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Overcurrent Protection Fundamentals

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Relay protection against high current was the earliest relay protection mechanism to develop. From this basic method, the graded overcurrent relay protection system, a discriminative short circuit protection, has been formulated. This should not be mixed with 'overload' relay protection, which typically utilizes relays that function in a time related in some degree to the thermal capacity of the equipment to be protected. On the contrary, overcurrent relay protection is completely directed to the clearance of short circuits, even though with the settings typically assumed some measure of overload relay protection may be obtained.

COORDINATION TECHNIQUE

Precise overcurrent relay usage asks for the knowledge of the short circuit current that can flow in each section of the power network. Since large-scale measurements and tests are typically unfeasible, system calculations have to be used. The information needed for a relay protection setting analysis is:

- Single-line diagram of the electrical power system, presenting the type and rating of the relay protection elements and their related current transformers

- Impedances in ohms, per cent or per unit, of all power transformers, rotating machine and transmission lines

- Maximum and minimum figures of short circuit currents that are anticipated to go through each protection element

- Maximum load current through protection elements

- Starting current requirements of electrical motors and the starting and locked rotor/stalling times of induction motors

- Transformer inrush, thermal withstand and damage curves

- Decrement curves presenting the decay rate of the short circuit current supplied by the generators

- Performance curves of the current transformers

The protection relay adjustments are first calculated to provide the shortest tripping times at maximum fault currents and then verified to understand if tripping will also be acceptable at the minimum short circuit current anticipated. It is typically suggested to print the curves of protection relays and other protection elements, such as fuses, that are to trip in series, on a common graph and scale. It is typically more convenient to utilize a scale referring to the current anticipated at the lowest voltage base, or to utilize the dominant voltage base. The options are a mutual MVA base or a different current scale for each system voltage. The fundamental rules for proper protection relay co-ordination can typically be presented as follows:

- When feasible, utilize protection relays with the same tripping characteristic in series with each other

- Ensure that the protection relay farthest from the source has current settings same to or less than the protection relays behind it, that is, that the primary current needed to trip the protection relay in front is always same to or less than the primary current needed to trip the protection relay behind it.

RULES OF TIME/CURRENT GRADING

Among the different feasible methods utilized to accomplish precise protection relay co-ordination are those utilizing either time or overcurrent, or a mix of both. The common objective of all three methodologies is to provide precise discrimination. That is to say, each one has to isolate only the faulty part of the electrical power system network, leaving the rest of the power system untouched.

RELAY PROTECTION DISCRIMINATION BY TIME

In this system, an adequate time setting is provided to each of the protection relays controlling the power circuit breakers in an electrical power system to make sure that

the circuit breaker nearest to the fault location opens first. A fundamental radial distribution electrical system is presented in Figure 1, to demonstrate the operational logic.

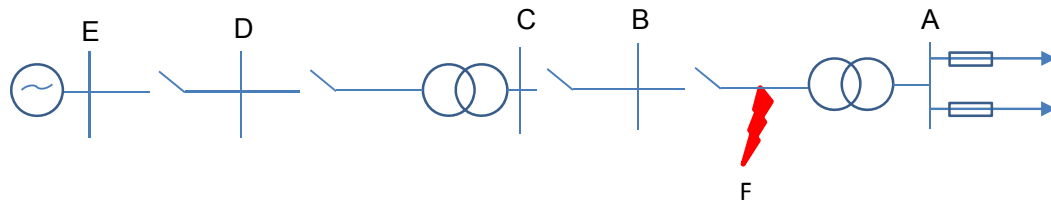


Figure 1. Radial electrical system with time discrimination

Overcurrent relay protection is given at B, C, D and E, that is, at the infeed position of each part of the electrical power system. Each relay protection device comprises a definite-time delay overcurrent protection relay in which the trip of the current sensitive element starts the time delay device. Given the setting of the current device is below the short circuit current value, this device plays no role in the accomplishment of discrimination. For this reason, the protection relay is sometimes known as an ‘independent definite-time delay protection relay’, since its tripping time is for practical uses independent of the overcurrent level.

It is the time delay device, hence, which gives the means of discrimination. The protection relay at location B is set at the shortest possible time delay to permit the fuse to operate for a fault at location A on the secondary side of the power transformer. After the time delay has completed, the protection relay output contact closes to operate the power circuit breaker. The protection relay at location C has a time delay setting equal to t_1 seconds, and likewise for the protection relays at locations D and E. If a short circuit happens at location F, the protection relay at location B will trip in t seconds and the later tripping of the power circuit breaker at location B will clear the short circuit before the protection relays at locations C, D and E have time to trip. The time interval t_1 between each protection relay time setting must be sufficiently long to make sure that the upstream protection relays do not trip before the power circuit breaker at the short circuit location has operated and cleared the short circuit.

The main drawback of this discrimination procedure is that the longest short circuit clearance time happens for short circuits in the section nearest to the power source, where the short circuit level (MVA) is the greatest.

RELAY PROTECTION DISCRIMINATION BY CURRENT

Relay protection discrimination by current is based on the fact that the short circuit current changes with the location of the fault because of the difference in impedance figures between the source and the short circuit. Therefore, usually, the protection relays controlling the different power circuit breakers are programmed to trip at appropriately tapered values of current such that only the protection relay closest to the fault operates its breaker. Figure 2 presents the method. For a fault at location F_1 , the electrical system fault current is expressed as:

$$I = \frac{6350}{Z_s + Z_{L1}} A$$

where:

$$Z_s - \text{source impedance} = \frac{11^2}{250} = 0.485 \Omega$$

$$Z_{L1} = \text{cable impedance between C and B} = 0.24 \Omega$$

$$\text{Therefore } I = \frac{6350}{0.725} = 8800 A$$

Therefore, a protection relay controlling the power circuit breaker at location C and programmed to trip at a short circuit current of 8800A would in theory save the whole of the underground cable section between locations C and B. Nevertheless, there are two critical practical points that impact this co-ordination procedure:

It is not efficient to differentiate between a fault at location F_1 and a fault at location F_2 , since the separation between these locations may be only a few meters, corresponding to a variation in short circuit current of roughly 0.1%. In practice, there would be variations in the source short circuit level, usually from 250MVA to 130MVA. At this lower short circuit level the short circuit current would not surpass 6800A, even for an underground cable short circuit near to location C. A protection relay set at 8800A would not save any part of the underground cable section concerned.

Relay protection discrimination by current is hence not a practical suggestion for correct grading between the power circuit breakers at locations C and B. Nevertheless,

the issue changes appreciably when there is major impedance between the two circuit breakers concerned. Note the grading needed between the power circuit breakers at locations C and A in Figure 2. Presuming a short circuit at location F₄, the short-circuit current is presented as:

$$I = \frac{6350}{Z_s + Z_{L1} + Z_{L2} + Z_r}$$

Where

$$Z_s - \text{source impedance} = \frac{11^2}{250} = 0.485 \Omega$$

$$Z_{L1} - \text{cable impedance between locations C and B} = 0.24 \Omega$$

$$Z_{L2} - \text{cable impedance between location B and 4 MVA transformer} = 0.04 \Omega$$

$$Z_r - \text{transformer impedance} = 0.07 \left(\frac{11^2}{4} \right) = 2.12 \Omega$$

$$\text{Therefore, } I = \frac{6350}{2.885} = 2200 \text{ A}$$

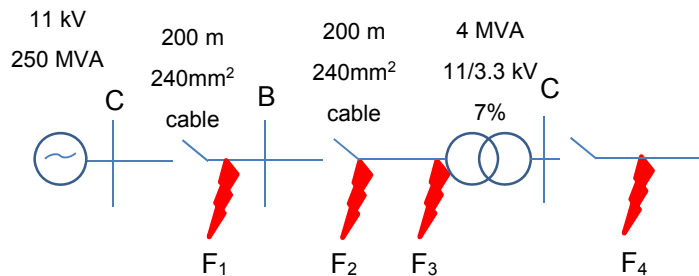


Figure 2. Radial electrical system with current discrimination

Due to this, a protection relay controlling the power circuit breaker at location B and programmed to trip at a current of 2200A plus a safety margin would not trip for a short circuit at F₄ and would therefore discriminate with the protection relay at location A. Presuming a safety margin of 20% to allow for protection relay errors and a further 10% for changes in the system impedance quantities, it is fair to select a protection relay setting of 1.3x2200A, that is, 2860A, for the protection relay at location B. Now, analyzing a short circuit at location F₃, at the end of the 11kV underground cable supplying the 4MVA transformer, the short-circuit current is presented as:

$$I = \frac{6350}{Z_s + Z_{L1} + Z_{L2}}$$

This, presuming a 250 MVA source short circuit current level:

$$I = \frac{6350}{0.485 + 0.24 + 0.04} = 8300 \text{ A}$$

Instead, presuming a source short circuit current level of 130 MVA:

$$I = \frac{6350}{0.93 + 0.214 + 0.04} = 5250 \text{ A}$$

For either value of source level, the protection relay at location B would precisely function for short circuits anywhere on the 11kV underground cable supplying the transformer.

RELAY POTECTION DISCRIMINATION BY BOTH TIME AND CURRENT

Each of the two presented methodologies so far has a fundamental drawback. In the case of discrimination only by time, the drawback is due to the fact that more serious short circuits are cleared in the longest tripping time. On the other side, discrimination by current can be used only where there is considerable impedance between the two considered power circuit breakers. It is due to the limitations introduced by the independent usage of either time or current co-ordination that the inverse time overcurrent protection relay characteristic has developed. With this characteristic, the tripping time is reciprocally proportional to the short circuit current level and the real characteristic is a function of both 'time' and 'current' settings. Figure 3 presents the characteristics of two protection relays given different current/time adjustments. For a great change in short circuit current between the two feeder ends, quicker tripping times can be accomplished by the protection relays closest to the source, where the short circuit level is the greatest. The drawbacks of grading by time or current alone are resolved.

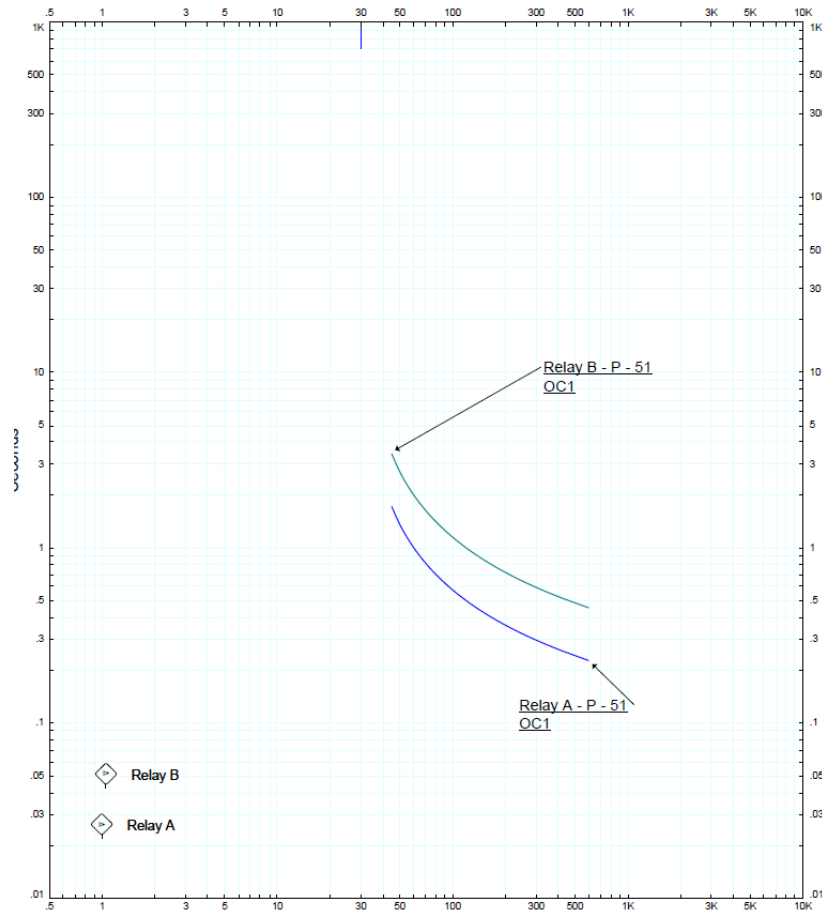


Figure 3. Protection relay characteristics for different settings

Relay A: Current setting=1000 A; TMS=0.1; Relay B: Current setting=300 A;
TMS=0.2

STANDARD IDMT OVERCURRENT PROTECTION RELAYS

The current/time tripping characteristics of IDMT protection relays may need to be changed according to the functioning time needed and the characteristics of other relay protection elements used in the electrical network. For these needs, IEC 60255 determined a number of standard characteristics. These are:

- Standard Inverse characteristic (SI)
- Very Inverse characteristic (VI)
- Extremely Inverse characteristic (EI)

- Definite Time characteristic (DT)

The mathematical definition of the curves are presented in Table 1, and the curves based on a common setting current and time multiplier setting of 1 second are presented in Figure 4.

