Line Protection Response to a Three-Phase Intercircuit Fault

Ernie Hodge, *Gainesville Regional Utilities*
Edsel Atienza, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Line protection schemes are commonly set based on single fault conditions on the protected line and adjacent lines. Multiple simultaneous faults such as intercircuit faults can impact the apparent impedance seen by line protection relays, affecting protection speed and sensitivity. Review of an actual intercircuit fault is used to improve the performance of a line protection scheme.**

This paper describes the post-fault analysis following a three-phase intercircuit fault on parallel 138 kV transmission lines. Fault study data associated with single fault conditions on each line are compared with time-synchronized disturbance data from the protective relays. The performance of the following three protection schemes is evaluated for both the single fault conditions and the intercircuit fault condition:

- **Permissive overreaching transfer trip (POTT)**
- **Time-delayed step distance backup**
- **Alpha Plane line current differential**

Lessons learned and possible settings enhancements are described in the paper.

I. Introduction

Gainesville Regional Utilities (GRU) is a multiservice utility owned by the City of Gainesville that serves approximately 93,000 retail and wholesale customers. GRU operates a looped 138 kV subtransmission network with multiple generation sources and interties to neighboring transmission utilities. On January 14, 2014, a lightning strike on a tower resulted in a three-phase intercircuit fault between two parallel 138 kV subtransmission lines. Two sets of primary protective relays protect each of the faulted lines: Relay Set 1 and Relay Set 2.

Relay Set 1 includes a line current differential protection scheme based on the Alpha Plane characteristic for high-speed clearing of faults and a backup time-delayed step distance protection scheme during loss of communications. All four relays that were involved properly tripped and targeted for the intercircuit fault, clearing the fault within six cycles.

Relay Set 2 includes a permissive overreaching transfer trip (POTT) scheme using distance elements for high-speed clearing. Three of the four involved relays properly tripped and targeted for the intercircuit fault. The fourth relay did not operate or target for this fault.

Although this intercircuit fault was cleared quickly using Relay Set 1, the nonoperation of one of the four relays involved in Relay Set 2 triggered additional investigation. GRU relies on Relay Set 2 for high-speed clearing in the event of a communications failure or relay failure on Relay Set 1. Failure by the line protection relays to trip for an intercircuit fault could result in tripping of generation or tripping of adjacent lines and buses. A simplified one-line diagram that includes the relays and faulted lines is shown in Fig. 1.

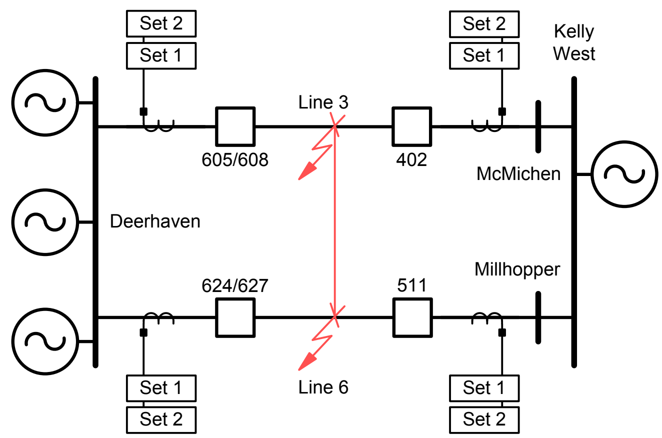

Fig. 1. Simplified one-line diagram showing faulted lines and adjacent buses.

This paper describes the expected operation for the relays that protect Line 3 and Line 6 for a fault on Line 3, a fault on Line 6, and an intercircuit fault between Line 3 and Line 6. The expected operation for the intercircuit fault is compared with the actual operation of the relays during the fault. The Alpha Plane line current differential scheme, POTT scheme, and time-delayed step distance backup scheme are evaluated using the actual time-synchronized disturbance data from the relays and simulation data.

