

Finding Common Ground: A Case Study of Phantom Currents and Ground Loops

Matthew Boecker and Genardo Corpuz, *Lower Colorado River Authority*
 Jared Candelaria and Ariana Hargrave, *Schweitzer Engineering Laboratories, Inc.*

Abstract—In February of 2018, a current differential relay protecting a 138 kV/69 kV autotransformer tripped for an out-of-zone ground fault. System conditions were such that the low side of the autotransformer was open, but the relay event reports showed fault currents present on the low side. Initial investigation hinted at a current transformer (CT) secondary circuit problem (the CT, cable wiring, or relay input), and three more faults that occurred the following week helped narrow it down. This paper describes the investigation into these faults, how root cause was found, and how ground potential rise can cause phantom currents to flow in relay CT circuits.

I. INTRODUCTION

In February of 2018, a series of faults occurred on the LCRA Transmission Services Corporation system that called the performance of the differential relay protecting a transformer into question. Each fault was located external to the transformer relay’s differential zone of protection. Although the low side of the transformer was open when the faults occurred, the transformer relay measured currents on the secondary winding. These “phantom currents” caused the differential relay to operate. In this paper we share details on the faults, the investigation, and the discovery of root cause. We also share recommendations for proper relay installation and testing.

II. REVIEW OF TRANSFORMER DIFFERENTIAL PROTECTION

Transformers are most commonly protected using current differential protection. The simplest form of current differential protection can be described using Kirchhoff’s current law. The current entering the zone of protection must equal the current leaving the zone. If these currents are not equal, there must be another path for current to flow inside the zone (i.e., a fault).

The currents entering and exiting the transformer’s zone of protection are measured using current transformers (CTs) with opposing polarity. The relay then calculates an operate (IOP) and restraint (IRT) quantity, as shown in Fig. 1. The variable k is a design constant that varies with the relay design and is usually equal to 1 or 2. The relay compares the IOP quantity to the IRT quantity, scaled by a slope threshold setting, to determine if it should operate. This is called percentage-restrained differential protection.

The operate and restraint values for an external and internal fault (assuming a CT ratio of 1:1) are shown in Fig. 2. A graphical representation of the two faults in Fig. 2 is shown in Fig. 3. If the relay has a slope of 25 percent, the relay will not operate for the external fault, since the operate current does not exceed the slope multiplied by the restraint current. The relay would operate for the internal fault, though, since the operate

current is greater than the slope multiplied by the restraint current. For more information on percentage-restrained differential protection, see [1].

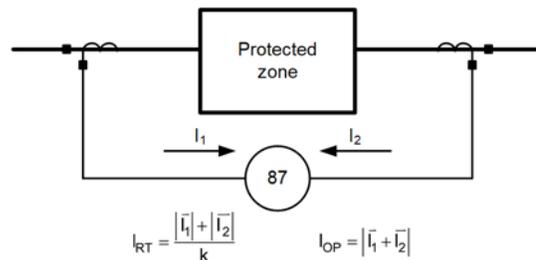


Fig. 1. Operate and restraint calculations for a percentage-restrained differential relay.

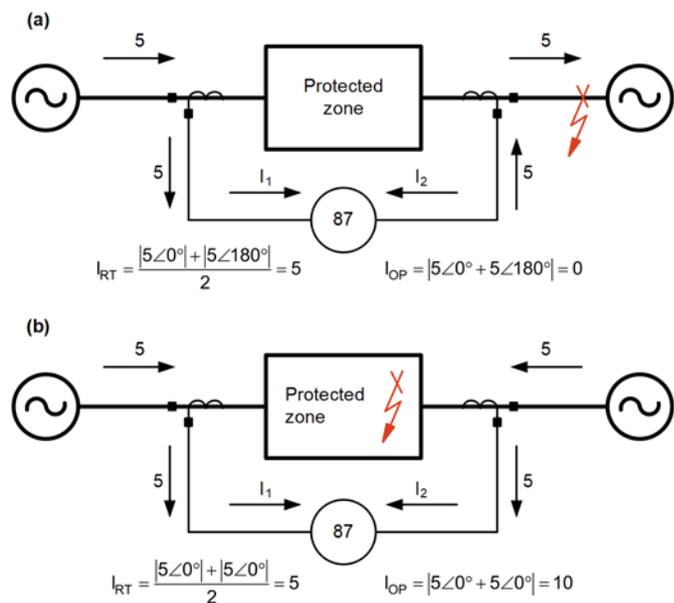


Fig. 2. Operate and restraint values for an external (a) and internal (b) fault.

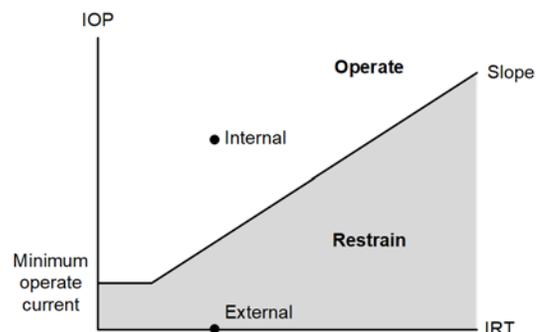


Fig. 3. Single-slope percentage-restrained differential characteristic.

