Application of Overreaching Distance Relays

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1. Introduction

Why we are writing this document.

Overreaching distance relays tripping under load have played a part in many major blackouts. The August 14, 2003 blackout is the most notable, recent event in North America demonstrating these tripping operations. This document describes the vulnerability of distance relays to overload tripping and discusses methods to minimize susceptibility to this tripping.

As far back as November 9th, 1965 distance relays have been identified as tripping undesirably on line loading during significant system events. A backup distance relay initiated the November 9th, 1965 blackout when it tripped on load on one of five 230kV lines out of the Sir Adam Beck No. 2 Hydroelectric plant on the Niagara River in Ontario. The remaining four lines loaded up and tripped by their respective backup distance relays immediately thereafter. Those relays where set with a load pickup of 375MW to provide stuck breaker protection for breakers at the remote Burlington, Ontario substation. The relays load pickup was significantly below the loading capability of the protected lines.

As recently as November 4th, 2006, distance relays have been identified as tripping on line loading during significant system events. A distance relay on the Wehrendorf end of the Wehrendorf-Landesbergen 380kV transmission line in North Germany operated on load during one of the most severe and largest disturbances ever to occur in Europe. More than 15 million European households lost service and the UCTE system was split into 3 islands. It was concluded that the distance protection operated as designed and might have prevented an even more severe blackout as their operations resulted in the system separating in desirable pieces.

The August 14, 2003 blackout in North America exposed some of these same issues with overreaching distance relays. In an effort to help protection engineers avoid repeating history this document is being written to describe some of the susceptibilities of distance relaying and methods to circumvent them while adequately providing the intended protection function these relays are in place to provide.

An excellent reference on the protection of transmission lines with distance relays is the IEEE Std C37.113-1999(R2004) - IEEE Guide for Protective Relay Applications to Transmission Lines.

2. Background

2.A. Zone Descriptions

The historical use of zone descriptions has been blurred by the modern microprocessor based relaying that can have as many as 5 zones of protection. The following descriptions are commonly accepted terminology and will be used in this paper.

Zone 1: An instantaneous (high-speed, no intentional delay) tripping zone that is normally set to provide less than 100% coverage of the protected line (MN as in Figure 2.A.1). Zone 1 should never reach to the next bus (N).

Zone 2: A time delayed tripping zone that covers the protected line (MN) and overreaches to part of the next line (NO). The primary purpose of zone 2 is to clear faults in the protected line (MN) beyond Zone 1. Zone 2 also provides backup for a failed zone 1 element, both in the protected line (MN) and in the next line (NO). Zone 2 is typically set to reach less than the zone 1 reach of the next line. If there is infeed at Bus N, it will reduce the reach of zone 2. However, in all cases zone 2 will protect line MN which is its primary purpose. If the protected line (MN) zone 2 element cannot be set to reach less than the next line (NO) zone 1 element, a fault (while considering infeed at N) might fall into the reach of both the (MN) zone 2 and (NO) zone 2 relay elements. Coordination is then obtained by adjusting the time delay of one or both of the overreaching zone 2 elements.

Zone 3: A time delayed tripping zone for back-up protection. Zones 1 and 2 preserve continuity of service or preserve system stability whereas zone 3 is a remote backup to clear a fault in the event a remote breaker does not trip. Zone 3 is set to cover 100% of the next line (NO). Zones 1 and 2 are set in relation to the actual impedance of the lines, ignoring infeed. Zone 3 must be set for maximum infeed conditions. Sometimes zone 3 setting becomes high enough to operate on load or on power swings. Adequate measures must be taken to prevent zone 3 operation for such situations by using shaped characteristics, load encroachment detection and power swing blocking. Some users tend to use zone 3 for tripping during power swing conditions which may impact system stability as tripping during power swing condition is not required for ALL lines in an interconnected system. Additionally, this (forward-looking) back-up protection may utilize the same instrument transformer or battery power supply as the protection it is backing up and may fail to operate for the same reason.

Reverse Zone 3: The relay at M in Figure 2.A.1 provides (forward-looking) zone 3 back-up protection for a fault on the line NO. But the relay at N can also provide this back-up by reversing the zone 3. In other words, back-up protection can also be provided by reversing all zone 3 protections so that they cover the lines behind them instead of the lines in front of them. The same back-up protection will be provided but the reach of the zone 3 will be reduced by the impedance of line (MN). This could reduce the risk of the zone 3 protection operating on load and on power swings. Also, by providing back-up protection with the relay nearest the fault, tapped loads on unfaulted line (MN) will be in service whereas they would not be in service following an operation of (forward-looking) back-up protection at terminal M. The reversed zone 3 back-up protection is located on a different breaker and does not utilize the same instrument transformer or battery power supply as the protection it is backing up.

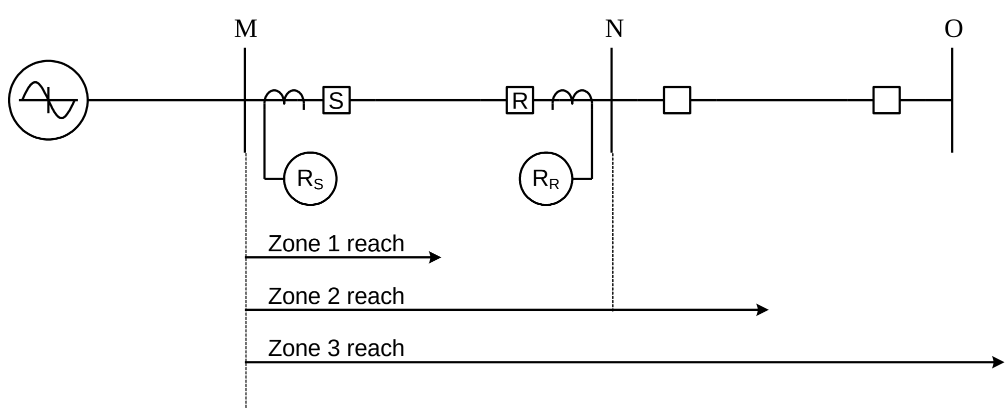

Figure 2.A.1 Typical step-distance zone reaches.

2.B. Purpose of overreaching distance zones; step-distance and pilot

Overreaching distance zones are used in both step-distance and pilot schemes. In the step-distance scheme, they are programmed with increasing time delays in direct proportion to the remote station zones they overreach. For example, the local zone 2 relay will be delayed to coordinate with a remote terminal's zone 1 relay to allow the remote terminal to trip before the local zone 2. Similarly, a remote terminal's zone 2 will trip before the local terminal's zone 3.

Typical reach settings for a step-distance scheme would be

- 80% - 90% of the impedance of the protected line for zone 1
- As low as 120% of the impedance of the protected line for zone 2
- For zone three (if the zone three reach calculation is not strictly based on line loadability) 120% of the highest measured impedance for a remote station line-end-open fault (a fault at the end of a line with the remote terminal breaker open).

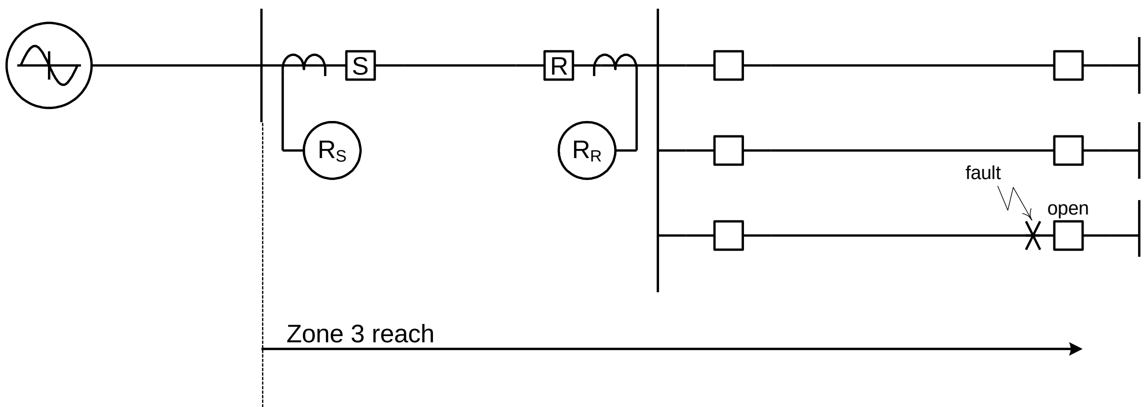

Figure 2.B.1 A Zone Three overreaching setting consideration (line-end-open fault)

Overreaching distance zones used in pilot schemes rely on communication mediums such as power line carrier or fiber optic to exchange information between remote terminals. Overreaching distance elements in pilot schemes are typically set to reach 150% to 300% of the impedance of the protected line. The overreaching element will typically operate faster when compared to the same element whose reach is set to exactly 100% of the line impedance.

It is common practice when utilizing microprocessor based relaying to allow the overreaching distance elements used in pilot schemes to also trip by time delay as a component of a step-distance protection scheme.

2.C. Susceptibility of the overreaching distance zones to undesirable operation

Traditionally, zone 3 in a step-distance relay scheme is used to provide remote back-up protection in the event of the failure of the protection system that is normally expected to operate for the fault condition. This zone 3 is given a delay longer than that associated with zone 2 to achieve time coordination, and the time delay is typically in the range of 1-2 seconds. Because zone 3 is set to detect faults down adjacent lines out of the remote station, infeed at the remote station causes the relay to underreach. Likewise, outfeed causes an overreach effect. Additionally, distance relays may misoperate for such events as transient and voltage instability [1]-[4], and this undesirable zone 3 tripping has often contributed to cascading outages.

To overcome these problems, various methods have been proposed and employed. Some digital distance relays utilize the zero- and negative-phase sequence currents, and sense the incremental positive-phase sequence current.

Occasionally, the zone 3 algorithms have been combined with algorithms based on the derivatives of the voltage, and current, the derivative of the phase angle of the current or the derivative of the impedance. The shape of the distance element operating characteristic is important and often a forward offset mho characteristic can provide good backup protection without the load encroachment problems of a mho element with no forward offset [5]-[8]. These are discussed further in section 4 and are shown in Figure 4.B.1.2.

Some utilities have taken their remote backup zone 3 relays out of operation all together. Appendix A provides a mathematical treatment of zone 3 and load power.

3. Application Practice

3.A. Application of high-speed distance functions (forward and reverse) in pilot schemes

For more detailed descriptions of the operation of pilot schemes and the utilization of overreaching distance elements in those schemes refer to section five of IEEE Std C37.113-1999(R2004) - IEEE Guide for Protective Relay Applications to Transmission Lines.

3.A.1. Permissive and blocking schemes

The forward overreaching distance element and the reverse reaching distance element are generally set similarly in a permissive overreaching transfer trip scheme (POTT) and in a directional comparison blocking (DCB) pilot scheme. In the case of the DCB scheme each end has a forward looking element that is set to overreach the remote bus to ensure coverage for the entire line. In many cases distance element times-to-operate increase as the fault is measured closer to the reach point of the element. Setting the element to overreach the protected line's impedance avoids this lengthened operating time concern. Each end also has a reverse looking distance element that should be set to detect all faults that the remote end's forward overreaching element can see so it can properly block pilot tripping for faults not on the protected line.

3.A.2. Phase versus ground distance

Ground distance protection, though typically set to the same positive sequence impedance reach setting as phase distance protection, is designed to detect single phase to ground faults. This design difference typically significantly reduces the possibility of operation due to load conditions.

3.B Stepped-distance and remote backup applications

Power utilities have different criteria when considering transmission system back-up protection. Depending on the strategic importance of the network as it is viewed from the fault clearing speed requirements to meet the stability of the power system, primary and back-up protection will be impacted from the relay duplication approach and back-up principles.

Distance protection may fail to operate and, as a result, fail to clear a fault. Alternate protection system or systems must be provided to remove the fault from the power system as quickly as possible. These alternate protection systems are usually referred to as duplicate, back-up or breaker failure protection systems. The main protection system for a given zone of protection is called the primary protection system. It operates in the fastest time possible and removes the least amount of equipment from service. If a second set of relays does the same thing (relay redundancy) the two systems are generally called Primary 1 and Primary 2. Another set of relays that are slower and /or trip more elements of the power system may be referred to as backup relays.

The duplication of relays is intended to cover the failure of the relays themselves. For instance, one utility may duplicate distance relays from the same manufacturer (perhaps configured to utilize a different principle of operation) to improve the overall protection performance in case of inadequacies in the design of the primary protection (hardware or software). Other utilities may only consider protection duplication if the relays are designed by different manufacturers (with the same or different operation principles). In all cases, the operating times of the duplicate systems are basically the same. Depending on the relative importance of a part of the power system, simply the network voltage level of a system may dictate the utility's practice of distance relay duplication.

The term back-up should be considered as a device that operates independently when the primary protection fails. In some designs the back-up protection is slower than the primary protection. Utilities usually install back-up protection to improve the dependability of their fault clearance time. The addition of a second primary protection may be regarded on the perspective of improving the availability, and dependability of the power system. Ideal back-up protection would be completely independent of the primary protection. However, it may be difficult to justify the use of independent cts, vts, auxiliary tripping relays, trip coils and auxiliary DC supply systems. Some compromises are usually considered depending on the risk involved should a protective relay or a switching device fail to operate.

3.B.1. Remote backup by zone two or zone three

Remote back-up protective relaying (often located in a separate substation) is completely independent of the local protective relays, instrument transformers, and tripping circuits that would normally be expected to operate in order to clear a given fault condition. It is also independent of the battery DC supply and the breakers in the local substation.
Remote back-up coordination should always be considered when setting relays. This would include a careful examination of relay operation time delays to provide for the minimal number of circuit breaker operations required to deenergize the faulted line.
There are limitations in the utilization of remote back-up protective relay elements. It may be difficult to provide for remote back-up relaying operation along the entire length of a line due to the power system configuration and changing network topology. Due to the effect of current infeed from other sources into the faulted zone, the zone three relay elements serving in a remote back-up role may require a reach setting which could be in conflict with the expected normal or contingency power flow of some transmission circuits. Another limitation for remote back-up is with respect to unacceptably lengthy total fault clearing times, particularly when the sequential operation of relays in two or more locations is considered.

3.C Special Considerations

3.C.1. Three-terminal applications

A transmission line that is connected to three fault current sources is a particularly difficult application that illustrates some of the considerations of remote back-up protection within a single zone of protection. Prior to the operation of any of the protective scheme circuit breakers it is desirable that at least one zone be able to see a line-end-open fault with an appropriate margin. This overreaching margin is typically 20% to 30% of the measured reach to the fault point while including the effect of fault current infeed to the fault from the third line terminal.

It may be considered appropriate, in the case where there are redundant relay schemes, for only one overreaching distance zone element from each relay package to see the line-end-open fault due to the fact that the two independent relay packages together will provide operations to clear the fault promptly.

It is desirable to be able to see the line-end-open fault with the strongest source behind the relay disconnected. This change to system topology typically increases the infeed effect from the third terminal. It should be noted that the measured apparent impedance may actually increase once the far terminal opens.

Where the third terminal is a stronger source, it may be necessary to permit a sequential clearing of line-end-open faults (i.e. both the other two terminals of the three-terminal line have cleared) before the last connected terminal will measure adequate fault quantities to detect the fault. Since the last terminal had such a weak source the detrimental effects of the longer time required for sequential clearing may be acceptable. An example of this scenario would be a higher voltage source substation (assumed to be much stronger source of fault current) being connected into the line which will often significantly reduce the current from the other two terminals until it has been disconnected.

The major coordination issue that arises is how far the distance zones overreach the third terminal if the second terminal is open. On three-terminal lines it is not unusual during this temporary system configuration that distance relaying will overreach beyond remote zone 1 coverage and perhaps beyond zone 2 or 3 depending on line lengths. Normally zone 1 would be set 80% to 90% of the radial impedance to the nearest breakered terminal. Zone 2 would typically be set to overreach the infeed point to protect for line-end-open faults while that infeed is present.

Figure 3.C.1.1 illustrates the reach of a zone 2 in a three-terminal application with respect to an adjacent zone 1 reach at a remote station. Figure 3.C.1.2 shows this reach increased as the third infeed terminal is opened.