II. Simulation Results

Lightning strike data identified a strike near a tower shared by both faulted lines approximately 1 mile from the Deerhaven substation, 7.5 miles from the McMichen substation, and 2.5 miles from the Millhopper substation. Visual inspection of the tower confirmed there was an arcing fault on the tower. Table I shows the expected fault currents associated with a BCG fault on Line 3, a three-phase fault on Line 6, and an intercircuit fault between Lines 3 and 6 at the tower.

Fault current contributions from each line terminal are expected to be less during the intercircuit fault compared with single faults on either Line 3 or Line 6. The reduced fault current at each terminal can have a negative impact on the sensitivity of the supervision elements associated with the distance-based and differential-based line protection schemes.

TABLE I
SIMULATED FAULT CURRENT CONTRIBUTIONS

Line Terminal	Line 3 BCG Fault	Line 6 Three-Phase Fault	Intercircuit Fault
Deerhaven Line 3	14,482 A	1,421 A	9,172 A
Deerhaven Line 6	1,886 A	13,770 A	9,598 A
McMichen Line 3	2,346 A	1,421 A	1,849 A
Millhopper Line 6	1,886 A	2,406 A	3,016 A

Based on fault studies, Table II documents the secondary impedances expected to be detected by the relays, along with the forward-looking distance element reaches. Both Line 3 and Line 6 terminals at Deerhaven were expected to trip instantaneously based on Zone 1 phase distance elements. The impedances seen by the McMichen and Millhopper terminals are just outside of the Zone 1 reach, but they should be within the Zone 2 reach, resulting in high-speed tripping through the POTT scheme. Zone 4 represents a long-reaching, forward-looking, time-delayed element used for backup protection. The highlighted zones are expected to pick up.

TABLE II
EXPECTED IMPEDANCES SEEN BY RELAYS AND
RELAY DISTANCE ELEMENT REACH SETTINGS IN SECONDARY OHMS

Line Terminal	Expected Impedance	Zone 1 Reach	Zone 2 Reach	Zone 4 Reach
Deerhaven Line 3	0.25	1.83	2.56	5.06
Deerhaven Line 6	0.26	0.66	1.82	5.90
McMichen Line 3	1.92	1.83	2.33	3.67
Millhopper Line 6	0.66	0.65	1.15	9.34

III. ALIGNMENT OF THE FAULT DATA

Because the fault current contributions from Deerhaven into the fault and from the Kelly West substation into the fault are distributed between the two lines, the oscillography data from both lines must be time-aligned before they can be analyzed. All of the relays at Deerhaven are connected to the same Global Positioning System (GPS) time clock for time synchronization. Based on the capabilities of these relays, the time stamps associated with oscillography data from the relays should be within ±5 milliseconds. The prefault bus voltages measured by all relays at Deerhaven should be identical, so the alignment of the data can be verified and further improved by comparing the phase angles of the prefault voltages recorded by different relays. Fig. 2 shows the peak of the A-phase voltage recorded by a relay on Line 3 approximately 1 millisecond out of phase with the peak A-phase voltage recorded by a relay on Line 6.

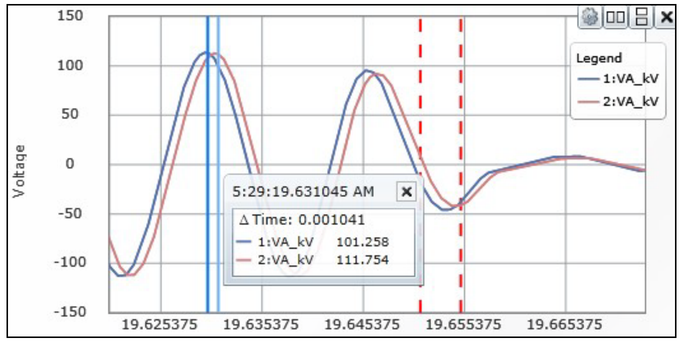

Fig. 2. A-phase bus voltages recorded by relays on Line 3 and Line 6.