The tripping characteristics for various TMS settings using the SI curve are presented in Figure 6.

Relay protection characteristic	Formula (IEC 60255)
Standard inverse (SI)	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very inverse (VI)	$t = TMS \times \frac{13.5}{I_r - 1}$
Extremely inverse (EI)	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long-time standby earth fault	$t = TMS \times \frac{120}{I_r - 1}$

Table 1. Definitions of standard relay protection characteristics

Relay protection characteristic	Formula
IEEE moderately inverse	$t = \frac{TD}{7} \left[\left(\frac{0.0515}{I_r^{0.02} - 1} \right) + 0.114 \right]$
IEEE very inverse	$t = \frac{TD}{7} \left[\left(\frac{19.61}{I_r^2 - 1} \right) + 0.491 \right]$
IEEE extremely inverse	$t = \frac{TD}{7} \left[\left(\frac{28.2}{I_r^2 - 1} \right) + 0.1217 \right]$
US CO8 inverse	$t = \frac{TD}{7} \left[\left(\frac{5.95}{I_r^2 - 1} \right) + 0.18 \right]$
US CO2 short time inverse	$t = \frac{TD}{7} \left[\left(\frac{0.02394}{I_r^{0.02} - 1} \right) + 0.01694 \right]$

Table 2. ANSI IDMT definitions of standard relay protection characteristics

$$I_r = \frac{I}{I_s}$$

Where

I- Measure current

I_s - Relay setting current

TMS – Time Multiplier Setting

TD – Time Dial Setting

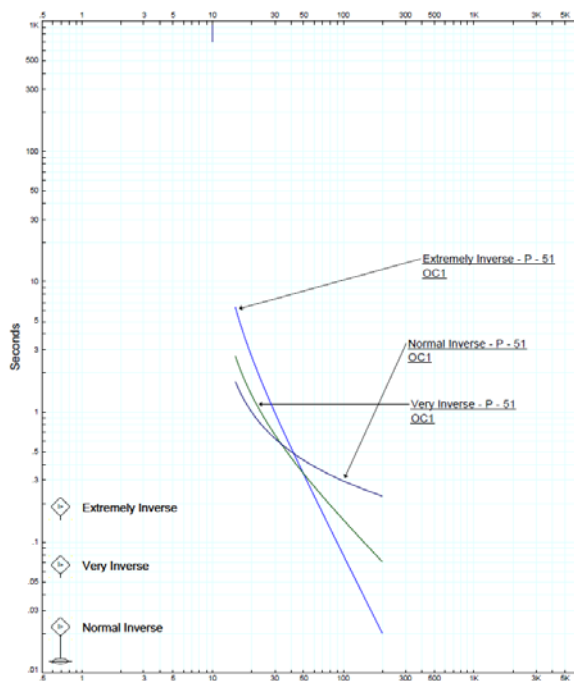


Figure 4. IEC 60255 IDMT protection relay characteristics

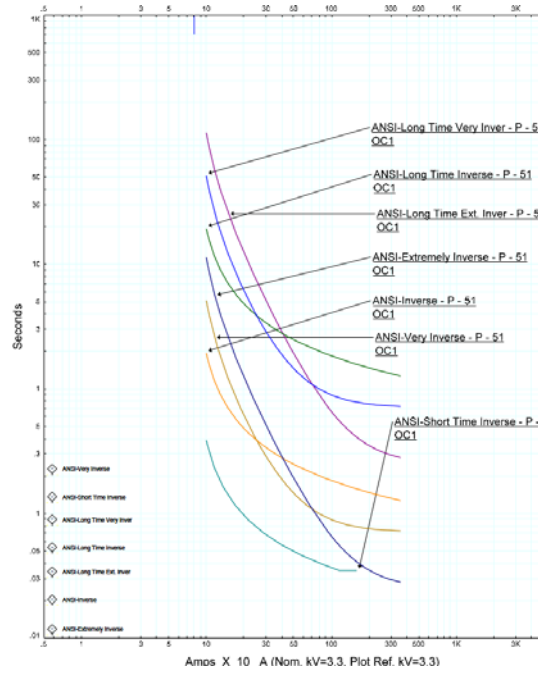


Figure 5. ANSI IDMT protection relay characteristics

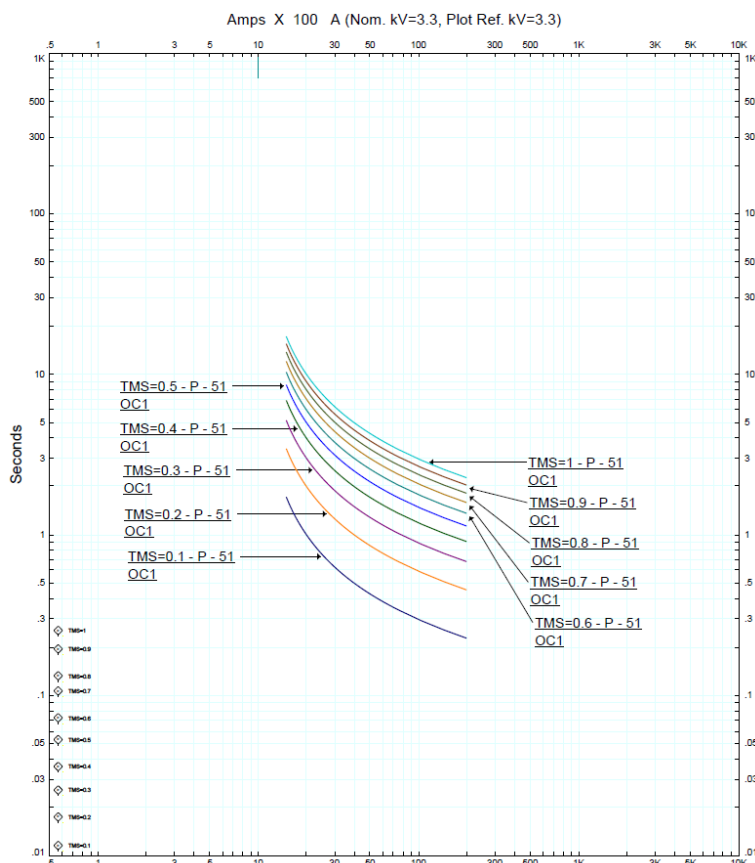


Figure 6. Common time/current characteristics of typical IDMT protection relay

Even though the protection curves are only presented for discrete values of TMS, continuous settings may be feasible in an electromechanical protection relay. For other relay protection types, the protection setting steps may be so small as to efficiently give continuous adjustment. Also, almost all overcurrent protection relays are also equipped with high-set instantaneous devices. In majority of situations, use of the standard SI protection curve proves satisfactory, but if acceptable grading cannot be accomplished, utilization of the VI or EI protection curves may assist to solve the issue. When digital or numeric protection relays are utilized, other characteristics may be given, including the possibility of user-definable protection curves. More information is given in the following paragraphs. Protection relays for electrical power systems made according to North American standards use ANSI/IEEE protection curves. Table 2 provides the mathematical description of these protection characteristics and Figure 5 presents the protection curves standardised to a time dial setting of 7. It is important to note that various vendors may standardise their protection curves at various settings other than TD=7. The relay protection engineer has to ensure if the factor of 7, or some

other nominal, is used.

MIXED IDMT AND HIGH SET INSTANTANEOUS OVERCURRENT PROTECTION RELAYS

A high-set instantaneous device can be utilized where the source impedance is small in comparison with the protected circuit impedance. This allows a decrease in the operating time at high short circuit levels possible. It also enhances the overall electrical system grading by allowing the 'discriminating protection curves' behind the high set instantaneous device to be reduced. One of the benefits of the high set instantaneous devices is to decrease the tripping time of the circuit protection. If the source impedance stays constant, it is then feasible to accomplish high-speed relay protection over a large part of the protected circuit. The quick short circuit clearance time helps to decrease damage at the short circuit location. Grading with the protection relay directly behind the protection relay, which has the instantaneous devices enabled, is accomplished at the current setting of the instantaneous devices and not at the maximum short circuit level.

TRANSIENT OVERREACH

The reach of a protection relay is that portion of the protected electrical system by the protection relay if a short circuit happens. A protection relay that trips for a short circuit that lies beyond the intended protection zone is said to overreach. When applying instantaneous overcurrent devices, care has to be taken in selecting the settings to stop them tripping for short circuits beyond the protected area. The initial current due to a D.C. offset in the current wave may be higher than the protection relay pick-up value and cause it to trip. This may happen although the steady state R.M.S. figure of the short circuit current for a short circuit at a location beyond the needed reach point may be less than the protection relay setting. This process is known as transient overreach, and is expressed as:

$$\% \text{ Transient over - reach} = \frac{I_1 - I_2}{I_2} \times 100\% \quad (1)$$

where

I_1 – RMS steady state pickup current

I_2 – steady state RMS current which when completely offset just causes protection relay pickup

When applied to power transformers, the high set instantaneous overcurrent devices have to be set above the maximum through short circuit current than the power transformer can supply for a short circuit across its LV terminals, to keep discrimination with the protection relays on the transformer LV side.

VERY INVERSE (VI) OVERCURRENT PROTECTION RELAYS

Very inverse overcurrent protection relays are especially suited if there is a considerable decrease of short circuit current as the distance from the power source grows, i.e. there is a considerable increase in short circuit impedance. The VI tripping characteristic is such that the tripping time is roughly doubled for decrease in current from 7 to 4 times the protection relay current setting. This allows the use of the same time multiplier setting for more protection relays connected in series.

Figure 8 shows the SI and VI curves for a protection relay. The VI curve is much steeper and hence the operation increases much faster for the same decrease in current in comparison to the SI protection curve. This allows the requisite grading margin to be found with a lower TMS for the same setting current, and therefore the tripping time at source can be minimized.

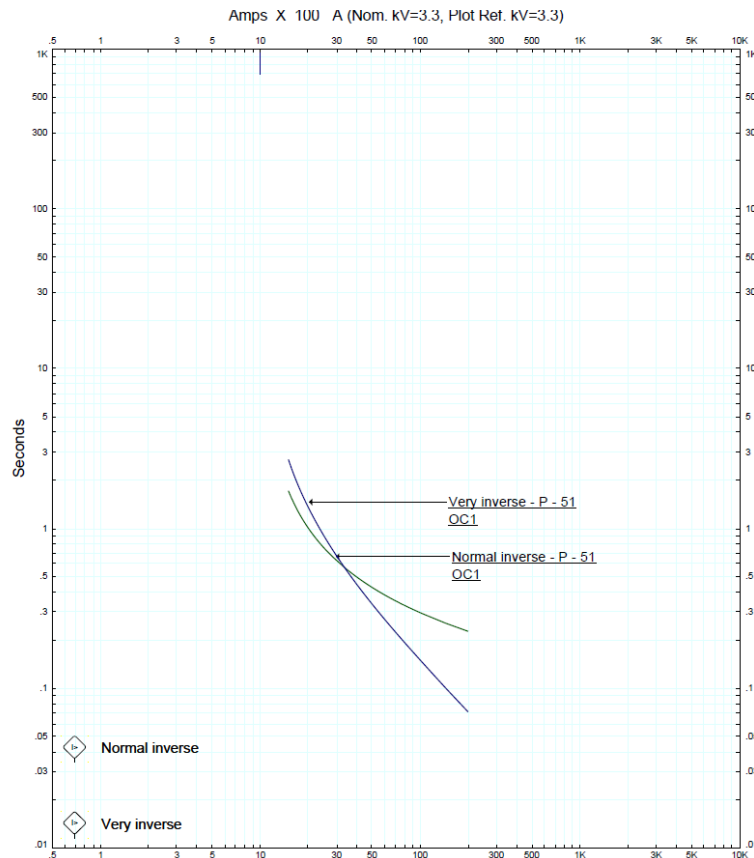


Figure 8. Cross comparison of SI and VI protection relay characteristics

EXTREMELY INVERSE (EI) OVERCURRENT PROTECTION RELAYS

With this protection characteristic, the tripping time is roughly inversely proportional to the square of the applied current. This makes it suited for the protection of distribution transmission lines in which the transmission line is subjected to peak currents on switching in, as would be the case on a power circuit supplying refrigerators, pumps, water heaters and so on, which stay connected even after a sustained interruption of the power. The long-time tripping characteristic of the extremely inverse protection relay at normal peak load quantities of current also makes this protection relay especially suited for grading with fuses. Figure 9 presents common protection curves. The EI characteristic provides a satisfactory grading margin, but the VI or SI characteristics at the same settings do not. Another usage of this protection relay is in conjunction with auto-reclosers in low voltage distribution lines. The majority of short circuits are transient in nature, and unneeded blowing and replacing of the protection fuses present in the final circuits of such an electrical system can be averted if the

auto-reclosers are made to trip before the fuse blows. If the short circuit continues, the auto-recloser locks itself in the closed position after one opening, and the fuse operates to set apart short circuit location.