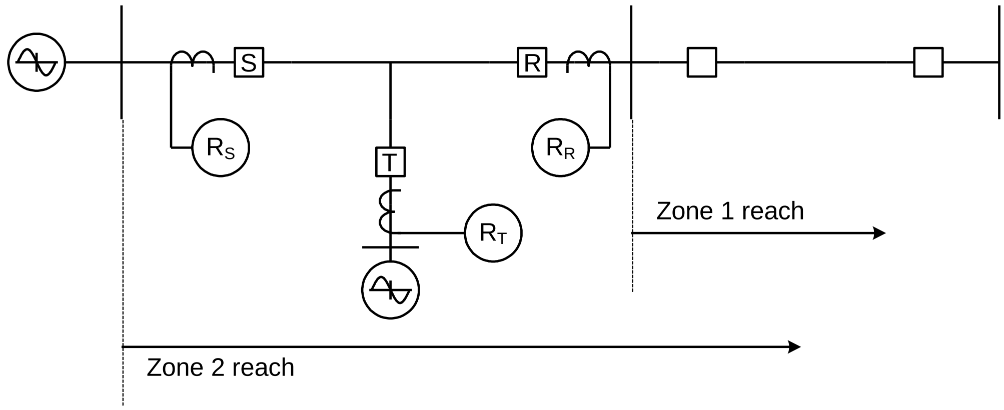

Figure 3.C.1.1. Zone 2 forward overreaching remote terminal in three-terminal application with third terminal infeed source present.

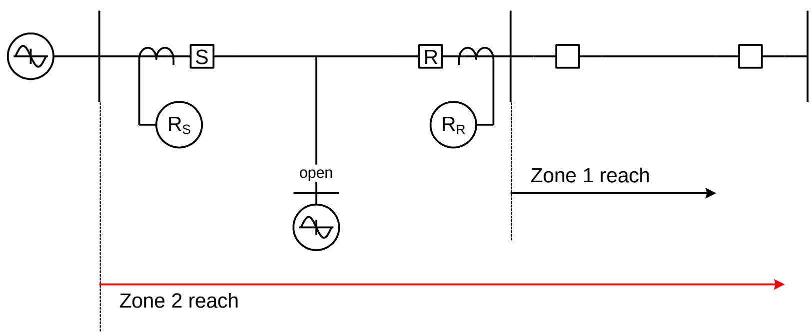

Figure 3.C.1.2. Zone 2 forward greatly overreaching remote terminal in three-terminal application with third terminal infeed source absent. In this case it overreaches remote station adjacent zone 1 reach.

Where more than three stepped distance protective zones are available there is more flexibility with relay setting considerations. Zone 2 can be set with a reduced reach. This reduction in reach minimizes the time delay required in relay settings for coordination. This reduced-reach zone 2 may not see line-end-open faults on its' protected line once the infeed terminal trips. Overall it will often provide faster clearing times for more of the faults that occur on the line compared to its reach being set larger. When zone 2 is set like this, a third zone could be applied to ensure detection of line-end-open faults including the presence of infeed. A fourth zone could be set to see line-end-open faults with the strongest source out-of-service behind the relay location This fourth zone would often then have a very long reach and an appropriately long time delay. The very long reach could come into conflict with line loadability requirements.

In most cases, long lines with third terminal infeed will result in long relay element reach settings that may require some type of mitigation to prevent operation for line load current. Blinder elements or load encroachment relay logic to supervise the long relay element reach could provide for the desired line loadability.

It is also a consideration that electro-mechanical relays should have continuously-rated fault current detector elements (if used) in order to allow the distance element to trip. The use of fault current detectors is sometimes precluded due to system conditions (weak fault current source) or if needed with very long distance element reach settings. In the case of some electromechanical relays, the thermal rating/continuous rating of fault current detectors may actually limit the protective reach unless their use is forgone to allow higher loading.

3.C.2. Loadability limitations

It is important to note that there is a difference between line loading and relay loadability. Permissible line loading is governed by thermal ratings of the conductor and terminal equipment, as well as voltage drop and stability criteria. For longer lines, loading may be based on the St. Clair Curve [9], which provides allowable surge impedance loading (SIL - the transmission loading at which the total shunt capacitive VArs equal the total I^2X inductive VArs dropped across the line) as a function of the length of the line.

For mho relay impedance settings, minimum trip MVA is often calculated in accordance with the following formula:

$$MVA_T = \frac{(0.85V)^2}{Z_R \times \cos(MTA - 30°)}$$

Where,
MVA_T = minimum MVA required to trip
0.85V = nominal line voltage depressed to 85% of normal
MTA = maximum torque angle of relay (characteristic impedance angle)
Z_R = relay reach in primary ohms at MTA
30º = maximum anticipated phase angle of load

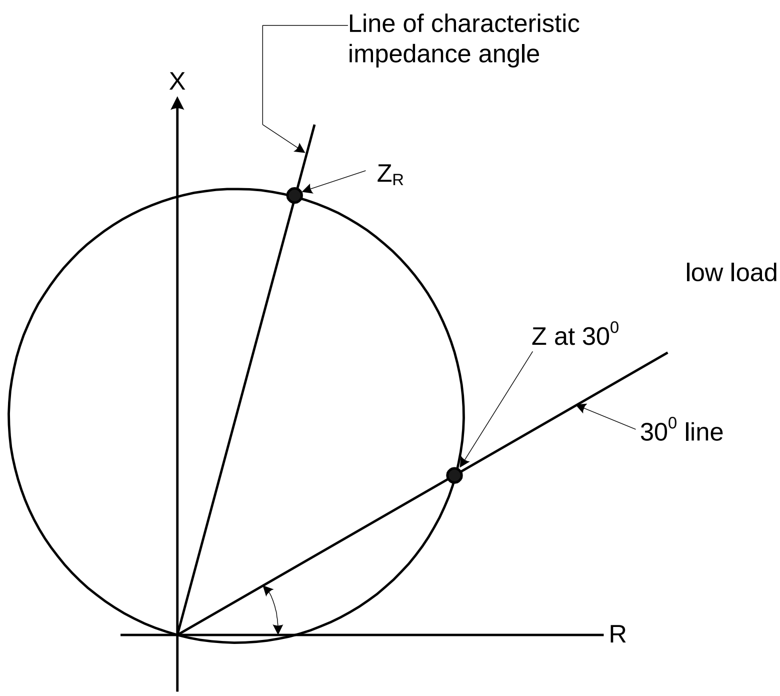

Figure 3.C.3.1 – Calculating MVA pickup of mho element

e.g. Consider a mho distance element setting of 42.0 ohms primary applied on a 230kV transmission line with a characteristic angle of 60º (MTA set on 60º).

$$\mathrm{MVA_T} = \frac{(0.85 \times 230{,}000)^2}{42.0 \times \cos(60° - 30°)}$$

$$\mathrm{MVA_T} = 1{,}050$$

Minimum trip MVA is then compared with the various thermal ratings (with margin) of the line to determine if the line protection is susceptible to tripping under credible loading scenarios.

3.C.3. Power swing considerations

The IEEE PES Power System Relaying Committee working group D6 created the paper entitled ‘Power Swing and Out-of-Step Considerations on Transmission Lines’ that details this subject [18]. It examines in detail the means of detecting power swings and out-of-step conditions and the options that exist for the protection engineer.

4. Overreaching Distance Functions and Line Loadability

4.A. Definition of loadability and sample calculations

In 1953, St Clair [9] introduced what later became known as the St Clair Curve. This curve was developed using the empirical knowledge of the day. Transmission engineers knew that the maximum loading of a 50 mile (80 km) transmission line was three times its Surge Impedance Loading (SIL). Engineers also knew that at 300 miles (480 km) line loading was equal to SIL. St Clair recognized the relationship was non linear between these two points and introduced a sliding scale. In 1979, Dunlop et al [11] revisited the St Clair Curve and demonstrated that up to 200 miles (320 km) line voltage drop is the dominant factor in determining loadability. Above 200 miles, the steady state stability limit is dominant. A drawback of the St Clair Curve is that is assumes infinite reactive (VAr) capability for the line and the line is modeled as a point to point transmission line. A third paper by Kay et al [11] published in 1982, demonstrated the effect VAr supply has on loadability.

From a protection point of view, the St Clair Curve is deficient in that it models SIL as real power. The modeling of the line as a point to point transmission line can aid the protection engineer in setting their relays because the line represents a worst case scenario during a system contingency where the line is expected to transmit power and not trip. To include the effect of VArs at the load point, the St Clair Curve was raised 25% and the line loading was developed using the following conditions.

- System voltage of 500 kV was chosen
- Sending power was equal to three times the SIL at the voltage chosen (3000 MW).
- VAr supply was finite and equal to 1840 MVAr boost and 920 MVAr buck
- At the receiving end bus, a synchronous condenser with an Xd’ of 20% with the same MVAr output as the sending machine.
- Line voltage drop was set to 5% by having the sending end machine regulate the sending end bus at 1.05 pu voltage and the receiving end bus was regulated by the synchronous condenser at 1.00 pu voltage.
- Steady State Stability Limit was set at 35% corresponding to a system angle of 40^{o}.
- Sending and receiving end Thévenin equivalent impedances were based on the largest commercially available breaker short circuit rating of 63 kA.
- Load was modeled as constant MVA with a 0.9 pf.

A commercially available power flow program was used to develop the model of the system. The system model is shown below. When setting up the receiving end VAr supply, the user has the choice of setting the VArs to correct for load or maintain voltage. As noted in Kay's paper [10] use of the VAr supply to correct load power factor results in a different maximum power transfer.

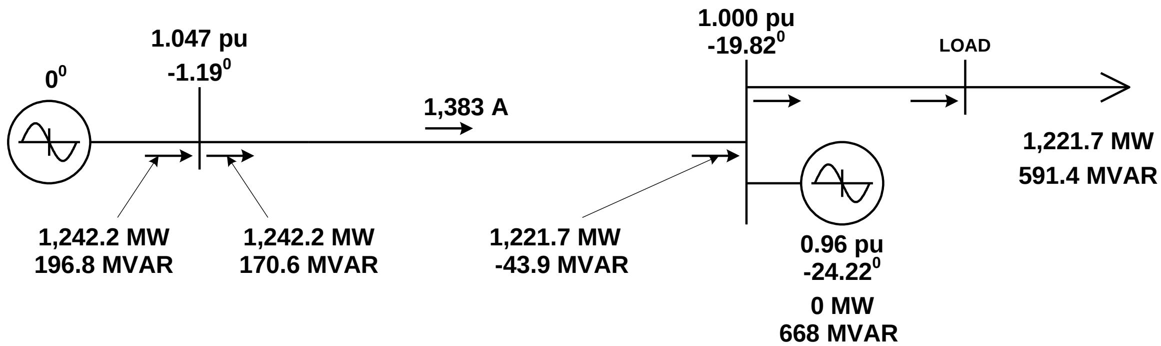

Figure 4.A.1 Power flow example.

The results are shown in the following plot.

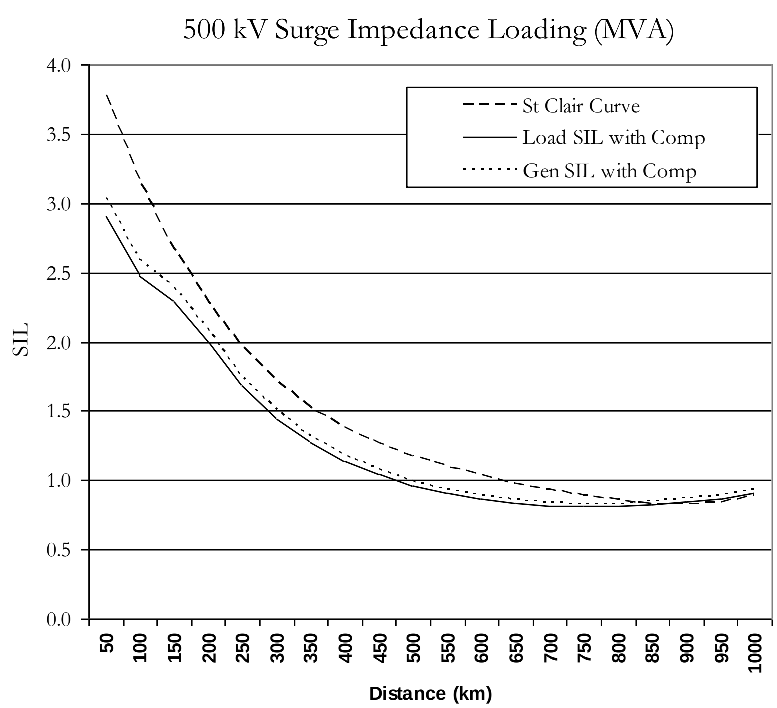

Figure 4.A.2 Surge Impedance Loading.

The resulting plot shows good correlation with MVA St Clair curve. The large VAr source at the receiving end effects where the curve changes from angle dependency to voltage dependency. In effect, the change over takes place around 100 miles (170 km), not around 200 miles as shown in Dunlop's paper [10]. A smaller VAr supply will result in a lower maximum transfer capability.

4.B. Zone Characteristics Impacting Loadability

For distance elements, such as the traditional "mho" characteristic, the susceptibility of the zone to pickup on load generally increases as the reach (impedance setting) is increased. The mho characteristic is most likely to respond to system transient load swings, but may also detect steady-state load - especially when it is heavy and inductive in nature. Alterations in zone characteristics can be made that will reduce the susceptibility of a sensitively set distance zone responding undesirably to a load condition; some of them are outlined in the following sections.

4.B.1 Variations in Zone Positioning

The most traditional means of increasing a mho distance element's loadability involves a repositioning of the basic characteristic. The traditional mho characteristic will be used to illustrate a couple of common positional adjustments:

4.B.1.a. Mho characteristic angle adjustment

Maintaining a given mho circle diameter, the simplest alteration that will reduce the zone susceptibility to responding to load conditions (when adjustment is possible) is to increase the maximum sensitivity ("torque") angle. Such a measure, of course, is always paid for with a reduction in the resistive coverage for faults (refer to Figure 4.B.1.1). In situations where both under reaching and overreaching zones are applied, having a lower maximum sensitivity angle for the under reaching zone (below the impedance angle of the protected line), and a higher angle for the overreaching zone (at or slightly above the line angle) is usually most desirable. This arrangement optimizes the resistive coverage for close-in faults (where fault resistance has the greatest impact on a measured fault locus), while maintaining lower susceptibility to false operations under load swings (much less, steady-state load).

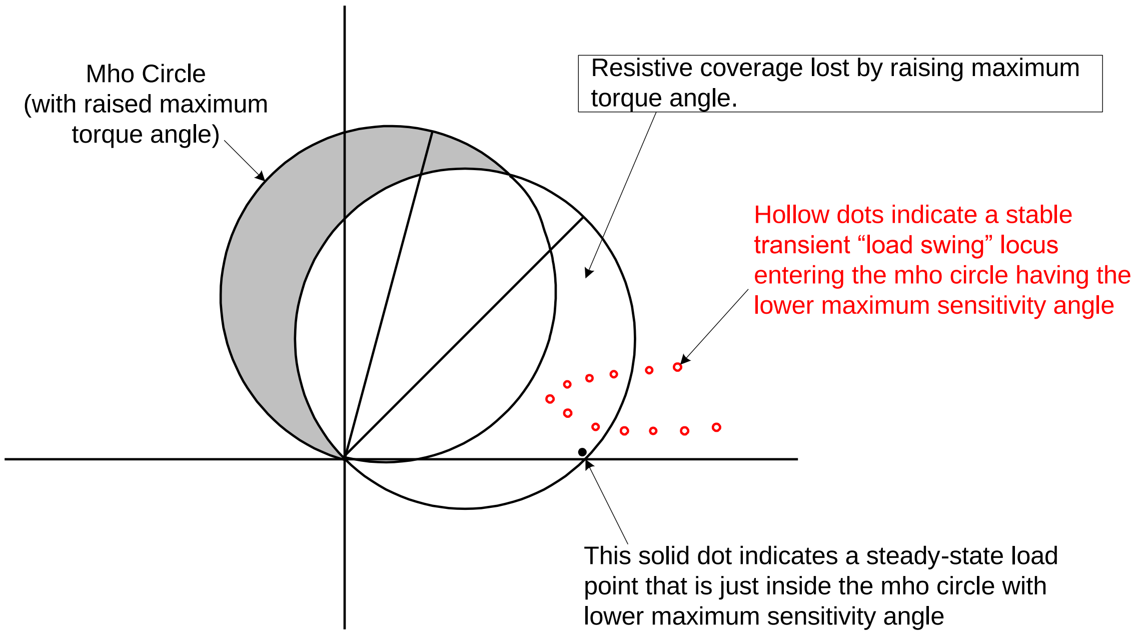

Figure 4.B.1.1 <u>Mho circle torque angle adjustment.</u>

4.B.1.b. Offsetting mho characteristics

The very common mho circle positional adjustment referred to as "offsetting" may also be employed to reduce load susceptibility. Offsets in mho characteristics are normally produced by developing an additional voltage from the monitored line currents, and adding (or subtracting) it in as a component of the normal polarizing voltage. Such modifications can be used in two basic ways: Reverse offsetting pulls or expands the steady-state mho circle back away from the main forward reach, so as to encompass the relay's monitoring location (see Figure 4.B.1.2).