Oscillography data time stamps from different relays are shifted using software tools to allow more accurate alignment of the data before analysis. More advanced relays time-synchronize the sampling of the relays to GPS to provide COMTRADE files that are synchronized to within microseconds. More advanced synchronization capabilities reduce manual time alignment of data.

The Line 3 and Line 6 differential relays at Deerhaven also recorded current data from the differential relays at McMichen and Millhopper. This allowed review and analysis of the currents at McMichen and Millhopper with little additional effort.

IV. MEASURED FAULT CURRENT CONTRIBUTIONS

Fig. 3 shows the measured fault current contributions from McMichen and Millhopper and the calculated total fault current contribution from Kelly West. The distribution of currents appeared to be equal, and contributions from each line were consistent with balanced three-phase faults. When compared with the expected currents from the fault studies, the fault currents measured at McMichen and Millhopper were slightly higher than expected.

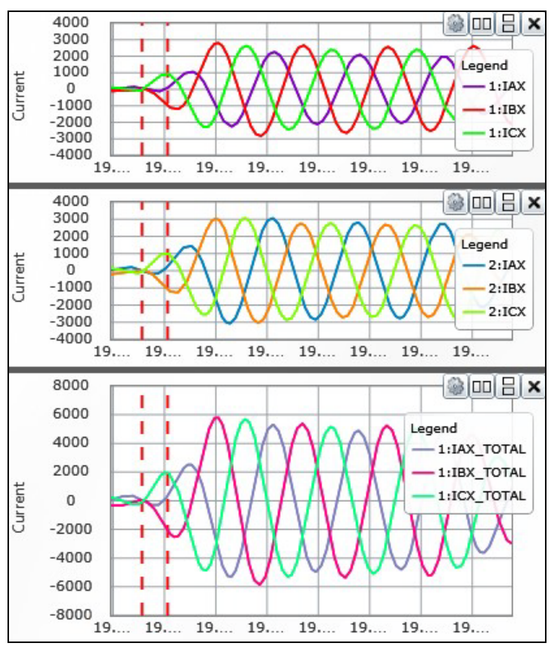

Fig. 3. Fault current contributions from McMichen measured from Line 3 (top), contributions from Millhopper measured from Line 6 (middle), and the calculated total from Kelly West on Lines 3 and 6 (bottom).

Unlike the fault current contributions from McMichen and Millhopper, the fault current contributions of each line terminal at Deerhaven as seen by the Line 3 and Line 6 relays exhibited significant unbalance. Although the individual fault contributions from each terminal were unbalanced, the total fault contribution from Deerhaven was balanced, as shown in Fig. 4. The total fault current contribution from Deerhaven was slightly lower than expected, but the unbalanced current contribution from the Deerhaven terminal of Line 6 was not expected. This current unbalance can result in unintended operation of unbalance or ground elements for the three-phase fault.