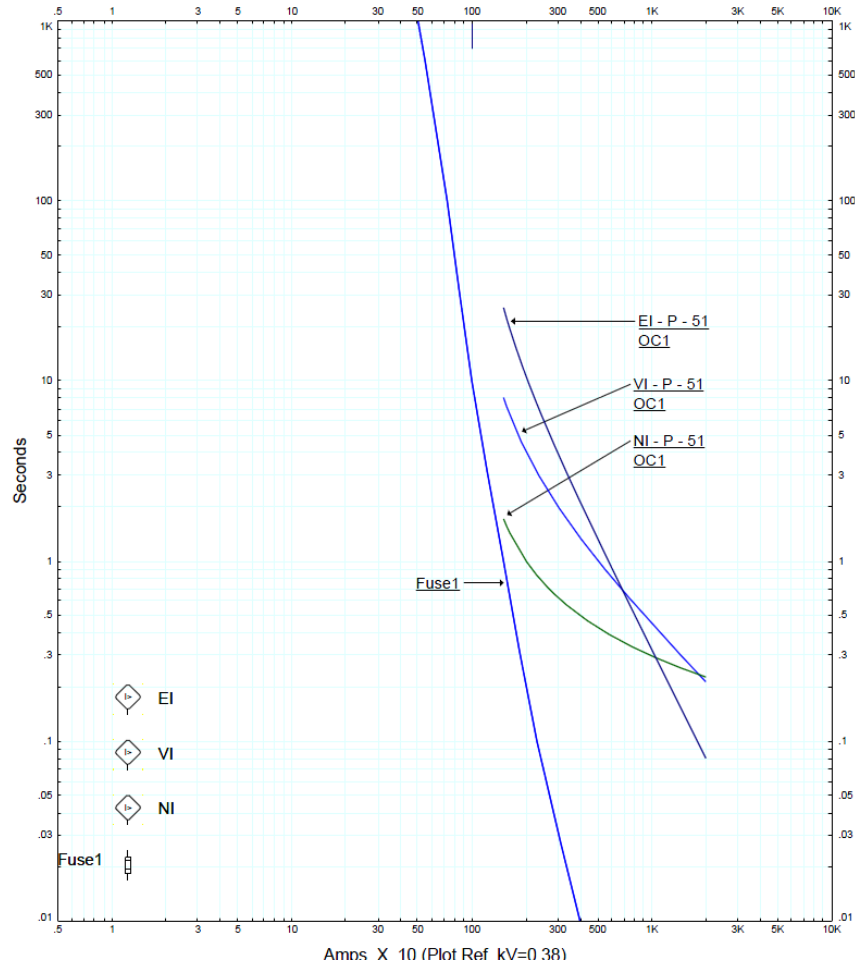


Figure 9. Cross-comparison of protection relay and fuse characteristics

OTHER RELAY PROTECTION CHARACTERISTICS

User defined protection curves may be given on some types of digital or numerical protection relays. The general rule is that the engineer provides a series of current/time co-ordinates that are kept in the relay memory. Interpolation between points is used to give a smooth trip characteristic. Such a characteristic, if present, may be utilized in special situations if none of the standard operating characteristics is suited. Nevertheless, grading of upstream protection may become more challenging, and it is necessary to assure that the protection curve is adequately documented, along with

the application reasons. Since the typical curves cover most situations with tolerable tripping times, and most devices are made with standard protection curves in mind, the requirement to use this protection form is rare.

Digital and numerical protection relays may also let in pre-defined logic arrangements using digital (relay) I/O given in the protection relay to apply typical protection schemes such as CB failure and trip circuit supervision. This saves the provision of separate relay protection hardware to complete these functions.

INDEPENDENT (DEFINITE) TIME OVERCURRENT PROTECTION RELAYS

Overcurrent protection relays are typically also supplied with elements having independent or definite time protection characteristics. These protection characteristics give means of co-ordinating more protection relays in series in arrangements in which the system short circuit current changes very widely due to variations in source impedance, as there is no variation in time with the change of short circuit current. The time/current protection characteristics of this protection curve are presented in Figure 10, together with those of the standard IDMT protection characteristic, to point out that lower tripping times are accomplished by the inverse protection relay at the higher values of short circuit current, whereas the definite time protection relay has lower tripping times at the lower current values.

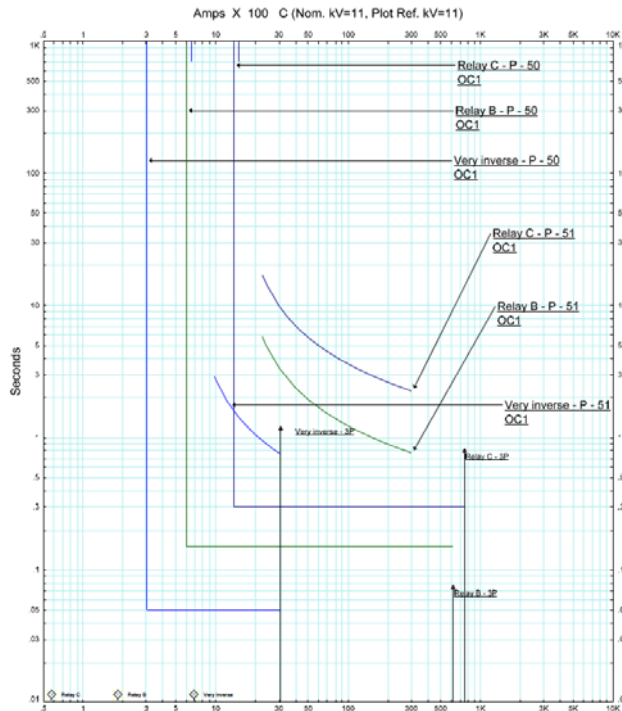


Figure 10. Cross-comparison of definite time and standard IDMT protection relays. Vertical lines point out the reduction in tripping times accomplished by the inverse protection relay at high short circuit levels.

PROTECTION RELAY CURRENT ADJUSTMENTS

An overcurrent protection relay has a minimum tripping current, known as the current setting of the protection relay. The current setting has to be selected so that the protection relay does not trip for the maximum load current in the circuit being protected, but does trip for a current same or higher to the minimum anticipated short circuit current. Even though by using a current setting that is only just above the maximum load current in the circuit, a degree of protection against overloads as well as short circuits may be given. The main objective of overcurrent relay protection is to set apart primary system short circuits and not to give overload protection. In principle, the current setting will be chosen to be above the maximum short time rated current of the protected circuit. Since all protection relays have hysteresis in their current settings, the protection setting must be sufficiently high to allow the protection relay to reset when the rated current of the protected circuit is being transferred.

The amount of hysteresis in the current setting is referred by the pick-up/drop-off ratio

of a protection relay – the figure for a modern protection relay is usually 0.95. Therefore, a protection relay minimum current setting of at least 1.05 times the short-time rated current of the protected circuit is likely to be needed.

PROTECTION RELAY TIME GRADING MARGIN

The time interval that must be granted between the tripping of two nearby protection relays to accomplish correct discrimination between them is known as the grading margin. If a grading margin is not given, or is not enough, more than one protection relay will function for a short circuit, leading to troubles in finding out the position of the short circuit and unneeded loss of supply to some devices.

The grading margin is dependent on a number of different factors:

1. The fault current interrupting time of the power circuit breaker
2. Protection relay timing errors
3. The overshoot time of the protection relay
4. CT errors
5. Final margin on tripping completion

Factors 2 and 3 are dependent on the protection relay technology. For example, an electromechanical protection relay has a greater overshoot time than a numerical protection relay.

Grading is initially carried out for the maximum short circuit current level at the relaying point under consideration, but verification is also made that the needed grading margin exists for all current levels between protection relay pick-up current and maximum anticipated short circuit current level.

POWER CIRCUIT BREAKER INTERRUPTING TIME

The power circuit breaker interrupting the short circuit has to totally interrupt the

current before the discriminating protection relay ceases to be energized. The time taken depends on the circuit breaker type and the short circuit current to be cleared. Vendors typically give the short circuit tripping time at rated interrupting capacity and this figure is constantly utilized in the computation of grading margin.

PROTECTION RELAY TIMING ERROR

All protection relays have errors in their timing in comparison to the ideal protection characteristic as specified in IEC 60255. For a protection relay defined to IEC 60255, a protection relay error index is cited that fixes the maximum timing error of the protection relay. The timing error has to be taken into consideration when finding out the grading margin.

PROTECTION RELAY OVERSHOOT

When the protection relay is de-energised, tripping may continue for a little longer until any kept energy has been released. To illustrate, an induction disc protection relay will have kept kinetic energy in the motion of the disc; static protection relay circuits may have energy kept in capacitors. Protection relay design is aimed to minimizing and absorbing these energies, but some adjustment is typically required. The overshoot time is determined as the difference between the tripping time of a protection relay at a defined value of input current and the maximum duration of input current, which when abruptly decreased below the protection relay tripping level, is insufficient to cause protection relay function.

CURRENT TRANSFORMER ERRORS

Current transformers have phase and ratio errors due to the exciting current needed to magnetise their cores. The consequence is that the CT secondary current is not an identical scaled reproduction of the primary current. This heads to protection relay operation errors, particularly in the tripping time. CT errors are not applicable for independent definite-time delay overcurrent protection relays.

FINAL MARGIN

After provisions have been made for power circuit breaker interrupting time, protection

relay timing error, overshoot and CT errors, the discriminating protection relay must just fail to finish its function. Some additional safety margin is needed to make sure that protection relay tripping does not happen.

SUGGESTED GRADING MARGINS

The following paragraphs provide the suggested complete grading margins for between different protection elements.

GRADING: PROTECTION RELAY TO PROTECTION RELAY

The complete interval needed to cover power circuit breaker clearing time, protection relay timing error, overshoot and CT errors, is dependent on the tripping speed of the power circuit breakers and the protection relay performance. At one time 0.5s was a typical grading margin. With quicker modern power circuit breakers and a lower protection relay overshoot time, 0.4s is fair, while under the best circumstances even lower intervals may be feasible. The utilization of a fixed grading margin is popular, but it may be better to compute the needed value for each protection relay location. This more accurate margin comprises a fixed time, covering power circuit breaker short circuit interrupting time, protection relay overshoot time and a safety margin, plus a varying time that allows for protection relay and CT errors. Table 3 presents common protection relay errors according to the applied technology.

It should be kept in mind that application of a fixed grading margin is only allowed at high short circuit levels that head to short protection relay operating times. At lower short circuit current levels, with longer operating times, the allowed error defined in IEC 60255 (7.5% of tripping time) may surpass the fixed grading margin, ending in the possibility that the protection relay fails to grade precisely while keeping within specification. This needs consideration when studying the grading margin at low short circuit current levels.

A feasible answer for finding out the optimum grading margin is to make sure that the protection relay closer to the short circuit location has a maximum possible timing error of $+2E$, where E is the basic timing error. To this complete effective error for the protection relay, 10% should be added for the total current transformer error.

	Relay protection type			
	Electro-mechanical	Static	Digital	Numerical
Typical basic timing error (%)	7.5	5	5	5
Overshoot time (s)	0.05	0.03	0.02	0.02
Safety margin (s)	0.1	0.05	0.03	0.03
Common complete grading margin – relay to relay (s)	0.4	0.35	0.3	0.3

Table 3. Common protection relay timing errors – standard IDMT protection relays

A suited minimum grading time interval, t' , may be computed as follows:

$$t' = \left[\frac{2E_R + E_{CT}}{100} \right] t + t_{CB} + t_0 + t_s \quad (2)$$

Where:

E_R – protection relay timing error (IEC60255-4)

E_{CT} – allowance for CT ratio error (%)

t – nominal operating time of protection relay nearer to fault location (sec)

t_{CB} – circuit breaker interrupting time (sec)

t_0 – protection relay overshoot time (sec)

t_s – safety margin (sec)

If, for instance $t=0.5s$, the time interval for an electromechanical protection relay operating a conventional power circuit breaker would be 0.375s, while, at the lower extreme, for a static protection relay operating a vacuum power circuit breaker, the interval could be 0.25s.

When the overcurrent protection relays have independent definite time delay protection characteristics, it is not required to include the provision for CT error. Therefore:

$$t = \left[\frac{2E_R}{100} \right] t + t_{CB} + t_0 + t_s \quad (3)$$

Computation of particular grading times for each protection relay can often be demanding when completing a relay protection grading computation on an electrical power system. Table 3 also provides feasible grading times at high short circuit current levels between overcurrent protection relays for different technologies. Where protection relays of different technologies are utilized, the time appropriate to the technology of the downstream protection relay should be utilized.

GRADING: FUSE TO FUSE

The tripping time of a fuse is a function of pre-arcing and arcing time of the fusing component, which adheres to I^2t law. So, to accomplish precise coordination between two fuses in connected series, it is mandatory to assure that the complete I^2t taken by the smaller fuse is not higher than the pre-arcing I^2t value of the bigger fuse. It has been founded by tests that acceptable grading between the two fuses will typically be accomplished if the current rating ratio between them is higher than two.

