Loss of Effective System Grounding – Best Practices, Protection Challenges, and Solutions

Darren De Ronde, Rick VanHatten, and Austin Wade
Schweitzer Engineering Laboratories, Inc.

Presented at the
69th Annual Georgia Tech Protective Relaying Conference
Atlanta, Georgia
April 29–May 1, 2015

Previous revised edition released October 2014

Originally presented at the
41st Annual Western Protective Relay Conference, October 2014

Loss of Effective System Grounding – Best Practices, Protection Challenges, and Solutions

Darren De Ronde, Rick VanHatten, and Austin Wade, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Typically, high-voltage transmission systems are effectively grounded through the wye windings of transformers and autotransformers. If a ground fault occurs on the system, a ground overcurrent relay or impedance relay recognizes the zero-sequence current flow and takes the appropriate action. Having an effectively grounded system allows protection engineers to use simple methods to detect and isolate ground faults. What happens, then, if the ground source is removed in order to clear a fault? Can the resulting system be left ungrounded with adequate protection and continue serving load? Ungrounded systems can often be avoided with proper planning and design. When this is not possible, a thorough understanding of the system behavior and the application of voltage protection schemes can provide an acceptable solution.**

This paper introduces why effectively grounded systems are preferred and offers ways to avoid situations where an effective ground might be removed. For systems where such situations are unavoidable, the paper provides insight and details about protection design options. Additionally, transient conditions that occur when switching from grounded to ungrounded operation are investigated. Finally, the paper examines a real-world event from a system that lost effective grounding.

I. Introduction

Grounding affects the types of protection schemes that are implemented in any power system because systems ranging from ungrounded to effectively grounded respond differently to disturbances and faults. Voltage-based schemes are implemented for ungrounded systems. Current-based schemes are implemented for effectively grounded systems. Following common grounding standards provides common protection practices, which are usually sufficient for system-wide protection. However, protection engineers need to understand and recommend the appropriate grounding and then apply the necessary protection because exceptions do exist that require a special approach. This paper discusses a case study in which a particular system can change between effectively grounded and ungrounded and remain in service through normal switching and fault clearing. It provides a theoretical view of how ungrounded and grounded systems behave as well as techniques for providing proper protection for both. Drawing upon an actual event, the paper further shows how the system behaved before, during, and after the transition from effectively grounded to ungrounded. A proper understanding of grounding can prevent or alleviate system design problems while offering economical and time-effective engineering solutions at any stage of a project.

II. Ungrounded Systems

As the name indicates, an ungrounded system does not intentionally connect the neutral to ground. While no physical connection exists, the system is pseudoconnected to ground through line-to-ground capacitances. A unique advantage of running a power system ungrounded is the ability to operate indefinitely with a fault on one phase [1]. There are two main reasons why this is possible. The first relates to the magnitude of the ground fault current. The virtual connection to ground through line-to-ground capacitances, as shown in Fig. 1, is a near infinite impedance, thus causing any zero-sequence current flow to be very low.

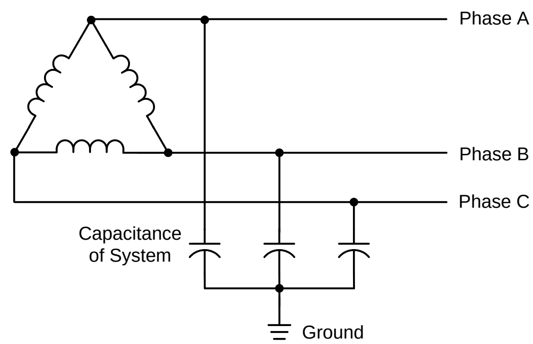

Fig. 1. Line-to-Ground Capacitance of an Ungrounded System

The second reason relates to the voltage vector triangle. A single-line-to-ground (SLG) fault only shifts the system neutral voltage to the faulted phase. The phase-to-phase voltage vector triangle stays relatively intact, allowing the system to continue to be operational [2]. Fig. 2 shows the voltage vector triangle shift between an ungrounded, unfaulted system (a) and a system with an SLG fault on Phase A (b).

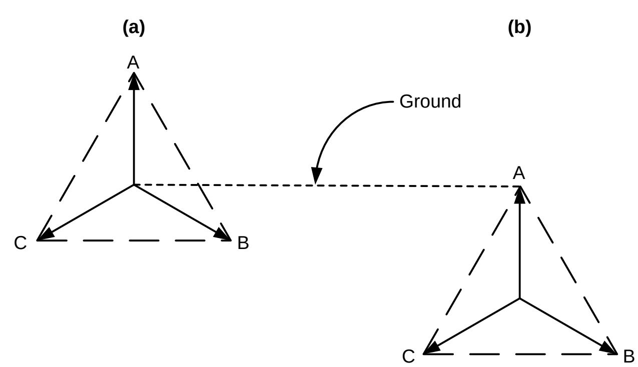

Fig. 2. Voltage Vector Triangle for an Unfaulted System (a) and a System With an SLG Fault (b)

A. Typical Applications of Ungrounded Systems

Ungrounded systems are best suited to facilities with critical loads. For example, in industrial facilities that manufacture products with long production cycles, power loss would ruin an entire batch or process. The auxiliary bus of a generation plant, which supplies power to critical oil lube pumps and cooling water pumps for the generator, is another commonly ungrounded system. Ungrounded systems allow operators to conveniently time an outage to locate and clear a fault [3].