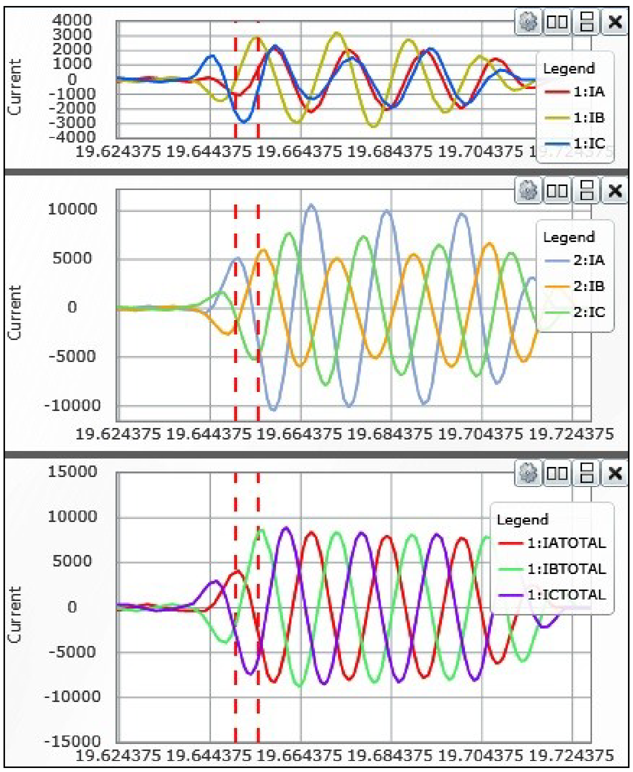

Fig. 4. Fault current contributions from Deerhaven measured from Line 3 (top) and Line 6 (middle), and the calculated total from Lines 3 and 6 (bottom).

V. Differential Elements

The Alpha Plane restraint differential elements are based on comparison of the phase and sequence currents from the remote terminal versus phase and sequence currents from the local terminal, as shown in Fig. 5 [1]. In the case of the Deerhaven Line 3 relay, the remote currents are measured from the McMichen end, and the local currents are measured from the Deerhaven end, as shown in Fig. 6. The A-phase currents on Line 3 represent currents on an unfaulted phase: the magnitudes of the two currents are equal, and the phase angles of the currents are 180 degrees apart. This results in the A-phase alpha quantity plotting within the restraint region at $1\angle 180°$. The B-phase and C-phase currents appear to have roughly equal magnitude currents between both ends of the lines, but the currents are roughly in phase with each other. This results in the B-phase and C-phase alpha quantities plotting in the tripping region near $1\angle 0°$. Alpha quantities calculated on the McMichen Line 3 differential relay equal the reciprocal of the alpha quantities calculated in the Deerhaven Line 3 differential relay.

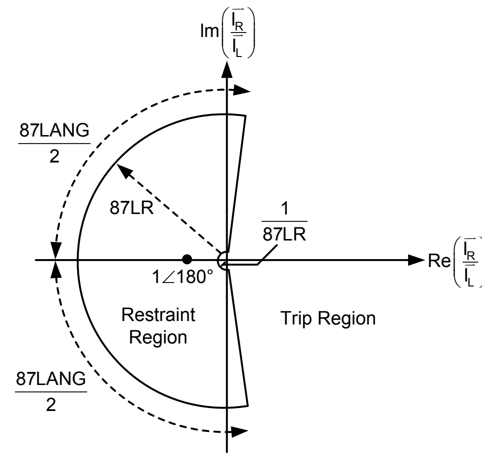

Fig. 5. Alpha Plane restraint characteristic.

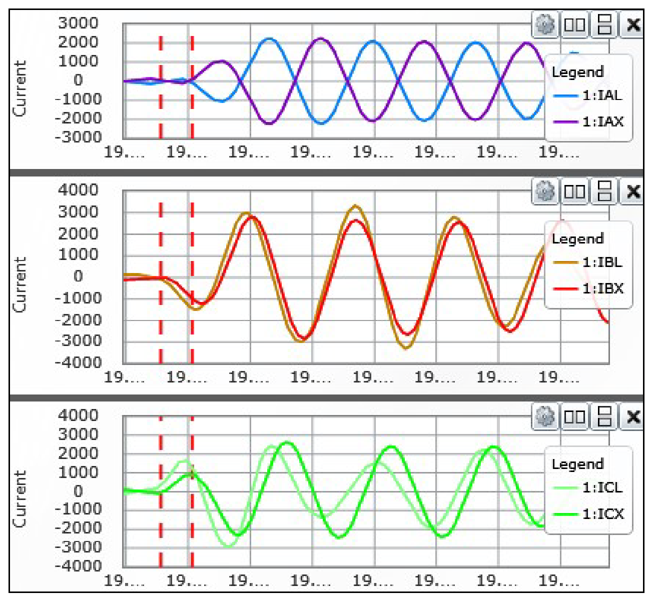

Fig. 6. Line 3 comparison of Deerhaven currents (IAL, IBL, and ICL) versus McMichen currents (IAX, IBX, and ICX).