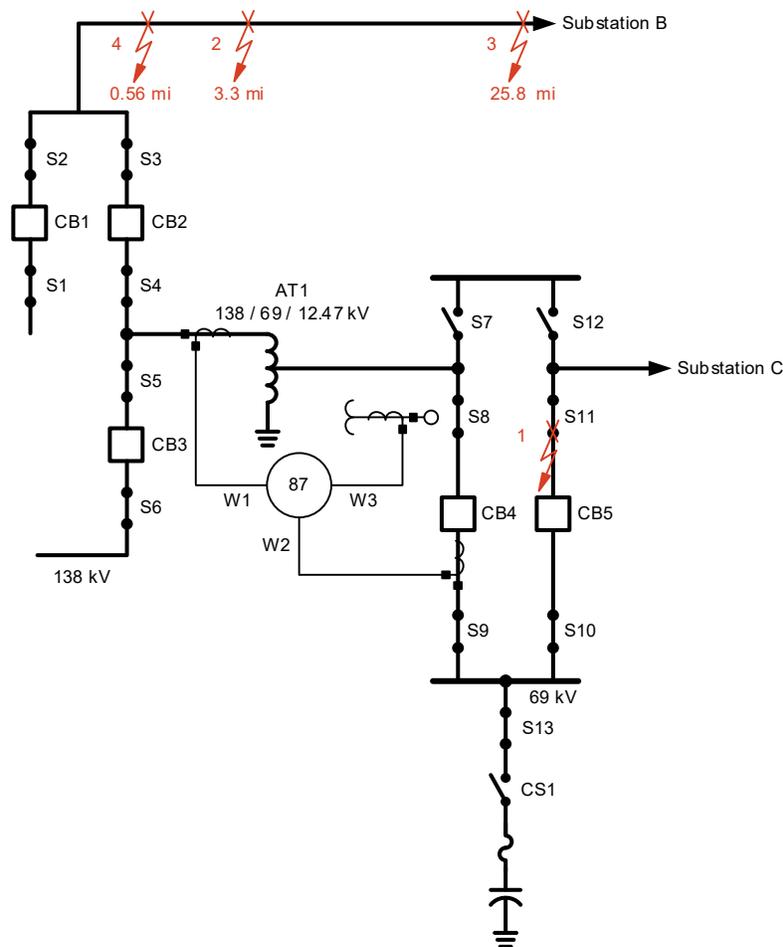


Fig. 4. One-line diagram of Substation A.

When a current differential relay is applied to a transformer, the current into the differential zone does not equal the current leaving the zone under normal conditions. Any current mismatch and shift in phase angle must be accounted for before calculating IOP and IRT. TAP settings scale each set of current inputs to compensate for current magnitude mismatches, and winding compensation settings account for changes in phase angle. A detailed discussion of this can be found in [2].

III. SYSTEM CONFIGURATION

The one-line diagram of Substation A and the system configuration at the time of the event are shown in Fig. 4. The transformer shown is a 138 kV/69 kV/12.47 kV wye-wye-delta (YYD) grounded autotransformer, with the delta tertiary used for station service. Circuit Breaker CB5, Circuit Switcher CS1, and Switches S7 and S12 were all open, effectively open-circuiting the load side of the transformer. A microprocessor-based current differential relay was protecting the transformer.

IV. THE FAULTS

The four faults that occurred near Substation A and the resulting investigation for each are described in this section.

A. First Fault

The first fault occurred on February 14 at 3:34 a.m. It was an AG fault on Switch S11 on the line side of the open circuit breaker, CB5. Fig. 5 shows the switch, where a flashover to the structure caused the switch to break away from the insulator. The location on the system is shown as Fault Location 1 in Fig. 4. Even though this fault was clearly not in the transformer relay's zone of protection, the relay tripped on the C-phase percentage-restrained differential element. The 138 kV circuit breakers (CB2 and CB3) and the 69 kV circuit breaker (CB4) opened in response.

Fig. 6a shows the filtered event report and Fig. 6b shows the raw event report retrieved from the transformer differential relay after the fault. Winding 1 (W1) currents are from the 138 kV side and Winding 2 (W2) currents are from the 69 kV side.

Analyzing the events, what immediately stands out is that the W1 currents are all approximately equal, low in magnitude, and in phase with each other. This is characteristic of zero-sequence ground current. This current is expected, since there is a long path that connects the Substation A 138 kV side to another 138/69 kV grounded autotransformer at another substation and to the 69 kV system. This provides an alternate

path for ground current to flow to the fault. The ground current will go up through the ground on the 138 kV side of the transformer at Substation A and feed the fault via this long path. This ground current will flow through the W1 CTs and be detected by the relay.



Fig. 5. First fault on A-phase of Switch S11.

