POWER SYSTEM PROTECTION FUNDAMENTALS

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1. INTRODUCTION

Protection is the branch of electric power engineering concerned with the principles of design and operation of equipment (called 'relays' or 'protective relays') that detects abnormal power system conditions, and initiates corrective action as quickly as possible in order to return the power system to its normal state. The quickness of response is an essential element of protective relaying systems – response times of the order of a few milliseconds are often required. Consequently, human intervention in the protection system operation is not possible. The response must be automatic, quick and should cause a minimum amount of disruption to the power system. The entire subject is governed by these general requirements: correct diagnosis of trouble, quickness of response and minimum disturbance to the power system. To accomplish these goals, we must examine all possible types of fault or abnormal conditions which may occur in the power system. We must further examine the possibility that protective relaying equipment itself may fail to operate correctly, and provide for a backup protective function. It should be clear that extensive and sophisticated equipment is needed to accomplish these tasks.

2. THE NATURE OF RELAYING

We will now discuss certain attributes of relays which are inherent to the process of relaying. In general, relays do not prevent damage to equipment: they operate after some detectable damage has already occurred. Their purpose is to limit, to the extent possible, further damage to equipment, to minimize danger to people, to reduce stress on other equipment and, above all, to remove the faulted equipment from the power system as quickly as possible so that the integrity and stability of the remaining system is maintained.

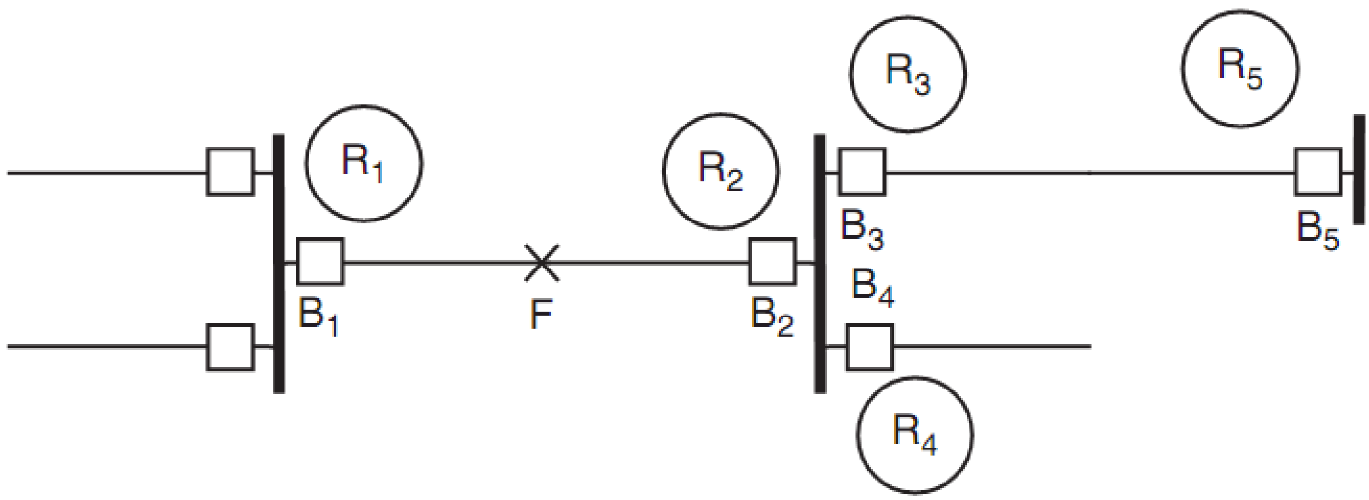
2.1. RELIABILITY, DEPENDABILITY AND SECURITY

Relays, in contrast with most other equipment, have two alternative ways in which they can be unreliable: they may fail to operate when they are expected to, or they may operate when they are not expected to. This leads to a two-pronged definition of reliability of relaying systems: a reliable relaying system must be dependable and secure.

<u>Dependability:</u> the measure of the certainty that the relays will operate correctly for all the faults for which they are designed to operate.
<u>Security:</u> the measure of the certainty that the relays will not operate incorrectly for any fault.

Example:

Consider the fault F on the transmission line shown in Figure 1.8. In normal operation, this fault should be cleared by the two relays R1 and R2 through the circuit breakers B1 and B2. If R2 does not operate for this fault, it has become unreliable through a loss of dependability. If relay R5 operates through breaker B5 for the same fault, and before breaker B2 clears the fault, it has become unreliable through a loss of security.



2.2. SELECTIVITY OF RELAYS AND ZONES OF PROTECTION

Relays usually have inputs from several current transformers (CTs), and the zone of protection is bounded by these CTs. The CTs provide a window through which the associated relays 'see' the power system inside the zone of protection. While the CTs provide the ability to detect a fault inside the zone of protection, the circuit breakers (CBs) provide the ability to isolate the fault by disconnecting all of the power equipment inside the zone. The relays will be considered to be secure if it responds only to faults within its zone of protection. Thus, a zone boundary is usually defined by a CT and a CB. When the CT is part of the CB, it becomes a natural zone boundary.

In order to cover all power equipment by protection systems, the zones of protection must meet the following requirements:

• All power system elements must be encompassed by at least one zone. Good relaying practice is to be sure that the more important elements are included in at least two zones.

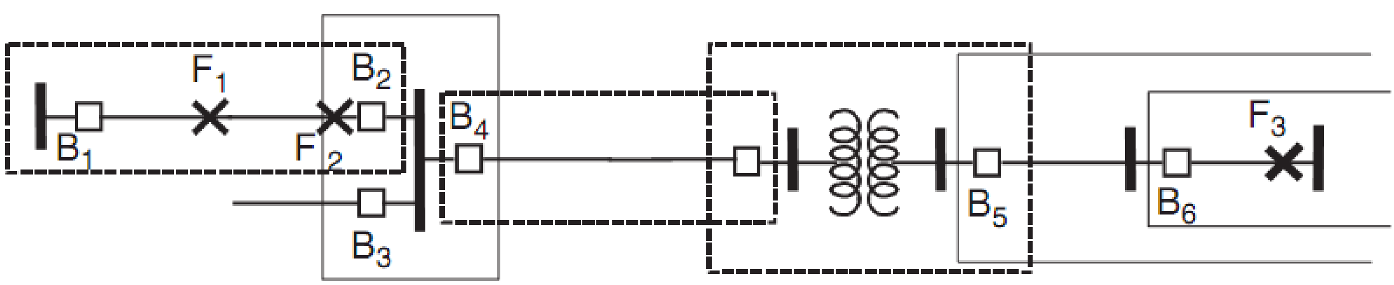
• Zones of protection must overlap to prevent any system element from being unprotected. Without such an overlap, the boundary between two non overlapping zones may go unprotected. The region of overlap must be finite but small, so that the likelihood of a fault occurring inside the region of overlap is minimized. Such faults will cause the protection belonging to both zones to operate, thus removing a larger segment of the power system from service.

A zone of protection may be closed or open. When the zone is closed, all power apparatus entering the zone is monitored at the entry points of the zone. Such a zone of protection is also known as 'differential', 'unit' or 'absolutely selective'.

Conversely, if the zone of protection is not unambiguously defined by the CTs, i.e. the limit of the zone varies with the fault current, the zone is said to be 'non-unit', 'unrestricted' or 'relatively selective'.

Example:

This fault lies in a closed zone, and will cause circuit breakers B1 and B2 to trip. The fault at F2, being inside the overlap between the zones of protection of the transmission line and the bus, will cause circuit breakers B1,B2,B3 and B4 to trip, although opening B3 and B4 is unnecessary. Both of these zones of protection are closed zones.



Now consider the fault at F3. This fault lies in two open zones. The fault should cause circuit breaker B6 to trip. B5 is the backup breaker for this fault, and will trip if for some reason B6 fails to clear the fault.

2.3. Relay speed

It is, of course, desirable to remove a fault from the power system as quickly as possible. However, the relay must make its decision based upon voltage and current waveforms which are severely distorted due to transient phenomena which must follow the occurrence of a fault.

Although the operating time of relays often varies between wide limits, relays are generally classified by their speed of operation as follows:

1. Instantaneous. These relays operate as soon as a secure decision is made. No intentional time delay is introduced to slow down the relay response.

2. Time delay. An intentional time delay is inserted between the relay decision time and the initiation of the trip action.

3. High speed. A relay that operates in less than a specified time. The specified time in present practice is 50 milliseconds (3 cycles on a 60 Hz system).

4. Ultra high speed. This term is not included in the Relay Standards but is commonly considered to be operation in 4 milliseconds or less.

2.4. Primary and backup protection

A protection system may fail to operate and, as a result, fail to clear a fault. It is thus essential that provision be made to clear the fault by some alternative protection system or systems. These alternative protection system(s) are referred to as duplicate, backup or breaker-failure protection systems.

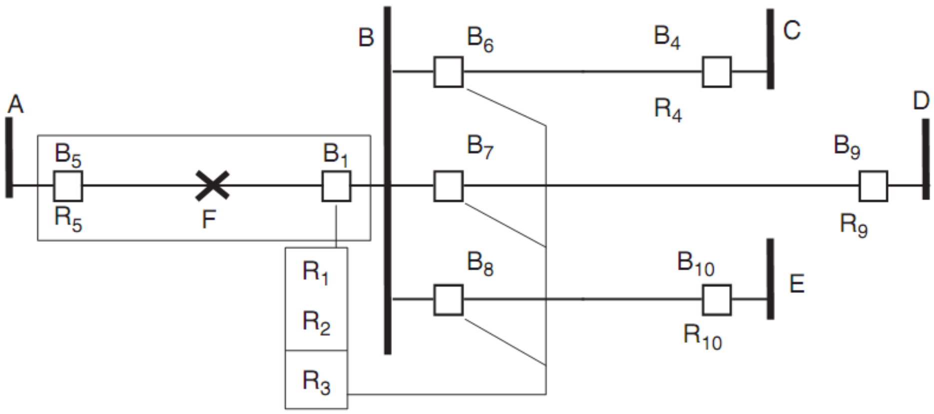
On EHV systems it is common to use duplicate primary protection systems in case an element in one primary protection chain may fail to operate. This duplication is therefore intended to cover the failure of the relays themselves.

On lower voltage systems, even the relays themselves may not be duplicated. In such situations, only backup relaying is used. Backup relays are generally slower than the primary relays and remove more system elements than may be necessary to clear a fault.

Breaker failure relays are a subset of local backup relaying that is provided specifically to cover a failure of the circuit breaker. This can be accomplished in a variety of ways. The most common, and simplest, breaker failure relay system consists of a separate timer that is energized whenever the breaker trip coil is energized and is de-energized when the fault current through the breaker disappears.

Example:

Consider the fault at location F in Figure. It is inside the zone of protection of transmission line AB. Primary relays R1 and R5 will clear this fault by acting through breakers B1 and B5. At station B, a duplicate primary relay R2 may be installed to trip the breaker B1 to cover the possibility that the relay R1 may fail to trip. R2 will operate in the same time as R1 and may use the same or different elements of the protection chain. For instance, on EHV lines it is usual to provide separate CTs, but use the same potential device with separate windings. The circuit breakers are not duplicated but the battery may be. On lower voltage circuits it is not uncommon to share all of the transducers and DC circuits. The local backup relay R3 is designed to operate at a slower speed than R1 and R2; it is probably set to see more of the system. It will first attempt to trip breaker B1 and then its breaker failure relay will trip breakers B5, B6, B7 and B8. This is local backup relaying, often known as breaker-failure protection, for circuit breaker B1. Relays R9, R10 and R4 constitute the remote backup protection for the primary protection R1. No elements of the protection system associated with R1 are shared by these protection systems, and hence no common modes of failure between R1 and R4, R9 and R10 are possible. These remote backup protections will be slower than R1, R2 or R3; and also remove additional elements of the power system – namely lines BC, BD and BE – from service, which would also de-energize any loads connected to these lines. A similar set of backup relays is used for the system behind station A.



2.5. SINGLE- AND THREE-PHASE TRIPPING AND RECLOSING

As a large proportion of faults on a power system are of a temporary nature, the power system can be returned to its prefault state if the tripped circuit breakers are reclosed as soon as possible. Manual reclosing is too slow for the purpose of restoring the power system to its pre-fault state when the system is in danger of becoming unstable. Automatic reclosing of circuit breakers is initiated by dedicated relays for each switching device, or it may be controlled from a substation or central reclosing computer.

- Some of the common interlocks for reclosing are the following:

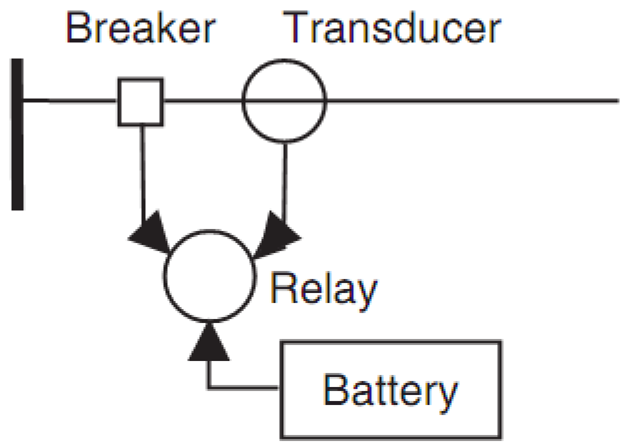
1. Voltage check. Used when good operating practice demands that a certain piece of equipment be energized from a specific side. For example, it may be desirable to always energize a transformer from its high-voltage side. Thus if a reclosing operation is likely to energize that transformer, it would be well to check that the circuit breaker on the low-voltage side is closed only if the transformer is already energized.

2. Synchronizing check. This check may be used when the reclosing operation is likely to energize a piece of equipment from both sides. In such a case, it may be desirable to check that the two sources which would be connected by the reclosing breaker are in synchronism and approximately in phase with each other. If the two systems are already in synchronism, it would be sufficient to check that the phase angle difference between the two sources is within certain specified limits. If the two systems are likely to be unsynchronized, and the closing of the circuit breaker is going to synchronize the two systems, it is necessary to monitor the phasors of the voltages on the two sides of the reclosing circuit breaker and close the breaker as the phasors approach each other.

3. Equipment check. This check is to ensure that some piece of equipment is not energized inadvertently.

Automatic reclosing can be high speed, or it may be delayed. The term high speed generally implies reclosing in times shorter than a second. Many utilities may initiate high-speed reclosing for some types of fault (such as ground faults), and not for others.

3. Elements of a protection system



3.1. Battery and DC supply

Since the primary function of a protection system is to remove a fault, the ability to trip a circuit breaker through a relay must not be compromised during a fault, when the AC voltage available in the substation may not be of sufficient magnitude. For example, a close-in three-phase fault can result in zero AC voltage at the substation AC outlets. Tripping power, as well as the power required by the relays, cannot therefore be obtained from the AC system, and is usually provided by the station battery.

The battery is also rated to maintain adequate DC power for 8–12 hours following a station blackout.

The battery is permanently connected through a charger to the station AC service, and normally, during steady-state conditions, it floats on the charger.

3.2. Circuit breaker

It would take too much space to describe various circuit breaker designs and their operating principles here. Instead, we will describe a few salient features about circuit breakers, which are particularly significant from the point of view of relaying.

