• 11 • Distance Protection

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11.1 INTRODUCTION

The problem of combining fast fault clearance with selective tripping of plant is a key aim for the protection of power systems. To meet these requirements, high-speed protection systems for transmission and primary distribution circuits that are suitable for use with the automatic reclosure of circuit breakers are under continuous development and are very widely applied.

Distance protection, in its basic form, is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral overcurrent protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations.

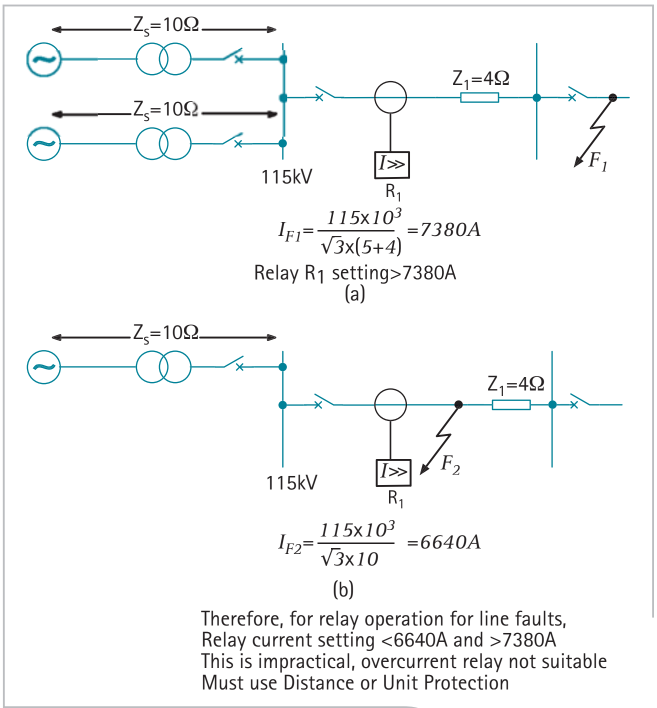


Figure 11.1: Advantages of distance over overcurrent protection

This is illustrated in Figure 11.1, where it can be seen that overcurrent protection cannot be applied satisfactorily.

Distance protection is comparatively simple to apply and it can be fast in operation for faults located along most of a protected circuit. It can also provide both primary and remote back-up functions in a single scheme. It can easily be adapted to create a unit protection scheme when applied with a signalling channel. In this form it is eminently suitable for application with high-speed auto-reclosing, for the protection of critical transmission lines.

11.2 PRINCIPLES OF DISTANCE RELAYS

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as a distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections.

The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point.

The reach point of a relay is the point along the line impedance locus that is intersected by the boundary characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied.

11.3 RELAY PERFORMANCE

Distance relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual ohmic reach of the relay under practical conditions with the relay setting value in ohms. Reach accuracy particularly depends on the level of voltage presented to the relay under fault conditions. The impedance measuring techniques employed in particular relay designs also have an impact.

Operating times can vary with fault current, with fault position relative to the relay setting, and with the point on the voltage wave at which the fault occurs. Depending on the measuring techniques employed in a particular relay design, measuring signal transient errors, such as those produced by Capacitor Voltage Transformers or saturating CT's, can also adversely delay relay operation for faults close to the reach point. It is usual for electromechanical and static distance relays to claim both maximum and minimum operating times. However, for modern digital or numerical distance relays, the variation between these is small over a wide range of system operating conditions and fault positions.

11.3.1 Electromechanical/Static Distance Relays

With electromechanical and earlier static relay designs, the magnitude of input quantities particularly influenced both reach accuracy and operating time. It was customary to present information on relay performance by voltage/reach curves, as shown in Figure 11.2, and operating time/fault position curves for various values of system impedance ratios (*S.I.R.'s*) as shown in Figure 11.3, where:

$$S.I.R. = Z_S / Z_L$$

and

Z_S = *system source impedance behind the relay location*

Z_L = *line impedance equivalent to relay reach setting*

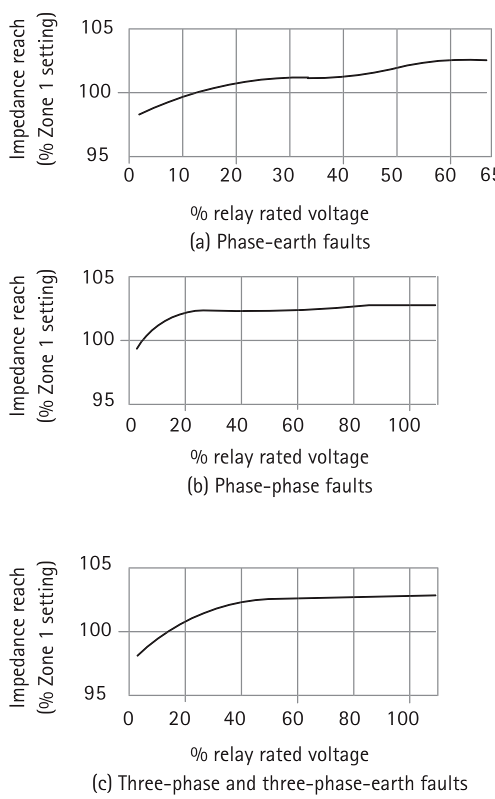


Figure 11.2: Typical impedance reach accuracy characteristics for Zone 1

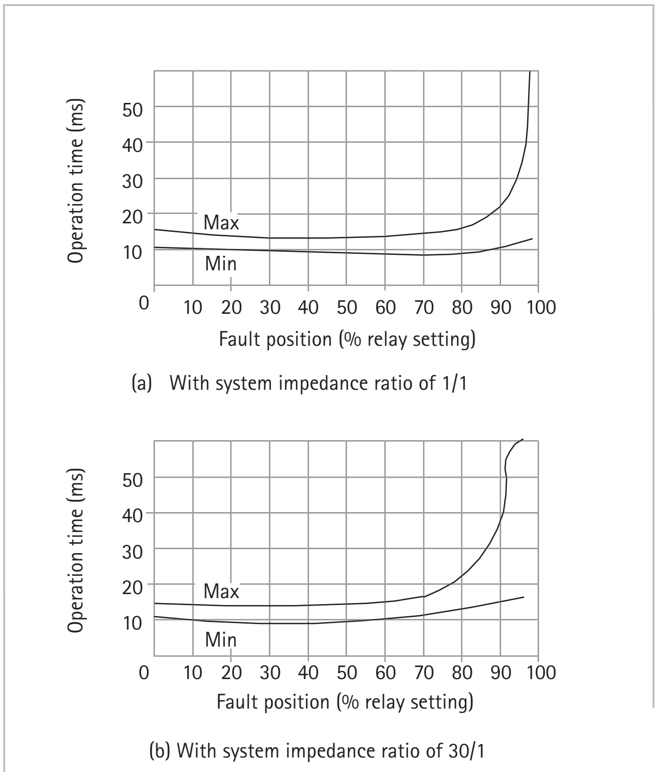


Figure 11.3: Typical operation time characteristics for Zone 1 phase-phase faults

Alternatively, the above information was combined in a family of contour curves, where the fault position expressed as a percentage of the relay setting is plotted against the source to line impedance ratio, as illustrated in Figure 11.4.

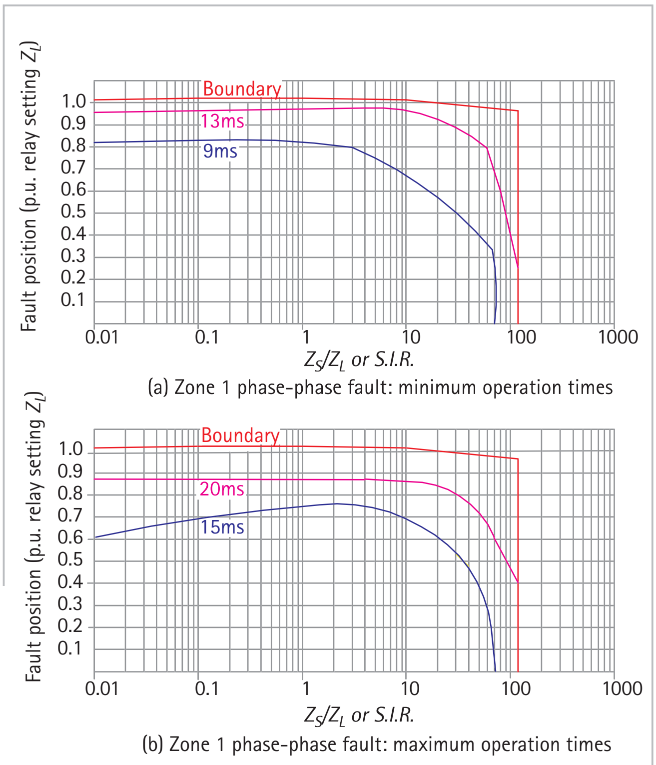


Figure 11.4: Typical operation-time contours

11.3.2 Digital/Numerical Distance Relays

Digital/Numerical distance relays tend to have more consistent operating times. They are usually slightly slower than some of the older relay designs when operating under the best conditions, but their maximum operating times are also less under adverse waveform conditions or for boundary fault conditions.

11.4 RELATIONSHIP BETWEEN RELAY VOLTAGE AND Z_S/Z_L RATIO

A single, generic, equivalent circuit, as shown in Figure 11.5(a), may represent any fault condition in a three-phase power system. The voltage V applied to the impedance loop is the open circuit voltage of the power system. Point R represents the relay location; I_R and V_R are the current and voltage measured by the relay, respectively.