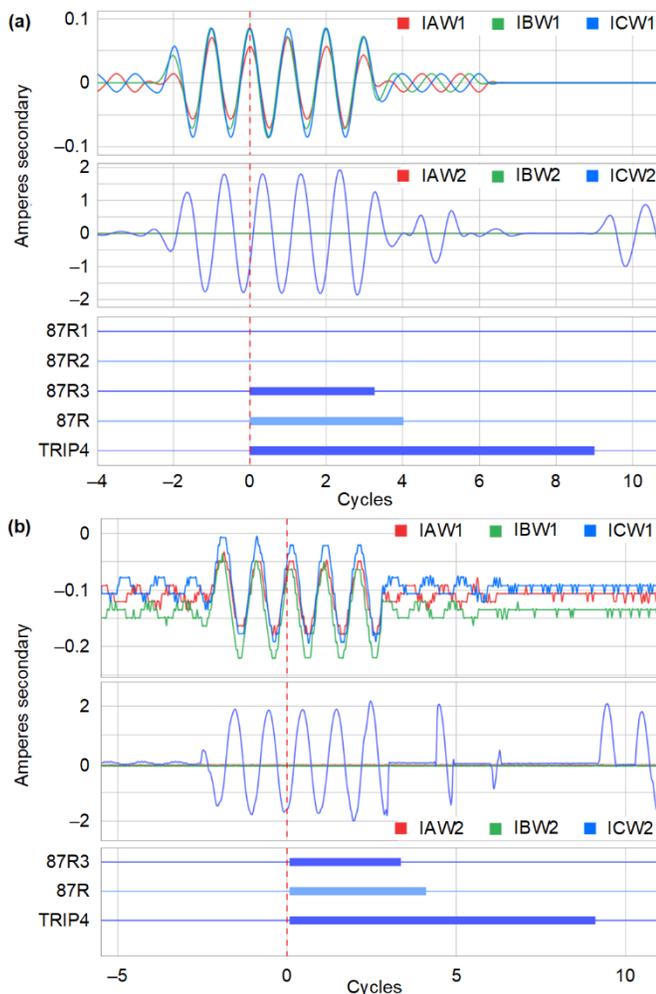


Fig. 6. Filtered (a) and raw (b) event reports from transformer relay after first fault.

The second thing of note is that W2 measured current on the C-phase. This was not expected. With the 69 kV side of the transformer isolated, as shown in Fig. 4, no current should flow on W2. The events also show that the current on C-phase W2 is arcing. This arcing continued even after the transformer tripped. The length of this arcing time was due to the remote electromechanical ground time-overcurrent relay taking 34 cycles to clear the fault.

Based on the explanation in Section II of how current differential protection works and how IOP and IRT are calculated, we can conclude that the transformer relay tripped due to the relay detecting current on W2 and very low (effectively zero) current on W1. Since current into the zone of protection did not equal current leaving the zone of protection, an operate current was present and caused the relay to trip. The relay operated correctly based on the currents it was measuring, but the question remained: Why was it measuring these currents in the first place?

Initial analysis led to the idea of a possible secondary circuit problem. Was there an issue with the CT wiring, or perhaps a problem with CT grounding? Was there a problem in the relay? Could the relay inputs not be measuring correctly? Was there any way that current detected on W1 could be induced onto W2 in the circuit boards of the relay?

Maintenance crews performed a quick, high-level investigation of the CT circuit where they verified connections at the circuit breaker and the relay, examined the equipment for flash marks, and verified that all connections were tight. Nothing unusual was found, and the transformer was put back into service while investigation continued.

B. Second Fault

One week later, on February 20 at 11:55 p.m., a BG fault occurred on the 138 kV transmission line going to Substation B, 3.3 miles from Substation A. Operations noted that the probable cause of the event was the presence of lightning storms in the area. Crews inspected the line and found no evidence of a fault. The system configuration at this time was the same as it had been when the first fault occurred, as shown in Fig. 4. The second fault was located at Fault Location 2. The transformer relay again tripped on the C-phase percentage-restrained differential element.

Fig. 7 shows the filtered event report from the transformer relay. The raw event looks similar.

Immediately evident is that the W1 currents are all exactly equal and in phase with each other, again indicating pure zero-sequence ground current. The magnitude is higher this time, since the transformer is serving as a ground source to a fault on a nearby line. W2 is again detecting current on the C-phase with the 69 kV side open. The magnitude is higher this time, as well, and there is no arcing on the W2 currents.

At this point there had been two faults when the 69 kV side of the transformer was open. Neither fault involved the C-phase, but the relay had detected current on C-phase W2 on both events. The engineers thought that this was too coincidental, so they decided to take the transformer out of

service and check the CT circuits for any issues. If no problem was found, they would replace the relay.

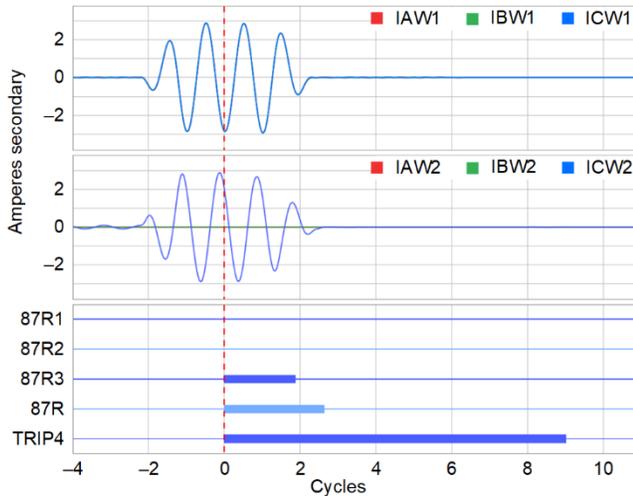


Fig. 7. Filtered event report from transformer relay after second fault.

C. Third Fault

Before any testing could be performed, the power system delivered another surprise. The next day, on February 21 at 9:56 a.m., a CG fault occurred on the 138 kV transmission line going to Substation B, 25.8 miles from Substation A. This is shown as Fault Location 3 in Fig. 4. This time, the transformer was completely isolated from the system with Breakers CB2, CB3, CB4, and CB5 all open. Operations again attributed the fault to lightning in the area, since no physical evidence of a fault was found. Although the line relay operated for this fault, the transformer relay did not trip.

D. Fourth Fault

Later that same day, at 12:58 p.m., a CAG fault occurred on the 138 kV transmission line going to Substation B, 0.56 miles from Substation A. This fault was also attributed to lightning in the area and is shown as Fault Location 4 in Fig. 4. The A-, B-, and C-phase differential elements all asserted and caused the transformer relay to trip.

Fig. 8 shows the filtered event report retrieved from the transformer relay after the fault. Since the transformer was completely isolated from the system, there should not be any currents on either of the windings. However, there is still current detected on C-phase W2.

