SECURITY AND DEPENDABILITY OF MULTITERMINAL TRANSMISSION LINE PROTECTION

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ABSTRACT

There are numerous pilot-protection designs for multiterminal line applications. Common schemes applied to multiterminal lines are:

- Directional comparison protection based upon distance and directional elements (DCB, DCUB, POTT, etc.)
- Current differential or other current-only protection
- Combinations of the above schemes

In this paper, we discuss application considerations for each of these schemes.

Each protection scheme or system listed above has advantages. We explore technical performance issues of applying these protection systems from the perspective of dependability and security. Issues we discuss for distance (21), directional (32), and line differential (87L) elements and the associated schemes include:

- Effects of current infeed and outfeed
- Limits of fault resistance (R_F) coverage
- Current transformer (CT) saturation effect on sensitivity of directional-comparison and 87L schemes
- Communications channel requirements with respect to channel-delay asymmetry
- Security to sympathetic and line energization transformer inrush

We discuss different line current differential characteristics and how they affect dependability and security. In our review we plot these characteristics on the alpha plane. The alpha plane helps us to better understand relay performance during CT saturation and extreme communications channel asymmetry.

INTRODUCTION

Pilot (communications-assisted) protection should provide high-speed, simultaneous fault clearing for faults anywhere along the protected transmission line. A 1988 IEEE survey [1] indicated that the most widely used pilot protection systems are directional comparison systems (DCB, DCUB, POTT, etc.). This report stated that about 80 percent of the critical lines in 116 utilities use directional-comparison protection. The main reasons for this wide acceptance are the limited channel requirements and the inherent redundancy and backup of directional-comparison systems. However, directional-comparison systems require both current and voltage information.

Current-only systems only use current information but require a reliable, high-capacity communications channel. Current-only systems exhibit good performance for complex protection problems, such as evolving, intercircuit, and cross-country faults, mutual induction, power swings, and series impedance unbalance. Current-only systems are also a good solution for series-compensated, three-terminal, and short transmission lines. (Directional-comparison schemes are equally applicable to electrically short lines if the relays are properly polarized.) Modern digital communications channels ([2], [3]) fulfill the requirements of current-only pilot protection systems.

A basic limitation of traditional line current differential systems is that the user must select a slope, or slopes, appropriate to the expected current transformer saturation and maximum channel asymmetry. This slope setting defines a relay characteristic with a given tolerance to channel-delay asymmetry and CT saturation. Often the tolerance to those sources of error is a complex function of load and fault current. Later in this paper we show a new current differential operating principle that is secure, with tolerance to various error sources that does not change as a function of fault or load current.

COMPARING PILOT PROTECTION SYSTEMS

Pilot protection is any protection scheme that uses a communications channel or channels to exchange information between the transmission line terminals. Basic differences between directional comparisons and current-only pilot systems make them complementary: advantages of one type are drawbacks of the other and vice versa.

Advantages of Directional-Comparison Pilot Systems

- Channel-delay and channel asymmetry requirements are not stringent
- Inherent remote back-up protection provided by the directional and/or distance elements with suitable timers
- Fault location and fault recording capabilities of both voltage and current provided by most relays with directional or distance elements
- CT saturation tolerance

References [11] - [13] detail the sensitivity limitations of the directional and distance elements used in these schemes. In summary, these limitations are not set by the relays, but by power system unbalances and instrument transformer inaccuracies. Because these references cover the topic of sensitivity for ground distance and directional elements in considerable detail, we do not repeat that work for directional comparison schemes.

Advantages of Current-Only Pilot Systems

- Very simple to understand and set
- Do not require voltage information, avoiding loss-of-potential problems for close-in faults and blown potential fuses, ferroresonance in VTs, transients in CVTs, etc.
- Immune or much less susceptible to:
  - Zero-sequence mutual induction effects
  - Series impedance unbalance
  - Current reversals and power swings

- Perform well for evolving, intercircuit, and cross-country faults
- Tolerate high line loading
- May handle outfeed, depending on the operating characteristic

The basic limitations of current-only systems are related to their requirement for available, high-capacity communications channels. The channel limitations are rapidly disappearing with modern communications equipment. In addition, digital technology permits inclusion of many protection functions in a relay unit. It is now possible to combine a directional comparison and a current-only pilot system in the same relay. Diversity of operating principles in the same unit enhances the overall scheme performance without a significant cost increase.

DIRECTIONAL COMPARISON PILOT PROTECTION SYSTEMS

In this paper we refer to distance and directional element systems that communicate element status over a communications channel as directional comparison schemes. Examples of directional comparison schemes include Permissive Overreaching Transfer Trip (POTT), Directional Comparison Unblocking (DCUB), and Directional Comparison Blocking (DCB). We may classify directional comparison schemes as either blocking or transfer trip systems. This classification corresponds to the way the local relay uses remote terminal information to generate the tripping signal. Blocking systems do not require the remote signals to trip. Transfer trip systems must receive the remote signals to issue a local tripping signal.

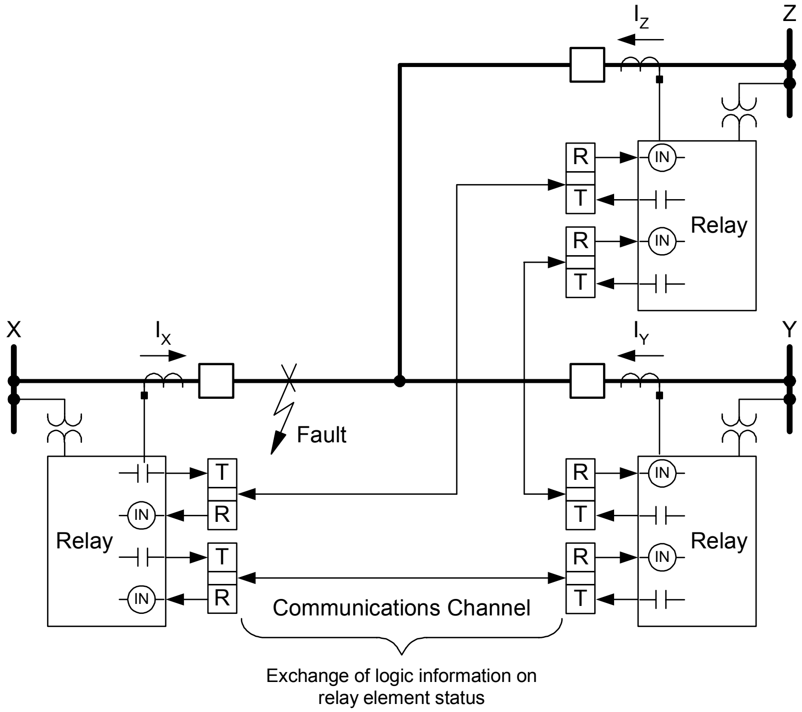
Blocking systems tend toward higher dependability than security because a failure to receive a blocking signal from a remote terminal can result in misoperation for an external fault. These same schemes also achieve high fault resistance coverage for higher impedance faults close to one terminal because they can trip when only one relay senses an in-section fault. After one terminal trips, the remote relays may sense the fault and trip sequentially.

Transfer trip systems tend toward higher security than dependability, because a failure to receive a tripping signal can result in a failure to operate for an internal fault. Assuming equal channel-delay times, transfer trip pilot systems are faster than blocking systems when all terminals have approximately equal strength. However, transfer trip schemes require additional logic to ensure operation for internal faults when one line terminal is open or weak. Under these conditions, the blocking scheme trip speed may be slightly faster than the transfer trip scheme when we consider the necessary communications channel security timers for a poor communications channel.

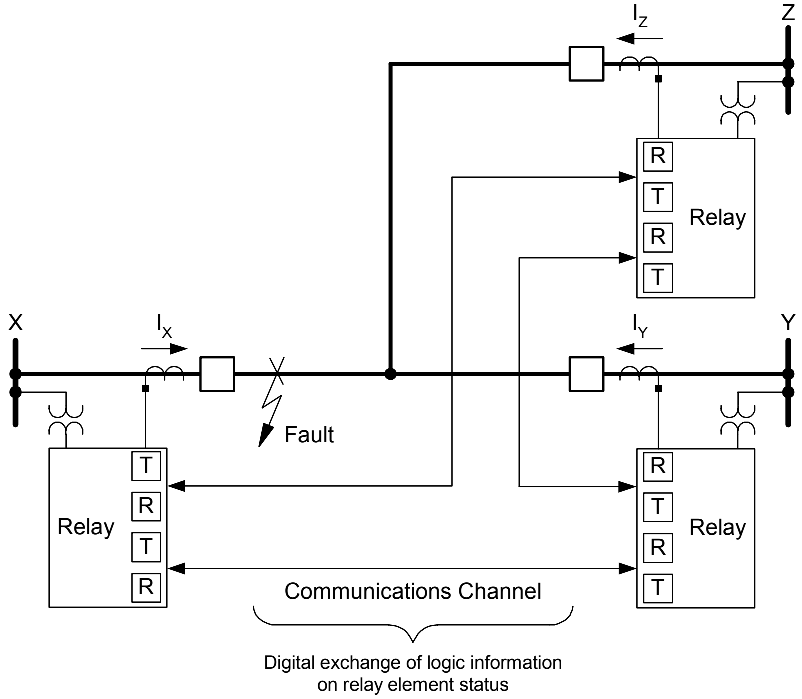
With the additional logic capability of today’s microprocessor-based relays, the sensitivity of POTT and DCUB schemes is now approaching that of blocking schemes.

Directional Comparison Protection of Three-Terminal Lines

Figure 1 shows a diagram of two possible three-terminal directional comparison systems. This system uses directional and distance elements to discriminate internal from external faults.



a. Contact Input/Output Interface to Communications Channel Equipment



b. Digital Interface Between Relay and Communications Channel

Figure 1 Schematic Diagram of a Traditional Directional Comparison System

Relays at all terminals require current and voltage information to determine the fault direction. The protection system uses communications channels to exchange logic information about relay element status. In the system shown in Figure 1a, the relay interface to the communications channel equipment is via contact inputs and outputs. For some blocking schemes each relay only needs a single receive input. The two-state information usually only requires very low channel throughput, about 0.8 to 1.2 kHz bandwidth. For the system shown in Figure 1b, the relay interface to the communications channel is serial. With a slight increase in channel bandwidth, to about 3 kHz, the protection system communicates the status of eight digital outputs and eight digital inputs. These systems communicate up to eight times the information, important for today's trip and control schemes, while simultaneously monitoring the channel health and availability. If the interface carries more information per Hertz of channel bandwidth, the channel must have a higher signal-to-noise ratio to maintain reliable communication. Regardless of the interface type, channel delay or asymmetry is less critical to these schemes. For transfer trip schemes, a delay in receiving the remote signal may delay tripping, but the delay does not affect whether the trip or restrain decision is correct.

Infeed and Outfeed Complicate Apparent Impedance Considerations

Applying distance relays to protect three-terminal lines is more complex than the application to two-terminal lines because of the infinite variety of tap locations, line impedances, source impedances, system loading requirements, and system operating conditions.

To determine appropriate settings for distance elements in three-terminal lines, calculate the apparent impedance seen by a distance relay for various system and fault conditions. Typically this requires an updated fault study and an understanding of which equipment outage causes worst-case conditions. Note that the apparent impedance, or the impedance measured by a distance relay, is not always the actual line impedance from a relay terminal to the fault. This inequality between actual and apparent impedance is because the voltage used by the relay to measure impedance is influenced by remote sources feeding current to the same fault. This infeed influences the voltage drop between the relay location and the fault. Thus, the impedance measured by the relay depends upon the current contributions from the other terminals.

Consider the system shown in Figure 2. Because of infeed current from Source Z, the distance element of Relay 1 measures an apparent impedance of 2.5 Ω, which is greater than the actual impedance to the fault. Thus, the distance element of Relay 1 underreaches for the fault shown in Figure 2.

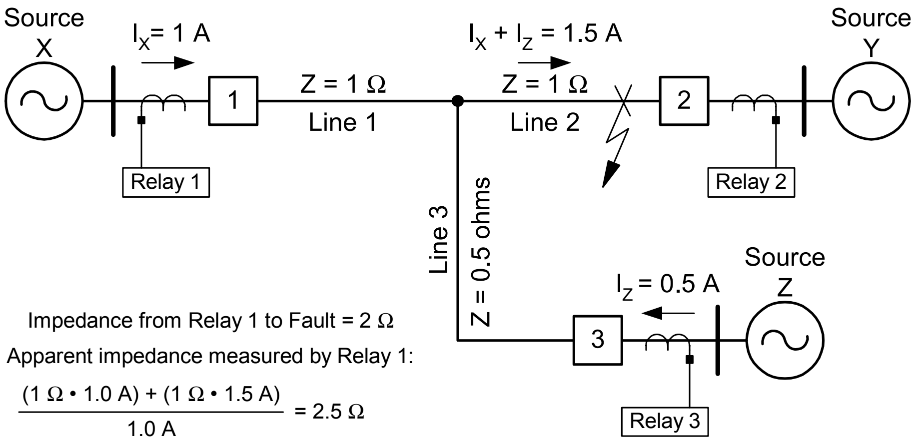


Figure 2 Infeed Causes Distance Element Underreach

The system shown in Figure 3 has an outfeed current at Terminal 3 rather than an infeed current for an internal fault. In this case, the apparent impedance seen by the distance elements of Relay 1 for the fault shown is 1.5 Ω. Since this measured impedance is less than the actual impedance to the fault, the distance element overreaches. When considering the Zone 1 element coverage for Relay 1, also consider the scenario where the tie line between the Source Y and Source Z buses is open. In this scenario, the distance element again underreaches.