B. Ground Fault Protection for Ungrounded Systems

Zero-sequence current magnitudes in ungrounded systems do not change enough to apply a traditional overcurrent scheme. Flux balance current transformers (CTs) can be applied on medium- and low-voltage systems if the conductors are insulated. Otherwise, voltage-based schemes must be used to detect problems. Voltage-based schemes operate by looking at zero-sequence voltages developed during unbalanced conditions. Relay pickups are set above normal unbalanced fluctuations but sensitive enough to detect when the system is connected to ground.

1) Measuring Zero-Sequence Voltage

Voltage protection on ungrounded systems requires a connection to three phase instrument voltage transformers (VTs). The secondary sides of the three phase VTs are connected together in a broken-delta configuration, and two wire leads are brought to a single overvoltage relay. A stabilizing resistor can be used to dampen out transients. Zero-sequence current that circulates in the delta develops a voltage according to the impedance of the transformer winding. The voltage is across three windings, so the relay connected to the broken delta measures 3V0.

2) Calculating Zero-Sequence Voltage

Measuring 3V0 only requires two wires but does not provide individual phase measurement of the voltage. Modern microprocessor-based relays make it possible to calculate 3V0 values internally when connected to all three phases by computing the phasor sum of all three phase-to-ground quantities, as shown in (1).

$$3V0 = \overline{VA} + \overline{VB} + \overline{VC} \tag{1}$$

C. Problems With Ungrounded Systems

There are two significant tradeoffs for using an ungrounded system.

1) Voltage Ratings and Transients

While ground fault current is limited during a fault when a system is operated ungrounded, operating ungrounded does not minimize voltage stress on equipment. Notice in Fig. 2 that during the SLG fault, the faulted phase potential decreases nearly to zero and the potential on the unfaulted phases increases by a factor of 1.73. Therefore, power system equipment on ungrounded systems must be rated for line-to-line voltages. Adding insulation on low-voltage equipment is relatively easy but becomes increasingly cost-prohibitive at higher voltages due to the extra size and insulation material required.

Not only must an ungrounded system contend with line-to-line voltages, it must also contend with transient voltages that can exceed 5 per unit of nominal system voltage if restrikes occur in quick succession [4]. Voltage transients decrease quickly on effectively grounded systems because there is a low-impedance path to ground. Ungrounded systems have a high-impedance path to ground through line-to-ground-connected equipment, such as instrument transformers, surge arresters, and natural capacitance. These high-impedance paths cause transients to decrease slowly and may not quickly subdue voltage spikes. A situation could develop where multiple restrikes from arcing ground faults lead to a buildup of voltage several times the nominal peak line-to-neutral voltage [5].

To illustrate, Fig. 3 shows an ideal case with no dampening. The system is pseudoconnected to ground through line-to-ground capacitances and capacitor current leads the voltage by 90 degrees [6]. V_S is a normal voltage waveform used as reference. The dashed line is the deviation from the normal voltage waveform caused by the voltage capacitance (V_C) and the reference voltage (V_S). When the reference voltage reaches the first peak in Fig. 3, the arc self-extinguishes because the current is at zero, but the system capacitance holds the voltage. The system voltage continues its cycle according to the new reference point, resulting in the deviation waveform. The voltage difference reaches twice the original voltage at the negative peak of the reference voltage and a restrike occurs. The momentary connection to ground changes the capacitance offset voltage by an additional 2 per unit. In the next half cycle, the voltage difference reaches four times the initial value and a second restrike occurs. At this point, an insulation failure and permanent fault is likely [7].

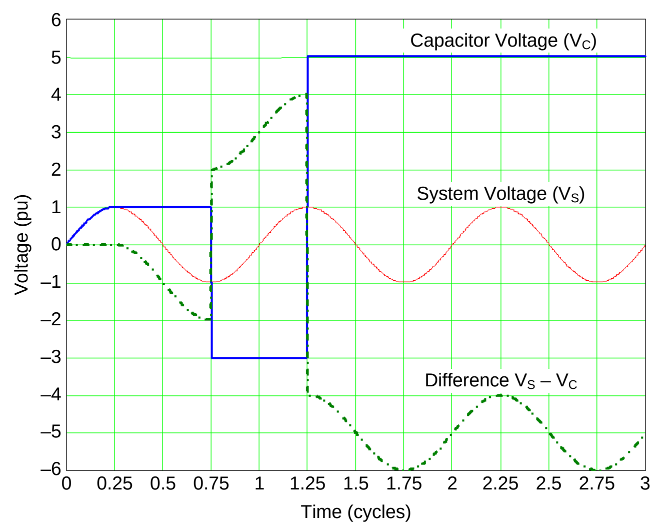

Fig. 3. Transient Overvoltage From a Restriking Ground Fault

2) Selectivity

As stated previously, ground faults on ungrounded systems have small levels of current flowing to the fault, so it is generally not possible to accurately locate the fault based on current. Voltage-based schemes can only tell if there is a fault somewhere on the system. Therefore, operators have to isolate individual sections and determine where the fault is by trial and error, which can take hours in some cases.

III. Effective Grounding

Typically, most high-voltage systems are effectively grounded. One reason for this can be found in the definition of an effectively grounded system in the National Electric Safety Code (NESC), which states:

> An effectively grounded system is intentionally connected to earth through a ground connection or connections of sufficiently low impedance and having sufficient current carrying capacity to limit the buildup of voltage levels below that which may result in undue hazard to persons or to connected equipment. [8]

In contrast to ungrounded systems, where high voltages can develop, effectively grounded systems prevent such occurrences. The tradeoff is high ground fault current, which must be interrupted quickly to prevent equipment damage. Current-based schemes are used and, with proper coordination, can provide selective isolation of ground faults. Even though load interruption occurs, effectively grounded systems are generally preferred for transmission systems because of selectivity and the avoidance of voltage buildup. There are a few ways to effectively ground a system.