The assertion of all three-phase differential elements was correct based on the transformer compensation settings, which were set at 12 for both W1 and W2. For further information about transformer differential compensation, see [2]. For this fault, the relay again operated correctly based on the currents that it measured. But the question remained: Why did the relay measure those currents?

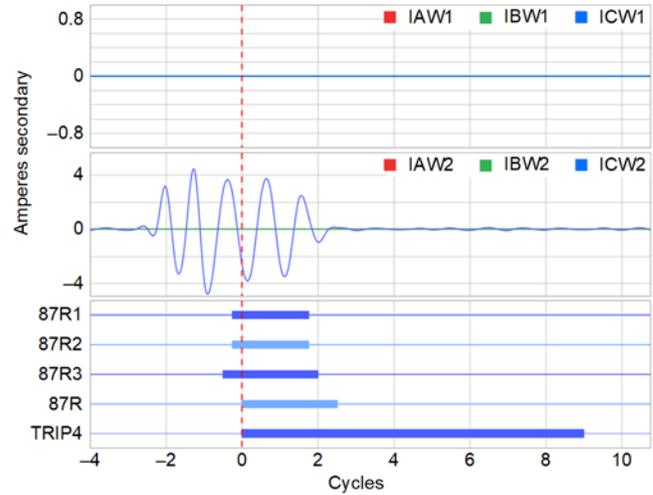


Fig. 8. Filtered event report from transformer relay after fourth fault.

V. HYPOTHESIS

What all three faults that caused the transformer relay to operate had in common was that they were all ground faults that occurred in or near the substation. When the fourth fault occurred, and the relay still detected C-phase current even though the transformer was completely isolated from the system, a new theory emerged. If more than a single safety ground existed on the W2 C-phase CT circuit, ground potential rise could cause current to flow through that circuit. If the relay's current input was in between those two grounds, the relay would measure that current.

A. Ground Potential Rise

When ground faults occur, the zero-sequence current returns to the source through the earth, as well as through other paths such as neutral conductors, overhead ground wires, and cable shields. The total zero-sequence current splits between the earth and these alternate paths [3] [4]. When a fault occurs near a substation, a large amount of current flows through the station ground grid. Because the ground grid has some impedance, the zero-sequence current flowing through it causes a voltage to develop across the grid. This is known as ground potential rise (GPR) and is illustrated in Fig. 9. IEEE 80 defines GPR as:

...the maximum electrical potential that a ground electrode may attain relative to a distant grounding point assumed to be at the potential of remote earth. [GPR voltage] is equal to the maximum grid current multiplied by the total grid resistance. [3]

The GPR voltage only defines the maximum voltage possible. The voltage will drop across the substation ground grid, resulting in a gradient of different voltages at different points on the grid, as illustrated in Fig. 9.

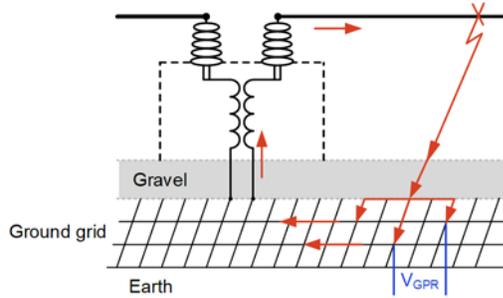


Fig. 9. Ground current flow during a ground fault causes GPR at a substation.

Similar to GPR, step potential can put workers at risk when walking through a substation when a fault occurs. When walking, each foot sits above the ground grid at a different location, and there is a voltage difference between them. Step potential is the voltage that a person would be exposed to if they were standing on the ground grid with their feet 1 m apart [3]. The risks of step potential can be minimized by taking small steps or shuffling feet when walking in a substation.

B. CT Grounding and Current Flow

In the case of this misoperation, how would GPR cause current to flow through the relay? To answer this, we must first understand the grounding recommendations for CT secondary circuits.

1) Need for Grounding of Secondary Circuits

IEEE C57.13.3-2014 Guide for Grounding of Instrument Transformer Secondary Circuits and Cases states that the secondary circuit of a CT must be grounded to protect the connected equipment and ensure safety of personnel who may come into contact with it [5]. Stray capacitances exist between the high-voltage circuit and the secondary circuit. These capacitances can cause a substantial electrostatic potential to build up between the secondary circuit and ground or between the case of the equipment and ground. Proper grounding short-circuits the capacitance between the secondary circuit and ground (or between the case and ground) and does not allow this electrostatic potential to build, ensuring the safety of personnel and connected equipment.

2) Grounding Recommendations

Each CT secondary circuit is defined as a set of three-phase secondary windings and all the coils, contacts, and other components connected to those windings by insulated metallic wires [5]. Reference [5] recommends that this circuit be solidly connected to the station grounding grid at one point only.

Common practice is to place the ground at either the CT location or in the control house. For safety, [5] recommends that the grounding of all in-service secondary circuits be at the first point of application (where the CT circuit will be used, typically a relay or a meter). This connection point is typically located in the relay panel, which is preferred because it provides the greatest amount of protection to personnel and equipment from potential overvoltages. Grounding all secondary circuits at the

relay panel also makes testing for a single-point ground easier when testing multiple circuits (e.g., during commissioning).

3) Hazards of Multiple Grounds

Reference [5] prescribes a single ground for two reasons. First, a single ground makes it easier to test the insulation of the secondary circuit, which will be discussed in Section VIII. Second, as explained in Section V, Subsection A, ground faults can cause currents to flow through the ground grid. Since the impedance of the grid is not zero, different points along the grid will be at different potentials. If the CT is grounded in two different locations, the potential difference between these locations will cause current to flow in the secondary circuit between the ground points. This can create two problems:

1. If the relay current input is in between the two grounding points, then the relay will measure this secondary circuit current flow.
2. If the neutral conductor is grounded at two separate locations, then the secondary circuit current flow can cause the conductor to overheat, therefore damaging the insulation.