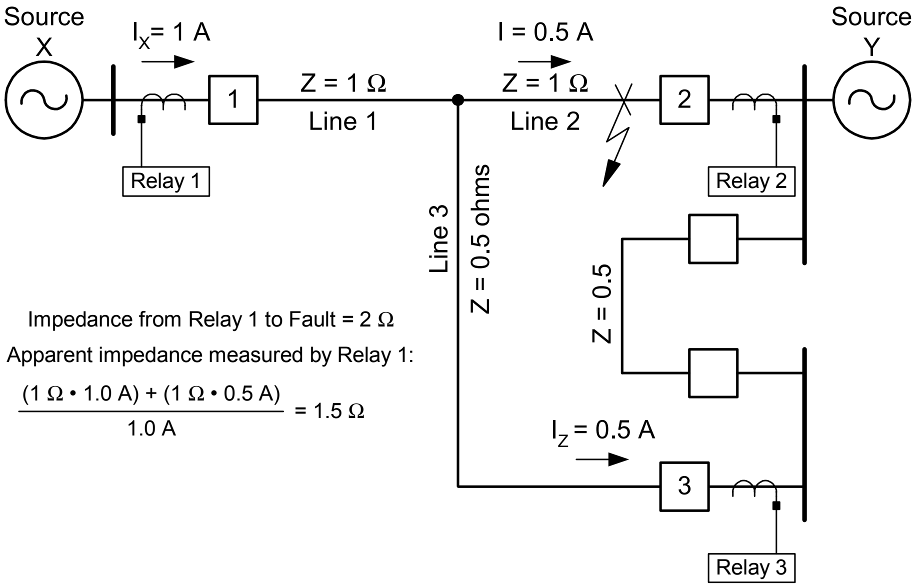


Figure 3 Outfeed Causes Distance Element Overreach

From these simple examples you can see that the apparent impedance measured by the distance relay is affected by the current contributions at the various line terminals. The reach of the Zone 1 instantaneous-tripping elements and the Zone 2 permissive-overreaching elements must be based on worst-case system conditions to ensure that these elements provide the desired performance.

Infeed Increases Reliance on Communications

For three-terminal lines with sources at each terminal, at least two terminals are desensitized for any internal fault, except in the case of a fault exactly at the tap point. The next examples quantify the loss of fault resistance coverage for single-line-to-ground (SLG) faults in solidly grounded systems.

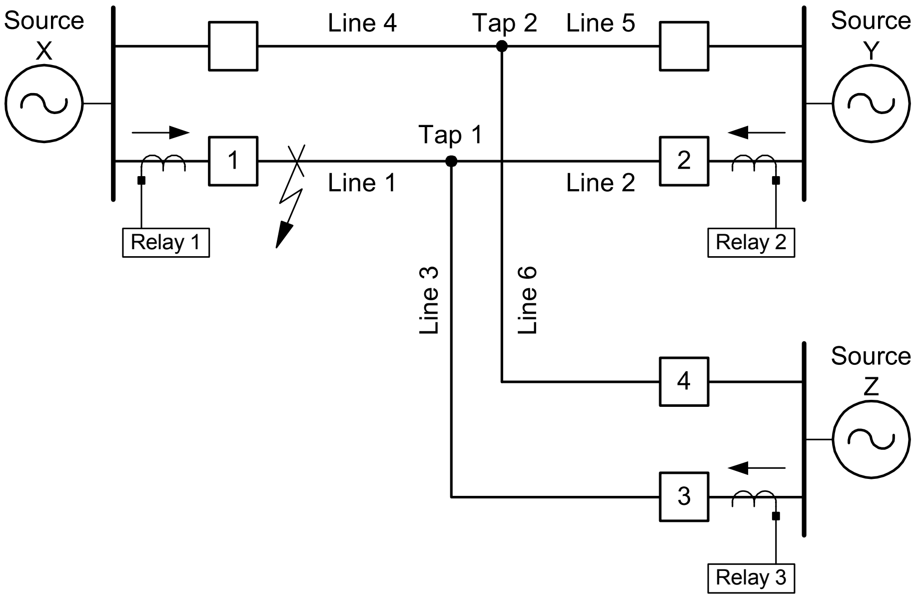


Figure 4 Infeed Desensitizes Two Terminals of Three-Terminal Directional Comparison Scheme

Table 1 lists the source and line impedances for the example system shown in Figure 4.

Table 1 System Impedances for the System Shown in Figure 4

	Positive-Sequence [Ω secondary]	Zero-Sequence [Ω secondary]
Source X	0.53 Ω ∠90° (strongest source)	1.59 Ω ∠90°
Source Y	10.58 Ω ∠90°	31.74 Ω ∠90°
Source Z	105.8 Ω ∠90° (weakest source)	317.4 Ω ∠90°
Line 1	1.97 Ω ∠90°	6.18 Ω ∠80.1°
Line 2	1.97 Ω ∠90°	6.18 Ω ∠80.1°
Line 3	0.99 Ω ∠90°	3.09 Ω ∠80.1°

For this three-terminal example, we set the Zone 1 elements at 80 percent of the impedance to the closest terminal. For all relays, Zone 1 = 2.37 Ω secondary (0.8 • (1.97 + 0.99) Ω).

Overreaching Pilot Protection Zone Should Be Independent from Time-Delayed Overreaching Zone

Next, place an A-phase-to-ground fault 10 percent of the distance from Terminal 1 to Tap 1. As expected for a bolted ($R_F = 0$) fault, Relay 1 trips via the Zone 1 ground distance element. For this ground fault, the minimum reach required for Relay 2 and Relay 3 to just detect the fault is 5.11 Ω and 6.33 Ω, respectively. Consider next the Zone 2 ground distance element reach for Relays 2 and 3. We obviously cannot use the conventional rule-of-thumb of setting these elements at 120 - 130 percent of the longest positive-sequence replica line impedance (1.97 Ω + 1.97 Ω). Doing so would result in Zone 2 settings much less than those required to detect this remote ground fault. This demonstrates that the overreaching zone or directional element used by the directional comparison scheme for this application should be independent from the time-delayed element used to detect end-of-zone faults when the communications channel is out-of-service.

For the remainder of this example, we use pilot ground distance elements with a reach limit of 64 Ω secondary and pilot negative-sequence directional elements, (32Q [12]) with a minimum forward sensitivity of $|3I_2| = 0.5$ A. A Permissive-Overreaching Transfer Trip (POTT) scheme using pilot elements with these settings trips all line terminals simultaneously for all internal bolted ground faults.

Time-Delayed Overreaching Zone 2 Elements May Not Sequentially Sense All Internal Faults

We must consider the event of a communications channel failure. Increasing R_F to 8.4 Ω for a ground fault location shown in Figure 4 places the apparent impedance outside the reach of the Zone 1 ground distance element at Relay 1. For any ground fault at the same location with $R_F < 8.4$ Ω, the Zone 1 ground distance element at Relay 1 picks up. If the directional comparison scheme is so equipped, Relay 1 can send a Direct Transfer Trip (DTT) to Relays 2 and 3 to cause high-speed tripping. If the communications channel is unavailable, the protection scheme relies upon Zone 2 time-delayed elements of the time-stepped distance scheme. For this example, we set the reach of the Zone 2 ground distance elements at 4.73 Ω (= 3.94 Ω • 1.2). After Breaker 1 opens, the minimum ground distance element reaches required at Relay 2 and Relay 3 to just detect this fault are 8.15 Ω and 6.06 Ω, respectively. Note that these minimum reaches are greater than the set Zone 2 reaches. To rectify this nontripping condition, we could increase the Zone 2 reach at Relay 3 from 120 percent to 154 percent. This allows Relay 3 to trip in Zone 2 delay, followed by Relay 2 tripping in time delay after Breaker 3 opens. However, increasing this reach further encroaches on the Zone 1 reach of adjoining line sections.

It is interesting to note that Relay 3 has greater sensitivity for this fault than Relay 2, even though Relay 2 is closer to a stronger source than is Relay 3. This is because the fault current from the parallel line flows through Breaker 3. If we open Breaker 4, then Relay 2 senses the ground fault within its Zone 2 ground distance element reach and trips after a delay. After Breaker 2 clears its contribution to the fault, Relay 3 senses the fault in its Zone 2 and trips, after some delay, to finally clear the fault.

With all breakers closed, the Zone 2 ground distance element of Relay 1 can sense ground faults at the location shown in Figure 4 with $R_F < 12.7$ Ω secondary. Even after Breaker 1 clears its contribution to the fault, the minimum reach required by Relays 2 and 3 is now very large, 11.9 Ω and 8.9 Ω, respectively. Such large reaches for Zone 2 time-delayed tripping elements may be prohibitive, because these same elements now risk overreaching the Zone 1 elements of the adjoining line sections. Such an overreach causes a race condition between Zone 2 time-delayed elements. A possible solution to this problem is to use time-coordinated directional time-overcurrent elements at each terminal. Note that these elements require considerable effort to properly coordinate. This exercise should be repeated every time there is a significant source or line change. A more cost-effective solution from a personnel perspective is to provide alternate communications channels or to use another directional comparison relaying system whose communications are not routed the same way as the primary protection channel.

POTT Can Have Sensitivity Comparable to DCB

Today's microprocessor based relays include ancillary logic such as weak-infeed and echo-logic to address almost every system operating condition where only one terminal is strong. This same logic permits tripping for higher resistance faults close to one terminal. The logic shown in Figure 5 illustrates a greatly simplified example of today's advanced POTT logic. Note that this logic increases the sensitivity performance of POTT schemes to that of DCB schemes. The benefit of using POTT versus DCB schemes is operating speed for bolted faults when no source is too weak to contribute significant fault current. DCB schemes require a short carrier coordination delay to wait for the receipt of a block signal. When one or more terminals is weak in a POTT scheme, the delays introduced by the weak-infeed or echo-logic qualification timers add delay, but these times are approximately those of the DCB coordination time delay.

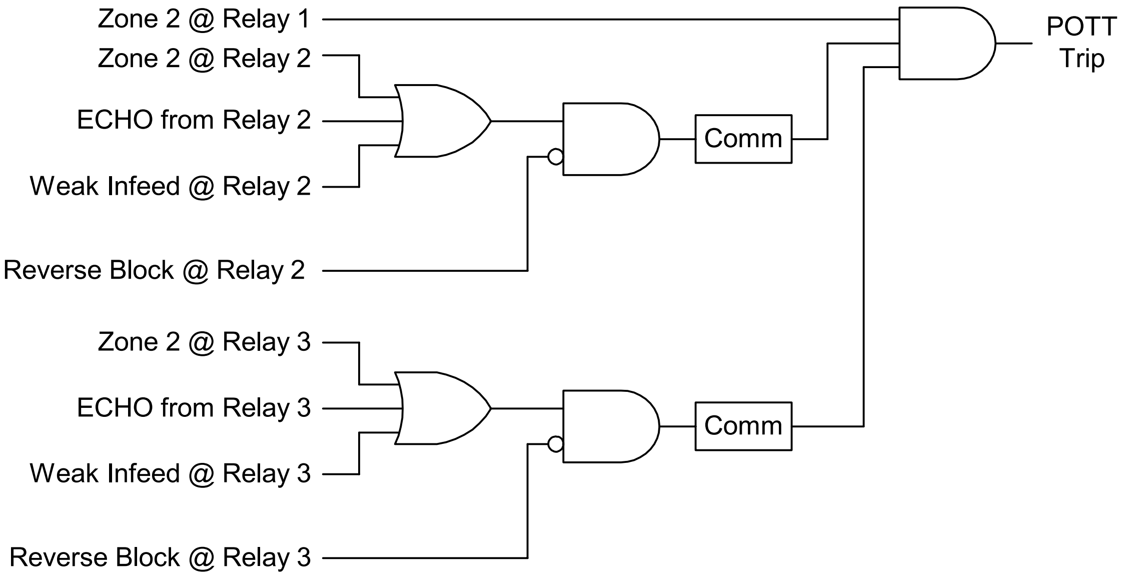


Figure 5 POTT Logic Permits High-Speed Tripping for Higher Resistance Faults (Relay 1 Logic Shown)

Outflow Can Defeat Directional Comparison Schemes

The logic shown in Figure 5 does not remedy the situation where fault current flows out one terminal for an internal fault. For example, given the system in Figure 6 with the A-phase-to-ground fault shown and a tie line in-service, fault current flows into the Relay 3 terminal from the faulted line. Because current is flowing into Relay 3, its directional and distance elements detect the fault current as reverse. This reverse declaration blocks tripping for either the POTT or DCB directional comparison schemes. We assume no terminal is using offset or high-set elements to block the reverse declarations.

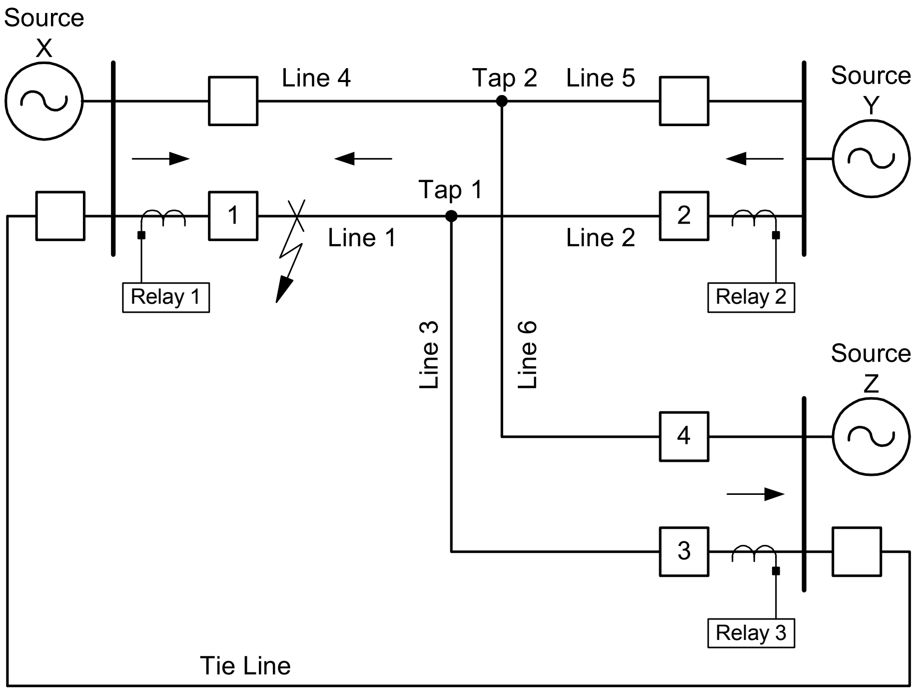


Figure 6 Outflow at Source Z Bus Defeats Directional Comparison Scheme

Table 2 lists example source and line values for the system shown in Figure 6 to create an outflow condition at Relay 3 given an A-phase-to-ground fault on the line side of Breaker 1.