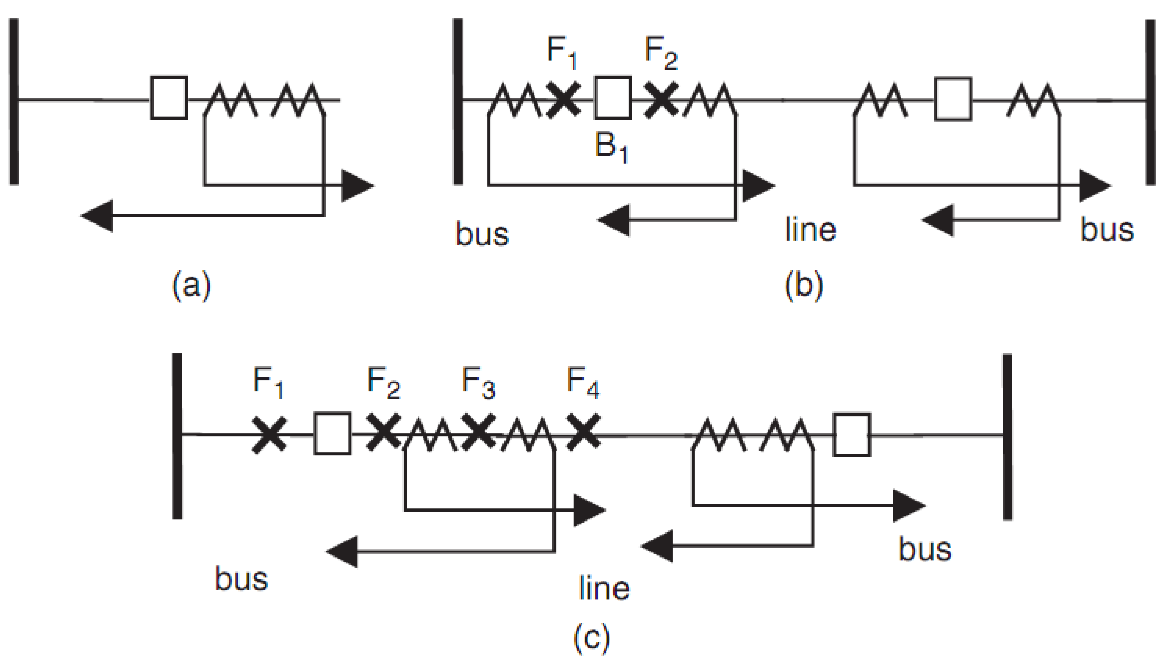
Knowledge of circuit breaker operation and performance is essential to an understanding of protective relaying. It is the coordinated action of both that results in successful fault clearing.

At the present time, an EHV circuit breaker can interrupt fault currents of the order of 105 A at system voltages up to 800 kV. It can do this as quickly as the first current zero after the initiation of a fault, although it more often interrupts at the second or third current zero.

As the circuit breaker contacts move to interrupt the fault current, there is a race between the establishment of the dielectric strength of the interrupting medium and the rate at which the recovery voltage reappears across the breaker contacts. If the recovery voltage wins the race, the arc re-ignites, and the breaker must wait for the next current zero when the contacts are farther apart.

Circuit breakers of several designs can be found in a power system, and it's name is according to the medium used to interrupt the fault current In addition, better insulating materials, better arc quenching systems and faster operating requirements resulted in a variety of circuit breaker characteristics: interrupting medium of oil, gas, air or vacuum; insulating medium of oil, air, gas or solid dielectric;

Operating mechanisms using impulse coil, solenoid, spring–motor–pneumatic or hydraulic.



Zone overlap with different types of CTs and circuit breakers

3.3. RELAY OPERATING PRINCIPLES

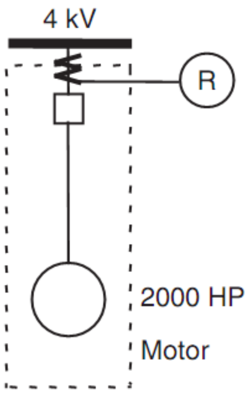
The fundamental problem in power system protection is to define the quantities that can differentiate between normal and abnormal conditions. This problem of being able to distinguish between normal and abnormal conditions is compounded by the fact that 'normal' in the present sense means that the disturbance is outside the zone of protection. This aspect – which is of the greatest significance in designing a secure relaying system – dominates the design of all protection systems.

3.3.1. Detection of faults

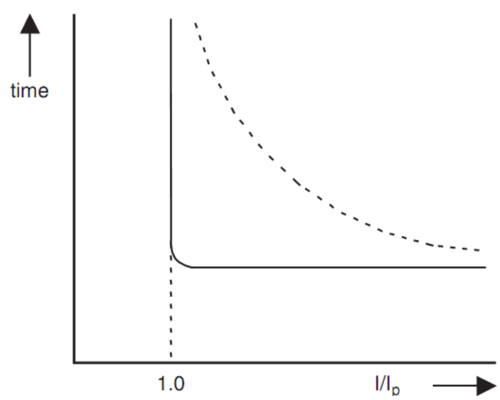
I. level detection

This is the simplest of all relay operating principles. As indicated above, fault current magnitudes are almost always greater than the normal load currents that exist in a power system.

The full load current for the motor is 245 A. Allowing for an emergency overload capability of 25%, a current of 1.25 × 245 = 306 A or lower should correspond to normal operation. The level above which the relay operates is known as the pickup setting of the relay. For all currents above the pickup, the relay operates, and for currents smaller than the pickup value, the relay takes no action. It is of course possible to arrange the relay to operate for values smaller.



Over current protection of motor



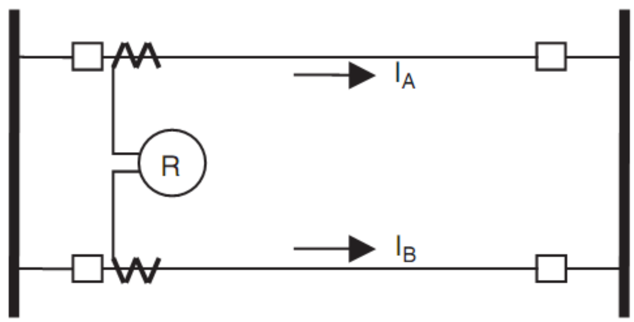
level detector relay characteristics

Note that: an under-voltage relay is an example of such a relay.

II. Magnitude comparison

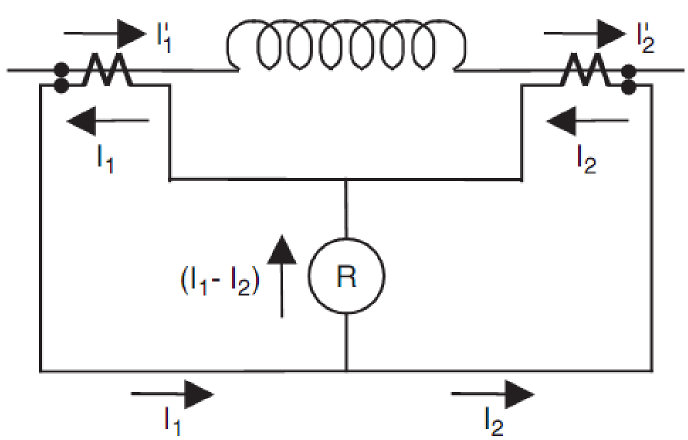
This operating principle is based upon the comparison of one or more operating quantities with each other.

The relay will operate when the current division in the two circuits varies by a given tolerance. Figure shows two identical parallel lines which are connected to the same bus at either end. One could use a magnitude comparison relay which compares the magnitudes of the two line currents IA and IB. If |IA| is greater than |IB|+ ∈ (where ∈ is a suitable tolerance), and line B is not open, the relay would declare a fault on line A and trip it.



III. Differential comparison

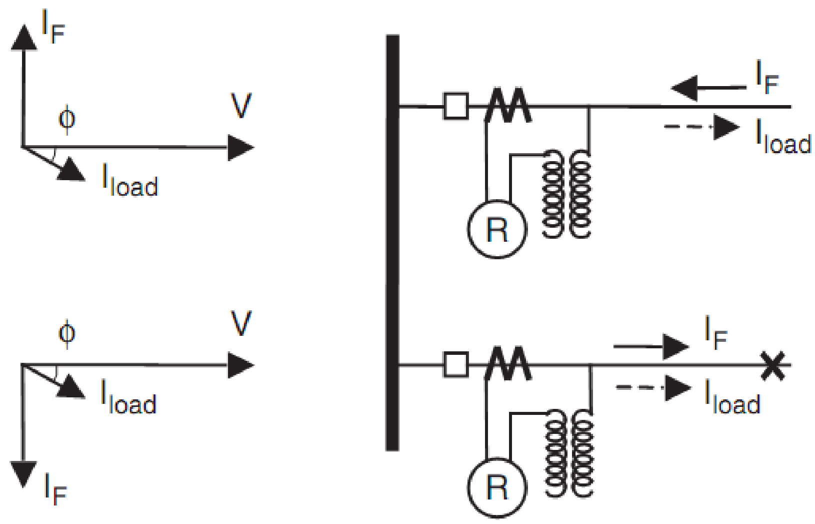
The concept of differential comparison is quite simple, and can be best understood by referring to the generator winding shown in Figure. As the winding is electrically continuous, current entering one end, I1, must equal the current leaving the other end, I2. One could use a magnitude comparison relay described above to test for a fault on the protected winding. When a fault occurs between the two ends, the two currents are no longer equal. Alternatively, one could form an algebraic sum of the two currents entering the protected winding, i.e. (I1 – I2), and use a level detector relay to detect the presence of a fault.



IV. Phase angle comparison

This type of relay compares the relative phase angle between two AC quantities. Phase angle comparison is commonly used to determine the direction of a current with respect to a reference quantity. For instance, the normal power flow in a given direction will result in the phase angle between the voltage and the current varying around its power factor angle, say approximately ±30◦.When power flows in the opposite direction, this angle will become (180◦ ± 30◦).

These relationships are explained for two transmission lines in the Figure. This difference in phase relationships created by a fault is exploited by making relays which respond to phase angle differences between two input quantities – such as the fault voltage and the fault current in the present example.



V. Distance measurement

Instead of comparing the local line current with the far end line current, the relay compares the local current with the local voltage.

This, in effect, is a measurement of the impedance of the line as seen from the relay terminal. An impedance relay relies on the fact that the length of the line (i.e. its distance) for a given conductor diameter and spacing determines its impedance.

VI. Pilot relaying

Certain relaying principles are based upon information obtained by the relay from a remote location. The information is usually – although not always – in the form of contact status (open or closed). The information is sent over a communication channel using power line carrier, microwave or telephone circuits.

VII. Harmonic content

Currents and voltages in a power system usually have a sinusoidal waveform of the fundamental power system frequency. There are, however, deviations from a pure sinusoid, such as the third harmonic voltages and currents produced by the generators that are present during normal system operation. Other harmonics occur during abnormal system conditions, such as the odd harmonics associated with transformer saturation, or transient components caused by the energization of transformers. These abnormal conditions can be detected by sensing the harmonic content through filters in electromechanical or solid-state relays, or by calculation in digital relays. Once it is determined that an abnormal condition exists, a decision can be made whether some control action is required.

VIII. Frequency sensing

Normal power system operation is at 50 or 60 Hz, depending upon the country. Any deviation from these values indicates that a problem exists or is imminent. Frequency can be measured by filter circuits, by counting zero crossings of waveforms in a unit of time or by special sampling and digital computer techniques.

Frequency-sensing relays may be used to take corrective actions which will bring the system frequency back to normal.

3.3.2. Relay designs

The following discussion covers a very small sample of the possible designs and is intended only to indicate how parameters required for fault detection and protection can be utilized by a relay. Specific details can be obtained from manufacturers' literature.

Relays are devices requiring low-level inputs (voltages, currents or contacts). They derive their inputs from transducers, such as current or voltage transformers, and switch contacts. They are fault-detecting devices only and require an associated interrupting device – a circuit breaker – to clear the fault.

3.3.2.1. Fuses

The fuse is a level detector, and is both the sensor and the interrupting device. It is installed in series with the equipment being protected and operates by melting a fusible element in response to the current flow. The melting time is inversely proportional to the magnitude of the current flowing in the fuse.

- The two major disadvantages of fuses are the following:

1. The single-shot feature referred to above requires that a blown fuse be replaced before service can be restored.

2. In a three-phase circuit, a single-phase-to-ground fault will cause one fuse to blow, de-energizing only one phase, permitting the connected equipment – such as motors – to stay connected to the remaining phases, with subsequent excessive heating and vibration because of the unbalanced voltage supply.

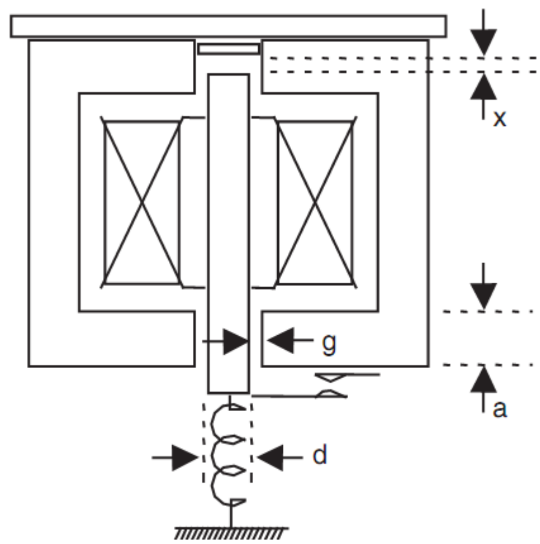
3.3.2.2. Electromechanical relays

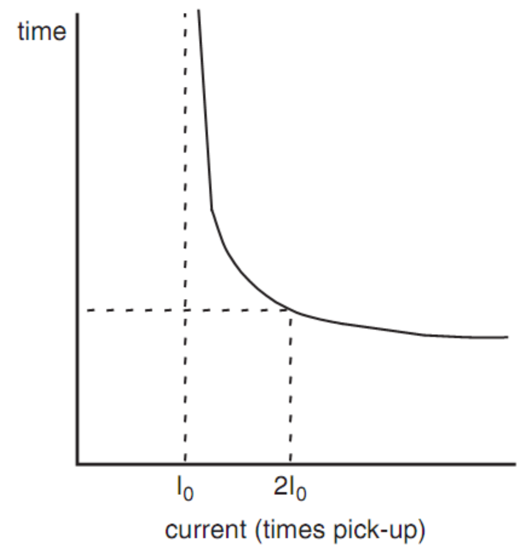
The early relay designs utilized actuating forces that were produced by electromagnetic interaction between currents and fluxes, much as in a motor.

In electromechanical relays, the actuating forces were created by a combination of the input signals, stored energy in springs and dashpots.

- Types of electromechanical relays:

1. Plunger-type relays





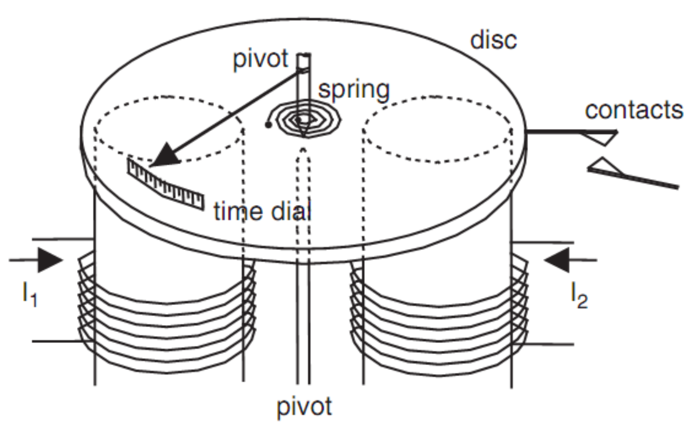
Operating time versus current of a plunger relay

2. Induction-type relays

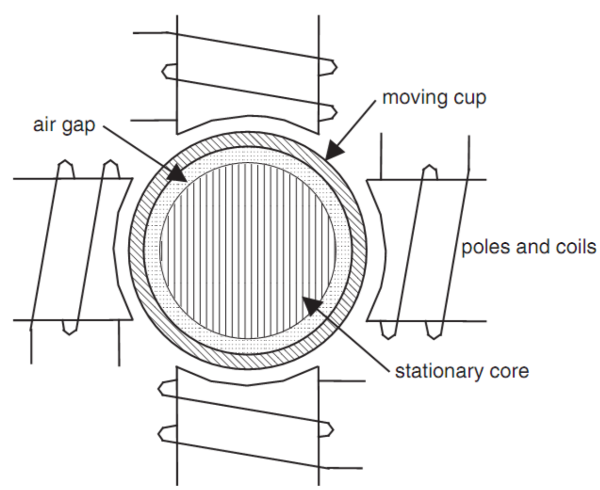
These relays are based upon the principle of operation of a single-phase AC motor. As such, they cannot be used for DC currents.