Problem 1 was the primary hypothesis for the root cause of the three misoperations at Substation A.

As a side note, the presence of multiple grounds is not only a problem for relays during fault conditions, but it is also possible for multiple grounds to cause misoperations during normal load conditions. Annex C in [5] gives an example of a line relay that operated during normal load conditions when a second ground was temporarily introduced in the secondary CT circuit.

C. Finding Common Ground

To determine if the hypothesis of multiple grounds was correct, we needed to locate the unintentional ground. To lead the technicians on their search, we used data we already had to get an idea of where it might be located. First, we needed to know where the intentional ground was located on the CT circuit. Fig. 10 shows a simplified three-line diagram of the differential circuit. The intentional ground is shown at the bottom left of the drawing. This was located in the control house, on the W1 side, before the CTs connect to the relay. The drawings showed no additional ground for the W2-side CTs; the neutral connection of those CTs was connected to this common ground point as well.

We now knew where the intentional ground was located, and we also knew that current flowed through the C-phase current input (IC) on W2 of the relay. Since the primary circuit on the 69 kV side was open at the time of the faults, that open circuit would reflect on the secondary side of the CT, causing the secondary CT winding (1x2 to 1x5) to appear as an open circuit as well. Keeping this in mind, the only way for current to flow from the intentional ground through the IC input of the relay was through the highlighted path shown in Fig. 10. The unintentional ground would have to be located on the polarity side of the C-phase W2 input of the relay, as shown in Fig. 10.

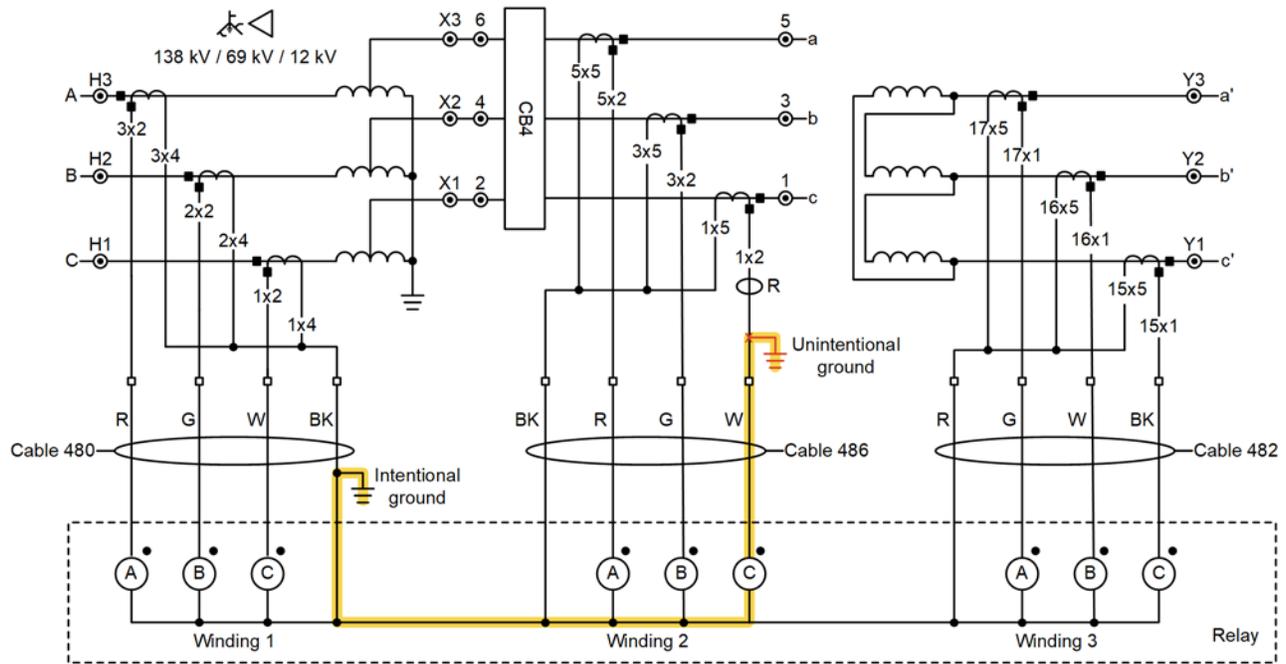


Fig. 10. Simplified three-line diagram of differential circuit.

There are several possible causes of an unintentional ground. A common cause of multiple grounds is the inadvertent specification of additional grounds on the design drawings. If a CT circuit is connected to multiple relays, it is easy to mistakenly show a ground on two different ac schematics. It is also easy to accidentally show grounds on two different terminal blocks for that circuit on the wiring diagram. Mistakes like these add multiple grounds in locations where intentional connections to ground already exist: in the relay panels. When both grounds are common to the same panel ground bus(es), current in the ground grid will take a path between them and not through the secondary input of the relay. That is why mistakes like these do not affect normal operation of the protection equipment.

In addition to design errors, technicians can accidentally make multiple ground connections on a CT circuit when wiring, such as making a connection to ground in the breaker control cabinet as well as in the control panel. We did not consider this to be the case in this instance due to the arcing that occurred in the first event. If the unintentional ground was a solid connection, then we likely would not have seen any arcing.

An unintentional connection to ground may also occur when the integrity of the insulation on the CT secondary leads has been compromised. Due to the arcing, we hypothesized that insulation breakdown was causing the unintentional ground and was the reason for the misoperations. We asked the technicians to look for an unintentional ground between the polarity side of the C-phase CT and the polarity side of the C-phase W2 input of the relay.

