Transmission Line Applications of Directional Ground Overcurrent Relays

Working Group D24 Report to the Line Protection Subcommittee
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1 Introduction

This report is prepared for the Line Protection Subcommittee of the Power System Relaying Committee on the application of directional ground overcurrent relays for transmission lines.

Multiple application items are discussed and include topics from pick-up and time-delay determinations to topics about ground source issues and the use of negative sequence overcurrent elements.

2 Purpose

This report discusses the justifications and application criteria for applying directional overcurrent relays for ground fault detection as applied for protection of transmission lines. Polarization topics, pilot scheme setting practices, and resonance grounding issues are not addressed.

3 Definitions

This report uses terminology that is consistent with other IEEE standards and guides. No new terms or definitions are introduced.

This report only discusses directional ground overcurrent relays. Thus, throughout the report, directionality is implied for all cases where either the time overcurrent ground element or instantaneous overcurrent ground element is used in the discussion.

4 Summary

Both ground distance and directional ground overcurrent relays are commonly used to detect transmission line ground faults. Ground distance relays, however, may not have adequate sensitivity to detect all impedance limited ground faults because the distance element characteristic limits resistive reach. Ground overcurrent relays, on the other hand, are better suited to detect these faults because their characteristic has better sensitivity to resistance limited faults.

The type of grounding, system parameters, and specific fault impedance determine the magnitude of ground faults. Faults that contain significant impedance are relatively low in current magnitude when compared to faults that do not contain appreciable impedance. Such faults can pose a challenge to distance relays due to their sensitivity associated with the line characteristic impedance angle. Directional overcurrent ground relays may be set sensitive enough to detect these faults with minimal effects on security due to the fact that transmission networks are inherently designed such that zero sequence currents created by system imbalances are minimized. The limits that exist on how sensitively a relay is allowed to be set are truly part of the "art" of protective relaying.

Methods of setting the directional ground overcurrent relays vary among companies, locations, etc. Pickup settings, based on primary zero sequence fault levels or a comparable concept that allows these pickup settings to be uniformly applied, improves the ability to achieve effective coordination. Regardless of the method, setting the ground relay sensitive enough to detect faults that the ground distance elements do not detect, is desirable.

The selection of the characteristic curve for time delayed tripping is a matter of preference, but is much more effectively coordinated with other ground fault protection by using the same or similar characteristic curves. Coordination with other similar relays at remote terminals need only be effective for the range of fault currents reasonably expected at that location.

The system model must contain a level of accuracy that supports the desired relay setting sensitivity. Transmission lines need to be correctly modeled including specific conductor types, series-compensation, structure type, earth resistivity, etc. The zero-sequence mutual coupling for circuits must be accurately modeled with the correct orientation between line segments and the corresponding mutual coupling effects. Under-built distribution lines may also need to be considered. System fault data should also be used to validate and revise the model as necessary.

Negative sequence overcurrent can also be utilized to detect unbalanced faults, including ground faults. However, the negative sequence overcurrent element can be difficult to coordinate with conventional ground overcurrent elements because the negative- and zero-sequence current distribution factors are typically different for transmission line protection applications. Negative sequence overcurrent elements can provide adequate fault protection in parts of the systems that are poorly grounded and during contingencies that may reduce available ground fault current. Conversely, negative-sequence overcurrent elements will not operate properly when the source becomes an isolated zero-sequence current source. For example, this condition can occur near generation sources when the generation is off line, but the delta-wye generator step-up transformer is still connected to the system.

5 Application Items

5.1 Comparison of Directional Ground Overcurrent Relaying and Ground Distance Relaying

Directional ground overcurrent and ground step distance are the most common ground fault detection methods used in transmission line protection. Each of the two methods has its own advantages and disadvantages.

Directional ground overcurrent elements respond to zero-sequence current. Sources of zero-sequence current during normal, unfaulted conditions include unequal per-phase connected load and unequal phase impedances due to differences between the individual series and/or shunt impedances on the transmission system. Generally, such “system inherent” imbalance is minimal. However, the imbalance can impose a limit on the sensitivity of ground overcurrent element settings. More significant levels of zero-sequence current typically result from the short circuit faults connecting one or two of the three phase conductors to ground. However, ground fault current can be limited by fault impedance. In severe cases, the ground fault current may be nearly the same magnitude as the inherent system unbalance current.

Directional ground overcurrent protective elements generally provide effective resistive fault coverage since they can usually be set sensitively enough to detect many such ground faults.

Directional ground overcurrent elements are relatively easy to understand and visualize. Pickup current thresholds can be determined from readily available fault study data.

The ground overcurrent element is not generally affected by load current, which is typically balanced on a transmission system and thus, contains low ground current magnitudes under normal conditions. Also, the ground overcurrent element is not affected by phase-to-phase connected loads, balanced or unbalanced, because the loads do not produce residual ground current.

Transmission line protection using directional ground overcurrent elements has several limitations. Available fault current is affected by changes in the power system source impedance, and thus, the ground overcurrent element is susceptible to varying system conditions. Because the transmission system configuration may change over a period of time, the settings may need to be reviewed more frequently than those of ground distance relays.

Both ground distance and directional ground overcurrent elements are affected by zero-sequence mutual coupling of transmission lines. These affects can result in incorrect direction determination, as well as an increased or reduced sensitivity for detecting faults.

Although directional ground overcurrent elements are minimally affected by steady state load conditions, in some situations, higher pickup thresholds may be required to prevent undesirable operation for unusually pronounced system imbalance. For example, the presence of non-transposed lines may lead to unusually high levels of steady state zero-sequence current. Also, the operation of line switches to open or close loaded lines, may lead to momentary levels of high zero sequence current caused by unequal pole opening and closing times. Higher settings, of course, whether applied constantly or during periods of line switching, will result in decreased sensitivity for ground fault detection.

The main disadvantage of the ground distance element is its limitation in detecting impedance limited ground faults. The voltage measured by the ground distance function is the sum of the line voltage drop to the fault and the voltage drop across the fault impedance. The voltage drop across the fault impedance can change due to current infeed from other line terminals. The net effect of the infeed condition amplifies the apparent fault impedance seen by the element at the line terminal, thus further impeding its ability to detect an impedance limited fault.

Ground distance protection for transmission lines is generally easier to apply than directional ground overcurrent protection. Distance relay reach is practically immune to variations in source impedance, providing a relatively fixed impedance reach regardless of source conditions. Directional overcurrent protection reach, on the other hand, is greatly impacted by source impedance variations, making it more difficult to provide settings that will coordinate with both upstream and downstream protection under all conditions.

Ground overcurrent and ground distance protection response to an impedance limited fault can be compared on an R-X impedance plane as shown in Figure 5.1.1. The sensitivity of each relay can be shown as an area on the impedance plane where the relay will operate when the apparent impedance moves into that area. Ground distance elements are most commonly shown as a “mho” circle that has one end of its diameter at the origin, and the other end at its reach setting at the characteristic maximum torque angle. A non-directional overcurrent relay element’s impedance reach characteristic can be shown as a circle with the radius of the circle as a function of the overcurrent element pickup setting, converted to an impedance based on the system voltage using the simple equation $Z = V/I$.

The ground overcurrent element’s reach is usually larger than the impedance reach due to the fact that the pick-up is normally set below the minimum fault within its zone of protection. This pickup value may allow the detection of ground faults a few busses away; while the ground distance element's reach is limited by constraints on its sensitivity for near zero impedance faults. Also, the ground overcurrent element reach does not have a characteristic angle as the distance elements do. The lack of this angle makes the reach a circle with its center at the relay location and has a directional characteristic that is perpendicular to the maximum torque angle. The impedance reach in the figure does not account for expansion as different relays use different techniques.

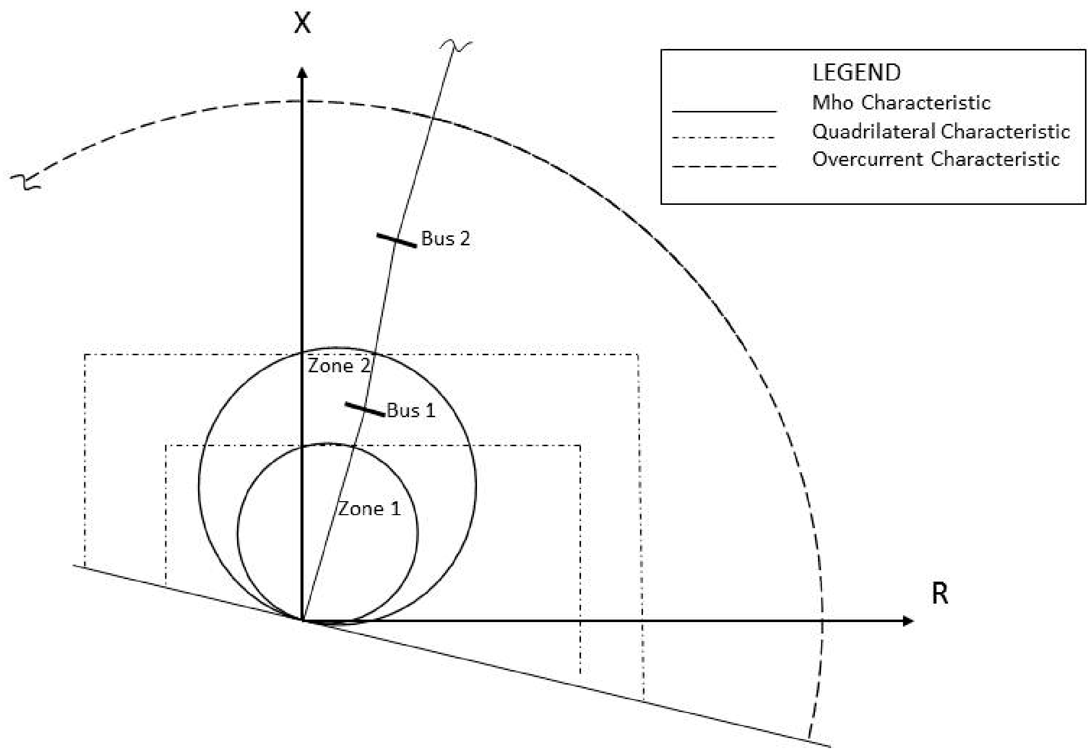


Figure 5.1.1
Ground distance and ground overcurrent fault coverage shown on an R-X impedance plane.