Table 2 System Values for Outflow Example

	Positive-Sequence [Ω secondary]	Zero-Sequence [Ω secondary]
Source X	10.58 Ω ∠90°	31.74 Ω ∠90°
Source Y	0.53 Ω ∠90° (strongest source)	1.59 Ω ∠90°
Source Z	105.8 Ω ∠90° (weakest source)	317.4 Ω ∠90°
Line 1	1.97 Ω ∠90°	6.18 Ω ∠80.1°
Line 2	1.97 Ω ∠90°	6.18 Ω ∠80.1°
Line 3 & Tie Line	0.99 Ω ∠90°	3.09 Ω ∠80.1°

For this three-terminal example, we again set the Zone 1 elements at 80 percent of the impedance to the closest terminal. For all relays, Zone 1 = 2.37 Ω (0.8 • [1.97 Ω + 0.99 Ω]). The Zone 1 ground distance element at Relay 1 can detect faults with up to 9.1 Ω of fault resistance and trips Breaker 1 with no intentional delay.

After Breaker 1 opens, the outflow path for fault current from Source Y is interrupted and the outflow condition stops at Relay 3. As we described earlier, the means for opening Breaker 1 for ground faults in this location are tripping via Zone 1, tripping via Zone 2 ground distance with time delay, or tripping via the communications scheme. For higher resistance ground faults that are outside the reach of the Zone 2 time-delayed element at Relay 1, the communications channel must be in-service to affect a selective trip from Relay 1 unless we use a directional ground inverse time-overcurrent element.

Directional Element Setting

References [11] - [13] describe a directional element system that maximizes sensitivity and security. This directional element system measures either the zero- or negative-sequence source impedance and compares the result against forward and reverse thresholds. If the measured impedance is less than the forward impedance, the relay declares the fault direction as forward. If the measured impedance is greater than the reverse threshold, the relay declares the fault direction as reverse.

Setting the forward and reverse thresholds for two-terminal applications is very straightforward. Assuming infinite sources are both line ends, the relay measures zero impedance for forward faults and the line impedance for faults immediately behind the relay. Thus, set the forward threshold at one-half of the line impedance and the reverse threshold 0.1 Ω greater. We can keep this same setting philosophy if we use the impedance to the tap point from the relay location as the replica line impedance. Not following this simple guideline can lead to directional element misdeclarations.

CURRENT-ONLY TRANSMISSION LINE PROTECTION

Current Ratio Plane (Alpha Plane)

Distance and directional elements are often depicted on either the complex admittance or impedance plane. We can also depict current-only elements such as current differential protection on a complex plane. Warrington ([8], [9]) introduced a complex plane he called the alpha plane. The alpha plane depicts the complex ratio I_R/I_L as shown in Figure 7.

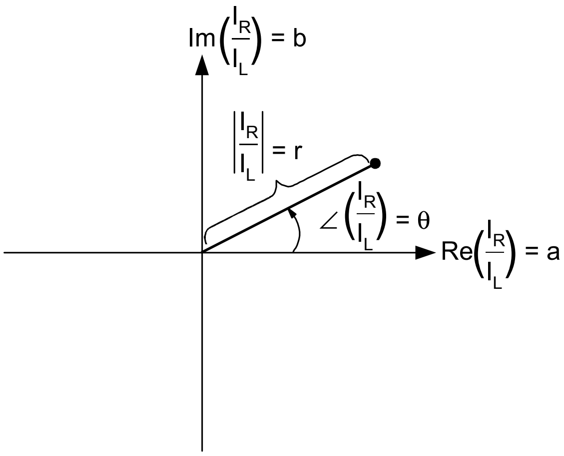


Figure 7 Alpha Plane Represents Complex Ratio of I_R/I_L

We can decompose I_R/I_L into rectangular components:

$$\frac{I_R}{I_L} = a + jb$$

where

$$a = \mathrm{Re}\left(\frac{I_R}{I_L}\right),\ b = \mathrm{Im}\left(\frac{I_R}{I_L}\right), \text{ and } j = \sqrt{-1}$$

or polar components,

$$\frac{I_R}{I_L} = r\angle\theta$$

where

$$r = \left|\frac{I_R}{I_L}\right| \text{ and } \theta = \mathrm{ang}(I_R) - \mathrm{ang}(I_L)$$

A different alpha plane exists for every possible current pair. For example, the A-phase alpha plane depicts the ratio of remote to local A-phase current: I_{AR}/I_{AL}. A separate negative-sequence alpha plane depicts the ratio of remote to local negative-sequence current: I_{2R}/I_{2L}.

Representing Power System Conditions on the Alpha Plane

Load Current and Faults

The alpha plane is useful for visualizing various power system conditions, protection system conditions, and sources of error. For example, consider load current flowing from Terminal L to Terminal R in Figure 8.

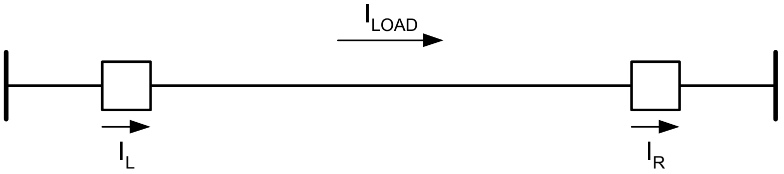


Figure 8 Terminal Currents Are Opposite for Through-Load Current

We take the convention that current flowing into the protected line has zero angle. Neglecting line-charging current, the magnitude of I_{AL} and I_{AR} are equal, and their phases are separated by 180 degrees. Therefore:

$$I_{AR}/I_{AL} = 1\angle 180° = -1$$

Load current plots one unit to the left of the alpha plane origin, at a = -1, regardless of the size or angle of the load current (Figure 9).

The current ratio for external faults is the same as the current ratio for load conditions. Therefore, external faults also plot at a = -1 on the alpha plane (Figure 9).

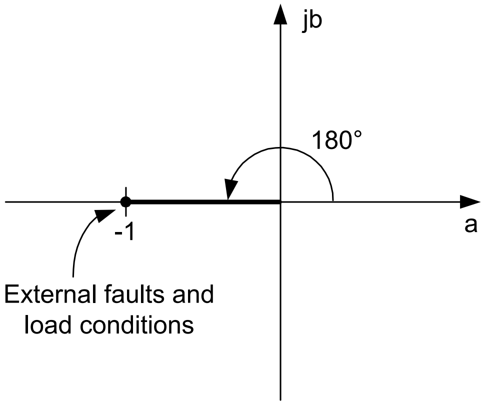


Figure 9 Through-Current Plots at a = -1 on the Alpha Plane

Consider line or load unbalance producing negative-sequence load current. The negative-sequence current magnitudes at the local and remote terminals are equal, and their phases are separated by 180 degrees. Therefore:

$I_{2R}/I_{2L} = 1\angle 180° = -1$

Regardless of the magnitude or relative angle of the load current unbalance, the ideal alpha plane ratio always lies at a = -1. The same argument extends to the other phase alpha planes and the other sequence alpha planes.

Figure 10 adds some possible internal fault conditions to Figure 9. If we disregard all measurement errors, power system angle, source impedance nonhomogeneity, and line-charging current, the alpha plane ratio falls along the real or a-axis. As discussed above, a = -1 for ideal through-current conditions, such as normal loads or external faults. For internal faults with infeed from both line ends a > 0. For internal faults with outfeed at one terminal a < 0.

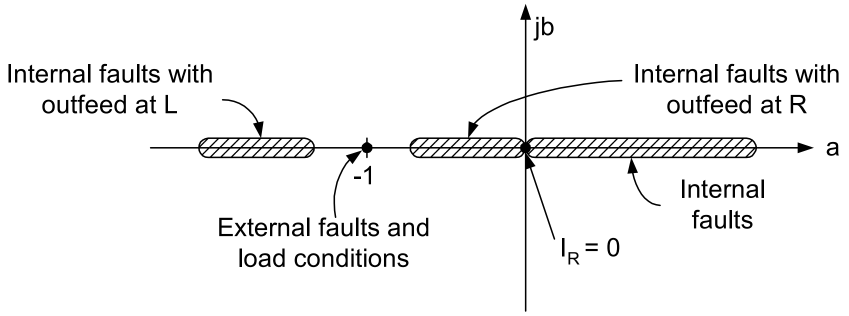


Figure 10 Alpha Plane Regions for Ideal Fault and Load Conditions

System Power Angle and System Impedance Nonhomogeneity

For internal faults, the angles of the phase currents I_L and I_R depend on the angles of the corresponding source voltages and on the angles of the impedances from the corresponding source to the fault point. In general, the currents at both line ends are not exactly in phase for an internal fault. Figure 11 shows the modification of the fault regions allowing ±30° for system power angle and impedance angle difference. Note that the point corresponding to load and external faults is not affected.

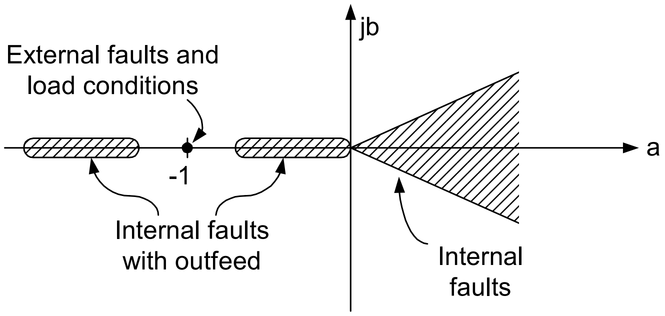


Figure 11 Effects of the System Power Angle and System Impedance Nonhomogeneity on the Alpha Plane

Channel Time-Delay Compensation Errors

If we discuss the ratio of two currents, we must also discuss how those currents are measured. Since the relays that measure the two currents are not co-located, communication is involved. The communications delay produces an apparent phase shift between the local current and the received remote current. The relay must compensate for the channel delay to prevent the apparent phase shift from corrupting the current ratio calculation.

A common technique to compensate for the channel delay, known as the ping-pong technique, involves measuring the roundtrip channel delay. The relay calculates the one-way channel delay as half the roundtrip delay.

This calculation is accurate if the delays in transmit and receive directions are equal. In some channels the transmit path has a different propagation delay from the receive path. This asymmetrical communications delay can exist, for example, on SONET systems. The level of asymmetry depends on the architecture of the communications system. The delay differences are typically less than 2 ms. Delays of 3 - 5 ms are rare.

Delay asymmetry produces an error in the channel-delay compensation. The effect of the error is to rotate the current ratio around the origin on the alpha plane. A 1 ms error rotates the current ratio 21.6 degrees when the system frequency is 60 Hz. The steady-state magnitude of the ratio is unchanged. Figure 12 shows this effect. Note that channel asymmetry expands the ideal fault and load regions of Figure 11.

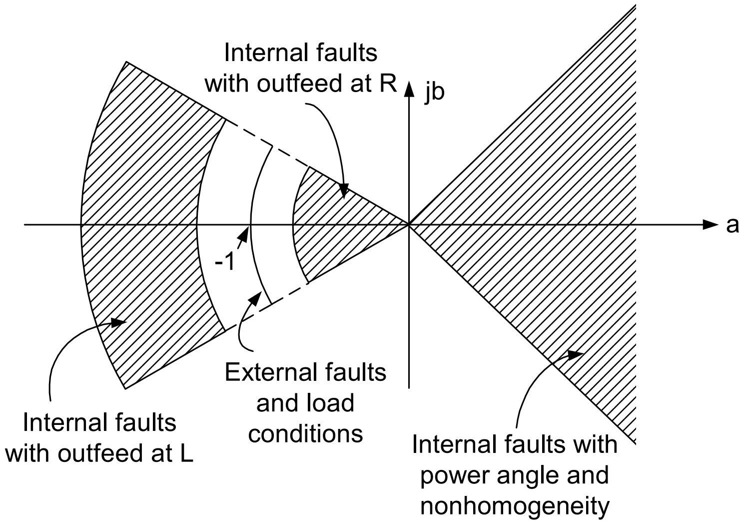


Figure 12 Effect of the Channel Time-Delay Compensation Errors on the Alpha Plane

Line-Charging Current

Line-charging current can flow into the line from one or both line terminals to create a differential current. Figure 13a represents the current components for a normal load condition. The currents at both line terminals are:

$I_L = I_{LOAD} + I_{CL}$ and $I_R = -I_{LOAD} + I_{CR}$

Where I_{LOAD} is the load current and I_{CL} and I_{CR} are the charging current sourced from Terminals L and R, respectively. Then,

$$\frac{I_R}{I_L} = a + jb = \frac{I_{LOAD} + I_{CR}}{I_{LOAD} + I_{CL}} \tag{1}$$

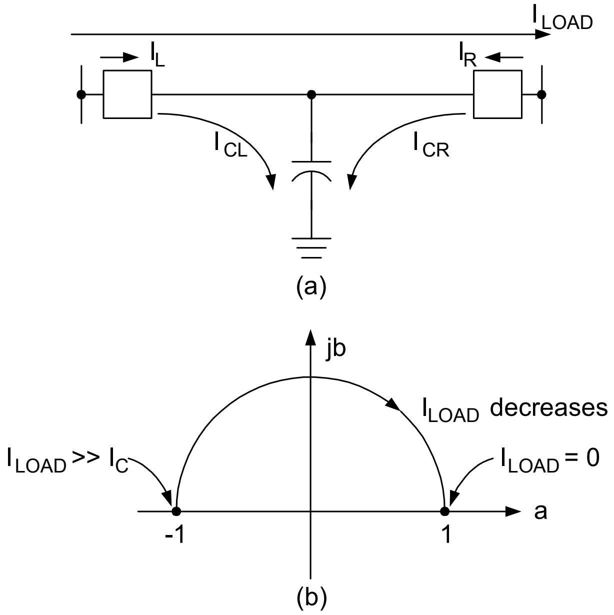


Figure 13 Effect of Line-Charging Current Changes with Magnitude of Load Flow

Figure 13b shows the current-ratio locus in Equation (1) for different values of I_{LOAD}. The trajectory is not generally circular. Note that for small load currents the current-ratio value lies in the right half-plane. One way to avoid relay misoperation is to set the relay minimum pickup current greater than the line-charging current value. For differential elements responding to phase currents, this sensitivity limitation affects the relay fault resistance coverage for internal faults. The negative- or zero-sequence components of the charging current are very low compared to the positive-sequence or phase components. A negative-sequence or a zero-sequence differential element can often be set to be much more sensitive than a phase element.

