A Review of Ground Fault Protection Methods For Transmission Lines

Developed by the ERCOT System Protection Working Group

An examination of methods and best practices associated with transmission system ground fault protection.

ERCOT SPWG Ground Fault Focus Group
3/2/2017

Contents

Background

Every major system disturbance since the 1965 Northeast Blackout has been caused or exacerbated by protection system performance ranging from incorrect relay settings to communication failures.

In NERC's *2013 State of Reliability* report, it was recommended as a high priority to perform a more thorough investigation into the root causes of protection system misoperations. Based on the NERC Glossary, a protection system misoperation is defined as any of the following:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip** – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip** – During Fault – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip** – Other Than Fault – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

Under the NERC Planning Committee's direction, the Protection System Misoperation Task Force (PSMTF) began to analyze misoperations in March 2012 and completed its report in April 2013. The PSMTF reviewed over 1,500 misoperation records collected from January 1, 2011 to June 30, 2012 across all eight Regions. Additionally, a summary of each Region's misoperation process and observations and conclusions from data collected prior to January 1, 2011 were evaluated. Approximately 65% of misoperations were found to have one of the following three cause codes:

1. Incorrect settings/logic/design errors
2. Relay failures/malfunctions
3. Communication failures

Protection system misoperations were identified in NERC's *State of Reliability 2014* report as an outage cause code that had a significant probability of occurrence and was positively correlated with transmission severity when outages do occur. Below were additional findings from NERC's analysis of misoperations from 2011 through 2013:

- Misoperation occurrences were consistent from 2011-2013, with approximately 2,000 misoperations per year.
- The rate of misoperations, as a percentage of total operations, also remained consistent during the period at approximately 10% (i.e., roughly one in 10 operations is a misoperation).

- The three most common causes of misoperations remained the same (approximately 65% of misoperations are caused by incorrect setting/logic/design errors, communication failures, and relay failures/malfunctions).

NERC-wide in 2013, there were 71 transmission-related system disturbances that resulted in a NERC Event Analysis reported event. Of those 71 events, 47 (66%) had associated misoperations. Of the 47 events, 38 (81%) experienced misoperations that were contributory to or exacerbated the severity of the event. In several cases, multiple misoperations occurred during a single disturbance.

NERC-wide in 2014, there were 54 transmission-related system disturbances that resulted in a NERC Event Analysis reported event. Of those 54 events, 47 (87%) had associated misoperations. Of the 47 events, 37 (79%) experienced misoperations that were contributory to or exacerbated the severity of the event.

Relay Misoperation Data

Texas Reliability Entity (Texas RE) collects protection system misoperation data on a quarterly basis. Since January 2011, the overall protection system misoperation rate is 7.4% when normalized by the number of system events, not including failures to reclose.

From January 2011 through June 2015, Texas RE analyzed over 860 misoperation records in an attempt to categorize the predominant causes of these misoperations. This analysis is shown in the figure below.

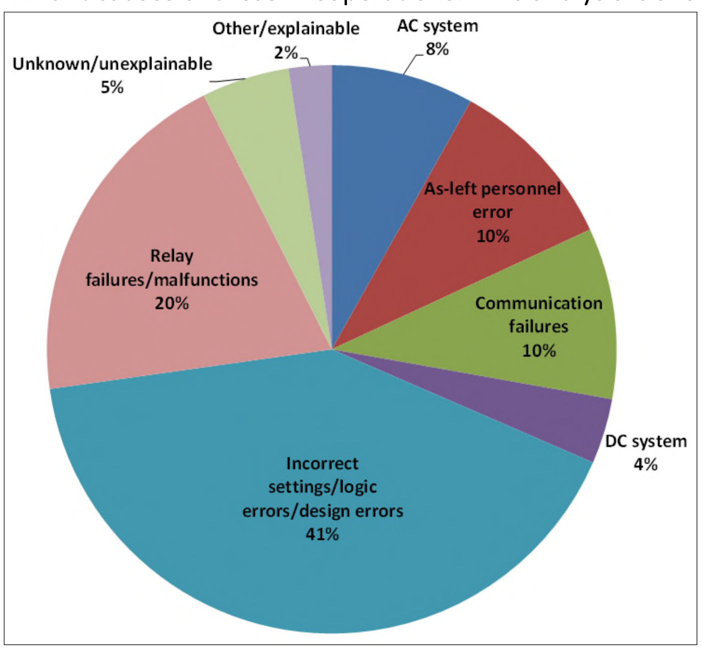


Figure 1 – ERCOT Region Protection System Misoperations by Cause, 2011-2015

Approximately 71% of misoperations have the following cause codes:

- Incorrect settings, logic, and design errors (41%)
- Relay failures/malfunctions (20%)
- Communication failures (10%)

In the NERC PSMTF published its final report on the analysis of NERC-wide misoperations and obtained similar findings. The PSMTF analyzed 1,500 misoperations and found that the predominant causes of misoperations were incorrect settings, logic and design errors (28%), relay failures (20%), and communication failures (17%).

Clearly, in order to reduce the overall misoperation rate, it is necessary to address the predominant cause of incorrect settings, logic, and design errors.

Texas RE performed further analysis of misoperations caused by incorrect settings, logic, and design errors and found that 41% of these misoperations were due to miscoordination of ground overcurrent settings. Reference the figure below.

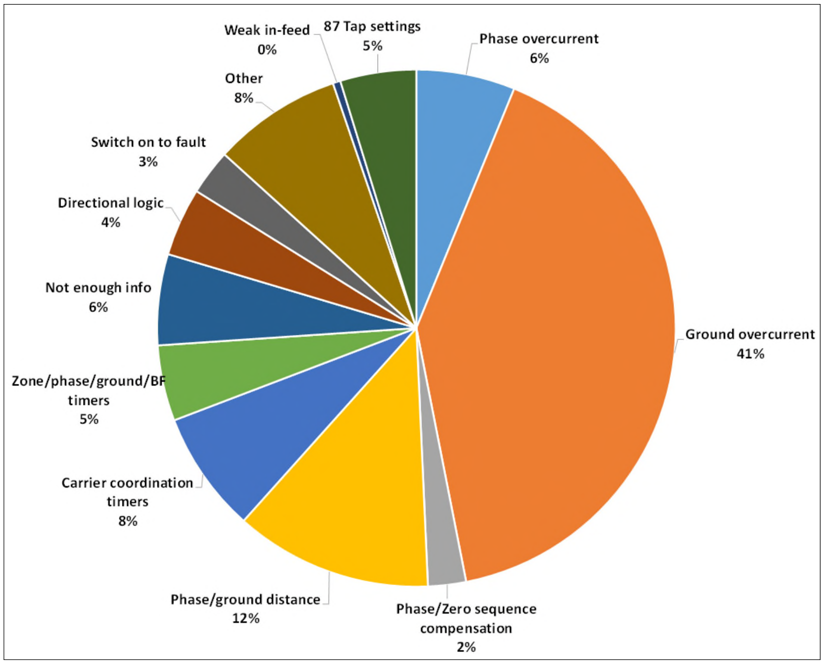


Figure 2 – ERCOT Region Incorrect Setting Misoperations, 2011-2015

Ground Fault Characteristics

Ground faults are abnormal conditions on the power system that involve the flow of zero sequence current. In a balanced, three-phase power system, some amount of zero sequence current flow associated with load imbalance will naturally be present. However, ground fault conditions increase the system zero sequence current flow above the levels normally experienced due to load imbalance.