5.2 Determination of Pickup Setting

5.2.1 Directional Ground Instantaneous Overcurrent Elements

The pickup setting for an instantaneous overcurrent element must take into consideration various fault scenarios and the worst-case contingency outages that are acceptable to the utility. The pickup must be set with sufficient margin so the relay will neither operate for out-of-zone faults, external faults on mutually coupled lines, low-side faults on tapped transformers, nor on transformer magnetizing inrush current for tapped transformers on the line.

Various operating conditions can cause the worst-case outage for which the relay must protect. These conditions include possible changes in zero sequence source and zero sequence infeed at the remote bus. Zero sequence source changes behind the relay can be permanent, such as the addition of generation or auto-transformers, or temporary when equipment is out of service. The temporary condition reduces the zero sequence fault current levels and the amount of the line covered by the instantaneous element.

To minimize remote bus effects on the application of the instantaneous ground overcurrent element, settings can be applied based on three commonly used methods. Method one is based on applying a line-end fault, with the remote terminal open,with margin added. This method is the most conservative and, therefore, may result in limited coverage under normal conditions, especially for short lines. The second method, applies a remote bus fault with added margin and the third method applies a remote bus fault with removal of the strongest external zero sequence source into the remote bus. This last method provides a fault level that inherently adjusts to the worst-case single contingency condition. The determination of how many contingencies to consider in setting the pickup must be evaluated by the utility and is further discussed in Section 5.7.

Whichever fault method is used, a security margin is almost always applied to minimize over-tripping risks. This margin should take into consideration the line length, the source strength at each end of the line, and associated ground distance relaying.

Higher margins provide more security against a misoperation for an external fault, but result in less instantaneous coverage of faults on the protected line. Inverse overcurrent elements can be used to supplement the line coverage and provide coordination for faults beyond the instantaneous overcurrent application. The time-overcurrent element will need to be coordinated with the other time-overcurrent elements in the area. A time overcurrent relay that utilizes the instantaneous tripping relay on a remote line for coordination will have less margin for a higher set instantaneous relay. Increasing an instantaneous relay pickup too much could result in inadequate time overcurrent coordination margin in the area. Refer to Section 5.2.2 for more discussion on time overcurrent coordination.

A few other points should be considered with respect to margin. First, the dc offset during a fault can cause an undesired operation of an instantaneous relay. Different types of overcurrent relay designs operate differently. Electromechanical overcurrent relays operate on the RMS quantity of the composite current, even though they are tuned to the fundamental component. Most microprocessor overcurrent relays operate on fundamental frequency, and an RMS quantity, but may also operate on a selectable quantity. Regardless of the type of relay used, if the fault current angle is expected to be greater than 70 degrees, then the adequacy of the margin that is used should be checked to allow for dc offsets. Second, if an instantaneous relay is set on a line with a tapped transformer, then the pickup should be set well above the maximum transformer low-side fault, such as 150% to 175%. The margin should be set toward the high end of this range when utilizing relays sensitive to dc offset and when the X/R ratio exceeds a large value, such as 20, since the maximum current resulting from dc offset will approach 170% of the through-fault current. For two-winding transformers with a high-side delta winding, applying margin to low-side transformer faults is unnecessary since the ground overcurrent relay will not operate for low-side faults.

In the consideration of transformer magnetizing inrush, ground instantaneous overcurrent elements must be set above maximum inrush only if the transformers are connected wye-grounded on the high-side or for a grounded autotransformer with a closed delta tertiary. Coordination of ground instantaneous overcurrent elements for transformer magnetizing inrush is not required if the transformers are delta-connected on the high-side.

5.2.2 Directional Ground Time Overcurrent Elements

Directional Ground Time Overcurrent elements are generally applied for backup protection to impedance relays and sometimes for the specific purpose of providing sensitive protection for ground faults. 67N elements assure maximum sensitivity for ground faults limited by impedance due to inability of the impedance units to detect these types of faults. Some utilities use a fixed value of impedance, like 40 ohms or 200 ohms, when determining minimum pickup. Usually, when a utility uses such a factor, the basis stems from years of experience on the particular system. Experience, in this case, as defined by the many operations and subsequent setting reviews. Some utilities use a minimum value of fault current, like 120A and then verify margin for some set of contingencies. Another method is to set the pickup at a low percentage, like 25% to 50%, of a remote end single-line-to-ground fault with weak source (i.e., strongest source behind the relay out of service), taking into consideration some minimum value so as not to be too sensitive, and possibly some upper limit, so as to be sensitive enough. Regardless of the particular method chosen, the pickup settings should be as low as possible for fault detection sensitivity, but with sufficient margin above any non-fault related zero sequence current flows.

Since most transmission lines in the US are not transposed, it is important to consider the imbalance currents that can exist. Under heavy loading, the zero sequence current can be significant depending on the construction type. With electromechanical ground overcurrent relays, the pickup must be set above the maximum load imbalance with sufficient margin so that nuisance tripping does not occur. To enhance security, some microprocessor-based relays have restraint elements that provide blocking of the directional elements when the percentage of zero sequence to positive sequence current is less than the specified setting. Under heavy loading, the ground current could be in excess of the time overcurrent ground pickup, but would be blocked from operating due to the restraint element. With ground fault conditions, the percentage of zero sequence current to positive sequence current is much higher and the directional element is no longer blocked from operating.

The process of verifying coordination between the local relay and the relays at the remote bus should take into consideration the instantaneous element applied for ground fault protection of the remote line. If the coordination between the protected line and the remote line is developed using the current resulting from a fault just beyond the remote line instantaneous ground or distance relay, fault currents will be somewhat lower at the local terminal, resulting in better coordination margins. In addition, if the remote bus has additional sources, the effects of infeed from these sources improve coordination margin. The local relay will reach less into the remote line as the current at the local terminal is lower.

5.3 Determination of Time Delay Setting

In some transmission applications, the ground time overcurrent relay may be used as either primary or backup ground protection for the line and can provide backup protection for ground faults on lines connecting to the remote terminal bus. As shown for fault F1 in Figure 5.3.1, the time dial on the ground overcurrent relay at Substation L must be set to allow the remote line's primary protection at Substation R to operate first. Coordination of these relays is optimized if the time-current characteristics for the system lines are consistent.

If relays to be coordinated experience the same fault current levels, coordination is achieved by comparing the trip time for each of the relays to assure a typical margin of approximately 0.3 to 0.5 seconds. This margin may vary based on relay types and other system protection considerations, including breaker failure. If the relays are experiencing the same zero sequence fault levels, trip times can be best coordinated by applying the fastest acceptable time delay to the relay closest to the fault and adding coordination delays to each device further from the zero sequence source.

When fault current levels are affected by sources of infeed, the infeed improves the coordination by providing higher currents into the remote bus relays.

In Figure 5.3.1, a fault on the line served by breaker B at Substation R will result in current contributions from breaker A at Substation L and from the other breakers at Substation R, assuming they have remote sources. If Substation R does not have local backup protection, a failure of breaker B to clear the fault will require backup protection from Station L breaker A and from the other sources at Substation R.

Figure 5.3.2 provides another example of remote backup coordination. The fault beyond the end of the line served by Substation R, breaker B, will require the operation of the ground fault protection on breaker B. The tripping provided by this protection must be coordinated with the Substation L, breaker A ground fault protection. If the lines connecting to remote substations, like those of Substation R in Figure 5.3.1, do not have any type of local backup protection, F1 fault clearing will require tripping of the 67N on breaker A and tripping of each of the other breakers at Substation R, if they are connected to sources. For fault F1, the time dial setting for the 67N of breaker A should be set to have a trip time that ensures breaker B, when tripped by the primary protection, will clear first with an appropriate margin such as 0.3 to 0.5 seconds. If the lines connecting to substation R have local backup protection, the time dial for breaker A should be set to have a trip time that ensures that breaker B will clear first with an appropriate margin, such as 0.3 to 0.5 seconds, plus the breaker failure pickup delay. The time margin is irrespective of the curve types used.

For the close-in ground fault F1, the relaying at breaker B should operate instantaneously. If local breaker failure protection is applied at Substation R, the 67N time dial for breaker A should be set to allow the breaker failure scheme to operate first, and have all necessary breaker clearings (local and remote) to be accomplished first, with margin, such as 0.3 to 0.5 seconds.