The Alpha Plane differential characteristic is supervised by a minimum phase differential current pickup to restrain for charging current under low load conditions [1]. Typical pickup is 6 A secondary, so with a CT ratio of 1200/5, there must be a minimum of 1,440 A primary differential current for the differential elements to trip. Fig. 7 shows sufficient B-phase and C-phase differential current on Line 3 to allow tripping of the differential relays. B-phase and C-phase are easily identified as faulted phases on Line 3 based on the alpha quantities and phase differential currents.

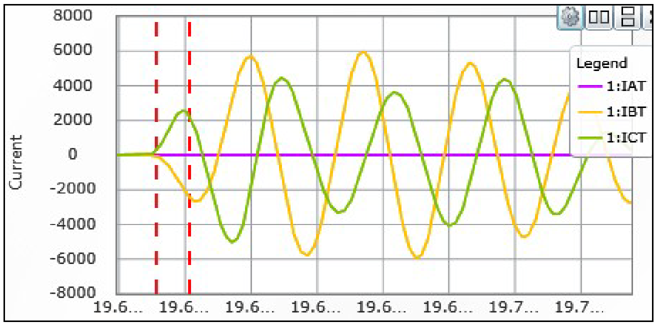

Fig. 7. Line 3 total phase differential currents.

In the Line 6 differential relays, the A-, B-, and C-phase currents on the Deerhaven terminal are roughly in phase with the currents on the Millhopper terminal, as shown in Fig. 8. When plotted on the Alpha Plane, this results in alpha quantities for the A-, B-, and C-phase elements to plot in the tripping region near the 0-degree line. Fig. 9 shows that the total differential current for A-phase, B-phase, and C-phase was well above the 1,440 A minimum pickup of the differential relays. A-, B-, and C-phases are easily identified as faulted phases on Line 6 based on the alpha quantities and phase differential currents.

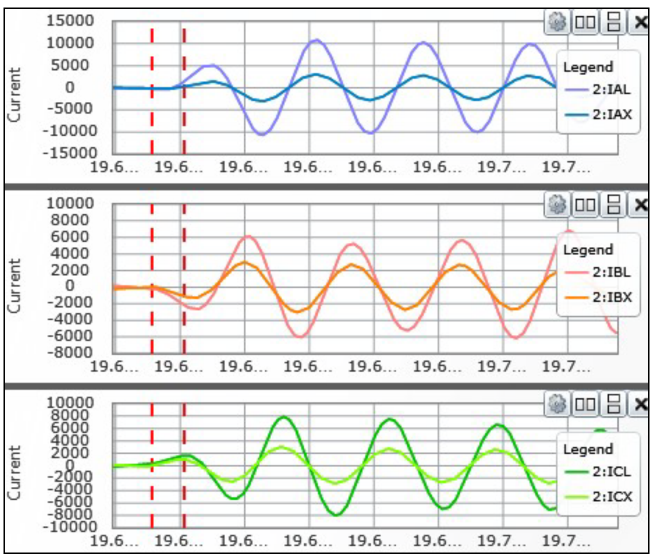

Fig. 8. Line 6 comparison of Deerhaven currents (IAL, IBL, and ICL) versus Millhopper currents (IAX, IBX, and ICX).

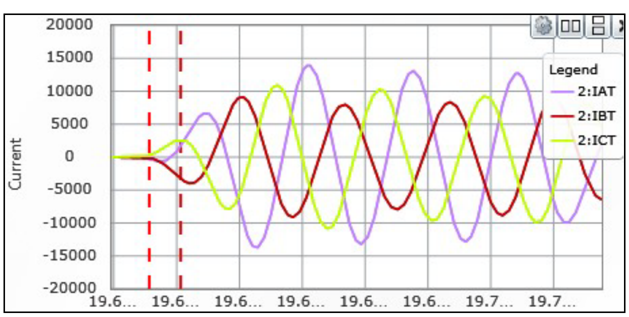

Fig. 9. Line 6 total phase differential currents.