A ground fault condition may occur as either a “series” fault or a “shunt” fault. A series-connected ground fault condition occurs when one or more of the power system phases opens up and no longer carries current flow. For example, in a three phase power system, if phase A is open and no longer carries current flow, this will lead to an increase in zero sequence current, i.e. ground current. The zero sequence current flow will increase by approximately an amount equivalent to the amperage that had been previously flowing on phase A. This occurs since normally all three current carrying phases are electrically ~120 degrees apart from each other which allows them to cancel each other out in the neutral or ground path. Once one or more phases is removed for any reason, the ground current will increase. Mathematically, this is shown as:

$$Ia + Ib + Ic = Ig = In = 3 \times Io$$

Given Ia = 100 < 0 deg, Ib = 100 < -120 deg, Ic = 100 < 120 deg, then the resulting Ig value will be zero. However, if Ia = 0 due to an open connection, Ig will increase to 100 amps. The magnitude of the ground current is a function of the load current.

In reality, this type of series fault condition may occur for several reasons – for example:

1. A single phase opens up due to an equipment apparatus failure (i.e. transmission line jumper failing open).
2. A device is closed (or opened) and one or more phases fails to close (or open) (i.e. motor operated disconnect).

This type of series-connected ground fault condition has the following characteristics:

1. Increased ground current flow – yet usually at a much lower magnitude than a shunt-connected ground fault.
2. Little or no decrease to the system operating voltage.

Due to these characteristics, these types of conditions are generally detected by a ground time overcurrent (51G) element and possibly by a ground differential (87G) element. When detected and cleared by a ground time overcurrent element using an inverse time curve, the clearing time tends to be rather long since the ground current magnitude is so low. Impedance based relaying and ground instantaneous elements are generally not effective at detecting these conditions due to the lack of an impact on system voltage and the relatively low levels of ground current flow, respectively.

In contrast to a series-connected ground fault, another potential condition is a shunt-connected ground fault. In practice, this type of ground fault tends to be much more common than a series-connected ground fault. This type of ground fault occurs when a physical connection with a low enough impedance to allow current flow is connected between one or more energized phases and ground. Typical connections include L-G and 2L-G (i.e. L-L-G). Connections such as 3L-G and L-L are not considered ground faults because they do not lead to zero sequence current flow.

This type of shunt fault condition occurs for a multitude of reasons – for example:

1. A tree branch falls on an energized conductor and static wire.
2. An arrester fails and flashes over from phase to ground.
3. An animal bridges the length of a bushing.
4. A personal protective ground was left connected during energization.

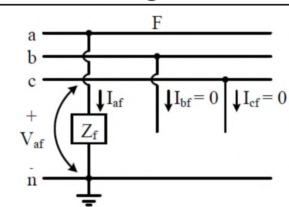
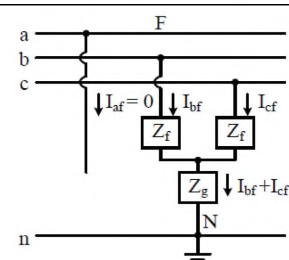
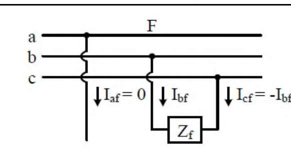
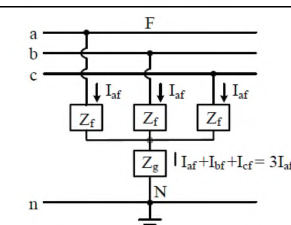
This type of shunt-connected ground fault condition has the following characteristics:

1. Increased ground current flow, where the magnitude is determined by the ground fault impedance and the system source strength.
2. A significant decrease in system operating voltage; the phase voltage at the point of the fault goes to zero.

Due to these characteristics, shunt-connected ground faults are generally much easier to detect than a series-connected ground fault. Typical protective relay elements utilized for protection against these types of conditions include ground time overcurrent (51/67G), ground instantaneous (50/67G), ground distance (21G), and ground or negative sequence differential (87G/87Q). In each case the "visibility" of a fault is determined in large part by the ground fault impedance. A high impedance fault can "mask" the fault condition by limiting the ground current flow and minimizing the decrease in system operating voltage, both factors which can hinder fault detection. A high impedance fault, for example, may not be detected by a ground distance element. This demonstrates the benefit of a layered approach which utilizes different protective elements to detect a wide variety of fault conditions.

An aspect common to all ground faults is the fact that since ground current flow is normally very small in a well-balanced power system, ground fault detection can be set very sensitively. This is in contrast to phase fault protection which must naturally be set less sensitively in order to provide for relay loadability and allow load current to flow.

Since line to ground faults by definition only involve a connection from a single phase to ground, they tend to be the most frequent. The more phases that become involved in the fault, the rarer those types of faults become. At higher voltages, with increased phase separation, experiencing fault types other than single line to ground can be very rare.

Type	**Frequency**	**Ground fault?**	**Diagram**
Line to ground (L-G)	65-70%	Yes	
Line to line to ground (2L-G or L-L-G)	15-20%	Yes	
Line to line (L-L)	5-10%	No	
Three line to ground (3LG)	2-5%	No	

Due to their high frequency of occurrence relative to other fault types, there is a great interest within the utility industry in detecting and clearing ground fault conditions while balancing security and sensitivity requirements. This paper will further examine the various protective relay elements designed to detect ground fault conditions and outline the pros & cons, setting considerations, coordination requirements, and best practices for each type of element.

System Modeling of Ground Fault Conditions

The detection of ground faults requires settings relays properly to act sensitively and securely in response to power system conditions. An accurate system short circuit model serves as the basis for setting relays properly. Key elements of the system short circuit model required for this purpose include the zero sequence impedance of transmission lines and autotransformers and the modeling of mutual coupling effects.

The ERCOT SPWG Short Circuit Case Building Procedure Manual includes guidelines for including mutual coupling effects within the short circuit cases. Absent specific company policies in this area, suggested guidelines for the modeling of mutual impedance effects by ERCOT TSPs are as follows:

1. Mutual impedances should be included for circuits sharing a common structure and if the coupled length of adjacent circuits exceeds 10% of the shortest line circuit or if the mutual impedance exceeds 10% of the smallest circuit zero sequence impedance.
2. Mutual impedances should be included for circuits sharing a common ROW less than 100 feet wide and if the coupled length of adjacent circuits exceeds 10% of the shortest line circuit or if the mutual impedance exceeds 10% of the smallest circuit zero sequence impedance.
3. TSPs may opt to model the mutual impedance of certain circuits in greater detail as warranted.
4. In the case of mutual impedances between two circuits owned/operated by different TSPs, the two TSPs shall come to an agreement on which entity shall submit the mutual impedance ("Mutual Pair" in ASPEN OneLiner) information during the annual case building process.

Mutual coupling effects can have a significant impact on how ground fault conditions are perceived by protective relays. For example, due to the apparent fault impedance seen by the relay, mutual coupling may have the effect of requiring zone 1 ground distance elements to be set "shorter" than normal to guarantee security, while zone 2 ground distance elements may need to be set "longer" than usual to guaranteed coverage for all internal faults. Similarly, ground instantaneous elements may need to be set higher than normal to guarantee security for all fault conditions. In extreme instances with severe mutual couple effects, a dual-pilot scheme (such as dual line differential systems) may need to be installed in order to guarantee security, sensitivity, and relay coordination for all fault conditions.