CT Saturation

When a CT saturates, the fundamental component of the secondary waveform decreases in magnitude, and advances in angle. If the local CT saturates, and the CT at the remote end of the protected line does not saturate, the alpha plane ratio magnitude increases, and the phase angle of the ratio advances, creating an error with significant magnitude and angle components. We discuss CT saturation and its effect on the trajectory of I_R/I_L later in this paper.

Representing Protective Relay Operating Principles on the Alpha Plane

The Restrain Region

As described above, plotting the complex ratio of remote to local current on the alpha plane for various power system and protection system conditions helps visualize those conditions. If we also plot the operate/restrain characteristic of a current-only relay on the alpha plane, we can see how it reacts to those power system conditions.

Deriving Restrain Region Characteristics from Relay Operating Principle

A current-only relay must restrain for load current. Therefore it must contain a restrain region on the alpha plane that includes the point 1∠180°. The relay must trip for internal faults, so the restrain region on the alpha plane must exclude the crosshatched areas shown in Figure 12. It is possible to derive the alpha plane operate/restrain characteristic of current-only relays from the published operate/restrain principle. Roberts, et al. ([16]) derived such restrain regions and compared them to the regions depicted in Figure 12. In the same work, they derived a closed-form solution for various operate and restrain signals used in line differential relays. The authors describe the resulting restrain regions as a circle or a cardioid with a center and diameter that are a function of relay setting parameters.

Calculating Restrain Region Characteristics Point-by-Point

If we are unable to derive the operate/restrain characteristic, we can still create the alpha plane restrain region through an exhaustive search of the alpha plane. For each point on the alpha plane, substitute appropriate values of local and remote current into the published relay operating equations, and obtain a trip/restrain decision from the relay. Mark each point on the alpha plane as being inside the restrain region (relay restrains) or outside the restrain region (relay trips).

Depending on the resolution required, this exhaustive search can be time consuming. A more efficient method, shown in Figure 14, starts at the point 1∠180° on the alpha plane and verifies the relay restrains. From the point 1∠180°, the search sweeps outward on the alpha plane at some angle, until the relay decision transitions from restrain to trip. At that point the search records the transition alpha plane magnitude and angle, advances to the next angle, and begins the radial magnitude sweep again. This procedure repeats for various local currents and relay settings, each of which may change the restrain region.

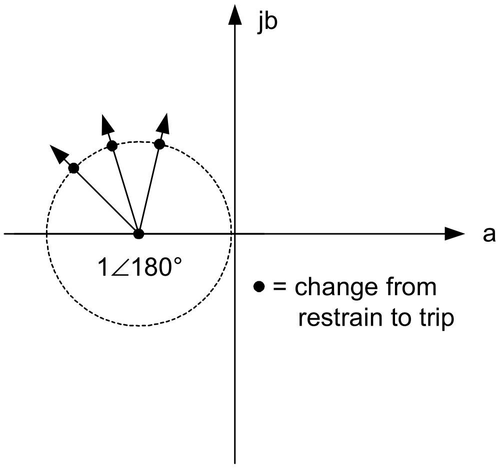


Figure 14 Method of Calculating Alpha Plane Restrain Region

Example Calculation of a Current-Only Restrain Region

We used the search method shown in Figure 14 to analyze a popular current differential operating principle. This operating principle compares an operate current given by Equation (2) with a restraint current given by Equation (3) using the dual slope percentage restrain characteristic shown in Figure 15.

$$I_{OP} = \left| I_L + I_R \right| \tag{2}$$

$$I_{RT} = \frac{1}{2}\left(\left| I_L \right| + \left| I_R \right| \right) \tag{3}$$

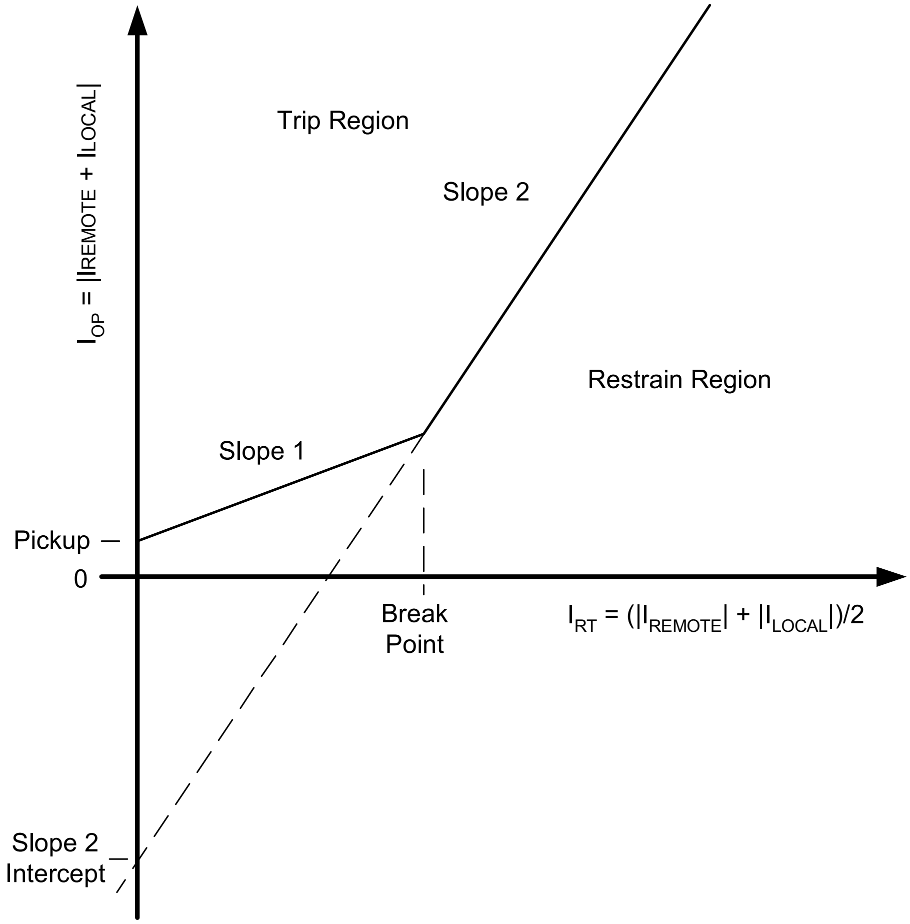


Figure 15 Dual Slope Differential Characteristic

Each slope corresponds to distinct alpha plane restrain regions. Let Slope 1 = 30%, Pickup = 0.2 per-unit nominal, and Break Point = 2.0 per-unit nominal. The first slope and the pickup setting determine relay sensitivity. The second slope is intended to avoid misoperations at magnitudes of current where CTs can saturate. We used the search method described previously to find the alpha plane restrain region for various local current magnitudes.

Slope 1 Gives Decreasing Tolerance to Channel-Delay Compensation Errors for Increasing Load

As Figure 16 shows, the resulting restrain region for Slope 1 is approximately circular, and is centered on the point $1\angle 180°$. Note that the diameter of the restrain region decreases with increasing local current. Combined with our previous analysis, we see this characteristic has decreasing tolerance to channel-delay compensation errors as load current increases. At 1.0 per-unit load current, the tolerance is only 30 electrical degrees. If communications channel asymmetry produces more than about 30 degrees of channel-delay compensation error, this relay trips on load current. For a 60 Hz power system, 30 degrees corresponds to a channel-delay compensation error of 1.4 ms. This situation is of special concern if power system switching operations occur while channel-delay asymmetry exists.

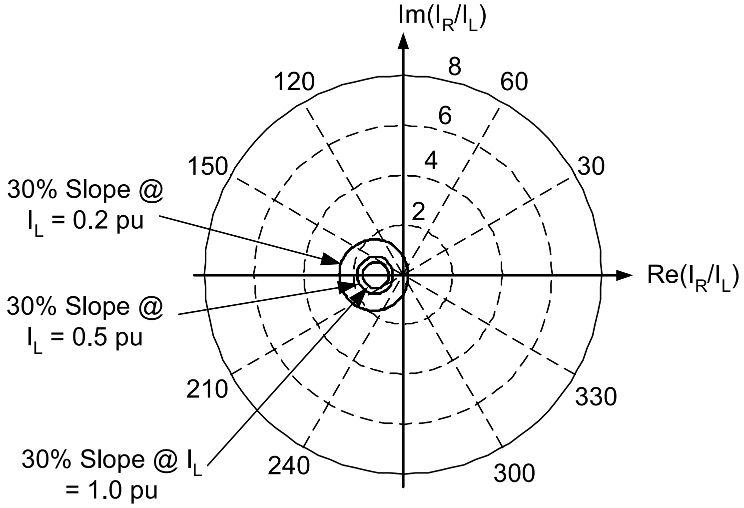


Figure 16 Increasing Local Current Decreases Security to Channel-delay Compensation Errors

Slope 2 Gives Decreasing Tolerance to CT Saturation for Increasing Saturation

Figure 17 shows the restrain region corresponding to Slope 2. It is more cardioidal in shape, and does not have a constant center. Notice the area covered increases with increasing local current. At first glance, this seems appropriate, since the restrain region increases in area for currents more likely to produce CT saturation during an external fault, the very purpose of Slope 2. However, as the local CT saturates the local secondary current magnitude reduces, which decreases the size of the restrain region, and increases the possibility that the relay may misoperate.

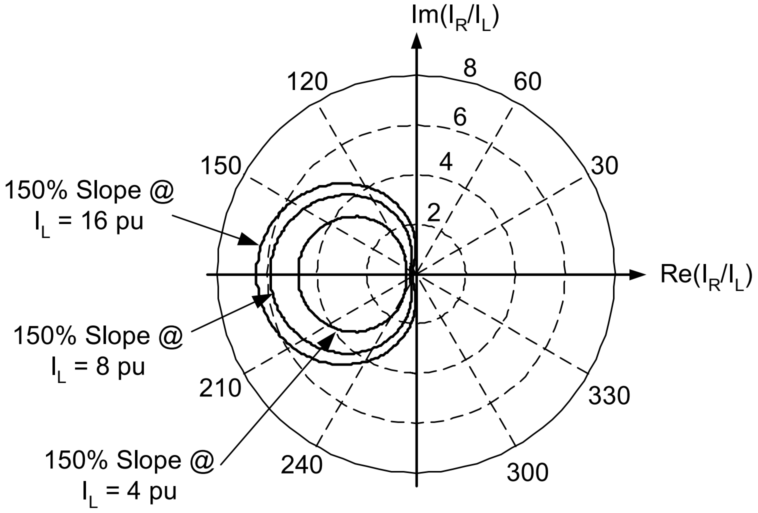


Figure 17 Decreasing Local Current Decreases CT Saturation Security

Notice that for Slope 1, the restrain region area decreases for larger local current, while for Slope 2 the restrain region area increases for larger local current. This is because Slope 1 intercepts the operate current axis above the origin (at the pickup setting), and Slope 2 intercepts the operate current axis below the origin. See Figure 15.

Slope 2 Setting Requires Care

When setting Slope 2, understand where it intercepts the operate current axis. In particular, be very certain of the consequences of setting the relay such that the second slope intercepts the operate current axis above the origin. For example, with Slope 1 = 0.3, Pickup = 0.2, and Break Point = 2, if Slope 2 is set less than 0.4 (= 0.2 / 2 + 0.3), the resulting restrain region of Slope 2 gets smaller for larger fault currents, which is opposite of the effect intended: greater security for higher magnitude fault currents.

A New Restrain Region Retains Tolerance to Channel-delay Compensation Errors and CT Saturation

Roberts, et al. ([16]) realized that power system disturbances and measurements errors can be defined as magnitude and angle effects on the alpha plane. In that paper they created a restrain region directly on the alpha plane, which allows for variations in both magnitude and angle from the ideal load and external fault point ($1\angle 180°$). This restrain region, shown in Figure 18, fits well with the power system conditions and measurement errors described by Figure 12. The size of this restrain region is determined by two settings. One setting determines the outer radius.