Induction-type relays require two sources of alternating magnetic flux in which the moving element may turn. The two fluxes must have a phase difference between them; otherwise, no operating torque is produced.

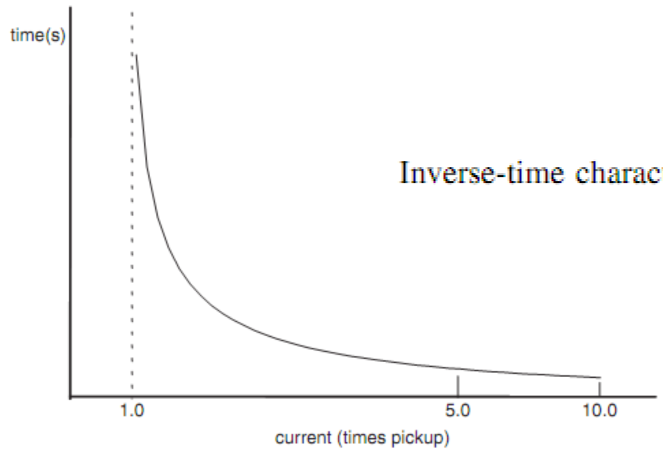
- Two variants of these relays are fairly standard: one with an induction disc and the other with an induction cup:



an induction disc relay.



Moving cup induction relay



Inverse-time characteristic of an induction disc overcurrent relay

Induction disc- or cup-type relays may be energized from voltage sources to produce under- or overvoltage relays. Also, by providing one of the coils with a current source and the other coil with a voltage source, the relay may be made to respond to a product of current and voltage inputs. It should be remembered that the phase angle between the currents in the current coil and the voltage coil appears in the torque equation.

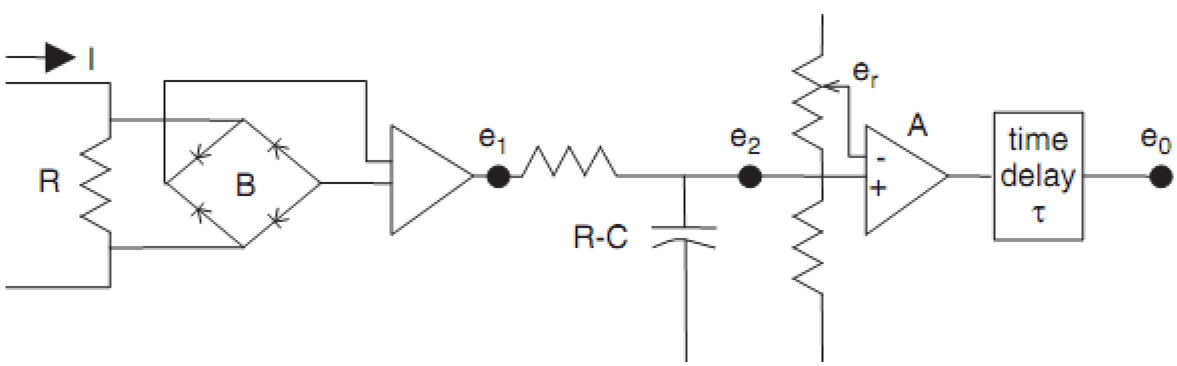
3.3.2.3. Solid-state relays

All of the functions and characteristics available with electromechanical relays can be performed by solid-state devices, either as discrete components or as integrated circuits.

Solid-state relay circuits may be divided into two categories: analog circuits that are either fault sensing or measuring circuits, or digital logic circuits for operation on logical variables.

- Some examples of circuits which can provide desired relay characteristics:

1. Solid-state instantaneous over-current relays

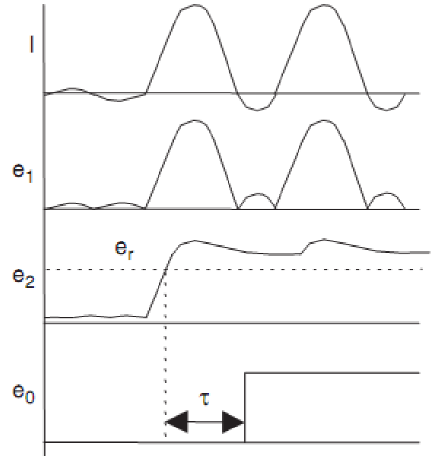


Possible circuit configuration for a solid-state instantaneous overcurrent relay

The input

operation: current I is passed through the resistive shunt R, full-wave rectified by the bridge rectifier B, filtered to remove the ripple by the R–C filter and applied to a high-gain summing amplifier A. The other input of the summing amplifier is supplied with an adjustable reference voltage e_r. When the input on the positive input of the summing amplifier exceeds the reference setting, the amplifier output goes high, and this step change is delayed by a time-delay circuit, in order to provide immunity against spurious transient signals in the input circuit.

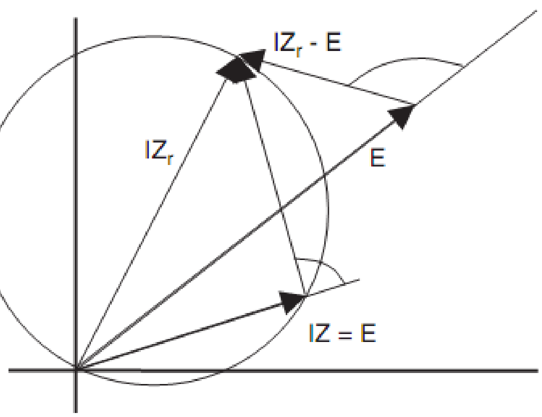
Waveforms of a solid-state instantaneous overcurrent relay



2. Solid-state distance (Mho) relays

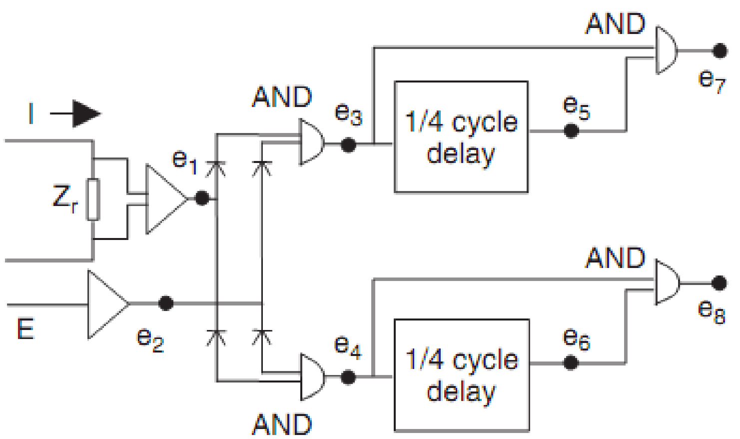
The performance equation of mho relay is $E - IZr\sin(\theta + \phi) = 0$,

The mho characteristic may be visualized as the boundary of the circle, with all points inside the circle leading to a trip and all points outside the circle producing a no-trip – or a block – signal.

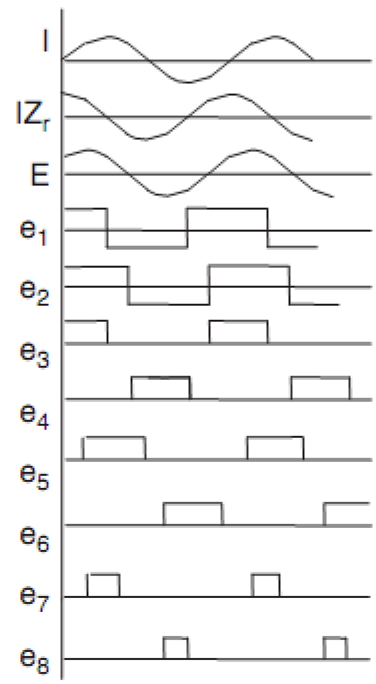


Phasor diagram for a mho distance relay

The negative of this signal, as well as the relay input voltage signal, are fed to high- gain amplifiers, which serve to produce rectangular pulses with zero-crossing points of the original sinusoidal waveform retained in the output, as shown in next Figure. The positive and negative portions of these square waves are isolated by two half-wave bridges, and supplied to a logic AND gate. Assuming steady-state sine wave current and voltage inputs, the outputs of the two AND gates are at logic level 1 for the duration equal to the phase angle between the phasors −IZr and E. If the angle is greater than 90◦, i.e. if the duration of the outputs of these two AND gates is greater than 4.16 ms (for a 60 Hz power system), the relay should operate



Possible circuit configuration for a solid-state distance relay



Waveforms in the circuit

3.3.2.4. Computer relays

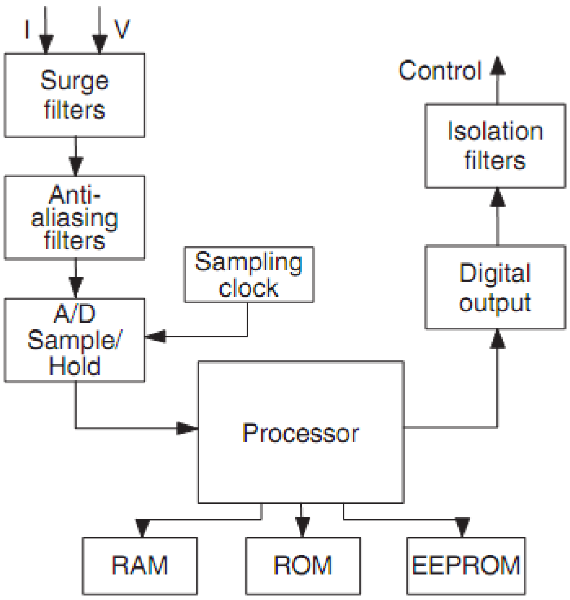
The observation has often been made that a relay is an analog computer. It accepts inputs, processes them electromechanically, or electronically, to develop a torque, or a logic output representing a system quantity, and makes a decision resulting in a contact closure or output signal. With the advent of rugged, high-performance microprocessors, it is obvious that a digital computer can perform the same function. Since the usual relay inputs consist of power system voltages and currents, it is necessary to obtain a digital representation of these parameters. This is done by sampling the analog signals, and using an appropriate computer algorithm to create suitable digital representations of the signals. This is done by a digital filter algorithm. The functional blocks shown in Figure represent a possible configuration for a digital relay.

The current and voltage signals from the power system are processed by signal conditioners consisting of analog circuits, such as transducers, surge suppression circuits and anti-aliasing filters, before being sampled and converted to digital form by the analog-to-digital converter. The sampling clock provides pulses at sampling frequency. Typical sampling frequencies in use in modern digital relays vary between 8 and 32 times the fundamental power system frequency. The analog input signals are generally frozen by a sample-and-hold circuit, in order to achieve simultaneous sampling of all signals regardless of the data conversion speed of the analog-to-digital converter. The relaying algorithm processes the sampled data to produce a digital output.

The relaying algorithm processes the sampled data to produce a digital output. The algorithm is, of course, the core of the digital relay, and a great many algorithms have been developed and published in the literature.

A major advantage of the digital relay was its ability to diagnose itself, a capability that could only be obtained in an analog relay – if at all – with great effort, cost and complexity. In addition, the digital relay provides a communication capability.

As digital relay investigations continued, and confidence mounted, another dimension was addedto the reliability of the protective system. The ability to adapt itself, in real time, to changing system conditions is an inherent feature in the software-dominated digital relay.



Major subsystems of a computer relay

3.4. TRANSDUCERS

The function of current and voltage transformers (collectively known as transducers) is to transform power system currents and voltages to lower magnitudes, and to provide galvanic isolation between the power network and the relays and other instruments connected to the transducer secondary windings.

The ratings of the secondary windings of transducers have been standardized, so that a degree of interchangeability among different manufacturers' relays and meters can be achieved. In the USA and several other countries, current transformer secondary windings are rated for 5 A, while in Europe a second standard of 1 A secondary is also in use. Voltage transformer secondary windings are rated at 120 V for phase-to-phase voltage connections, or, equivalently, at 69.3 V for phase-to-neutral connections.

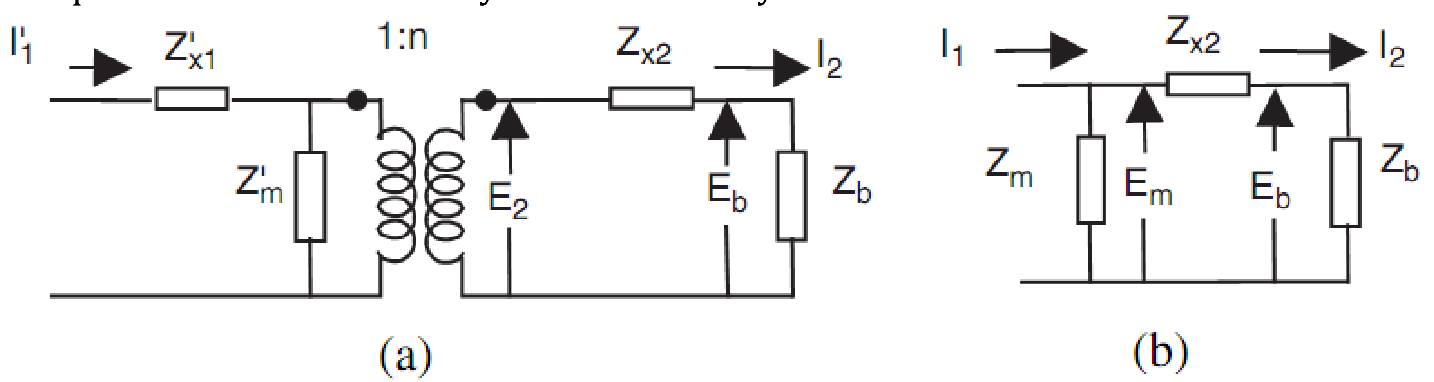
3.4.1. Current transformers:

Some current transformers are used for metering, and consequently their performance is of interest during normal loading conditions. Metering transformers may have very significant errors during fault conditions, when the currents may be several times their normal value for a very short time. Since metering functions are not required during faults, this is not significant.

Current transformers used for relaying are designed to have small errors during faulted conditions, while their performance during normal steady-state operation, when the relay is not required to operate, may not be as accurate.

Steady-state performance of current transformers

The different values of equivalent circuit parameters are responsible for the difference in performance between the various types of CTs.Their performance can be calculated from an equivalent circuit commonly used in the analysis of transformers.