Verifying actual fault magnitudes recorded by Disturbance Monitoring Equipment is an important feedback loop for confirming accurate system models. In some instances, errors may be detected when actual fault magnitude values do not match expected values. In other cases, relay settings may need to be set based on actual fault magnitude values rather than model values to due modeling uncertainties.

Ground Fault Relaying Elements & Schemes

Ground Instantaneous Overcurrent (50/67G)

Ground Instantaneous Overcurrent (GIT) units operate with no intentional time delay, and generally in the order of 0.90–3 cycles. This requires that they generally be set not to overreach any other protective device. The basic criteria are that instantaneous overcurrent relays should be set as sensitive as possible, with the constraint that it must not operate on non-fault conditions or for any fault outside of its zone of protection. Protection engineers should recognize that instantaneous relays are a very simple and highly valuable protective function, and every effort should be taken to take advantage of its benefits.

When a reasonable difference in the fault current exists between the close-in and far-bus faults, instantaneous units can be used to provide fast protection for faults out on the line. Situations do occur where this differential is less than optimal for GIT setting purposes, resulting in limited protection for the maximum fault condition and none for minimum faults. Thus, their application becomes marginal from a protection coverage standpoint. Still, they can provide fast clearing for the heaviest close-in faults. This is most likely to occur with short-line applications.

GIT element reach is sensitive to fault current changes / system impedance changes and must be re-evaluated as levels change.

1. GIT Advantages
    a. Fast, dependable operation
    b. Non-directional element is not dependent on PT signals
    c. Electromechanical and microprocessor relays available
    d. Simplicity of testing and commissioning
    e. Proven record of historical use
2. GIT Limitations
    a. Prone to misoperation due to fault level variability
        i. Cumulative system changes must be accounted for
        ii. Dynamic system contingencies must be accounted for
    b. Mutual coupling effects must be accounted for
    c. Lack of a fixed reach

Direct-tripping zero-sequence overcurrent elements should be set greater than the maximum out-of-section fault current.

In circumstances where the line is mutually coupled with other transmission lines the maximum zero-sequence current may be for a fault at the end of a parallel line with the breaker close-in to the fault open (sometimes referred to as end-of-line faults). The end-of line fault current could result in the maximum external fault current because the mutual coupling between circuits is at its maximum.

If the line is not mutually coupled, the maximum fault current is typically for faults at the remote bus. One possible practice in obtaining the maximum fault current is to calculate the remote bus fault with an outage of the strongest source at the remote bus such as an Autotransformer. This will ensure ground IOC coordination during a contingency scenario. The ASPEN OneLiner program has a "Check Overcurrent Instantaneous Setting" tool which is very helpful with identifying the mutual coupling and remote bus fault scenarios to check coordination.

Set the direct tripping element greater than the maximum external fault current plus some margin.
The margin is determined by the steady-state and transient overreach error of the protective relay. Refer to the protective relay support documentation or contact the relay manufacturer for this information. Additional margin should be added to the setting to account for fault study, line modeling, and current transformer errors (typically 5 to 10% is adequate). Set the direct tripping element using the following equation:

Pickup = $I_F \times \left(1 + \frac{\varepsilon_{SS}}{100} + \frac{\varepsilon_T}{100} + 0.05\right)$

Where:
I_F = maximum external fault current
ε_{SS} = percent of steady-state error
ε_T = percent of transient error
0.05 = additional 5% margin to account for modeling and CT errors.

A special circumstance occurs when the Local end operates on Ground INST relay setting (67G1) due to a Remote bus fault having the last CB to clear the bus fault being this line's Remote terminal. The faulted bus is served by two Autotransformers and two lines. All Remote CBs clear the fault properly with the last Remote CB clearing in approximately 6.5 cycles, which is proper for an old Oil CB.

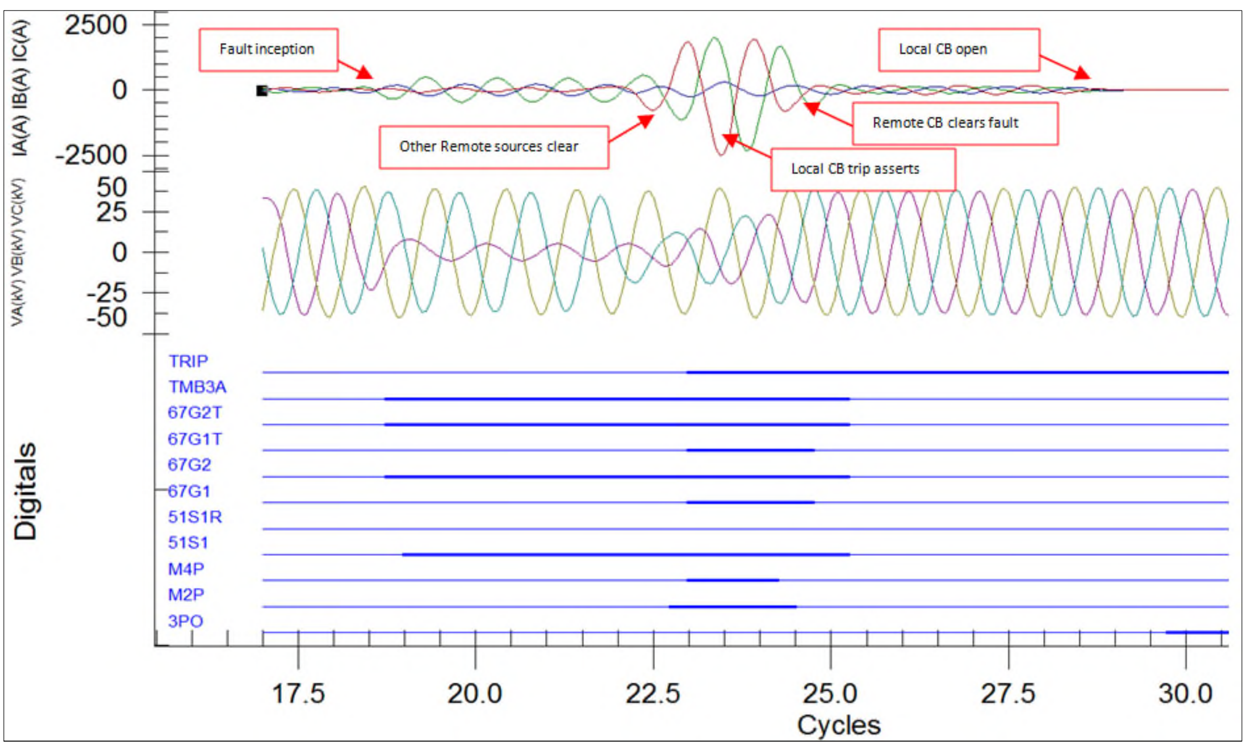


Figure 3 - Ground Instantaneous Special Circumstance

In this case the 67G1 (Ground INST) was not set considering the outage of the two Autotransformers and was also not set by looking at the end of line fault with the Remote end open. Either of these considerations would have produced a setting that would not have tripped for this fault case.

Following are setting considerations to avoid inadvertent Remote Ground INST trips for a Local Bus fault due to all Local CBs not clearing at the same instant. Consider the Local 138kV Bus#1 LG fault for 138kV Remote1 source. Evaluate the following fault cases to determine the available fault currents through Remote1 source.