VI. UTILITY INVESTIGATION AND FINDINGS

To test for multiple grounds, the utility first isolated Cable 486 (shown in Fig. 10) and performed an insulation resistance test on each of the three-phase CTs to which the cable was connected. They found that the C-phase CT failed the test and had a short to ground. The A-phase and B-phase CTs passed the test with no short to ground.

Next, the utility removed the CT cover from Pole 1 (C-phase) on the 69 kV side of the transformer to inspect the CT wires. This is shown in Fig. 11.



Fig. 11. Cover of Pole 1 removed.

Fig. 12 shows a close-up view of the CT wires. The differently colored wires correspond to the different CT taps of the multi-ratio CT. The wires from the CT are run in flex conduit to the breaker control cabinet, where each wire is terminated. Cable 486 is then connected from the chosen tap points at the breaker control cabinet and routed back to the relay at the control house. Fig. 12 shows that two of the wires (red and yellow) had nicks in them. The wires were rubbing against the side of the flex conduit coupler.

The red wire in Fig. 12 is connected to 1x2, and the yellow wire is connected to 1x4. Fig. 10 shows that 1x2 is brought back to the relay via the white wire in Cable 486. This wire hits the polarity side of the C-phase W2 input on the relay, which is exactly where the phantom current in the event reports was measured.

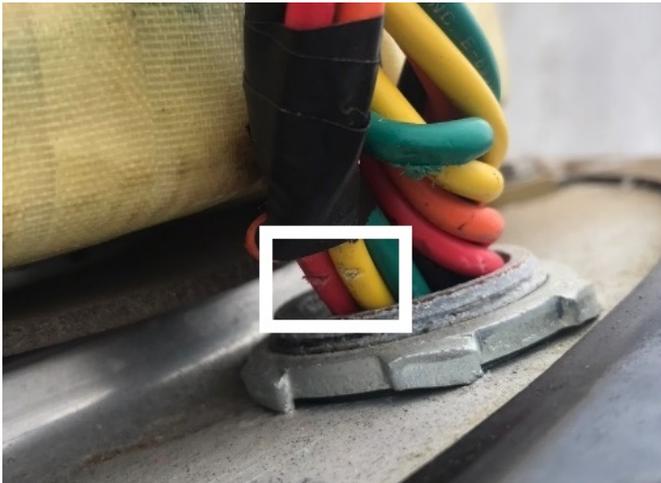


Fig. 12. Nicked CT wires (red and yellow).

One may initially think that the nicks on the yellow wire (1x4) could not cause an issue since that wire corresponds to an unused tap on the multi-ratio CT. The yellow wire is terminated at the breaker control cabinet and not brought back to the relay. Fig. 13, however, shows how the unintentional ground on the yellow wire could have also caused a problem if the 69 kV side of the transformer had not been open. If 1x4 and 1x5 are both grounded, it effectively creates a short circuit on the secondary side of the CT between 1x4 and 1x5 (highlighted path). This short will cause all the current on the secondary side of the CT to circulate in this highlighted path, instead of forcing the desired ratio current to flow between 1x2 and 1x5. A similar issue could have occurred due to the unintentional ground on the red wire, with current circulating in the short circuit between 1x2 and 1x5, and not being sent to the relay. A misoperation could have easily occurred for either of these cases since the relay would not be measuring correct ratio current.

When the technicians discovered the nicks in the CT wires, they moved the wires to prevent them from contacting the conduit coupler. Before the wires could move again, they quickly performed another insulation resistance test, which passed. Because they were able to turn the problem on and off, root cause was confirmed.

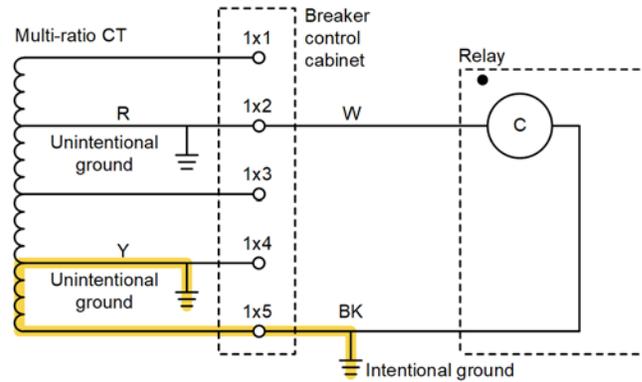


Fig. 13. Ground current path due to unintentional ground on yellow wire.

To repair the issue permanently, the technicians first applied electrical tape to the individual conductors, to cover and insulate any exposed wiring. They then bundled the conductors and secured them together. Cork was then inserted into the flex coupler to prevent the cables from contacting and wearing against the side of the coupler. This final solution is shown in Fig. 14. The technicians performed a final insulation resistance test on the CTs and Cable 486 and everything passed.



Fig. 14. Corrective action.

VII. RECOMMENDATIONS

Proper grounding of secondary CT circuits is important. In this section, we provide recommendations for grounding and guidance on how to test for multiple grounds during commissioning and troubleshooting.

A. Follow Grounding Recommendations in IEEE C57.13.3

As mentioned in Section V, [5] gives recommendations for the proper grounding of secondary circuits. A summary of these recommendations follows:

1. Connect each instrument transformer secondary circuit to ground via a single connection point.
2. Place the ground in the relay panel to provide greatest protection to personnel and equipment.
3. Connect the ground in a way that allows for convenient conduction of a ground/unground test as described in Section VIII. We recommend placing the ground on the field side of the relay panel terminal block. This reduces the likelihood of a CT becoming ungrounded if any panel wiring is disturbed.