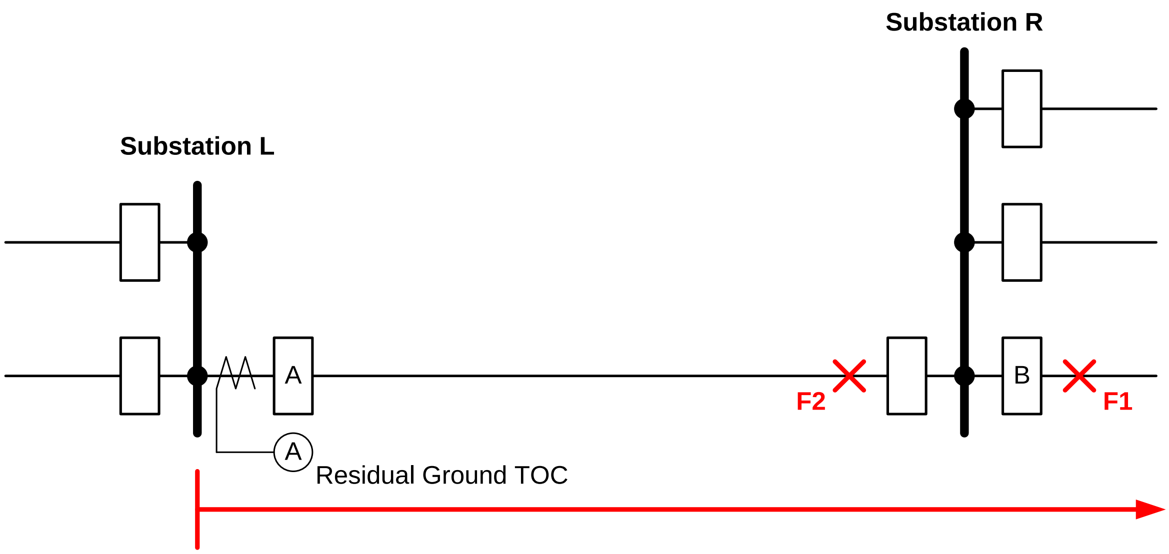


Figure 5.3.1
Ground Faults near the Remote Terminal

In Figure 5.3.1, consider the reduction in fault current flow as F1 is moved down the line, away from breaker B. Typically, due to the effect of infeed at Substation R, the fault current contribution through breaker A will decrease as compared to the fault current through breaker B.

If the remote substation has a feed-through configuration as shown in Figure 5.3.2, no infeed will exist. Figure 5.3.3 shows a case of inconsistent curve types that can cause coordination problems for various levels of faults currents. Therefore, selection of a time-current characteristic for relay A that has a similar or greater degree of inverse characteristic than that of relay B is desirable. In other words, if relay A and B were the same curve and the setting margin was the same, coordination will always be maintained, such as the case shown in Figure 5.6.1.

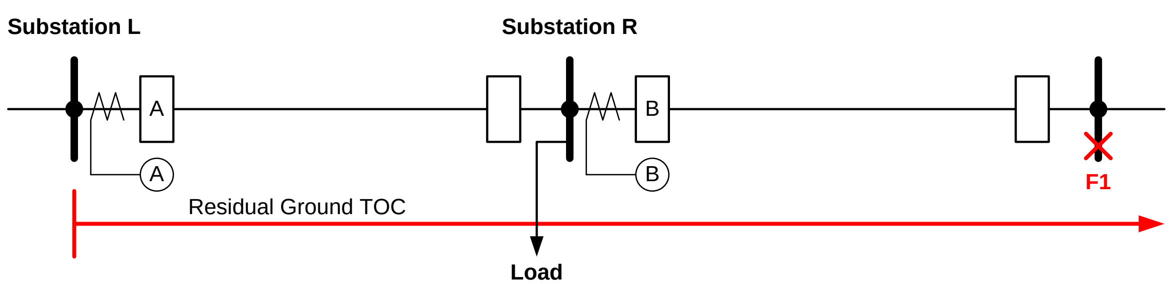


Figure 5.3.2
A "Line in, Line out" Configuration

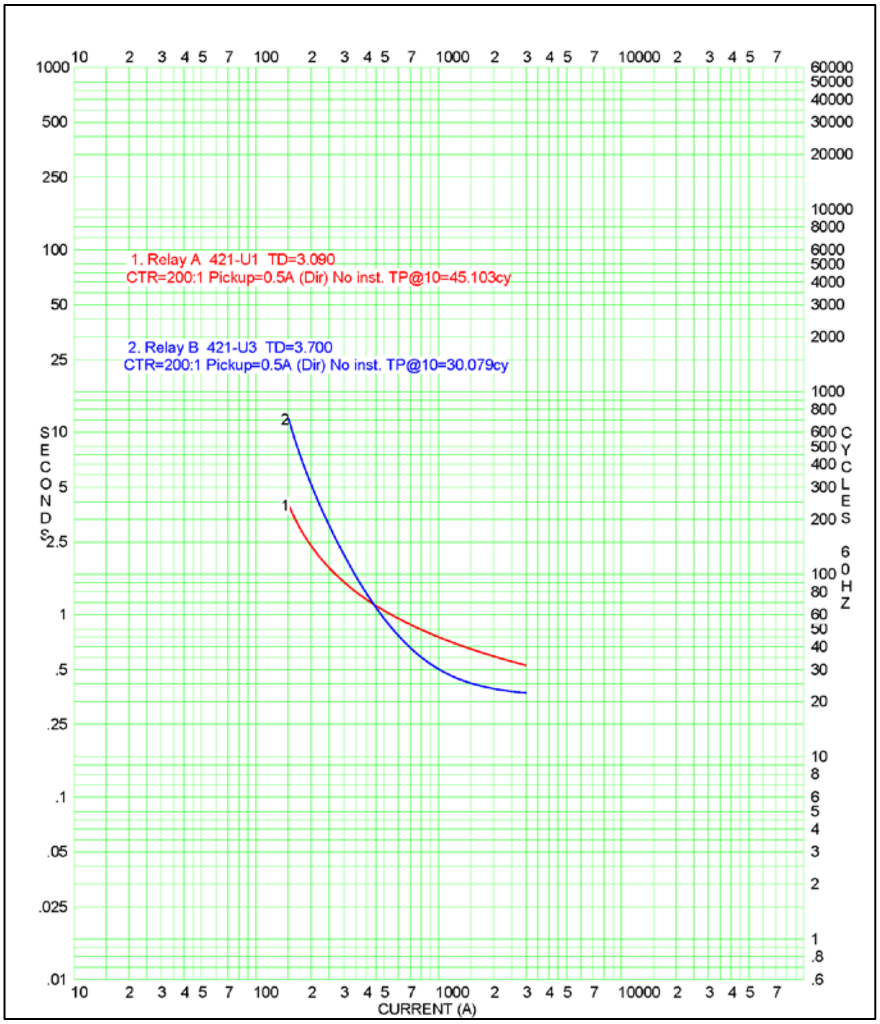


Figure 5.3.3
Different 67N Curves

In general, the use of inverse-time 67N elements in conjunction with ground distance elements or under reaching 67N elements often provides the added benefit of better sensitivity for ground faults in the last 10 to 20% of the line. Zone 2 impedance elements typically operate under a definite time delay regardless of fault location. For faults in the far end of the line from the local terminal, the remote end terminal breaker typically trips instantaneously under either an under reaching distance zone or an under reaching instantaneous ground element. This quick removal of the remote source would allow the local instantaneous ground element to reach farther, possibly speeding up the tripping of the local breaker. This technique to create sequential tripping can frequently be a valuable means to improve total clearing time for line ground faults. However, depending on the network, sometimes the 3Io from the local terminal actually decreases when the remote terminal opens. In this case, the local terminal must still operate with the time-delayed clearing.

Special considerations should be taken into account when coordinating 67N relays or elements, especially if pilot schemes are not employed. The object of the coordination is to obtain the combination of the fastest operation of the local relay being set by considering all sources of ground fault current and the slowest operation of the remote relay by removing a large ground source such as a line or autotransformer. in lieu of ground source removal unless redundant pilot schemes are used.

The coordination of all elements that are used in a protection scheme must be checked against each other. This checking is easier when only one type of element is used. However, most protection schemes use a combination of definite-time and time-overcurrent functions that include both impedance and overcurrent elements. The use of time-current plots can be useful to determine coordination, especially for definite-time and time-overcurrent elements. However, impedance elements are not generally plotted with overcurrent curves, but must be considered in overall coordination. Working Group discussions indicated several cases where overcurrent relays coordinated with each other but did not coordinate with impedance relays.

5.4 Single Phase Tripping Considerations

A single phase trip and reclose system is one which trips only the faulted phase on a single phase to ground fault and trips all three phases of the circuit breaker on a multi-phase fault. For a single-phase trip the system will automatically reclose the open phase after a suitable time interval. If the single-phase fault has cleared, the reclosing will be successful and the protection system resets. If the single-phase fault is still present, the system trips all three phases of the breaker, and makes no further reclosing attempts. For a multi-phase fault, the system may or may not automatically reclose, depending on the scheme programming and the operating requirements.

If a fault is cleared by a single phase trip, the open interval following the single-phase trip causes an imbalance condition on the power system. This condition results in negative and zero sequence currents and voltages. Depending on the magnitude and direction of the load as well as the duration of the open interval, the directional ground overcurrent relays on the line may cause a false trip. If it is determined the relay could trip due to the possible loading and the duration of the open interval, several options are available to prevent the false trip. The directional ground relays (or such relay elements in a multifunction relay) could be disabled in the single phase trip system logic during the open phase reclosing interval and restored to service when the open phase is reclosed. Another option is to either increase the current setting or the time delay of the directional ground overcurrent relay during the single phase trip system logic. However, increasing the setting of the directional ground overcurrent relay reduces its sensitivity to detect ground faults. The advantages of a higher setting and simpler scheme logic should be carefully evaluated against the disadvantage of reduced sensitivity.