The impedances Z_S and Z_L are described as source and line impedances because of their position with respect to the relay location. Source impedance Z_S is a measure of the fault level at the relaying point. For faults involving earth it is dependent on the method of system earthing behind the relaying point. Line impedance Z_L is a measure of the impedance of the protected section. The voltage V_R applied to the relay is, therefore, $I_R Z_L$. For a fault at the reach point, this may be alternatively expressed in terms of source to line impedance ratio Z_S/Z_L by means of the following expressions:

$$V_R = I_R Z_L$$

where:

$$I_R = \frac{V}{Z_S + Z_L}$$

Therefore :

$$V_R = \frac{Z_L}{Z_S + Z_L} V$$

or

$$V_R = \frac{1}{(Z_S/Z_L)+1} V$$

...Equation 11.1

The above generic relationship between V_R and Z_S/Z_L, illustrated in Figure 11.5(b), is valid for all types of short circuits provided a few simple rules are observed. These are:

i. for phase faults, V is the phase-phase source voltage and Z_S/Z_L is the positive sequence source to line impedance ratio. V_R is the phase-phase relay voltage and I_R is the phase-phase relay current, for the faulted phases

$$V_R = \frac{1}{(Z_S/Z_L)+1} V_{p-p}$$

...Equation 11.2

ii. for earth faults, V is the phase-neutral source voltage and Z_S/Z_L is a composite ratio involving the positive and zero sequence impedances. V_R is the phase-neutral relay voltage and I_R is the relay current for the faulted phase

$$V_R = \frac{1}{(Z_S/Z_L)\left(\frac{2+p}{2+q}\right)+1} V_{l-n}$$

...Equation 11.3

where

$Z_S = 2Z_{S1} + Z_{S0} = Z_{S1}(2+p)$

$Z_L = 2Z_{L1} + Z_{L0} = Z_{L1}(2+q)$

and

$$p = \frac{Z_{S0}}{Z_{S1}}$$

$$q = \frac{Z_{L0}}{Z_{L1}}$$

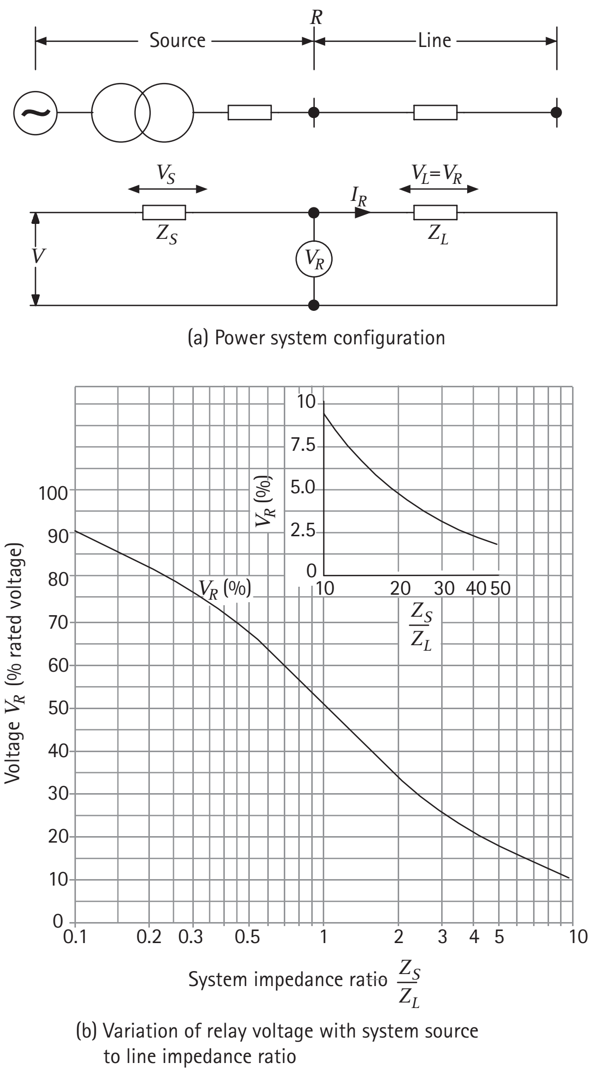


Figure 11.5: Relationship between source to line ratio and relay voltage

11.5 VOLTAGE LIMIT FOR ACCURATE REACH POINT MEASUREMENT

The ability of a distance relay to measure accurately for a reach point fault depends on the minimum voltage at the relay location under this condition being above a declared value. This voltage, which depends on the relay design, can also be quoted in terms of an equivalent maximum Z_S/Z_L or $S.I.R.$

Distance relays are designed so that, provided the reach point voltage criterion is met, any increased measuring errors for faults closer to the relay will not prevent relay operation. Most modern relays are provided with healthy phase voltage polarisation and/or memory voltage polarisation. The prime purpose of the relay polarising voltage is to ensure correct relay directional response for close-up faults, in the forward or reverse direction, where the fault-loop voltage measured by the relay may be very small.

11.6 ZONES OF PROTECTION

Careful selection of the reach settings and tripping times for the various zones of measurement enables correct co-ordination between distance relays on a power system. Basic distance protection will comprise instantaneous directional Zone 1 protection and one or more time-delayed zones. Typical reach and time settings for a 3-zone distance protection are shown in Figure 11.6. Digital and numerical distance relays may have up to five zones, some set to measure in the reverse direction. Typical settings for three forward-looking zones of basic distance protection are given in the following sub-sections. To determine the settings for a particular relay design or for a particular distance teleprotection scheme, involving end-to-end signalling, the relay manufacturer's instructions should be referred to.

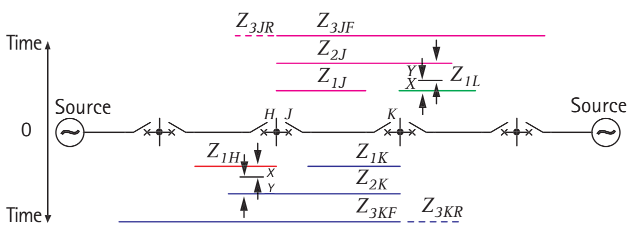
11.6.1 Zone 1 Setting

Electromechanical/static relays usually have a reach setting of up to 80% of the protected line impedance for instantaneous Zone 1 protection. For digital/numerical distance relays, settings of up to 85% may be safe. The resulting 15-20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line due to errors in the current and voltage transformers, inaccuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. Otherwise, there would be a loss of discrimination with fast operating protection on the following line section. Zone 2 of the distance protection must cover the remaining 15-20% of the line.

11.6.2 Zone 2 Setting

To ensure full cover of the line with allowance for the sources of error already listed in the previous section, the reach setting of the Zone 2 protection should be at least 120% of the protected line impedance. In many applications it is common practice to set the Zone 2 reach to be equal to the protected line section +50% of the shortest adjacent line. Where possible, this ensures that the resulting maximum effective Zone 2 reach does not extend beyond the minimum effective Zone 1 reach of the adjacent line protection. This avoids the need to grade the Zone 2 time settings between upstream and downstream relays. In electromechanical and static relays, Zone 2 protection is provided either by separate elements or by extending the reach of the Zone 1 elements after a time delay that is initiated by a fault detector. In most digital and numerical relays, the Zone 2 elements are implemented in software.

Zone 2 tripping must be time-delayed to ensure grading with the primary relaying applied to adjacent circuits that fall within the Zone 2 reach. Thus complete coverage of a line section is obtained, with fast clearance of faults in the first 80-85% of the line and somewhat slower clearance of faults in the remaining section of the line.



Zone 1 = 80-85% of protected line impedance
Zone 2 (minimum) = 120% of protected line
Zone 2 (maximum) < Protected line + 50% of shortest second line
Zone 3F = 1.2 (protected line + longest second line)
Zone 3R = 20% of protected line
X = Circuit breaker tripping time
Y = Discriminating time

Figure 11.6: Typical time/distance characteristics for three zone distance protection

11.6.3 Zone 3 Setting

Remote back-up protection for all faults on adjacent lines can be provided by a third zone of protection that is time delayed to discriminate with Zone 2 protection plus circuit breaker trip time for the adjacent line. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault at the remote end of the second line section.

On interconnected power systems, the effect of fault current infeed at the remote busbars will cause the impedance presented to the relay to be much greater than the actual impedance to the fault and this needs to be taken into account when setting Zone 3. In some systems, variations in the remote busbar infeed can prevent the application of remote back-up Zone 3 protection but on radial distribution systems with single end infeed, no difficulties should arise.

11.6.4 Settings for Reverse Reach and Other Zones

Modern digital or numerical relays may have additional impedance zones that can be utilised to provide additional protection functions. For example, where the first three zones are set as above, Zone 4 might be used to provide back-up protection for the local busbar, by applying a reverse reach setting of the order of 25% of the Zone 1 reach. Alternatively, one of the forward-looking zones (typically Zone 3) could be set with a small reverse offset reach from the origin of the R/X diagram, in addition to its forward reach setting. An offset impedance measurement characteristic is non-directional. One advantage of a non-directional zone of impedance measurement is that it is able to operate for a close-up, zero-impedance fault, in situations where there may be no healthy phase voltage signal or memory voltage signal available to allow operation of a directional impedance zone. With the offset-zone time delay bypassed, there can be provision of 'Switch-on-to-Fault' (SOTF) protection. This is required where there are line voltage transformers, to provide fast tripping in the event of accidental line energisation with maintenance earthing clamps left in position. Additional impedance zones may be deployed as part of a distance protection scheme used in conjunction with a teleprotection signalling channel.

11.7 DISTANCE RELAY CHARACTERISTICS

Some numerical relays measure the absolute fault impedance and then determine whether operation is required according to impedance boundaries defined on the R/X diagram. Traditional distance relays and numerical relays that emulate the impedance elements of traditional relays do not measure absolute impedance. They compare the measured fault voltage with a replica voltage derived from the fault current and the zone impedance setting to determine whether the fault is within zone or out-of-zone. Distance relay impedance comparators or algorithms which emulate traditional comparators are classified according to their polar characteristics, the number of signal inputs they have, and the method by which signal comparisons are made. The common types compare either the relative amplitude or phase of two input quantities to obtain operating characteristics that are either straight lines or circles when plotted on an R/X diagram. At each stage of distance relay design evolution, the development of impedance operating characteristic shapes and sophistication has been governed by the technology available and the acceptable cost. Since many traditional relays are still in service and since some numerical relays emulate the techniques of the traditional relays, a brief review of impedance comparators is justified.

11.7.1 Amplitude and Phase Comparison

Relay measuring elements whose functionality is based on the comparison of two independent quantities are essentially either amplitude or phase comparators. For the impedance elements of a distance relay, the quantities being compared are the voltage and current measured by the relay. There are numerous techniques available for performing the comparison, depending on the technology used. They vary from balanced-beam (amplitude comparison) and induction cup (phase comparison) electromagnetic relays, through diode and operational amplifier comparators in static-type distance relays, to digital sequence comparators in digital relays and to algorithms used in numerical relays.

Any type of impedance characteristic obtainable with one comparator is also obtainable with the other. The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic centred at the origin of the R/X diagram. If the sum and difference of V and I are applied to the phase comparator the result is a similar characteristic.

11.7.2 Plain Impedance Characteristic

This characteristic takes no account of the phase angle between the current and the voltage applied to it; for this reason its impedance characteristic when plotted on an R/X diagram is a circle with its centre at the origin of the co-ordinates and of radius equal to its setting in ohms. Operation occurs for all impedance values less than the setting, that is, for all points within the circle. The relay characteristic, shown in Figure 11.7, is therefore non-directional, and in this form would operate for all faults along the vector AL and also for all faults behind the busbars up to an impedance AM. It is to be noted that A is the relaying point and RAB is the angle by which the fault current lags the relay voltage for a fault on the line AB and RAC is the equivalent leading angle for a fault on line AC. Vector AB represents the impedance in front of the relay between the relaying point A and the end of line AB. Vector AC represents the impedance of line AC behind the relaying point. AL represents the reach of instantaneous Zone 1 protection, set to cover 80% to 85% of the protected line.