1. All Local sources in service: Remote1 3I0 contribution = 300 amps
2. Local-Remote1 Line end fault with Local end open: Remote1 3I0 = 1956 amps
3. Local N-1 (Local Auto #2 out)(strongest source): Remote1 3I0 = 529 amps
4. Local N-2 (Local Auto #1 & #2 out)(two strongest sources): Remote1 3I0 = 1170 amps
5. Last Local CB to Clear bus fault: Remove Local single CB sources on Local 138kV Bus #1 (Remote3 circuit and Remote4 circuit): Remote1 3I0 = 1951 amps. Refer to the system one-line diagram on Figure 4.

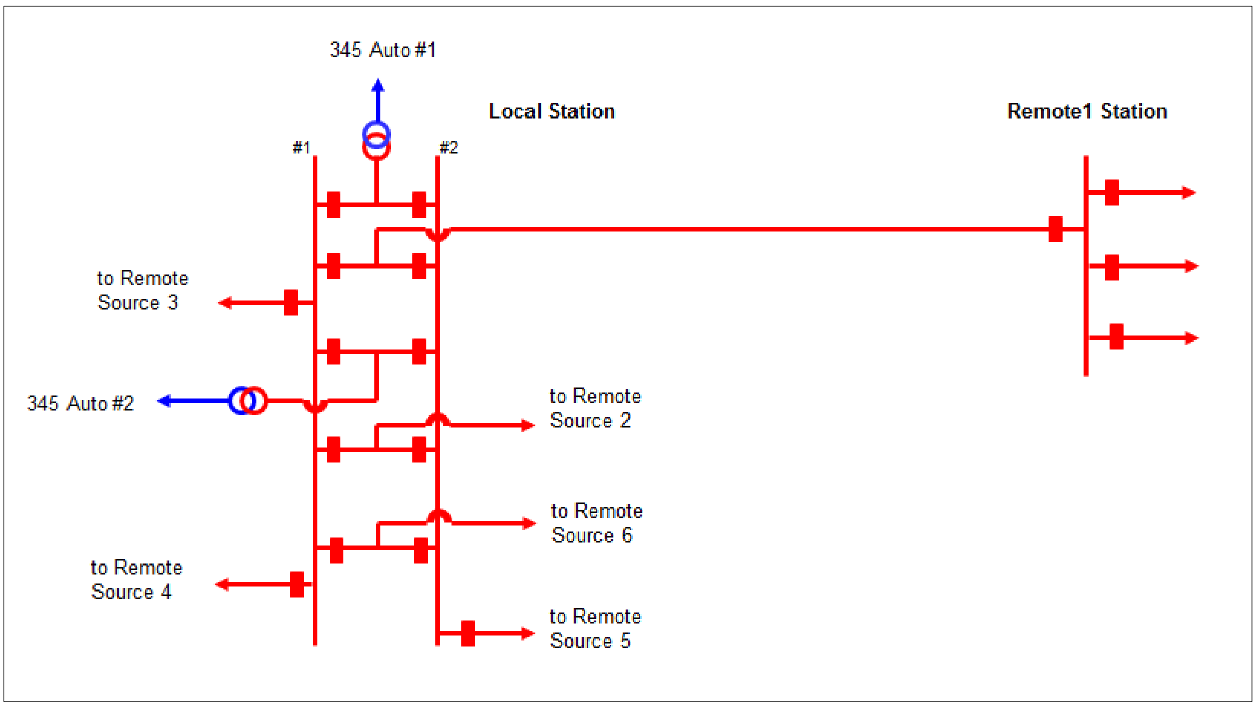


Figure 4 – System One-line Diagram

To ensure that the Ground INST relay will not inadvertently trip for an out-of-zone fault scenario, set the 67G1 to higher than the Case 2 and Case 5 values plus the intended margin. If the 67G1 does not provide the necessary line coverage, implement a secondary high-set Ground overcurrent element (67G4) with a definite time delay of 6-10 cycles.

Ground Time Overcurrent (51/67G)

Ground Time-Overcurrent (GTO) units operate with intentional-configurable time delay. This allows for overreach of other protective devices and requires coordination of operating times. The basic criteria is that time-overcurrent relays should be set as sensitive as possible, with the constraint that it must not operate on non-fault conditions.

1. GTO Advantages
    a. Coordinated over-reach results in out-of-segment/remote-backup protection
    b. Good sensitivity
    c. Non-directional element is not dependent on PT signals
    d. Electromechanical and microprocessor relays available
    e. Simplicity of testing and commissioning
    f. Proven record of historical use
2. GTO Limitations
    a. Coordination study required due to fault level variability of networked systems
    b. Coordination scenarios can lead to undesirably lengthy fault clearing times
    c. Mutual coupling effects must be accounted for

The objective is to set the GTO unit protection to operate as fast as possible for faults in the primary zone, yet delay sufficiently for faults in the backup zones. Close-in fault coordination can be difficult without the aid of ground instantaneous coverage. The selection of a time curve characteristic (Inverse, Very Inverse, Extremely Inverse) is driven by factors such as equipment damage curves. Consistent use of a selected time curve characteristic for multiple units is helpful with coordination.

The delay, or Coordination Time Interval (CTI), values frequently used in relay coordination range between 12 and 30 cycles, depending on the degree of confidence or the conservatism of the protection engineer—*18 cycles*, is the frequently used CTI value. The settings must be below the minimum fault current for which they should operate, but not operate on all normal and tolerable conditions. Occasionally, these requirements provide very narrow margins or no margins. This is especially true in loop-type lines, for which there can be a large variation in fault magnitudes with system operation. Fault currents can be high at peak-load periods with all the generation and lines in service, but quite low when equipment is removed during light-load periods. The fault study should document these extremes.

When coordination is not possible, either a compromise must be made or pilot protection applied. An example of a compromise solution is restricting the GTO unit from operation (Torque Control) until an alternate, coordinated protection scheme experiences an alarm condition (Loss of Potential (LOP) alarm or communications failure).

GTO units have over-travel and reset times, which can be important for some applications. Over-travel in the electromechanical units is the travel of the contacts after the current drops below the pick-up value. Typical values are of the order of 1.8–3.6 cycles, generally negligible in most applications. Most induction disk time–overcurrent relays will not start to reset until the current drops below about 60% of the pickup current. Reset time can be important in coordination with fast-reclosing or fast-repetitive faults. It is a function of the time–dial setting and the design. Data on reset are available from the manufacturers. The values are generally negligible or adjustable for solid- state or microprocessor types. Fast reset may not be advantageous when coordinating with fuses and relays that do not have fast-reset characteristics.

Sensitive set tripping elements should be set above normal system load unbalance or the unbalance caused by line asymmetry under balanced fault conditions.

To maintain scheme security, the sensitive set elements should be set above normal load unbalance.

The ground TOC elements should be set to pick up for the minimum fault along the line which is typically the line-end or remote bus fault. A best practice in obtaining the minimum fault current is to calculate the line-end or remote bus fault with an outage of the strongest local source such as an Autotransformer. This will ensure that the ground TOC can operate during a contingency scenario. The ASPEN OneLiner program has a “Check Minimum Pickup” tool which is very helpful with identifying whether the ground TOC can see the minimum fault.

The timing of the ground TOC element should first coordinate with the Bus Differential and Breaker Failure scheme of the remote bus breakers by an acceptable margin. Additionally, the ground TOC element should coordinate with ground elements of each remote bus breaker relaying by tripping slower with an acceptable coordination time interval such as 15-24 cycles or more, where possible. Lastly, the ground TOC element should coordinate with any ground elements at breakers behind which have ground elements possibly tripping for faults along the local line. Similarly, the ground TOC element should trip faster than the ground elements behind by an acceptable coordination time interval such as 15-24 cycles or more, where possible. Coordination time intervals may need to be longer for electromechanical ground time overcurrent relays vs. digital time overcurrent relays.