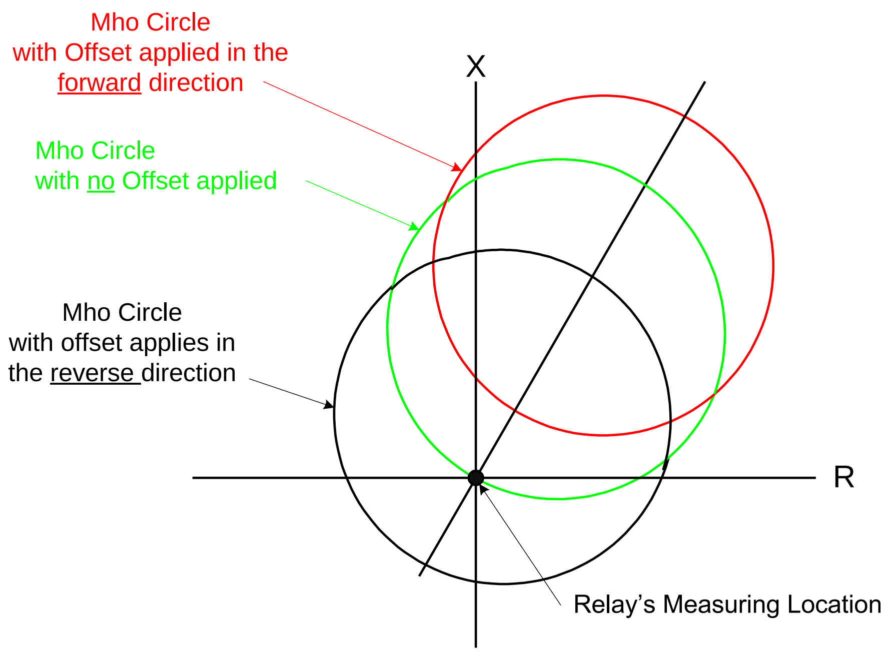

Figure 4.B.1.2 Mho circle offsets.

A forward offsetting moves the circle into the direction of the protected line, thereby placing the relay location definitely outside of the detection zone (upper most circle in Figure 4.B.1.2). A forward offset can be applied to move a sensitively set overreaching zone beyond the range of steady state (as well as transient) load impedance loci. If such a measure is taken for loadability concerns; however, a shorter reaching distance zone must be relied upon to protect the close-in portion of the line uncovered by the forward offset (see composite characteristic shown in Figure 4.B.1.3).

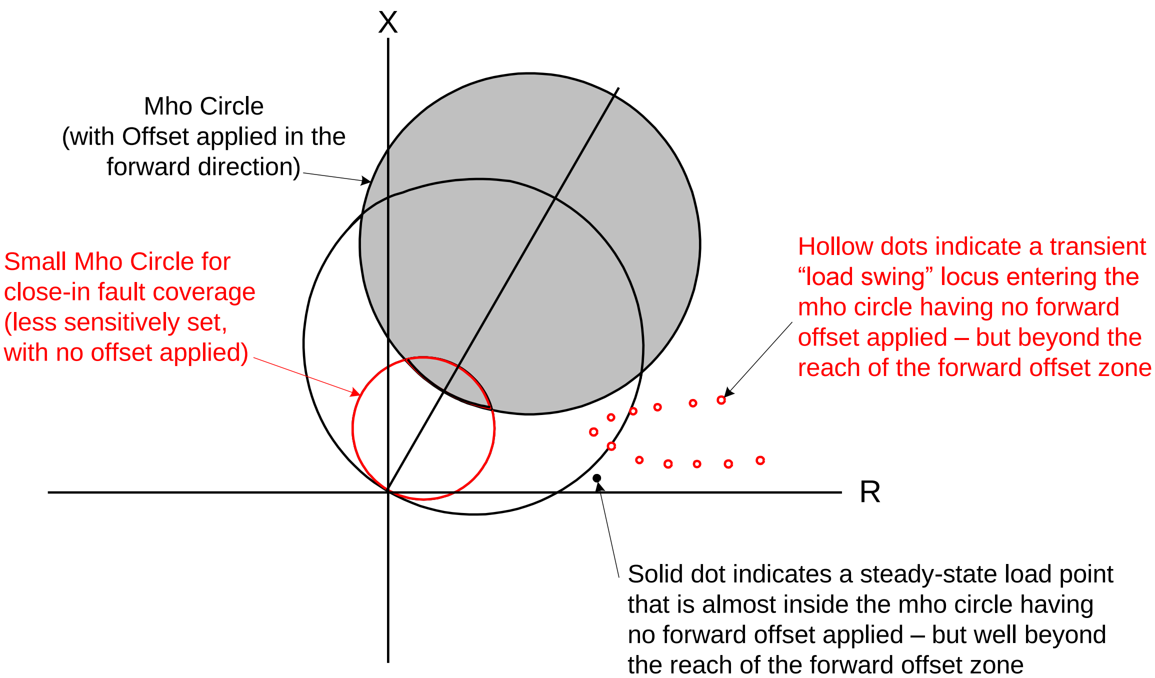

Figure 4.B.1.3 Mho circle composite characteristic.

4.B.2 Variations in Zone Shape

Modifications to the standard phase-detecting mho characteristic or the use of a phase-detecting rectangular shaped characteristic may also be used to reduce (or eliminate entirely) an impedance zone's coverage in possible load regions:

4.B.2.a. Lens Characteristic

A distance element's polarization may be set-up to form what amounts to the intersection of two mho circles (the lens), with maximum sensitivity axis as shown in Figure 4.B.1.4. With the angle of maximum sensitivity closely aligning with the impedance angle of the covered line, a sensitively set, overreaching zone will maintain full reach for bolted faults in the forward direction, yet resistive coverage will be significantly reduced. The lens characteristic possesses much less tendency than a standard mho circle to operate for load swings or steady state load.

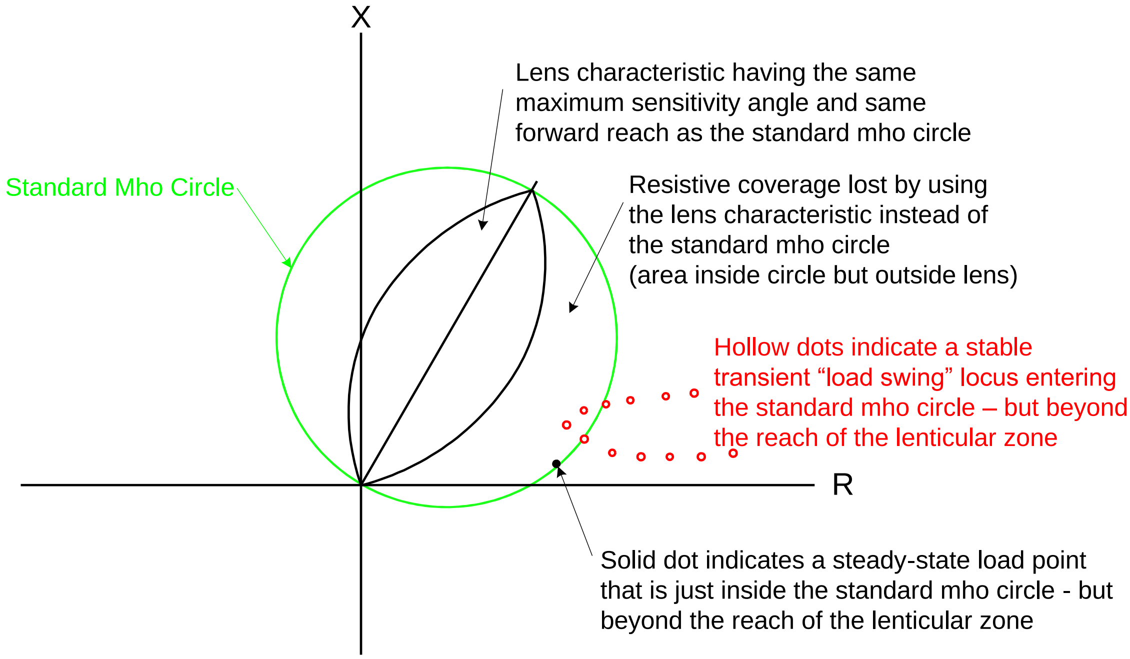

Figure 4.B.1.4 Lens characteristic.

4.B.2.b. Rectangular (Quadrilateral) characteristic

Quadrilateral characteristics are comprised of two lines intended to provide fault reactance boundaries and two lines intended to provide fault resistance boundaries. Ideally, the angle of these lines relative to the R and X axes will adapt in response to pre-fault load flow. The composite of these lines creates a rectangular or trapezoidal shaped impedance zone similar to that shown in Figure 4.B.1.5. By limiting the resistive reach appropriately, this characteristic can be made to avoid load regions in a similar manner to that of the lens. Unlike the lens, however, the quadrilateral provides a fixed resistive coverage from the relay location to the end of zone coverage.

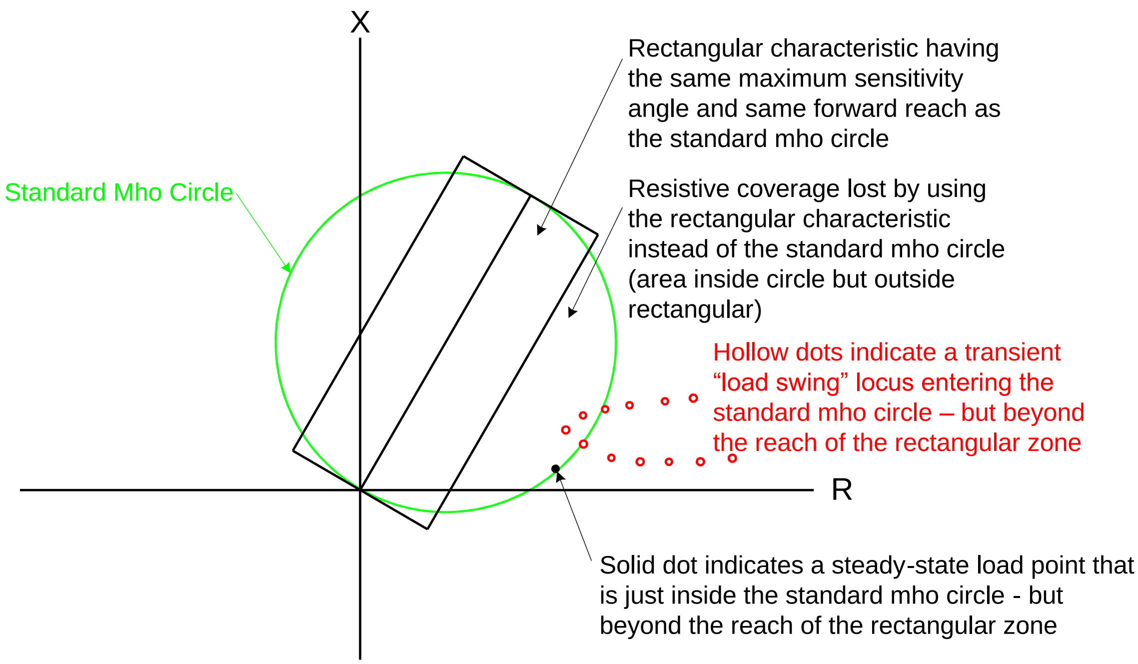

Figure 4.B.1.5 Quadrilateral characteristic.

4.B.3 Supervision of Zone Tripping

An alternate means of preventing or eliminating a distance zone's response to transient or steady state load conditions is to supervise its operation with other distance elements.

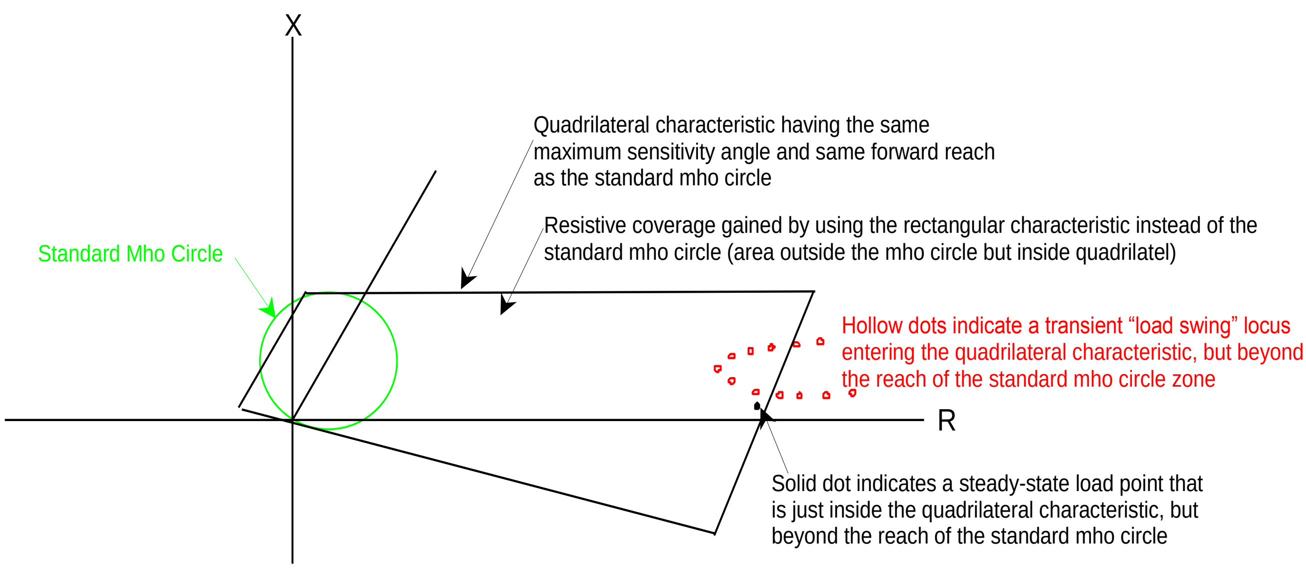

Figure 4.B.1.6 Quadrilateral characteristic.

On short line applications, quadrilateral characteristic distance elements, particularly ground quadrilateral distance elements, may be applied to improve the resistive fault sensitivity beyond that supplied by the standard mho characteristic, as shown in Figure 4.B.1.6. The use of a quadrilateral phase distance element with extended resistive fault sensitivity is quite obviously going to be susceptible to tripping under heavy static load or power swings as shown in the figure. The need to restrict the resistive reach of a quadrilateral phase distance element is therefore quite obvious. However, some may consider the quadrilateral ground distance element immune from tripping due to heavy load, and extend the ground resistive reach to the maximum setting. The tendency is to also set the zero-sequence or negative-sequence ground fault detectors very low to maximize the ground fault sensitivity. This is not advisable for relays that use phase current quantities in the quadrilateral ground distance element impedance measurement because heavy phase current loading during heavy load and load swing conditions may cause the apparent phase-to-ground impedance to move into the quadrilateral characteristic. Combine this with sufficient phase current unbalance under heavy load conditions and sensitive supervising ground fault detectors can pick up, causing the quadrilateral distance relay element to trip undesirably.

4.B.3.a. Use of blinders

The "impedance blinder" characteristic is created by applying two reactance-type elements having a predominately resistive reach, each directed toward the other. In the same manner as the resistive reaching elements of the quadrilateral characteristic, the blinders are shifted to positions paralleling, the impedance of the protected line at a resistive distance to each side. One blinder covers the impedance plane area to the left of its setting, while the other covers the plane area to its right. The supervised characteristic (typically an impedance mho) provides the boundaries for limiting forward and reverse reach, while the two blinder elements limit operation to a banded area to either side of the impedance of the protected line. The composite characteristic is very similar to the rectangular characteristic, mentioned previously under Variations in Zone Shape (see Figure 4.B.1.7).