Since the primary winding of a CT is connected in series with the power network, its primary current I1 is dictated by the network. Consequently, the leakage impedance of the primary winding Zx1 has no effect on the performance of the transformer, and may be omitted. Referring all quantities to the secondary winding, the simplified equivalent circuit of Figure 3.1(b) is obtained. Using the turns ratio (l : n) of the ideal transformer of Figure (a) one can write:

$$I_1 = \frac{I_1'}{n}, \qquad Z_m = n^2 Z_m'$$

The load impedance Z_b includes the impedance of all the relays and meters connected in the secondary winding, as well as that of the leads connecting the secondary winding terminals of the CT located in the substation yard to the protection equipment, which is located in the control house of the substation, Z_b is also known as the burden on the CT.

The voltage E_m across the magnetizing impedance Z_m is given by:

$$E_m = E_b + Z_{x2} I_2$$

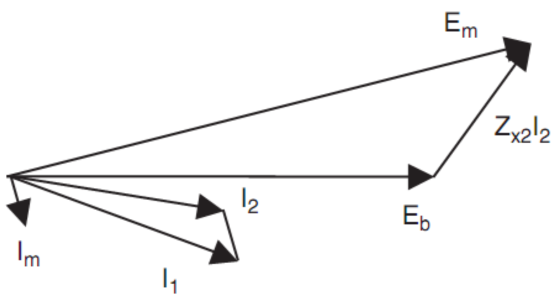
, and the magnetizing current I_m is given by:

$$I_m = \frac{E_m}{Z_m}$$

The primary current I1 (referred to the secondary winding) is given by:

$$I_1 = I_2 + I_m$$

CT phasor diagram



For small values of the burden impedance, E_b and E_m are also small, and consequently I_m is small. The per unit current transformation error defined by:

$$\varepsilon = \frac{I_1 - I_2}{I_1} = \frac{I_m}{I_1}$$

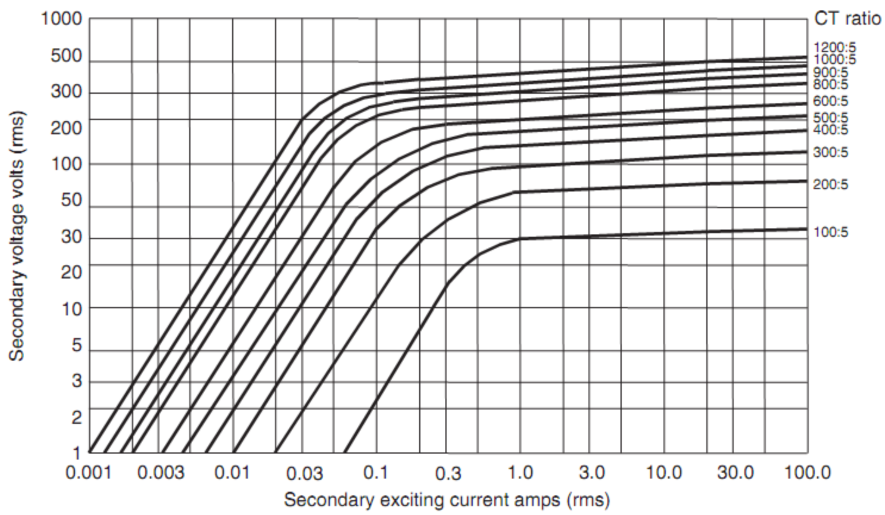
CTs work at their best when they are connected to very low impedance burdens. The CT error is presented in terms of a ratio correction factor R instead of the per unit error E discussed above. The ratio correction factor R is defined as the constant by which the

$$R = \frac{1}{1 - \varepsilon}$$

name plate turns ratio n of a current transformer must be multiplied to obtain the effective turn's ratio.

Since the magnetizing branch of a practical transformer is nonlinear, Z_m is not constant, and the actual excitation characteristic of the transformer must be taken into account in determining the factor R for a given situation. The magnetizing characteristic of a typical CT is shown in next Figure

Magnetizing characteristic of a typical CT

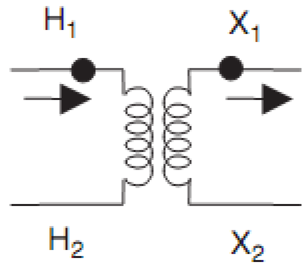


- <u>Standard class designation</u>

The CT performance may be made through its standard class designation as defined by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). The ANSI/IEEE class designation of a CT consists of two integer parameters, separated by the letter 'C' or 'T': for example, 10C400 or 10T300, The first integers describe the upper limit on the error made by the CT when the voltage at its secondary terminals is equal to the second integer, while the current in the transformer is 20 times its rated value, The letter 'C' in the class designation implies that the transformer design is such that the CT performance can be calculated, whereas the letter 'T' signifies some uncertainties in the transformer design, and the performance of the CT must be determined by testing the CT.

- <u>Polarity markings on CT windings</u>

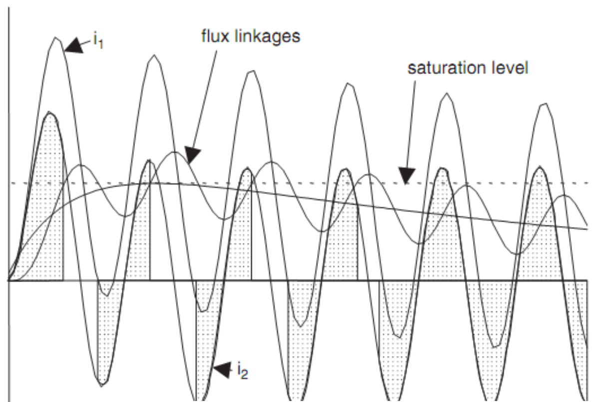
Polarity markings of transformer windings are a means of describing the relative directions in which the two windings are wound on the transformer core. The terminals identified by solid marks indicate the starting ends of the two windings, in a transformer, if one of the winding currents is considered to be flowing into the marked terminal, the current in the other winding should be considered to be leaving its marked terminal, An alternative way is to label the primary winding terminals H1 and H2, and the secondary winding terminals Xl and X2.H1 and X1 may then be assumed to have the polarity mark on them. Both of these conventions are shown in next Figure



Polarity markings of a CT

- <u>Transient performance of current transformers</u>

The performance of CTs when they are carrying the load current is not of concern as far as relaying needs are concerned. When faults occur, the current magnitudes could be much larger, the fault current may have substantial amounts of DC components and there may be remanence in the CT core. All of these factors may lead to saturation of the CT core, and cause significant distortion of the secondary current waveform.



Primary and secondary currents and core flux linkages of a CT

The important fact to be noted in Figure is the time behavior of the flux linkages. The DC component in the fault current causes the flux linkages to increase considerably above their steady- state peak. Now consider the effect of saturation. The dotted line in Figure represents the flux level at which the transformer core goes into saturation. As an approximation, assume that in the saturated region the magnetizing curve is horizontal, i.e. the incremental core inductance is zero. Thus, for the duration that is above the dotted line in Figure, it is held constant at the saturation level, and the magnetizing inductance L_m in the equivalent circuit of Figure becomes zero. As this short-circuits the load impedance, the secondary current for this period also becomes zero. This is represented by the non-shaded i_2 curve in Figure. It should be noted that the flux linkages will return to zero DC offset in time, so that the current transformer will get out of saturation after some time, depending upon the circuit parameters.

- <u>Special connections of current transformers</u>

1. Auxiliary current transformers:

Auxiliary current transformers are used in many relaying applications for providing galvanic separation between the main CT secondary and some other circuit. They are also used to provide an adjustment to the overall current transformation ratio.

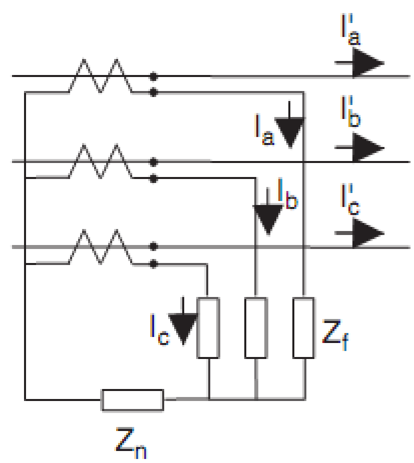
The auxiliary CT, however, makes its own contributions to the overall errors of transformation.

The burden connected into the secondary winding of the auxiliary CT is reflected in the secondary of the main CT.

2. Wye and delta connections:

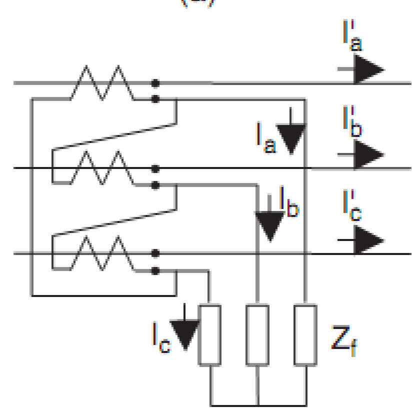
In three-phase circuits, it is often necessary to connect the CT secondaries in wye or delta connections to obtain certain phase shifts and magnitude changes between the CT secondary currents and those required by the relays connected to the CTs.

The wye connection shown in Figure (a) produces currents proportional to phase currents in the phase burdens Zf and a current proportional to 3I0 in the neutral burden Zn. No phase shifts are introduced by this connection>



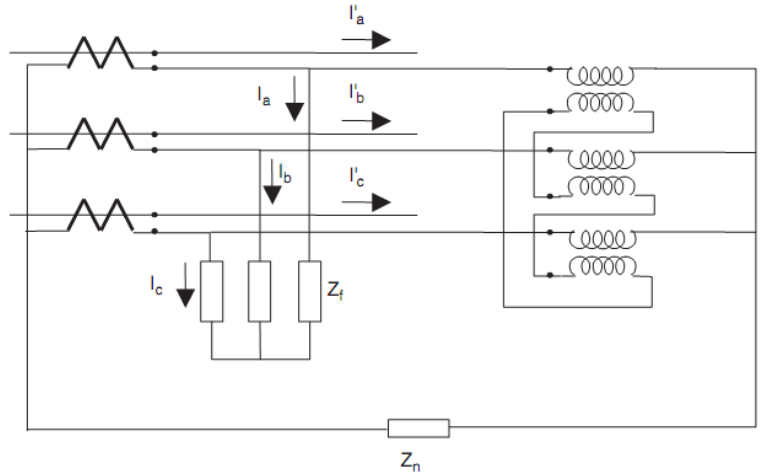
(a)

The delta connection shown in Figure 3.10(b) produces currents proportional to (Ia − Ib), (Ib − Ic)and(Ic − Ia) in the three burdens Zf. If the primary currents are balanced, (Ia − Ib) $=\sqrt{3}|Ia| \exp(j\pi/6)$, and a phase shift of 30° is introduced between the primary currents and the currents supplied to the burdens Zf. By reversing the direction of the delta windings, a phase shift of -30° can be obtained.



(b)

3. Zero-sequence current shunts:

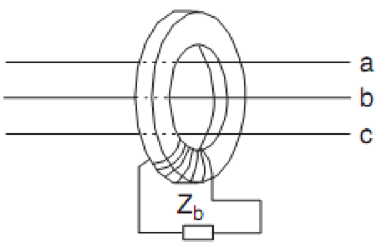


Zero-sequence current shunt

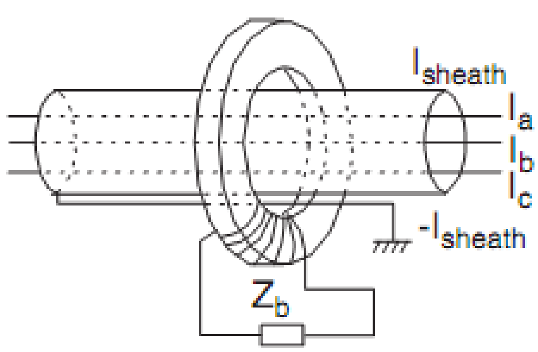
Recall the wye connection of CT secondaries Each of the phase burdens Zf carries phase currents, which include the positive, negative and zero-sequence components. Sometimes it is desired that the zero-sequence current be bypassed from these burdens. This is achieved by connecting auxiliary CTs which provide an alternative path for the zero-sequence current. This is illustrated in next Figure. The neutral of the main CT secondaries is not connected to the burden neutral.

4. Flux-summing CT:

It is possible to obtain the zero-sequence current by using a single CT, rather than by connecting the secondaries of three CTs. If three phase conductors are passed through the window of a toroidal CT.



it must be recognized that such a CT application is possible only in low-voltage circuits, where the three phase conductors may be passed through the CT core in close proximity to each other. If the three phase conductors are enclosed in a metallic sheath, and the sheath may carry some (or all) of the zero-sequence current, it must be compensated for by threading the sheathgrounding lead through the CT core.



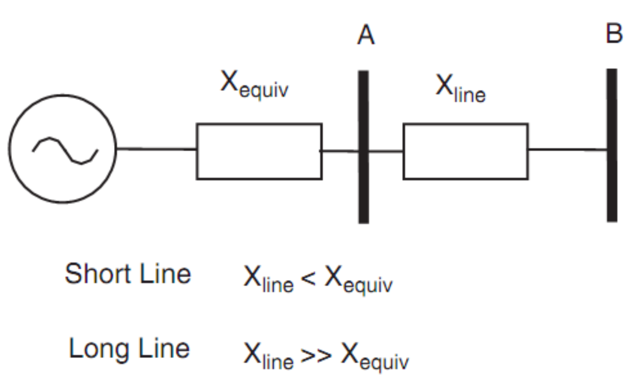
4. Protection of power system elements

4.1. Protection of transmission lines:

Transmission lines are primarily exposed to short circuits between phases or from phase to ground. This is also the main source of damage to all other electrical equipment. The range of the possible fault current, the effect of load, the question of directionality and the impact of system configuration are all part of the transmission line protection problem. The solution to this problem, therefore, is a microcosm of all other relaying problems and solutions. Since transmission lines are also the links to adjacent lines or connected equipment, the protection provided for the transmission line must be compatible with the protection of all these other elements. This requires coordination of settings, operating times and characteristics.

A radial system, i.e. one with a single generating source, can have fault current flowing in only one direction: from the source to the fault. In a loop or network, however, fault current can flow in either direction, and the relay system must be able to distinguish between the two directions.

The length of the line, as one would expect, has a direct effect on the setting of a relay, there is no appreciable impedance between the end of one line segment and the beginning of the next. A relay, therefore, cannot be set on fault current magnitude alone in order to differentiate between a fault at the end of one zone or the beginning of the next. The problem is further complicated if the line is short, that is, as shown in Figure, its impedance is much less than the source impedance. In such a case there is very little difference in current magnitude for a fault at one end of the line compared to a fault at the other. It is then difficult to set a relay so that it only protects its own line and does not overreach into the next.



In order of ascending cost and complexity, the protective devices available for transmission line protection are:

1. fuses.
2. sectionalizers, reclosers.
3. instantaneous overcurrent.
4. inverse, time delay, overcurrent.
5. directional overcurrent.
6. distance.
7. pilot.

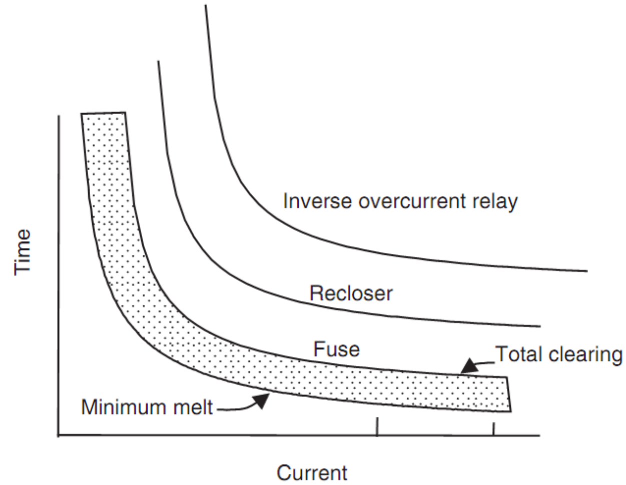
- ## Fuses, sectionalizers, reclosers:

The distribution system is divided into mains and laterals. The mains are three-phase systems providing the backbone of the distribution service; the laterals are single-phase taps connected to the mains. Industrial and commercial customers that require three-phase service are fed from the mains. Residential and smaller industrial customers are usually serviced by the laterals. It is the function of the distribution planning engineer to equalize the single-phase loads so the load at the substation is essentially balanced.