B. Grounding Differential Circuits

In electromechanical differential relays, all CTs associated with the differential relay had to share a single ground. The reason for this was due to the electromechanical relay sharing operate and restraint coils between all the connected CTs on a single phase. This caused the CTs to be electrically connected inside the relay, as shown in Fig. 15. Grounding each CT individually would cause multiple grounds in the differential circuit, which, as we have seen, can cause undesired current to flow through the relay and result in misoperations.

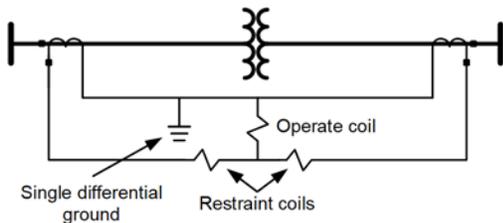


Fig. 15. Electromechanical differential relay connection diagram.

In modern microprocessor-based differential relays, each set of CT inputs is isolated from one another. Because they are no longer electrically connected, each CT circuit can be grounded individually. Individual grounding of CT circuits is preferred for multiple reasons. First, the insulation integrity test described in Section VIII yields more accurate results when measuring a single circuit versus multiple circuits in parallel. Second, with each CT circuit grounded individually, the possibility of having a design error with a ground at each location where a CT cable lands on a panel is minimized.

C. Test for Multiple Grounds

It is common practice to test for a single point ground on CT circuits during substation commissioning. This can be done using the two tests described in Section VIII.

VIII. TESTING FOR MULTIPLE GROUNDS

Two common tests are performed that confirm the existence of a single ground on a CT circuit: the insulation resistance test and the ground/unground test. The purpose of these two tests, as well as how they are performed, are described in the following.

A. Insulation Resistance Test

The purpose of an insulation resistance test (or insulation integrity test) is to identify any damage that may have occurred to the cable insulation when the CT cable was pulled from the substation yard to the control house. IEEE 525-2016 recommends that the test be performed before connecting the cable to any equipment [6].

The test is performed by first isolating the cable from any known grounds. Use a megohmmeter to apply a high dc voltage (a minimum of 500 V is required, per [6]) between the cable and ground, and simultaneously measure the resistance between the cable and ground. Since the cable is isolated from ground, no current should flow through it and it should measure a very high resistance (in the $M\Omega$ range for an open circuit). If current flows through the cable, then the measured resistance will be low, indicating an unintentional path to ground.

The following procedure for performing an insulation resistance test is outlined in [7], and Fig. 16 shows a typical test setup:

1. Disconnect the cable from all equipment and circuits.
2. Discharge all stored capacitance in the cable by grounding each conductor.
3. Connect the line terminal of the megohmmeter to the conductor being tested.
4. Connect all other conductors together and to ground. Connect this point to the Earth terminal of the megohmmeter.
5. Perform test.

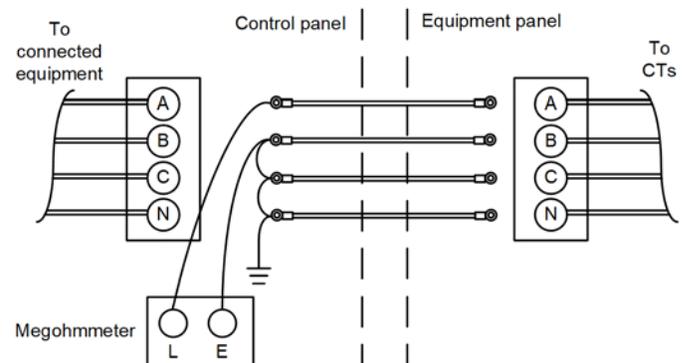


Fig. 16. Insulation resistance test connections

The minimum acceptable resistance (in $M\Omega$) measured by the megohmmeter is calculated using (1).

$$R_{M\Omega} = (kV_{RATED} + 1) \cdot \left(\frac{1,000}{L_{CABLE}} \right) \quad (1)$$

where:

kV_{RATED} = rated cable voltage in kV.

L_{CABLE} = length of the conductor under test in feet.

The typical insulation rating for CT secondary circuits is 600 V, and in some cases 1,000 V. Table I lists the minimum acceptable resistance values for various lengths of 600 V and 1,000 V cable based on (1).

TABLE I
MINIMUM ACCEPTABLE RESISTANCE VALUES FOR VARIOUS LENGTHS
OF 600 V AND 1,000 V CONTROL CABLE

Length (ft)	R (M Ω)	
	600 V Cable	1,000 V Cable
100	16.00	20.00
200	8.00	10.00
300	5.33	6.67
400	4.00	5.00
500	3.20	4.00
600	2.67	3.33
700	2.29	2.86
800	2.00	2.50
900	1.78	2.22
1,000	1.60	2.00

B. Ground/Unground Test

The purpose of the ground/unground test is to prove the existence of a single ground point on the circuit after all CT leads have been connected to the equipment and all intentional grounds have been landed. This test should be performed first during substation commissioning and again during routine maintenance testing. Performing this test regularly can detect problems before they cause misoperations.

This test is performed by first confirming that a connection to ground exists on all three phases. The intentional ground is then removed, and another test is performed to confirm that there is no longer a connection to ground on any phase.

This test can be performed with either a megohmmeter or a multimeter. A megohmmeter is preferred, as it will detect any unintentional ground point, whether they are solid ground connections or due to insulation degradation. Using a multimeter will only detect intentional grounds. If you are using a megohmmeter for the test and want to leave the connected equipment connected, consult the equipment manufacturer prior to performing the test to ensure that the equipment is rated for the test voltage [8].