A. Wye-Connected Transformers

Wye-connected transformers can be used on ungrounded systems by simply not connecting the neutral point to ground. Most of the time, though, the neutral is connected to ground because the wye-connected transformer provides a convenient location for an effective ground connection that does not require any additional capital costs. The transformer generally has to have a second winding, configured as a delta connection, that provides a low-impedance path for the flow of zero-sequence current, which establishes the system ground reference.

When applying a two-winding delta-wye or wye-delta transformer, it is important to understand which connection to apply to which side. Common practice dictates placing the delta connection on the source (upstream) side and the wye on the load (downstream) side. Grounding the wye on the downstream side allows zero-sequence current to flow from the grounded neutral connection through the wye transformer winding and downstream to the ground fault. The high-side delta functions as a zero-sequence current filter, thus allowing greater selectivity and higher sensitivity for relaying purposes [9]. Large power transformers are costly long-lead items, so it is important to make the right choice on transformer configurations during the system design and planning phases.

B. Grounding Transformer

As the name implies, grounding transformers provide a ground source to the system. If a ground path cannot be added without reconfiguring a power transformer, a grounding transformer can be a more cost-effective solution. Grounding transformers are shunt connections to ground and do not have to be rated for the full megavolt-ampere load of the system, making them much cheaper and smaller than replacement power transformers. Two common types of grounding transformers are two-winding grounded neutral wye-delta and zig-zag. The grounded neutral wye-delta transformer is connected with the wye to the primary and the delta unloaded. This allows zero-sequence current to flow from the wye neutral connection through each of the phase windings in the primary. Even though the delta winding is unloaded, zero-sequence current circulates inside the delta-connected windings. The zig-zag transformer has six coils wound around three magnetic cores. The two coils on each magnetic core are from different phases and are wound in opposite directions from each other, allowing the ampere-turns from zero-sequence current produced by the coils to balance each other, resulting in low series impedance for the zero-sequence current [10].

IV. Case Study

A. Description of the System

Fig. 4 shows a basic one-line drawing of the system in this case study. It consists of a 230 kV line source feeding parallel 230/60 kV transformers to a 60 kV bus, a 60/4 kV transformer feeding a radial load, and a short transmission line to a 60/12 kV substation feeding a radial load. During normal operation, either Transformer A or B is in service and either Transformer D or E is in service. The offline transformers serve as standbys.

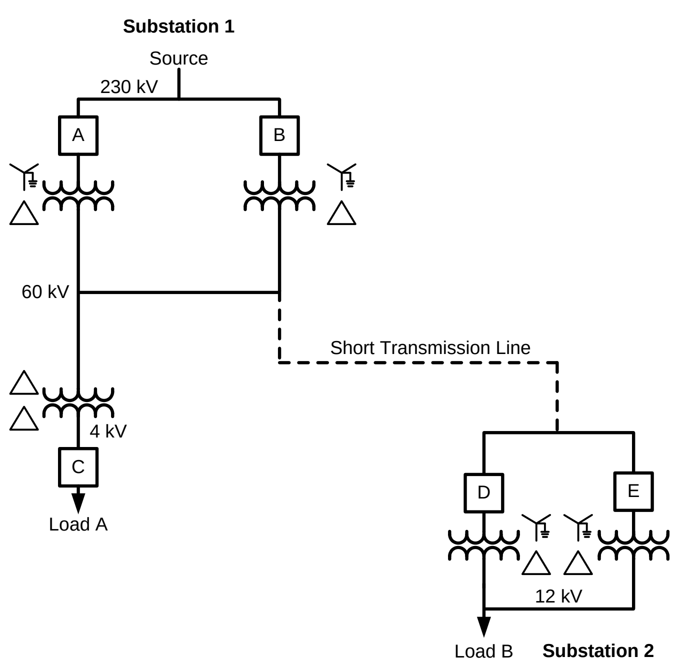

Fig. 4. Portion of the System With Transformer Configurations

B. Identifying the Problem

This case study covers three issues with the system. First, notice the configuration of Transformers A, B, D, and E. The delta-wye configuration is reversed from the one discussed previously; the transformers are oriented with the delta winding on the load side and a grounded wye on the source side. Transformer C is delta-delta and therefore does not have a ground connection. The 60 kV system is effectively grounded through the wye winding of Transformer D or E. Second, the effective ground connection is downstream from Breakers D and E. If both breakers open, the 60 kV system will no longer be effectively grounded. However, the system could remain in service and still serve load through Transformer C. Third, notice that the 60 kV transmission line is connected directly to the 60 kV bus. Depending on the type of fault on the transmission line, Breakers A and B might not need to trip.

C. Solutions to the Problem

The obvious solution is to reconfigure the delta-wye transformer windings so that the delta side is connected to the source and the grounded wye is connected to the load. Because the system is radial, there would always be a ground connection while in service. However, this project already had all the power transformers ordered and built, so replacing them was deemed too costly.

The next logical alternative is to install a grounding transformer on the 60 kV bus and remove the ground connections on Transformers D and E to allow for easier coordination, as shown in Fig. 5. While purchasing and installing a grounding transformer on the 60 kV system is far less costly than replacing the power transformers, it would still require a large capital investment and delay the schedule.