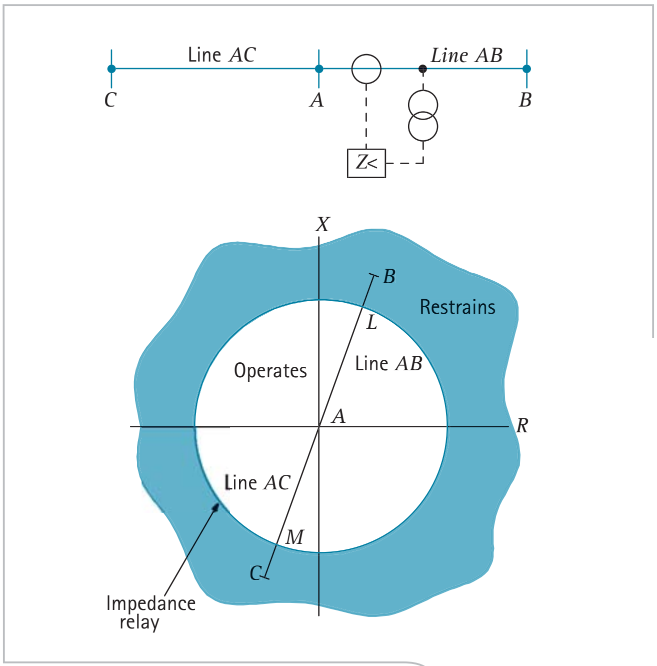


Figure 11.7: Plain impedance relay characteristic

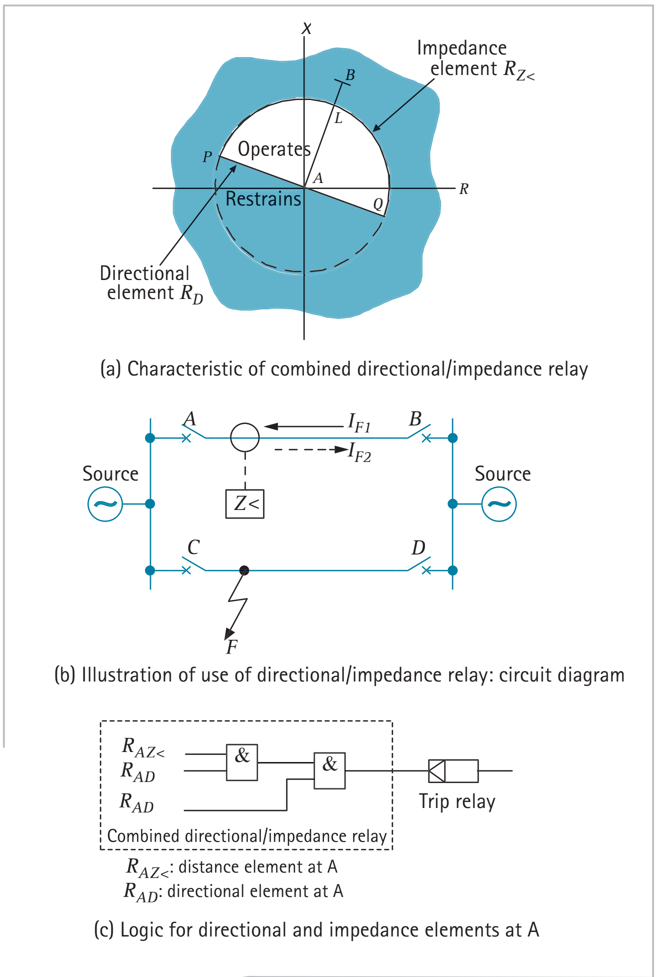


Figure 11.8: Combined directional and impedance relays

A relay using this characteristic has three important disadvantages:

i. it is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination

ii. it has non-uniform fault resistance coverage

iii. it is susceptible to power swings and heavy loading of a long line, because of the large area covered by the impedance circle

Directional control is an essential discrimination quality for a distance relay, to make the relay non-responsive to faults outside the protected line. This can be obtained by the addition of a separate directional control element. The impedance characteristic of a directional control element is a straight line on the R/X diagram, so the combined characteristic of the directional and impedance relays is the semi-circle $APLQ$ shown in Figure 11.8.

If a fault occurs at F close to C on the parallel line CD, the directional unit R_D at A will restrain due to current I_{F1}. At the same time, the impedance unit is prevented from operating by the inhibiting output of unit R_D. If this control is not provided, the under impedance element could operate prior to circuit breaker C opening. Reversal of current through the relay from I_{F1} to I_{F2} when C opens could then result in incorrect tripping of the healthy line if the directional unit R_D operates before the impedance unit resets. This is an example of the need to consider the proper co-ordination of multiple relay elements to attain reliable relay performance during evolving fault conditions. In older relay designs, the type of problem to be addressed was commonly referred to as one of 'contact race'.

11.7.3 Self-Polarised Mho Relay

The mho impedance element is generally known as such because its characteristic is a straight line on an admittance diagram. It cleverly combines the discriminating qualities of both reach control and directional control, thereby eliminating the 'contact race' problems that may be encountered with separate reach and directional control elements. This is achieved by the addition of a polarising signal. Mho impedance elements were particularly attractive for economic reasons where electromechanical relay elements were employed. As a result, they have been widely deployed worldwide for many years and their advantages and limitations are now well understood. For this reason they are still emulated in the algorithms of some modern numerical relays.

The characteristic of a mho impedance element, when plotted on an R/X diagram, is a circle whose circumference passes through the origin, as illustrated in Figure 11.9(b). This demonstrates that the impedance element is inherently directional and such that it will operate only for faults in the forward direction along line AB.

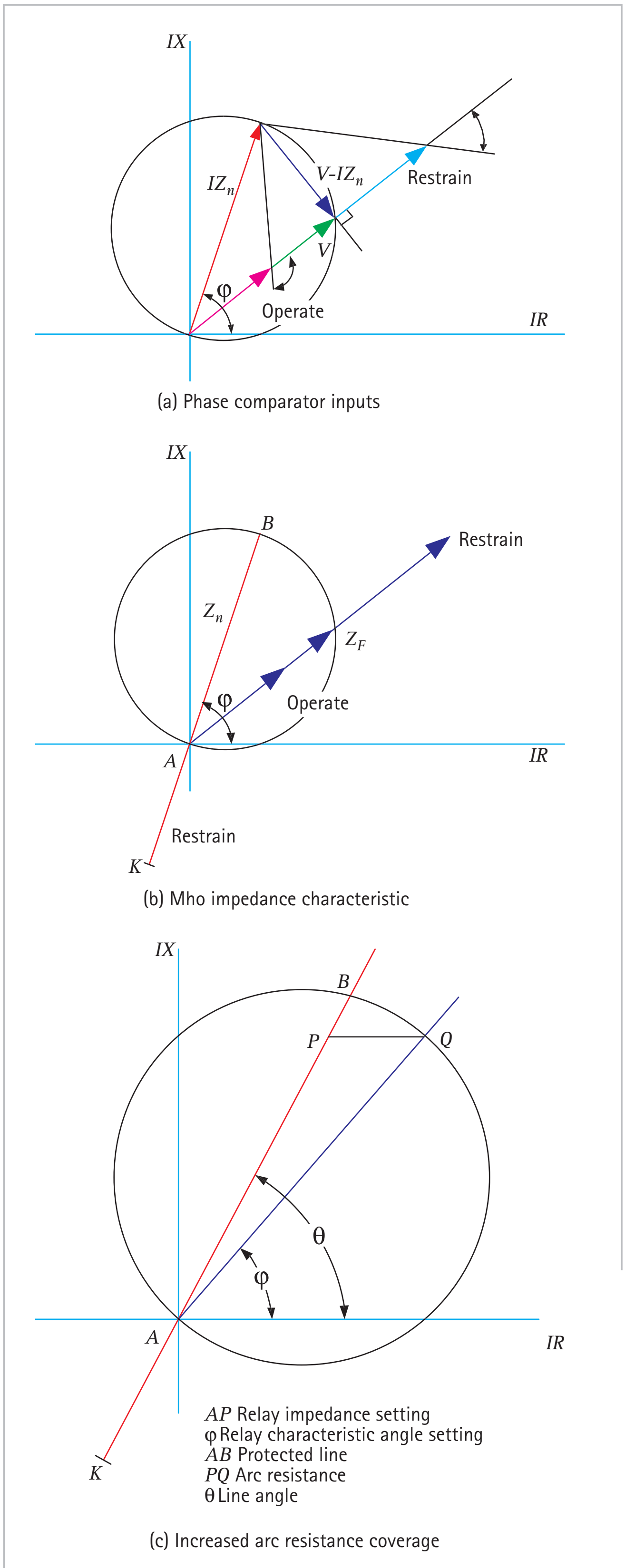


Figure 11.9: Mho relay characteristic

The impedance characteristic is adjusted by setting Z_n, the impedance reach, along the diameter and φ, the angle of displacement of the diameter from the R axis. Angle φ is known as the Relay Characteristic Angle (*RCA*). The relay operates for values of fault impedance Z_F within its characteristic.

It will be noted that the impedance reach varies with fault angle. As the line to be protected is made up of resistance and inductance, its fault angle will be dependent upon the relative values of R and X at the system operating frequency. Under an arcing fault condition, or an earth fault involving additional resistance, such as tower footing resistance or fault through vegetation, the value of the resistive component of fault impedance will increase to change the impedance angle. Thus a relay having a characteristic angle equivalent to the line angle will under-reach under resistive fault conditions.

It is usual, therefore, to set the RCA less than the line angle, so that it is possible to accept a small amount of fault resistance without causing under-reach. However, when setting the relay, the difference between the line angle θ and the relay characteristic angle φ must be known. The resulting characteristic is shown in Figure 11.9(c) where AB corresponds to the length of the line to be protected. With φ set less than θ, the actual amount of line protected, AB, would be equal to the relay setting value AQ multiplied by cosine (θ-φ). Therefore the required relay setting AQ is given by:

$$AQ = \frac{AB}{\cos(\theta - \varphi)}$$

Due to the physical nature of an arc, there is a non-linear relationship between arc voltage and arc current, which results in a non-linear resistance. Using the empirical formula derived by A.R. van C. Warrington, [11.1] the approximate value of arc resistance can be assessed as:

$$R_a = \frac{28710}{I^{1.4}} L$$

...Equation 11.4

where:

R_a = arc resistance (ohms)

L = length of arc (metres)

I = arc current (A)

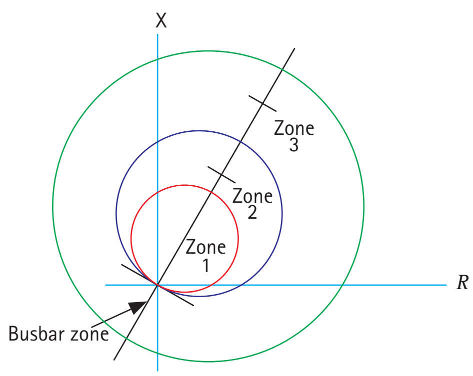
On long overhead lines carried on steel towers with overhead earth wires the effect of arc resistance can usually be neglected. The effect is most significant on short overhead lines and with fault currents below 2000A (i.e. minimum plant condition), or if the protected line is of wood-pole construction without earth wires. In the latter case, the earth fault resistance reduces the effective earth-fault reach of a mho Zone 1 element to such an extent that the majority of faults are detected in Zone 2 time. This problem can usually be overcome by using a relay with a cross-polarised mho or a polygonal characteristic.