GRADING: FUSE TO PROTECTION RELAY

For grading inverse time protection relays with fuses, the basic strategy is to make sure whenever feasible that the protection relay backs up the fuse and not vice versa. If the fuse is upstream of the protection relay, it is very challenging to keep precise discrimination at great values of short circuit current because of the fast tripping of the fuse. The protection relay characteristic best fitted for this coordination with fuses is typically the extremely inverse (EI) protection characteristic as it uses a similar I^2t protection characteristic. To make sure acceptable coordination between protection relay and fuse, the primary current setting of the protection relay should be roughly three times the current rating of the fuse. The grading margin for precise coordination, when conveyed as a fixed figure, should not be less than 0.4s or, when conveyed as a varying quantity, should have a minimum figure of:

$$t = 0.4t + 0.15 \quad (4)$$

where t is the nominal tripping time of the fuse.

COMPUTATION OF PHASE FAULT OVERCURRENT PROTECTION RELAY SETTINGS

The precise coordination of overcurrent protection relays in an electrical power system asks for the computation of the approximated protection relay settings in terms of both current and time. The final settings are then typically printed in appropriate log/log format to present pictorially that an appropriate grading margin exists between the protection relays at adjacent substations. Printing is typically completed using suitable software even though it can be completed by hand. The main protection relay information can be put in a table such as that presented in Table 4, populating the first five columns.

Location	Fault current (A)		Maximum load current (A)	CT Ratio	Relay current setting		Relay time multiplier setting
	Maximum	Minimum			Per Cent	Primary Current (A)	

Table 4. Common protection relay data table

It is common to print all time/current characteristics to a common voltage/MVA base on log/log scales. The graph considers all protection relays in a single path, starting with the protection relay closest to the load and finishing with the protection relay closest the source of supply. A different graph is needed for each independent path. Settings of any protection relays that lie on multiple paths have to be cautiously considered to make sure that the final adjustments are appropriate for all operational scenarios. Ground short circuits are treated separately from line short circuits and need different graph. After protection relay settings have been completed they are out into a table such as that presented in Table 4, entering information in the last three columns. This also helps in record keeping during commissioning of the protection relays at site.

INDEPENDENT (DEFINITE) TIME PROTECTION RELAYS

The choice of protection settings for independent (definite) time protection relays presents little trouble. The overcurrent protection elements have to be given settings

that are lower, by a sensible margin, than the short circuit current that is likely to go to a fault at the remote end of the electrical system up to which back-up relay protection is needed, with the minimum elements in operation. The protection settings have to be sufficiently high to avert protection relay tripping with the maximum probable load, a suited margin being allowed for large motor starting currents or transformer inrush transients. Time settings will be selected to provide suited grading margins.

INVERSE TIME PROTECTION RELAYS

When the electrical power system consists of a series of short sections of underground cable, so that the complete transmission line impedance is low, the value of short circuit current will be checked mainly by the impedance of transformers or other fixed devices and will not change greatly with the position of the short circuit. In such situations, it may be feasible to grade the inverse time protection relays in the same way as definite time protection relays. Nevertheless, when the prospective short circuit current changes considerably with the position of the short circuit, it is feasible to make use of this fact by utilizing both current and time grading to enhance the total tripping of the protection relay.

The process starts by selection of the adequate protection relay characteristics. Current settings are then selected, with eventually the time multiplier settings to provide adequate grading margins between protection relays. Otherwise, the process is similar to that for definite time delay protection relays.

DIRECTIONAL PHASE SHORT CIRCUIT OVERCURRENT PROTECTION RELAYS

When short circuit current can go in both directions through the protection relay location, it may be required to make the response of the protection relay directional by the initiation of a directional control device. The device is provided by the use of extra voltage inputs to the protection relay.

PROTECTION RELAY CONNECTIONS

There are many ways for an appropriate connection of voltage and current signals. The different connections depend on the phase angle, at unity system power factor, by which the current and voltage used to the protection relay are displaced.

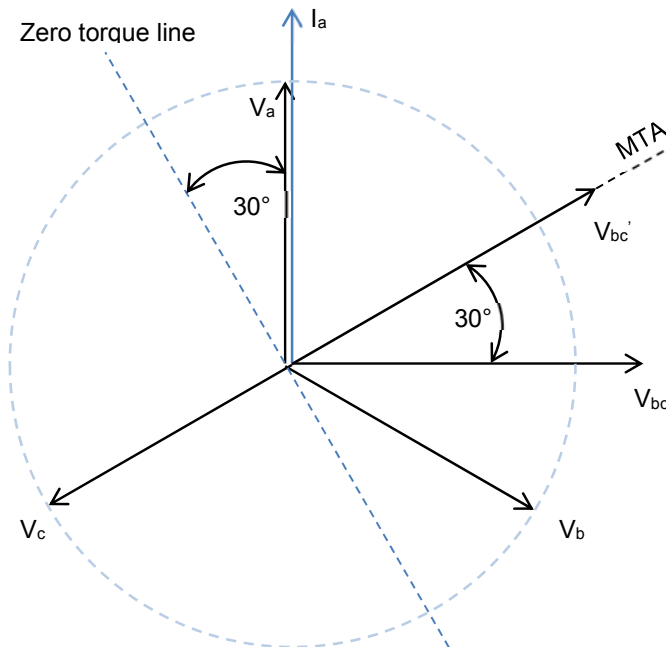
Nevertheless, only very few connections are utilized in current practice and these are presented below. In a digital or numerical protection relay, the phase displacements are determined by software, while electromechanical and static protection relays typically get the needed phase displacements by connecting the input signals to the protection relay. The history of the topic ends in the protection relay connections being specified as if they were received by appropriate connection of the input signals, irrespective of the actual process used.

90° PROTECTION RELAY QUADRATURE CONNECTION

This is the typical arrangement for static, digital or numerical protection relays. Depending on the angle by which the used voltage is shifted to generate maximum protection relay sensitivity (the protection Relay Characteristic Angle, or RCA), two types are usable.

90°-30° CHARACTERISTIC (30° RCA)

The A phase protection relay element is furnished with I_a current and V_{bc} voltage displaced by 30° in an anti-clockwise direction. In this situation, the protection relay maximum sensitivity is generated when the current lags the system phase to neutral voltage by 60°. This relay connection provides precise directional tripping zone over the current range of 30° leading to 150° lagging as shown in Figure 11. The protection relay sensitiveness at unity power factor is 50% of the relay maximum sensitivity and 86.6% at zero power factor lagging. This characteristic is suggested when the protection relay is used for the protection of plain lines with the zero sequence source behind the relaying location.

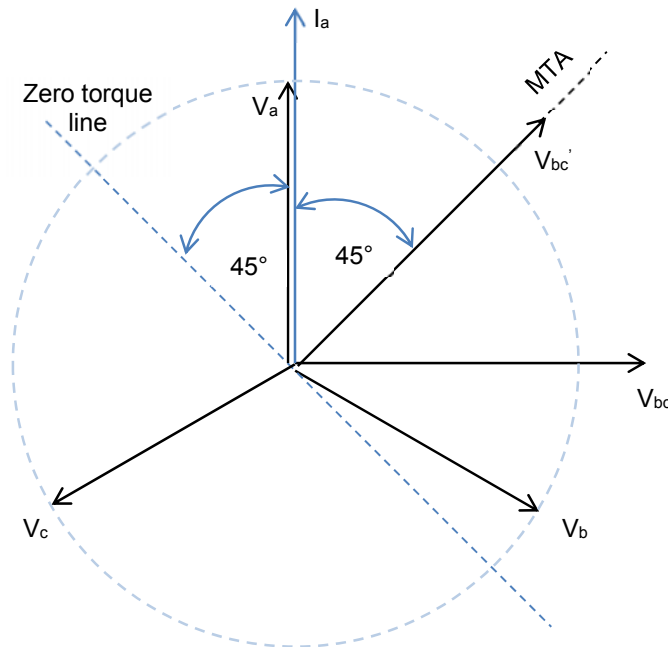


A phase device connected	I_a	V_{bc}
B phase device connected	I_b	V_{ca}
C phase device connected	I_c	V_{ab}

Figure 11. Vector graph for the 90°-30° arrangement (phase A device)

90°-45° CHARACTERISTIC (45° RCA)

The A phase protection relay device is furnished with current I_a and voltage V_{bc} shifted by 45° in an anti-clockwise direction. The protection relay maximum sensitiveness is generated when the current lags the system phase to neutral voltage by 45°. This arrangement provides a precise directional tripping zone over the current range of 45° leading to 135° lagging. The protection relay sensitivity at unity power factor is 70.7% of the maximum torque and the same at zero power factor lagging as shown in Figure 12. This arrangement is suggested for the protection of transformer feeders or lines that have a zero sequence source in front of the protection relay. It is required in the situation of parallel transformers or transformer lines, to assure precise protection relay tripping for short circuits beyond the star/delta transformer.



A phase device connected	I_a	V_{bc}
B phase device connected	I_b	V_{ca}
C phase device connected	I_c	V_{ab}

Figure 12. Vector graph for the 90°-45° arrangement (phase A device)

For a digital or numerical protection relay, it is typical to grant user selection of the RCA within a wide range.

In theory, three short circuit conditions can start maloperation of the directional device:

- a line-line-earth short circuit on a plain line
- a line-earth short circuit on a transformer line with the zero sequence source in front of the protection relay
- a line-line short circuit on a power transformer with the protection relay looking into the transformer delta winding. These circumstances are presumed to establish the maximum angular shift between the current and voltage quantities at the protection relay. The magnitude of the current input to the protection relay is insufficient to start the overcurrent device to trip. The possibility of maloperation with the 90°-45° arrangement is non-existent.

USAGE OF DIRECTIONAL PROTECTION RELAYS

If non-unit, non-directional protection relays are used to parallel lines having a common generator, any short circuits that might happen on any one transmission line will, irrespective of the protection relay settings utilized, set apart both feeders and totally disconnect the power supply. With this system arrangement, it is essential to use directional protection relays at the receiving end and to grade them with the non-directional protection relays at the sending end, to assure precise discriminative tripping of the protection relays during transmission line faults. This is accomplished by setting the directional protection relays R'_1 and R'_2 in Figure 13 with their directional components looking into the protected feeder, and providing them with lower time and current settings than protection relays R_1 and R_2 . The common practice is to program protection relays R'_1 and R'_2 to 50% of the normal full load of the protected feeder and 0.1 TMS, but care has to be taken to assure that the uninterrupted thermal rating of the protection relays of twice rated current is not surpassed.

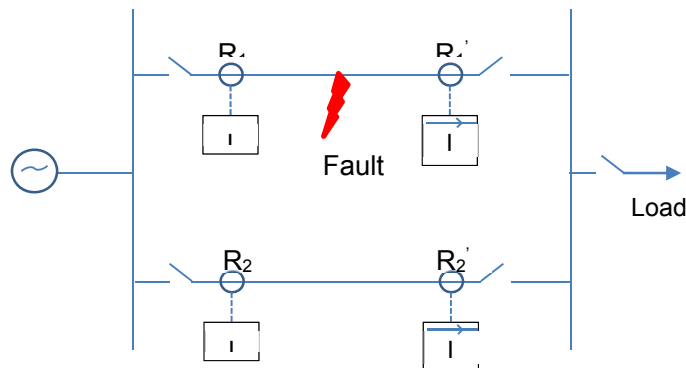


Figure 14. Directional protection relays utilized to parallel lines

RING MAINS

Typical scheme within electrical distribution networks is the Ring Main. The main reason for its application is to keep supplies to consumers in case of short circuit conditions happening on the interconnecting lines. Current may go in either direction through the different protection relay locations, and hence directional overcurrent protection relays are used.

In the situation of a ring main fed at the single point, the settings of the protection

relays at the supply side and at the mid-point substation are same. Hence, they can be made non-directional, if, in the latter situation, the protection relays are placed on the same line, that is, one at each end of the line. It is interesting to note that when the number of lines round the ring is an even number, the two protection relays with the same tripping time are at the same substation. Hence, they will have to be directional. When the number of lines is an odd number, the two protection relays with the same tripping time are at different substations and hence do not need to be directional. It may also be remembered that, at intermediate substations, whenever the tripping time of the protection relays at each substation are different, the difference between their tripping times is never lower than the grading margin, so the protection relay with the longer tripping time can be non-directional. With modern numerical protection relays, a directional facility is often applicable for little or no additional cost, so that it may be easier in practice to use directional protection relays at all locations. Also, in the case of an extra line being installed subsequently, the protection relays that can be non-directional have to be re-determined and will not inevitably be the same – giving rise to issues of changing a non-directional protection relay for a directional one. If a VT was not initially given, this may be very challenging to provide at a later date.