The inner radius is the reciprocal of the outer radius. The other setting determines the angular extent of the restrain region. This restrain region does not change as a function of any current.

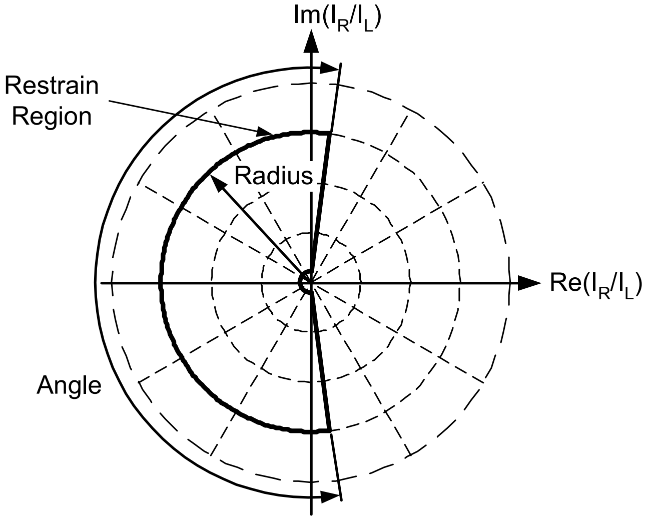


Figure 18 New Alpha Plane Restrain Characteristic Has Settable Radial and Angular Size

Figure 19 compares the restrain region shown in Figure 18 with the restrain regions shown in Figure 16 and Figure 17. From Figure 19a, notice that the proposed restrain region has increased tolerance for channel-delay compensation errors. This is especially true for heavier load currents, since the proposed restrain region does not change as a function of load or fault current.

As mentioned previously, the Slope 2 restrain region size increases with increasing local current. Even at 16 per-unit local current (80 A for a 5 A nominal application), the Slope 2 restrain region does not achieve the security of the proposed restrain region. This indicates the proposed restrain region tolerates more CT saturation while also being very predictable. The proposed restrain region is especially helpful in dealing with the combined effects of CT saturation and communications channel asymmetry.

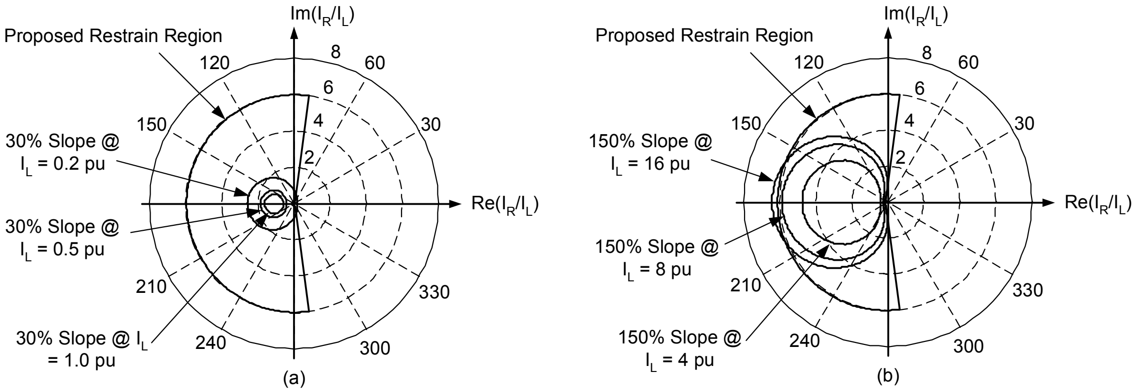


Figure 19 Proposed Restrain Region Is More Secure to Channel-Delay Compensation Errors and CT Saturation

New Alpha Plane Differential Element Has High Sensitivity

The proposed restrain region is secure because it is relatively large. The relay trips if the alpha plane ratio lies outside the restrain region, and the difference current is above a pickup setting. A high impedance ground fault can cause significant outfeed on the faulted phase. In that case, the faulted phase alpha plane ratio may not leave the restrain region. It may remain in the left half-plane, and so the phase element may not trip. Therefore, the restrain region often determines the sensitivity of phase current differential elements.

A relay employing such an alpha plane restrain region can still be very sensitive. An internal ground fault cannot cause significant zero- or negative-sequence current outflow in a balanced system. Therefore, the zero- and negative-sequence alpha plane ratios lie outside their respective restrain regions, even for very small fault currents. Unlike the phase current differential element, the pickup setting of residual current differential elements determines element sensitivity. This gives residual current differential elements very high sensitivity, as shown in Figure 20.

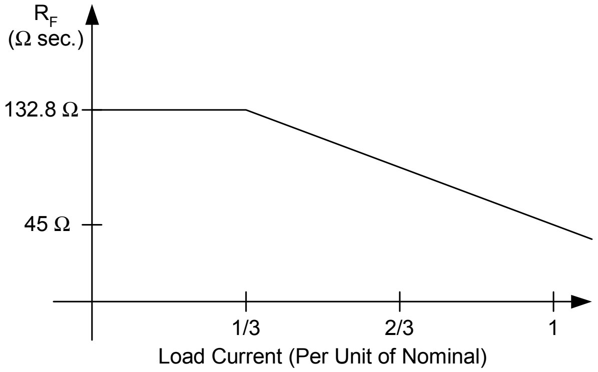


Figure 20 87L2 ($3I_2$) and 87LG ($3I_0$) Sensitivity With Pickup Setting = 0.1 pu, V_{NOM} = 66.4 V

To allow for system unbalance, the relay intentionally desensitizes for load currents above 1/3 nominal current.

By using a residual difference element to detect ground faults, the phase element only needs to detect phase faults. Therefore, we can ignore outfeed when setting both types of elements. A relatively large restrain region still gives very good sensitivity and dependability.

Three-Terminal Current-Only Protection

Traditional Three-Terminal Current-Only Protection on the Alpha Plane

The dual-slope percent restrain characteristic shown in Figure 15 extends to lines or protected objects with more than two terminals. This can be especially useful for protecting transformers where channel-delay compensation errors are not present. The operate current of Equation (2) and the restraint current of Equation (3) are easily extended to three terminals, and beyond, as shown in Equation (4) and Equation (5).

$$I_{OP} = |I_X + I_Y + I_Z| \tag{4}$$

$$I_{RT} = k(|I_X| + |I_Y| + |I_Z|) \tag{5}$$

Three-Terminal Current-Only Protection Using Alpha Plane Concepts

The following discussion concentrates on extending the new alpha plane restrain characteristic of Figure 18 to three-terminal transmission lines.

Divide Three-Terminal Line Into Three Two-Terminal Lines

Consider the three-terminal line shown in Figure 21. If we could place CTs near the line tap point, we could divide this three-terminal line into three two-terminal lines as shown in Figure 22.

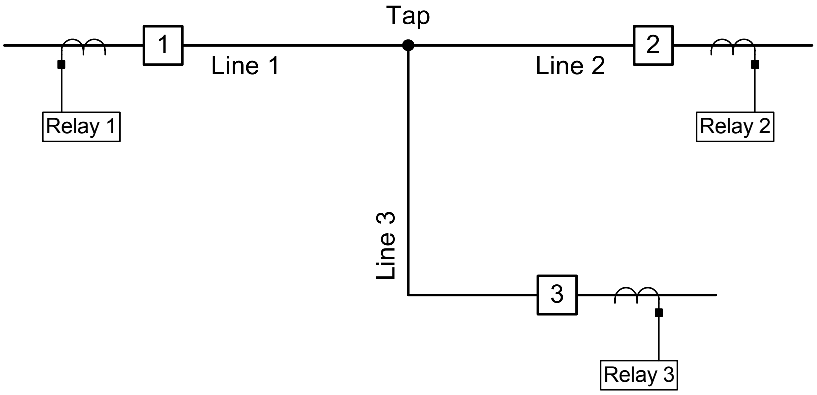


Figure 21 Single-Line Diagram of Example Three-Terminal Line

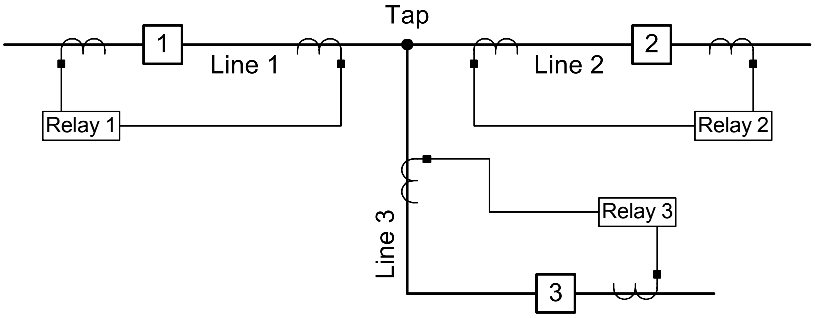


Figure 22 Three-Terminal Line Represented as Three Two-Terminal Lines

Using this concept, Relay 1 protects Line 1, Relay 2 protects Line 2, and Relay 3 protects Line 3. Since each relay protects a virtual two-terminal line, we can use the alpha plane concepts developed earlier to create a restrain region, and to analyze the current differential protection.

Unfortunately, we cannot place CTs near the tap point as depicted in Figure 22. We can approximate the current flowing through each tap point CT as the sum of the currents measured by the other two relays. For example, we can approximate the current flowing through the CT near the tap point on Line 1 as the sum of the currents measured by Relay 2 and Relay 3. This approach requires that each relay receive the currents measured by the other two relays. Figure 23 shows one possible communications topology that allows us to implement this three-terminal protection scheme.

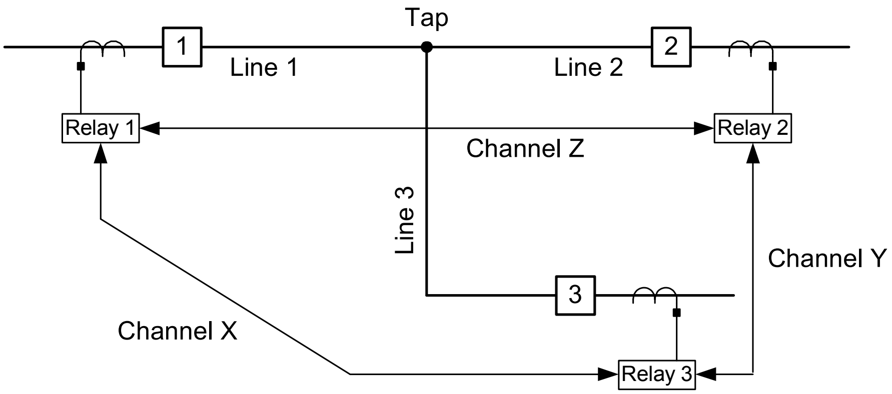


Figure 23 Conceptual Communications Topology

To examine how the scheme detects an internal fault, assume a fault on Line 1. Relay 1 measures the local current, and calculates the sum of the currents received from Relay 2 and Relay 3. Since Line 2 and Line 3 are not faulted, the sum of the currents measured by Relay 2 and Relay 3 is very nearly equal to the current flowing into Line 1 from the tap point. The error is only the total charging current of Line 2 and Line 3. Thus, the local and remote currents used by Relay 1 are an accurate depiction of the currents flowing towards the fault from the ends of Line 1. Therefore, Relay 1 can dependably detect a fault on Line 1. Likewise, Relay 2 and Relay 3 can dependably detect a fault on Line 2 and Line 3, respectively.

Since all three relays have access to currents from all three terminals, it is possible for each relay to perform protection for all three lines. Each relay forms a logical OR of all three trip decisions, and trips if any line is faulted. Therefore, all relays can perform identical calculations, and no transfer trip signals are required. We shall see later that transfer tripping can increase protection dependability during a communications channel failure.

Algorithm Securely Restrains for External Faults

The proposed method is secure for external faults. Recall that if any two segments are not faulted, the current entering the third segment from the tap is the sum of the currents entering the two unfaulted segments from their respective terminals. For an external fault, none of the protected line segments are faulted, so all three current differential protection zones correctly restrain.

Algorithm Tolerates Communications Channel Failure

Assume communications Channel X between Terminals 2 and 3 fails. Relay 1 still receives measurements from Terminals 2 and 3. Relay 1 can still perform current differential protection for all three line segments. If Relay 1 detects an internal fault on any line, it sends a transfer trip signal to the other two relays. Therefore, this method remains dependable and secure for a single communications channel failure, and also could be installed on a three-terminal circuit with only two communications channels.

CT Saturation

Assume an external fault behind Terminal 3 as shown in Figure 24. In most instances we expect the current flowing out of Terminal 3 to be the largest of the three-terminal currents, because it carries the sum of the fault contributions from Terminals 1 and 2. Therefore, CTs at Terminal 3 may be more likely to saturate than CTs at the other terminals. For the example fault, assume 10 per-unit current enters Line 1 from Terminal 1, and 20 per-unit current enters Line 2 from Terminal 2. Then 30 per-unit current flows from Line 3 through Terminal 3 to the fault. The three line-segment alpha ratios for this situation are shown in Table 3. Each of the segment alpha ratios correctly evaluates to $1\angle 180°$, indicating an external fault.