Where a power system is resistance-earthed, it should be appreciated that this does not need to be considered with regard to the relay settings other than the effect that reduced fault current may have on the value of arc resistance seen. The earthing resistance is in the source behind the relay and only modifies the source angle and source to line impedance ratio for earth faults. It would therefore be taken into account only when assessing relay performance in terms of system impedance ratio.

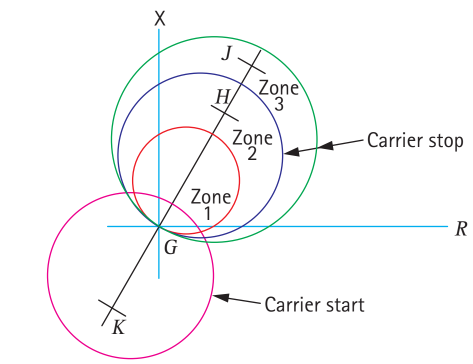
11.7.4 Offset Mho/Lenticular Characteristics

Under close up fault conditions, when the relay voltage falls to zero or near-zero, a relay using a self-polarised mho characteristic or any other form of self-polarised directional impedance characteristic may fail to operate when it is required to do so. Methods of covering this condition include the use of non-directional impedance characteristics, such as offset mho, offset lenticular, or cross-polarised and memory polarised directional impedance characteristics.

If current bias is employed, the mho characteristic is shifted to embrace the origin, so that the measuring element can operate for close-up faults in both the forward and the reverse directions. The offset mho relay has two main applications:



(a) Busbar zone back-up using an offset mho relay



(b) Carrier starting in distance blocking schemes

Figure 11.10: Typical applications for the offset mho relay

11.7.4.1 Third zone and busbar back-up zone

In this application it is used in conjunction with mho measuring units as a fault detector and/or Zone 3 measuring unit. So, with the reverse reach arranged to extend into the busbar zone, as shown in Figure 11.10(a), it will provide back-up protection for busbar faults. This facility can also be provided with quadrilateral characteristics. A further benefit of the Zone 3 application is for Switch-on-to-Fault (SOTF) protection, where the Zone 3 time delay would be bypassed for a short period immediately following line energisation to allow rapid clearance of a fault anywhere along the protected line.

11.7.4.2 Carrier starting unit in distance schemes with carrier blocking

If the offset mho unit is used for starting carrier signalling, it is arranged as shown in Figure 11.10(b). Carrier is transmitted if the fault is external to the protected line but inside the reach of the offset mho relay, in order to prevent accelerated tripping of the second or third zone relay at the remote station. Transmission is prevented for internal faults by operation of the local mho measuring units, which allows high-speed fault clearance by the local and remote end circuit breakers.

11.7.4.3 Application of lenticular characteristic

There is a danger that the offset mho relay shown in Figure 11.10(a) may operate under maximum load transfer conditions if Zone 3 of the relay has a large reach setting. A large Zone 3 reach may be required to provide remote back-up protection for faults on the adjacent feeder.

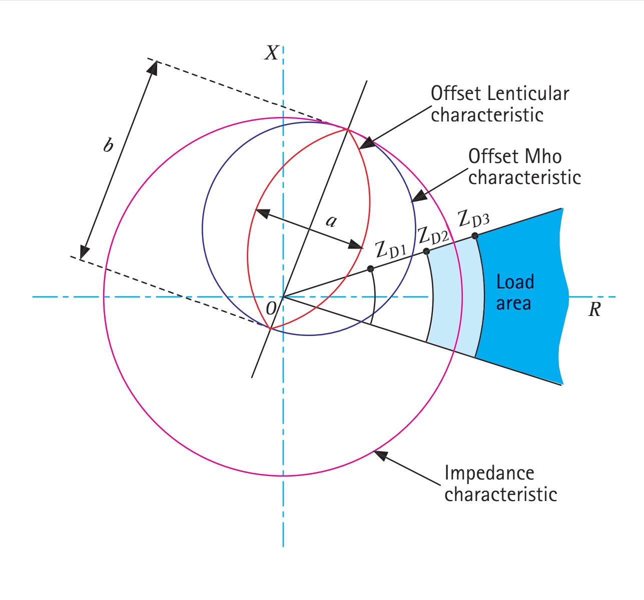


Figure 11.11: Minimum load impedance permitted with lenticular, offset mho and impedance relays

To avoid this, a shaped type of characteristic may be used, where the resistive coverage is restricted. With a 'lenticular' characteristic, the aspect ratio of the lens $\left(\frac{a}{b}\right)$ is adjustable, enabling it to be set to provide the maximum fault resistance coverage consistent with non-operation under maximum load transfer conditions.

Figure 11.11 shows how the lenticular characteristic can tolerate much higher degrees of line loading than offset mho and plain impedance characteristics.

Reduction of load impedance from Z_{D3} to Z_{D1} will correspond to an equivalent increase in load current.

11.7.5 Fully Cross-Polarised Mho Characteristic

The previous section showed how the non-directional offset mho characteristic is inherently able to operate for close-up zero voltage faults, where there would be no polarising voltage to allow operation of a plain mho directional element. One way of ensuring correct mho element response for zero-voltage faults is to add a percentage of voltage from the healthy phase(s) to the main polarising voltage as a substitute phase reference. This technique is called cross-polarising, and it has the advantage of preserving and indeed enhancing the directional properties of the mho characteristic. By the use of a phase voltage memory system, that provides several cycles of pre-fault voltage reference during a fault, the cross-polarisation technique is also effective for close-up three-phase faults. For this type of fault, no healthy phase voltage reference is available.

Early memory systems were based on tuned, resonant, analogue circuits, but problems occurred when applied to networks where the power system operating frequency could vary. More modern digital or numerical systems can offer a synchronous phase reference for variations in power system frequency before or even during a fault.

As described in Section 11.7.3, a disadvantage of the self-polarised, plain mho impedance characteristic, when applied to overhead line circuits with high impedance angles, is that it has limited coverage of arc or fault resistance. The problem is aggravated in the case of short lines, since the required Zone 1 ohmic setting is low. The amount of the resistive coverage offered by the mho circle is directly related to the forward reach setting. Hence, the resulting resistive coverage may be too small in relation to the expected values of fault resistance.

One additional benefit of applying cross-polarisation to a mho impedance element is that its resistive coverage will be enhanced. This effect is illustrated in Figure 11.12, for the case where a mho element has 100%

cross-polarisation. With cross-polarisation from the healthy phase(s) or from a memory system, the mho resistive expansion will occur during a balanced three-phase fault as well as for unbalanced faults. The expansion will not occur under load conditions, when there is no phase shift between the measured voltage and the polarising voltage. The degree of resistive reach enhancement depends on the ratio of source impedance to relay reach (impedance) setting as can be deduced by reference to Figure 11.13.

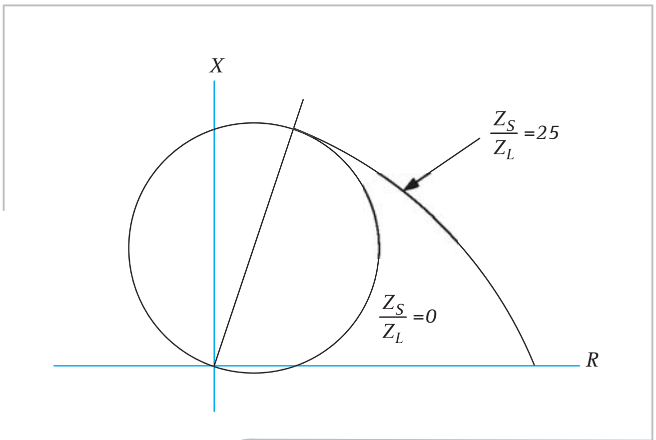


Figure 11.12: Fully cross-polarised mho relay characteristic with variations of Z_S/Z_L ratio

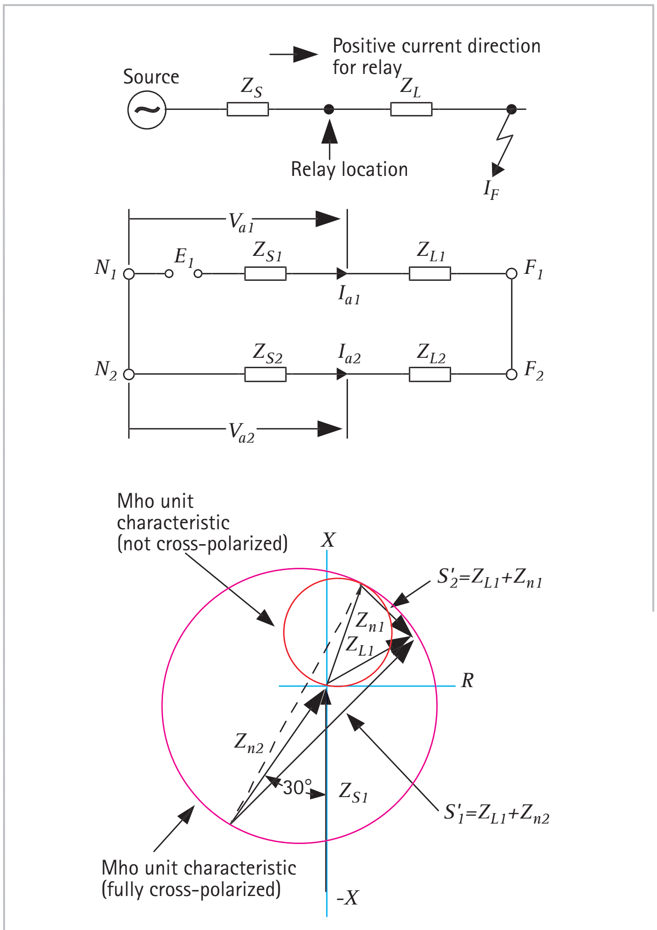


Figure 11.13: Illustration of improvement in relay resistive coverage for fully cross-polarised characteristic

It must be emphasised that the apparent extension of a fully cross-polarised impedance characteristic into the negative reactance quadrants of Figure 11.13 does not imply that there would be operation for reverse faults. With cross-polarisation, the relay characteristic expands to encompass the origin of the impedance diagram for forward faults only. For reverse faults, the effect is to exclude the origin of the impedance diagram, thereby ensuring proper directional responses for close-up forward or reverse faults.

Fully cross-polarised characteristics have now largely been superseded, due to the tendency of comparators connected to healthy phases to operate under heavy fault conditions on another phase. This is of no consequence in a switched distance relay, where a single comparator is connected to the correct fault loop impedance by starting units before measurement begins. However, modern relays offer independent impedance measurement for each of the three earth-fault and three phase-fault loops. For these types of relay, maloperation of healthy phases is undesirable, especially when single-pole tripping is required for single-phase faults.

11.7.6 Partially Cross-Polarised Mho Characteristic

Where a reliable, independent method of faulted phase selection is not provided, a modern non-switched distance relay may only employ a relatively small percentage of cross polarisation.