It is difficult to theoretically determine the normal system load unbalance on the power system. It is also possible to take measurements at the time of relay installation, but setting adjustments may be required in the field to decrease the sensitivity of overcurrent elements.

Ground Distance (21G)

Ground distance (21G) relaying compares relay voltages and relay currents to create a measured impedance phasor. The measured impedance phasor can be shown in the impedance R-X plane and the relay operates once the impedance phasor is within the relay operating characteristic. In general two types of relay operate characteristics are used; mho and quad. The mho element is the most commonly used of the two but the specifics of mho and quad elements will not be discussed in this paper.

Ground distance zones can be used for ground fault protection instead of or in concert with Ground Time Overcurrent elements. Ground distance zones are less likely to misoperate due to system fault current changes as with Ground TOC elements but may be more susceptible to not clearing high resistive faults.

21G relays typically use several zones to provide a step distance protection scheme. Almost all 21G schemes will utilize two forward reaching zones, Zone 1 and Zone 2, to provide complete coverage of the protected transmission line. A third forward reaching zone or a reverse reaching third tripping zone, Zone 3, may also be utilized to provide backup or remote protection of other lines in the system, see Figure 5 below. The Zone 3 protection nomenclature as discussed in this paper may vary from utility to utility as well as by vendor. While a reverse third tripping zone scheme may have a lower impedance than a third forward zone scheme it is susceptible to a single point of failure if only one battery set is available in the station. The protection engineer should take this into account when determining which scheme should be used.

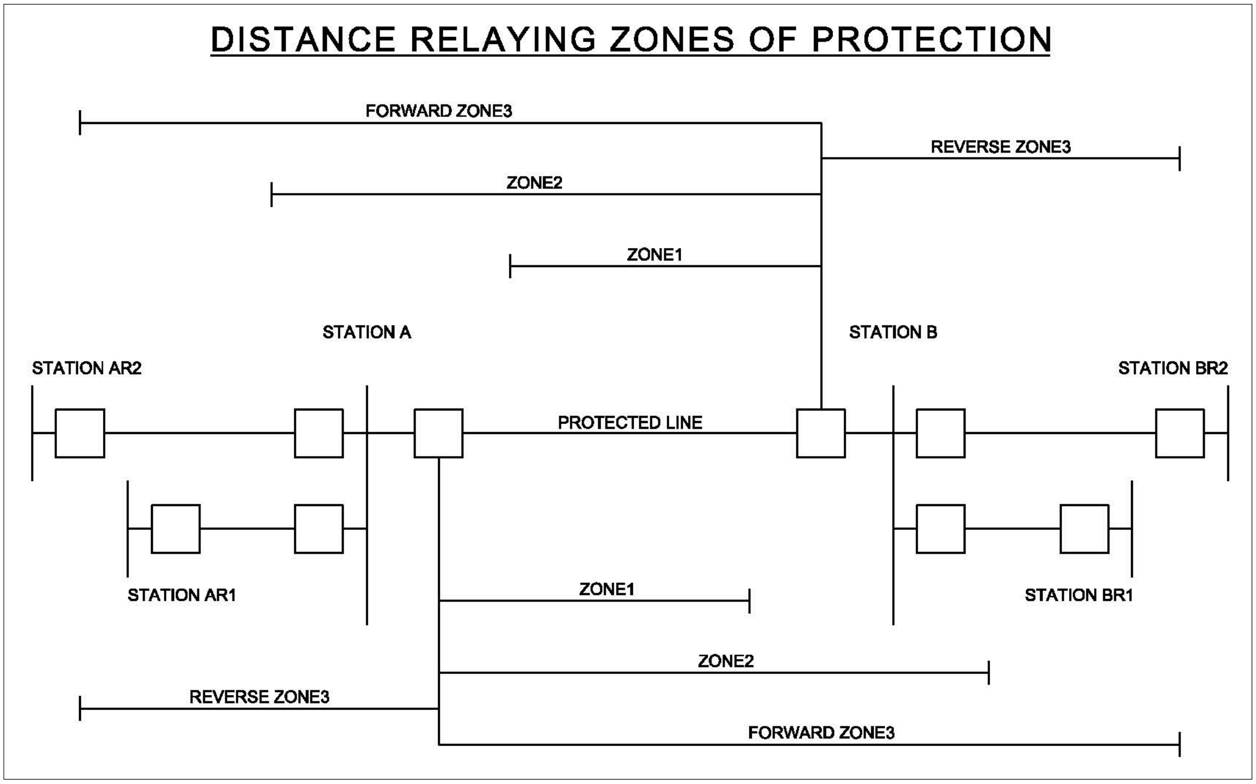


Figure 5 – Distance Relaying Zones of Protection

Zone 1, the first forward reaching zone in Figure 5, is typically set to reach between 70-85% of the line and with no intentional time delay. The positive-sequence line impedance or the minimum apparent fault impedance for a fault at or beyond the remote bus is used to determine the reach setting.

Protected lines with mutual coupling need to be checked to ensure Zone 1 reach does not over trip for faults outside of the protected line. When mutual coupling is present it is recommended to study line-end faults, faults at the remote bus both with and without lines at the remote station out of service, faults at the remote bus both with and without mutually coupled lines out of service and grounded, and faults at given intervals along the lines that have mutual coupling with the protected line. Due to the mutual coupling effect, any of these faults apparent impedance may appear closer to the local end than a fault on the protected line, thus resulting in a potential misoperation.

Another consideration the protection engineer must take into account for Zone 1 protection is an extremely short line or a line with a Source Impedance Ratio (SIR) greater than 4. The SIR is calculated by the following equation, ($SIR = \frac{Z_{SOURCE}}{Z_{LINE}}$), or by use of a modeling software such as ASPEN. With either of these conditions the protection engineer may choose to reduce the reach percentage below the suggested minimum of 70% or to not use Zone 1 protection all together. If Zone 1 protection is not used it is suggested the protections engineer utilize a communication assisted protection schemes on both the primary and backup relay.

Zone 2, the second forward reaching zone in Figure 5, must be set to reach all faults along the protected line plus some additional margin, typically an additional 10-25%, and will trip with an intentional time delay of anywhere between 18 and 30 cycles. The Zone 2 intentional time delay must be longer than the breaker failure trip timing by an acceptable margin to minimize the number of elements tripped during a breaker failure scenario.

As with Zone 1 settings, positive-sequence line impedance or the maximum apparent fault impedance for a fault at the remote bus can be used to determine the Zone 2 reach setting. It is recommended to study faults along the protected line, line-end faults, faults at the remote bus both with and without lines at the remote station out of service, and faults at the remote bus both with and without mutually coupled lines out of service and grounded.

Zone 2 reach at the local breaker should not over-reach the Zone 1 and GIT protection of any of the lines out of the remote station. In some instances, such as a "long line, short line" scenario this is over-reaching is unavoidable to guarantee 100% coverage of the protected line. When the protected lines Zone 2 must over-reach the Zone 1 or 50/67G protection of the remote stations lines, the Zone 2 element time delay should be increased to allow the remote stations lines Zone 2 relaying time to operate plus some additional margin (typically 12-30 cycles) to take into account a breaker failure scenario.