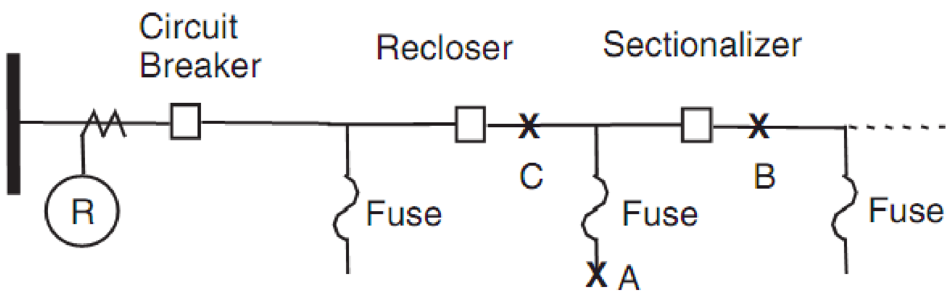
Figure shows a single-line representation of a typical distribution circuit. In practice, the horizontal feeder would be a three-phase main and each tap would be a single-phase load, each load coming from a different phase.

there is some concern over the safety and potential physical damage that could occur from a violent
type of failure. This has led to the application of current-limiting (CL) fuses, which drastically reduce the 'let-through' energy for a high-current fault compared to other types of fuse. The most commonly used protective device in a distribution circuit is the fuse. Fuse characteristics vary considerably from one manufacturer to another, and the specifics must be obtained from manufacturers' appropriate literature.
The interrupting devices, in addition to the fuse itself, are sectionalizers and reclosers. A sectionalizer cannot interrupt a fault. It 'counts' the number of times it 'sees' faultcurrent and opens after a preset number while the circuit is de-energized. A recloser has limited fault-interrupting capability and recloses automatically in a programmed sequence.

Referring to Figures, a fault at A should be cleared by the branch fuse, leaving service to the main line and to the other branches undisturbed. A fault at B should be cleared by the sectionalizer, but, since the sectionalizer cannot interrupt a fault, the actual clearing is performed by the recloser. The sectionalizer 'sees' the fault current, however, and registers one count. The recloser also sees the fault and trips, de-energizing the line. If the sectionalizer setting is '1' it will now open, allowing the recloser to reclose and restore service to the rest of the system. If the sectionalizer setting is more than '1', e.g. '2', the sectionalizer will not open after the first



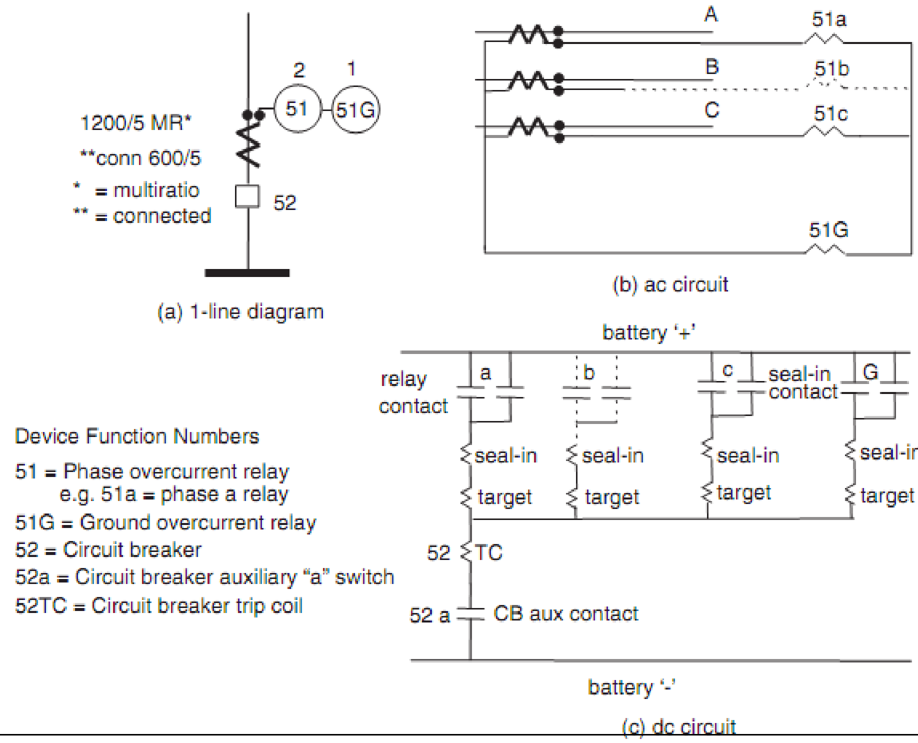
trip.Instead, the recloser recloses a second time. If the fault is still on, the sectionalizer will see a second count of fault current. The recloser will trip again, allowing the sectionalizer now to open, removing the fault, and the recloser will



successfully reclose, restoring service up to the sectionalizer. For a fault at C, the recloser trips and recloses as it is programmed to do. The sectionalizer does not see the fault and does not count.

- <u>Inverse, time-delay overcurrent relays</u>:

The principal application of overcurrent relays is on a radial system where they provide both phase and ground protection.



Setting rules:

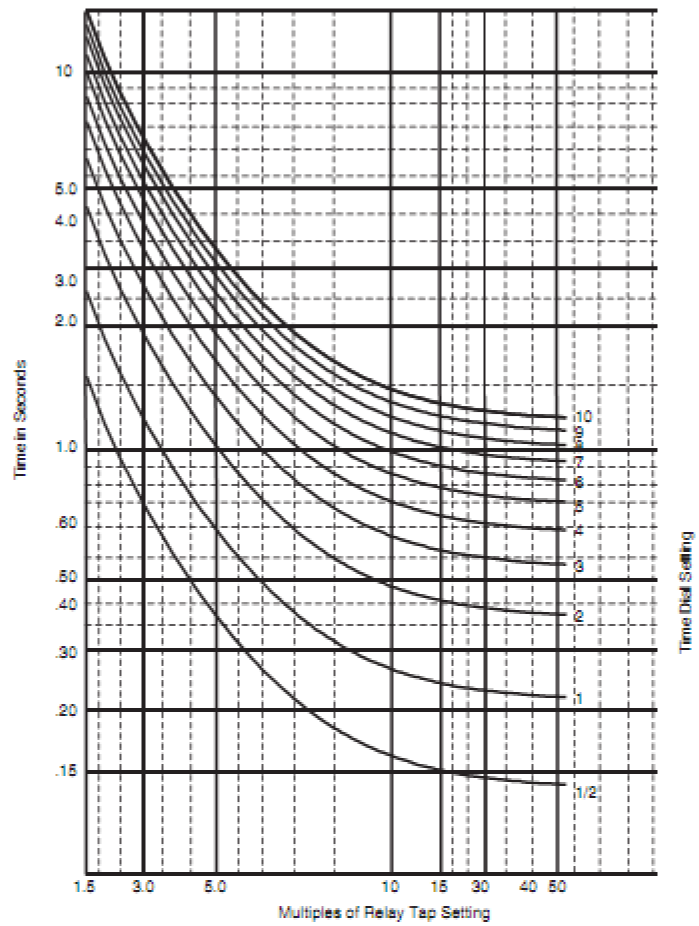
There are two settings that must be applied to all time-delay overcurrent relays: the pickup and the time delay.

1. Pickup setting:

This is a fundamental function and it must be set so it will always operate for faults in that zone of protection. This will require margins above normal operating currents and below minimum fault currents.

If possible, this setting should also provide backup for an adjacent line section or adjoining equipment such as a line-terminated transformer. It should be emphasized, however, that the backup function is a secondary consideration.

The pickup of a relay (as shown in Figure) is the minimum value of the operating current, voltage or other input quantity reached by progressive increases of the operating parameter that will cause the relay to reach its completely operated state when started from the reset condition.



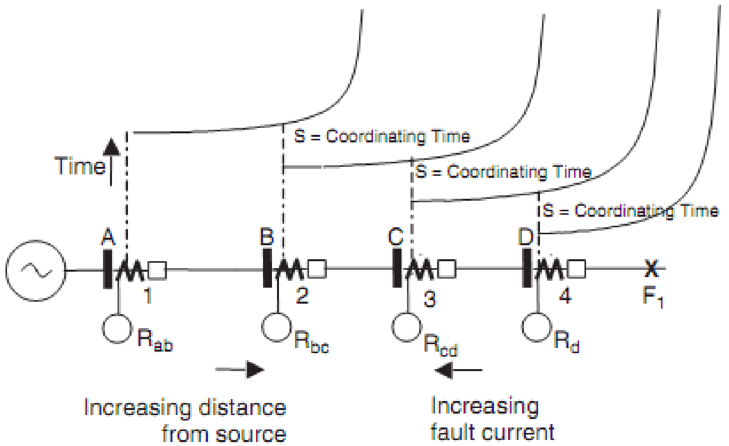
2. Time-delay setting:

The time-delay feature of the relay is an independent parameter that is obtained in a variety of ways, depending on the design of the relay.

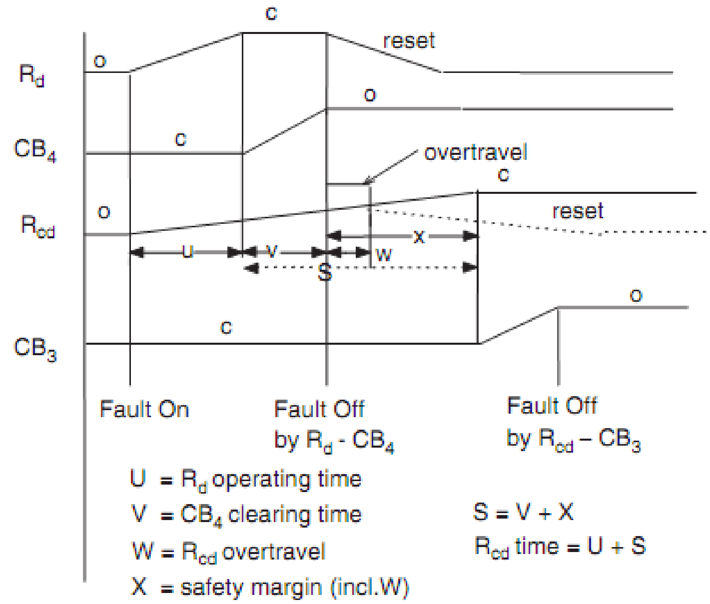
The dial is marked from a setting of 1/2 to 10, This is an inverse time–current relationship, i.e. the greater the operating current, the less time it takes to travel from the reset position to the operating position.

The purpose of the time-delay setting is to enable relays to coordinate with each other. A family of curves must be provided so two or more relays, seeing the same fault as defined by the multiples of pickup, can operate at different times.

The principle of relay coordination can be explained by reference to Figure which shows a series of radial lines and the time–distance characteristics of the associated inverse-time relays. These are relay operating curves selected for each of the relays, plotted as a function of fault location. Since the magnitude of the fault current decreases as the fault moves away from the source.

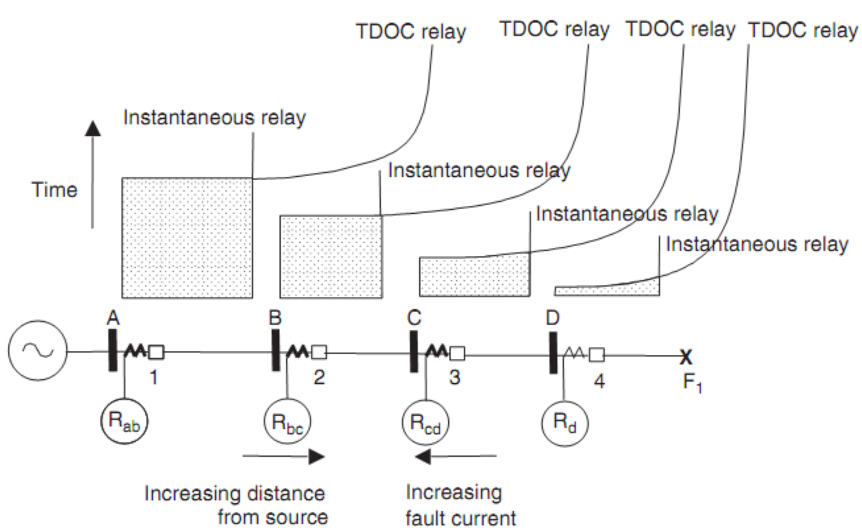


For fault F1 at the end farthest from the generating source, relay Rd, tripping breaker (4), operates first; relay Rcd at breaker (3) has a higher time lever setting which includes a coordinating time delay S to let breaker (4) trip if it can; similarly, relay Rbc, at breaker (2), coordinates with the relay at breaker (3) by having a still longer time delay (including the same coordinating time S); and finally, relay Rab at breaker (1) has the longest time delay and will not trip unless none of the other breakers trips, provided it can see the fault, i.e. provided the fault current is greater than its pickup setting.



- <u>Instantaneous overcurrent relays:</u>

The closer the fault is to the source, the greater the fault current magnitude, yet the longer the tripping time. The addition of instantaneous overcurrent relays makes this system of protection viable. If an instantaneous relay can be set to see almost up to, but not including, the next bus, all of the fault-clearing times can be lowered, as shown in front Figure



Setting rules:

Since the instantaneous relay must not see beyond its own line section, the values for which it must operate are very much higher than even emergency loads. Therefore, load is not usually a consideration for the instantaneous relay settings, As a result, there is no need to set an instantaneous overcurrent relay with margins such as 200% of load and one-third of fault current.

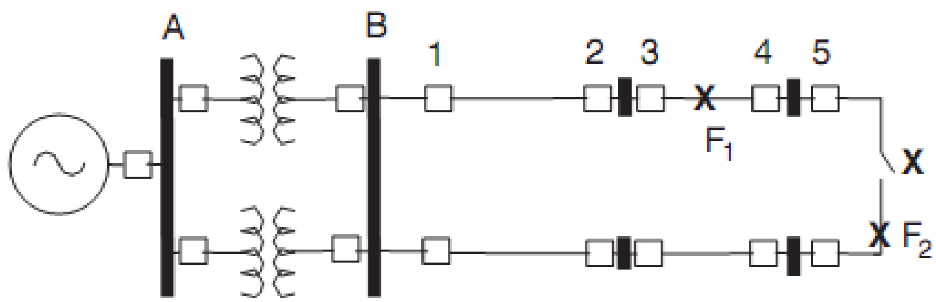
In order to overcome transient overreach problem, It is common to set an instantaneous relay about 125–135% above the maximum value for which the relay should not operate, and 90% of the minimum value for which the relay should operate.

• Directional overcurrent relays:

Directional overcurrent relaying is necessary for multiple source circuits, when it is essential to limit relay tripping for faults in only one direction. It would be impossible to obtain correct relay selectivity through the use of a nondirectional overcurrent relay in such cases. If the same magnitude of the fault current could flow in either direction at the relay location, coordination with the relays in front of, and behind, the nondirectional relay cannot be achieved except in very unusual system configurations. Therefore, overcurrent relaying is made directional to provide relay coordination between all of the relays that can see a given fault.