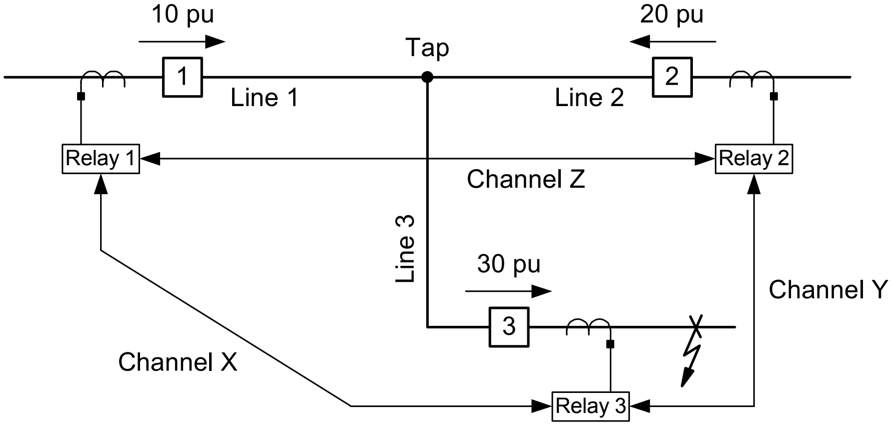


Figure 24 Example System Single-Line Diagram Showing External Fault Behind Terminal 3

Table 3 Ratios of I_R/I_L for Example External Fault

Line Segment	Ideal I_R/I_L
1	$\frac{I_{@2}+I_{@3}}{I_{@1}}=\frac{20-30}{10}=-1$
2	$\frac{I_{@1}+I_{@3}}{I_{@2}}=\frac{10-30}{20}=-1$
3	$\frac{I_{@1}+I_{@2}}{I_{@3}}=\frac{10+20}{-30}=-1$

Now assume the CTs at Terminal 3 saturate, and the magnitude of the fundamental component drops to 20 per-unit. The alpha plane ratio for each line segment changes to that depicted in the second column of Table 4.

Table 4 Ratios of I_R/I_L for External Fault With CT Saturation at Terminal 3

Line Segment	I_R/I_L When $I_{@3}$ Saturates to 20 pu
1	$\frac{I_{@2}+I_{@3}}{I_{@1}}=\frac{20-20}{10}=0$
2	$\frac{I_{@1}+I_{@3}}{I_{@2}}=\frac{10-20}{20}=-0.5$
3	$\frac{I_{@1}+I_{@2}}{I_{@3}}=\frac{10+20}{-20}=-1.5$

Notice that the alpha plane ratio for Line 1 is zero, indicating an internal fault. Also notice that the other two line segment alpha plane ratios correctly indicate an external fault.

Improved CT Saturation Tolerance

We improved the situation described above by modifying the protection scheme. Instead of producing the trip decision from the logical OR of the three line segment trip decisions, the relay chooses the trip/restrain decision created for the line associated with the largest terminal current.

The method originally proposed failed when the CTs at Terminal 3 saturated such that the secondary current fundamental magnitude dropped below 66 percent of its perspective value (from 30 per-unit to 20 per-unit).

In the modified method, the relays at all three terminals use the trip/restrain decision produced by the protection for Line 3, because that line segment is associated with the terminal with the largest current (Terminal 3). The relay system uses that trip/restrain decision until the secondary current entering Relay 3 drops below 20 per-unit, at which time the current measured at Relay 3 is no longer the largest current. All three relays begin to use the trip/restrain decision from the protection for Line 2, because Terminal 2 now has the largest current. The protection for Line 2 continues to produce a correct restrain decision unless the secondary current from Terminal 3 reduces to less than 10 per-unit.

The example fault with CT saturation discussed above matches many existing installations where one terminal is much weaker than the other two. However, it is not worst case for the modified protection algorithms. In the case described, the modified protection algorithms produce a correct trip/restrain decision until the fundamental component of the secondary current from the CTs at Terminal 3 decreases below 33 percent of the perspective value, a reduction from 30 per-unit to 10 per-unit.

Assume instead that the currents entering Lines 1 and 2 are each 15 per-unit, and the current exiting the line at Terminal 3 is 30 per-unit. As shown in Table 5, the protection for all three segments correctly restrains until the secondary current at Terminal 3 decreases because of CT saturation below 15 per-unit (a 50 percent reduction).

Table 5 Ratios of I_R/I_L as a Function of CT Saturation for External Fault With Unequal Remote Sources

I_{LOCAL}	Ideal I_R/I_L	$I_{@3}$ Saturates by 50%
Line 1	$\frac{I_{@2}+I_{@3}}{I_{@1}}=\frac{15-30}{15}=-1$	$\frac{I_{@2}+I_{@3}}{I_{@1}}=\frac{15-15}{15}=0$
Line 2	$\frac{I_{@1}+I_{@3}}{I_{@2}}=\frac{15-30}{15}=-1$	$\frac{I_{@1}+I_{@3}}{I_{@2}}=\frac{15-15}{15}=0$
Line 3	$\frac{I_{@1}+I_{@2}}{I_{@3}}=\frac{15+15}{-30}=-1$	$\frac{I_{@1}+I_{@2}}{I_{@3}}=\frac{15+15}{-15}=-2$

COMMON CONSIDERATIONS FOR DIRECTIONAL COMPARISON AND CURRENT ONLY SCHEMES

Three-Terminal Protection Relies on Communication

As discussed earlier, it is often difficult or impossible to protect three-terminal lines with time-step distance elements because of the effects of infeed and outfeed on element reach and sensitivity. These lines must use communications-assisted tripping, such as DCB, DCUB, etc. to achieve nonsequential tripping of all three terminals for internal faults, and securely block for external faults. These schemes require only a small amount of information exchange to function. Often directional comparison schemes work reliably on a single voice-band channel, or even on channels with less bandwidth.

Current-only protection eases the burden of the protection engineer because settings considerations are much less complex than other pilot protection schemes. Current-only protection also gives excellent sensitivity and speed, but requires more communications bandwidth than directional comparison schemes. A channel that carries more information can tolerate less noise while maintaining dependable communications [17].

When using both protection methods as primary/backup or dual primary for a three-terminal line, protection engineers should keep in mind that many single points of failure can exist in the communications equipment. Ideally the two communications channels should have diverse routing, use different communications equipment, and avoid other single modes of failure. Often such diverse routing of multiple digital communications circuits is not available. For directional comparison schemes, power line carrier, audio tone, and other nondigital, low bandwidth forms of communication can be used effectively to improve protection system reliability, even when a large bandwidth digital communications network is available.

Effects of Current Transformer Saturation for External Ground Faults

Let us next review a CT saturation case for a 69 kV, external A-phase-to-ground fault (see Figure 25) to illustrate how negative-sequence directional elements and the new alpha plane 87L element maximize sensitivity while remaining secure.

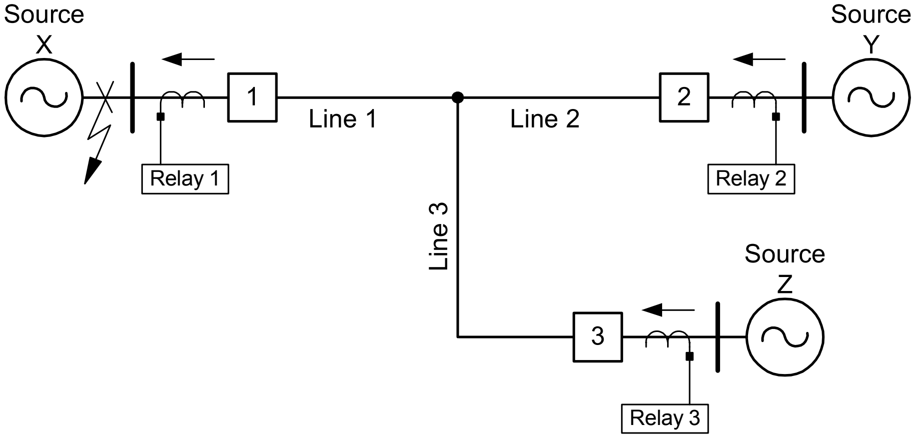


Figure 25 CT Saturation Study System Single-Line Diagram

Table 6 System Values for CT Saturation During External A-Phase-to-Ground Fault Example

	Positive-Sequence [Secondary]	**Zero-Sequence [Secondary]**
Source X	39.00 Ω ∠84° (weakest source)	123.95 Ω ∠81.5°
Source Y	0.13 Ω ∠84° (strongest source)	0.41 Ω ∠81.5°
Source Z	0.33 Ω ∠84°	1.03 Ω ∠81.5°
Line 1 = Line 2	0.68 Ω ∠70°	2.23 Ω ∠72.6°
Line 3	0.34 Ω ∠70°	1.12 Ω ∠72.6°

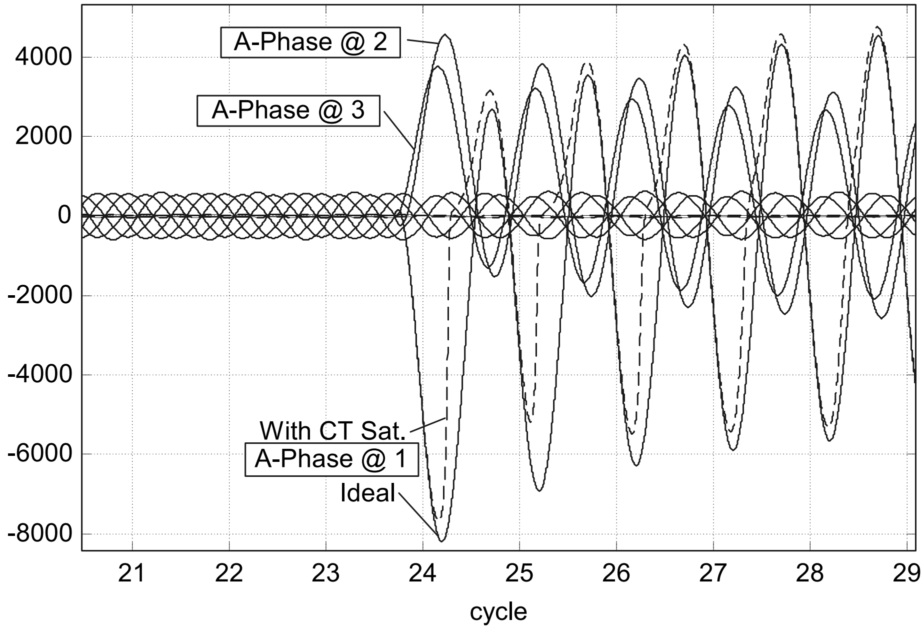
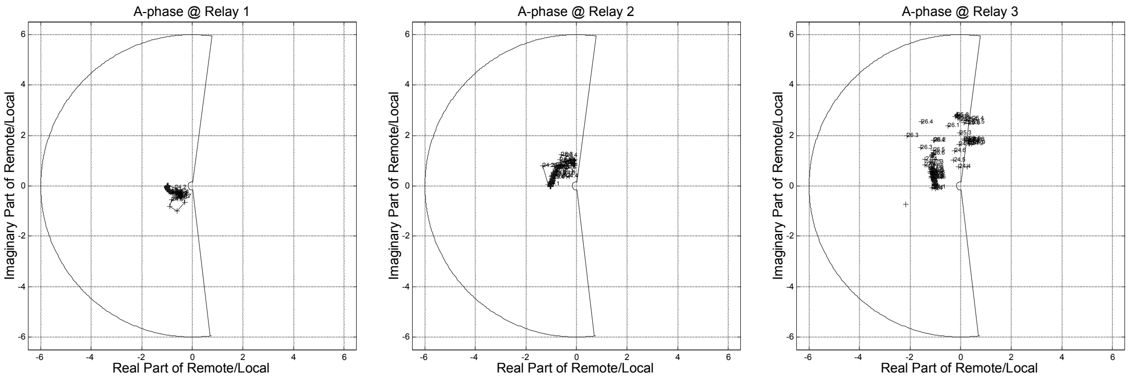


Figure 26 Phase Currents for Out-of-Section A-Phase-to-Ground Fault With $R_F = 0$

For the fault shown in Figure 25, only the A-phase current transformer associated with Relay 1 saturates. The CTs at all line ends are C100, have 1.5 Ω of burden, and a ratio of 500/5. Figure 26 shows the phase currents generated for the fault. If the CT connected to Relay 3 had not saturated, the calculated local and remote currents for each line would differ only by line-charging current. However, because the CT associated with Relay 1 did saturate, the 87L scheme is presented with a significant amount of difference current.



a. Line 1 A-Phase 87L b. Line 2 A-Phase 87L c. Line 3 A-Phase 87L

Figure 27 A-Phase Alpha Plots Show Selecting Terminal Z Decision Makes Scheme Secure

The plots in Figure 27 show the A-phase alpha plane I_R/I_L results for each line for the out-of-section A-phase-to-ground fault described in Figure 25. The dots in each plot represent the calculated alpha plane results when the difference current exceeds the 6 A secondary phase current differential element pickup setting. To obtain this figure, we calculated the fundamental phasor values of currents I_L and I_R. We then determined the phasor I_R/I_L ratio at each relay and plotted the result on the complex plane.

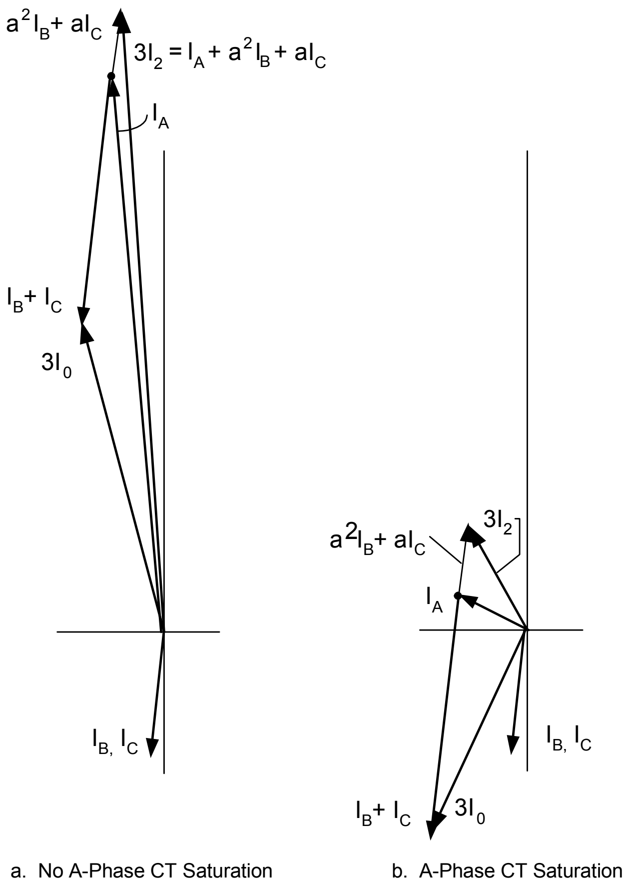
For this example, the fundamental component of the current measured by Relay 1 is always the maximum of the three-terminal currents. Therefore, the relay always uses the alpha plane in Figure 27a. Also notice that the relay would have misoperated had it used the alpha plane in Figure 27c.