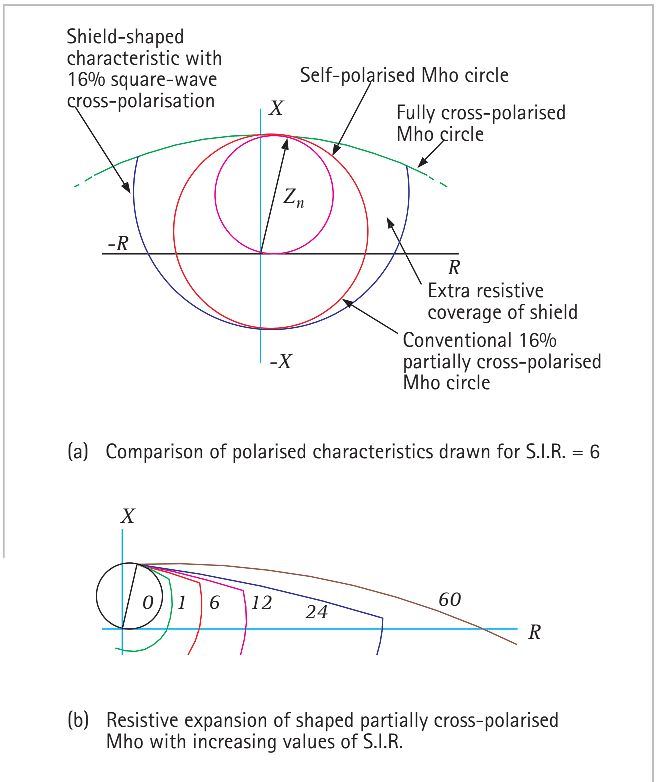


Figure 11.14: Partially cross-polarised characteristic with 'shield' shape

The level selected must be sufficient to provide reliable directional control in the presence of CVT transients for close-up faults, and also attain reliable faulted phase selection. By employing only partial cross-polarisation, the disadvantages of the fully cross-polarised characteristic are avoided, while still retaining the advantages. Figure 11.14 shows a typical characteristic that can be obtained using this technique.

11.7.7 Quadrilateral Characteristic

This form of polygonal impedance characteristic is shown in Figure 11.15. The characteristic is provided with forward reach and resistive reach settings that are independently adjustable. It therefore provides better resistive coverage than any mho-type characteristic for short lines. This is especially true for earth fault impedance measurement, where the arc resistances and fault resistance to earth contribute to the highest values of fault resistance. To avoid excessive errors in the zone reach accuracy, it is common to impose a maximum resistive reach in terms of the zone impedance reach. Recommendations in this respect can usually be found in the appropriate relay manuals.

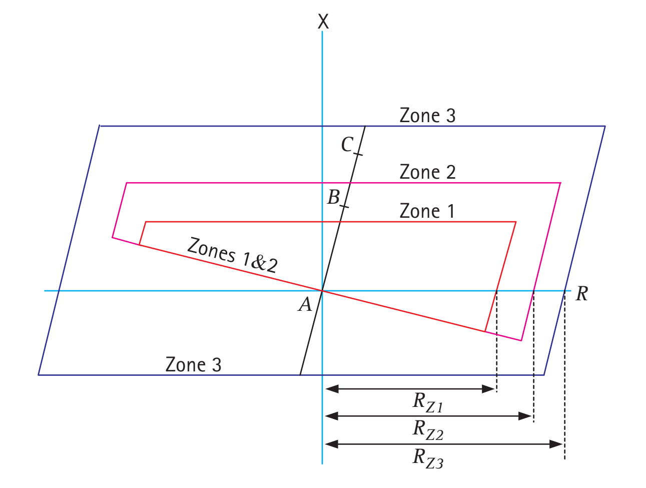


Figure 11.15: Quadrilateral characteristic

Quadrilateral elements with plain reactance reach lines can introduce reach error problems for resistive earth faults where the angle of total fault current differs from the angle of the current measured by the relay. This will be the case where the local and remote source voltage vectors are phase shifted with respect to each other due to pre-fault power flow. This can be overcome by selecting an alternative to use of a phase current for polarisation of the reactance reach line. Polygonal impedance characteristics are highly flexible in terms of fault impedance coverage for both phase and earth faults. For this reason, most digital and numerical distance relays now offer this form of characteristic. A further factor is that the additional cost implications of implementing this characteristic using discrete component electromechanical or early static relay technology do not arise.

11.7.8 Protection against Power Swings – Use of the Ohm Characteristic

During severe power swing conditions from which a system is unlikely to recover, stability might only be regained if the swinging sources are separated. Where such scenarios are identified, power swing, or out-of-step, tripping protection can be deployed, to strategically split a power system at a preferred location. Ideally, the split should be made so that the plant capacity and connected loads on either side of the split are matched.

This type of disturbance cannot normally be correctly identified by an ordinary distance protection. As previously mentioned, it is often necessary to prevent distance protection schemes from operating during stable or unstable power swings, in order to avoid cascade tripping. To initiate system separation for a prospective unstable power swing, an out-of-step tripping scheme employing ohm impedance measuring elements can be deployed.

Ohm impedance characteristics are applied along the forward and reverse resistance axes of the R/X diagram and their operating boundaries are set to be parallel to the protected line impedance vector, as shown in Figure 11.16. The ohm impedance elements divide the R/X impedance diagram into three zones, A, B and C. As the impedance changes during a power swing, the point representing the impedance moves along the swing locus, entering the three zones in turn and causing the ohm units to operate in sequence. When the impedance enters the third zone the trip sequence is completed and the circuit breaker trip coil can be energised at a favourable angle between system sources for arc interruption with little risk of restriking.

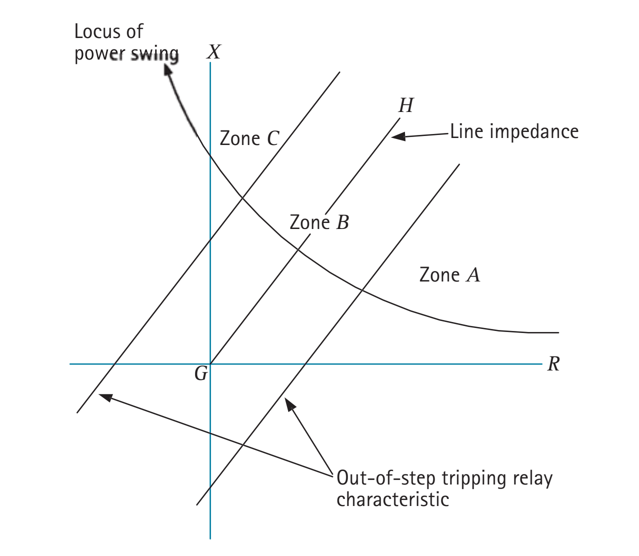


Figure 11.16: Application of out-of-step tripping relay characteristic

Only an unstable power swing condition can cause the impedance vector to move successively through the three zones. Therefore, other types of system disturbance, such as power system fault conditions, will not result in relay element operation.

11.7.9 Other Characteristics

The execution time for the algorithm for traditional distance protection using quadrilateral or similar characteristics may result in a relatively long operation time, possibly up to 40ms in some relay designs. To overcome this, some numerical distance relays also use alternative algorithms that can be executed significantly faster. These algorithms are based generally on detecting changes in current and voltage that are in excess of what is expected, often known as the 'Delta' algorithm.

This algorithm detects a fault by comparing the measured values of current and voltage with the values sampled previously. If the change between these samples exceeds a predefined amount (the 'delta'), it is assumed a fault has occurred. In parallel, the distance to fault is also computed. Provided the computed distance to fault lies within the Zone reach of the relay, a trip command is issued. This algorithm can be executed significantly faster than the conventional distance algorithm, resulting in faster overall tripping times. Faulted phase selection can be carried out by comparing the signs of the changes in voltage and current.

Relays that use the 'Delta' algorithm generally run both this and conventional distance protection algorithms in parallel, as some types of fault (e.g. high-resistance faults) may not fall within the fault detection criteria of the Delta algorithm.

11.8 DISTANCE RELAY IMPLEMENTATION

Discriminating zones of protection can be achieved using distance relays, provided that fault distance is a simple function of impedance. While this is true in principle for transmission circuits, the impedances actually measured by a distance relay also depend on the following factors:

1. the magnitudes of current and voltage (the relay may not see all the current that produces the fault voltage)
2. the fault impedance loop being measured
3. the type of fault
4. the fault resistance
5. the symmetry of line impedance
6. the circuit configuration (single, double or multi-terminal circuit)

It is impossible to eliminate all of the above factors for all possible operating conditions. However, considerable success can be achieved with a suitable distance relay. This may comprise relay elements or algorithms for starting, distance measuring and for scheme logic.

The distance measurement elements may produce impedance characteristics selected from those described in Section 11.7. Various distance relay formats exist, depending on the operating speed required and cost considerations related to the relaying hardware, software or numerical relay processing capacity required. The most common formats are:

a. a single measuring element for each phase is provided, that covers all phase faults

b. a more economical arrangement is for 'starter' elements to detect which phase or phases have suffered a fault. The starter elements switch a single measuring element or algorithm to measure the most appropriate fault impedance loop. This is commonly referred to as a switched distance relay

c. a single set of impedance measuring elements for each impedance loop may have their reach settings progressively increased from one zone reach setting to another. The increase occurs after zone time delays that are initiated by operation of starter elements. This type of relay is commonly referred to as a reach-stepped distance relay

d. each zone may be provided with independent sets of impedance measuring elements for each impedance loop. This is known as a full distance scheme, capable of offering the highest performance in terms of speed and application flexibility

Furthermore, protection against earth faults may require different characteristics and/or settings to those required for phase faults, resulting in additional units being required. A total of 18 impedance-measuring elements or algorithms would be required in a full distance relay for three-zone protection for all types of fault.

With electromechanical technology, each of the measuring elements would have been a separate relay housed in its own case, so that the distance relay comprised a panel-mounted assembly of the required relays with suitable inter-unit wiring. Figure 11.17(a) shows an example of such a relay scheme.

Digital/numerical distance relays (Figure 11.17(b)) are likely to have all of the above functions implemented in software. Starter units may not be necessary. The complete distance relay is housed in a single unit, making for significant economies in space, wiring and increased dependability, through the increased availability that stems from the provision of continuous self-supervision. When the additional features detailed in Section 11.11 are taken into consideration, such equipment offers substantial user benefits.

Figure 11.17 (a): First generation of static distance relay

Figure 11.17 (b): MiCOM P440 series numerical distance relay

11.8.1 Starters for switched distance protection

Electromechanical and static distance relays do not normally use an individual impedance-measuring element per phase. The cost and the resulting physical scheme size made this arrangement impractical, except for the most demanding EHV transmission applications. To achieve economy for other applications, only one measuring element was provided, together with 'starter' units that detected which phases were faulted, in order to switch the appropriate signals to the single measuring function. A distance relay using this technique is known as a switched distance relay. A number of different types of starters have been used, the most common being based on overcurrent, undervoltage or under-impedance measurement.