RING MAINS GRADING

The typical grading process for protection relays in a ring main circuit is to trip the ring at the supply point and to grade the protection relays first clockwise and then anti-clockwise. That is, the protection relays looking in a clockwise direction around the ring are made to trip in the sequence 1-2-3-4-5-6 and the protection relays looking in the anti-clockwise direction are made to trip in the sequence 1'-2'-3'-4'-5'-6'.

The directional protection relays are set in accordance with the invariable standard, relevant to all forms of directional relay protection that the current in the system has to go from the substation bus into the protected feeder so the protection relays may trip. Tripping of the faulted feeder is completed according to time and short circuit current direction. As in any parallel electrical system, the short circuit current has two parallel paths and separates itself in the inverse ratio of their impedances. Therefore, at each substation in the ring, one set of protection relays will be made defunct because of the direction of current flow, and the other set operative. It will also be noted that the

tripping times of the protection relays that are defunct are quicker than those of the operative protection relays, with the exclusion of the mid-point substation, where the tripping times of protection relays are equal.

The protection relays that are operative are graded downwards towards the short circuit location and the last to be impacted by the short circuit trips first. This is applicable to both paths to the short circuit. Accordingly, the affected feeder is the only one to be switched off from the ring and the power supply is kept to all the substations.

When two or more power sources supply the ring main, time graded overcurrent protection is challenging to use and complete discrimination may not be achievable. With two power sources of supply there are two possible solutions. The first is to trip the ring at one of the supply locations, whichever is more practical, by means of a suited high set instantaneous overcurrent protection relay. The ring is then graded as in the situation of a single supply. The second technique is to treat the portion of the ring between the two supply locations as a continuous bus separate from the ring and to save it with a unit protection arrangement, and then go forward to grade the ring as in the case of a single supply.

GROUND FAULT PROTECTION

In the foregoing paragraph, care has been primarily orientated towards line fault overcurrent protection. More sensitive protection against ground short circuit currents can be accomplished by utilizing a protection relay that acts only to the residual system current, since a residual component is available only when short circuit current goes to ground. The ground fault protection relay is hence totally untouched by load currents, whether balanced or not, and can be provided a setting which is determined only by the equipment arrangement and the presence of unbalanced leakage or capacitance currents to ground. This is crucial consideration if settings of only a several percent of system rating are looked at, since leakage currents may generate a residual quantity of this magnitude.

On a whole, the low settings allowable for ground fault protection relays are very practical, as ground short circuits are not only the most frequent of all short circuits, but may be determined in magnitude by the neutral grounding impedance, or by

ground contact resistance. The residual element is extracted by linking the phase current transformers in parallel as shown in Figure 15. The simple arrangement shown in Figure 15(a) can be extended by linking overcurrent devices in the individual phase leads, as shown in Figure 15(b), and placing the ground fault protection relay between the star points of the protection relay group and the current transformers.

Line short circuit overcurrent protection relays are typically given on only two lines since these will sense any interphase short circuit; the arrangements to the ground short circuit protection relay are unaffected by this condition. The principal scheme is presented in Figure 15(c).

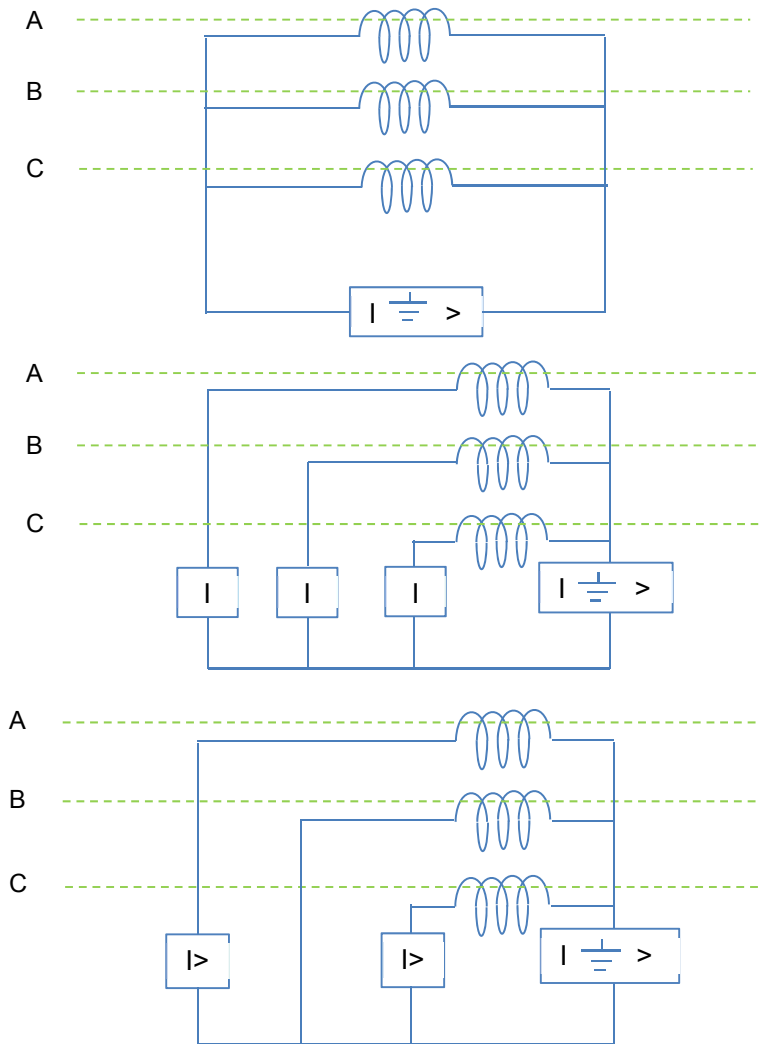


Figure 15. Residual arrangement of current transformers to ground fault protection relays

The common settings for ground fault protection relays are 30% to 40% of the total-load current or minimum ground short circuit current on the portion of the system being protected.

EFFECTIVE SETTING OF GROUND FAULT PROTECTION RELAYS

The primary setting of an overcurrent protection relay can typically be taken as the protection relay setting multiplied by the CT ratio. The CT can be presumed to keep a sufficiently precise ratio so that, conveyed as a percentage of rated current, the primary setting is directly relative to the protection relay setting. Nevertheless, this may not be correct for ground fault protection relay. The operation changes according to the applied protection relay technology.

STATIC, DIGITAL AND NUMERICAL PROTECTION RELAYS

When static, digital or numerical protection relays are applied the relatively low value and fixed variation of the protection relay burden over the protection relay setting range ends in the above statement being true. The variation of input burden with current should be verified to assure that the change is sufficiently small. If not, substantial errors may happen, and the setting process will have to follow that for electromechanical protection relays.

ELECTROMECHANICAL PROTECTION RELAYS

When using an electromechanical protection relay, the ground fault device typically will be similar to the phase devices. It will have a similar VA usage at setting, but will enforce a far greater burden at nominal or rated current, because of its lower setting. For instance, a protection relay with a setting of 20% will have an impedance of 25 times that of a similar device with a setting of 100%. Very often, this burden will surpass the rated burden of the current transformers. It might be believed that correspondingly higher current transformers should be applied, but this is conceived to be unneeded. The current transformers that handle the line burdens can trip the ground fault protection relay and the greater errors can be allowed for.

Not only is the exciting current of the energising current transformer relatively high due to the great burden of the ground fault protection relay, but the voltage drop on this

protection relay is impressed on the other current transformers of the paralleled group, whether they are transferring primary current or not. The overall exciting current is hence the product of the magnetizing loss in one CT and the other current transformers operating in parallel. The overall magnetising loss can be considerable in comparison with the working current of the protection relay, and in utmost situations where the setting current is small or the current transformers are of low performance, may even surpass the output to the protection relay. The 'effective setting current' in secondary terms is the sum of the protection relay setting current and the overall excitation loss. Strictly speaking, applied setting is the vector sum of the protection relay setting current and the overall exciting current, but the arithmetic sum is near sufficient, because of the similarity of power factors. It is informative to compute the applied setting for a range of setting values of a protection relay, a process that is shown in Table 5, with the results presented in Figure 16.

The effect of the comparatively high protection relay impedance and the summation of CT excitation losses in the residual circuit is increased still further by the fact that, at setting, the flux density in the current transformers matches to the bottom bend of the excitation characteristic. The exciting impedance under these circumstances is comparatively low, causing the ratio error to be big. The current transformer really enhances in operation with raised primary current, while the protection relay impedance reduces until, with an input current few times higher than the primary setting, the multiple of setting current in the protection relay is appreciably greater than the multiple of primary current setting which is implemented on the primary circuit. This causes the protection relay tripping time to be shorter than might be anticipated.

At still greater input currents, the CT operation falls off until eventually the output current ceases to grow considerably. Beyond this value of input current, function is additionally complicated by distortion of the output current waveform.

Table 5. Computation of actual relay settings

Protection relay plug setting		Coil voltage at setting (V)	Exciting current I_e	Applied setting	
%	Current (A)			Current (A)	%
5	0.25	12	0.583	2	40
10	0.5	6	0.405	1.715	34.3
15	0.75	4	0.3	1.65	33
20	1	3	0.27	1.81	36
40	2	1.5	0.17	2.51	50
60	3	1	0.12	3.36	67
80	4	0.75	0.1	4.3	86
100	5	0.6	0.08	5.24	105

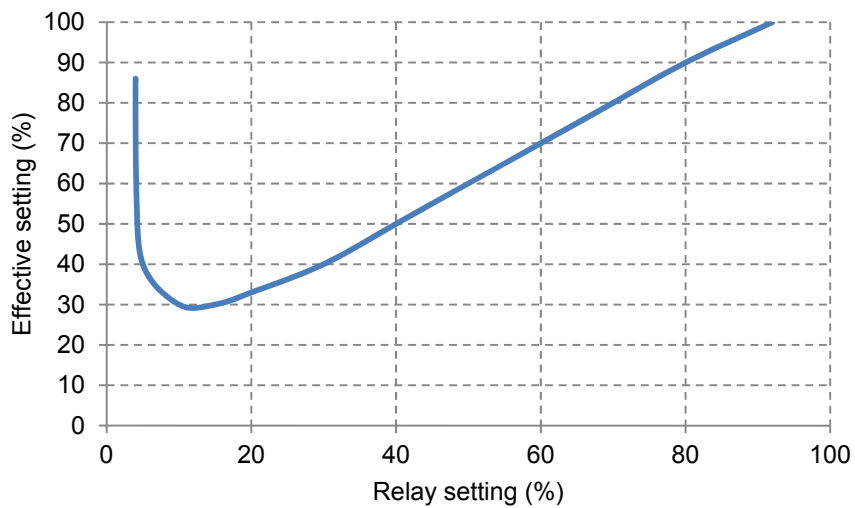
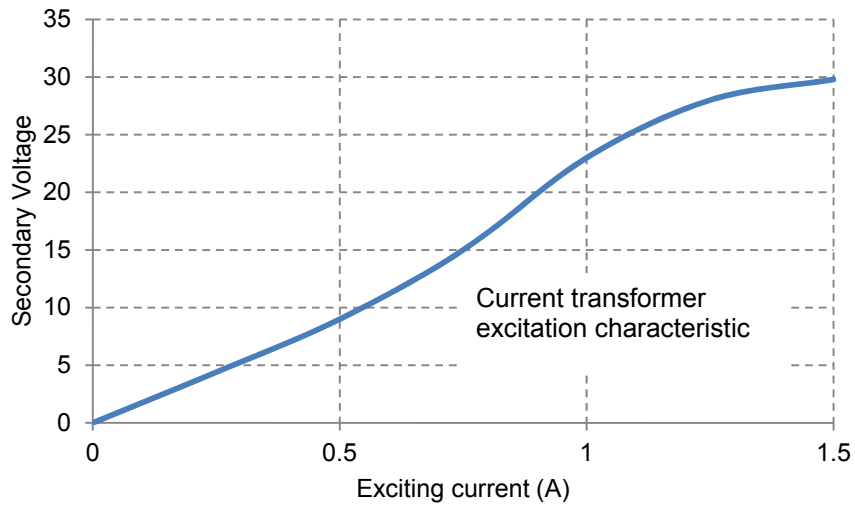


Figure 16. Applied setting of ground fault protection relay

TIME GRADING OF ELECTROMECHANICAL GROUND FAULT PROTECTION RELAYS

The time grading of ground fault protection relays can be organized in the same style as for phase short circuit protection relays. The time/primary current characteristic for electromechanical protection relays cannot be kept proportionate to the protection relay characteristic with anything like the precision that is feasible for phase short circuit protection relays. As mentioned above, the ratio error of the current transformers at protection relay setting current may be very big. It is evident that time grading of electromechanical ground fault protection relays is not simple issue as the process used for phase protection relays in Table 4. Either the above considerations must be considered with the errors computed for each current level, making the overall procedure much more challenging, or longer grading margins must be applied. Nevertheless, for other relay protection types, the process used for line fault protection relays can be applied.