Directional relays require two inputs, the operating current and a reference, or polarizing, quantity (either voltage or current) that does not change with fault location.

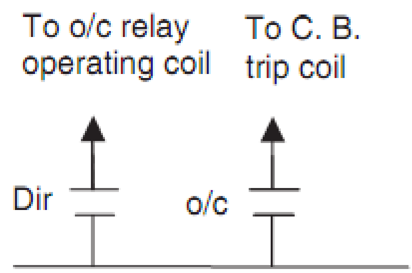
Referring to Figure, with switch X closed, assume that the current through (4) and (5) for a fault at F1 is 100 A and for a fault at F2 is 400 A. Setting the relay at (4) for pickup at 25 A gives 4 × pu for the fault at F1 and 16 × pu for the fault at F2. This relay must, therefore, be directional to see faults only in the direction from breaker (4) to breaker (3). Setting the relay at (5) at 125 A, however, allows it to have 3.2 × pu for the fault in its protected zone at F2, but less than 1.0 × pu for the fault at F1. It therefore does not have to be directional. However, such a condition may change with system growth and pass unnoticed until a false trip occurs. It is therefore good practice to use directional relays at both locations.



<u>There are two approaches to providing directionality to an overcurrent relay:</u>

<u>1. Directional control.:</u>

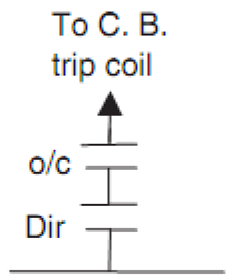
the design of the relay is such that the over- current element will not operate until the directional element operates, indicating that the fault is in the tripping direction.



Directional control
(a)

<u>2. Directional overcurrent.:</u>

this relay has independent contacts, connected in series with the circuit breaker trip coil. Both relay contacts must close before a trip output is obtained.



Directional o/c
(b)

- ## <u>distance protection:</u>

Distance relays are normally used to protect transmission lines. They respond to the impedance between the relay location and the fault location. As the impedance per mile of a transmission line is fairly constant, these relays respond to the distance to a fault on the transmission line – and hence their name. Similar principles are applicable in case of a three-phase transmission line, provided that appropriate voltages and currents are chosen to energize the distance relay. The R–X diagram is an indispensable tool for describing and analyzing a distance relay characteristic, and we will examine it initially with reference to a single-phase transmission line.

The distance relay is set to underreach the remote terminal. The corollary to this definition, of course, is that the relay will see faults less than the setting. 'Overreaching' protection is a form of protection in which the relays at one terminal operate for faults beyond the next terminal. They may be constrained from tripping until an incoming signal from a remote terminal has indicated whether the fault is beyond the protected line section.

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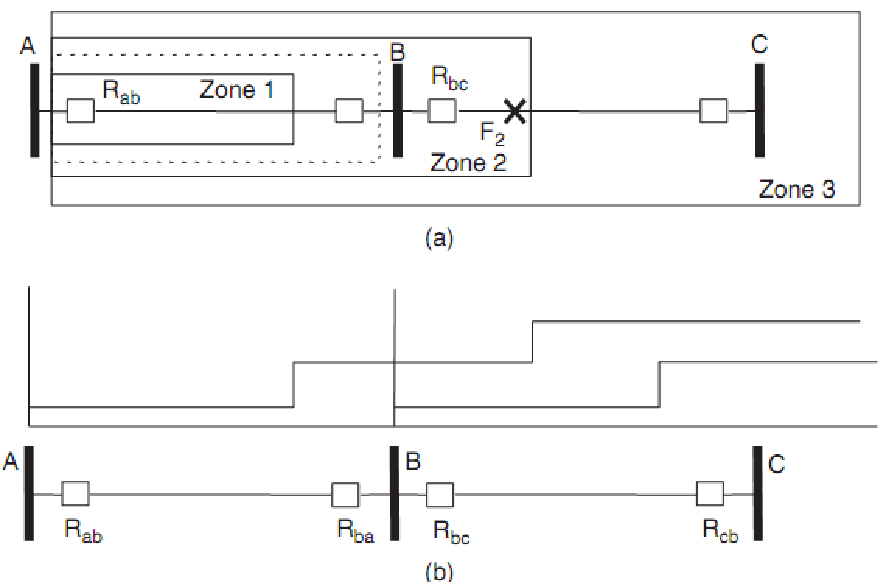
Referring to Figure , the desired zone of protection is shown with a dotted line. The ideal situation would be to have all faults within the dotted area trip instantaneously.

Owing to the uncertainty at the far end, however, to be sure that we do not overreach the end of the line section, we must accept an underreaching zone (zone 1). It is customary to set zone 1 between 85 and 90% of the line length and to be operated instantaneously.

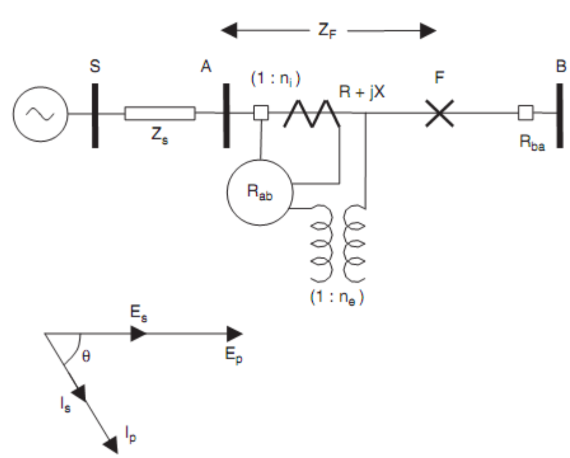
the area between the end of zone 1 and bus B is not protected. Consequently, the distance relay is equipped with another zone, which deliberately overreaches beyond the remote terminal of the transmission line. This is known as zone 2 of the distance relay, and it must be slowed down to be 0.3s, The reach of the second zone is generally set at 120–150% of the line length AB.

In order to provide a backup function for the entire line, it is customary to provide yet another zone of protection for the relay at A. This is known as the third zone of protection, and usually extends to 120–180% of the next line section. The third zone must coordinate in time and distance with the second zone of the neighboring circuit, and usually the operating time of the third zone is of the order of 1 s.



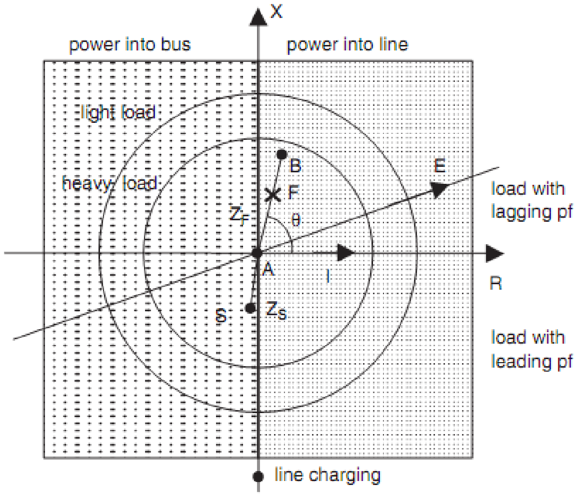
- <u>R–X diagram</u>

For the product-type relay, such as the distance relay, analyzing the response of the relay for all conditions is difficult because the voltage varies for each fault, or varies for the same fault but with different system conditions. To resolve this difficulty, it is common to use an R–X diagram to both analyze and visualize the relay response. By utilizing only two quantities, R and X (or Z

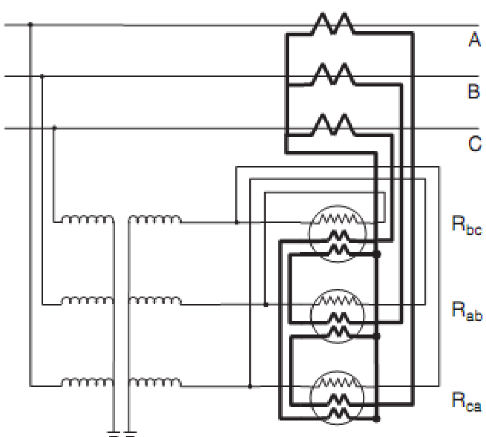


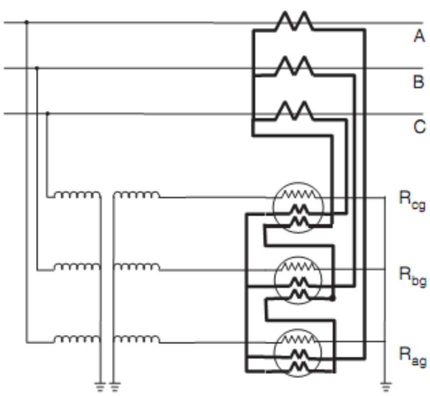
and θ), we avoid the confusion introduced by using the three quantities E, I and θ. There is an additional significant advantage in that the R–X diagram allows us to represent both the relay and the system on the same diagram. Consider an ideal (zero resistance) short circuit at location F in the single-phase system shown in Figure.

Now consider the fault at location F as shown in previous Figure . The corresponding apparentimpedance is shown at F in Figure . As the location of the fault is moved along the transmission line, the point F moves along the straight line AB in Figure 5.5. Thus, the transmission line as seen by the relay maps into the line AB in the R–X plane. The line AB makes an angle θ with the R axis, where θ is the impedance angle of the transmission line. (For an overhead transmission line, θ lies between 70◦ and 88◦ , depending upon the system voltage, the larger angles being associated with higher transmission voltages.) When the fault is on the transmission line, the apparent impedance plots on the line AB; for all other faults or loading conditions, the impedance plots away from the line AB.



- Connections of c.t. and v.t. for distance relay (3-ph)



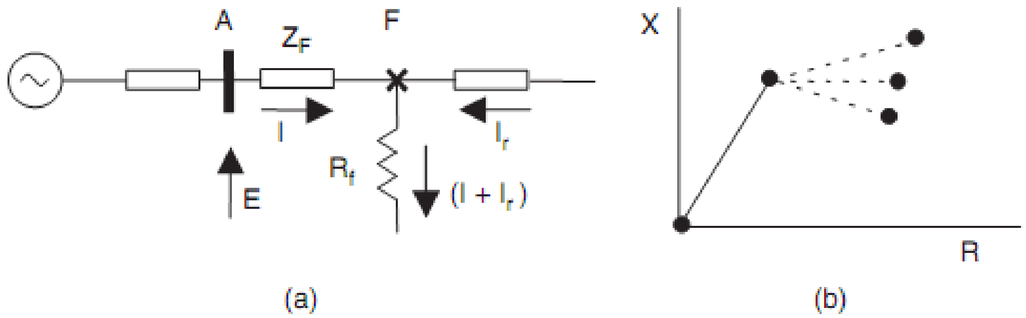


Current transformer and voltage transformer connections for distance relays for ground faults

Current transformer and voltage transformer connections for distance relays for phase faults

- Fault resistance:

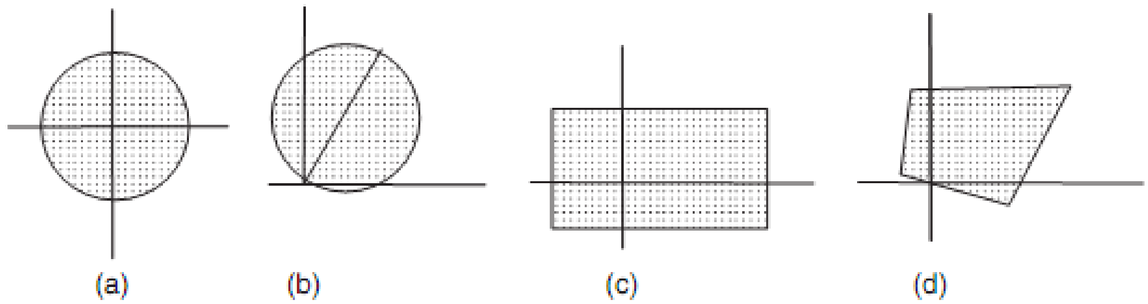
the fault path will have a resistance in it, which may consist of an arc resistance or an arc resistance in series with the tower footing resistance in the case of a ground fault. The tower footing resistance is practically constant during the fault (and ranges between 5 and 50), whereas the arc resistance changes in time as the fault current continues to flow. During the early period of the arc, say in the first few milliseconds, the arc resistance is negligible, and as the arc channel gets elongated in time, the arc resistance increases. the fault arc resistance for a 345 kV transmission line fault at a place with short-circuit capacity of 1500 MVA is (76 × 3452/1500 × 103) ~ = 50. The fault resistance introduces an error in the fault distance estimate, and hence may create an unreliable operation of a distance relay.



Fault path resistance, and its effect on the $R-X$ diagram

- <u>Distance relay types:</u>

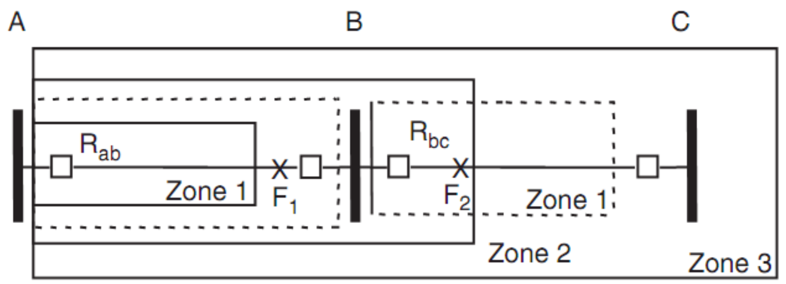
Four general relay types are recognized according to the shapes of their operating zones: (1) impedance relays, (2) admittance or mho relays, (3) reactance relays and (4) quadrilateral relays. These four relay characteristic shapes are illustrated in Figure:



The impedance relay has a circular shape centered at the origin of the R–X diagram. The admittance (or mho) relay has a circular shape which passes through the origin. The reactance relay has a zone boundary defined by a line parallel to the R axis. The zone extends to infinity in three directions as shown in Figure (c). The quadrilateral characteristic, as the name implies, is defined by four straight lines. This last characteristic is only available in solid-state or computer relays.

- <u>Pilot protection of transmission lines:</u>

nonpilot protection using overcurrent and distance relays, contain a fundamental difficulty. It is not possible to instantaneously clear a fault from both ends of a transmission line if the fault is near one end of the line. This is due to the fact that, in detecting a fault using only information obtained at one end, faults near the remote end cannot be cleared without the introduction of some time delay. there is always an uncertainty at the limits of a protective zone.to avoid loss of coordination for fault at F2, the relays at terminal B trip instantaneously by the first zone and the relays at terminal A use a time delay for second zone or backup tripping. This results in slow clearing for a fault at F1. The ideal solution would be to use the differential princible.



<u>The communication channels generally used are:</u>

- power line carrier
- microwave
- fiber optics
- communication cable.

The relaying schemes can be classified as directional comparison, phase comparison, current differential or pilot wire depending on the type of sensing used, and are further described as blocking, unblocking or transfer trip depending on how the transmitted signal is used.

The transfer trip schemes are again divided into direct, permissive underreaching and permissive overreaching. There are, of course, advantages and disadvantages associated with each scheme and the specific application depends on all of the individual factors and conditions involved.

Directional distance relaying is the most commonly used throughout the world, but it has application and setting problems when series capacitors are present. Phase comparison and current differential are immune to such problems, and only require current inputs, eliminating the need for potential sources.