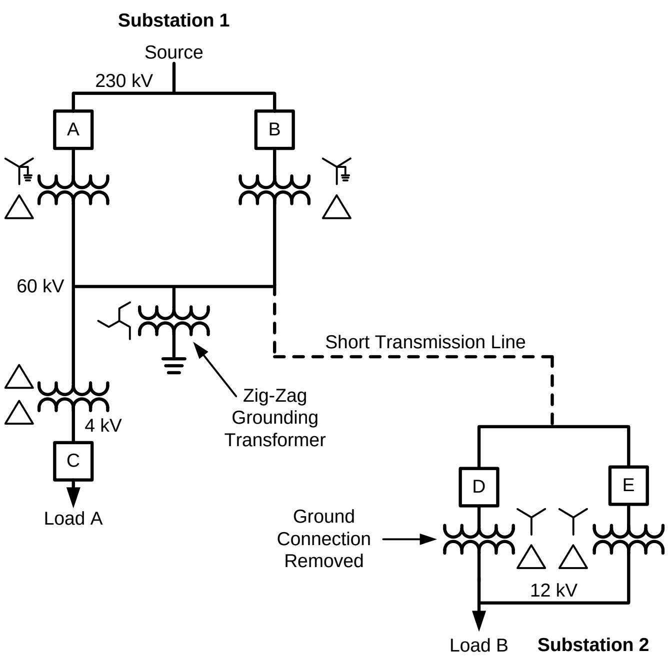

Fig. 5. Implementing a Grounding Transformer

In this case study, the solution selected was a protection scheme covering both grounded and ungrounded scenarios. The drawbacks of possibly operating ungrounded were acceptable compared to the large capital costs of effectively grounding.

D. Implementing the Protection Scheme

Protecting a system during effectively grounded and ungrounded power system states requires a combination of current and voltage protection. Fig. 6 shows a sample of the relays applied to provide protection.

Relay 1 contains overcurrent and distance elements to protect the line toward Breakers D and E. Because a ground source does not exist behind the relay, the distance elements will not operate for a phase-to-ground fault on the line. Further explanation of this is provided in Section V.

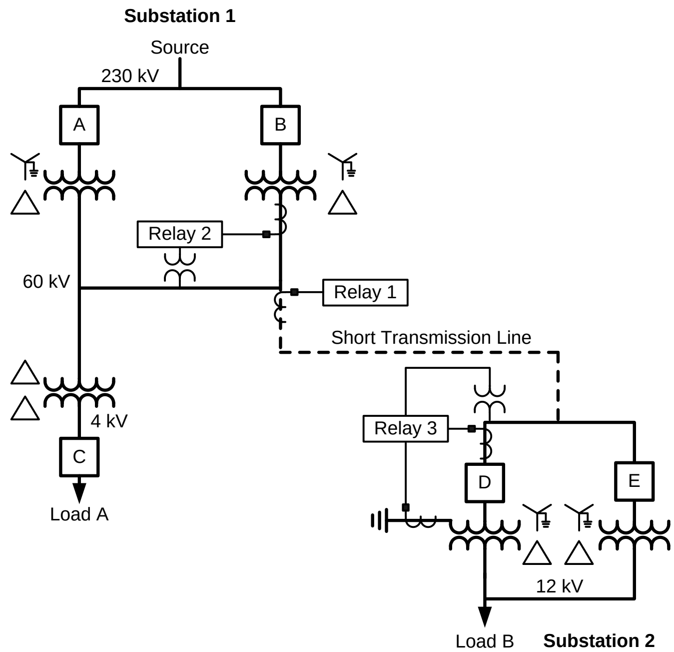

Fig. 6. Relaying Applied to the 60 kV System

Relay 2 contains zero-sequence voltage elements to protect the 60 kV bus. The voltage-based scheme uses a relay connected to the bus VT for zero-sequence voltage detection. This application requires measuring all three phase voltages, measuring or calculating 3V0 for ungrounded protection, and implementing a stabilizing resistor to dampen transients caused by switching or temporary faults. In addition, only one bus VT secondary winding is available for relaying. In order to measure phase voltage values and 3V0 from the same VT, there are two connection options.

The first option is a typical four-wire connection, as shown in Fig. 7. The stabilizing resistors are connected phase-to-neutral and, thus, dissipate power under normal conditions. Sizing the resistors for a four-wire connection requires balancing the volt-ampere rating of the VT with physical space constraints and acceptable resistor power consumption. Note that the lower the ohmic value of the resistor, the faster the system can be damped, but also the more power that is consumed during normal conditions.

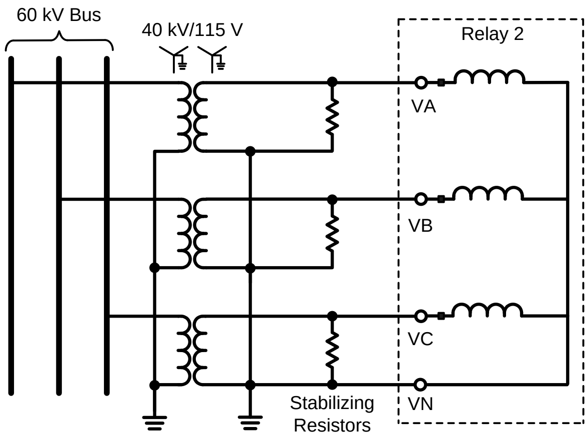

Fig. 7. Four-Wire VT Connection

The second option is a six-wire connection, as shown in Fig. 8. The stabilizing resistor is connected phase-to-phase across the broken delta. This method minimizes power losses because current only flows through the resistor during unbalanced or transient conditions and eliminates the need to balance power consumption with system dampening speed. Instead, the resistor size is only dictated by the volt-ampere rating of the VT. With this connection, the relay can measure all voltage values, including V_{LN}, V_{LL}, V1, V2, and 3V0.