SENSITIVE GROUND FAULT RELAY PROTECTION

LV electrical systems are not typically grounded through impedance, due to the over-voltages that may take place and eventful safety considerations. HV electrical systems may be organized to suit such over-voltages, but not the majority of LV systems. Nevertheless, it is quite typical to ground HV electrical systems through impedance that fixes the ground fault current. Next, in some countries, the resistivity of the ground path may be great due to the nature of the earth itself (e.g. desert). A short circuit to ground not involving ground conductors may end in the transfer of only a small current, insufficient to trip a typical relay protection mechanism. A similar trouble also occurs in the case of broken line conductors, which, after coming down on to hedges or dry metalled roads, stay energised because of the low leakage current, and hence present a risk to life. To resolve the issue, it is mandatory to supply ground fault relay protection mechanism with a setting that is substantially lower than the normal line relay protection. This is not an issue for a modern digital or numerical protection relay. Nevertheless, older electromechanical or static protection relays may introduce problems due to the great effective burden they may present to the CT.

The needed sensitivity cannot typically be given by means of conventional CTs. A core

balance current transformer (CBCT) will typically be utilized. The CBCT is a current transformer placed around all three line (and neutral if available) conductors so that the CT secondary current is relative to the residual (i.e. ground) current. Such a CT can be designed to have any convenient ratio suited for tripping a sensitive ground fault relay protection device. By use of such arrangements, ground fault settings down to 10% of the current rating of the line to be protected can be achieved.

Attention has to be taken to place a CBCT correctly in an underground cable circuit. If the underground cable sheath is grounded, the ground link from the underground cable gland/sheath junction has to be taken through the CBCT primary to assure that line-sheath short circuits are sensed. Figure 17 presents the correct and wrong arrangements. With the wrong arrangement, the short circuit current in the sheath is not detected as an unbalance current and therefore protection relay tripping does not happen.

The normal residual current that may go during normal operation limits the usage of non-directional sensitive ground fault relay protection. Such residual effects can happen due to unbalanced leakage or capacitance in the electrical system.

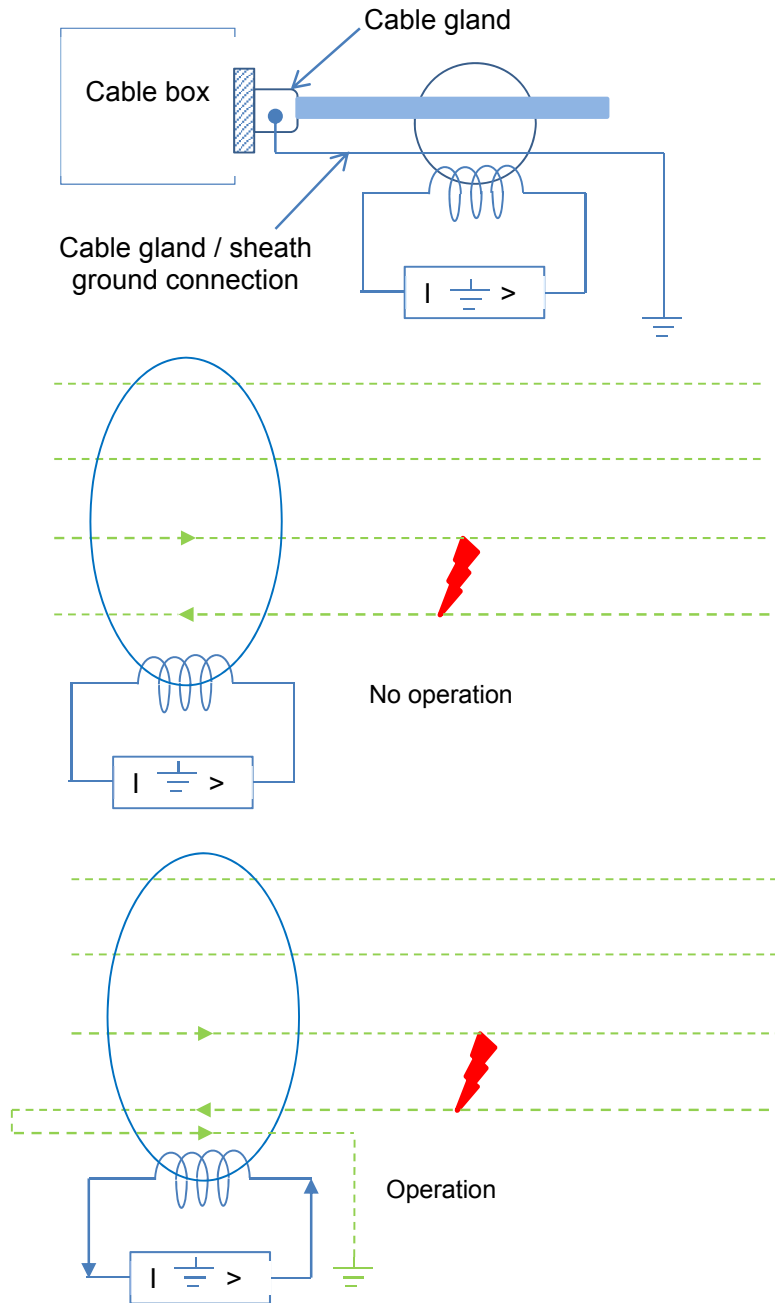


Figure 17. Installation of core balance current transformers (a) Physical arrangement
 (b) Wrong placement (c) Correct placement

DIRECTIONAL GROUND FAULT OVERCURRENT RELAY PROTECTION

Directional ground fault overcurrent has to be used in the following cases:

- for ground fault protection where the overcurrent relay protection is by directional protection relays
- in insulated-ground power networks
- in Petersen coil grounded power networks
- where the sensitivity of sensitive ground fault relay protection is deficient – application of a directional ground fault protection relay may give a higher sensitivity

The protection relay devices, previously mentioned as phase short circuit elements, react to the flow of ground fault current, and it is crucial that their directional reaction is adequate for this situation.

PROTECTION RELAY CONNECTIONS

The residual current is extracted as presented in Figure 15. Since this current may be gained from any line, to get a directional response it is mandatory to get an adequate quantity to polarize the protection relay. In digital or numerical protection relays, there are typically two given options.

RESIDUAL VOLTAGE

A suited amount is the residual voltage of the system. This residual voltage is the vector sum of the individual line voltages. If the secondary windings of a three-line, five limb voltage transformer or three single-line units are linked in broken delta, the voltage built up across its terminals will be the vector sum of the line to earth voltages and therefore the residual voltage of the electrical system, as presented in Figure 18.

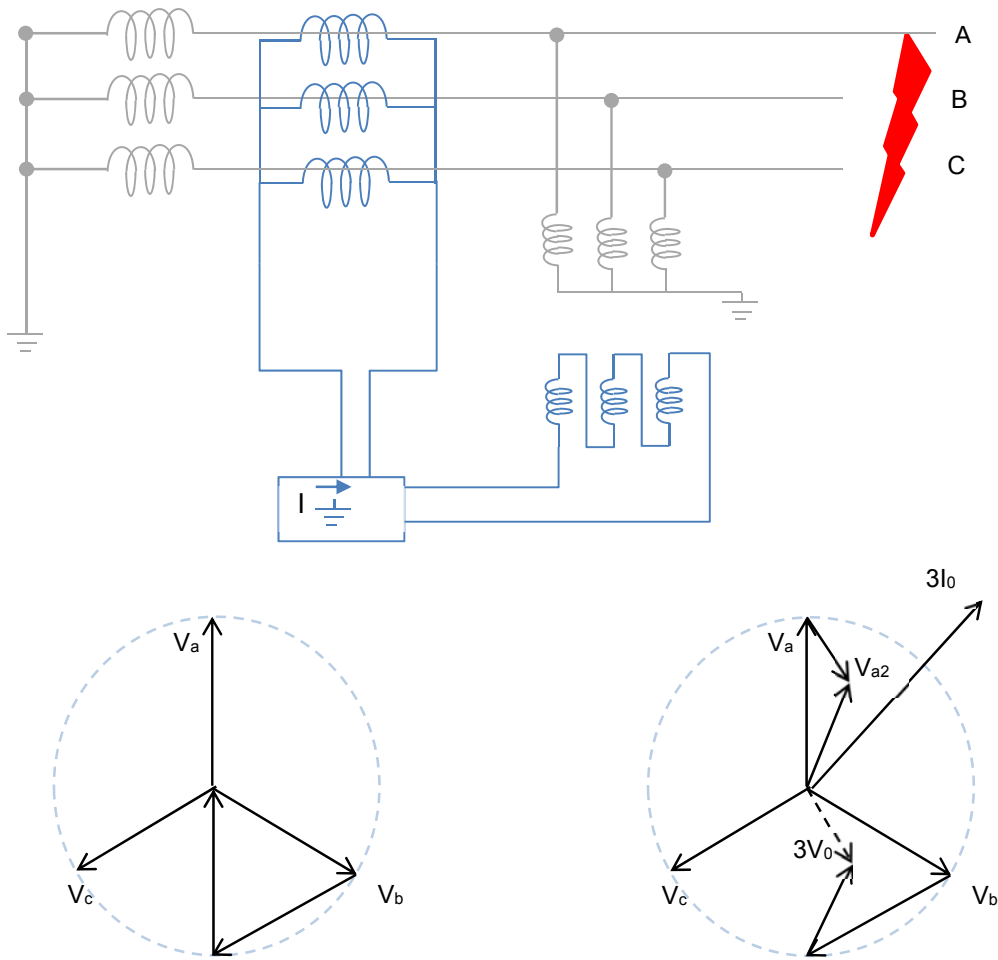


Figure 18. Voltage polarized directional ground fault protection relay (a) Protection relay links (b) Balanced system (zero residual volts) (c) Unbalanced system phase A to earth fault ($3V_0$ residual volts)

The primary star point of the VT has to be grounded. Nevertheless, a three-line, three limb VT is not suitable, as there is no path for the residual magnetic flux.

When the main voltage transformer related with the high voltage system is not supplied with a broken delta secondary winding to polarize the directional ground short circuit protection relay, it is allowable to utilize three single-line interposing voltage transformers. Their primary windings are arranged in star, and their secondary windings are arranged in broken delta. For satisfactory functioning, nevertheless, it is required to assure that the main voltage transformers are of a suitable design to replicate the residual voltage and that the star point of the primary winding is directly

grounded. Also, the star point of the primary windings of the interposing voltage transformers has to be linked to the star point of the secondary windings of the main voltage transformers.

The residual voltage will be zero for balanced line voltages. For simple ground short circuit circumstances, it will be same to the depression of the faulted line voltage. In all situations the residual voltage is same to three times the zero sequence voltage drop on the source impedance and is hence shifted from the residual current by the characteristic angle of the source impedance. The residual quantities are applicable to the directional device of the ground short circuit protection relay. The residual current is phase offset from the residual voltage and therefore angle adjustment is needed. Generally, the current will lag the polarizing voltage. The grounding system arrangement also impacts the Relay Characteristic Angle (RCA), and the next settings are typical:

- Resistance-grounded system: 0° RCA
- Electrical distribution system, directly-grounded: -45° RCA
- Electrical transmission system, directly-grounded: -60° RCA

The different adjustments for distribution and transmission electrical systems come up from the various X/R ratios found in these systems.

NEGATIVE SEQUENCE CURRENT

The residual voltage at any system point may not be sufficient to polarize a directional protection relay, or the voltage transformers available may not meet the conditions for providing residual voltage. In these situations, negative sequence current can be applied as the polarizing quantity. The short circuit current direction is found out by cross comparison of the negative sequence voltage with the negative sequence current. The RCA has to be set based on the angle of the negative phase sequence source voltage.

GROUND FAULT RELAY PROTECTION ON INSULATED ELECTRICAL NETWORKS

Periodically, a power system is operated totally insulated from the ground. The benefit of this arrangement is that a single line-ground short circuit on the system does not cause any ground short circuit current to flow, and so the whole electrical system stays functional. The electrical system has to be made to resist high transient and steady-state over-voltages nevertheless, so its application is typically limited to low and medium voltage systems. It is important that sensing of a single line-ground short circuit is accomplished, so that the short circuit can be traced and corrected. While electrical system performance is unaffected for this situation, the occurrence of a second ground short circuit allows significant currents to flow.

The absence of ground short circuit current for a single line-ground short circuit evidently presents some challenges in short circuit current detection. Two techniques are available using modern protection relays.

RESIDUAL VOLTAGE

When a single line-ground short circuit happens, the healthy line voltages increase by a factor of 3 and the three phase voltages no longer have a vector sum of zero. Therefore, a residual voltage device can be utilized to sense the short circuit current. Nevertheless, the technique does not allow any discrimination, as the unbalanced voltage happens on the complete of the impacted portion of the electrical system. One benefit of this technique is that no CTs are needed, as voltage is being measured. Grading is a problem with this technique, since all protection relays in the impacted section will see the short circuit. It may be feasible to utilize definite-time grading, but in principle, it is not feasible to give completely discriminative protection using this method.