4.2. ROTATING MACHINERY PROTECTION:

The protection of rotating equipment involves the consideration of more possible failures or abnormal operating conditions than any other system element. Although the frequency of failure, particularly for generators and large motors, is relatively low, the consequences in cost and system performance are often very serious.

<u>Some of the abnormal conditions that must be dealt with are the following</u>:

1. Winding faults: stator – phase and ground fault
2. Overload
3. Overspeed
4. Abnormal voltages and frequencies.

<u>For generators we must consider the following.</u>

5. Underexcitation
6. Motoring and startup.

<u>For motors we are concerned with the following.</u>

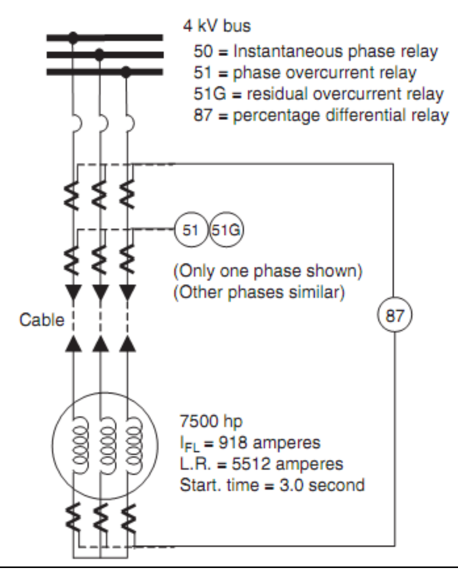
7. Stalling (locked rotor)
8. Single phase
9. Loss of excitation (synchronous motors).

4.2.1. Stator faults:

- <u>Phase fault protection:</u>

For short circuits in a stator winding, it is standard practice to use differential protection on generators rated 1000 kVA or higher and on motors rated 1500 hp or larger or rated 5 kV and above. Rotating equipment provides a classic application of this form of protection since the equipment and all of the associated peripherals such as current transformers (CTs), breakers, etc. are usually in close proximity to each other, thereby minimizing the burden and possible error due to long cable runs.

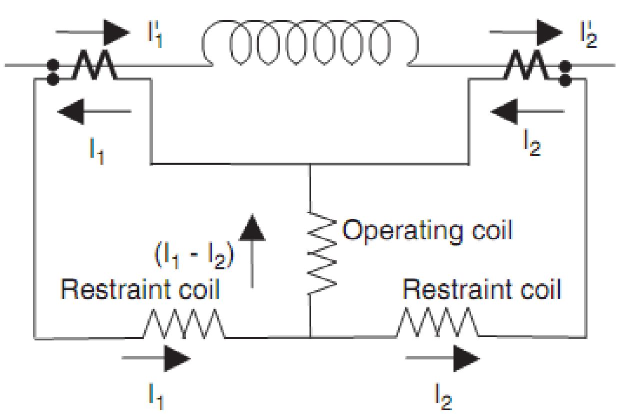
The CTs used for the generator differential are almost invariably located in the buses and leads immediately adjacent to the generator winding. This is done to limit the zone of protection so a fault in the generator is immediately identifiable for quick assessment of damage, repair and restoration of service.



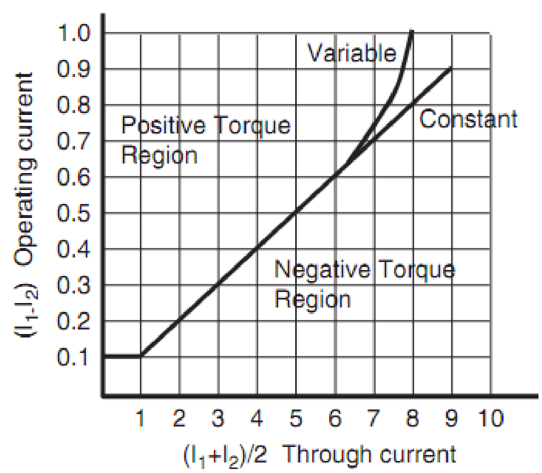
In motor differential circuits, three CTs should be located within the switchgear in order to include the motor cables within the protection zone. The other three CTs are located in the neutral connection of the motor. Six leads must be brought out of the motor: three on the incoming cable side to connect to the switching device and three on the motor neutral to accommodate the CTs before the neutral connection is made (refer to Figure). Above 1500 hp this is standard manufacturing practice. Below 1500 hp the provision and connections for the CTs must be specified when the motor is purchased.

this arrangement would be ideal if the CTs always reproduced the primary currents accurately. Actually, however, the CTs will not always give the same secondary current for the same primary current, even if the CTs are commercially identical. The difference in secondary current, even under steady-state load conditions, can be caused by the variations in manufacturing tolerances and in the difference in secondary loading, i.e. unequal lengths of leads to the relay, unequal burdens of meters and instruments that may be connected in one or both of the secondaries. What is more likely, however, is the 'error' current that can occur during short-circuit conditions.

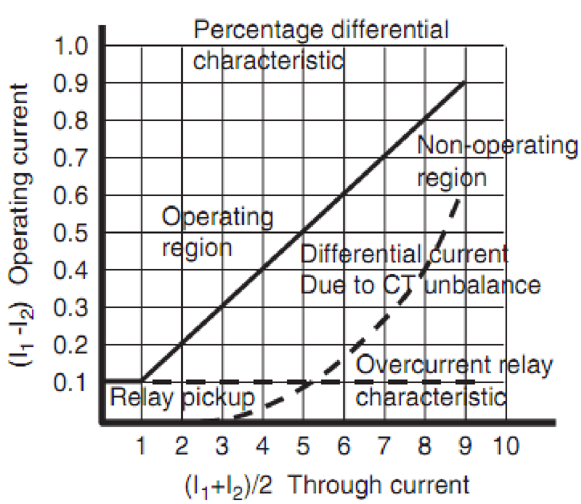
The percentage differential relay solves this problem without sacrificing sensitivity. The schematic arrangement is shown in Figures ➔



Generator differential using percentage differential relay



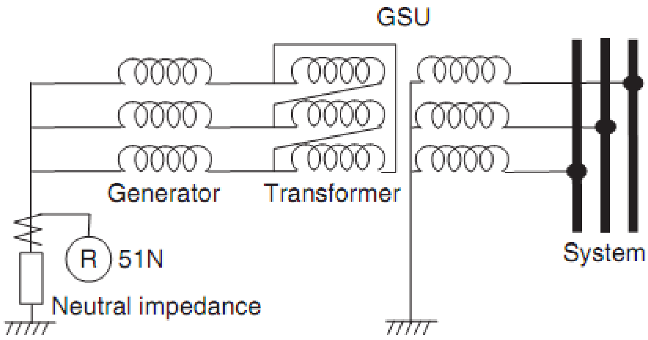
Percentage differential relay characteristics

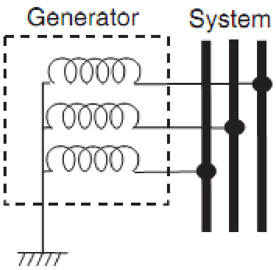


Comparison between percentage differential and overcurrent relay performance

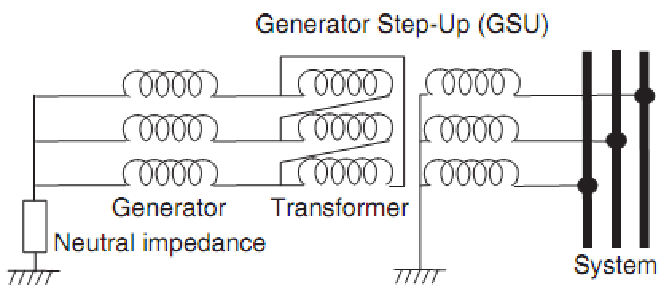
- <u>Ground fault protection:</u>

The method of grounding affects the amount of protection that is provided by differential relay.When the generator is solidly grounded, there is sufficient phase current for a phase-to-ground fault to operate almost any differential relay, as in Figure ➔





If the generator has a neutral impedance to limit ground current, there are relay application problems that must be considered for the differential relays that are connected in each phase. as shown in Figure ➔



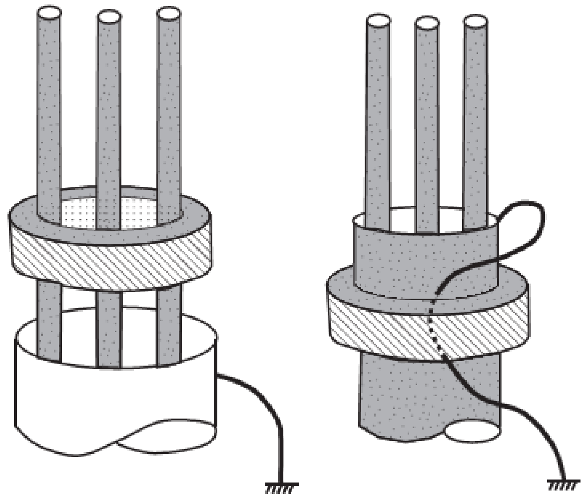
The higher the grounding impedance, the less the fault current magnitude and the more difficult it is for the differential relay to detect low-magnitude ground faults.

If a CT and a relay are connected between ground and the neutral point of the circuit, , sensitive protection will be provided for a phase-to-ground fault since the neutral relay (51N)sees all of the ground current and can be set without regard for load current.as shown in Figure ➔

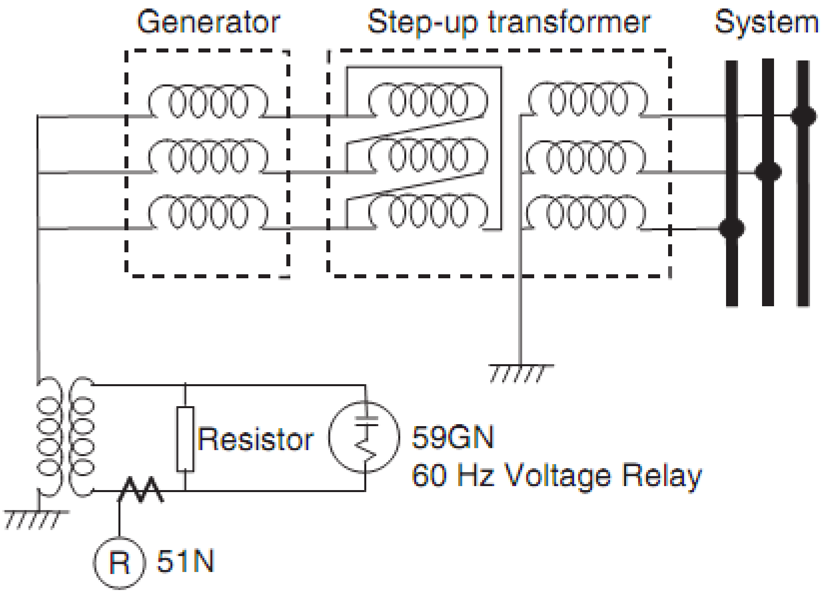
As the grounding impedance increases, the fault current decreases and it becomes more difficult to set a current-type relay. The lower the relay pickup, the higher is its burden on the CT and the more difficult it is to distinguish between ground faults and normal third harmonic unbalance. This unbalanced current that flows in the neutral can be as much as 10–15% of the rated current. Other spurious ground current may flow due to unbalances in the primary system. The total false ground.

An alternative to the residually connected ground relay in motor applications is the toroidal CT, shown in Figure➔

The CT ratio can be any standard value that will provide the relay current from the available ground current for adequate pickup. Since there will be no error current, the relay can be an instantaneous relay set at a low value.



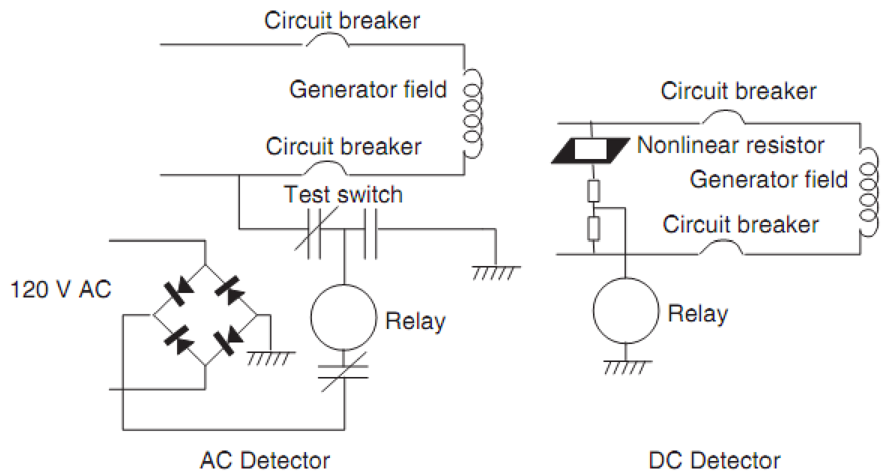
If a generator is connected directly to a grounded transmission system, as shown before, the generator ground relay may operate for ground faults on the system. It is therefore necessary for the generator ground relay to coordinate with any other relays that see the same fault. If the generator is connected to the system through a wye-delta transformer, zero sequence current cannot flow in the generator bus beyond the delta connection of the stepup transformer. Faults on the wye side will, therefore, not operate ground relays on the delta side. as shown in Figure➔



4.2.2. Rotor faults:

The field circuits of modern motors and generators are operated ungrounded. Therefore, a single ground on the field of a synchronous machine produces no immediate damaging effect. However, the existence of a ground fault stresses other portions of the field winding, and the occurrence of a second ground will cause severe unbalance, rotor iron heating and vibration.

Two commonly applied field ground detection schemes. The ground in the detecting circuit is permanently connected through the very high impedance of the relay and associated circuitry. If a ground should occur in the field winding or the buses and circuit breakers external to the rotor, the relay will pick up and actuate an alarm. as shown in Figure➔



The primary concern with rotors in squirrel-cage induction motor construction or insulated windings in wound-rotor induction or synchronous motor construction involves rotor heating. In almost all cases, this is the result of unbalanced operation or a stalled condition. Protection is therefore provided against these situations rather than attempt to detect the rotor heating directly.

4.2.3. Unbalanced currents:

Unsymmetrical faults may produce more severe heating in machines than symmetrical faults or balanced three-phase operation. The negative sequence currents which flow during these unbalanced faults induce 120 Hz rotor currents which tend to flow on the surface of the rotor forging and in the nonmagnetic rotor wedges and retaining rings. The resulting I^2R loss quickly raises the temperature.

Typical conditions that can give rise to the unbalanced generator currents are:

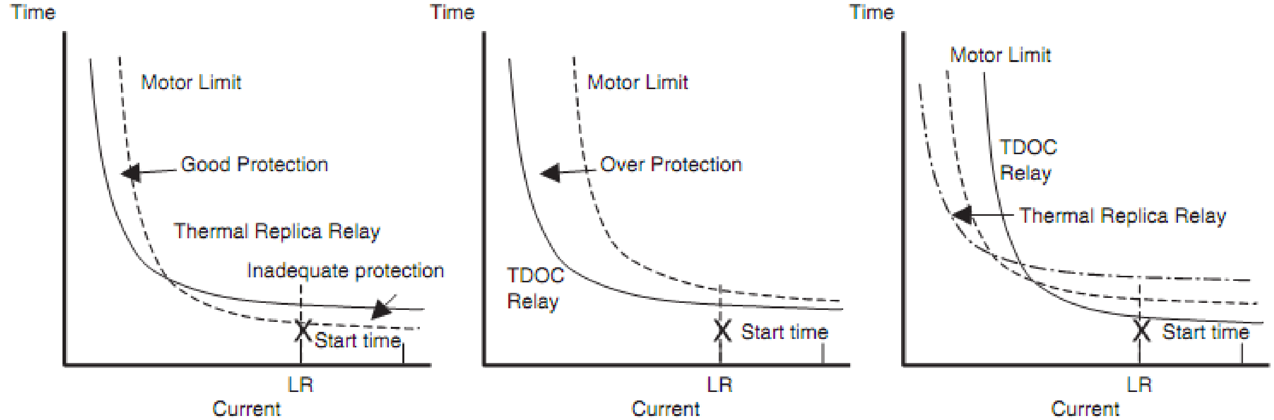
- accidental single-phasing of the generator due to open leads or buswork;
- unbalanced generator stepup transformers;
- unbalanced system fault conditions and a failure of the relays or breakers;
- planned single-phase tripping without rapid reclosing.