With total phase differential currents on both Line 3 and Line 6 differential relays greater than three times the minimum sensitivity of the differential relays, the differential relays exhibit very fast operation and high sensitivity for the intercircuit fault. Operation time is nearly instantaneous with a delay only to allow communication of the current values between the relays. Any speed or sensitivity reduction associated with the lower currents of the intercircuit fault is negligible.

VI. Distance Elements

If line differential protection is lost due to loss of communications or the failure of a relay, distance-based elements are used to detect and trip for these line faults. These distance elements include fault identification logic to supervise the distance elements to prevent overreaching [2]. Fig. 10 demonstrates sufficient zero-sequence and negative-sequence current to enable the fault identification logic on Deerhaven Line 3, and the relay correctly selected the AG/BCG fault type asserting the FSA bit, allowing the Zone 1 and Zone 2 BC distance elements to pick up. Fig. 10 also shows the impedance trajectory during the fault plotted within the Zone 1 BC distance element, allowing it to trip instantaneously for the fault as expected.

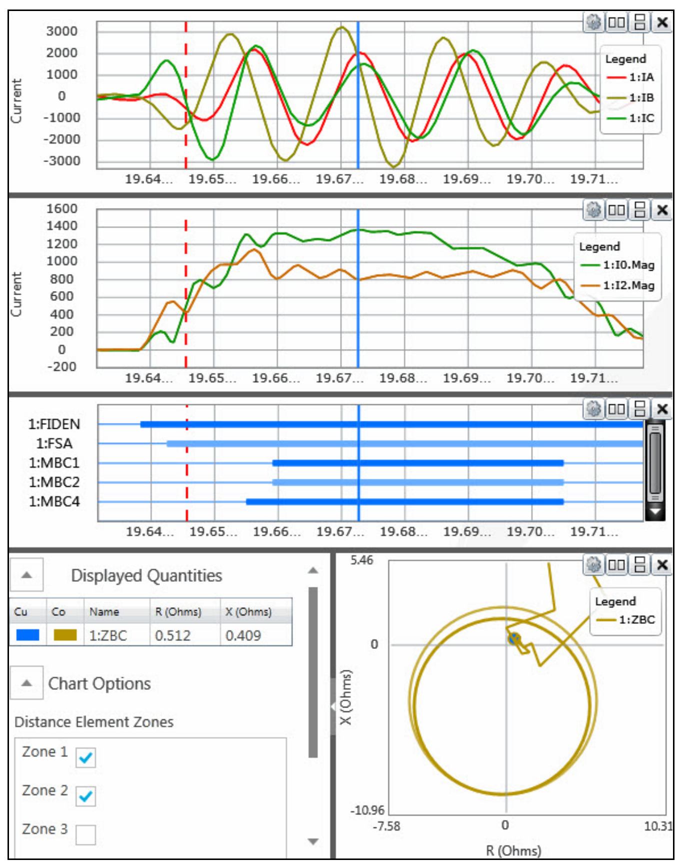

Fig. 10. Deerhaven Line 3 fault identification and impedance plots.

For a three-phase fault on Line 6, there should not have been any negative-sequence or zero-sequence currents associated with the balanced fault, allowing only the phase-to-phase elements to operate. Because of the unbalance caused by the faulted B-phase and C-phase on adjacent Line 3, the fault identification logic also asserted the FSA bit, indicating an AG/BCG fault, as shown in Fig. 11. This allowed both Zone 1 AG and BC distance elements to pick up, also shown in Fig. 11.