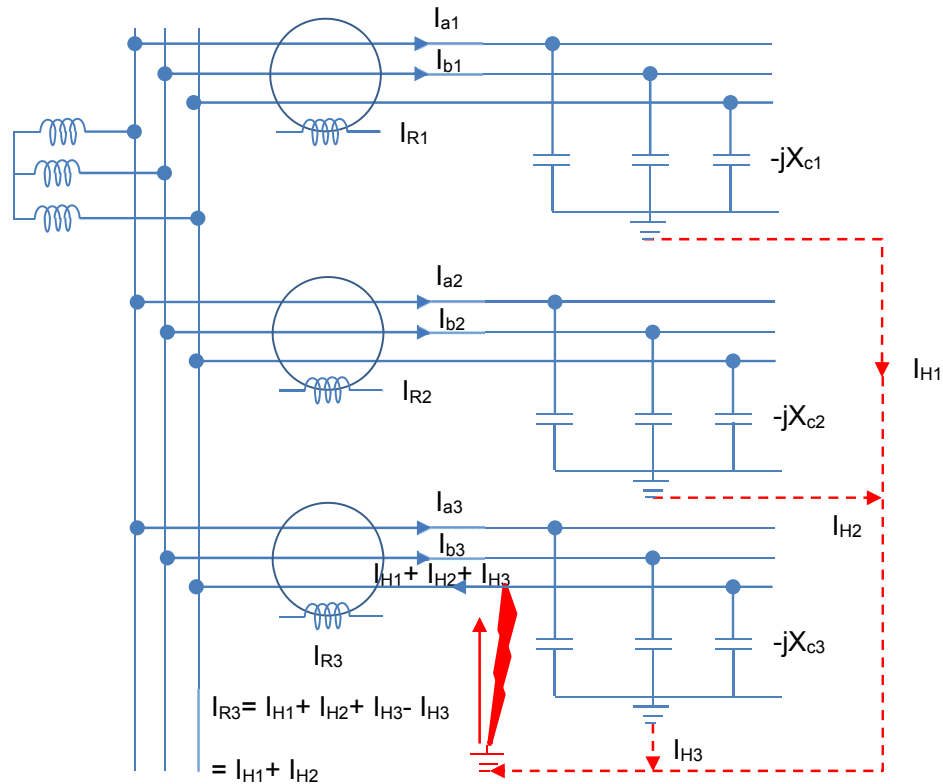


Figure 19. Current distribution in an insulated electrical system with a C phase-ground short circuit

SENSITIVE GROUND FAULT

This technique is generally used to MV electrical systems, as it relies on detection of the imbalance in the per-line charging currents that exist. Figure 19 presents the case that happens when a single line-ground short circuit is present. The protection relays on the healthy lines see the unbalance in charging currents for their own lines. The protection relay in the faulted line detects the charging currents in the rest of the electrical system, with the current of its' own lines cancelled out. Figure 20 presents the phasor graph.

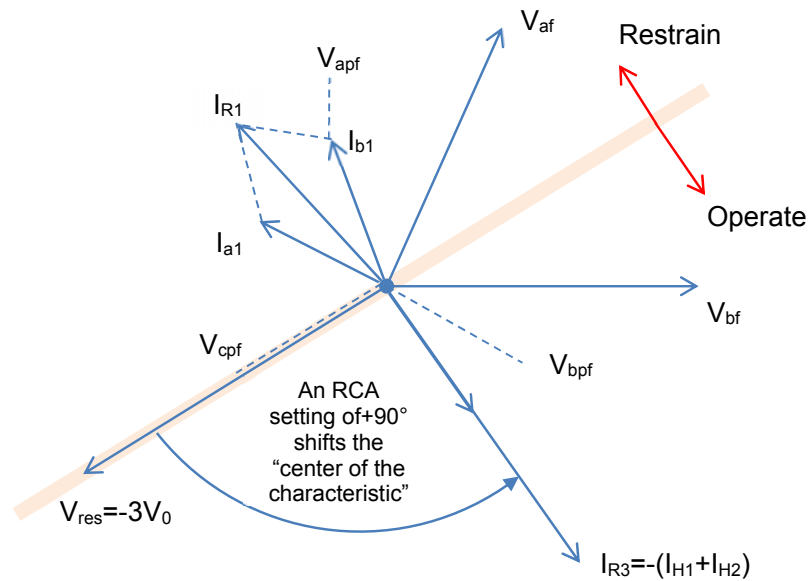


Figure 20. Phasor graph for insulated electrical system with C line-ground short circuit

Use of Core Balance CTs is mandatory. With reference to Figure 20, the unbalance current on the healthy lines lags the residual voltage by 90° . The charging currents on these lines will be $\sqrt{3}$ times the normal value, as the line-ground voltages have increased by this amount. The magnitude of the residual current is hence three times the steady-state charging current per line. As the residual currents on the live and faulted lines are in anti-phase, application of a directional ground fault protection relay can give the needed discrimination.

The polarizing quantity applied is the residual voltage. By shifting it by 90° , the residual current detected by the protection relay on the faulted line lies within the 'operate' area of the directional characteristic, while the residual currents on the healthy lines lie within the 'restrain' region. Therefore, the RCA needed is 90° . The protection relay setting has to lie between one and three times the per-line charging current.

This may be computed at the design stage, but check by means of tests on-site is common. A single line-ground short circuit is deliberately applied and the resulting currents noted; a procedure made simpler in a modern digital or numeric protection relay by the measurement facilities given. As previously noted, usage of such a fault for a short period does not call for any interruption to the electrical network, or short circuit currents, but the duration needs to be as short as possible to save against a

second such short circuit happening.

It is also feasible to dispense with the directional device if the protection relay can be programmed at a current value that lies between the charging current on the line to be protected and the charging current of the rest of the electrical system.

GROUND FAULT RELAY PROTECTION ON PETERSEN COIL GROUNDED ELECTRICAL NETWORKS

Petersen Coil grounding is a special arrangement of high impedance grounding. The electrical system is grounded via a reactor, whose reactance is designed to be same to the complete electrical system capacitance to ground. Under this condition, a single line-ground short circuit does not end in any ground fault current in steady state operation. Hence, the impact is similar to having an insulated electrical system. The effectiveness of the arrangement depends on the precision of tuning of the reactance value – modifications in system capacitance (for example, due to electrical system configuration variations) demand modifications to the coil reactance. In reality, absolute matching of the coil reactance to the electrical system capacitance is hard to accomplish, so that a small ground short circuit current will flow. Petersen Coil grounded electrical systems are typically found in locations where the electrical system consists dominantly of rural overhead transmission lines, and are especially useful in locations subject to a high incidence of transient short circuits.

To understand how to exactly use ground short circuit protection to such electrical systems, system behaviour underground fault conditions has to be understood. Figure 21 presents a basic electrical network grounded through a Petersen Coil. The formulas clearly present that, if the reactor is precisely tuned, no ground fault current will flow.

Figure 22 presents a radial distribution system grounded using a Petersen Coil. One distribution feeder has a line-ground short circuit on phase C. Figure 23 presents the resulting phasor graphs, presuming that no resistance is present. In Figure 23(a), it can be noted that the short circuit causes the healthy line voltages to increase by a factor of $\sqrt{3}$ and the charging currents lead the voltages by 90° .

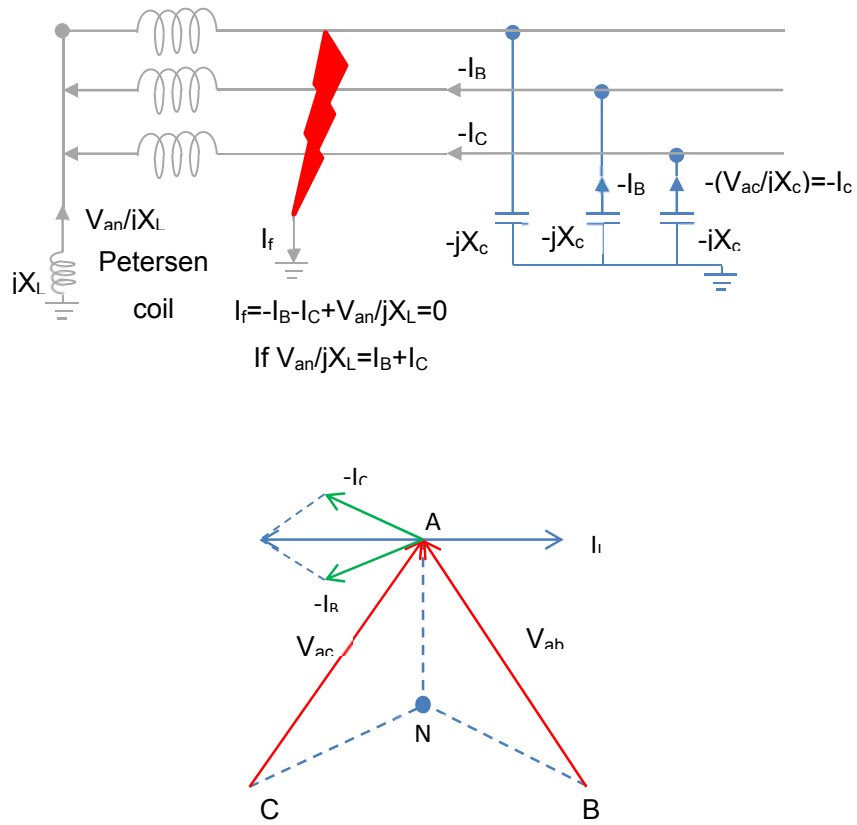


Figure 21. Ground short circuit in Petersen coil grounded electrical system

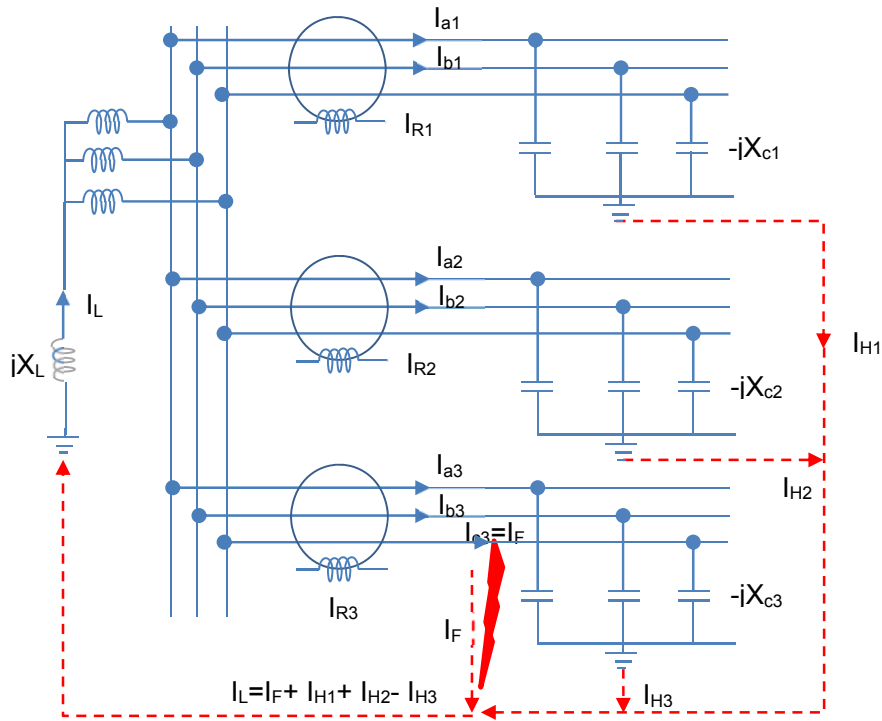


Figure 22. Distribution of currents during a C line-ground fault-radial distribution electrical system