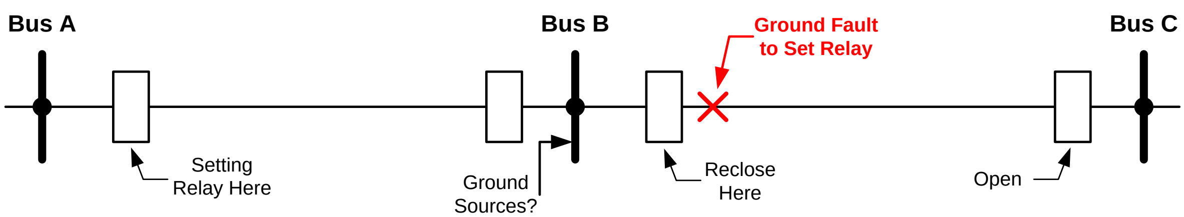
On mutually coupled lines, the tripping of a single phase on one line can introduce 3I0 into the other line. Thus, the ground relaying schemes of coupled lines need to be reviewed together to prevent false trips on coupled lines that use of single phase tripping schemes. Mutual coupling is further discussed in Section 5.8.

5.5 Effects of System Reconfigurations

The transmission system is not always in the same configuration due to several factors, such as reclosing and maintenance outages. The changes to the system can impact ground sources and thus affect overcurrent ground relay operation.

5.5.1 Effects of Automatic Reclosing

Automatic reclosing is a special case of a system configuration change, as it represents a non-typical operating scenario where one terminal of the line is closed while the other end is open as shown in Figure 5.5.1. Instantaneous directional ground protection can cover a significant percentage of the line. A reclose of a remote line onto a close-in fault (with its remote end open or closed) is often the external fault simulation used to set the local terminal relay, as the loss of this line's source will tend to force more ground current through the terminal being set. A setting method for the local terminal relay that takes into consideration the possible special configurations presented by reclosing and other typical maintenance outages would be a solution to undesirable over-trips. Further discussion of instantaneous relay elements can be found in Section 5.2.1.



<u>Figure 5.5.1</u>
<u>Reclosing</u>

5.5.2 Maintenance Outages

Removal of large remote ground sources during maintenance outages can have the same effect as that of reclosing. The result is that more ground current will flow from the local terminal thus impacting overcurrent settings by possibly allowing overreach conditions. If the directional ground relay setting takes into account the loss of the strongest remote source, then during normal operation, with all ground sources in service, the relay's reach will be shorter. Company practices vary, but generally, a shorter reach is preferred to that of possibly over-tripping when the source is removed.

Also, the grounding of a transmission line that is mutually coupled to the protected line for maintenance activities can make a significant change to the network fault current distribution. The relay settings need to account for this scenario as the mutual coupling effect can significantly impact ground relay operation. Mutual coupling effects are discussed in Section 5.8.

5.6 Line Length Considerations

The length of a transmission line plays an important role in determining pickup levels and sensitivity requirements for directional ground overcurrent relaying. Transmission line length is not only defined by the physical length but also by the relative difference in short-circuit current from a close-in fault to an end of line fault. The difference in short-circuit currents is a function of the source impedance relative to the line impedance.

For short lines, there is little difference between the close-in fault and end of line fault levels. Even a line considered physically long could be classified as a short line if it has relatively high source impedance. Instantaneous overcurrent elements that trip directly should not be used on short lines because the difference in fault current is insufficient to discriminate between close-in and end of line faults. Instantaneous directional ground overcurrent relaying is, therefore, not a good choice for protection of short lines unless applied in a pilot scheme. Since the difference in fault current is small between the two ends of a short line, the selection of time-overcurrent pickup and time-dial will be dependent on coordinating with the upstream and downstream relaying. If margins are insufficient for adequate coordination, a communication assisted scheme should be considered over directional ground overcurrent relaying.

For medium length lines, pickup sensitivity may be further restricted to levels that provide adequate coordination with area relays. Using lower pickup levels to improve sensitivity could result in a time-current characteristic that may result in a “flat” response that's difficult to coordinate.

For example, Figure 5.6.1 displays coordination between directional ground overcurrent relays that are providing backup protection for two 115 kV transmission lines. Both relays have a 360 A pickup and there is a coordination margin of 0.30 seconds for a line-end ground fault. Note that the time-current characteristics provide an inverse characteristic up to their respective instantaneous pickups.

Figure 5.6.2 displays time-current characteristics for the same relays, but the pickups have been reduced to 120 A in order to cover an impedance limited fault. The respective operating time of each relay for the line-end fault condition has been maintained, but the coordination margin is reduced to 0.15 seconds for the line-end ground fault condition. With sensitive pickups, the time portion of the curves is nearly flat up to the instantaneous pickup and, therefore, does not allow sufficient coordination.

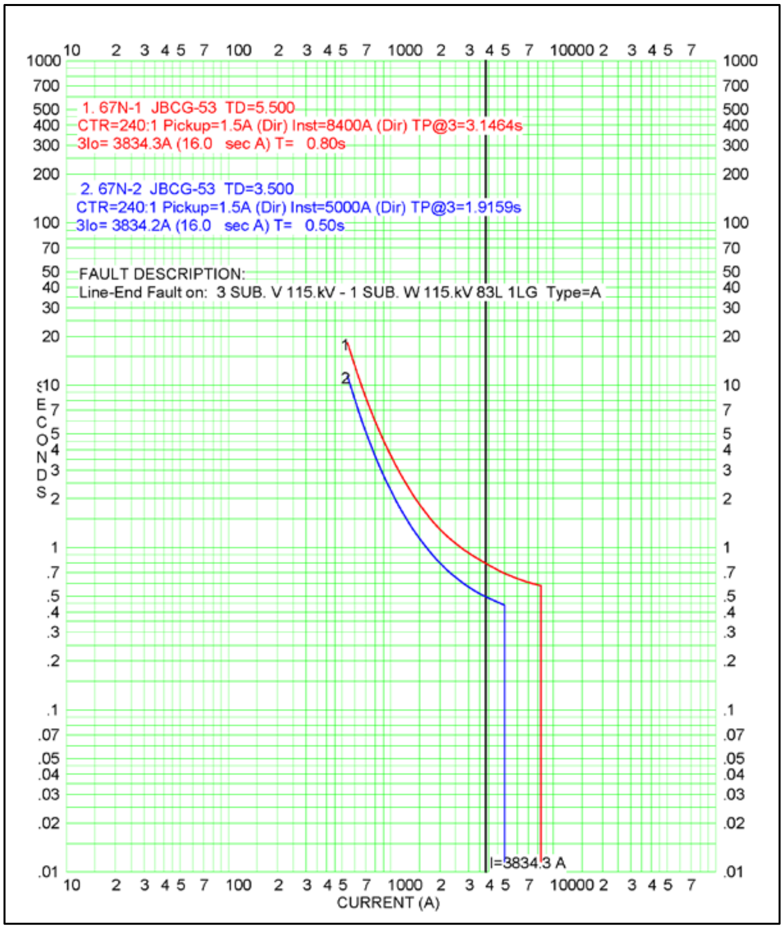


Figure 5.6.1
Standard Pickups on Medium Length Lines

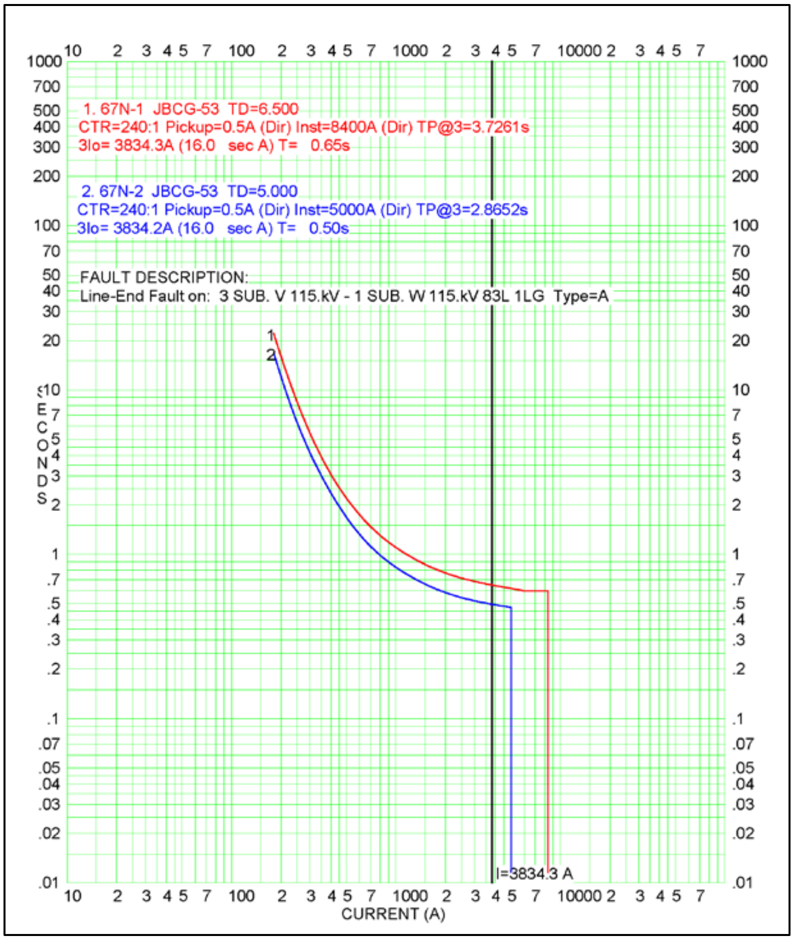


Figure 5.6.2
Sensitive Pickups on Medium Length Lines

Long lines are typically easier to coordinate due to the large difference between the close-in and end of line fault currents. An instantaneous element can typically be set to cover a large portion of the line, but sensitive pickup levels for the time-overcurrent element may reduce performance and security, especially in electromechanical relays.