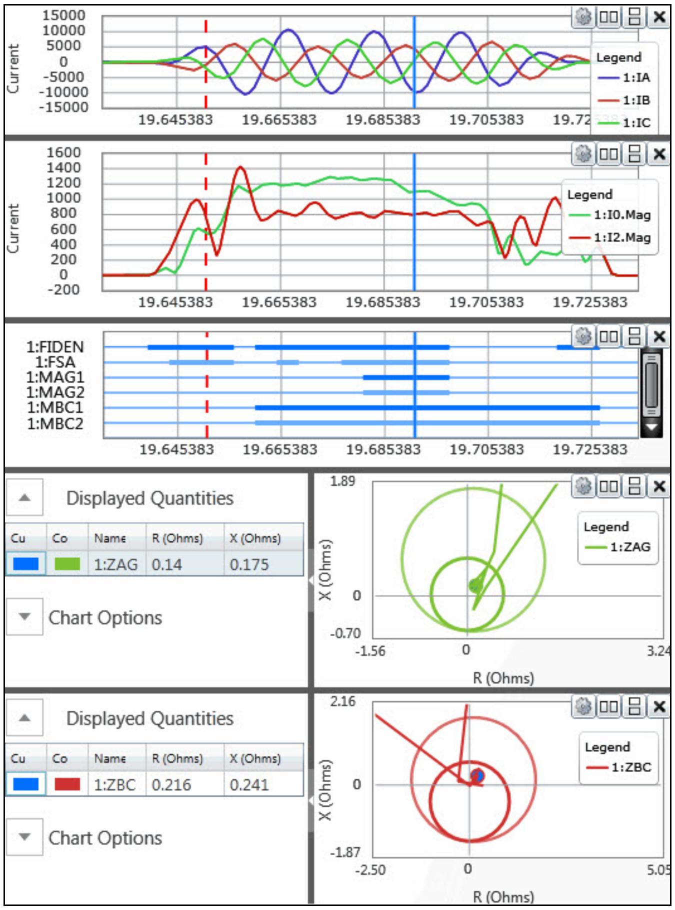

Fig. 11. Deerhaven Line 6 fault identification and impedance plots.

Unlike the fault contributions from Deerhaven, fault contributions from Millhopper and McMichen were balanced and included very little negative-sequence or zero-sequence currents for the intercircuit fault. This resulted in no continuous assertion of fault identification logic in the Relay Set 2 distance relays. This prevented ground distance elements from picking up and enabled phase distance elements to pick up in the Relay Set 2 relays. Fig. 12 shows the impedance trajectories for all three phase distance elements in the Millhopper plotting within Zone 2 reaches. This, combined with Zone 1 and Zone 2 pickup of the Deerhaven Line 6 relays, allowed high-speed tripping of Line 6 using the POTT scheme.

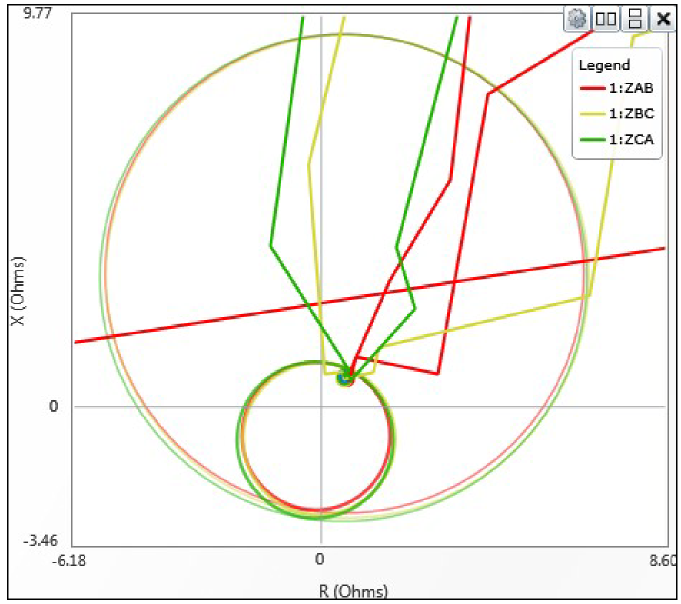

Fig. 12. Impedance trajectory of Millhopper distance elements relative to Zone 2 and Zone 4 reaches.