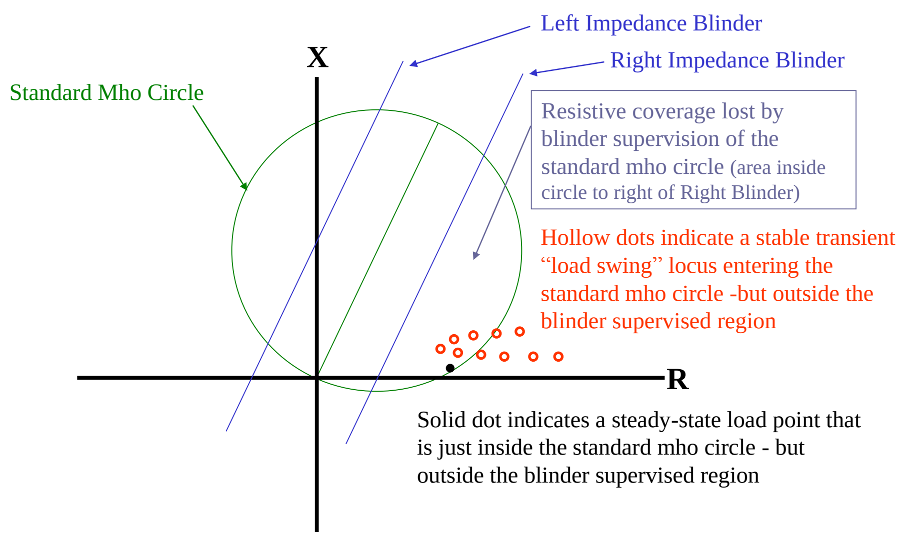

Figure 4.B.1.7 Impedance blinders.

Impedance blinders can significantly reduce the expansive resistive coverage afforded by the full mho circle, thereby greatly reducing the susceptibility for responding to load conditions.

4.B.3.b. Use of load encroachment characteristics

The traditional methods for avoiding detection in the load regions generally result in a significant loss of the impedance plane coverage. Almost always, improved loadability has been paid for with a loss in the coverage for resistive faults. Some of the modern line protection packages offer a much more optimal method of discerning between load and fault conditions. This feature, referred to as "load-encroachment", imposes more "knowledgeable" restrictions on distance element operation than any of the methods discussed so far. Since load (on a transmission system especially) is primarily a balanced three phase condition, supervisory restrictions are placed only on the operation of the 3-phase distance elements. Relay operation for phase-to-phase, phase-to-ground, and double phase-to-ground faults are unaffected by the Load-Encroachment feature! With the feature enabled, the user is able to define "custom" load regions in both the forward and reverse directions. As seen in Figure 4.B.1.8, these load regions reject only a minimal portion of a 3-phase mho distance characteristic. The relay calculates the positive sequence voltage (V_1) and current (I_1) from the measured phase quantities, and from them calculates the magnitude and phase angle of the positive sequence impedance (Z_1). If the measured positive sequence impedance lies within a defined load region, the 3-phase distance element is blocked from operating. Under this supervision, only resistive 3-phase faults (very unlikely occurrences) corresponding to a positive sequence impedance in a load region would be missed.

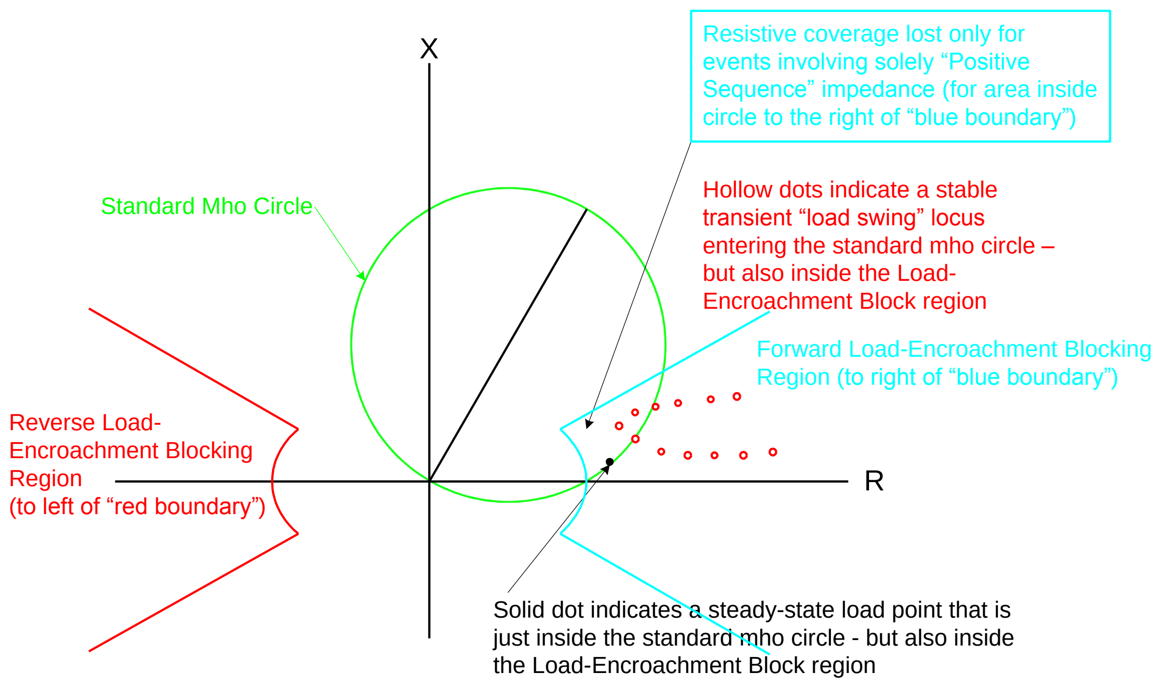

Figure 4.B.1.8 Load encroachment characteristic.

4.C. Means to prevent tripping on load.

4.C.1. Shaping the characteristics & load encroachment blocking.

Electromechanical as well as modern digital relays can be prevented from tripping on load by characteristic shaping and load encroachment blocking. Figures 4.C.1.1 through 4.C.1.4 show relay characteristics that can be set or programmed so that heavy line loading will not result in tripping via the relay's impedance characteristic. Some relay characteristics can be programmed to passively prevent tripping on load. Figures 4.C.1.1 through 4.C.1.4 are more typical of older electromechanical relays using this "avoidance" technique. The offset characteristic shown in figure 4.C.1.2 is not a very typical mho characteristic as it leaves a short portion of the line unprotected.

Modern relays can be set to actively block the relay from tripping when loading begins to traverse the relay's mho characteristic. Figure 4.C.1.4 illustrates this type of blocking in a modern digital relay.

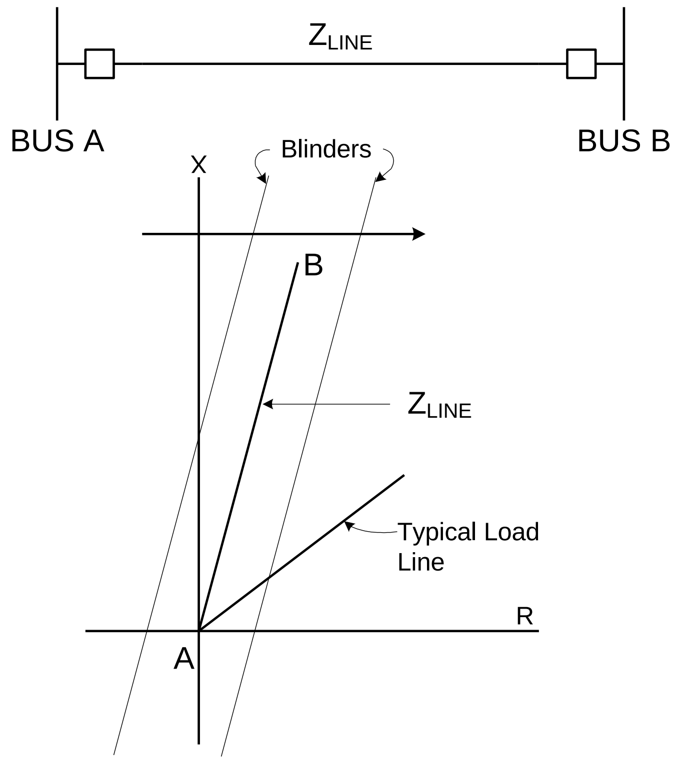

Figure 4.C.1.1 Use of Blinders to Restrict Tripping Area

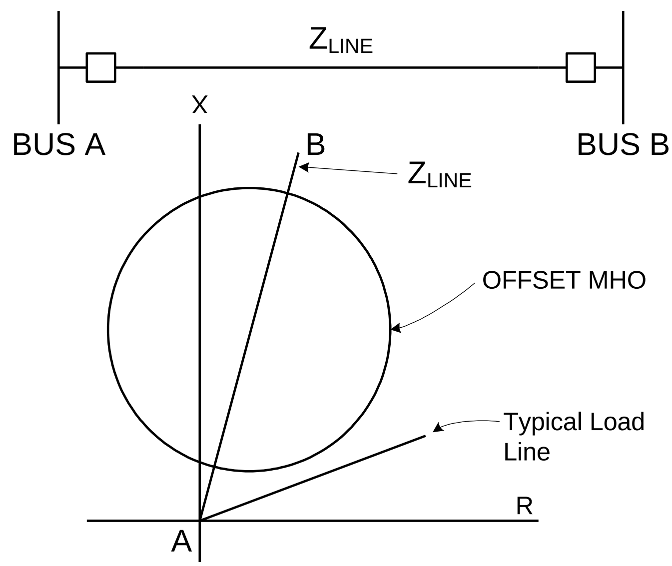

Figure 4.C.1.2 Use of Offset Mho to Avoid Load Line.

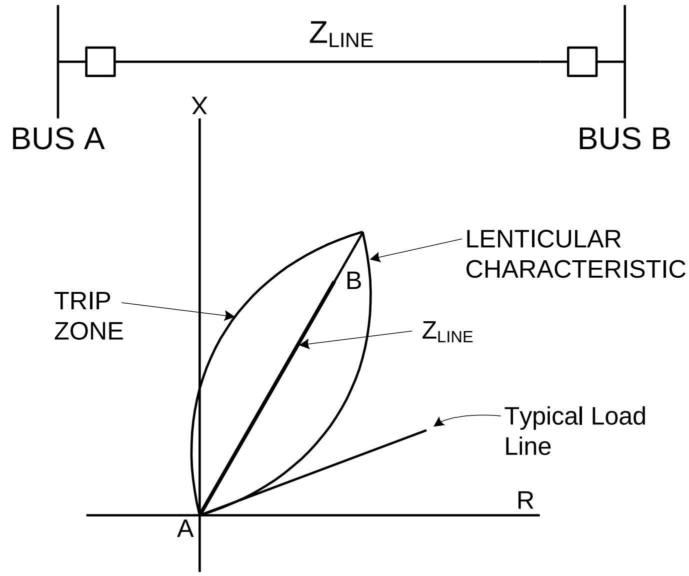

Figure 4.C.1.3 <u>Use of Lenticular Characteristic to Restrict Tripping to values closer to Line Impedance</u>

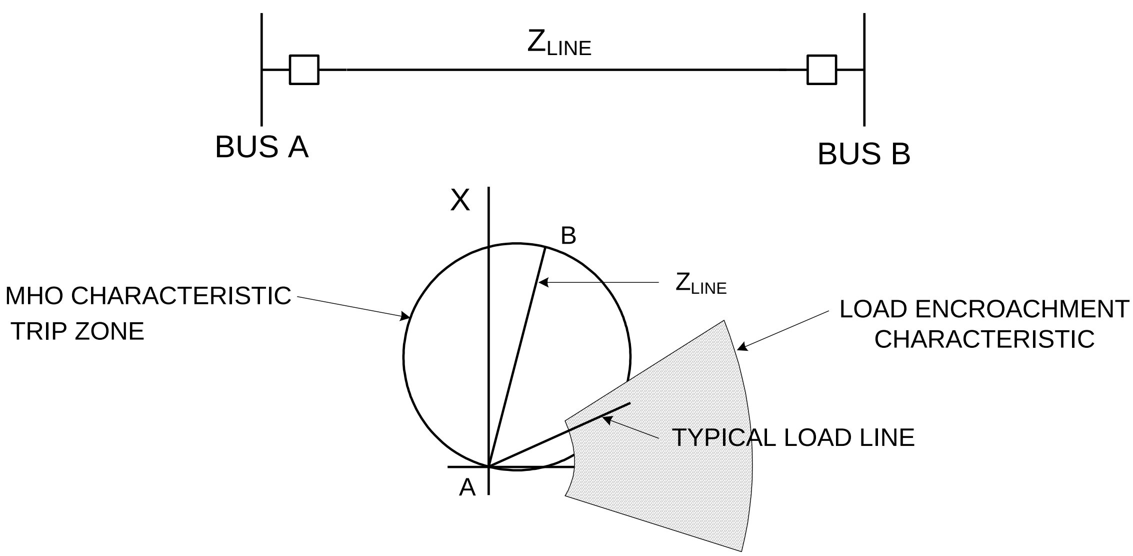

Figure 4.C.1.4 <u>Load Encroachment Characteristic Blocks Mho Tripping in Overlapping Area</u>

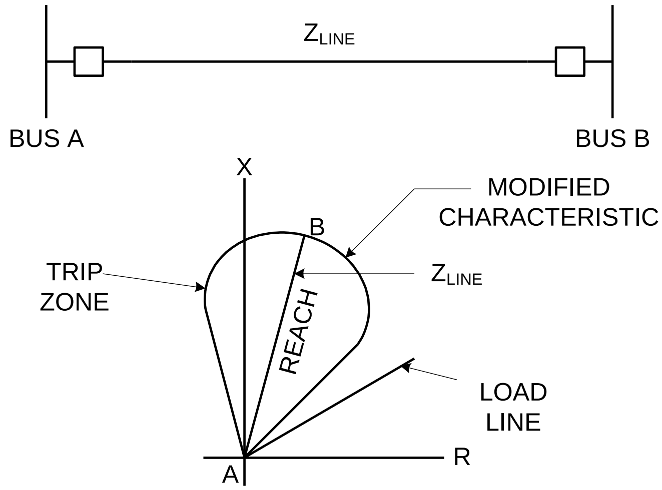

Figure 4.C.1.5 Additional Shaping of Mho Characteristic Avoids Load Line.

4.C.2. Using ground directional overcurrent (67N) instead of Z2 in pilot schemes.

In typical primary relay protection schemes, such as Directional Comparison Blocking (DCB), directional distance fault detectors are used for phase faults and directional overcurrent and directional ground distance fault detectors for ground faults. At each terminal, the phase and ground tripping elements must be forward directional and set to overreach the remote terminal. The reverse blocking elements should be reverse directional, with the exception of the ground overcurrent-blocking element, which can be non-directional. The blocking elements must reach farther, or be set more sensitively, than the corresponding tripping elements at the remote terminal. Using only ground directional overcurrent (67N), without Z2 phase impedance in pilot schemes, is not recommended. Z2 phase impedance relays are typically required to recognize 3 phase and phase-to-phase faults. Three phase faults involving ground chains and phase-to-phase conductor contact for wind and galloping conductors are examples where phase impedance relays are necessary. Ground overcurrent relays are typically applied to provide increased sensitivity. Depending on the application, the directional control of the ground overcurrent relays may use $3I_0$, V_0, or negative sequence voltage, V_2.

Setting Ground Directional 3I0 Overcurrent tripping elements:

The low set (reverse or non-directional) carrier-starting element should be set sensitive enough to assure fast pickup.

The high set (forward) element should be set sufficiently higher than the low set at the remote end to assure coordination.

On a line with a tapped transformer as in the Figure 4.C.2.1 below, consider the carrier tripping and blocking elements relay at each terminal.

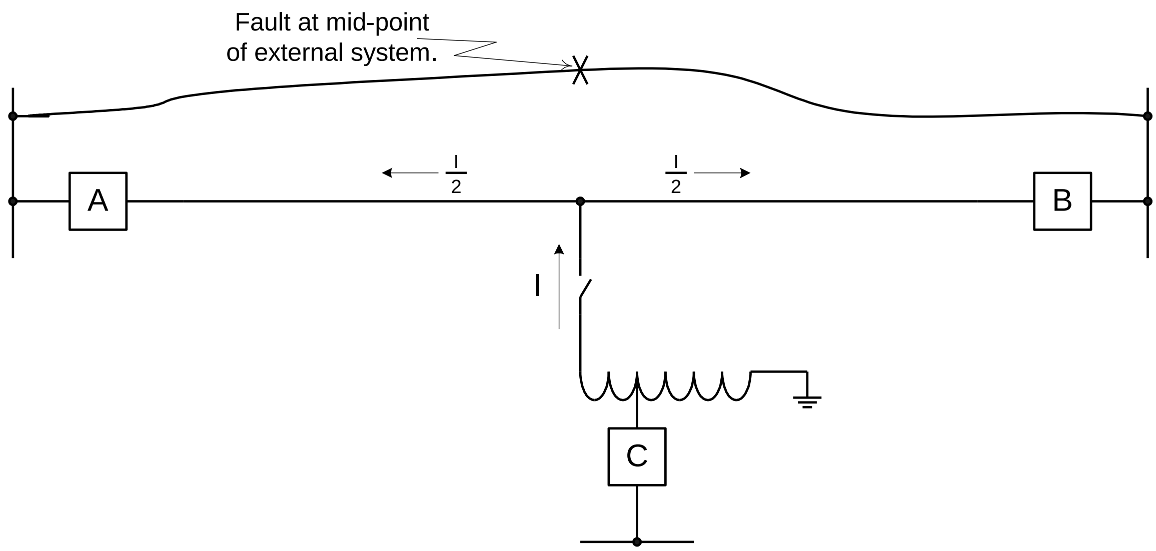

Figure 4.C.2.1 Three-terminal line with tapped transformer/weak source.

