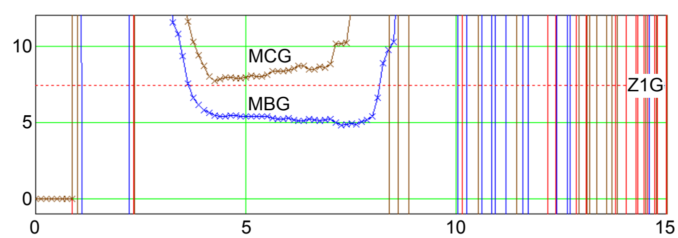

Fig. 34. Gillespie T-192 line primary relay ground distance element impedance calculations

Based on the fault location of approximately 29 miles from Gillespie and the positive-sequence line impedance of 9.89 ohms secondary, the correct apparent impedance would be 7.3 ohms secondary. As mentioned previously, based on the I2 and I0 relation, the relay enabled the BG and CAG elements. Fig. 33 shows that the CA element calculated an apparent impedance approximately equal to the Zone 1 phase reach (Z1P) of 8.41 ohms secondary. This aligns with the M1P word bit status in Fig. 32 that shows it chattering. Compared to the actual reach, this element underreached.

According to Fig. 34, the BG element calculated an apparent impedance of approximately 5 ohms secondary. This is less than 70 percent of the accurate value of 7.3 ohms secondary.

Therefore, the relay incorrectly identified the fault as a BG fault and thus enabled the BG element, which overreached the actual fault by 146 percent. This did not cause a misoperation from a system perspective. However, if a similar fault were to occur on an adjacent line, there is a possibility that the Zone 1 ground distance element set to see 75 percent of the line could overreach the remote bus and trip at high speed. This would be an incorrect operation.

Fig. 33 indicates that the AB and BC elements calculated an apparent impedance approximately equal to the actual value. However, they were blocked from operation due to the incorrect output of the relay FIDS logic.

1) Solution 1: Adjust a2 Setting

As mentioned previously, the FIDS logic was enabled due to |I2| relative to |I1|. The threshold for this ratio is settable in the relay. Increasing the a2 setting above the 23 percent seen in this event would have blocked the FIDS logic, resulting in the three-phase distance elements being enabled. As Fig. 33 shows, the AB and BC elements would have correctly operated on Zone 1.

An acceptable a2 setting must be determined, however. To provide the correct result for this event, a2 must be set greater than 0.23. However, caution must be exercised to prevent setting it too high. This setting is also used for the negative-sequence directional element in the relay. This directional element is used to determine the direction and supervise the distance elements for all unbalanced faults. As a result, if a2 were set too high, it could potentially block the distance elements, preventing the relay from tripping for an unbalanced fault.

Therefore, the a2 threshold must be lower than the ratio for all unbalanced faults. As such, the relationship between |I2| and |I1| should be considered for an LLG fault. This fault type is used because I1 must divide between I2 and I0 for an LLG fault, while |I1| equals |I2| for an LL or LG fault. Note that some margin should be applied to account for additional factors that can affect this ratio.

From the Gillespie substation, the T-448 and T-192 lines are very similar. For this fault, the T-448 line experienced a fault with currents resembling a CAG fault. Therefore, actual fault data can be used to determine the relationship of |I2| to |I1| for a CAG fault. The relative magnitudes of these sequence components are shown for the Gillespie T-448 line primary relay in Fig. 35.

The ratio of |I2|/|I1| during the fault was above 0.55. Therefore, a2 should be less than this value plus some margin.

As an example test, the fault data were replayed to the relay with a2 increased to 0.4. The results of the test are shown in Fig. 36. Note that FIDEN does not assert until the breaker is interrupting the currents. This indicates that the FIDS logic is not enabled, allowing all phase distance elements to operate. The figure indicates that the AB and BC elements both operated on Zone 1, which matches the impedance calculations shown in Fig. 33.

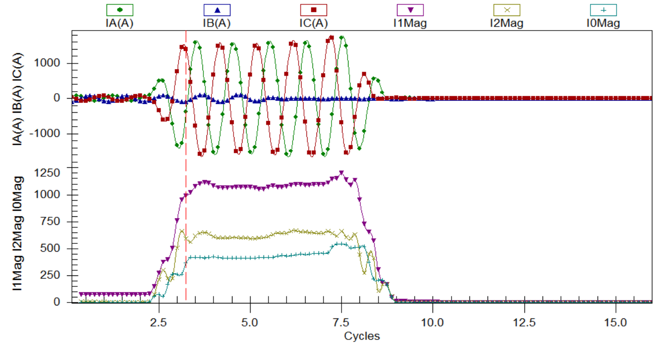

Fig. 35. Gillespie T-448 line primary relay sequence component current magnitudes