Unlike Line 6, McMichen Line 3 Relay Set 2 did not target for this fault. Fig. 13 shows that the impedance trajectories plotted within the reaches of the Zone 4 distance elements, but they did not plot within the Zone 2 distance elements. This prevented the POTT scheme from tripping. If the differential relay was not available, tripping of Line 6 should have redistributed the currents sufficiently to allow the distance relays on Line 3 to operate, resulting in sequential trip. In addition, the Zone 4 distance elements should have allowed McMichen Line 3 Relay Set 2 to trip after a time delay.

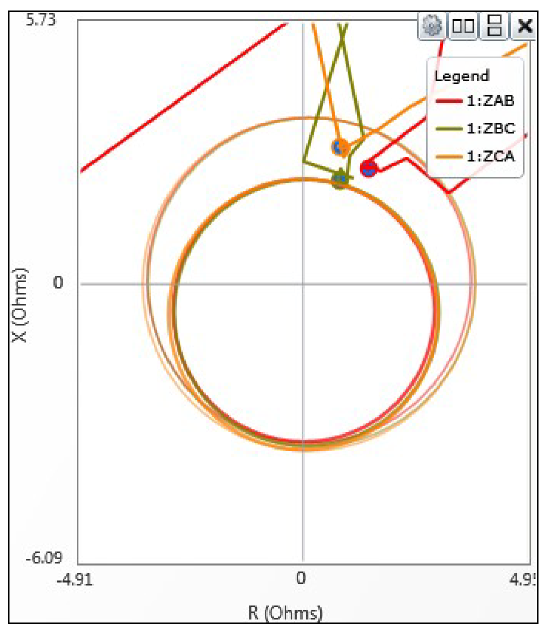

Fig. 13. Impedance trajectory of McMichen distance elements relative to Zone 2 and Zone 4 reaches.

Impedance plots from all four line terminals showed apparent impedances larger than the expected impedances shown in Table II, indicating some measurable fault impedance.

VII. Conclusion

Compared with faults involving only a single line, intercircuit faults generally result in reduced fault currents at line terminals. Reduced fault currents due to an intercircuit fault combined with the effect of arc impedance can negatively impact the sensitivity and speed of impedance-based line protection schemes. Identification of the fault type using fault identification logic and impedances is difficult for an intercircuit fault. Under some conditions, POTT schemes based on the overreaching Zone 2 distance element may not provide sufficient coverage to trip during intercircuit faults or may be delayed. A properly set backup time-delayed Zone 4 distance element is critical if relay communications are lost.

Line differential protection using the Alpha Plane characteristic provided sufficient speed and sensitivity to detect and clear the intercircuit fault discussed in this paper. Identifying the faulted phases was easy using the phase differential elements compared with the distance-based scheme. The decreased fault magnitude associated with the intercircuit fault and arc impedance was still greater than three times larger than the minimum sensitivity for all of the phase differential elements involved.

VIII. References

[1] D. Tziouvaras, H. Altuve, G. Benmouyal, and J. Roberts, "Line Differential Protection With an Enhanced Characteristic," proceedings of MedPower 2002, Athens, Greece, November 2002.

[2] E. O. Schweitzer, III and J. Roberts, "Distance Relay Element Design," proceedings of the 46th Annual Conference for Protective Relay Engineers, College Station, TX, April 1993.

IX. Biographies

Ernie Hodge received his BSEE from the Georgia Institute of Technology in December 1995. Since 1997, he has worked with Gainesville Regional Utilities (GRU), a municipality in Gainesville, Florida. He started as the revenue meter and power quality engineer at GRU and is currently the protection and control engineer. Ernie is a registered professional engineer in Florida, a certified power quality professional by the AEE, and a member of the IEEE.

Edsel Atienza received his BSEE from the University of Idaho in 2001. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2002 as an international field application engineer. In 2006, Edsel joined Tampa Electric as a substation operations engineer responsible for relay testing and maintenance. He returned to SEL in 2008 and currently serves the northwestern United States as a field application engineer.

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