Set the low set element at each terminal as stated earlier. If the relays have the same CT ratio at A, B and C, the high set carrier trip element at C must not be set lower than 2.5 times the low set at A or B. The reason is as follows: Consider a fault at some fictitious point X as shown in the above figure such that the current comes up the transformer and divides equally between the two line sections. If the high set at C is set exactly 2.5 times the low set at A, the low set at A will have 1.25 times pickup while the high set at C will have 1 times pickup, which is exactly the same situation as a two terminal line. Consider the case where the BCT ratios are different at all three-terminals. Working in primary amperes, set the high set at C:

> 1.25 (low set at A+ low set at B)

This will always guarantee coordination between the low set elements and high set elements for external faults.

On "rare" occasions there is no tie between Stations A and B other than the line being set. In that case, the high set element at the tapped station may be set 2.5 times the low set at the remote terminals while trying to maintain adequate pickup for faults at the remote terminals, the 2.5 factor could be lowered without doing any harm.

The same coordination restrictions exist if there is a close system tie between Stations A and C, or between Stations B and C.

On a three-terminal line set with the same restrictions as above.

Remote Breaker Failure: Ordinarily, the pickup on the ground backup time overcurrent relay is set low enough to protect for a breaker failure at the remote station. However, sometimes this becomes impossible because at the same time that relay has to coordinate with time overcurrent relays in the next line section. Where local breaker failure relaying exists at the remote station, the ground carrier tripping scheme can be considered to provide for remote tripping since the local breaker failure will stop carrier transmission on the line. Consider the circuit configuration as shown in Figure 4.C.2.2 where a G fault occurs, breakers C2 and B trip and C fails. The local breaker failure relaying at Station C will trip C1 and stop the carrier blocking signal to Station A allowing the high set at A to pickup. For that case, 1.4 to 1.5 times pickup for the high set at A would be acceptable. The effect of any active taps or zero-sequence paths must be evaluated.

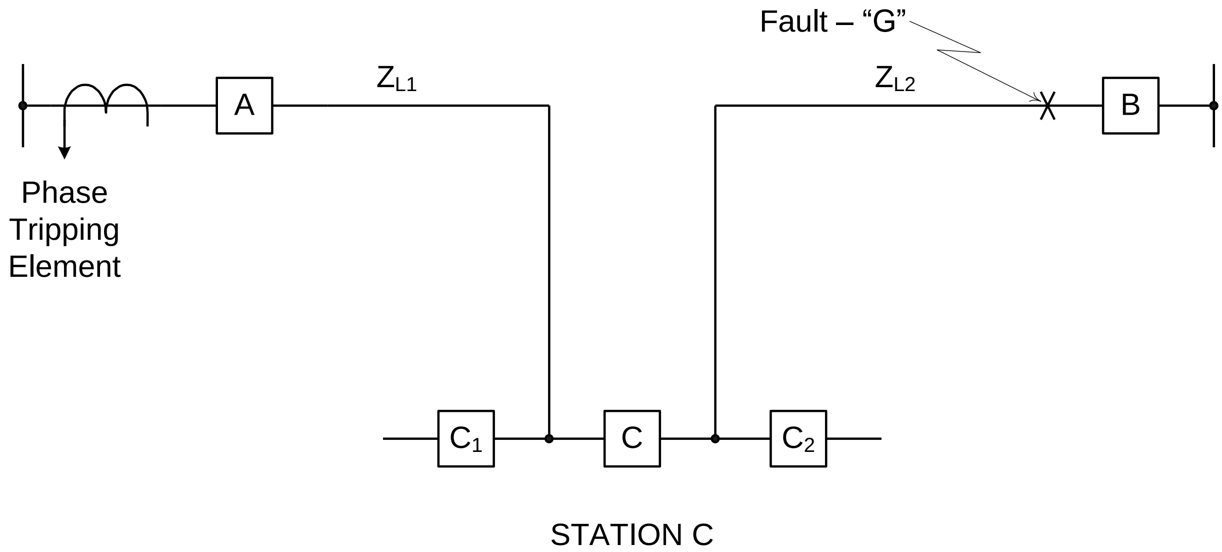

Figure 4.C.2.2 Three station configuration.

Sensitive ground directional elements used in place of ground distance elements should not be set so sensitive that they pick up due to system unbalance current during heavy load and load swing conditions. Load unbalance, non-transposed transmission lines, series impedance unbalance, unbalanced transformers or reactors, and single-phase tripping schemes can contribute to system unbalance current.

4.C.3. Maximum sensitivity angle (characteristic or torque angle) Considerations

Electromechanical mho distance relays are designed such that maximum operating torque results for fault quantities that result in a measured impedance that falls on the line that bisects the mho circle (see Figure 3.C.3.1). This line is commonly referred to as the “maximum torque angle” or “characteristic angle”. In some electromechanical relays this angle is fixed and cannot be adjusted (typically 75°). However, some electromechanical relays and most solid-state and microprocessor based relays allow this angle to be adjusted. This can be a very easily implemented change that improves the loadability of the mho distance relay. The trade off is slightly reduced resistive coverage which is generally not of significant concern for multi-phase faults.

For example, the distance relay characteristic shown in Figure 3.C.3.1 will carry 1,050MVA at a load angle of 30° with its 60° maximum torque angle. If the maximum torque angle is changed to 75° then the relay can carry 1,285MVA at a load angle of 30°. Note that these MVA are calculated load for a point on the circle, no safety margin has been included in these examples. The point being simply to show how raising the characteristic angle reduces the relays susceptibility to operating on load.

Referencing the formula given in section 3.C.3.1 it can be shown that the percentage increase in MVA loading when going from a lower maximum torque angle to a higher torque angle is:

$$\%\text{increase} = 100 \times \left(\frac{\cos(MVA_{old} - 30°)}{\cos(MVA_{new} - 30°)} - 1\right)$$

Following our example,

$$\%\text{increase} = 100 \times \left(\frac{\cos(60° - 30°)}{\cos(75° - 30°)} - 1\right)$$

$$\%\text{increase} = 22.5\%$$

5. Overreaching Distance Functions and Power Swings

In this section the impact of power swings on overreaching distance functions and the consequences on the security of power systems are discussed. How severe power swings can be seen as multi-phase faults by distance relays, cause unwanted tripping of transmission lines, and consequently threaten the security of the power system is reviewed. Also discussed is the need for protection functions that block distance elements from operating during power swings and in the event of unstable power swings to allow tripping of key system elements at pre-selected network locations to maintain system stability and minimize the impacts of a major system disturbance. The IEEE Power System Relaying Committee published a special report on the topic of “Power Swing and Out-of-Step Considerations on Transmission Lines” [12] that addresses the topic in great detail and should be consulted by users.

5.A.1. Impedances Seen by Distance Relays During Power Swings

Traditionally, power swing protection functions monitor the rate of change of the positive-sequence impedance. During a major system disturbance, a distance relay may see a power swing as a multi-phase fault if the positive-sequence impedance trajectory enters the operating characteristic of the relay. To demonstrate this, let us look at the impedance that a distance relay measures during a power swing condition for a simple two-source system.

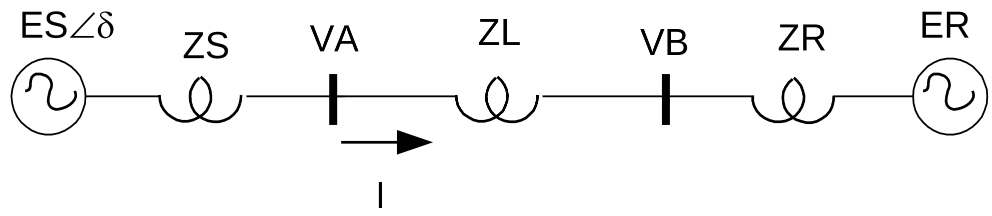

Figure 5.A.1.1 Two-Machine System

Considering Figure 5.A.1.1, the current I at bus A is computed as:

$$I = \frac{E_S\angle\delta - E_R}{ZS + ZL + ZR} = \frac{E_S\angle\delta - E_R}{ZT} \tag{1}$$

The voltage measured at bus A can be found as,

$$VA = E_S\angle\delta - Z_S \bullet I \tag{2}$$

The impedance measured at the relay at bus A can then be expressed as,

$$Z1 = \frac{VA}{I} = -Z_S + ZT\frac{E_S\angle\delta}{E_S\angle\delta - E_R} \tag{3}$$

Assuming $|E_S| = |E_R|$ for a special case, then,

$$Z1 = \left(\frac{ZT}{2} - Z_S\right) - j\left(\frac{ZT}{2}\cot\frac{\delta}{2}\right) \tag{4}$$

The details on deriving equation 4 can be found in [14]. Remembering that δ is the phase angle between the sources, there is a geometrical interpretation to equation 4 that is represented in Figure 5.A.1.2.

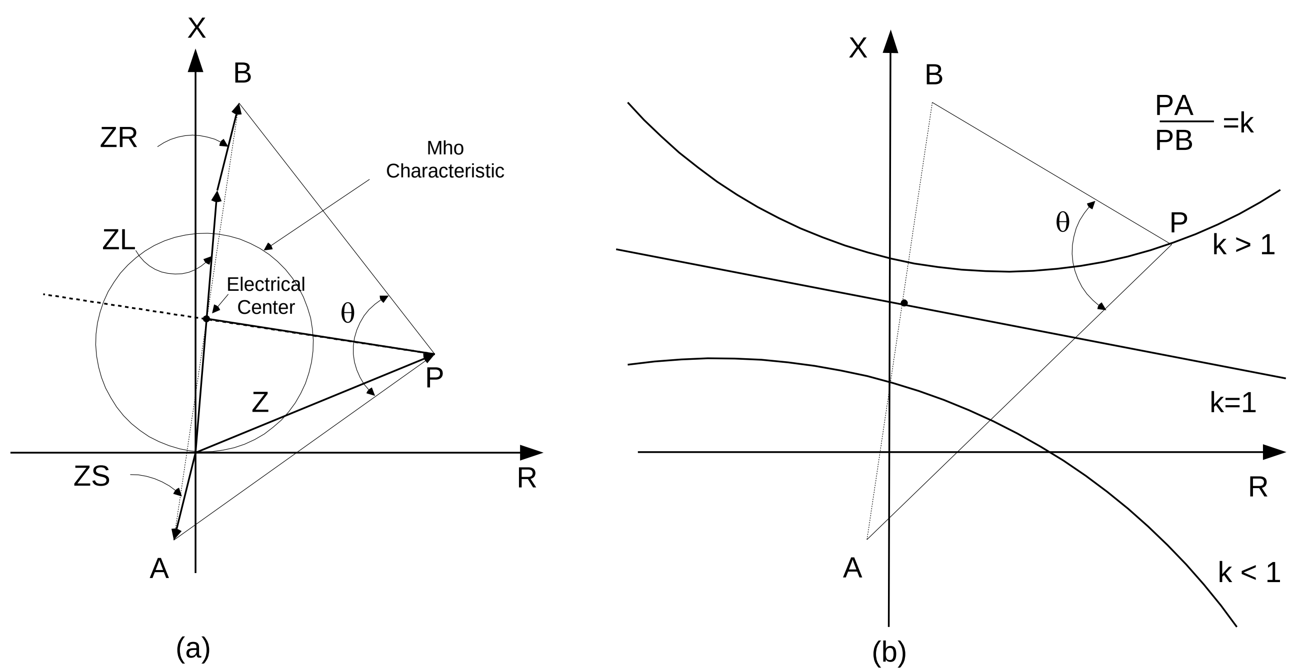

Figure 5.A.1.2 Impedance Trajectories at the Relay During a Power Swing for Different k Values

For the special case considered above, the trajectory of the measured impedance at the relay during a power swing, when the angle between the two source voltages varies, corresponds to the straight line that offsets from the origin by $(ZT/2 - Z_S)$, is perpendicular to the total reactance ZT, and intersects the segment A to B at its middle point. This point is called the **electrical center** of the swing. The angle between the two segments that connect P to points A and B is equal to the angle δ. When the angle δ reaches the value of 180°, the impedance is precisely at the location of the electrical center. It can be seen that the impedance trajectory during a power swing will cross any relay characteristic that covers the line, provided the electrical center falls inside the line.

In situations where the k, the ratio of the sources magnitudes, would be different from one, it can be demonstrated that the impedance trajectory will correspond to circles. This is shown in Figure 5.A.1.2 (b). The circle's center and radius values as a function of the k ratio can be found in the reference [15].

5.A.2. Effect of Power Swings on Distance Relays

Phase distance relays measure the positive-sequence impedance for three-phase and two-phase faults. It has been shown earlier that the positive-sequence impedance measured at a line terminal during an OOS condition varies as a function of the phase angle separation δ between the two equivalent system source voltages. Distance relay elements may operate during a power swing, stable or unstable, if the swing locus enters the distance relay-operating characteristic. Zone 1 distance relay elements, with no intentional time delay, will be the distance relay elements most likely to operate during a power swing. Also very likely to operate are Zone 2 distance relay elements used in pilot relaying systems, for example blocking or permissive type relay systems. Backup zone step-distance relay elements will not typically operate during a swing, depending on their time-delay setting and the time it takes for the swing impedance locus to traverse through the relay characteristic. Figure 5.A.2.1 (a) shows the operation of a Zone 1 distance relay when the swing locus goes through its operating characteristic and Figure 5.A.2.1 (b) shows a directional comparison blocking scheme characteristic and how it may be impacted by the swing locus.

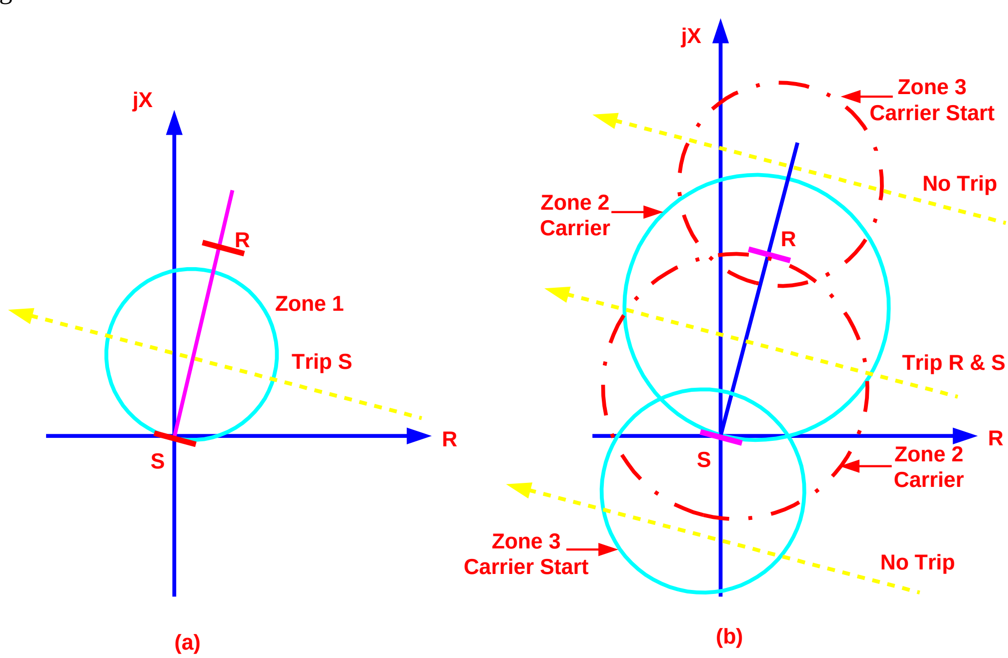

Figure 5.A.2.1 Zone 1 and Directional Comparison Blocking Scheme Characteristics

It is important to recognize that the relationship between the distance relay polarizing memory and the measured voltages and currents plays the most critical role in whether a distance relay will operate during a power swing. Another important factor in modern microprocessor-type distance relays is whether the distance relay has a frequency tracking algorithm to track system frequency. Relays without frequency tracking will experience voltage polarization memory rotation with respect to the measured voltages and currents. Furthermore, the relative magnitude of the protected line and the equivalent system source impedances is another important factor in the performance of distance relays during power swings. If the line positive-sequence impedance is large when compared with the system impedances, the distance relay elements may not only operate during unstable swings but may also operate during swings from which the power system may recover and remain stable.