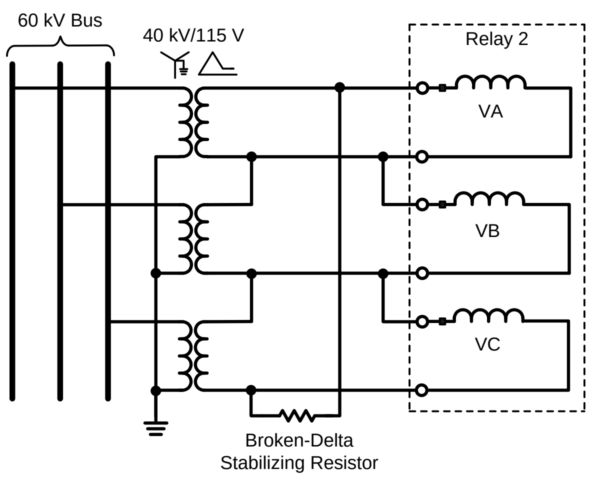

Fig. 8. Relay 2 Six-Wire VT Connection

The six-wire connection is a feature not available in all relays. Careful selection of a relay with six connections at the beginning of the design can save years' worth of operating costs on electricity usage alone. While the relay needs six voltage connections for this application, only four conductors are required between the VT and the relay, which can be helpful for retrofit projects. For these reasons, the six-wire connection was determined to be the best choice for this application.

During a transition from a grounded to an ungrounded state, the system naturally experiences a voltage transient as it finds its new ground reference point. The switching transient only lasts a few cycles before the stabilizing resistor dampens out the transient effects and brings 3V0 back to zero. Therefore, a short time delay of 6 cycles is applied to the zero-sequence voltage relay to prevent it from misoperating. If a ground fault persists after the ground source has cleared, the relay will operate and trip the 230 kV breakers after this short delay to prevent the system from operating with a standing fault. Tripping quickly avoids scenarios where the fault evolves into a multiple-line-to-ground fault as well as the possibility of restrikes causing larger voltage spikes.

Relay 3 contains transformer differential and neutral overcurrent elements to protect Transformer D. Notice that ground faults on the transmission line or 60 kV bus are detected by this relay when the high-side breaker is closed.

V. Event Analysis

On October 14, 2013, the system was operating with Breakers B, C, and D closed, as shown in Fig. 9. A fault occurred on the system that tripped Breaker D and caused an outage to Load B. During the fault, several relays picked up fault conditions; however, only Breaker D tripped, as shown in Fig. 10. While working through power restoration, system operators discovered that a bird had caused the fault on the 60 kV transmission line. They questioned why the upstream source Breaker B did not trip. The event reports were reviewed to determine if the protection design had operated as intended.

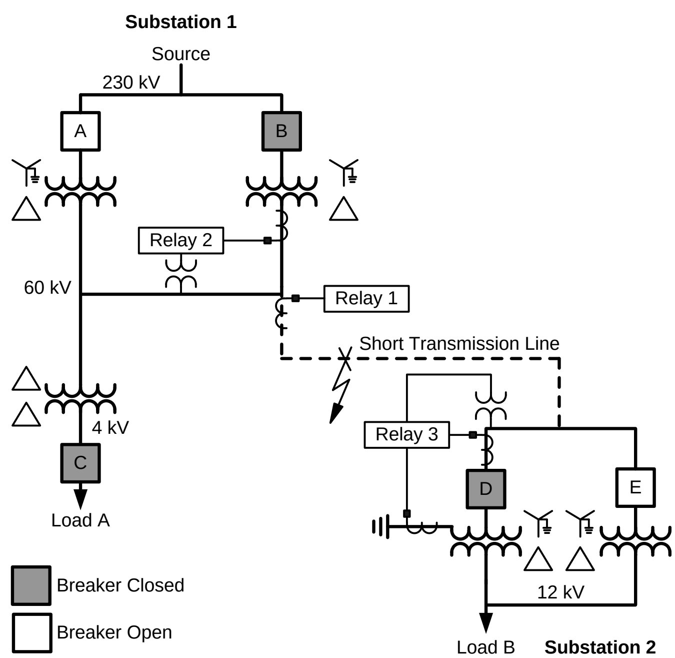

Fig. 9. System Configuration During a Ground Fault

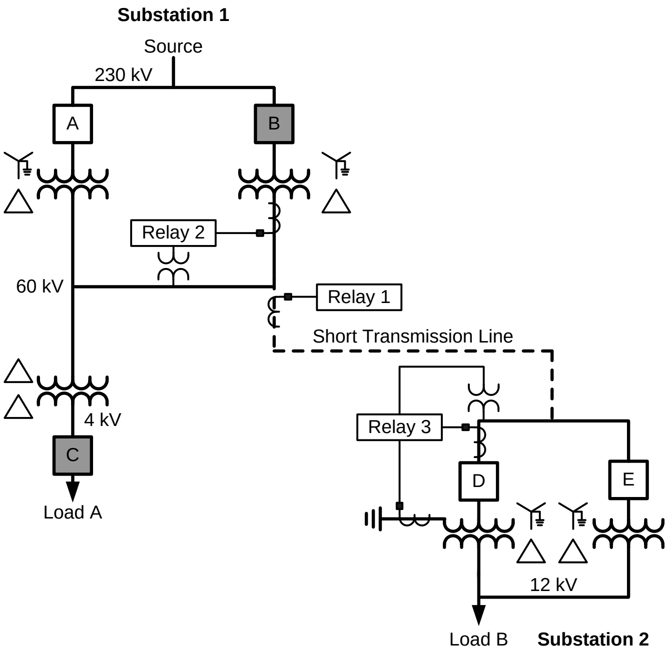

Fig. 10. Post-Fault System Configuration

A. Sequence of Events

Event reports were gathered from three relays on the 60 kV system. Each relay was synchronized with satellite clocks in order to ease event comparison. At 3:45 p.m. and 16.440 seconds, Relay 1 picked up on the phase overcurrent (51P) and Zone 3 phase (M3P) elements. Relay 3 picked up on the neutral overcurrent (51N) and phase overcurrent elements. Twenty-two cycles later, Relay 3 operated on the neutral overcurrent element and tripped Breaker D. Breaker D fully opened in 3 cycles at a time of 16.875 seconds. At this point, protective elements in Relays 1 and 3 dropped out. At the same time, Relay 2 picked up on the zero-sequence overvoltage elements and then dropped out 1.25 cycles later.