5.7 Contingency Analysis Considerations

Power system modifications due to switching or maintenance can result in substantial changes to the anticipated fault current flows. The switching duration can be brief and may not justify a complete settings recalculation or the performing of a new coordination study immediately prior to the modification. The effect of such single contingency temporary changes to the power system can be included in the initial settings calculations with specific attention to possible over reaching of instantaneous elements.

A typical method employed for contingency analysis uses short circuit analysis software that removes network elements sequentially to analyze the effects of such outages. The choice of which network elements are removed varies by the settings philosophy but should have the goal to identify the contingencies that have significant impact. Frequently, loss of the network elements adjacent to the relay location will significantly change ground fault currents effecting the ground fault relays applications and settings..

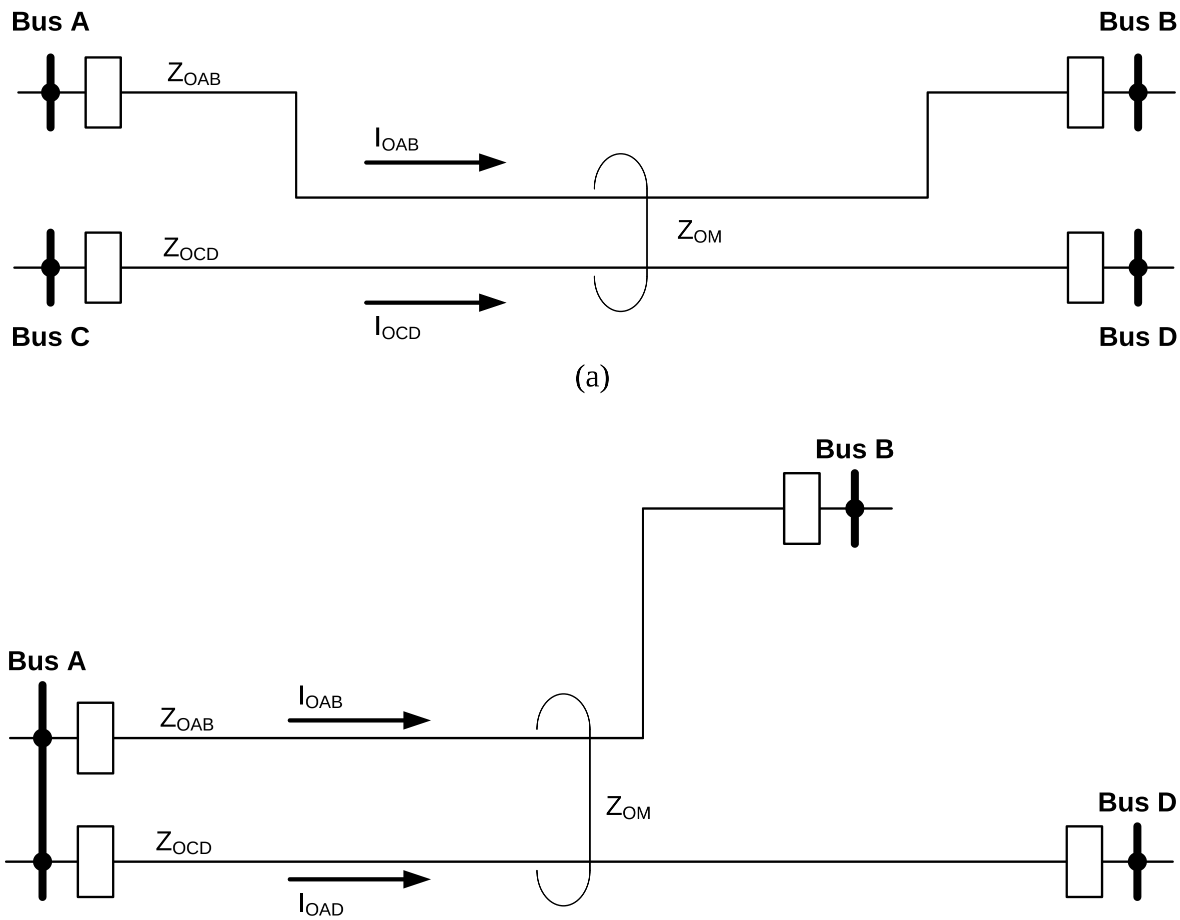
Philosophy regarding the removal of significant zero sequence current sources such as three winding and auto-transformer banks with delta tertiary windings, as well as generator step-up transformers, can vary due to the response such outages may initiate. Some utilities may consider the outage of these significant elements to be an event that prompts the recalculation of nearby relay settings or the utilization of pre-loaded alternate relay settings groups in the relays.

The utility's planning standard or the NERC reliability standards might be excellent starting sources for determining the worst case fault contingency analysis for setting the directional ground overcurrent protection. Some utilities use single-contingency planning criteria for peak loading conditions and double-contingency for off-peak conditions**.** Single contingency is the normal system with one component out of service, while double contingency is the normal system with two components out of service. However, the contingencies selected by system planners that have the worst impact on power flow and the stability study results may not necessarily be the contingencies that have the worst impact on fault analysis studies.

5.8 Mutual Coupling Issues and Effects

When transmission circuits run parallel in close proximity for part or all of their length, they have a mutual coupling due to the interaction of the magnetic flux produced by each circuit. These mutual effects are most significant when fault current is flowing in one or more of the circuits. Positive, negative, and zero sequence mutual coupling is present for all such circuits. Positive and negative sequence mutually coupled currents are generally only a small fraction of the line current and generally less than 7%. Their effects are considered negligible for the purpose of determining protection settings. In contrast, zero sequence mutual coupling can induce significantly higher levels of current. In the zero sequence network, the mutual impedance can be as high as 70 percent of the zero sequence self impedance of a circuit.

Many possible configurations that involve mutually coupled circuits exist. Figure 5.8.1 shows two different configurations to demonstrate that the coupling between circuits is not necessarily for the full length of either one of the circuits and that neither line has to terminate at a common node in the network. Whenever such coupling exists, the effect can cause ground overcurrent relay problems on either circuit, by increasing or decreasing the measured current. Configurations may include the coupling between many different circuits, as well as circuits operating at different voltage levels. An increase in the separation between circuits reduces the coupling effect. Alternatively, an increase in the length that circuits are mutually coupled, or an increase in operating voltage, will both result in increasing the mutual effect. Even ground faults on under-built distribution circuits have been known to contribute significant amounts of ground fault current to transmission lines. However, a fault on a higher voltage line effects a lower voltage line more than the reversed condition.



(b)

Figure 5.8.1
Mutual coupling between two circuit configurations

Figure 5.8.1(b) is shown as representing a typical system configuration. The mutual coupling can be expressed as an impedance between the two circuits coupled through a 1:1 ratio ideal transformer. This "mutual" impedance is effectively "shared" between the two circuits as shown in figure 5.8.2. Figure 5.8.3 is simply a different way of depicting the two circuits of Figure 5.8.1 (b) and the mutual coupling effect they share.

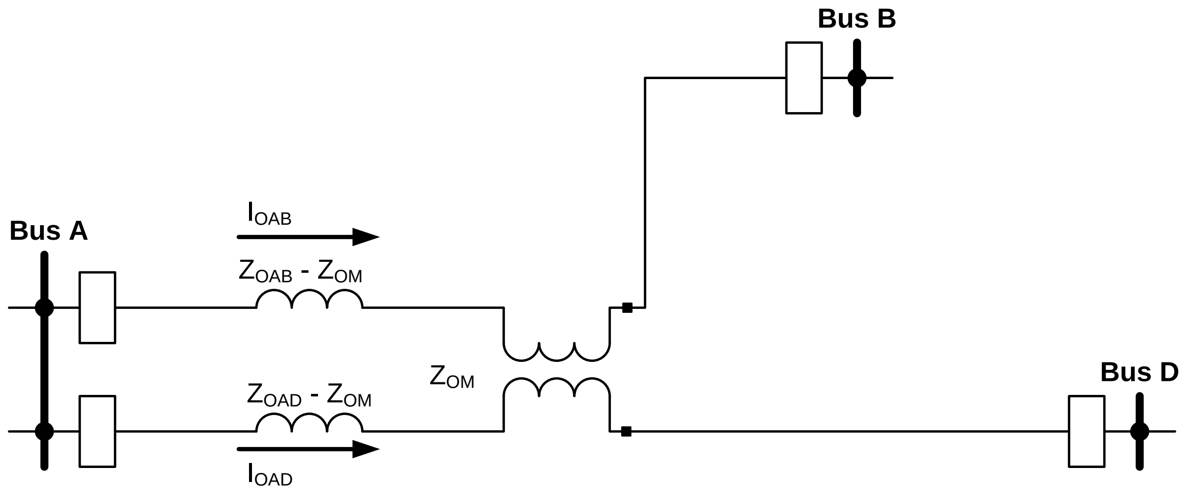


Figure 5.8.2
Mutual coupling representation between the two circuits of Figure 5.8.1 (b)