Directional Element Performance During CT Saturation

When the CT does not saturate during an external fault, the angle difference between V_{A2} and I_{A2} adjusted by the line angle is very nearly zero. As a CT saturates for an external fault, the magnitude of I_{A2} decreases and its angle advances. The negative-sequence voltage-polarized directional element algorithm shown in Equation (6) tolerates up to 90 degrees of phase error caused by CT saturation. The denominator term in (6) serves to scale the result and does not change sign. For the numerator term to change sign because of CT saturation, and thus change fault direction declaration, the angle of I_{A2} must advance more than 90 degrees. Both the magnitude reduction and angle advancement because of CT saturation reduce z2, but the result remains positive as we would expect for a reverse fault. Note that the reduction in z2 caused by angle advancement is offset somewhat by the division by the square of a smaller number. An adaptive threshold feature further reduces the reverse threshold to preserve the directional element integrity.

$$z2 = \frac{\mathrm{Real}\left[V_{A2} \bullet \left(I_{A2} \bullet 1\angle Z_{1L}\right)^*\right]}{\left|I_{A2}\right|^2} \tag{6}$$

Negative-sequence 87L or directional elements are more secure than zero-sequence elements during CT saturation. Figure 28 illustrates the basics of why negative-sequence elements are more secure for an out-of-section ground fault where only one line terminal CT saturates. Note that the two nonfaulted phase currents in this figure are unaffected. Adding the B- and C-phase current vectors to a reduced, and more leading, A-phase current causes the zero-sequence current to advance more than 90 degrees. Also notice that negative-sequence current shown in Figure 28 does not experience the same reversal. Incoming load flow aggravates this zero-sequence current reversal.



a. No A-Phase CT Saturation b. A-Phase CT Saturation

Figure 28 Zero-Sequence Current Experiences Phase Reversal Caused by CT Saturation

TAPPED LINE PROTECTION

Tapped lines are a special form of three-terminal lines. For these applications, the primary zone of protection is the mainline. Breakers on either end of the line must interrupt fault current flow for any mainline fault. Line protection can also provide backup protection for the tapped transformer. The line protection scheme should not operate high-speed for transformer low-side faults or out-of-section faults. The fact that the tapped transformer instrumentation and information from the tap location is excluded from the line-end trip or restrain decision presents several unique protection challenges for directional comparison and line current differential protection schemes. Specific challenges include:

- Zero-sequence impedance discontinuity if the tapped transformer is connected grounded-wye, grounded-wye.
- Infeed during ground faults if the transformer high voltage winding is connected grounded-wye and the low-voltage winding is connected in delta, or if there is a delta-connected tertiary winding.
- Transformer inrush during line energization or sympathetic inrush when an out-of-section fault clears.

Applying Distance Based Elements to Tapped Transformer Lines

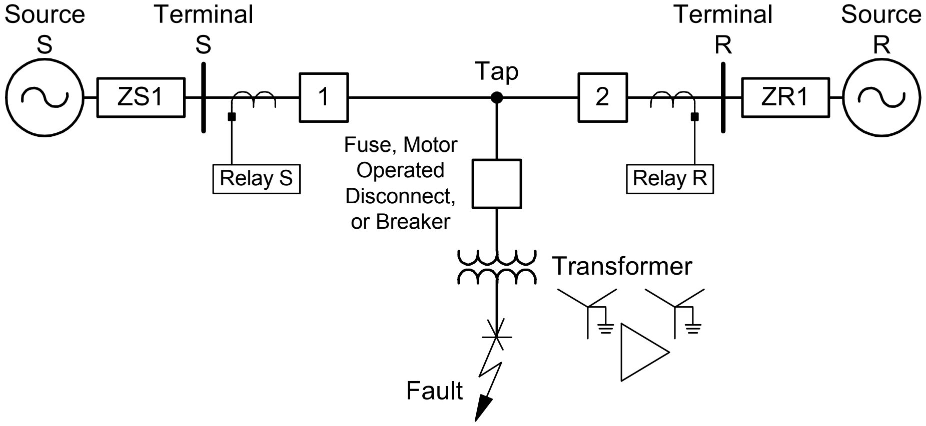


Figure 29 Tapped Transformer Application Single-Line Diagram

For the system shown in Figure 29, the Zone 1 ground distance protection at either line end must not operate for the fault shown. Single-line-to-ground faults involve all three sequence networks: positive-, negative-, and zero-sequence. Ground distance elements commonly use a zero-sequence compensation factor, k0, to relate this complex sequence network relationship to that of the positive-sequence network. Equation (7) shows a common definition of k0:

$$\mathrm{k0} = \frac{\mathrm{Z}_{0\mathrm{L}} - \mathrm{Z}_{1\mathrm{L}}}{3 \bullet \mathrm{Z}_{1\mathrm{L}}} \tag{7}$$

where:

$\mathrm{Z}_{0\mathrm{L}}$	Replica Line Zero-Sequence Impedance
$\mathrm{Z}_{1\mathrm{L}}$	Replica Line Positive-Sequence Impedance

Equation (8) [13] shows the mho ground distance algorithm used by one popular distance relay. This equation defines the minimum ground distance element reach required to just detect an A-phase-to-ground fault. The relay compares the calculated m against each zone threshold to determine if a zone of protection is picked up. If m is less than the set zone reach, that zone of A-phase ground distance is considered picked up, assuming that all supervisory logic conditions are satisfied.

$$\mathrm{m} = \frac{\mathrm{Real}\left(\mathrm{V}_{\mathrm{A}} \bullet \mathrm{V}_{\mathrm{A1MEM}}{}^{*}\right)}{\mathrm{Real}\left(1\angle \mathrm{Z}_{1\mathrm{L}} \bullet \left[\mathrm{I}_{\mathrm{A}} + \mathrm{k0} \bullet \mathrm{I}_{\mathrm{R}}\right] \bullet \mathrm{V}_{\mathrm{A1MEM}}{}^{*}\right)} \tag{8}$$

where

V_{A}	Measured A-Phase voltage
$\mathrm{V}_{\mathrm{A1MEM}}{}^{*}$	Complex conjugate of the positive-sequence voltage referred to A-phase
$1\angle \mathrm{Z}_{1\mathrm{L}}$	Vector of unity length at the angle of the positive-sequence replica line angle
I_{A}	Measured A-phase current
k0	Zero-sequence compensation factor
I_{R}	Residual current (= $\mathrm{I}_{\mathrm{A}} + \mathrm{I}_{\mathrm{B}} + \mathrm{I}_{\mathrm{C}}$)

The tapped transformer positive- and zero-sequence impedances are commonly equal. For an overhead line, the ratio of $|Z_{0L}| / |Z_{1L}|$ is typically in the range of 2 - 6. Thus, the k0 factor for the transformer is zero and that for the protected line ranges from 0.33 - 1.67. For ground faults on the transformer low-side, the effect of this zero-sequence impedance discontinuity on the ground distance protection at each line end is to overcompensate the I_R term in Equation (8). This overcompensation can cause ground distance element overreach. To prevent this from occurring, apply bolted ground faults on the transformer low-side in the fault study, and enter the calculated values into the distance element equation to determine the appropriate reach setting.

Let us next consider applying directional comparison protection to a line with a tapped transformer. Unless the tapped transformer is located very near one line end, or has a very large impedance relative to the protected line, the overreaching distance elements at both line ends sense faults on the transformer low-voltage side. This loss of selectivity makes any directional comparison scheme undesirable for most practical applications. Time-stepped distance protection is still a valuable approach for these applications.

Zero-Sequence Infeed

For ground faults between the tap and Terminal R, the zero-sequence current infeed from the transformer tap decreases the zero-sequence current contribution from Terminal S. This infeed causes underreach of the ground distance protection at Terminal S (the amount of underreach depends upon the amount of infeed). Set the Zone 1 ground distance protection to underreach the tapped transformer when the tapped transformer is out-of-service, and set the Zone 2 ground distance protection to overreach the remote terminal with the transformer in-service.

Transformer Inrush

This process of exciting the tapped transformer can draw appreciable current from the power system. The current drawn by the transformer upon energization is called inrush current. Inrush current exists upon transformer energization or when an external fault is cleared and full voltage is again applied to the transformer. Inrush currents usually have a high harmonic content. Today's microprocessor relays typically filter out these harmonics and operate on the fundamental component only. This means that we need only be concerned with the higher-than-normal fundamental component of transformer inrush. To illustrate how transformer inrush affects the reach of the ground distance protection at Terminal S, let us review the 60 Hz, 69 kV system shown in Figure 30. As compared with the system in Figure 29, Source R is out-of-service and is replaced with a 25 MVA load to illustrate picking up a line with maximum load.

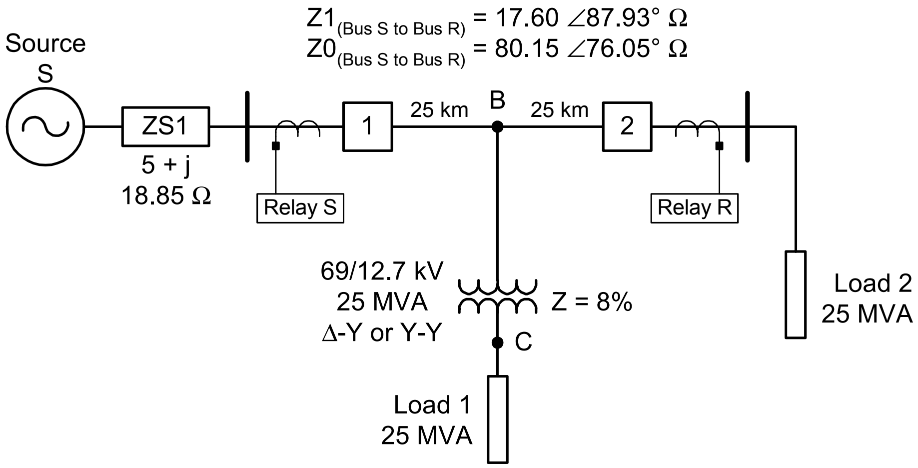


Figure 30 Inrush Test System Single-Line Diagram

The 25 MVA transformer nominal current is:

$$I_{NOM} = \frac{25 \bullet 10^6 \bullet \sqrt{3}}{3 \bullet 69 \bullet 10^3} = 209.18 \text{ A (rms)}$$

The transformer impedance is:

$$Z_T = \frac{69 \bullet 10^3 \bullet 0.08}{209.18 \bullet \sqrt{3}} = 15.236\,\Omega$$

Table 7 summarizes the maximum fundamental A-phase inrush current magnitude. We varied the amount of inrush by controlling the transformer flux prior to energization. The number shown in parenthesis in the second and third columns of Table 7 is the ratio of the maximum fundamental inrush current to the maximum transformer fundamental current. From Table 7, note that the wye-connected transformer requires the highest inrush current.

Table 7 Peak Inrush Current Summary

Severity of Inrush Current	Delta Connected	Wye Connected
Low	200 (0.96) A	350 (1.67) A
Medium	600 (2.87) A	700 (3.35) A
High	1050 (5.02) A	1450 (6.94) A

To illustrate the effects of high inrush current from the wye-connected transformer in the system shown in Figure 30, we simulated closing Breaker 1 with the system not faulted and then applied an A-phase-to-ground fault 18 cycles later. We included a fault in our inrush study to show the contrast between fault and inrush current quantities.