Numerical distance relays permit direct detection of the phases involved in a fault. This is called faulted phase selection, often abbreviated to phase selection. Several techniques are available for faulted phase selection, which then permits the appropriate distance-measuring zone to trip. Without phase selection, the relay risks having over or underreach problems, or tripping three-phase when single-pole fault clearance is required. Several techniques are available for faulted phase selection, such as:

a. superimposed current comparisons, comparing the step change of level between pre-fault load, and fault current (the 'Delta' algorithm). This enables very fast detection of the faulted phases, within only a few samples of the analogue current inputs

b. change in voltage magnitude

c. change in current magnitude

Numerical phase selection is much faster than traditional starter techniques used in electromechanical or static distance relays. It does not impose a time penalty as the phase selection and measuring zone algorithms run in parallel. It is possible to build a full-scheme relay with these numerical techniques. The phase selection algorithm provides faulted phase selection, together with a segregated measuring algorithm for each phase-ground and phase to phase fault loop (AN, BN, CN, AB, BC, CA), thus ensuring full-scheme operation.

However, there may be occasions where a numerical relay that mimics earlier switched distance protection techniques is desired. The reasons may be economic (less software required – thus cheaper than a relay that contains a full-scheme implementation) and/or technical.

Some applications may require the numerical relay characteristics to match those of earlier generations already installed on a network, to aid selectivity. Such relays are available, often with refinements such as multi-sided polygonal impedance characteristics that assist in avoiding tripping due to heavy load conditions.

With electromechanical or static switched distance relays, a selection of available starters often had to be made. The choice of starter was dependent on power system parameters such as maximum load transfer in relation to maximum reach required and power system earthing arrangements.

Where overcurrent starters are used, care must be taken to ensure that, with minimum generating plant in service, the setting of the overcurrent starters is sensitive enough to detect faults beyond the third zone. Furthermore, these starters require a high drop-off to pick-up ratio, to ensure that they will drop off under maximum load conditions after a second or third zone fault has been cleared by the first zone relay in the faulty section. Without this feature, indiscriminate tripping may result for subsequent faults in the second or third zone. For satisfactory operation of the overcurrent starters in a switched distance scheme, the following conditions must be fulfilled:

a. the current setting of the overcurrent starters must be not less than 1.2 times the maximum full load current of the protected line

b. the power system minimum fault current for a fault at the Zone 3 reach of the distance relay must not be less than 1.5 times the setting of the overcurrent starters

On multiple-earthed systems where the neutrals of all the power transformers are solidly earthed, or in power systems where the fault current is less than the full load current of the protected line, it is not possible to use overcurrent starters. In these circumstances under-impedance starters are typically used.

The type of under-impedance starter used is mainly dependent on the maximum expected load current and equivalent minimum load impedance in relation to the required relay setting to cover faults in Zone 3. This is illustrated in Figure 11.11 where Z_{D1}, Z_{D2}, and Z_{D3} are respectively the minimum load impedances permitted when lenticular, offset mho and impedance relays are used.

11.9 EFFECT OF SOURCE IMPEDANCE AND EARTHING METHODS

For correct operation, distance relays must be capable of measuring the distance to the fault accurately. To ensure this, it is necessary to provide the correct measured quantities to the measurement elements. It is not always the case that use of the voltage and current for a particular phase will give the correct result, or that additional compensation is required.

11.9.1 Phase Fault Impedance Measurement

Figure 11.18 shows the current and voltage relations for the different types of fault. If Z_{S1} and Z_{L1} are the source and line positive sequence impedances, viewed from the relaying point, the currents and voltages at this point for double phase faults are dependent on the source impedance as well as the line impedance. The relationships are given in Figure 11.19.

Applying the difference of the phase voltages to the relay eliminates the dependence on Z_{S1}. For example:

$$V'_{bc} = \left(a^2 - a\right) Z_{L1} I'_1 \quad \left(\textit{for 3 - phase faults}\right)$$

$$V'_{bc} = 2\left(a^2 - a\right) Z_{L1} I'_1$$

$$\left(\textit{for double - phase faults}\right)$$

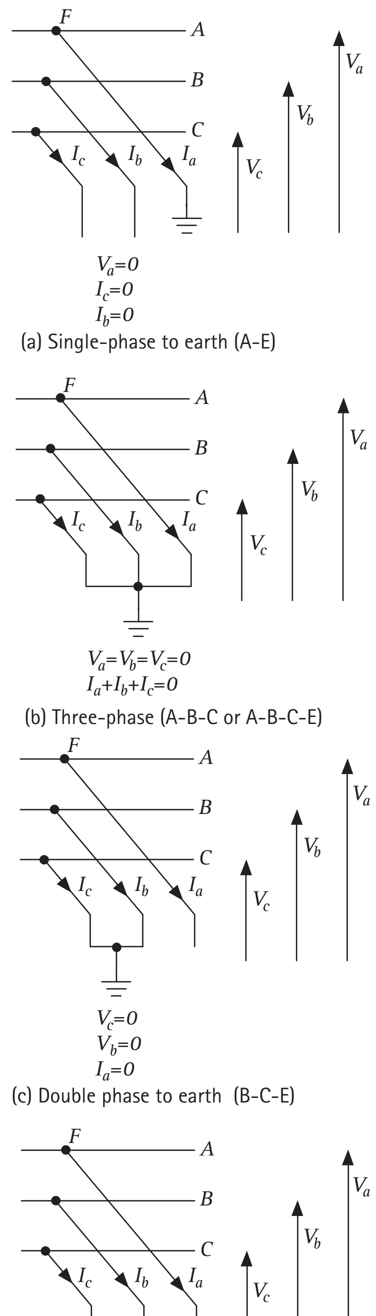


Figure 11.18: Current and voltage relationships for some shunt faults

Fault quantity	Three-phase (A-B-C)	Double-phase (B-C)
I'_a	I'_1	0
I'_b	$a^2I'_1$	$(a^2-a)I'_1$
I'_c	aI'_1	$(a-a^2)I'_1$
V'_a	$Z_{L1}I'_1$	$2(Z_{S1}+Z_{L1})I'_1$
V'_b	$a^2Z_{L1}I'_1$	$(2a^2Z_{L1}-Z_{S1})I'_1$
V'_c	$aZ_{L1}I'_1$	$(2aZ_{L1}-Z_{S1})I'_1$

Note: $I'_1 = \frac{1}{3}(I'_a+aI'_b+a^2I'_c)$

I' and V' are at relay location

Figure 11.19: Phase currents and voltages at relaying point for 3-phase and double-phase faults

Distance measuring elements are usually calibrated in terms of the positive sequence impedance. Correct measurement for both phase-phase and three-phase faults is achieved by supplying each phase-phase measuring element with its corresponding phase-phase voltage and difference of phase currents. Thus, for the B-C element, the current measured will be:

$$I'_b - I'_c = \left(a^2 - a\right)I'_1 \quad (3\text{ - phase faults})$$

$$I'_b - I'_c = 2\left(a^2 - a\right)I'_1 \quad (\text{double - phase faults})$$

and the relay will measure Z_{L1} in each case.

11.9.2 Earth Fault Impedance Measurement

When a phase-earth fault occurs, the phase-earth voltage at the fault location is zero. It would appear that the voltage drop to the fault is simply the product of the phase current and line impedance. However, the current in the fault loop depends on the number of earthing points, the method of earthing and sequence impedances of the fault loop. Unless these factors are taken into account, the impedance measurement will be incorrect.

The voltage drop to the fault is the sum of the sequence voltage drops between the relaying point and the fault. The voltage drop to the fault and current in the fault loop are:

$$V'_a = I'_1 Z_{L1} + I'_2 Z_{L1} + I'_0 Z_{L0}$$

$$I'_a = I'_1 + I'_2 + I'_0$$

and the residual current I'_N at the relaying point is given by:

$$I'_n = I'_a + I'_b + I'_c = 3I'_0$$

where I'_a, I'_b, I'_c are the phase currents at the relaying point. From the above expressions, the voltage at the relaying point can be expressed in terms of:

1. the phase currents at the relaying point,
2. the ratio of the transmission line zero sequence to positive sequence impedance, K, ($=Z_{L0}/Z_{L1}$),
3. the transmission line positive sequence impedance Z_{L1}:

$$V'_a = Z_{L1}\left\{I'_a + \left(I'_a + I'_b + I'_c\right)\frac{K-1}{3}\right\} \quad \text{...Equation 11.5}$$

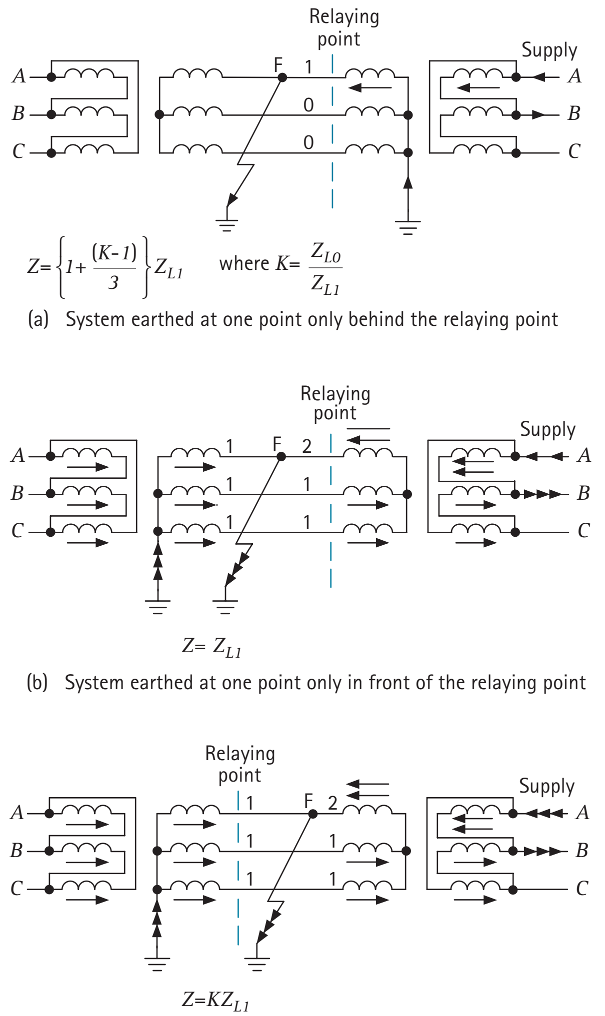


Figure 11.20: Effect of infeed and earthing arrangements on earth fault distance measurement

The voltage appearing at the relaying point, as previously mentioned, varies with the number of infeeds, the method of system earthing and the position of the relay relative to the infeed and earthing points in the system. Figure 11.20 illustrates the three possible arrangements that can occur in practice with a single infeed. In Figure 11.20(a), the healthy phase currents are zero, so that the phase currents I_a, I_b and I_c have a 1-0-0 pattern. The impedance seen by a relay comparing I_a and V_a is:

$$Z = \left\{1 + \frac{(K-1)}{3}\right\} Z_{L1}$$

...Equation 11.6

In Figure 11.20(b), the currents entering the fault from the relay branch have a 2-1-1 distribution, so:

$$Z = Z_{L1}$$

In Figure 11.20(c), the phase currents have a 1-1-1 distribution, and hence:

$$Z = KZ_{L1}$$

If there were infeeds at both ends of the line, the impedance measured would be a superposition of any two of the above examples, with the relative magnitudes of the infeeds taken into account.