The procedure for performing a ground/unground test proceeds as follows:

Part I (shown in Fig. 17a)

1. Perform this test at the location of the known ground, with all the control cables landed on terminal blocks.
2. Do not remove the known ground.
3. Connect the line lead from the megohmmeter (V/ Ω lead if using a multimeter) to the neutral terminal block.
4. Connect the earth lead from the megohmmeter (COM lead if using a multimeter) to the known ground.
5. Run the test. The test should result in a low resistance measurement because a ground is present.

Part II (shown in Fig. 17b)

1. Disconnect the known ground from the CT secondary circuit.
2. Run the test again. The test should result in high resistance values in the megaohm range.
3. If a low resistance value is still read, this indicates an additional ground in the circuit. Locate and remove the additional ground. Repeat the test until all unintentional grounds have been identified and removed.
4. Reconnect the intentional ground and perform Part I again to confirm the ground has returned.

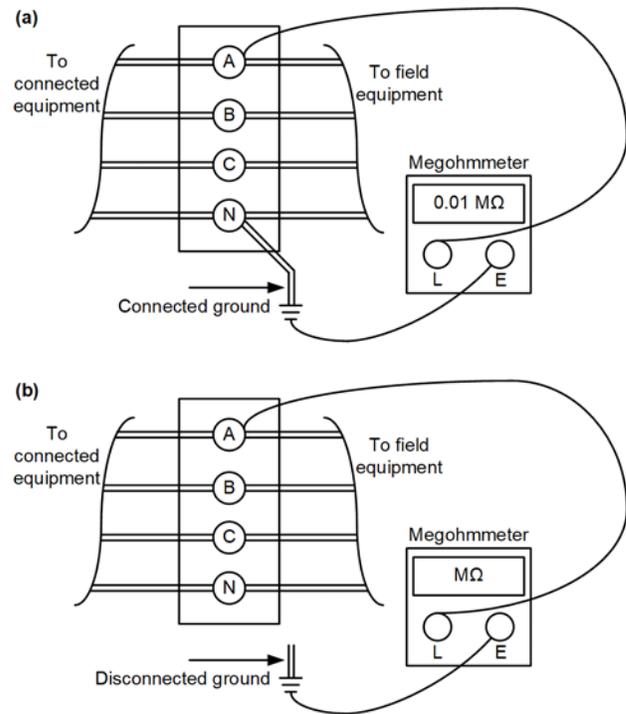


Fig. 17. Connections for ground/unground test using a megohmmeter, Part I (a) and Part II (b).

IX. CONCLUSION

This paper presents a series of transformer relay operations that were caused by an unintentional second ground on a secondary CT circuit. It explains how multiple grounds can cause protection system misoperations during external faults and addresses the importance of having only a single ground in secondary CT circuits. It also shares recommendations for proper grounding and shows two methods to detect multiple grounds during commissioning.

X. ACKNOWLEDGMENT

The authors would like to thank Mr. Bill Fleming, senior application engineer with Schweitzer Engineering Laboratories, Inc., for his assistance with this event analysis.

XI. REFERENCES

- [1] M. Thompson, "Percentage Restrained Differential, Percentage of What?," proceedings of the 37th Annual Western Protective Relay Conference, Spokane, WA, October 2010.
- [2] B. Edwards, D. Williams, A. Hargrave, M. Watkins, and V. Yedidi, "Beyond the Nameplate – Selecting Transformer Compensation Settings for Secure Differential Protection," proceedings of the 70th Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, April 2016.
- [3] IEEE 80-2000, IEEE Guide for Safety in AC Substation Grounding, 2000.
- [4] IEEE 367-2012, IEEE Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage From a Power Fault, 2012.
- [5] IEEE C57.13.3-2014, IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases, 2014.
- [6] IEEE 525-2016, IEEE Guide for the Design and Installation of Cable Systems in Substations, 2016.
- [7] P. Gill, *Electrical Power Equipment Maintenance and Testing*, CRC Press, Boca Raton, FL, 2009.
- [8] IEEE C57.13.1-2017, IEEE Guide for Field of Testing of Relaying Current Transformers, 2017.

XII. BIOGRAPHIES

Matthew Boecker received his BSE in Electrical Engineering in 2010 and MSE in Electrical Engineering in 2016 from the University of Texas, Austin. He is a licensed professional engineer in the state of Texas and currently works at the Lower Colorado River Authority (LCRA) in Austin, Texas. His work experience has been in system protection.

Genardo Corpuz received his BSE in Electrical Engineering from the University of Texas, Austin in 2005. He is a licensed professional engineer in the state of Texas and currently works at the Lower Colorado River Authority (LCRA) in Austin, Texas. His work experience includes substation design and system protection.

Jared Candelaria earned a BSEET from The Metropolitan State University of Denver in 2007, then an MSEE from the University of Colorado at Denver in 2012. Jared joined Schweitzer Engineering Laboratories, Inc., (SEL) in 2012 and is currently an application engineer in Lakewood, Colorado. Prior to joining SEL, Jared worked at consulting firms in the Denver area doing substation design, commissioning, and system protection. He is an IEEE member and a registered professional engineer in Colorado and California.

Ariana Hargrave earned her BSEE, magna cum laude, from St. Mary's University in San Antonio, Texas, in 2007. She graduated with a Master of Engineering degree in electrical engineering from Texas A&M University in 2009, specializing in power systems. Ariana joined Schweitzer Engineering Laboratories, Inc. in 2009 and works as a senior protection application engineer in Fair Oaks Ranch, Texas. She has published over 20 application guides and technical papers and was honored to receive the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017 and 2018. She is a senior IEEE member and a registered professional engineer in the state of Texas.