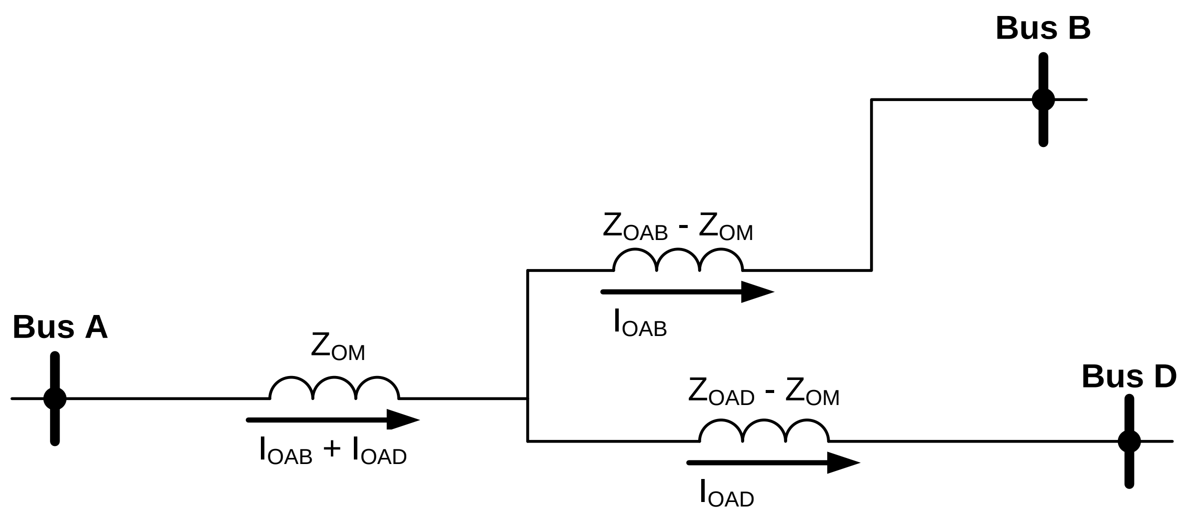


Figure 5.8.3
Equivalent network for the two mutually coupled circuits of Figure 5.8.1 (b)

The fault current as seen by the relays at a bus will increase as the fault position is further down the coupled line due to the mutual coupling affect. Referring to Figure 5.8.4, the intent is to determine an appropriate setting for the instantaneous ground overcurrent relays at Bus A. Line BC is mutually coupled with Line AC for some of its length. Faults are be placed along Line BC from one end to the other end. Different methods can be used to set the instantaneous element at Bus A, such as taking the safety margin times the remote bus fault, with or without infeed sources.

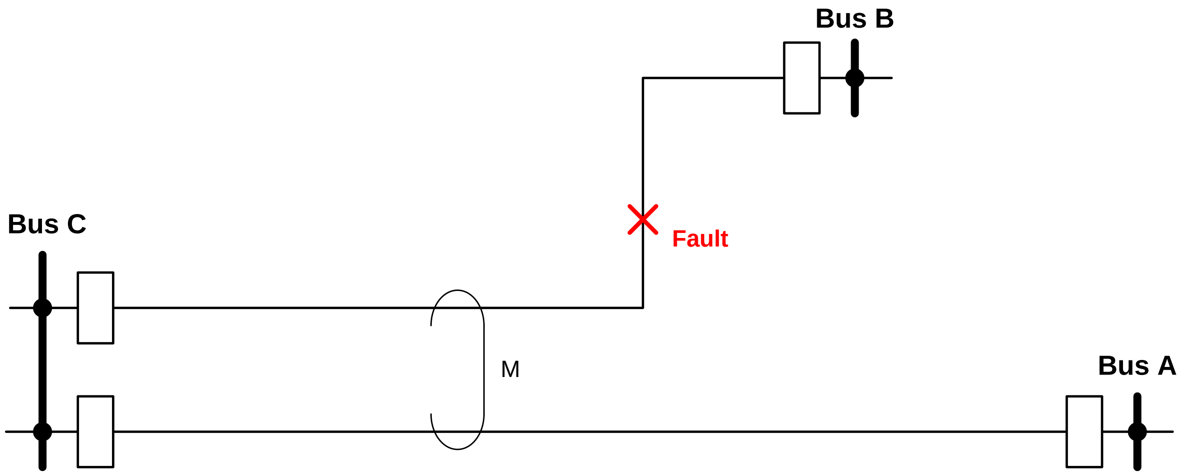


Fig. 5.8.4
Mutual Coupling Example

To assure no overreach the typical instantaneous element setting method is to find the maximum ground fault current level that will flow into the line at Bus A, and set the instantaneous current above that fault current with an appropriate safety margin. A fault at Bus C should be considered with the strongest ground source out of service at Bus C. Additionally, faults on the mutually coupled Line BC should also be considered to see if one exists that will bring a flow into the line at Bus A that is greater than the worst case remote end fault already considered. Note, however, that in considering the mutual effects, the instantaneous element reach may be significantly reduced below what it would be if only the highest remote line fault were considered. If the mutual coupling effect is not accounted for, the instantaneous element might well overreach the remote terminal.

Figure 5.8.5 and Table 5.8.1 provide the input for an example of a misoperation due to mutual coupling not taken into consideration. The fault currents are measured at the local terminal, STA. C, denoted with a solid rectangle.

Table 5.8.1 Fault Currents

Close-in	Remote Bus	Line End	Next Bus	Remote Terminal
14,309A	768 A	4,519A	884A	1,687A

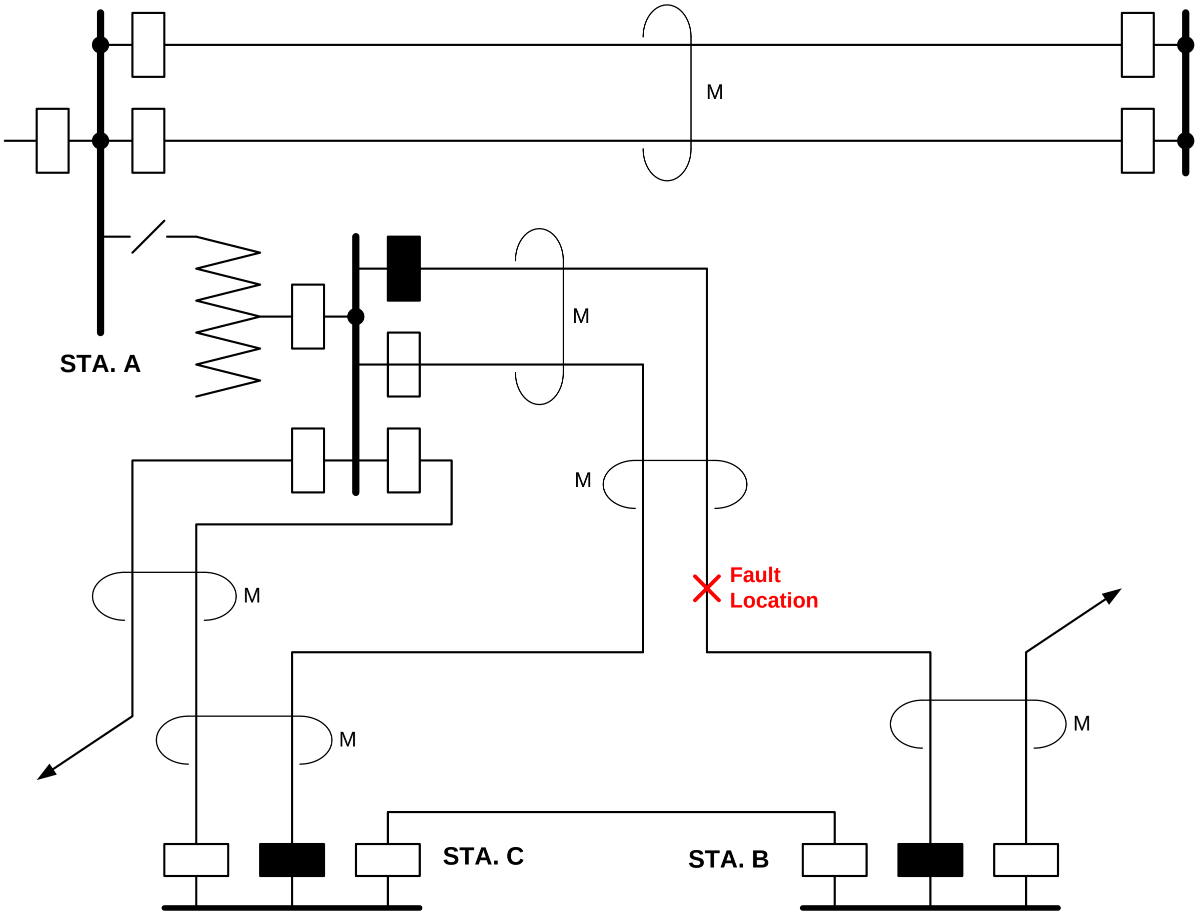


Figure 5.8.5
Mutual Coupling Misoperation

The setting criterion used for the instantaneous unit was to set the relay about 1.5 times the remote bus fault current, 1.5*768=1152A. The other criterion was to set the relay no higher than 0.67 times the line end fault current, or 0.67*4519=3028A. To ensure the relay did not operate for external faults, the remote bus and line end faults out of remote terminals were also reviewed. Using the same margins, an appropriate setting would be above 2530A (1.5*1687) but below 3028 amps. A setting of 2600A was chosen and was within these margins. A line fault occurred on an adjacent line A-B and the non-faulted line A-C relay at terminal STA. C tripped on ground overcurrent. Had the engineer performed a sliding fault in the simulation program, he would have observed that a fault at approximately 56 percent of the line produced a fault current of 2800A, or enough to operate the ground instantaneous overcurrent relay.

While the example applied to an instantaneous element, the time-overcurrent elements are equally subject to the same issues.

5.9 Adaptive Capability

Adaptive capabilities of microprocessor based relays are tools that can be used to optimize directional overcurrent settings. Relay element settings or logic can be automatically altered in response to changes in the power system. Operational switching of circuit breakers, bypass switches, or motor operated disconnect (MOD) switches can change the power system such that alternate settings would be useful. Alternate settings could also be beneficial when the ground source strength in the area is affected by either a generator or transformer outage.