This analysis shows that the relay can only measure an impedance which is independent of infeed and earthing arrangements if a proportion $K_N = \frac{(K-1)}{3}$ of the residual current $I_n=I_a+I_b+I_c$ is added to the phase current I_a. This technique is known as 'residual compensation'.

Most distance relays compensate for the earth fault conditions by using an additional replica impedance Z_N within the measuring circuits. Whereas the phase replica impedance Z_1 is fed with the phase current at the relaying point, Z_N is fed with the full residual current. The value of Z_N is adjusted so that for a fault at the reach point, the sum of the voltages developed across Z_1 and Z_N equals the measured phase to neutral voltage in the faulted phase.

The required setting for Z_N can be determined by considering an earth fault at the reach point of the relay. This is illustrated with reference to the A-N fault with single earthing point behind the relay as in Figure 11.20(a).

Voltage supplied from the VT's:

$$= I_1(Z_1+Z_2+Z_0) = I_1(2Z_1+Z_0)$$

Voltage across the replica impedances:

$$= I_aZ_1+I_NZ_N$$

$$= I_a(Z_1+Z_N)$$

$$= 3I_1(Z_1+Z_N)$$

Hence, the required setting of Z_N for balance at the reach point is given by equating the above two expressions:

$$3I_1(Z_1+Z_N) = I_1(2Z_1+Z_N)$$

$$Z_N = \frac{Z_0 - Z_1}{3}$$

$$= \frac{(Z_0 - Z_1)}{3Z_1} Z_1$$

...Equation 11.7

With the replica impedance set to $\frac{Z_0 - Z_1}{3}$, earth fault measuring elements will measure the fault impedance correctly, irrespective of the number of infeeds and earthing points on the system.

11.10 DISTANCE RELAY APPLICATION PROBLEMS

Distance relays may suffer from a number of difficulties in their application. Many of them have been overcome in the latest numerical relays. Nevertheless, an awareness of the problems is useful where a protection engineer has to deal with older relays that are already installed and not due for replacement.

11.10.1 Minimum Voltage at Relay Terminals

To attain their claimed accuracy, distance relays that do not employ voltage memory techniques require a minimum voltage at the relay terminals under fault conditions. This voltage should be declared in the data sheet for the relay. With knowledge of the sequence impedances involved in the fault, or alternatively the fault MVA, the system voltage and the earthing arrangements, it is possible to calculate the minimum voltage at the relay terminals for a fault at the reach point of the relay. It is then only necessary to check that the minimum voltage for accurate reach measurement can be attained for a given application. Care should be taken that both phase and earth faults are considered.

11.10.2 Minimum Length of Line

To determine the minimum length of line that can be protected by a distance relay, it is necessary to check first that any minimum voltage requirement of the relay for a fault at the Zone 1 reach is within the declared sensitivity for the relay. Secondly, the ohmic impedance of the line (referred if necessary to VT/CT secondary side quantities) must fall within the ohmic setting range for Zone 1 reach of the relay. For very short lines and especially for cable circuits, it may be found that the circuit impedance is less than the minimum setting range of the relay. In such cases, an alternative method of protection will be required.

A suitable alternative might be current differential protection, as the line length will probably be short enough for the cost-effective provision of a high bandwidth communication link between the relays fitted at the ends of the protected circuit. However, the latest numerical distance relays have a very wide range of impedance setting ranges and good sensitivity with low levels of relaying voltage, so such problems are now rarely encountered. Application checks are still essential, though. When considering earth faults, particular care must be taken to ensure that the appropriate earth fault loop impedance is used in the calculation.

11.10.3 Under-Reach – Effect of Remote Infeed

A distance relay is said to under-reach when the impedance presented to it is apparently greater than the impedance to the fault.

Percentage under-reach is defined as:

$$\frac{Z_R - Z_F}{Z_R} \times 100\%$$

where:

Z_R = *intended relay reach (relay reach setting)*

Z_F = *effective reach*

The main cause of underreaching is the effect of fault current infeed at remote busbars. This is best illustrated by an example.

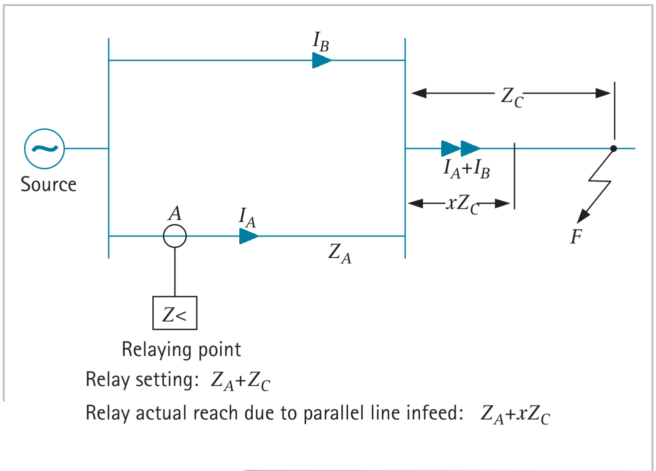


Figure 11.21: Effect on distance relays of infeed at the remote busbar

In Figure 11.21, the relay at A will not measure the correct impedance for a fault on line section Z_C due to current infeed I_B. Consider a relay setting of Z_A+Z_C.

For a fault at point F, the relay is presented with an impedance:

$$Z_A + \frac{I_A + I_B}{I_A} \times x \times Z_C$$

So, for relay balance:

$$Z_A + Z_C = Z_A + \frac{(I_A + I_B)}{I_A} \times x \times Z_C$$

Therefore the effective reach is

$$Z_A + \left(\frac{I_A}{I_A + I_B}\right) Z_C$$

...Equation 11.8

It is clear from Equation 11.8 that the relay will underreach. It is relatively easy to compensate for this by increasing the reach setting of the relay, but care has to be taken. Should there be a possibility of the remote infeed being reduced or zero, the relay will then reach further than intended. For example, setting Zone 2 to reach a specific distance into an adjacent line section under parallel circuit conditions may mean that Zone 2 reaches beyond the Zone 1 reach of the adjacent line protection under single circuit operation. If $I_B=9I_A$ and the relay reach is set to see faults at F, then in the absence of the remote infeed, the relay effective setting becomes Z_A+10Z_C.

Care should also be taken that large forward reach settings will not result in operation of healthy phase relays for reverse earth faults, see Section 11.10.5.

11.10.4 Over-Reach

A distance relay is said to over-reach when the apparent impedance presented to it is less than the impedance to the fault.

Percentage over-reach is defined by the equation:

$$\frac{Z_F - Z_R}{Z_R} \times 100\%$$

...Equation 11.9

where:

Z_R = *relay reach setting*

Z_F = *effective reach*

An example of the over-reaching effect is when distance relays are applied on parallel lines and one line is taken out of service and earthed at each end. This is covered in Section 13.2.3.

11.10.5 Forward Reach Limitations

There are limitations on the maximum forward reach setting that can be applied to a distance relay. For example, with reference to Figure 11.6, Zone 2 of one line section should not reach beyond the Zone 1 coverage of the next line section relay. Where there is a link between the forward reach setting and the relay resistive coverage (e.g. a Mho Zone 3 element), a relay must not operate under maximum load conditions. Also, if the relay reach is excessive, the healthy phase-earth fault units of some relay designs may be prone to operation for heavy reverse faults. This problem only affected older relays applied to three-terminal lines that have significant line section length asymmetry. A number of the features offered with modern relays can eliminate this problem.

11.10.6 Power Swing Blocking

Power swings are variations in power flow that occur when the internal voltages of generators at different points of the power system slip relative to each other. The changes in load flows that occur as a result of faults and their subsequent clearance are one cause of power swings.

A power swing may cause the impedance presented to a distance relay to move away from the normal load area and into the relay characteristic. In the case of a stable power swing it is especially important that the distance relay should not trip in order to allow the power system to return to a stable conditions. For this reason, most distance protection schemes applied to transmission systems have a power swing blocking facility available. Different relays may use different principles for detection of a power swing, but all involve recognising that the movement of the measured impedance in relation to the relay measurement characteristics is at a rate that is significantly less than the rate of change that occurs during fault conditions. When the relay detects such a condition, operation of the relay elements can be blocked. Power swing blocking may be applied individually to each of the relay zones, or on an all zones applied/inhibited basis, depending on the particular relay used.

Various techniques are used in different relay designs to inhibit power swing blocking in the event of a fault occurring while a power swing is in progress. This is particularly important, for example, to allow the relay to respond to a fault that develops on a line during the dead time of a single pole autoreclose cycle.

Some Utilities may designate certain points on the network as split points, where the network should be split in the event of an unstable power swing or pole-slipping occurring. A dedicated power swing tripping relay may be employed for this purpose (see Section 11.7.8). Alternatively, it may be possible to achieve splitting by strategically limiting the duration for which the operation a specific distance relay is blocked during power swing conditions.

11.10.7 Voltage Transformer Supervision

Fuses or sensitive miniature circuit breakers normally protect the secondary wiring between the voltage transformer secondary windings and the relay terminals.

Distance relays having:

a. self-polarised offset characteristics encompassing the zero impedance point of the R/X diagram

b. sound phase polarisation

c. voltage memory polarisation

may maloperate if one or more voltage inputs are removed due to operation of these devices.

For these types of distance relay, supervision of the voltage inputs is recommended. The supervision may be provided by external means, e.g. separate voltage supervision circuits, or it may be incorporated into the distance relay itself. On detection of VT failure, tripping of the distance relay can be inhibited and/or an alarm is given. Modern distance protection relays employ voltage supervision that operates from sequence voltages and currents. Zero or negative sequence voltages and corresponding zero or negative sequence currents are derived. Discrimination between primary power system faults and wiring faults or loss of supply due to individual fuses blowing or MCB's being opened is obtained by blocking the distance protection only when zero or negative sequence voltage is detected without the presence of zero or negative sequence current. This arrangement will not detect the simultaneous loss of all three voltages and additional detection is required that operates for loss of voltage with no change in current, or a current less than that corresponding to the three phase fault current under minimum fault infeed conditions. If fast-acting miniature circuit breakers are used to protect the VT secondary circuits, contacts from these may be used to inhibit operation of the distance protection elements and prevent tripping.

11.11 OTHER DISTANCE RELAY FEATURES

A modern digital or numerical distance relay will often incorporate additional features that assist the protection engineer in providing a comprehensive solution to the protection requirements of a particular part of a network.