B. Event Data

Event data from Relay 1 provide the current and voltage waveforms shown in Fig. 11. At the inception of the fault, the Phase B current increases to around 2,000 A while the Phase A and C currents also increase to around 1,000 A. Phases A and C are both in phase while Phase B is 180 degrees out of phase. The voltage graph shows that only the Phase B voltage collapsed while Phase A and Phase C remained healthy and 120 degrees out of phase from each other.

Event data from Relay 3 are shown in Fig. 12. Relay 3 measures three phase currents on the high side of Transformer D. At the inception of the fault, all three phase currents increase and become in phase with each other. It appears in Fig. 12 that only one current phase exists, when in fact all three phases overlap each other. Similar to Fig. 11, the Phase B voltage collapses while the Phase A and C voltages remain relatively healthy. Toward the end of the graph, a trip is issued and the breaker interrupts the current. There is also a voltage transient when the breaker opens. Relay 2 might shed light on the voltage waveform.

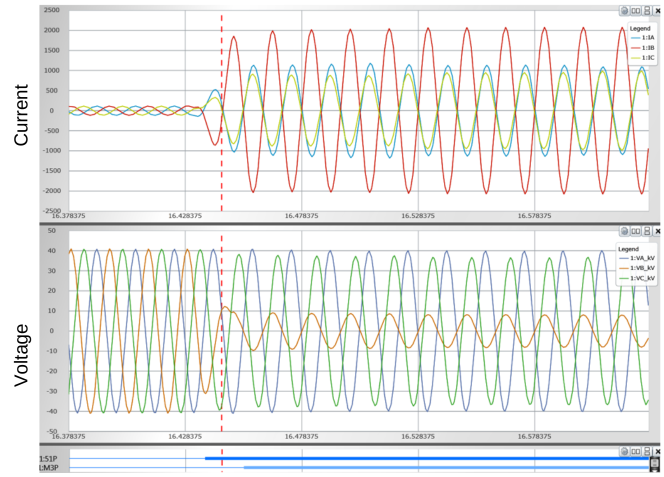

Fig. 11. Relay 1 Event Capture

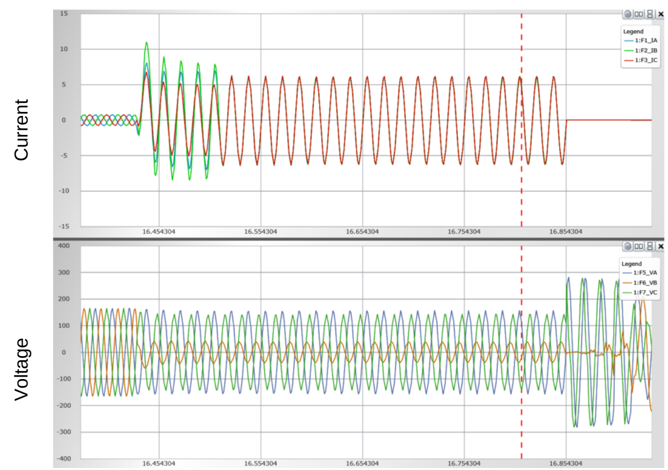

Fig. 12. Relay 3 Event Capture

The event data from Relay 2 in Fig. 13 show when the fault was cleared. Notice that the Phase B and C voltages increase when Breaker D opens (indicated by the vertical dashed line). Because the system is transitioning from effectively grounded to ungrounded, the voltage increase is due to a sudden shift in the voltage vector triangle. The third curve in the figure shows the zero-sequence voltage.

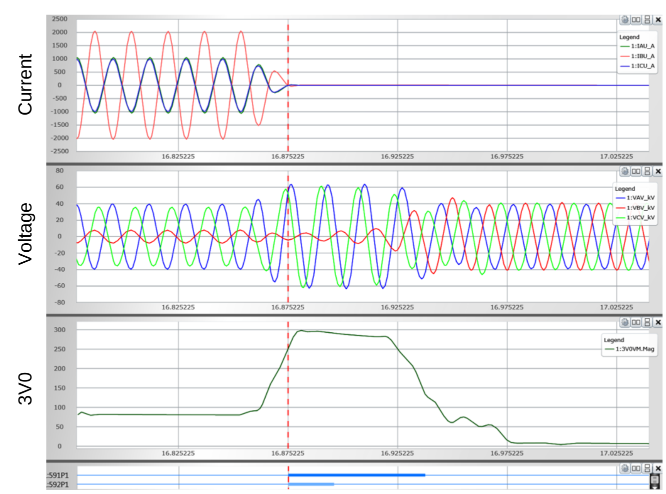

Fig. 13. Relay 2 Event Capture

As soon as the breaker operates, the zero-sequence voltage increases high enough to pick up both zero-sequence overvoltage elements (59P1 and 59P2) set in the relay. The magnitude of the zero-sequence voltage begins its natural decay until a few cycles later when it quickly drops back to zero, leaving the system ungrounded and unfaulted.