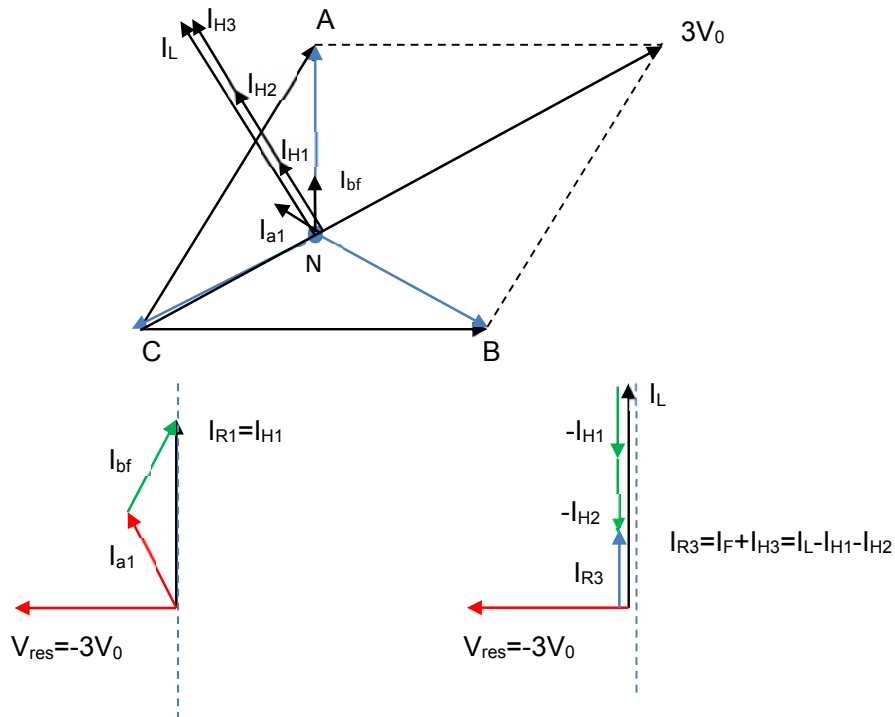
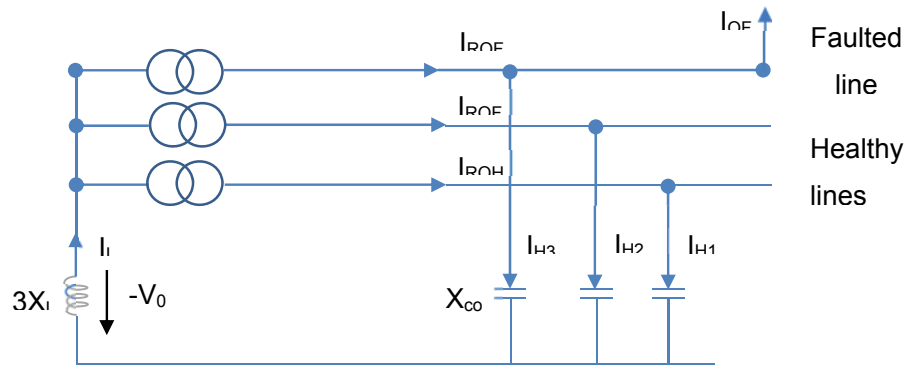


Figure 23. C line-ground short circuit in Peterson Coil grounded electrical system: theoretical situation-no resistance present in X_L or X_C (a) Capacitive and inductive currents (b) Unfaulted feeder (c) Faulted feeder

Utilizing a CBCT, the unbalance currents detected on the healthy transmission lines can be seen to be a simple vector addition of I_{a1} and I_{b1} and this lies at precisely 90° lagging to the residual voltage (as shown in Figure 23(b)). The magnitude of the residual current I_{R1} is same to three times the steady-state charging current per line. On the faulted transmission line, the residual current is same to $I_L - I_{H1} - I_{H2}$, as presented in Figure 23(c) and more clearly by the zero sequence network of Figure 24.

Nevertheless, in real situations, resistance is there and Figure 25 presents the resulting phasor graphs. If the residual voltage V_{res} is utilized as the polarising voltage, the residual current is phase shifted by an angle lower than 90° on the faulted transmission line and higher than 90° on the healthy transmission lines. Therefore, a directional protection relay can be applied, and with an RCA of 0° , the live transmission line residual current will fall in the ‘restrain’ section of the protection relay characteristic while the faulted circuit residual current falls in the ‘operate’ section.



Where:

I_{ROF} – Residual current on faulted line
 I_{ROH} – Residual current on healthy line

Hence, it can be seen that:

$$I_{OF} = I_L - I_{H1} - I_{H2} - I_{H3}$$

$$I_{ROF} = I_{H3} + I_{OF}$$

So:

$$I_{ROF} = I_L - I_{H1} - I_{H2}$$

Figure 24. Zero sequence electrical network presenting residual currents

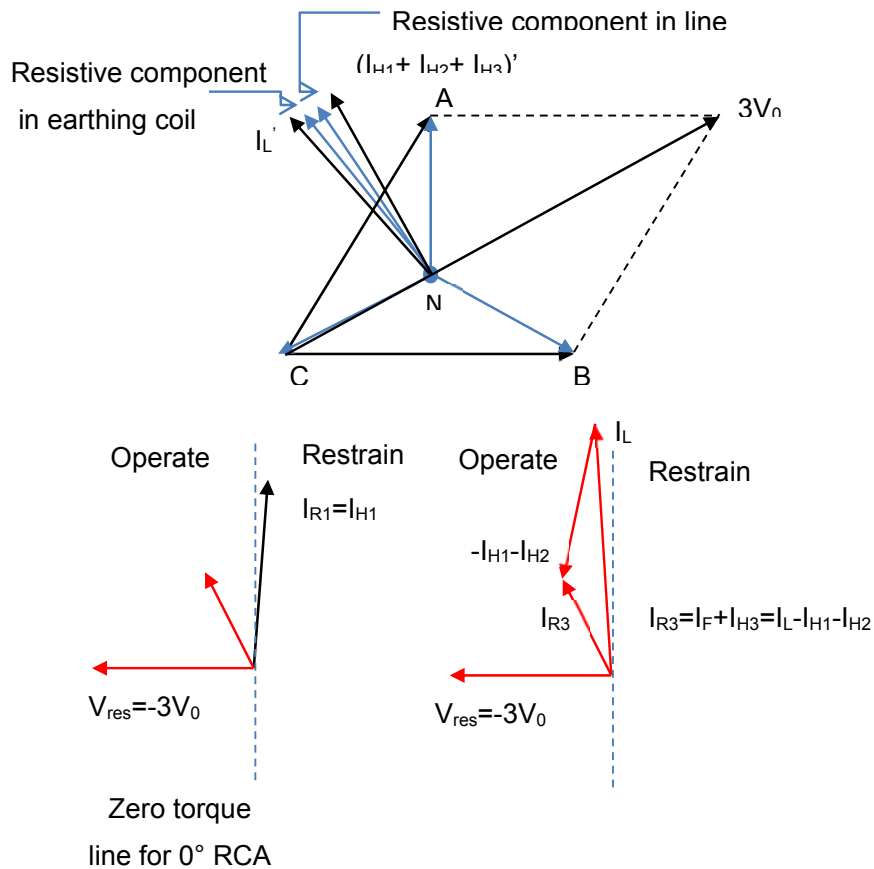


Figure 25. C line-ground short circuit in Petersen Coil grounded network: realistic situation with resistance present in X_L or X_C (a) Capacitive and inductive currents with resistive components (b) Unfaulted circuit (c) Faulted circuit

Usually, a resistance is intentionally placed in parallel with the Petersen Coil to make sure a measurable ground short circuit current and increase the angular difference between the residual signals to help protection relay application. Having demonstrated that a directional protection relay can be applied, two options are available for the method of protection element that can be used – sensitive ground short circuit and zero sequence watt-metric.

SENSITIVE GROUND SHORT CIRCUIT PROTECTION

To use this form of relay protection, the protection relay has to meet two requirements:

- current measurement setting capable of being set to very low figures

- an RCA of 0° , and capable of fine adjustment around this figure

The sensitive current component is needed because of the very low current that may flow – so adjustments of less than 0.5% of rated current may be needed. Nevertheless, as compensation by the Petersen Coil may not be complete, low levels of steady-state ground short circuit current will go and raise the residual current detected by the protection relay. Typically applied setting value is the per line charging current of the circuit being protected. Fine adjustment of the RCA is also needed around the 0° setting, to compensate for coil and circuit resistances and the performance of the CT applied. In reality, these settings are best implemented on site through careful application of short circuits and keeping record of the resulting currents.

SENSITIVE WATTMETRIC PROTECTION

It can be noted in Figure 25 that a small angular difference exists between the spill current on the live and faulted transmission lines. Figure 26 presents how this angular difference provides increase to active components of current which are in anti-phase to each other.

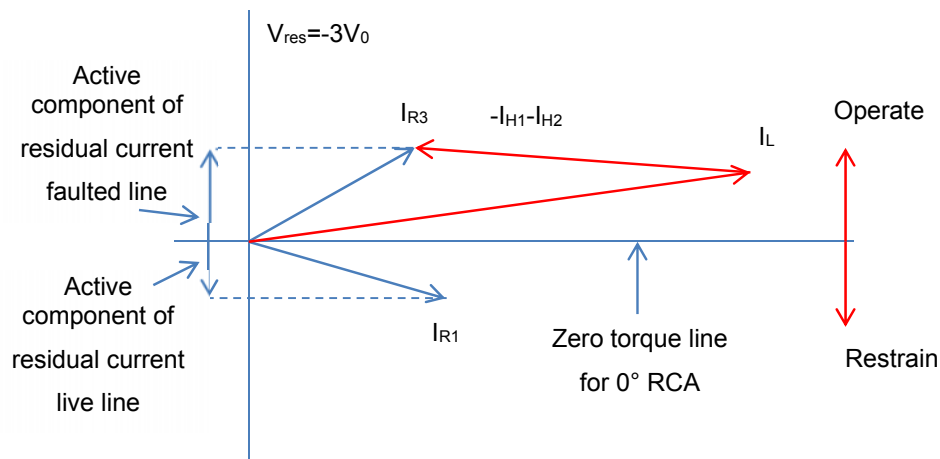


Figure 26. Resistive components of spill current

Accordingly, the active portions of zero sequence power will also lie in similar planes and a protection relay able to sense active power can make a discriminatory call. If the watt-metric portion of zero sequence power is sensed in the forward direction, it suggests a short circuit on that transmission line, while a power in the reverse direction

shows a short circuit elsewhere on the electrical system. This protection arrangement is more popular than the sensitive ground short circuit arrangement, and can give higher security against false operation due to spurious CBCT output under non-ground short circuit conditions. Watt-metric power is computed using residual measures instead of zero sequence ones. The final figures are hence nine times the zero sequence quantities as the residual figures of current and voltage are each three times the corresponding zero sequence figures. The formula applied is:

$$V_{res} \times I_{res} \times \cos(\varphi - \varphi_c) = 9 \times V_0 \times I_0 \times \cos(\varphi - \varphi_c) \quad (5)$$

Where

V_{res} – residual voltage

I_{res} – residual current

V_0 – zero sequence voltage

I_0 – zero sequence current

φ – angle between V_{res} and I_{res}

φ_c – protection relay characteristic angle setting

The current and RCA adjustments are as for a sensitive ground short circuit protection relay

HI-Z – HIGH IMPEDANCE DOWNED CONDUCTOR RELAY PROTECTION

High impedance (“Hi-Z”) short circuits are typically determined as the unwanted contact of an electrical circuit with a nonconductive surface like asphalt road, sand, wooden fences or some other area or object which prevents the short circuit current to a level below that which can be sensed by conventional overcurrent and ground fault protection relays. In some situations even sensitive ground short circuit current relay protection cannot reliably sense such low levels of short circuit current transfer. Undetected high impedance short circuits such as downed conductors are unsafe for nearby staff, the public, and livestock. The main aim of clearing such short circuits is hence towards protection of human life and not towards the integrity and selectivity of the electrical power system. Hence, high-impedance short circuit detection is

becoming more and more important for utilities and relay protection engineers, as moral and legal challenges push them to take a greater care for all that may be in the proximity of electrical power assets.

The common short circuit scenario is where an overhead distribution conductor has fallen. As mentioned, non-conductive surfaces will try to stop the short circuit current which flows. This is due to their high resistivity, and the requirement for the ground short circuit current to go back to the generator, and a legitimate zero sequence current source. Generally, this will demand the current going back to the nearest adjacent grounded tower, for the return current then to go in any aerial ground wire. If the circuit has no ground wire, the short circuit current will need to return to the ground star-point of the upstream distribution transformer. In the situation of a line falling onto rock or sand, the challenge is made all the harder in that the initial contact surface, and many meters of short circuit current flow in the same material composition which can drastically fix the prospective short circuit current. In the situation of a conductor falling onto a fence, if the wood is dry this may have a great resistivity, but that great resistance may only apply for a several meters, until the current can go in moist soil underground.

Sand is a special problem, because once a feeder falls onto it and arc current strikes, the heat in the arc can induce clumps of the surrounding sand to turn to glass, which partly insulates the line from the ground. Asphalt roads too can pose short circuit detection issues due to the natural good insulating properties, particularly if the road is dry.

It has been pointed out that such a downed feeder will tend to strike a fault arc. This provides a real benefit in terms of sensing of such short circuits, because arcs have special characteristics:

- Arcs are rich in harmonics, with a persistence and randomness of the harmonic profile which is not commonly detected in normal load current.
- The heat and energy in the arc, plus remaining tension in the conductor, tend to induce movement of the line – this leads to randomness in the flow of

fundamental current too.

- On several surfaces, the heat from the arc will impact the insulating characteristics, and any moisture in the contact location – this will cause randomness in current harmonics, fundamental current, and the continuity of any short circuit current flow.

Modern line management protection relays provide numerical algorithms which act to (1) sustained intermittence in current flow, and (2) strange levels or preponderance of harmonics, to be used independently, or in combination, as a reliable arrangement to sense high impedance short circuits such as downed feeders. These arrangements can be directionalized using power-based methods.