5.A.3 Means to prevent tripping on power swings.

Power swings are variations in power flow that occur when the internal voltages of generators at different locations of the power system slip relative to each other. Power systems under steady-state conditions operate close to their nominal frequency and voltage. A balance between generated and consumed active power exists during steady-state operating conditions. Power system faults, line switching, generator disconnection, and the loss or application of large blocks of load result in sudden changes to electrical power, whereas the mechanical power input to generators remains relatively constant. These system disturbances cause oscillations in machine rotor angles and can result in severe power flow swings.

Depending on the severity of the disturbance and the actions of power system controls, the system may remain stable and return to a new equilibrium state experiencing what is referred to as a stable power swing. Severe system disturbances, on the other hand, could cause large separation of generator rotor angles, large swings of power flows, large fluctuations of voltages and currents, and eventual loss of synchronism between groups of generators or between neighboring utility systems. Large power swings, stable or unstable, can cause unwanted relay operations at different network locations, which can aggravate further the power-system disturbance and cause major power outages or power blackouts. Protective relays prone to respond to stable or unstable power swings and cause unwanted tripping of transmission lines or other power system elements include: overcurrent, directional overcurrent, undervoltage, distance, and directional comparison systems. Power swings can cause the impedance presented to a distance relay to fall within its operating characteristics, away from the preexisting steady-state load condition, and cause an undesired tripping of a transmission line.

5.B.1 Power Swing Blocking and Tripping Functions

Distance relays should not trip during power swings, to allow the power system to obtain a new equilibrium and return to a stable operating condition. The philosophy of power-swing protection is simple and straightforward: avoid tripping of any power system element during stable power swings. Protect the power system during unstable power swings or OOS conditions. Traditionally, two basic types of functions are available to deal with power-swing detection and system separation during unstable power swings or OOS conditions.

The PSB function is designed to detect power swings, differentiate power swings from faults, and block distance relay elements from tripping during power swings. The PSB function prevents system elements from tripping at random and at unwanted source-voltage phase-angle difference between systems that are in the process of losing synchronism with each other. However, faults that occur during a power swing must be detected and cleared with a high degree of selectivity and dependability. In such situations, the PSB function should unblock and allow the distance relay elements to operate and clear any faults that occur in their zone of protection during a power-swing condition.

Large power system disturbances can sometimes lead to a loss of synchronism among interconnected power systems. If such a loss of synchronism occurs, it is imperative that the system areas operating asynchronously are separated immediately to avoid wide area blackouts and equipment damage. Utilities designate certain network points as separation points and implement relaying schemes to separate system areas during unstable power swings or OOS conditions.

An out-of-step tripping (OST) function is available in modern distance relays to differentiate between stable and unstable power swings. When two areas of a power system, or two interconnected systems, lose synchronism, the areas must be separated from each other quickly and automatically to avoid equipment damage and shutdown of major portions of the power system. During unstable power swings, the OST function initiates controlled tripping of appropriate breakers at predetermined network locations, to separate networks quickly and in a controlled manner in order to maintain power system stability and service continuity. The main purpose of the OST function is to detect stable from unstable power swings and initiate system area separation at the proper network locations and at the appropriate source-voltage phase-angle difference between systems.

Ideally, the systems should be separated in such locations as to maintain a load-generation balance in each of the separated areas. System separation does not always achieve the desired load-generation balance. In cases where the separated area load is in excess of local generation, some form of nonessential load shedding is necessary to avoid a complete blackout of the area. Uncontrolled tripping of circuit breakers during an OOS condition could cause equipment damage and pose a safety concern for utility personnel. Therefore, a controlled tripping of certain power system elements is necessary to prevent equipment damage and widespread power outages and to minimize the effects of the disturbance. Distance relay elements prone to operate during unstable power swings should be inhibited from operating to prevent system separation from occurring at random and in other than pre-selected locations.

5.B.2 Power Swing Blocking and Tripping Principles

Conventional PSB schemes use the difference between impedance rate of change during a fault and during a power swing to differentiate between a fault and a swing. This detection method is based on the fact that it takes a certain time for the rotor angle to advance because of system inertias. In other words, the rate of change of the impedance vector is slow during stable or unstable power swings, because it takes a finite time for the generator rotors to change position with respect to each other because of their large inertias. On the contrary, the rate of change of the impedance vector is very fast during a system fault. During a system fault, the rate of impedance change is determined primarily by the amount of signal filtering in the relay. During a system swing, the measured impedance moves slowly on the impedance plane, and the rate of impedance change is determined by the slip frequency of an equivalent two-source system.

Over time, different impedance characteristics have been designed for power-swing detection. These characteristics include the double blinders shown in Figure 5.B.2.1 (a), polygons in Figure 5.B.2.1 (b), and concentric circles in Figure 5.B.2.1 (c).

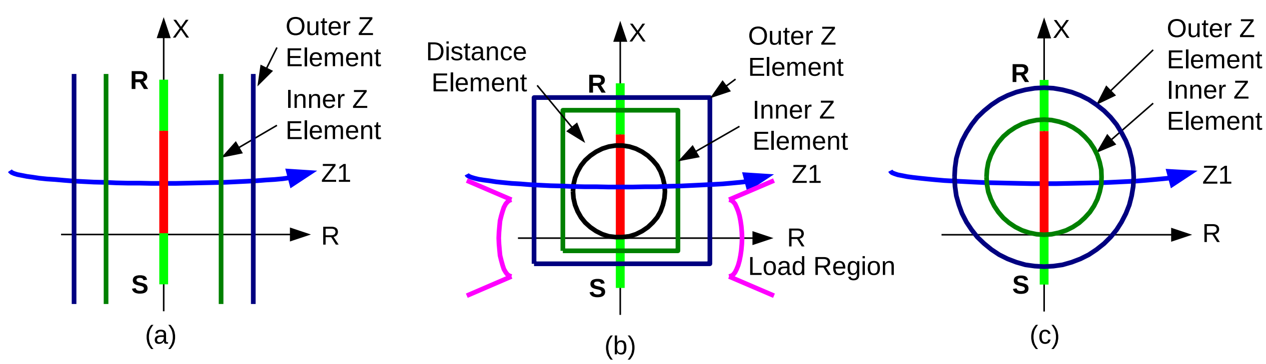

Figure 5.B.2.1 Conventional Blinder Schemes for Power-Swing Detection

Actual implementation of measuring the impedance rate of change is normally performed though the use of two impedance measurement elements together with a timing device. To accomplish this, one typically places two concentric impedance characteristics, separated by impedance ΔZ, on the impedance plane and uses a timer to time the duration of the impedance locus as it travels between them. If the measured impedance crosses the concentric characteristics before the timer expires, the relay declares the event a system fault. Otherwise, if the timer expires before the impedance crosses both impedance characteristics, the relay classifies the event as a power swing and issues a power-swing blocking signal to block the distance relay element operation.

There are a number of issues one must address with regards to properly applying and setting the traditional PSB and OST relaying functions. To guarantee that there is enough time to carry out blocking of the distance elements after a power swing is detected, the PSB inner impedance element must be placed outside the largest distance protection characteristic one wants to block. The PSB outer impedance element must be placed away from the load region to prevent PSB logic operation caused by heavy loads, thus establishing an incorrect blocking of the line mho tripping elements. These relationships among the impedance measurement elements are shown in Figure 5.B.2.1 (b), in which we use concentric polygons as PSB-detection elements.

The above requirements are difficult to achieve in some applications, depending on the relative line- and source-impedance magnitudes. Figure 4 shows a simplified representation of one line interconnecting two generating sources in the complex plane with a swing locus bisecting the total impedance. Figure 5.B.2.2 (a) depicts a system in which the line impedance is large compared to system impedances, and Figure 5.B.2.2 (b) depicts a system in which the line impedance is much smaller than the system impedances.

We can observe from Figure 5.B.2.2 (a) that the swing locus could enter the Zone 2 and Zone 1 relay characteristics during a stable power swing from which the system could recover. For this particular system, it may be difficult to set the inner and outer PSB impedance elements, especially if the line is heavily loaded, because the necessary PSB settings are so large that the load impedance could establish incorrect blocking. To avoid incorrect blocking resulting from load, lenticular relay characteristics, or blinders that restrict the tripping area of the mho elements are sometimes applied. On the other hand, the system shown in Figure 5.B.2.2 (b) becomes unstable before the swing locus enters the Zone 2 and Zone 1 relay characteristics, and it is relatively easy to set the inner and outer PSB impedance elements.

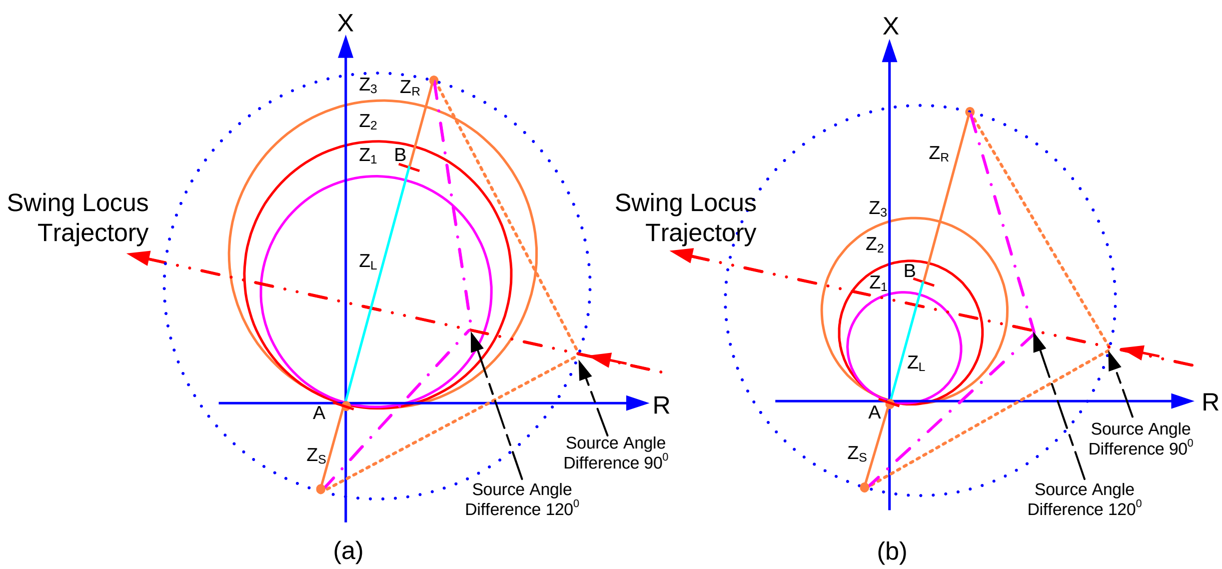

Figure 5.B.2.2 Effects of Source and Line Impedance on the PSB Function

Figures 5.B.2.2 (a) and (b) imply that if the phase angle difference between the source voltages reaches 120 degrees, the system will not be able to recover and will separate. The 120-degree point is a good initial estimate for determining the maximum stable power angle. It may allow the protection engineer to calculate better initial OOS setting estimates and reduce the stability studies required for confirmation. As this angle gets larger (without encroaching on the protection zones), the confidence level in the initial settings will also increase.

Another difficulty with traditional PSB systems is the separation between the PSB impedance elements and the timer setting that is used to differentiate a fault from a power swing. The above settings are not trivial to calculate and, depending on the system under consideration, it may be necessary to run extensive stability studies to determine the fastest power swing and the proper PSB impedance element settings. Typically, an extensive number of power system stability studies with different operating conditions must be performed. This is a costly exercise, and one can never be certain that all possible scenarios and operating conditions were considered.

The rate of slip between two systems is a function of the accelerating torque and system inertias. In general, a relay cannot determine the slip analytically because of the complexity of the power system. However, by performing system stability studies and analyzing the angular excursions of systems as a function of time, one can estimate an average slip in degrees/s or cycles/s. This approach may be appropriate for systems whose slip frequency does not change considerably as the systems go out of step. However, in many systems where the slip frequency increases considerably after the first slip cycle and on subsequent slip cycles, a fixed impedance separation between the PSB impedance elements and a fixed time delay may not be suitable to provide a continuous blocking signal to the mho distance elements. A solution might be out of step tripping at one or more planned locations during the first swing cycle. Once the systems separate, each will normally settle out to a different, but internally common frequency. The slip frequency between the separated systems is then no longer relevant to the out of step relaying at the system boundary.

Hou et al. [16] detailed steps for setting a polygon characteristic. These settings guidelines are applicable to all other blinder schemes shown in Figure 3 and are outlined as follows.

Set the outer characteristic resistive blinders inside the maximum possible load with some safety margin as illustrated in Figure 5.B.2.1 (b).

Set the inner resistive blinders outside the most overreaching protection zone that is to be blocked when a swing condition occurs. Normally, you want to block the distance elements that issue a trip without a time delay. These elements include the Zone 1 instantaneous tripping element and the Zone 2 element that is used in a communications-assisted tripping scheme.

Based on the outer and inner blinders set in the previous steps, the PSB timer value, OSBD, can be calculated from the following equation with information of the local source impedance, Z1S, the line impedance, Z1L, and the remote source impedance, Z1R. Ang6R and Ang5R are machine angles at the outer and inner blinder reaches, respectively, as illustrated in Figure 5.B.2.3. The maximum slip frequency, Fslip, is also assumed in the calculation. Typical maximum slip frequency is chosen anywhere between 4 to 7 Hz.

$$\mathrm{OSBD} = \frac{(\mathrm{Ang5R} - \mathrm{Ang6R}) \cdot \mathrm{Fnom}(\mathrm{Hz})}{360 \cdot \mathrm{Fslip}(\mathrm{Hz})}(\mathrm{cycle}) \tag{5}$$

It is very difficult in a complex power system to obtain the proper source impedance values, as shown in Figure 5.B.2.3, that are necessary to establish the blinder and OSBD timer settings. The source impedances vary constantly according to network changes, such as, for example, additions of new generation and other system elements. The source impedances could also change drastically during a major disturbance and at a time when the PSB and OST functions are called upon to take the proper actions. Note that the design of the PSB function would have been trivial if the source impedances remained constant and if it were easy to obtain them. Normally, very detailed system stability studies are necessary to consider all contingency conditions in determining the most suitable equivalent source impedance to set the conventional PSB function.

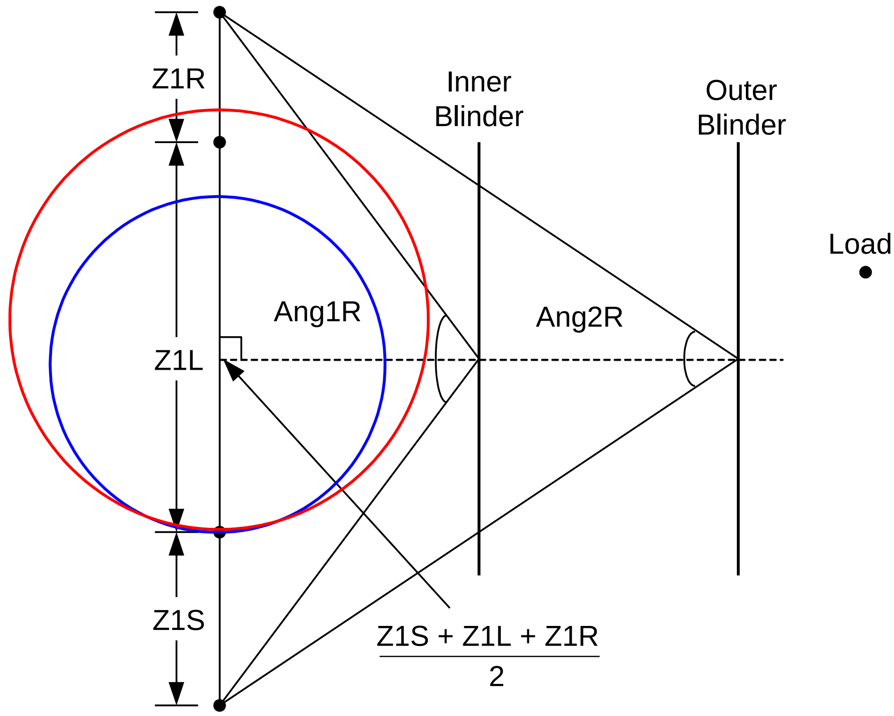

Figure 5.B.2.3 Equivalent Two-Source Machine Angles During OOS

Other than needing careful system studies and detailed source parameters, one may also experience difficulties for a long line with heavy loads, where the load region is close to the distance element that needs to be blocked in a swing condition. In this condition, the spacing between the inner and outer blinders may be small enough to cause a significant timing error for a power swing. If the load region encroaches the distance element one wants to block under swings, then it is impossible to place the PSB characteristics between the load and distance regions, and one cannot apply the conventional PSB blocking function.