The first thing to ascertain from these three relay events is which phase was faulted. Looking at the voltages, only Phase B collapses during the fault. After the breaker opens, but before the zero-sequence voltages disappear, Phase B is suppressed while the other phases remain relatively intact. Therefore, it can be concluded that the fault was a single-phase-to-ground fault on Phase B. Further analysis requires a detailed look at the sequence components.

C. *Sequence Diagram of Faulted System*

For the purposes of sequence component analysis, the system can be simplified as shown in Fig. 14.

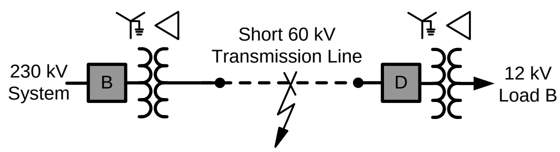

Fig. 14. Simplified System

Fig. 15 shows a sequence diagram for a single-phase-to-ground fault on the 60 kV transmission line. Notice that the only zero-sequence connection for the transmission line is from Transformer D. Therefore, a single-phase-to-ground fault on the transmission line will cause the fault current to flow from Transformer D, which is downstream from the fault.

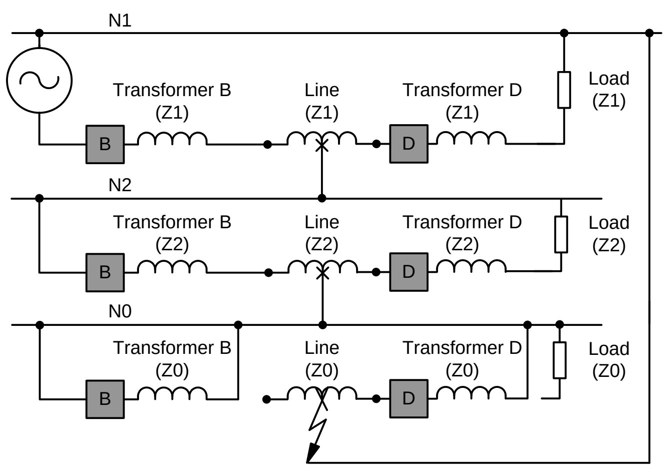

Fig. 15. Sequence Diagram of Single-Phase-to-Ground Fault When Breaker D Is Closed

Fig. 16 shows the three-phase circuit of the simplified diagram. The delta winding on the left side is the low-side delta winding of Transformer B, and the wye winding on the right side is the high side of Transformer D.

Notice the current path when the system is grounded and Breaker D is closed. Zero-sequence current flows up the neutral connection of the wye winding and then splits among the three windings. One phase feeds the fault directly while the other phases flow upstream to Transformer B, where they combine to feed the fault from the other direction. Notice the similarities between the current flow on the three-phase circuit and the event reports. The delta winding has two phases with current flowing in and one phase with current flowing out. The current shown in the event report from Relay 1 in Fig. 11 matches this expectation. Two of the phases are 180 degrees out of phase from the faulted phase. The current shown in the event report from Relay 3 in Fig. 12 also matches. All three currents are flowing in the same direction and are in phase with each other.

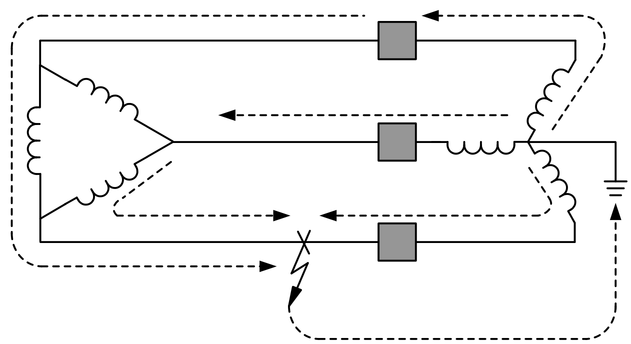

Fig. 16. Zero-Sequence Current Flow With Breaker D Closed

The ground fault relay trips Breaker D and the system configuration now loses the only ground source at Transformer D. The new sequence diagram in Fig. 17 shows the transmission line no longer connected to any zero-sequence source. As such, current no longer flows to the fault, as shown in Fig. 18. The cause of the original fault is still connecting Phase B to ground, so the triangle shifts to make Phase B the new ground reference point. A few cycles later, with the loss of a zero-sequence path, the fault current drops to a low value and the arc is able to self-extinguish, allowing the voltage triangle to shift again to an unfaulted state. The 3V0 magnitude also decreases to near zero.