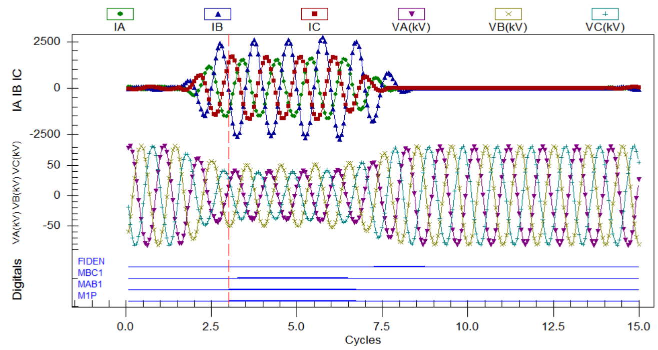

Fig. 36. Gillespie T-192 line primary relay with a2 = 0.4

In addition, as mentioned previously, it is possible for both phase and ground distance elements to overreach for one complex fault type and underreach for another. Therefore, to improve both security and dependability, Zone 1 reaches could be reduced and Zone 2 reaches could be increased. Because Zone 1 is unsupervised, it should never overreach the remote terminal. Zone 2 must be reliable and see all remaining faults on the line and back up adjacent lines.

Guaranteeing that Zone 1 will never overreach would require hundreds of simulations with no guarantee that the worst case had been covered. In reality, this is not practical. However, a realistic approach is to run a few simulations and add some additional margin to the results. This approach is often used to adjust ground element settings for security on lines affected by mutual coupling.

High-speed tripping can still be achieved by increasing the Zone 2 reach. With a permissive overreaching transfer trip (POTT) scheme, a large reach is acceptable because the elements cannot trip at high speed without receiving permission from the remote end. Note that load-encroachment elements may be required to provide security for the phase elements under heavy load conditions.

In the case of a blocking scheme, caution must be exercised to ensure security is maintained. If the reach is increased too much, there is potential that the relay could trip for a very remote fault if communications are lost. If a DCB scheme is applied over a communications medium with link status monitoring, the security of this scheme can be improved by supervising the DCB scheme with a healthy channel status bit.

2) *Solution 2: Line Current Differential*

Another viable solution is to use line current differential protection for the line. While complex faults have a significant effect on traditional distance relaying, they do not have an effect on line current differential relaying.

The T-192 line fault currents and voltages from both ends of the line were replayed to a set of relays identical to the secondary relays on the line, except that they had line current differential protection added. The event report data captured from each relay and the line current differential (87L) word bits from each relay are shown in Fig. 37 and Fig. 38.

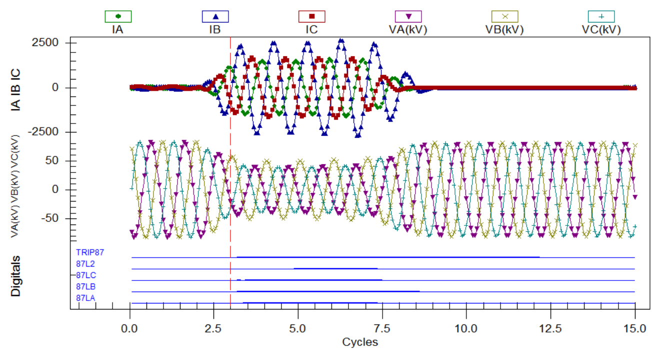

Fig. 37. Gillespie relay T-192 line replay with 87L elements

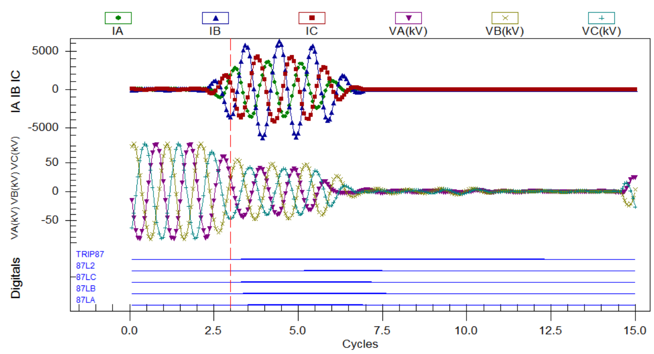

Fig. 38. Ferguson relay T-192 line replay with 87L elements

An additional benefit was seen in the 87L test results as shown in Fig. 39 and Fig. 40. It is common to apply backup distance relaying to run in parallel with the 87L elements. This ensures that the line remains protected if communications are interrupted. However, the distance protection is always enabled, not just when communications fail. As a result, the previous discussion is still relevant.