5.B.3 Additional Considerations

When the power system is in an OOS condition, the bus voltages and line currents vary in great magnitudes, and power system equipment is stressed to their limits. Although faults during stable power swings and system OOS conditions are events with very small probability, proper operation against these faults is nevertheless extremely important to ensure controlled power system separation and continuous operation of remaining part of the power system.

Ideally, the performance requirements of protective relays under system OOS condition should be identical to those under normal system operations in terms of speed, selectivity, reliability, and sensitivity. However, due to the nature of the distance relay elements under system OOS, it is almost impossible to demand the same performance of the distance elements as those under normal system fault conditions

Selectivity is critical to avoid cascade tripping.

5.B.4 Distance Protection Requirements During OOS Conditions

Because of the complexity and the rare occurrence of power system OOS, many utilities do not have clear performance requirements for distance relays during system OOS. The performances of distance elements are routinely exempt from being scrutinized in detail under system OOS conditions.

- Speed

A fault occurs instantaneously while a power swing can be characterized as a slow speed event. The PSB function takes advantage of this and relay logic may be used to block the distance element operations. The distance elements can be made operative in case of unbalanced faults, only if the relay logic resets the PSB condition during the fault condition. Traditionally, some time delay is necessary to coordinate with other protective devices in the event that the fault is external to the protected line section.

- Selectivity

If a PSB condition is removed due to an unbalanced fault, distance element loops may overreach protection zones simultaneously when the system electrical center falls on the protected line and when the fault occurs at a large machine δ angle. Therefore, it may not always be possible for a distance relay to perform single-pole tripping for SLG faults during system OOS. Distance elements, therefore, may trip three poles for internal SLG faults during system OOS conditions.

- Dependability

Distance elements must trip all internal line faults during system OOS conditions. Sometimes it may be difficult to reset the PSB when the fault occurs at a voltage peak and a current minimum during an OOS cycle, especially for three-phase faults that do not produce any negative-sequence currents. Regardless, the distance relay must be able to detect ensuing three-phase faults during OOS conditions even if the operating time is longer.

- Security

Distance elements must be secure to external faults during system OOS conditions. Distance elements, however, maybe challenged and trip on external faults if an OOS condition develops during a single-pole open condition. Traditionally, some time delay is necessary to coordinate with other protective devices in the event that the fault is external to the protected line section. A simple time delay does not guarantee the coordination when the system electrical center does not stay in one location on the system, and may not also be applicable on parallel-line systems to restrain the distance relay from tripping for external faults.

5.B.5 Power Swing Protection During Single Pole Open Conditions

Power swing conditions could occur after a single pole trip in weak areas of the power system. Distance relays should properly distinguish between a power swing and a fault during the open pole period following a single pole trip. The phase and ground distance elements still in-service should be blocked by the PSB logic if a power swing develops during the open pole period, and trip if a fault occurs in another phase during the power swing. Disabling the PSB function during the single pole open period is not desirable. If PSB function is inhibited due to an open pole, undesired tripping can occur if an ensuing swing enters the operating characteristics of the phase or ground distance elements for the two remaining phases.

5.B.6 Three-Phase Faults Following Power Swings

Power swings and three-phase faults involve all three-phases of the power system. The distance relay cannot simply use the measured impedance alone to determine whether or not phase distance protection should be inhibited or allowed to trip. A critical distinction between three-phase faults and power swings is the rate of change of the measured impedance. The rate of change is slower for a power swing than a three-phase fault. However, when concentric characteristics are used to detect a power swing the relay may not be able to detect a three-phase fault after PSB asserts; for example, the power swing evolves into a three-phase fault.

When a three-phase fault occurs during a power swing the measured impedance moves to the line angle and remains there until the fault is cleared. One solution is not to block a time-delayed zone; for example, allow tripping on a delayed Zone 2 operation. Manufacturers of numerical distance relays may account for this scenario using other techniques.

6. Alternatives to Remote Backup Application of Overreaching Zones

The main alternative to the use of remote backup schemes are the use of local schemes. A local scheme is a protection system contained at the local substation. Varying levels of breaker failure schemes, redundancy, independence, and communication schemes are typically employed at the local substation to speed up fault clearing, and thus, limit damage. A combination of these philosophies can be used to further reduce the need for remote backup protection systems that utilize overreaching distance elements.

6.A Local Breaker Failure Protection Systems

A breaker failure relay scheme is a local backup protection system that utilizes fault-clearing devices other than those tripped by the primary protection system. The breaker failure system is typically initiated by the line protection systems, bus protection systems, or transformer protection systems, upon fault detection. After a time delay, other fault clearing devices are tripped if the fault persists. The local fault clearing time delays are shorter than remote overreaching zone time delays. IEEE PC37.119, Guide for Breaker Failure Protection of Power Circuit Breakers, discusses many aspects of this local backup protection.

However, if the breaker failure scheme shares components, such as DC circuits, a single failure in the primary protection system may result in the loss to the local backup protection. To address this vulnerability, redundancy and independency are applied to local protection systems.

6.B Redundant Line Protection Systems

Redundant protection systems provide an additional means of fault detection and clearing. Ideally, failure of a single local protection system does not impact the overall local tripping functions, and remote backup schemes are not required. The level of application for a redundant system typically varies with the voltage level and risk tolerance. The higher the voltage level, the higher the fault energy. Therefore, faster and more reliable fault clearing is essential, thus driving redundancy and independence at the higher voltage levels. For example, the redundant protection system at a 34kV substation might include a simple duplicate of the primary protection system with many shared components, such as instrument transformers, breaker trip coils, and the DC system. A single failure of the battery could result in the loss of the local backup protection, thus prompting the need for the remote overreaching zone protection system for fault clearing. On the other hand, to avoid the risk of a single failure at a 500kV substation, fully redundant and independent schemes would be employed.

The ideal local backup protection schemes would be physically separated, electrically isolated, and fully redundant that any reasonable common mode or multi-mode failure would not result in loss of the tripping function. Attributes of such systems include separate DC voltage systems, individual instrument transformers, separate breaker trip coils, different control panels and cable routing, different relay types, etc. In order to strengthen the argument for alternatives to remote backup protection systems, simply apply a higher level of redundancy and independency at the local terminal.

6.C Communication Applications

Communication assisted schemes provide an alternative to the use of remote backup protection systems. Faults at the local substation can clear faults remotely prior to remote backup time delays. For example, a Direct Transfer Trip (DTT) scheme could send a trip to a remote terminal anytime a local tripping function required a trip. Other blocking or unblocking schemes could also produce similar results.

6.D Direct Transfer Tripping and other Teleprotection Applications

The employment of direct transfer tripping and other teleprotection applications can be used to enhance local backup schemes, by either reducing the time-delay associated with an overreaching, remote backup coverage, or eliminating entirely the reliance on a remote backup scheme. An example of such an application can be found as part of individual breaker failure protection schemes applied for the breakers in “Ring” or “Breaker-and-a-half” bus configurations. These local backup schemes can, of course, easily trip the adjacent breakers located in the substation when a failure is declared. The tripping of the adjacent breakers located in distant substations (remote line terminals); however, cannot be accomplished in the same direct and simple manner. Unless the breaker backup scheme can have the remote sectionalizations effected more quickly by other means, the delayed trip initiated by the remote overreaching line backup protection will have to be relied upon for covering faults within the failed breaker's other primary zone.

One method for effecting faster remote tripping, when the associated lines are protected using Directional Comparison Blocking pilot schemes, is to have a breaker failure operation stop the transmission of the pilot blocking signal on each line for which the failed breaker provides line terminal sectionalization. This action allows the much faster pilot tripping function of the remote line terminal to respond for faults in the breaker's other primary zone. (The other zone, for which the breaker has apparently failed to open, could be another line, a transformer, generating unit leads, etc.) Unblocking to effect remote tripping; however, still has the breaker failure scheme relying partially on a remote backup. In addition, greater reach requirements are forced on the high-speed, overreaching of any remote line terminals involved. Although proper coverage for breaker failure backup can generally be made without considering any infeed affects, the additional reach required, beyond the normal line protection overreach margin, may impinge upon the line terminal loadability.

Another method for assuring fast and dependable remote tripping is to have the breaker failure scheme initiate a direct transfer trip of the remote breakers. This method not only releases the local backup scheme from dependence on the remote backup protection, but also would prevent any automatic reclosing of the remote line terminal by the transfer trip signal being held-on by the breaker failure scheme's lockout auxiliary. Transfer tripping may be done in lieu of or in addition to the blocking signal stopping for a breaker failure declaration.

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Appendix A. Zone 3 and Load Power

The distance relay load limit is defined as the loading permitted by the relay including a security margin. In Figure A.1, the distance relay located at bus 1 will misoperate on load if the magnitude and phase angle result in a measured impedance that falls within the relays characteristic. The impedance measured by a distance relay is given by:

$$\overline{Z}_a = \frac{|\overline{V}|^2 (P + jQ)}{P^2 + Q^2} = \frac{|\overline{V}|^2 \overline{S}}{|\overline{S}|^2} \qquad (1)$$

Where, $\overline{Z}_a$ is the impedance measured by a distance relay, $\overline{V}$ is the measured voltage, $\overline{S}$ is the apparent power and P, Q are the real and the reactive powers, respectively. Under balanced three-phase conditions $\overline{Z}_a$ will be equal to any phase-neutral voltage phasor divided by its respective current phasor (e.g. $\overline{V}_{An} / \overline{I}_A$).

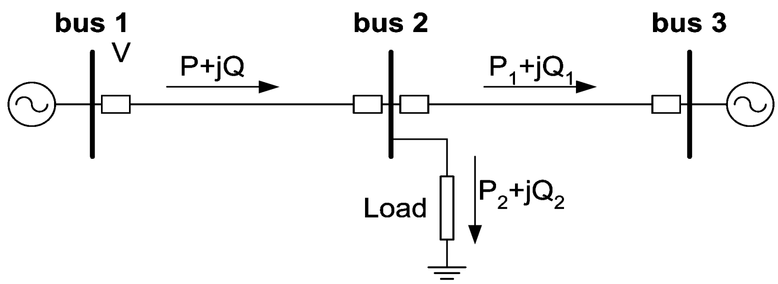


Figure A.1 Power system load flow.

When the magnitude of apparent power is fixed, the measured impedance is given as:

$$|\overline{Z}_a| = \frac{|\overline{V}|^2}{|\overline{S}|} \qquad (2)$$

The trajectories of the measured impedance (with constant magnitude apparent power) as the power flow changes are illustrated by either a_1 or a_2 in Figure A.2 in which, the larger the magnitude of the apparent power, the smaller the radius of the circle, and the measured impedance moves in the *m1* direction as the power factor decreases (load becoming more reactive, less resistive). When the power factor is held constant, the trajectory of the measured impedance is illustrated by b in Figure A.2. Since the magnitude of the apparent power is greater than that associated with fixed power, the measured impedance moves in the *m2* direction with a slope of θ; this effectively means that as the magnitude of the apparent power becomes larger (or the power factor becomes smaller), the probability of misoperation due to load power becomes greater.

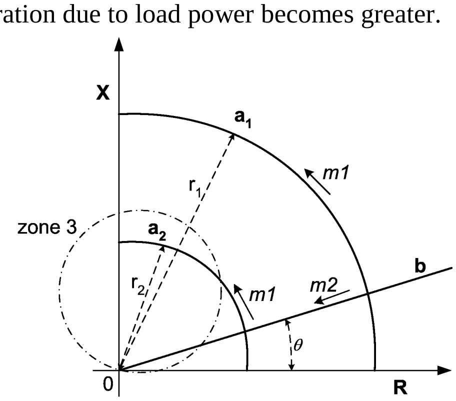


Figure A.2 Trajectories of the measured (apparent) impedance as the power flow varies.

The real and the imaginary parts of the measured impedance shown in (1) are written as :

$$R = \frac{|\overline{V}|^2 P}{P^2 + Q^2} \qquad (3)$$

$$X = \frac{|\overline{V}|^2 Q}{P^2 + Q^2} \qquad (4)$$

Where, R and X are the resistance and the reactance components of the measured impedance, respectively.
The R and X in (3) and (4) are written as:

$$R^2 + X^2 = \frac{|\overline{V}|^4}{P^2 + Q^2} \qquad (5)$$

Substituting (3) into (5) results in:

$$R^2 + X^2 = \frac{R|\overline{V}|^2}{P} \qquad (6)$$

This can be rearranged as:

$$(R - \frac{|\overline{V}|^2}{2P})^2 + X^2 = \frac{|\overline{V}|^4}{4P^2} \qquad (7)$$

When P is fixed, equation (6) is a circle with:

$$\text{Center} : \left(\frac{|\overline{V}|^2}{2P}, 0\right) \quad , \quad \text{Radius} : \frac{|\overline{V}|^2}{2P}$$

This circle is illustrated as “b” in Figure A.3 and is the trajectory of the measured impedance, which moves in the *m2* direction as the reactive power increases.
Similarly, substituting (4) into (5) results in:

$$R^2 + X^2 = \frac{X|\overline{V}|^2}{Q} \qquad (8)$$

This can be rearranged as:

$$R^2 + (X - \frac{|\overline{V}|^2}{2Q})^2 = \frac{|\overline{V}|^4}{4Q^2} \qquad (9)$$

When Q is fixed, equation (7) is a circle with:

$$\text{Center} : \left(0, \frac{|\overline{V}|^2}{2Q}\right) \quad , \quad \text{Radius} : \frac{|\overline{V}|^2}{2Q}$$

This circle is illustrated as “a” in Figure A.3 and traces the trajectory of the measured impedance, which moves in the *m1* direction as the real power increases.

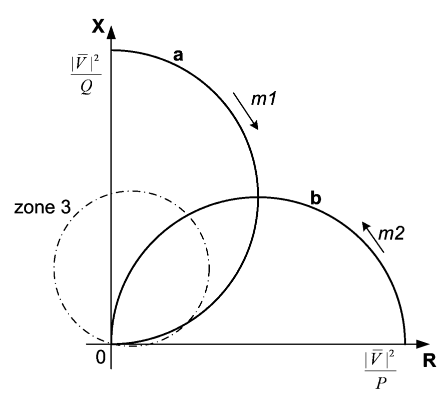


Figure A.3. Trajectories of the measured impedance as the real and the reactive power vary.

Therefore, an incremental increase in real or reactive power may cause susceptible distance relays to misoperate. This is particularly so in the increment of the reactive power as apparent from b in Figure A.3.

Appendix B. NERC Interim Requirements for Line Loadability

An August 14, 2003, the Northeast portion of the Eastern Interconnection experienced a cascading blackout. 61,000 MW of customer load was interrupted. The US Department of Energy and the Canadian Ministry of Natural Resources commissioned a Task Force to find the causes of the blackout and to author recommendations to minimize the likelihood and scope of similar events in the future. There report is entitled: **U.S.-Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations April 2004.**

The North American Electric Reliability Council, NERC, was an integral member of the outage task force. On February 10, 2004 NERC's Board of Trustees approved "**NERC Actions to prevent and Mitigate the Impacts of Future Cascading Blackouts"**

This report addressed the issue of operation of protective relays accelerating a cascade: "Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margin above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc. and should not compromise a power system's inherent physical capability to slow down or stop a cascading event.

NERC's February 10, 2004 mitigation report included recommendation 8a:

> *Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[6]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.*
>
> *Footnote 6: The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.*

Intent of Footnote 6

The Blackout Investigators recommended the limitations be placed on the reach of remote backup protection so as not to interfere with the operator's abilities to mitigate a cascading blackout. First, the power system must be protected. Second, the power system must be operable. Based on analyses and interviews, it was felt that an operator should have at least 15 minutes to perform emergency actions including the shedding of load during extreme system contingencies. A line loading of 150% of emergency rating allows for such emergency switching over about 70% of the hours of the year based on normal load duration curve. Actual system voltages lasting for minutes during the cascade were at of slightly below 0.85 pu. This qualifier too was considered practical rather than conservative. It is hoped that future studies will be able to prove that an undervoltage load shedding scheme can be deployed in areas of the system that will be able to aid the operator in mitigating power system cascades. Finally, many lines tripped when their apparent impedance entered their zone 3 mho circles at 30 degrees. During this phase of the cascade, the system remained stable. Generally, increased angles were coincident with systems pulling apart from each other.