Table 11.1 provides an indication of the additional features that may be provided in such a relay. The combination of features that are actually provided is manufacturer and relay model dependent, but it can be seen from the Table that steady progression is being made towards a 'one-box' solution that incorporates all the protection and control requirements for a line or cable. However, at the highest transmission voltages, the level of dependability required for rapid clearance of any protected circuit fault will still demand the use of two independent protection systems.

Fault Location (Distance to fault)
Instantaneous Overcurrent Protection
Tee'd feeder protection
Alternative setting groups
CT supervision
Check synchroniser
Auto-reclose
CB state monitoring
CB condition monitoring
CB control
Measurement of voltages, currents, etc.
Event Recorder
Disturbance Recorder
CB failure detection/logic
Directional/Non-directional phase fault overcurrent protection (backup to distance protection)
Directional/Non-directional earth fault overcurrent protection (backup to distance protection)
Negative sequence protection
Under/Overvoltage protection
Stub-bus protection
Broken conductor detection
User-programmable scheme logic

Table 11.1: Additional features in a distance relay

Relay parameter	Parameter description	Parameter value	Units
Z_{L1} (mag)	Line positive sequence impedance (magnitude)	48.42	Ω
Z_{L1} (ang)	Line positive sequence impedance (phase angle)	79.41	deg
Z_{L0} (mag)	Line zero sequence impedance (magnitude)	163.26	Ω
Z_{L0} (ang)	Line zero sequence impedance (phase angle)	74.87	deg
K_{Z0} (mag)	Default residual compensation factor (magnitude)	0.79	-
K_{Z0} (ang)	Default residual compensation factor (phase angle)	-6.5	deg
Z_1 (mag)	Zone 1 reach impedance setting (magnitude)	38.74	Ω
Z_1 (ang)	Zone 1 reach impedance setting (phase angle)	80	deg
Z_2 (mag)	Zone 2 reach impedance setting (magnitude)	62.95	Ω
Z_2 (ang)	Zone 2 reach impedance setting (phase angle)	80	deg
Z_3 (mag)	Zone 3 reach impedance setting (magnitude)	83.27	Ω
Z_3 (ang)	Zone 3 reach impedance setting (phase angle)	80	deg
R_{1ph}	Phase fault resistive reach value - Zone 1	78	Ω
R_{2ph}	Phase fault resistive reach value - Zone 2	78	Ω
R_{3ph}	Phase fault resistive reach value - Zone 3	78	Ω
T_{Z1}	Time delay - Zone 1	0	s
T_{Z2}	Time delay - Zone 2	0.35	s
T_{Z3}	Time delay - Zone 3	0.8	s
R_{1G}	Ground fault resistive reach value - Zone 1	104	Ω
R_{2G}	Ground fault resistive reach value - Zone 2	104	Ω
R_{3G}	Ground fault resistive reach value - Zone 3	104	Ω

Table 11.2: Distance relay parameters for example

11.12 DISTANCE RELAY APPLICATION EXAMPLE

The system diagram shown in Figure 11.22 shows a simple 230kV network. The following example shows the calculations necessary to apply three-zone distance protection to the line interconnecting substations ABC and XYZ. All relevant data for this exercise are given in the diagram. The MiCOM P441 relay with quadrilateral characteristics is considered in this example. Relay parameters used in the example are listed in Table 11.2.

Calculations are carried out in terms of primary system impedances in ohms, rather than the traditional practice of using secondary impedances. With numerical relays, where the CT and VT ratios may be entered as parameters, the scaling between primary and secondary ohms can be performed by the relay. This simplifies the example by allowing calculations to be carried out in primary quantities and eliminates considerations of VT/CT ratios.

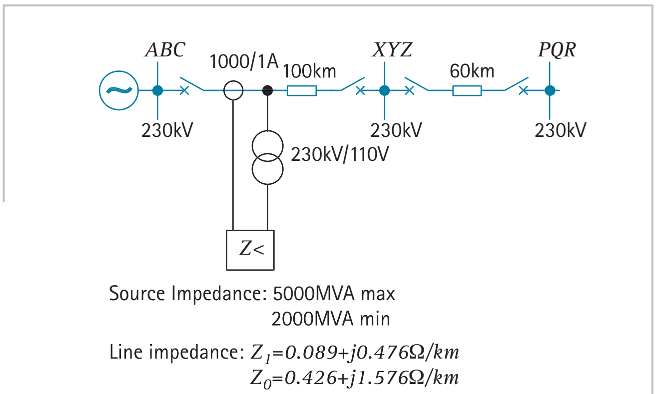


Figure 11.22: Example network for distance relay setting calculation

For simplicity, it is assumed that only a conventional 3-zone distance protection is to be set and that there is no teleprotection scheme to be considered. In practice, a teleprotection scheme would normally be applied to a line at this voltage level.

11.12.1 Line Impedance

The line impedance is:

$$Z_L = (0.089 + j0.476) \times 100$$

$$= 8.9 + j47.6\Omega$$

$$= 48.42 \angle 79.41^{\circ}\Omega$$

Use values of 48.42Ω (magnitude) and 80° (angle) as nearest settable values.

11.12.2 Residual Compensation

The relays used are calibrated in terms of the positive sequence impedance of the protected line. Since the zero sequence impedance of the line between substations *ABC* and *XYZ* is different from the positive sequence impedance, the impedance seen by the relay in the case of an earth fault, involving the passage of zero sequence current, will be different to that seen for a phase fault.

Hence, the earth fault reach of the relay requires zero sequence compensation (see Section 11.9.2).

For the relay used, this adjustment is provided by the residual (or neutral) compensation factor K_{Z0}, set equal to:

$$|K_{Z0}| = \left|\frac{(Z_0 - Z_1)}{3Z_1}\right|$$

$$\angle K_{Z0} = \angle \frac{(Z_0 - Z_1)}{3Z_1}$$

For each of the transmission lines:

$$Z_{L1} = 0.089 + j0.476\Omega \left(0.484 \angle 79.41^o \Omega\right)$$

$$Z_{L0} = 0.426 + j1.576\Omega \left(1.632 \angle 74.87^o \Omega\right)$$

Hence,

$$|K_{Z0}| = 0.792$$

$$\angle K_{Z0} = -6.5^o$$

11.12.3 Zone 1 Phase Reach

The required Zone 1 reach is 80% of the line impedance. Therefore,

$$0.8 \times \left(48.42 \angle 79.41^o\right) = 38.74 \angle 79.41^o \Omega$$

Use $38.74\angle 80°\Omega$ nearest settable value.

11.12.4 Zone 2 Phase Reach

Ideally, the requirements for setting Zone 2 reach are:

1. at least 120% of the protected line
2. less than the protected line + 50% of the next line

Sometimes, the two requirements are in conflict. In this case, both requirements can be met. A setting of the whole of the line between substations ABC and XYZ, plus 50% of the adjacent line section to substation PQR is used. Hence, Zone 2 reach:

$$= \left(\begin{array}{l} 48.42 \angle 79.41^o + \\ 0.5 \times 60 \times 0.089 + j0.476 \end{array}\right)\Omega$$

$$= 62.95 \angle 79.41^o \Omega$$

Use $62.95\angle 80^o \Omega$ nearest available setting.

11.12.5 Zone 3 Phase Reach

Zone 3 is set to cover 120% of the sum of the lines between substations ABC and PQR, provided this does not result in any transformers at substation XYZ being included. It is assumed that this constraint is met. Hence, Zone 3 reach:

$$= \left(\begin{array}{l} 48.42 \angle 79.41^o + \\ 1.2 \times 60 \times 0.484 \angle 79.41^o \end{array}\right)\Omega$$

$$= 83.27 \angle 79.41^o \Omega$$

Use a setting of $83.27\angle 80^o\Omega$, nearest available setting.

11.12.6 Zone Time Delay Settings

Proper co-ordination of the distance relay settings with those of other relays is required. Independent timers are available for the three zones to ensure this.

For Zone 1, instantaneous tripping is normal. A time delay is used only in cases where large d.c. offsets occur and old circuit breakers, incapable of breaking the instantaneous d.c. component, are involved.

The Zone 2 element has to grade with the relays protecting the line between substations XYZ and PQR since the Zone 2 element covers part of these lines. Assuming that this line has distance, unit or instantaneous high-set overcurrent protection applied, the time delay required is that to cover the total clearance time of the downstream relays. To this must be added the reset time for the Zone 2 element following clearance of a fault on the adjacent line, and a suitable safety margin. A typical time delay is 350ms, and the normal range is 200-500ms.

The considerations for the Zone 3 element are the same as for the Zone 2 element, except that the downstream fault clearance time is that for the Zone 2 element of a distance relay or IDMT overcurrent protection. Assuming distance relays are used, a typical time is 800ms. In summary:

$$T_{Z1} = 0ms \text{ (instantaneous)}$$

$$T_{Z2} = 250ms$$

$$T_{Z3} = 800ms$$

11.12.7 Phase Fault Resistive Reach Settings

With the use of a quadrilateral characteristic, the resistive reach settings for each zone can be set independently of the impedance reach settings. The resistive reach setting represents the maximum amount of additional fault resistance (in excess of the line impedance) for which a zone will trip, regardless of the fault within the zone.

Two constraints are imposed upon the settings, as follows:

i. it must be greater than the maximum expected phase-phase fault resistance (principally that of the fault arc)

ii. it must be less than the apparent resistance measured due to the heaviest load on the line

The minimum fault current at Substation ABC is of the order of 1.8kA, leading to a typical arc resistance R_{arc} using the van Warrington formula (Equation 11.4) of 8Ω. Using the current transformer ratio as a guide to the maximum expected load current, the minimum load impedance Z_{lmin} will be 130Ω. Typically, the resistive reaches will be set to avoid the minimum load impedance by a 40% margin for the phase elements, leading to a maximum resistive reach setting of 78Ω.

Therefore, the resistive reach setting lies between 8Ω and 78Ω. Allowance should be made for the effects of any remote fault infeed, by using the maximum resistive reach possible. While each zone can have its own resistive reach setting, for this simple example they can all be set equal. This need not always be the case, it depends on the particular distance protection scheme used and the need to include Power Swing Blocking.

Suitable settings are chosen to be 80% of the load resistance:

$$R_{3ph} = 78\Omega$$

$$R_{2ph} = 78\Omega$$

$$R_{1ph} = 78\Omega$$

11.12.8 Earth Fault Impedance Reach Settings

By default, the residual compensation factor as calculated in Section 11.12.2 is used to adjust the phase fault reach setting in the case of earth faults, and is applied to all zones.

11.12.9 Earth Fault Resistive Reach Settings

The margin for avoiding the minimum load impedance need only be 20%. Hence the settings are:

$$R_{3G} = 104\Omega$$

$$R_{2G} = 104\Omega$$

$$R_{1G} = 104\Omega$$

This completes the setting of the relay. Table 11.2 also shows the settings calculated.

11.13 REFERENCES

11.1 *Protective Relays – their Theory and Practice.* A.R. van C. Warrington. Chapman and Hall, 1962.