Zone 3, the third forward reaching zone or the reverse reaching third tripping zone in Figure 5, may also be used as a backup time-delayed remote protection plus some additional margin, typically 10-25%, and will trip with an intentional time delay anywhere between 36 and 120 cycles. The time delay must be longer than the Zone 2 timing plus the breaker failure trip timing by an acceptable margin to minimize the number of elements tripped during a breaker failure scenario. A forward Zone 3 is set to provide backup tripping for all faults on lines out of the remote station while a reverse Zone 3 is set to provide backup tripping for all faults on all lines out of the local station.

The maximum apparent fault impedance for a fault at the remote bus should be used to determine the Zone 3 reach setting. It is recommended to study both line-end faults and faults along all of the lines the Zone 3 relaying is intended to protect.

When applying 21G on a three-terminal line, faults on both remote busses must be considered for Zone 1 and Zone 2 settings as well as all lines out of both stations if using a third forward reaching Zone 3. If using a reverse third tripping zone for a three terminal line behind the protected line, faults on both ends of the line should also be considered.

The advantages and limitations of 21G relaying are listed below:

1. 21G Advantages
    a. Independent of source impedance variation
    b. Coordinated over-reach results in out-of-segment/remote-backup protection
2. 21G Limitations
    a. Sensitivity on high impedance faults
    b. Mutual coupling effects must be accounted for
    c. Dependent on PT signals

d. Selectivity on short lines can be hard to achieve

Directional Comparison Blocking (85 DCB)

Communications-assisted pilot schemes are employed to provide high-speed tripping for 100% of the protected transmission line. Two common attributes used to describe communications-assisted pilot schemes are dependability and security. A dependable pilot scheme is one that will detect and trip for any fault within its designated zone of protection; avoiding the “Failure to Trip – During Fault” misoperation. A secure scheme will not trip for faults outside its designated zone of protection; avoiding the “Unnecessary Trip – During Fault” misoperation.

Directional Comparison Blocking (DCB) schemes are biased toward dependability because of the use of forward-looking, instantaneous protective relay elements intentionally set to overreach the remote terminal(s). DCB scheme security is dependent upon a block signal received from the remote terminal(s) for faults beyond the remote terminal(s). A reliable block signal depends on properly coordinated blocking relay elements in addition to proper adjustment and working condition of the equipment associated with the pilot channel (transceivers, tuners, couplers, etc.). Proper adjustment and working condition of the pilot channel is not within the scope of this document and will be assumed in order to focus on issues associate with setting pilot scheme relay elements.

The most common protective relays included in pilot schemes are impedance (distance) relays and ground overcurrent relays. In legacy electromechanical DCB schemes, phase distance relays are a common choice for phase fault protection and ground overcurrent relays are used for ground fault protection. Phase distance elements are still in common use with microprocessor-based DCB schemes. Additionally, modern relays provide other options for ground fault protection, such as ground distance elements, which can be included in pilot schemes with little additional effort and no additional cost.

As mentioned above, the protective element building blocks of a DCB scheme include overreaching relays. For distance (impedance) relays, overreach is accomplished by setting the ohmic reach of the relay along the impedance angle of the line greater than the impedance of the protected line, with margin to ensure the distance relay will have adequate sensitivity for any fault on the protected line.

With overcurrent relays, overreach is accomplished by setting the operate current pickup below the expected fault current magnitude at the remote terminal(s), again with margin, to ensure the relay will be able to detect a fault anywhere on the protected line. A best practice in obtaining this operate current is to calculate the line-end or remote bus fault with an outage of the strongest local source such as an Autotransformer. This will ensure that the carrier overcurrent element can operate during a contingency scenario. The maximum pickup setting might be limited by factors other than system fault studies, such as a utility company’s policy or regulatory agency mandate. One regional transmission organization requires ground overcurrent protection on transmission lines with a pickup setting no higher than 600 Amps, primary, to help ensure sensitivity for a fault created by tree contact with the protected line although this requirement can be satisfied with either pilot ground overcurrent or direct-tripping ground time overcurrent elements.

The desire for overreaching settings of pilot scheme ground relays is to provide good sensitivity for high-resistance faults, such as the tree contact example, which is more likely in ground faults as opposed to phase faults. In addition, infeed at the remote terminal and source contingencies (for example, lines or autotransformers out of service behind the relay) will reduce the amount of ground fault current contribution measured by the relay.

To prevent a high-speed overtrip of these sensitive DCB pilot-scheme tripping elements for faults beyond the remote terminal(s), the relay elements at the remote terminal(s) must detect any fault in the reverse direction that the overreaching, forward-looking pilot relay elements at the opposite end can detect. To ensure the reverse-looking pilot blocking elements are more sensitive than the forward-looking pilot tripping elements at the opposite end of the protected line, sensitivity of the blocking element should include margin. In distance elements, this means the reverse reach of the blocking element must be set longer, with margin, than the remote forward reach beyond the blocking terminal. In overcurrent elements, this means the reverse operate current pickup setting must be set lower, with margin, than the remote forward operate current pickup setting.

COORDINATION OF PILOT OVERCURRENT ELEMENT PICKUP SETTINGS

An important consideration when discussing the coordination of pilot element operate quantities is to ensure coordination of settings on a primary quantities basis. The best effort to achieve coordination of secondary relay settings can be negated if a difference in current transformer ratios between opposite terminals is not taken into account.

A simple method of coordinating the pickup setting of forward pilot tripping ground instantaneous overcurrent with the reverse pilot blocking ground instantaneous overcurrent element at the remote terminal is to set the tripping element pickup at some multiple of the remote reverse element pickup. For example setting the local, forward pilot tripping ground overcurrent pickup at ≥ 2x the remote, reverse pilot blocking ground overcurrent pickup, or

$$67G_{FWD_L} \geq 2 \times 67G_{REV_R}$$

$$Where: 67G_{FWD_L} = local, forward\ pilot\ tripping\ ground\ overcurrent\ pickup$$

$$67G_{REV_R} = remote, reverse\ pilot\ blocking\ ground\ overcurrent\ pickup$$

should provide adequate operate current pickup margin for a two-terminal line.

Achieving this amount of margin could prove challenging if, after determining a maximum desired pilot tripping ground overcurrent pickup, the 2x margin results in a calculated secondary pickup setting of the reverse pilot blocking overcurrent element at the remote terminal lower than the setting range minimum available in the relay. Lowering the CT ratio at the blocking terminal would help attain the desired sensitivity; however, this requires reevaluating the possibility of saturation or constraint on line loadability. Lowering the CT ratio at one end may also create a coordination challenge for faults in the opposite direction that didn't previously exist. If lowering the CT ratio is undesirable, the margin could be reduced. If margin needs to be reduced, it is recommended to make the pilot tripping ground overcurrent pickup no less than 1.25x the remote pilot blocking ground overcurrent pickup, again, on a primary quantities basis.

To achieve the equivalent of the minimum 1.25x remote pilot blocking ground overcurrent margin in a DCB scheme applied on a three-terminal line, the local pilot tripping ground overcurrent pickup would be set at 1.25x the sum of both remote pilot blocking ground overcurrent pickups, or

$$67G_{FWD_L} \geq 1.25 \times (67G_{REV_{R1}} + 67G_{REV_{R2}})$$

$$Where: 67G_{FWD_L} = local, forward\ pilot\ tripping\ ground\ overcurrent\ pickup$$

$$67G_{REV_{R1}} = reverse\ pilot\ blocking\ ground\ overcurrent\ pickup\ at\ remote\ terminal\ 1$$

$$67G_{REV_{R2}} = reverse\ pilot\ blocking\ ground\ overcurrent\ pickup\ at\ remote\ terminal\ 2$$

where the remote terminals are connected to each other through a networked system.