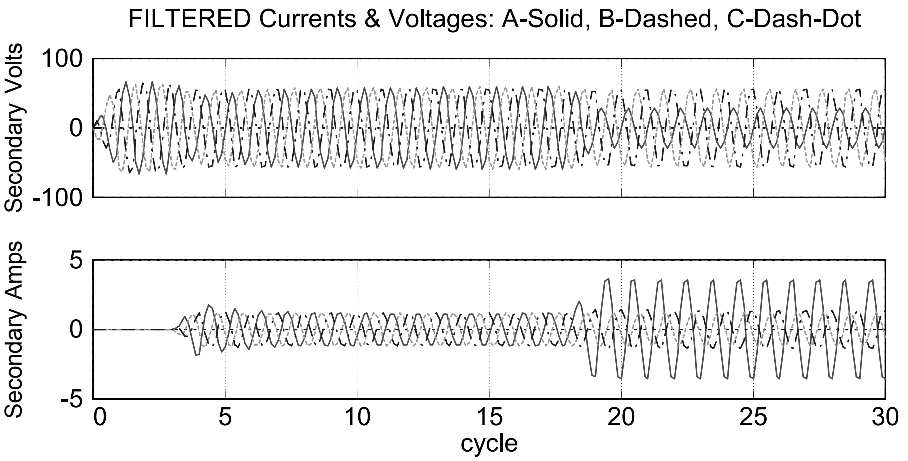


Figure 31 Inrush Current and Voltage Waveforms for Wye-Wye Connected Transformer, With Maximum System Load Followed by an A-Phase-to-Ground Fault at Location B in Figure 30

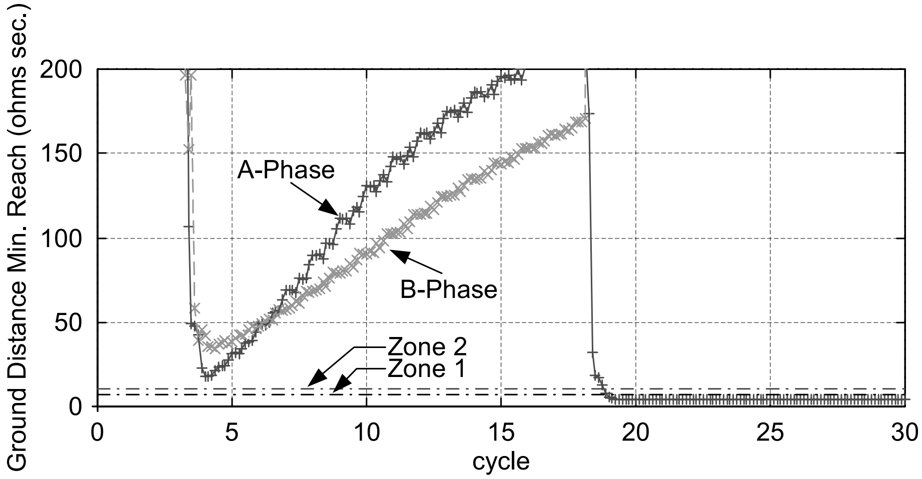


Figure 32 Minimum Ground Distance Reach Required for the Voltage and Current Waveforms Shown in Figure 30

Notice that in Figure 32 the transformer inrush coupled with the high load reduces the minimum m, shown in Equation (8), substantially during the initial inrush conditions. However, the minimum distance element reach never drops below the Zone 2 reach set at 120 percent of the entire 69 kV line. Earlier we noted that the application of distance protection to tapped lines is generally restricted to time-stepped distance or time-overcurrent protection. Thus, even if we extended the Zone 2 reach and the inrush conditions were to pick up the Zone 2 element, the relay would still not trip because of the security added by the Zone 2 time delay.

Applying Line Differential (87L) Protection to Tapped Transformer Lines

Because tapped load current is not included in the 87L calculations, the line 87L element can detect and operate for faults on the low-voltage side of the tapped transformer. It is undesirable for the 87L element to trip high-speed for these faults. Whether the line 87L element detects the fault is only controlled by the 87L sensitivity. The classical approach to gaining selectivity in such applications has been either to desensitize the 87L (by setting it up above the low-side transformer fault duty) or to supervise the 87L with a distance element that does not sense low-side transformer faults. The first solution is undesirable because it limits the ability to detect high-impedance mainline faults. The second solution may not be available if voltage transformers are not connected to the protective relay.

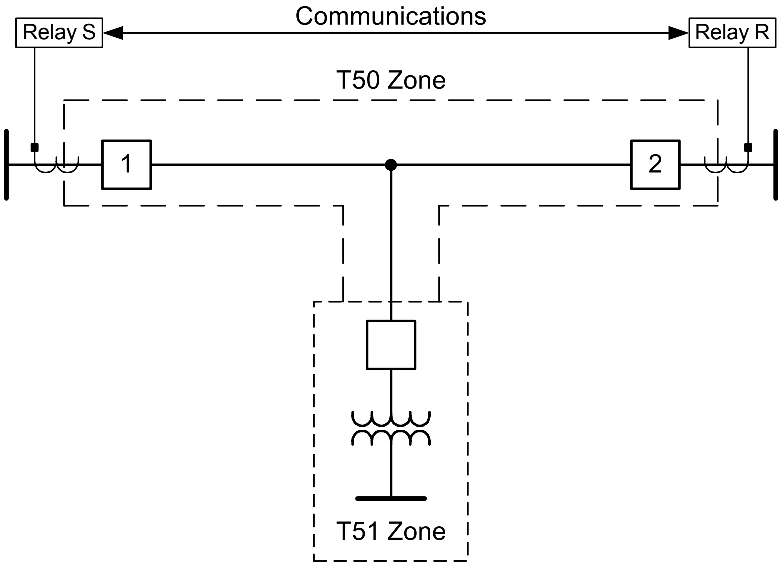


Figure 33 Total Line Current Measured by 87L Relay Transforms Two-Ended Line to Radial Line

For a transformer low-side A-phase-to-ground fault, $|I_{AS} + I_{AR}|$ measures the magnitude of the total A-phase fault current flowing into the transformer. This same current is also measured by the transformer high-voltage side protection. Thus we can easily perform direct time coordination with an 87L supervised total overcurrent element. Such an element could use the same pickups and a higher time dial than the transformer high-side protection.

This scheme is comprised of instantaneous/definite-time (T50) and time-overcurrent (T51) elements that operate on different current. Figure 33 shows the zones of protection afforded by the T50 and T51 elements. Supervision of phase, negative-sequence, or ground T50 and T51 elements by a corresponding 87L element gives additional scheme security for external mainline faults that may cause CT saturation.

This solution is very effective in many applications because the difference in fault duty between transformer high-side and low-side faults is appreciable. Note that higher resistance mainline faults are still detectable by the T51 element because of its lower pickup threshold. In those applications where the source strength changes appreciably, we recommend using a distance element instead of the high-set T50 element.

Figure 34 shows the total A-phase current as measured by the T50 and T51 elements inrush for the wye-connected transformer, followed by an A-phase-to-ground fault on the transformer low-side. Notice that the maximum fundamental inrush current is similar to the fault current, but the duration of the high inrush current is very short. Comparing the fault current in Figure 34 and Figure 35, we see that there is a large difference in magnitudes. Thus, we can set the T50 element pickup threshold such that it is above low-side fault duty and transformer inrush, yet below transformer high-side fault duty. A reasonable security measure would be to add a one-cycle time-delayed pickup to the T50 element.

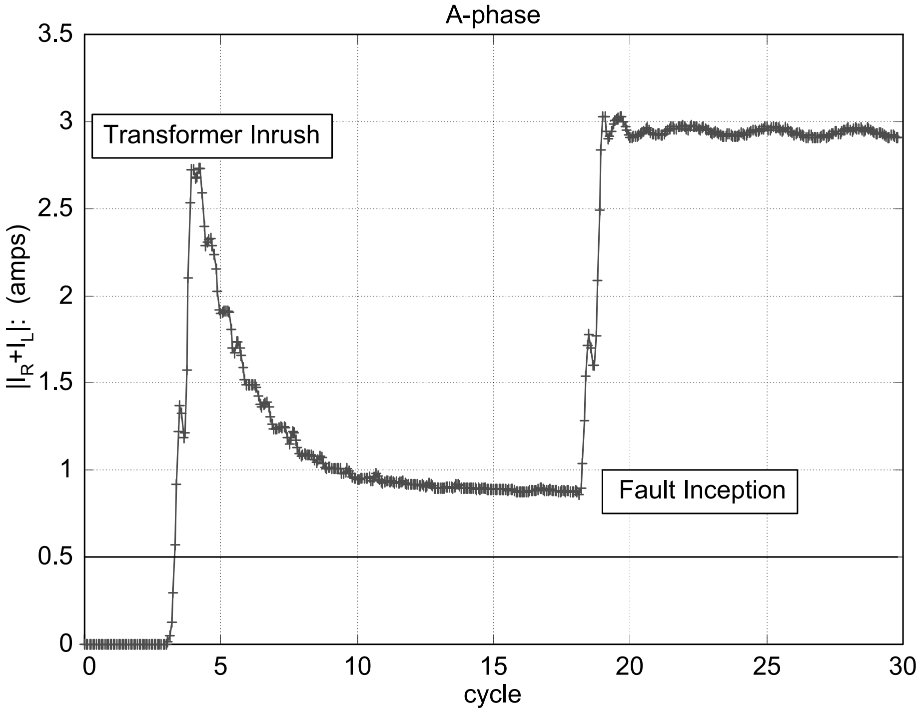


Figure 34 A-Phase Transformer Inrush and Total Fault Current for Transformer Low-Side Phase-to-Ground Fault as Measured by the 87L Scheme

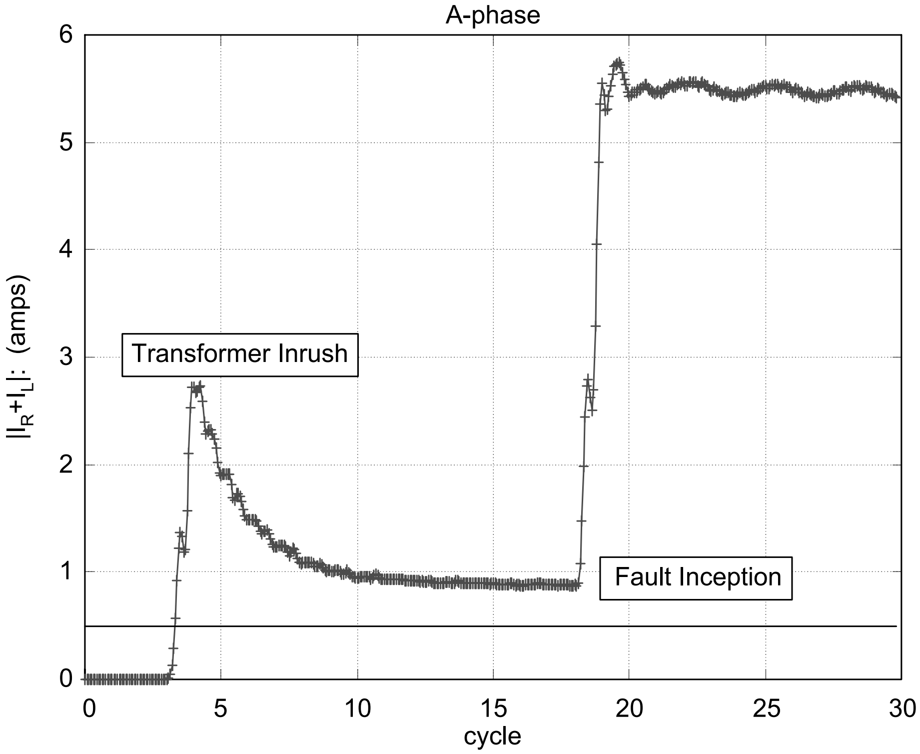


Figure 35 A-Phase Transformer Inrush and Total Fault Current for Transformer High-Side Phase-to-Ground Fault as Measured by the 87L Scheme

CONCLUSIONS

1. Current infeed and outfeed for internal faults on three-terminal lines make robust time-stepped distance protection difficult and sometimes impossible. Review existing lines for deficiencies.
2. Outflow can defeat directional comparison schemes on a three-terminal line.
3. Communications are critical for three-terminal protection dependability given infeed and outfeed. Directional overcurrent protection is more dependable, but is more difficult to coordinate, especially on three-terminal lines.
4. Overreaching pilot elements must be separate from overreaching time-delayed backup elements for many three-terminal applications.
5. Directional comparison protection and current-only protection are very complementary. They provide two separate methods of detecting all fault types.
6. When current-only and directional comparison protection are used, many common points of failure can exist in the communications network. Traditional directional comparison channels such as PLC, audio tone channels, etc. may be useful in maintaining diverse routing even when a high-bandwidth digital network is available.
7. The alpha plane helps visualize how various power system and protection system phenomena affect current-only protection security, dependability, and sensitivity.
8. It is possible to represent two-terminal current-only protection algorithms as a restrain/operate region on the alpha plane. A computerized search of the alpha plane helps find the alpha plane restrain region for such systems.
9. Traditional current differential protection restrain regions determine security, dependability, and sensitivity. It is difficult to increase one without decreasing another.
10. Current differential restrain regions corresponding to popular percent-restrain principles are often a non-obvious function of load and fault current. It is important to understand how the restrain region changes as a function of current and relay settings to avoid unexpected and undesirable operation.
11. Use a phase current differential element to detect phase faults, and a residual current differential element to detect ground faults. This approach permits the use of a larger, more secure restrain region without sacrificing dependability or sensitivity. A larger restrain region designed directly on the alpha plane can have more tolerance to the effects of errors. This is especially true if conditions such as CT saturation and channel-delay compensation errors occur simultaneously.
12. By dividing a three-terminal line into three two-terminal lines, it is possible to use alpha plane concepts to analyze and protect a three-terminal line.
13. Instantaneous and time-overcurrent elements that operate on difference current (T50 and T51) allow high-speed protection of the mainline, and coordinate with tapped transformer high-side protection. Supervise T50 and T51 elements with 87L elements to maintain security for external faults that cause CT saturation.

14. Residual current infeed from tapped loads with wye-wye grounded transformers often force the protection engineer to reduce Zone 1 ground distance reach to avoid overreaching low-side faults.
15. Weak-infeed and echo logic allows modern transfer trip schemes to achieve the same sensitivity as blocking schemes.
16. During severe CT saturation, negative-sequence differential and directional elements are more secure than zero-sequence elements. This is especially true for incoming load current conditions.

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BIOGRAPHIES

Jeff Roberts received his BSEE from Washington State University in 1985. He worked for Pacific Gas and Electric as a System Protection Engineer. In 1988, he joined Schweitzer Engineering Laboratories, Inc. as the first Application Engineer. Later he became Application Engineering Manager. He now serves as the Research Engineering Manager. He has written many papers in the areas of distance element design, sensitivity of distance and directional elements, line differential and directional element design, protection scheme design and analysis of event report data. Mr. Roberts holds over twenty patents granted or pending. He is also a senior member of IEEE.

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