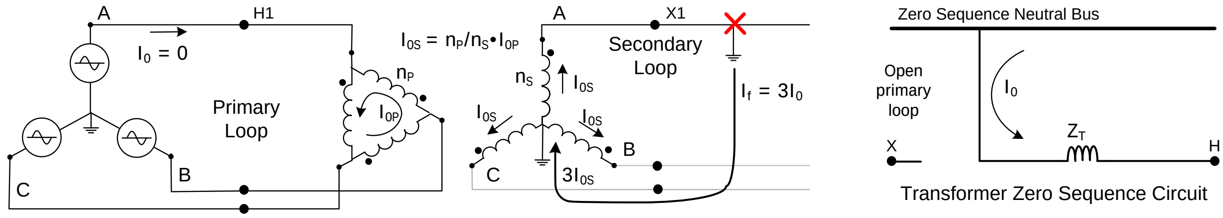
Because many system changes affect the fault current, adapting the relay settings can enhance the reliability of the protection system. As a result, optimal settings are provided to the relay, such as through automatic setting changes, based upon actual system operating conditions rather than worst case conditions. A downside to this approach is that the relay will be temporarily out of service while the settings are automatically changed, thus faults occurring during the setting change process could go undetected. However, methods can be used to overcome temporary disruptions, such as switching redundant relays to alternate settings at different times.

Generator or transformer outages can significantly impact the amount of ground fault current in an area. In fact, generators and transformers are the most influential power system elements within a local area that can affect ground fault current. The next section elaborates on the importance of this subject.

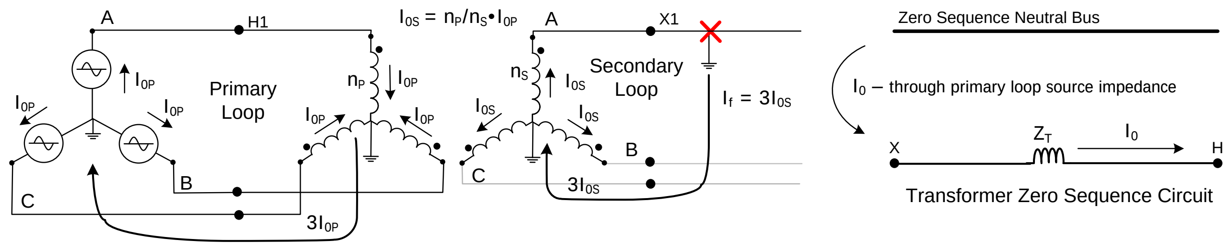
5.10 Ground Source Issues.

The term “ground source”, as it is commonly used, implies a source for zero sequence current from a grounded neutral connection during faults or other system unbalance conditions. The term is a bit of a misnomer in that a grounded neutral is indeed not a source of zero sequence current, but rather a path for zero sequence current. Even as a ground current path, the grounded neutral is not necessarily a ground source as it will be herein defined. The real source for ground fault current is the combination of the power system positive sequence generation to provide the fault current and the unbalanced fault condition.

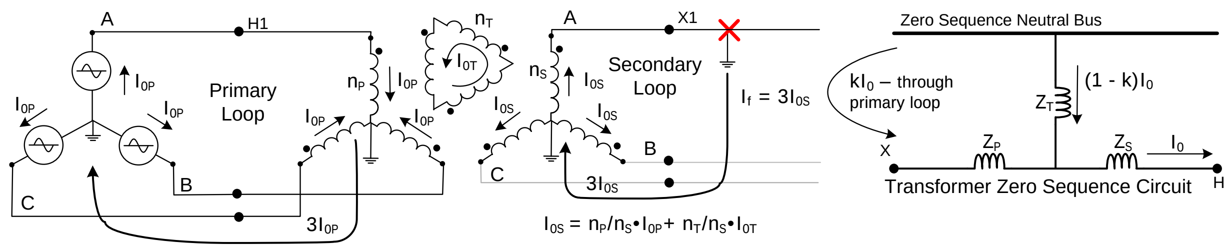
5.10.1 Ground Source Importance towards the Contribution of Fault Current.



(a) The delta winding is an open circuit in the primary ground fault loop (zero sequence circuit), but allows I_0 to flow in the secondary ground fault loop providing a shunt impedance path in the transformer's zero sequence circuit.



(b) I_0 in the primary wye-grounded winding is coupled by amp-turns to the secondary wye-grounded winding and is equal in per unit value, thus providing a series impedance in the transformer's zero sequence circuit.



(c) I_0 in the primary wye-grounded winding is coupled by amp-turns to the secondary wye-grounded winding and is equal in per unit value, thus providing a series impedance in the transformer's zero sequence circuit.

<u>Figure 5.10.1</u>
<u>Transformer Connections with Zero Sequence Circuits</u>

Figure 5.10.1(a) shows a generator or an equivalent source on the primary side of a transformer with the primary windings connected in delta and secondary windings connected grounded-wye. With a phase-to-ground fault on the primary side of the transformer the generator (source) will provide the current that must flow through the generator grounded neutral connection, which is usually a high impedance connection. This is indeed a ground current path that meets the definition of a ground source. Ground (zero sequence) current cannot, however, be provided from the secondary system for this fault because there is no primary ground connection at the transformer to provide phase-to-ground amp-turn coupling through the transformer. For a phase-to-ground fault on the transformer secondary side a fault current ($3I_0$) will be allowed to flow as there is a path for zero sequence current, I_0, to flow in each phase of the delta connected primary winding satisfying the transformer's amp-turn coupling requirements, i.e., $n_P I_{0P} + n_S I_{0S} = 0$, where n_P is the number of primary turns and n_s is the number of secondary turns. This coupling sets up the shunt ground path in the transformer equivalent zero sequence circuit.

Figure 5.10.1(b) shows the same configuration except the transformer is provided with wye-grounded windings on both the primary and secondary. The primary side, however, now has the ground connection to allow phase-to-ground amp-turn coupling through the transformer, i.e., $n_P I_{0P} + n_S I_{0S} = 0$. Therefore, the per unit ground current is the same on both sides of the transformer regardless of the location of the fault. This results in a series coupled zero sequence current path through the transformer from the primary system to secondary system. Although ground current is flowing in the transformer grounded neutral this connection is not a "ground source." It does, however, allow adjacent ground sources to be available for faults on the opposite side of the transformer. This can be referred to as a "passing" ground source.

Figure 5.10.1(c) shows the configuration with a three winding transformer with two wye-grounded and one delta windings. This configuration provides both a series path to the primary source and a shunt path at the transformer for zero sequence current that will flow through the neutral during secondary ground faults.

Considering the above discussion a ground source is therefore defined as a three-phase transformer or generator configuration with a grounded neutral connection that provides a shunt path in the zero sequence circuit for zero sequence current. For the transmission system, ground sources are provided with either delta-wye or a zigzag transformer winding connections.

5.10.2 Distributed Generation Influence on Transmission System Ground Sources

Distributed generation in the power system influences fault current and fault current distribution in a power system. The focus is how the distributed sources affect the magnitude of the ground fault current in the power system during a ground fault condition, so that proper coordination between ground overcurrent devices can be maintained. Take the example system shown in Figure 5.10.2.

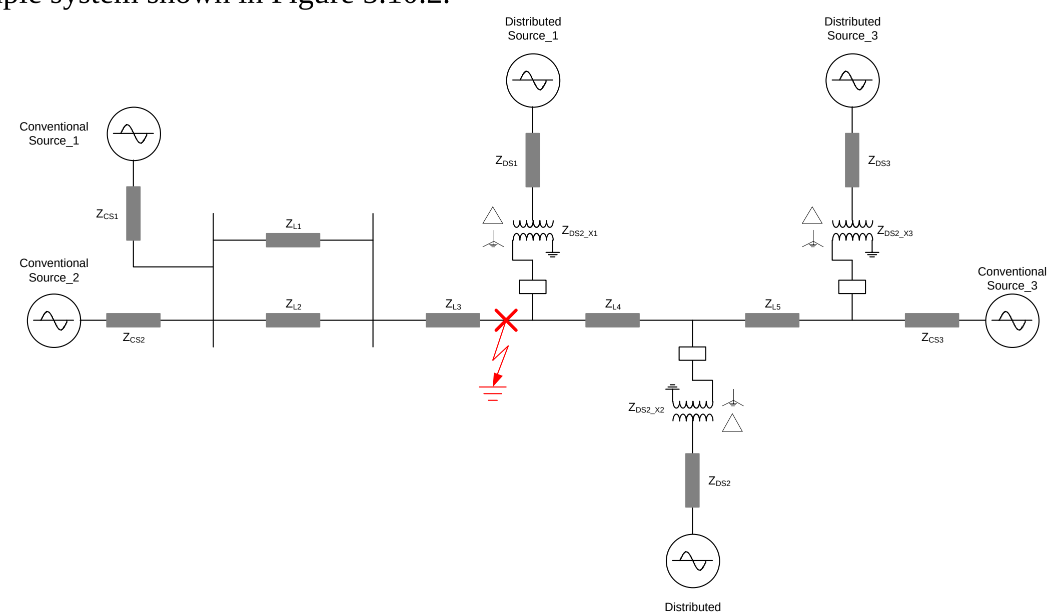


Figure 5.10.2
Simplistic Power System

For a ground fault at the location shown in Figure 5.10.2 the zero sequence diagram is drawn as shown in Figure 5.10.3:

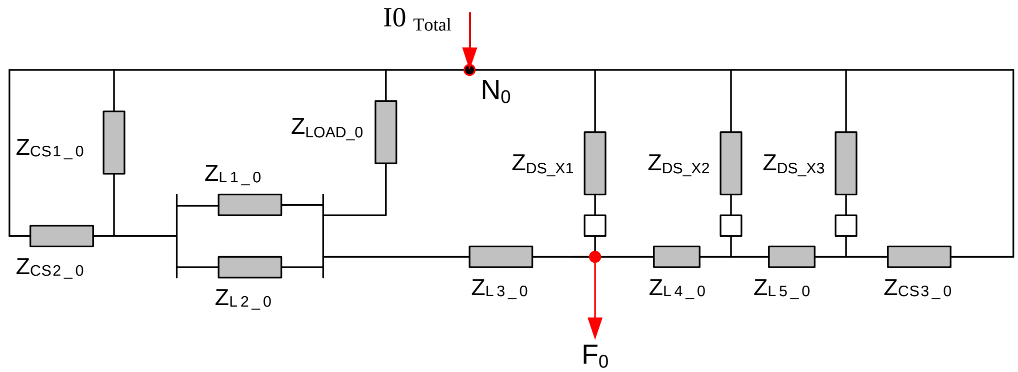


Figure 5.10.3
Zero Sequence Impedance of the Simplistic Power System

The distributed sources can be switched in and out of the system depending on the generation requirements of the power system. The conventional source will be considered as being in the circuit for the purpose of this discussion. Note that for this example the distributed sources have relatively high positive and negative sequence impedance when compared to the conventional sources. In other words, the distributed sources contribute very little to the overall fault current whether they are in or out of service, and as such we can ignore them. However, the distributed sources have relatively low impedance in the zero sequence network because of the wye-delta transformers used to connect them to the grid. Therefore, they have to be considered in the zero sequence circuit. Hence, the magnitude of $I0_{Total}$ is dependent on whether the distributed source is in or out of service. The more distributed sources that are in service, the lower the overall impedance of the zero sequence circuit, and therefore, the higher the magnitude of $I0_{Total}$.

All the ground sources are considered to be in service for the first case shown in Figure 5.10.4, and assumes that $Z_{Variable} << Z_{Fixed}$, i.e., all distributed sources transformers are in service. Thus, the maximum ground fault current is for a single line to ground fault (lowest zero sequence impedance). From the current distribution point of view it means that $I0_{RIGHT}$ is much larger than $I0_{LEFT}$. The result is that very little zero sequence current will flow through the fixed impedances of the system, meaning that protective devices used for a ground fault protection will have a reduced operating quantity, or longer operate time, or may even fail to detect the fault.

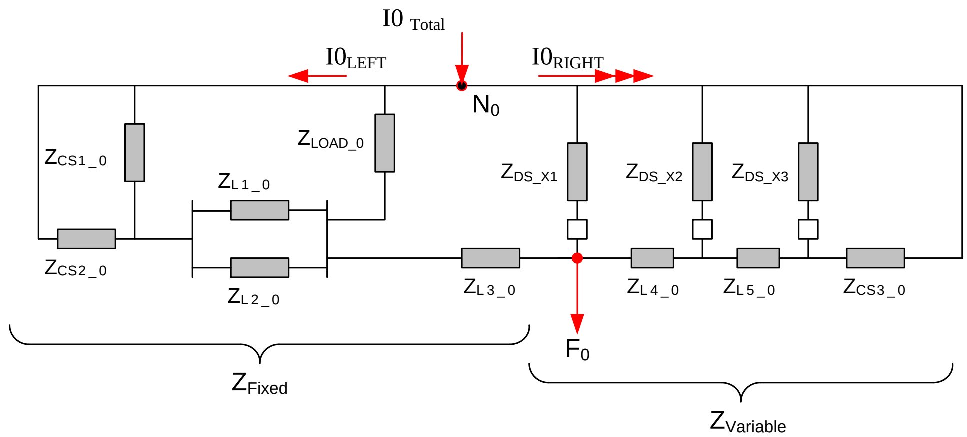


Figure 5.10.4
Zero Sequence Impedance of the Simplistic Power System
with all DistributedSources In Service.

For the second case assume that two of the distributed sources are out of service as shown in Figure 5.10.5 and that $Z_{Variable} = Z_{Fixed}$. Therefore, $I0_{LEFT} = I0_{RIGHT}$. Note that $I0_{Total}$ decreased, but the reduction is less than the change in the ratio of $Z_{Variable}$ vs Z_{Fixed}, meaning that the magnitude of $I0_{LEFT}$ increases as the number of distributed sources decrease, even though the total zero sequence fault current $I0_{Total}$ decreases.

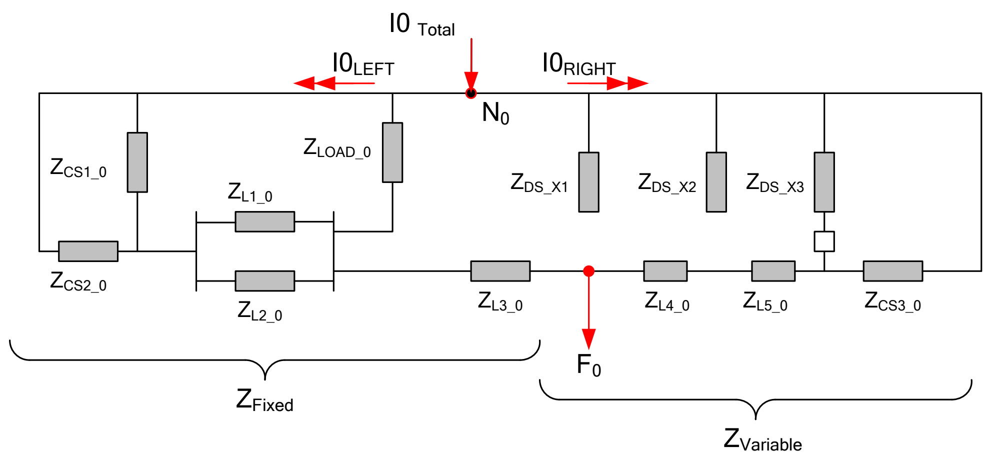


Figure 5.10.5
Zero-Sequence Impedance of the Simplistic Power System, with
Two of the Three Distributed Sources Out of Service.

The examples show that distributed generation sources not only influence the magnitude of the fault current they also influence the distribution of the zero sequence current.

5.10.3 System Models

Verifying the accuracy of the system model and all ground fault sources in the immediate area is important when performing a ground fault analysis. Errors can easily be overlooked and there can be a tendency to place blind faith with the model and develop settings that are based on inaccurate fault values. Transformer parameters, such as MVA ratings, impedances, winding connections, and system grounding should be verified against design documents that include drawings and the manufacturer's test report.

5.11 Negative Sequence Overcurrent

Zero sequence current is more commonly used as a relay operating quantity than negative sequence current for unbalanced conditions. However, negative sequence current can be helpful when used as a relay operating element under a limited set of conditions, such as on parts of the system that have weak ground sources, or on long radial lines that serve tapped ground source transformer banks. Even if the "normal" system provides an adequate ground fault source, certain contingencies may reduce available ground current to the point where an adequate operating quantity is no longer provided. Coordination of negative sequence overcurrent elements with other overcurrent elements is no different than coordinating ground or phase overcurrent elements, other than the sequence quantities that are used. Because the use of negative sequence overcurrent elements is not common, their inherent unfamiliarity can cause difficulties to achieve proper coordination.

5.11.1 Heavy Load on a Non-Transposed Line

Unequal mutual coupling inherent to a non-transposed line results in different phase impedances and is one cause of unbalanced load current flow. This unbalanced current has both negative and zero sequence components. For most line configurations, load flow through a non-transposed line produces more negative sequence than zero sequence current. High magnitude power flow, or three phase fault current flow during an external fault, may produce sufficient negative sequence current to operate sensitively set negative sequence overcurrent elements.

Pickup of the negative sequence overcurrent element must be set greater than the maximum negative sequence current flow at the highest possible power transfer level. This should be easily achievable for most well grounded transmission systems. However, in a poorly grounded transmission system, it may not be possible to obtain the desired sensitivity and remain secure for all load conditions. In this case, one solution is to increase the positive sequence restraint factor setting, which reduces the sensitivity of the negative sequence overcurrent element supervision as positive sequence current (i.e. load) increases. This results in only a slight reduction in sensitivity during normal system operation and a greater reduction in sensitivity during a system contingency, such as the loss of a parallel line, which results in a higher load situation.

5.11.2 Delta-Grounded Wye Transformer

The common delta-grounded wye substation transformer connection provides a ground source for low voltage side ground faults, but does not pass zero sequence current to the high side. For distribution systems fed by this transformer connection, there is no need to coordinate transmission line zero sequence overcurrent elements with low side ground overcurrent protections. However, negative sequence overcurrent elements applied on the transmission system will detect low side faults and must be coordinated with all low side overcurrent protection, regardless of type.

6 Conclusions

Many issues need to be considered when applying directional ground overcurrent relays for the protection of transmission lines: impedance of the fault, mutual coupling, changing system conditions, load unbalance, and utilization of single pole tripping. Directional ground overcurrent protection is easy to understand and presents a great alternative to distance elements by offering superior coverage for ground faults containing impedance. Topics of selecting pickup and time delay settings that achieve good balance between security and sensitivity for detecting faults are discussed. Careful attention should be paid to the available fault current for different source impedance conditions to ensure proper fault clearing. The addition or removal of zero sequence sources must be analyzed. For situations where a setting cannot cover all possible conditions, adaptive capabilities that are available in microprocessor relays may be used. Like any other protective relaying challenge, the application of directional overcurrent relays consists of part art and part science where the quantity of variables that must be considered call for thoughtful compromise.

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