Extra precaution should be taken when determining settings for sensitive DCB ground instantaneous overcurrent elements on protected lines that have zero-sequence mutual coupling with another parallel line as with multiple-circuit transmission line construction or lines within close proximity in a common transmission corridor. In such cases a fault on one line can induce zero-sequence current on the unfaulted line of sufficient magnitude to pick up the pilot tripping ground overcurrent element. When zero-sequence mutual coupling is a concern with regard to pilot ground overcurrent operate quantity, a negative-sequence polarizing quantity should be the preferred choice for directionality of the pilot ground overcurrent element.

Finally, the protection engineer needs to be familiar with the relay design and the choice of and modifications to the operate quantity against which the pickup setting is compared. An example is the use of a positive-sequence restraint by one microprocessor relay manufacturer to dynamically adjust the calculated zero-sequence current before it is compared to the neutral instantaneous overcurrent pickup setting. An attempt to account for this adjustment would require a prediction of load flow at the time of the ground fault, which could prove difficult. In such cases, concern over the effect on pickup coordination can be eliminated if the pilot scheme relays at both ends use identical methods.

COORDINATION OF PILOT OVERCURRENT ELEMENT DIRECTIONALITY

In addition to coordination of relay responses to operate quantities, the forward pilot tripping and corresponding reverse pilot blocking elements at the opposite end must agree on fault direction. Pilot scheme misoperations attributed to relay directional elements occur when an overreaching forward pilot tripping element picks up for a fault beyond the remote terminal and the relay at the opposite terminal either cannot detect the reverse fault or incorrectly makes a forward fault direction declaration. Either condition prevents the relay from sending a block signal to the remote relay and results in an overtrip.

Polarizing quantities are used by relays to add directionality to otherwise non-directional relay elements. In electromechanical relays, the mechanical torque created by a phase angle relationship between the polarizing quantity and operate quantity is used to provide a contact closing force for a forward fault direction or a restraining force for a reverse fault direction. This same method is simulated numerically in many microprocessor relays. Common polarizing quantity choices include zero-sequence voltage, zero-sequence current, or negative-sequence voltage.

Another method of determining fault direction used by one microprocessor relay manufacturer is the comparison of the measured negative-sequence or zero-sequence fault impedance with a portion of line positive-sequence or zero-sequence impedance, respectively, to make a declaration of fault direction [1]. This same manufacturer offers line relays with the capability of automatically selecting from a user-settable sequence of polarizing quantities during a fault until a quantity is detected that satisfies a minimum sensitivity threshold.

The various methods employed by relays must be considered when attempting to coordinate pilot tripping and pilot relays. To ensure agreement between the remote terminals on fault direction, the same polarizing method should be chosen at both (all) terminals. This planning requires not only that the pilot-scheme relays involved have the same capability to use similar polarizing quantities, but that similar polarizing quantities are available at each terminal [2]. An example is the choice of zero-sequence current polarizing. The polarizing source is typically a CT in the high-voltage, wye-connected winding neutral of a generator step-up transformer or CT's within the delta tertiary of an autotransformer. Unless a transformer providing a current polarizing source is available at each terminal, the use of zero-sequence current polarizing should be avoided at both terminals. In such case, if zero-sequence mutual coupling with a close parallel line is not a concern, perhaps the preferred polarizing quantity would be zero-sequence voltage polarizing.

In addition to the selection of a common method of polarizing, care should be taken to ensure coordinated pickup sensitivity of the polarizing element to available polarizing quantities between the pilot tripping relay and the pilot blocking relay for the same external fault. The obvious choice to remove the variability of relay capability from the burden of coordination is to select relays of identical polarizing methods and sensitivities and the best way to ensure identical response is to use identical relays at both terminals. A common relay manufacturer and relay model may be adequate to achieve this goal; however, even a difference in firmware version of the same relay model can include a difference in the calculated operate quantity. An example is one firmware version of a microprocessor relay operating on $1I_0$ for the zero-sequence operate quantity in its negative-sequence directional element and another firmware version of the same relay model operating on $3I_0$ for the same element. A difference like this can be accommodated if the engineer is aware of the difference and is diligent about coordinating on a primary basis but again, identical relays can help eliminate problems caused by such differences that are not obvious without a thorough understanding of the relay design.

Ground Distance Elements

In an effort to avoid DCB-scheme miscoordination for ground faults caused by any number of variables cited above in relay overcurrent operate quantities or directional determination methods, an option available in modern microprocessor relays is ground impedance, or ground distance elements. There are fewer, or less significant, differences affecting ground distance element behavior among various relay designs [3][2][4].

A disadvantage of ground distance is the lack of sensitivity to high-resistance ground faults, especially at the boundary of mho element reach along the line impedance angle, when compared to zero- and negative-sequence overcurrent elements. However, measures can be taken to alleviate this limitation. For example, the choice of relays with positive-sequence voltage memory polarization of ground distance elements offers the greatest amount of mho expansion and therefore the greatest amount of fault resistance coverage of available polarization methods [5]. This polarizing choice at both terminals also helps to ensure coordinated behavior of the relays employed in the DCB-scheme.

The reach of pilot-scheme ground distance elements can also be extended in an effort to increase resistive ground fault coverage. This might also be necessary if the presence of mutual coupling reduces the effective reach of the pilot tripping ground distance element intended to overreach the remote terminal. If the ground distance element associated with the pilot scheme can be used exclusively in the pilot scheme and is not an unconditional, direct-tripping element, then the only coordination concern of the increased reach would be the need for a correspondingly greater reverse reach of the blocking ground distance element at the remote terminal [3]. Even with the ground distance element reach increased in an effort to improve fault resistance sensitivity or overcome the effect of mutual coupling, the typical reach is of a sufficiently small multiple of line impedance that minimum current and voltage thresholds for polarizing, sequence component ratio checks, and supervising fault detectors can be satisfied for faults within the reach [4]. This helps in keeping less obvious differences in ground distance element characteristics among relay models and manufacturers from affecting pilot scheme coordination [2].

Another advantage of ground distance elements is their relative insensitivity to the momentary imbalance present due to non-simultaneous pole opening/closing during in-line load switching, defined above in the Ground Fault Characteristics section as a series-connected ground fault. As described in the Ground Fault Characteristics section, a series-connected ground fault causes little to no decrease in system phase voltage measured by the line relays and although the increase in ground current could be sufficient for pilot ground overcurrent elements to pick up, it could also be insufficient for detection by ground distance elements.

If the protection engineer still feels that the desired level of sensitivity to high-resistance ground faults has not been achieved with the use of ground distance elements in the DCB scheme, but must also coordinate relays with different overcurrent element characteristics, overcurrent elements can still be included in the pilot scheme. One approach is to include the pilot ground overcurrent element in the DCB-scheme logic with a short definite-time delay that does not apply to the more secure phase and ground distance elements and would be in addition to the carrier coordination time delay which applies to all pilot tripping elements. Time delays in the 8-10 cycles range have been successfully applied to pilot tripping ground overcurrent elements. The delay allows time for the normal complete closing or opening of all three phases of a motor-operated, in-line switch without the need to disable the pilot scheme prior to the switching operation. In the case of coordination uncertainty due to dissimilar relays applied in a DCB scheme, the delay would allow time for high-speed protection of the faulted zone to clear the out-of-zone (external) ground fault and reduce the possibility of overtrip. Although this approach may seem counter-productive when designing a high-speed pilot scheme, the compromise is usually acceptable since high-resistance ground faults have less impact on system stability [2][4].