In April, 2004 the U.S.-Canada recommendations report was issued. Among the 46 recommendations to minimize toe likelihood of similar events is recommendation U.S.-Canada Task Force Recommendation 21:

> ***21. Make more effective and wider use of system protection measures.***
>
> ***In its requirements of February 10, 2004, NERC:***
>
> **A. Directed all transmission owners to evaluate the settings of zone 3 relays on all transmission lines 230 kV and higher.**

The NERC Planning Committee within NERC appointed a task force, System Protection and Control Task Force, to carry out the task of implementing NERC Recommendation 8a. The SPCTF membership was comprised of relay engineers from transmission owners from all if NERC's Regions, NERC staff members, and members of the NERC Blackout Investigation Team. On July 24, 2004 the SPCTF's implementation plan was approved by the Planning Committee and NERC's Board of Trustees.

The SPCTF clarified the term "emergency ampere rating" in Footnote 6 as:

> ***Emergency Ampere Rating*** *— "The highest seasonal ampere circuit rating (that most closely approximates a 4-hour rating) that must be accommodated by relay settings to prevent incursion." That rating will typically be the winter short-term (four-hour) emergency rating of the line and series elements. The line rating should be determined by the lowest ampere rated device in the line (conductor, air switch, breaker, wavetrap, series transformer, series capacitors, reactors, etc) or by the sag design limit of the transmission line for the selected conditions. The evaluation of all Zone 3 relays should use whatever ampere rating currently used that most closely approximates a 4-hour rating.*

The SPCTF then defined the term Zone 3 as remote backup protection exactly as defined within the IEEE Standard C37.111- Guide for the Protection of Transmission Lines:

> ***Section 5.3.7.1 – Remote Backup***
>
> *"This form of protection relies on the remote relaying on adjacent circuits to overreach the primary zones of protection. Tripping is delayed to allow for the primary protection to operate. The effects of infeed from adjacent lines must be taken into account to ensure complete coverage. In some cases, if the remote backup relays cannot completely cover the protected zone under normal conditions, they must at least be able to operate sequentially. Obviously, this leads to lengthy delays in the clearing of faults. A serious drawback of remote backup protection is the complete loss of supply to the affected substations, because all lines into the station have to be opened to remotely clear the fault."*

The SPCTF and the relay engineers across North America were now tasked with an assignment of huge proportions. It was obvious that not all lines would need meet the recommendation of Footnote 6 and yet qualify as meeting the intent of the Recommendation 8a. To address this issue the SPCTF developed the concept of Technical Exceptions:

> ***Technical Exceptions*** *would be justified on technical merit where facilities could not under any reasonable contingency be loaded to a level that would initiate a protective relay operation, under current system conditions. Technical exceptions would be subject to review in light of future system changes. The SPCTF will develop (for the Planning Committees approval) the criteria by which facilities will receive an automatic technical exception to the thermal loading criteria based on these other factors. These criteria should be developed and communicated to the TPSOs by September 30, 2004. The SPCTF, under the direction of the NERC Planning Committee, should evaluate any exceptions requests made by the TPSOs to the Zone 3 loadability requirements.*

The SPCTF developed and posted on the NERC website:

"**Relay Loadability Exceptions Determination and Application of Practical Relaying Loadability Ratings**"
Version 1.1 November 2004

This technical document described 12 exception possibilities to Footnote 6 that would result in automatic reduction of requirements to meet the capabilities of the system being protected. They are summarized as follows:

1	If 15 minute winter emergency ratings are published, use it with a 15% margin.
2	If the theoretical maximum power transfer across the line is less than the 150% of winter emergency use it without any system impedance to calculate maximum line current.
3	Use a circuit breaker's interrupting rating to calculate a source impedance then include that in the maximum power transfer calculation.
4	Use a fault study to determine system impedance for the calculation of maximum power transfer. Set the voltage sources to 1.05 pu.
5	For series compensated lines, use the spark gap and/or MOV maximum voltage to calculate a maximum rated current
6	Weak System Source (high impedance) may limit maximum current to well below the lines thermal rating.
7	Extremely long lines may limit maximum current
8	Three terminal lines can limit line load while still allowing adequate relay margin to see all faults on a line
9	A generator (s) may be the only source behind a line and it may be well below the lines thermal limit
10	A Load may be the only system impedance behind a line.
11	Similar to #10, a group of line serve a load center and the total load is less than the thermal rating of one of the lines.
12	Same as #11, but now the line terminals at the load center, determine the maximum current flow from the load center to the electrical network.

Table B.1 <u>Relay Loadability Technical Exceptions</u>

The SPCTF proposed and NERC's Planning Committee (PC) approved an implementation timeline for Zone 3 relay review and mitigation. SPCTF and the PC allowed for delay in implementation due to scheduling of facility outages and therefore defined the Temporary Exception:

> ***Temporary Exceptions*** *would allow for a delayed implementation schedule for facilities that require modification due to the inability to complete the work within the prescribed time frame because of facility clearance or work force issues. Temporary exceptions may also be granted for application of temporary mitigation plans until full implementation can be achieved.*

The North American relay engineers were then tasked with the following implementation plan:

September 30, 2004	Each TPSO shall report to their Region on their review of their relaying systems in accordance with NERC Recommendation 8a, as modified in this document.
October 31, 2004	Each Region shall report to the NERC SPCTF on the compliance of each TPSO on evaluating it's relaying as of September 30, 2004, under Recommendation 8a, as modified in this document. That report shall include a list of the non-respondent and respondent TPSOs.
December 31, 2004	Each TPSO shall submit to their Region one or more of the following: i. Certification that their system meets all of the requirements of the loadability criteria.

	ii. Identify violations that will be mitigated by December 31, 2005. iii. Identify violations for which technical or temporary exceptions are being applied.
January 31, 2005	Each Region shall summarize and forward to the NERC SPCTF the responses due from the TPSOs on December 31, 2004. Regions should report on any non-respondent TPSOs.
December 31, 2005	Each TPSO shall submit to their Region one or more of the following: i. Certifications that all violations cited for mitigation by December 31, 2004, have been mitigated. ii. Apply for any additional technical or temporary exceptions.
January 31, 2006	Each Region shall summarize and forward to the NERC SPCTF the responses due from the TPSOs on December 31, 2005. Regions should report on any non-respondent TPSOs that have not already certified their systems fully compliant with Recommendation 8a, as modified by this document.

Table B.2 Zone 3 Review Implementation Plan

Table B.3 in the following section summarizes the findings of the North American Relay engineers for the Zone 3 review program and the subsequent program described below.

Protection System Review Program – Beyond Zone 3

The SPCTF concluded that limiting the emergency loadability requirement of Recommendation 8a to only the zone 3 relays fails to adequately address the need of relays operating securely in the presence of emergency loading conditions, and need to be expanded. This second stage review includes all phase protection relays applied to trip directly or as a backup on the bulk electric power system, other than Zone 3, and the lower voltage "critical circuit" protection system review cited in US-Canada Task Force Recommendation 21a. On December 7, 2006, NERC's Planning Committee approved the second loadability review program, Beyond Zone 3.

Details of the review program are contained in the *Protection System Review Program — Beyond Zone 3* report, approved by the Planning Committee in August, 2005. Similarly, the NERC Board of Trustees adopted the following resolution in August, 2005, approving the recommendations of that report.
TPSOs are reviewing the relay loadability for circuits 200 kV and above (including transformers with low-side voltages 200 kV and above), and mitigating non-conforming protection systems under the following schedule:

August 31, 2005	Send the *Protection System Review Program – Beyond Zone 3* document, the revised *Relay Loadability Exceptions* (Version 1.2) document, and updated reporting forms to the Regions
June 30, 2006	TPSOs submit review status and report mitigation plans (including Temporary Exception Requests) and submit Technical Exception Requests to Regions for review and acceptance
August 31, 2006	Regions submit June 30 reports to SPCTF for review and approval
December 2006	SPCTF to provide report on the 200 kV and above protection review to the Planning Committee for approval at the December 2006 PC meeting
February 2007	PC to provide summary report to the NERC Board at its February 2007 meeting
December 31, 2007	TPSOs complete mitigation (except where Temporary Exception requests have been approved)

Table B.3 Beyond Zone 3 Implementation Plan

All NERC regions reported that the TPSOs had certified completion of the EHV (200 kV and above) beyond zone 3 relay loadability review, and had provided summary reports and requests for temporary and technical exceptions to the NERC regions as of June 30, 2006. One TPSO with in MRO and two TPSOs within WECC that are known to own EHV protection systems (based on zone 3 relay review submittals) did not submit review summaries to the regions. Those entities are noted in the SPCTF review summary table (Table B.4) of this report.

The following table shows the statistics for the review of the zone 3 relay loadability for EHV circuits 200 kV and above.

Item Reviewed	EHV Zone 3	EHV Beyond Zone 3
Terminals reviewed	10,914	11,499
Non-conforming terminals	2,182	2,530
Non-conforming terminals as a percentage of terminals reviewed	20.0%	22.0 %
Technical Exception requests	297	270
Accepted by Region/SPCTF	297	169
Unresolved	0	101
Terminals requiring mitigation	1,885	2,293
Settings changes	1,520 (13.9%)	1,926 (16.7%)
Function disabled	65	77
Equipment replacement or addition	287 (2.6%)	263 (2.3%)
Other types of mitigation	13	27
Temporary Exception (beyond 2007) requests	130	65
Accepted by Region/SPCTF	130	49
Unresolved	0	16

Table B.4 Summary Review Statistics

PRC-023 Loadability Standard Development

Coincident with the voluntary process of maintaining loadability, NERC, is in the process of including within its standards process, a standard on relay loadability. It codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.* The implementation plan for standards development is as follows:

Proposed Effective Dates

- Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and 100–200 kV applicable circuits due dates are to be determined.

Appendix C. Effect of Fault Resistance in Loop System

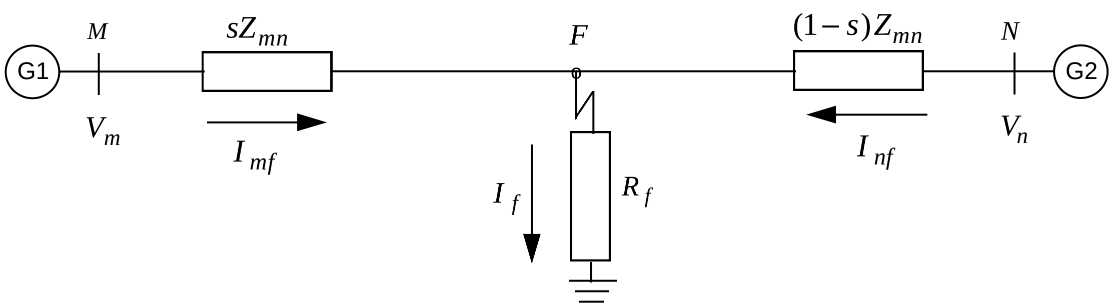
Consider the single-phase system shown in Figure C.1 which is connected to energy sources at both terminals. The impedances calculated from the fundamental frequency voltages and currents at the two line terminals can be expressed as

(C.1) $$Z_m = \frac{V_m}{I_{mf}} = sZ_{mn} + R_f\left(\frac{I_f}{I_{mf}}\right) \text{ and}$$

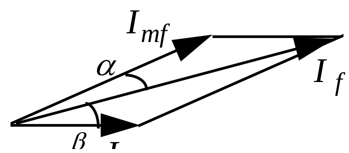
(C.2) $$Z_n = \frac{V_n}{I_{nf}} = (1-s)Z_{mn} + R_f\left(\frac{I_f}{I_{nf}}\right),$$

where: V_m and V_n are the voltages at buses M and N during the fault, I_{mf} and I_{nf} are the currents flowing in the line at buses M and N and, I_f is the fault current flowing into the fault at F.

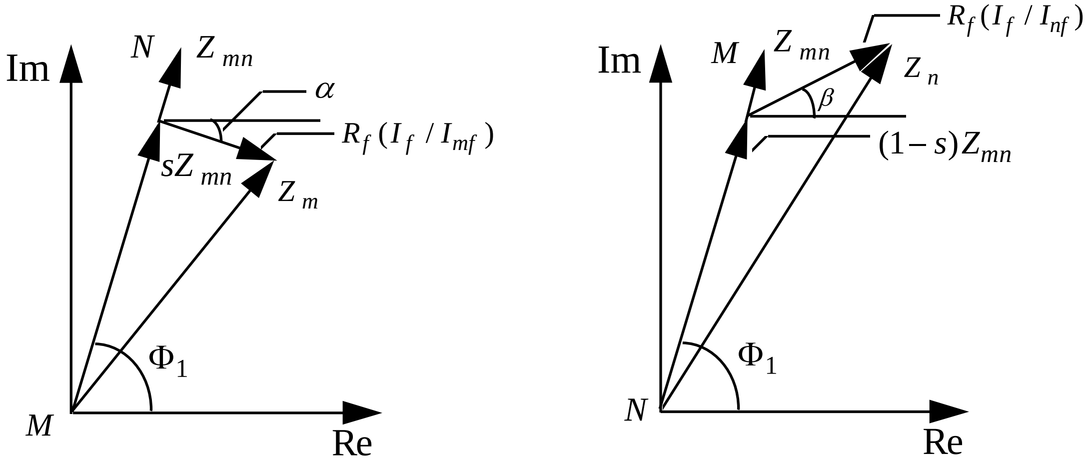
The currents I_{mf} and I_{nf} are usually phase shifted as shown in Figure C.1(b). Equations C.1 and C.2 can be represented on the $R-X$ plane as in Figure C.1(c). Current in the fault resistance is phase displaced from the currents at the line terminals. Because of these phase displacements, fault location estimate obtained from the fundamental frequency voltage and current measured at the line terminal, M, is smaller than the actual distance of the fault. The estimate obtained at bus N is larger than the actual distance of the fault. Therefore, if both terminals of a line are connected to energy sources, the fault resistance appears to the fault locator as an impedance that has both resistive and reactive components. Methods that estimate fault locations from impedance measurements are, therefore, adversely affected by the fault resistance if line fault is fed from both terminals of the line.



(a)



(b)



(c)

Figure C.1. Change of the apparent impedance seen from the fault locator terminal due to the fault resistance. (a) The single line diagram of a line connected to sources at both ends. (b) The phasor diagram. (c) The $R-X$ diagrams.

Appendix D. Transmission Circuits Protection Schemes and Limitations

In order to determine transmission circuit back-up protection, It is important to evaluate possible mode of failure and any fault detection limitation. The following table provides some limited comparison between the various schemes available.

PROTECTION SCHEME	**LIMITATIONS**
Current differential Protection	Dependent on communications Does not inherently offer remote back-up protection No detection of series faults
Pilot-wire Communication	Limited to short lines No remote back-up protection No detection of series faults
Transverse Current differential Protection (Parallel Circuits)	Requires permanent parallel circuits No remote back-up protection Sensitivity varies with load
Directional comparison Protection (Permissive)	Dependent on communications No remote back-up protection Directional ground fault protection must be inhibited during single pole dead times.
Directional comparison Protection (BLOCKING)	Security is dependent on communications No remote back-up protection Directional ground fault protection must be inhibited during single pole dead times.
Distance Protection without signaling channel (Multi-Zone) Distance protection with loss of load logic	Limited resistive fault coverage No detection of series faults Zone 1 reach may not be adequate on series compensated lines.
Permissive Underreach Accelerated Underreach Intertripping Underreach Permissive Overreach with/without weak infeed logic Blocking/Unblocking overreach	Delayed tripping with communication failure Resistive fault coverage limited by zone 1 (zone 2 for permissive overreach – blocking / unblocking overreach) No detection of series faults Zone reach limitation for series compensated lines.
Phase comparison Protection	Limited applications only No remote back-up protection Not suitable for series compensated lines with current reversal.

ZONE REACH DISTANCE	**LOCAL / REMOTE BACK-UP**
Zone 1 Distance	Partial local
Zone 2 Distance	Full Local but time delayed No remote back-up protection
Zone 3/4 Distance	Time delayed remote back-up or substation local back-up

OVERCURRENT LINE PROTECTION	**LOCAL / REMOTE BACK-UP**
Directional / Non-directional phase overcurrent	Local / remote back-up for multi-phase faults and sometimes ground faults.
Residual overcurrent	Supplement Phase overcurrent relay and is main protection for high resistive faults