There is a key advantage, however, for the distance relaying applied in the relay with the 87L elements enabled over the traditional distance relaying applied in the LCRA TSC case. When the 87L elements are asserted, they provide indication of the phases involved in the fault to the relay (FTBC, FTAB, FTBG, FTCG, and FTABC word bits). The relay then uses this information to override the output of the traditional FIDS logic described previously. As a result, the correct distance elements are enabled in the relay.

Note that although this improves performance, it does not guarantee that the relay will not overreach and operate for a fault on the adjacent line. In this case, the fault is out of the zone of protection for the 87L elements, and as such, they will not provide any supervision. Therefore, the settings recommendations described previously remain valid for this case.

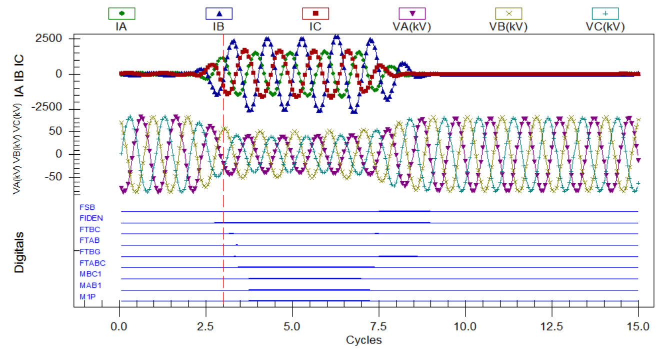

Fig. 39. Gillespie relay FIDS logic in T-192 line replay with 87L elements

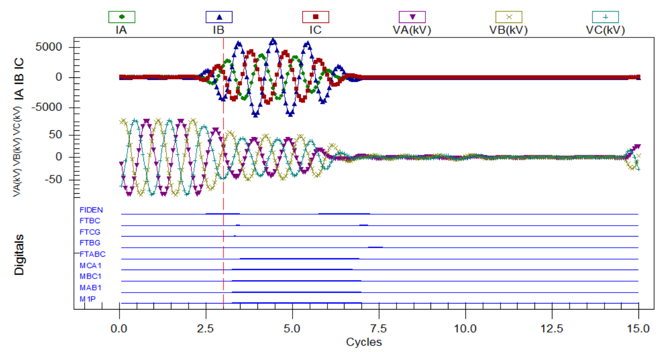

Fig. 40. Ferguson relay FIDS logic in T-192 line replay with 87L elements

However, some additional custom logic can be used to improve security for this case. The instantaneous tripping of a distance element for a fault on an adjacent line can be prevented by supervising the distance elements with the 87L elements. In short, the Zone 1 distance elements would only be enabled if an 87L element operates or the 87L elements are out of service (e.g., communications are lost).

One final benefit to using an 87L relay is that the state-of-the-art 87L relay at the time this paper was written (2014) has improved fault location ability. The relay has traveling wave fault location capabilities that are extremely accurate [14] [15]. This method of fault location does not rely on an impedance calculation, and as such, it will maintain its accuracy for simultaneous faults.

B. *Three-Phase Fault Indication*

The primary relays on both the T-448 and T-192 lines are programmed to initiate reclosing when the relay issues a trip from a Zone 1 element or DCB scheme element, provided it is not in response to a three-phase fault. For this event, the T-448 line correctly reclosed, while the T-192 line went directly to the lockout state according to design for a three-phase fault.

However, further analysis of the T-192 line relays showed that the indication of a three-phase fault could be improved. The reclosing functions in the Gillespie and Ferguson T-192 line primary relays were forced into the lockout state. The lockout bits (BK1LO and BK2LO) and the relevant bits from the drive-to-lockout equation are shown in Fig. 41.

As Fig. 41 shows, the reclosing function was forced into the lockout state before the reclosing cycle was initiated as a result of the trip being issued (3PT) while the Zone 2 phase distance element (M2P) was asserted and the negative-sequence forward directional output was deasserted (32QF). Although the directional output only dropped out momentarily, it was sufficient to assert the 79DTL equation. This result matches the operator's report that indicated that the T-192 line did not reclose automatically and had to be manually restored to service.