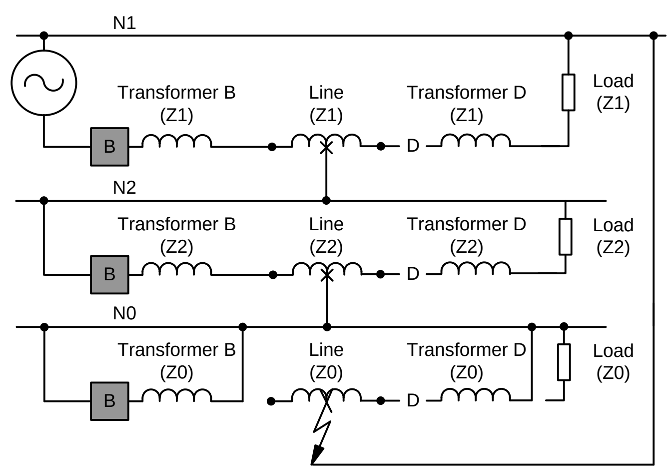

Fig. 17. Sequence Diagram of Fault When Breaker D Is Open

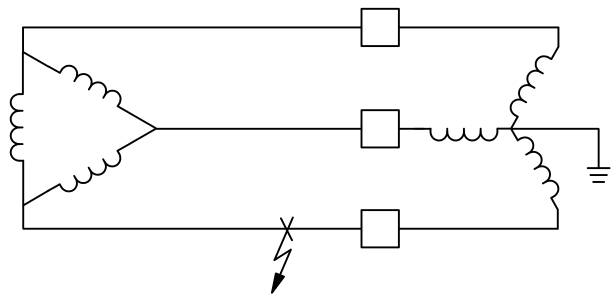

Fig. 18. Zero-Sequence Current Flow With Breaker D Open

D. Other Observations During Event

Relay 1 picked up on an overreaching Zone 3 phase element instead of a Zone 1 element for a fault on the transmission line. Fig. 16 helps to explain why Relay 1 did not operate on the Zone 1 distance elements. Without a ground source behind the distance relay, the relay cannot accurately determine the impedance for a phase-to-ground fault. Had the fault been phase-to-phase, the distance relay would have been able to accurately identify the impedance.

Load A never experienced a power interruption during the fault, which highlights the benefit of an ungrounded system. The zero-sequence voltage relay began timing during the transient caused by the breaker removing the ground source. However, the fault was temporary in nature, so the relay dropped out before the timer expired.

VI. Conclusion

Protection system designs require careful consideration of the grounding method; physical changes to the system grounding must be accompanied by corresponding changes to the protection schemes. Using consistent grounding methods leads to consistent protection schemes. Protection engineers must not only understand the implications of different grounding methods but must also be proactive in the planning and design stages of a project to ensure that proper techniques are applied.

Choosing a relay that allows for a six-wire VT connection, instead of the more common four-wire connection, allows for phase-to-phase voltage measurements on a broken-delta VT connection. In addition, a six-wire connection provides adequate transient dampening using stabilizing resistors without needless power dissipation during normal system conditions.

This case study highlights a system that uses a combination of current- and voltage-based protection in order to operate the system as either effectively grounded or ungrounded. Even with this added complexity, it is still possible to design a protection scheme with proper selectivity, albeit with certain caveats and atypical results. In particular, distance relaying may not be capable of protecting against ground faults on a transmission line, breakers may operate downstream instead of upstream from a fault, and voltage transients may require the relay to wait a short time to prevent misoperation during a grounded-to-ungrounded transition.

VII. References

[1] IEEE Standard 142-1991, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems.

[2] J. Roberts, H. J. Altuve, and D. Hou, "Review of Ground Fault Protection Methods for Grounded, Ungrounded, and Compensated Distribution Systems," proceedings of the 55th Annual Conference for Protective Relay Engineers, College Station, TX, April 2002.

[3] L. V. Dusang, "A Ground Fault Protection Method for Ungrounded Systems," proceedings of the IEEE Electric Power Conference, Vancouver, BC, Canada, October 2008.

[4] D. Reimert, *Protective Relaying for Power Generation Systems*. CRC Press, Boca Raton, FL, 2005.

[5] R. Beltz, I. Peacock, and W. Vilcheck, "Application Considerations for High Resistance Ground Retrofits in Pulp and Paper Mills," proceedings of the 46th Annual Pulp and Paper Industry Technical Conference, Atlanta, GA, June 2000.

[6] Eaton, "Transient Overvoltages on Ungrounded Systems From Intermittent Ground Faults," August 2009. Available: http://www.eaton.com.

[7] P. E. Sutherland and A. Mansoor, "Conversion of Ungrounded Systems to High-Resistance Grounding Systems," proceedings of the 42nd Annual IEEE Industrial and Commercial Power Systems Technical Conference, Detroit, MI, April 2006.

[8] IEEE Standard C2-2012, 2012 National Electrical Safety Code (NESC).

[9] J. L. Blackburn and T. J. Domin, *Protective Relaying: Principles and Applications*, 3rd ed. CRC Press, Boca Raton, FL, 2007.

[10] M. Shen, L. Ingratta, and G. Roberts, "Grounding Transformer Application, Modeling, and Simulation," proceedings of the IEEE Power and Energy Society General Meeting, Pittsburgh, PA, July 2008.

VIII. Biographies

Darren De Ronde received a BS in Electrical and Computer Engineering from Calvin College in 2003. He has worked on designing substation control, automation, and protection systems for a variety of utilities in the Upper Midwest and California. Darren joined Schweitzer Engineering Laboratories, Inc. in 2011 as a protection engineer in the California Bay Area. He is a registered professional engineer in the states of Minnesota and California and has been an IEEE member for 13 years.

Rick VanHatten received his BSEE from South Dakota State University in 1974 and is an IEEE PES member. He has broad experience in the field of power system engineering, operations, and protection. Upon graduating, he served for 32 years at Iowa Public Service, Midwest Resources, and MidAmerican Energy, where he worked in substation, distribution, and transmission engineering; system operations; and substation operations, managing various engineering groups. He has led a variety of utility projects to design and build electric and gas metering shops, plan for Y2K contingencies, and consolidate utility switching practices. In 2006, he joined Schweitzer Engineering Laboratories, Inc., where he is an engineering supervisor. Previously, he worked for two years for Cooper Power Systems in the energy automation solutions group (formerly Cannon Technologies) in the area of substation automation and integration.

Austin Wade received his BS in Electronic and Electrical Engineering, summa cum laude, from California State University, Sacramento, in 2013. He joined Schweitzer Engineering Laboratories, Inc. in 2012. He is presently working as a protection engineer in the Engineering Services division. He is a member of the IEEE Power and Energy Society.

20150318 • TP6668-01