Permissive Overreaching Transfer Trip (85 POTT)

In contrast with Directional Comparison Blocking schemes, Permissive Overreaching Transfer Trip (POTT) schemes have traditionally been considered to be biased toward security. This belief has roots in the original basic POTT scheme concept. Like DCB schemes, POTT schemes also employ directional overreaching protective relay elements. In a basic POTT scheme, when a forward-looking, overreaching protective element picks up, it will key trip permission to the remote terminal(s) but will not be allowed to trip the local terminal high-speed unless it also receives trip permission from the remote forward-looking protective relay. This basic design is considered secure since a loss of the pilot channel would not allow a high-speed overtrip for out-of-zone faults. For the same reason, the basic POTT scheme was not considered as dependable as a DCB scheme for internal faults.

As in DCB schemes, even a basic POTT scheme can cause a high-speed overtrip if the directional relay element with a fault behind it incorrectly declares the fault direction to be forward allowing the remote terminal to trip. However, the opportunity for overtrip misoperations has increased with advances to

POTT schemes and the introduction of echo logic. The echo logic of these hybrid POTT schemes will return trip permission upon receipt from the remote terminal unless additional reverse-looking elements, similar to blocking elements in a DCB scheme, detect a fault in the reverse direction. Echo logic improves POTT scheme dependability during weak infeed and remote open terminal conditions as well as improving the pilot scheme's sensitivity to high-resistance ground faults [4]. However, the presence of the reverse elements in the scheme demands the same diligence, described above for DCB schemes, in coordination between pilot tripping elements at one terminal and the reverse elements at the remote terminal.

As with DCB schemes, the protection engineer could choose to depend more on ground distance elements for ground fault coverage and either disable or add the short definite time delay to pilot ground overcurrent elements if differences in relay performance make overcurrent element coordination difficult or unpredictable. Another option available in hybrid POTT schemes is to disable echo logic [4]. The lack of a weak infeed condition would make this decision more acceptable and does not require pilot directional element coordination between terminals. The basic POTT scheme only requires forward pilot elements at both ends to detect an internal fault to trip high-speed.

Ground & Negative Sequence Differential (87G/87Q)

Ground differential (87G) and Negative sequence differential (87Q) relays measure currents at the local end of the line and compares them against the relay currents at the remote ends. The 87G function compares the zero sequence quantities while the 87Q compares the negative sequence quantities. Ideally, the relay currents at the local and remote ends would sum to zero except during faults on the protected line. For an internal fault on the protected line, the relay 87G and 87Q elements no longer sum up to zero and should fall in the operate region of the differential element. Based on relay manufacturer, the techniques used to develop the operate region may vary. The advantages of each manufacturer's technique will not be discussed in this paper.

Modern 87G and 87Q relays require a high speed point-to-point or multiplexed communications channel to receive the current data from the remote end. The protection engineer should take into account the communication bandwidth, availability, latency, bit errors, and channel symmetry. The performance of the current differential scheme is directly related to the performance of the communications channel. Fiber communication is the recommended medium for line differential schemes. Microwave can also be used but performance can be affected by weather.

87G and 87Q schemes operate solely on currents and thus the protection engineer should be concerned with CT saturation. Saturation is especially important to study when CTs are paralleled in dual breaker schemes such as a breaker-and-a-half or ring bus configuration. In cases where the CTs must be paralleled due to the type of relay and bus configuration, the pickup value of the 87G and 87Q settings should be increased or delayed (by 1-2 cycles) to avoid a potential misoperation due to CT saturation during an external fault.

The 87Q element must also be evaluated on a line with tapped load. Normally, the 87Q element should be disabled on a line with tapped load; but if used, it should be set to avoid tripping for a fault on the low voltage side of the transformer. These faults should be cleared by a downstream breaker and should be considered as out-of-zone faults for the line. In these conditions it is recommended to model the transformer and set the 87Q pickup value to at least 150% of the maximum negative sequence current on the high side of the transformer. Another alternative is to supervise the 87Q element with ground distance elements.

The advantages and limitations of 87G and 87Q relaying are listed below:

1. *87G and 87Q Advantages*
    a. *Independent of source impedance variation*
    b. *Sensitivity on high impedance faults*
    c. *Mutual coupling effects can practically be ignored*
    d. *Not dependent on PT signals*
    e. *Selectivity on short lines*
2. *87G and 87Q Limitations*
    a. *Must have a high speed digital communications channel to all terminals of the line*
    b. *The relays at each end of the line must be compatible and have the same firmware version*
    c. *The 87Q is sensitive to out-of-zone faults and caution should be taken when a tapped delta–wye transformer is present*

Summary of Recommendations

This paper examines the topic of ground fault protection. The previous sections include several key considerations and guidelines for securely setting those elements and schemes intended to detect ground faults. A few key takeaways in this regard are:

- Series ground faults (such as an open phase) may result in lower zero sequence current measurements, so detection via ground time overcurrent (51G) or ground differential (87G) can be used for detection and clearing, albeit with a slower clearing time.
- Shunt-connected ground faults (L-G, 2L-G) are typically higher current than series ground faults and are usually easier to detect. Elements such as ground time (51G), ground instantaneous (50G), ground distance (21G), and ground or negative sequence differential (87G/87Q) may be used effectively.
- Mutual coupling can have a significant impact on how ground faults conditions are perceived by protective relays. System modeling of mutual coupling and post-operation fault analysis are essential to verify that relay settings match with model assumptions.
- Ground instantaneous overcurrent (50G) is a common and well-understood protection scheme, but must be periodically reviewed for coordination with system changes and contingencies. The 50G element should be set greater than the maximum external fault current plus some margin.
- Ground time-overcurrent (51G) is a proven and effective method for system protection. GTO provides good sensitivity, non-directionality, simplicity of testing, and when used non-directionally an independence from the requirement for PT signals. Like its ground-instantaneous counterpart, though, coordination studies are required due to fault level variability, and the effects of mutual coupling must be considered.
- Ground Distance (21G) protection is based on an impedance phasor that is created by measurements of voltages and currents. Several stepped ground distance zones are typically used, and when this phasor enters one of these zones, the relay will operate. Ground distance

zones are less likely to misoperate due to system fault changes as compared to ground time-overcurrent, but they may be more susceptible to not clearing high resistive faults.

- Communications-assisted pilot schemes are used to provide high-speed tripping for the protected transmission line. Directional Comparison Blocking (DCB) and Permissive Overreaching Transfer Trip (POTT) are two of the more common schemes used with ground protection relaying. The use of a communication pilot scheme adds dependability and security to the protection system.
- Ground differential (87G/87Q) is sensitive for the detection of high impedance faults, is independent of variations in source impedance or surrounding system fault levels, and is not affected by mutual coupling. The 87Q element, however, is sensitive for out-of-zone faults for tapped loads, so this must be considered when implementing these schemes.

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Acknowledgments

The following ERCOT SPWG members contributed to the drafting, editing, and development of this document:

- Bret Burford, AEP
- Keith Calle, CPS Energy
- Mark Chronister, Oncor
- Brian Clowe, Centerpoint Energy
- Gene Corpuz, LCRA
- Mike Davis, Centerpoint Energy
- Keith Fleming, Austin Energy
- Kris Koellner, LCRA
- Andrew Mattei, Brazos Electric
- David Penney, TRE
- Bill Tucker, AEP