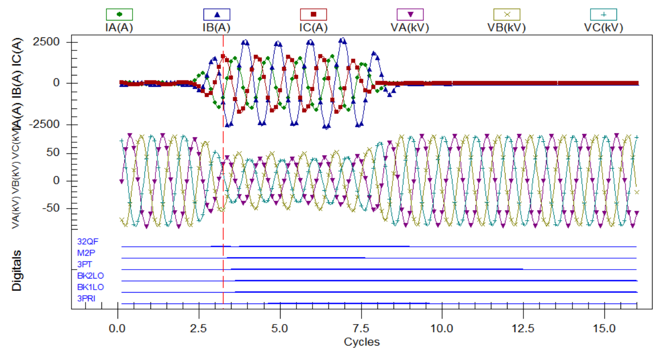

Fig. 41. Gillespie T-192 line primary relay reclose drive-to-lockout conditions

It is important to note that although this matches the desired operation for a three-phase fault, the condition to force the relay to the lockout state only existed for 0.25 of a cycle when 32QF deasserted as the fault developed. This equates to two processing intervals in this relay. For the remainder of the fault duration, the 32QF word bit was asserted. Again, this is a product of the complex fault, which caused significant unbalance on the line, despite the three-phase fault.

1) Solution 1: Account for Additional Unbalance

As mentioned previously, the a2 setting controls the negative-sequence directional element and is intended to provide a clear distinction between unbalance faults and three-phase faults. However, due to the intercircuit fault, |I2|/|I1| was greater than the a2 setting for the majority of the event.

Similar to the fault identification solution, if a2 is increased, taking the same precautions, the negative-sequence directional element will again be blocked from operation. In this case, it will ensure that the 32QF bit is deasserted at the time of the trip, guaranteeing that the reclosing function will go to the lockout state. Fig. 42 shows the results of the 32QF bit when the Gillespie T-192 line event is replayed with a2 increased to 0.4.

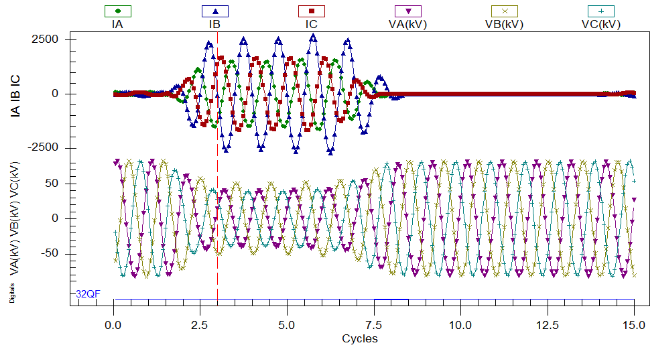

Fig. 42. Gillespie T-192 line primary relay event replay with a2 = 0.4

2) Solution 2: Use Phase Segregated Overcurrent Elements

Another option to improve the reliability of the scheme is to add an OR gate condition to the NOT 32QF input of the drive-to-lockout equation. An overcurrent element could be set above the maximum load on a per-phase basis. If all three elements are asserted when a trip occurs and M2P is asserted, then all three phases are involved in a fault and the relay will go to the lockout state.

VII. Conclusion

The process of analyzing the complex fault that occurred on the LCRA TSC 138 kV system on June 30, 2013, required significant effort for the authors. Several lessons were learned as a result, and they are summarized as follows:

- Complete event analysis is crucial, because a fault that appears to be correct on the surface may contain issues that have the potential to surface in the future.
- Proper event analysis requires a methodical approach.
- Analyzing complex faults requires an understanding of the phase and sequence component relationships for all simple fault types, including variations in the phases involved.
- Creating an equivalent system source for complex faults on parallel lines provides a complete system view of the fault.
- Analyzing the sequence component angles of an equivalent source may be required to provide a clearer view of the system fault type.
- The angle relationship of the negative- and zero-sequence quantities with respect to the positive-sequence quantities should be considered separately.
- Some complex fault types will result in zero- and negative-sequence components that reflect different simple fault types.
- Complex faults can cause traditional distance elements to overreach or underreach.
- To optimize security and dependability, the Zone 1 reach of phase and ground distance elements can be reduced, while the Zone 2 reach can be increased, with potential load-encroachment supervision of the Zone 2 phase element.
- Fault identification logic can incorrectly identify the fault type and enable the incorrect distance element for complex faults.
- Modifying fault identification logic thresholds to allow for greater unbalance in three-phase faults will improve the performance of the logic for simultaneous faults.
- Line current differential relays are immune to the effects of complex faults that challenge traditional distance elements.
- Line current differential relays use the 87L functionality to specify the fault type and improve fault identification logic.

- A state-of-the-art 87L relay includes traveling wave fault location functionality, which is accurate even for complex faults.
- Traditional criteria to detect a three-phase fault to block reclosing based on negative-sequence components may not work for complex faults.

VIII. Acknowledgment

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X. Biographies

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