When such an unbalance occurs, it is not uncommon to apply negative sequence relays (46) on the generator to alarm first, alerting the operator to the abnormal situation and allowing corrective action to be taken before removing the machine from service.

4.2.4. Overload:

Overload protection is always applied to motors to protect them against overheating. Fraconal horsepower motors usually use thermal heating elements such as bimetallic strips purchased with the motor starter

Thermal overload relays offer good protection for light and medium (long-duration) overloads, but may not be good for heavy overloads as shown in (a)➔



(a) Light load Overload Protection

(b) Heavy load Overload Protection

(c) Combination Overload Protection

A long-time induction overcurrent relay offers good protection for heavy overloads but overprotects for light and medium overloads (b)

A combination of two devices can provide better thermal protection as in (c)

Digital relays take advantage of the ability to model the rotor and the stator mathematically and use algorithms that calculate the conductor temperature resulting from operating current, add the effect of ambient temperature, and calculate the heat transfer and the heat decay. They are therefore responsive to the effects of multiple starts.

A motor that is rotating dissipates more heat than a motor at standstill, since the cooling medium flows more efficiently. When full voltage is applied, a motor with a locked rotor is particularly vulnerable to damage because of the large amount of heat generated. If the motor fails to accelerate, stator currents may typically range from 3 to 7 or more times full load value depending on motor design and supply system impedance. Digital relays are particularly suited to this type of logic combined with temperature sensing.

Two approaches are possible to solve this dilemma.

1. Use a motor zero-speed switch which supervises an additional overload relay set for locked rotor protection.

2. Use a relay that incorporates temperature change and discriminates between the sudden increase during locked rotor and the gradual increase during load increases.

Protective practices are different for generators and motors. In the case of generators, overload protection, if applied at all, is used primarily to provide backup protection for bus or feeder faults rather than to protect the machine directly.
a voltage-controlled overcurrent relay or an impedance relay can be used to distinguish between full-load and overcurrent.

4.2,5. Overspeed:

in practical situations, overspeed cannot occur unless the unit is disconnected from the system. Overspeed protection for generators is usually provided on the prime mover. Older machines use a centrifugal device operating from the shaft. More modern designs employ very sophisticated electrohydraulic or electronic equipment to accomplish the same function.
During overspeed the turbine presents a greater danger than the generator. Overspeed is not a problem with motors since the normal overcurrent relays will protect them.

4.2.6. Abnormal voltages and frequencies:

- Overvoltage:

The voltage at the terminals of a generator is a function of the excitation and speed. Overvoltage may result in thermal damage to cores due to excessive high flux in the magnetic circuits. Excess flux saturates the core steel and flows into the adjacent structures causing high eddy current losses in the core and adjacent conductor material. Severe overexcitation can cause rapid damage and equipment failure.
Overvoltage exists at 105% of rated voltage and per unit frequency or per unit voltage and 95% frequency.
Transformer can withstand up to 110% of rated voltage at no load and 105% at rated load with 80% power factor.

- Undervoltage:

Undervoltage presents a problem to the generator only as it affects the auxiliary system, Low voltage prevents motors from reaching rated speed on starting or causes them to lose speed and draw heavy overloads.
the overload relays will eventually detect this condition.

- <u>Overfrequency:</u>

Overfrequency is related to the speed of the unit and is protected by the overspeed device. It is possible to use an overfrequency relay as backup to mechanical devices. overfrequency relays can alert the operator. the governing devices will protect the unit from overspeed.

- <u>Underfrequency:</u>

operation at reduced frequency should be at reduced kVA. Underfrequency is a system condition that affects the turbine more than the generator. The turbine is more susceptible because of the mechanical resonant stresses which develop as a result of deviations from synchronous speed.
System load shedding is considered the primary turbine underfrequency protection The amount of load shed varies with coordinating regions and individual utilities but varies from 25 to 75% of system load. additional protection is required to prevent steam turbine damage. In order to have the unit available for restart, it is desirable to trip the turbine to prevent damage. This action in itself is considered as a last line of defense and is sure to cause an area blackout.

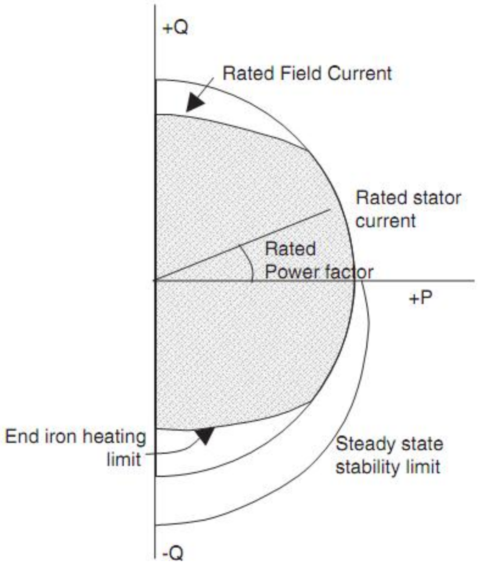
4.2.7. Loss of synchronism:

The primary difference in the protection requirements between induction motors and synchronous motors is the effect of the excitation system. Loss of synchronism of a synchronous motor is the
result of low excitation exactly as with the synchronous generator.

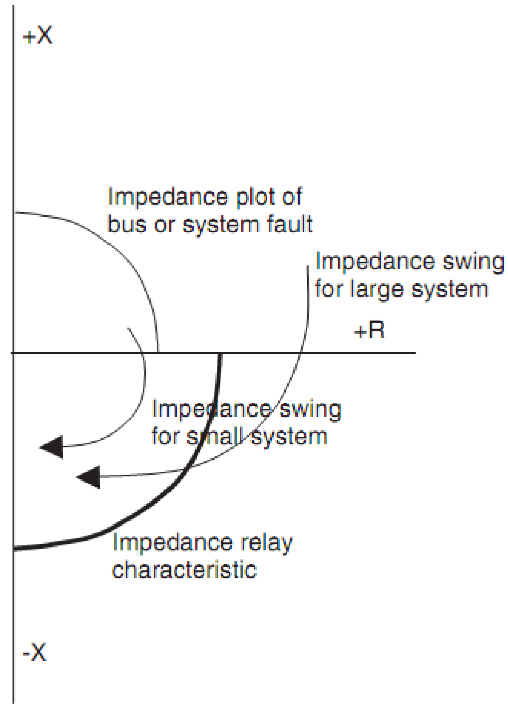
4.2.8. Loss of excitation:

When a synchronous generator loses excitation it operates as an induction generator running abovesynchronous speed with the system providing the necessary reactive support.
Salient-pole generators, which are commonly used with hydro machines have such damper windings and do not have the problem.
However, in addition to overheating, both salient-pole and round-rotor synchronous machines require a minimum level of excitation to remain stable throughout their load range.

The typical generator capability curve, hows the various limits associated with over- and underexcitation. The generator manufacturer supplies all of the temperature characteristics shown in Figure➔



how the impedance varies with loss of excitation for several system sizes. Despite the complexity of the phenomenon and the variation in conditions, the end result is surprisingly simple. Since the final impedance lies in the fourth quadrant of the R–X diagram, any relay characteristic that will initiate an action in this quadrant is applicable. Figure ➔



In almost every case, an alarm is provided early in the locus of the impedance swing so the operator can take the appropriate corrective action. Whether this is followed by a trip after a time delay or further advance in the swing path is a utility's decision.

4.2.9. Inadvertent energization:

A common, catastrophic mis-operation that has been reported many times involves the inadvertent closing of high-voltage breakers or switches while a unit is on turning gear or at some speed less than synchronous speed.

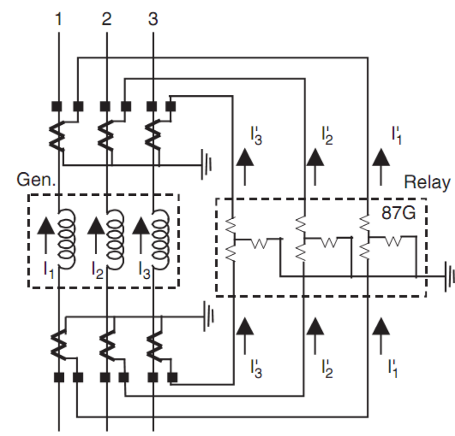
When energized in this fashion, if field has been applied, the generator behaves as a synchronous motor or generator that has been badly synchronized. The result can destroy the shaft or other rotating element. There are several causes for this incorrect switching. The same protection provided for startup can be used in this case. Some utilities use dedicated protective circuits that are activated when the unit is taken out of service.

4.2.10. Torsional vibration:

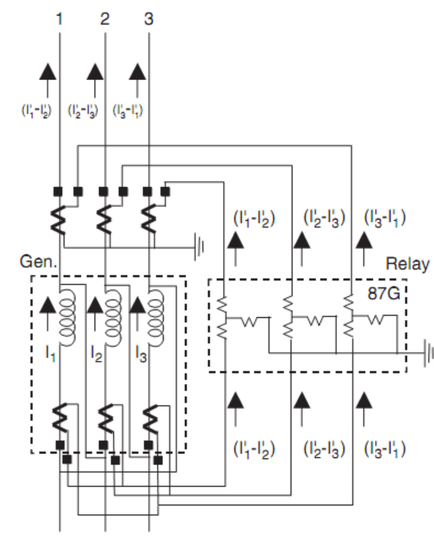
The potential for shaft damage can occur from a variety of electrical system events. In addition to short circuits or bad synchronizing, studies have indicated that subsynchronous resonance or automatic reclosing, particularly high-speed reclosing, can produce torque oscillations leading to fatigue and eventual damage.

4.2.11. Winding connections:

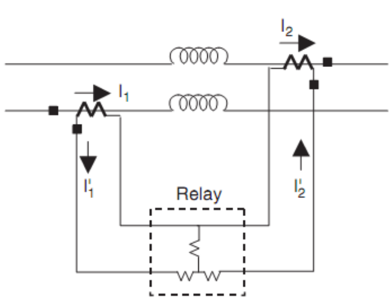
Most machines have star (wye) connections. So three relays that are connected to star-connected CTs provide both phase and ground protection. as shown in Figure ➔



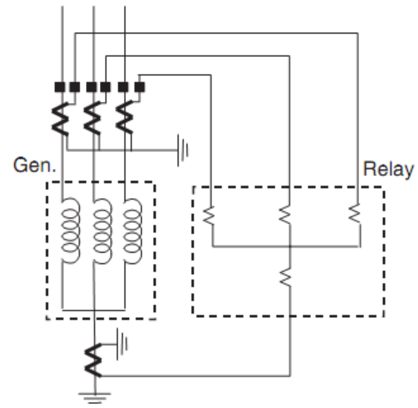
With delta-connected windings there is no connection to ground and the phase currents differ from the winding currents by √3 and a phase shift of 30◦. Care must be taken to obtain correct current flow, as shown in Figure ➔



Similarly, split-phase windings can be protected, as shown in Figure ➔



If the neutral connection is made inside the machine and only the neutral lead is
brought out, differential relays can only be provided for ground faults, as shown in Figure →



4.2.12. Sequential tripping:

The purpose of sequential tripping a synchronous generator is to minimize the possibility of damaging the turbine as a result of an overspeed condition occurring following the opening of the generator breakers.
Sequential tripping is accomplished by tripping the prime mover before tripping the generator and field breakers. Reverse-power relays, pressure switches and/or valve limit switches are used to determine that the steam input has been removed and then to complete the trip sequence.
Sequential tripping is essential because overspeeding the turbine is a more damaging operating condition than motoring.

4.3. Transformer protection:

Transformer faults – i.e. short circuits – are the result of internal electrical faults, the most common one being the phase-to-ground fault. Somewhat less common are the turn-to-turn faults. Unlike a transmission line, the physical extent of a transformer is limited to within a substation, and consequently differential relaying, the most desirable form of protection available, can be used to protect transformers. In general, a transformer may be protected by fuses, overcurrent relays, differential relays and pressure relays, and can be monitored for incipient trouble with the help of winding temperature measurements, and chemical analysis of the gas above the insulating oil. Which of these will be used in a given instance depends upon several factors as:

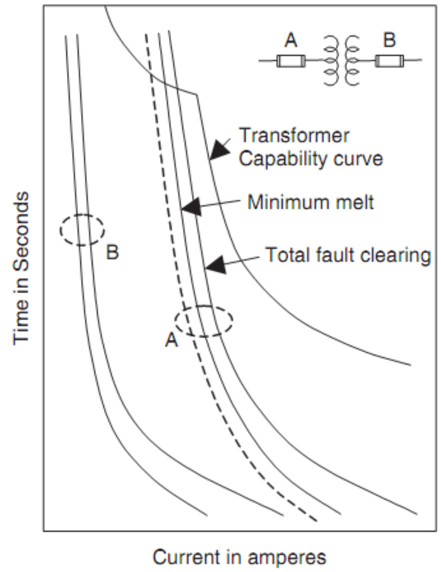
Transformer size, Location and function, Voltage, Connection and design.

4.3.1. Overcurrent protection:

As in all protection applications with overcurrent relays, the external faults or steady-state load currents must be distinguished from the currents produced by the internal faults. The effect of external faults that are not cleared promptly, or steady-state heavy loads, is to overheat the transformer windings and degrade the insulation.

- Protection with fuses:

Fuses are not used to protect transformers with ratings above 2.5 MVA. The basic philosophy used in the selection of fuses for the high-voltage side of a power transformer is similar to that used in other applications of fuses. Clearly, the fuse interrupting capability must exceed the maximum short-circuit current that the fuse will be called upon to interrupt. The continuous rating of the fuse must exceed the maximum transformer load. Typically, the fuse rating should be greater than 150% of the maximum load.
The minimum melt characteristic of the fuse must coordinate with (i.e. should be well separated from) the protective devices on the low side of the power transformer.

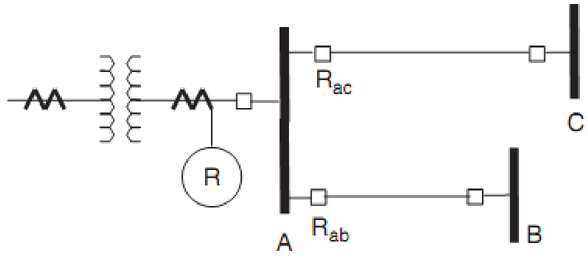


Protection of a transformer a fuse: coordination principles

- Time-delay overcurrent relays:

Protection against excessive overload, or persisting external fault, is provided by time-delay overcurrent relays. The pickup setting is usually 115% of the maximum overload acceptable. The time-delay overcurrent relays must coordinate with the low-side protective devices. These may include low-voltage bus relays for phase-to-phase faults, phase-directional relays on parallel transformers and the breaker failure relay timers on the low-voltage breakers.

As shown in Figure 8.2, the time dial selected for the relay should coordinate with overcurrent relays Rab and Rac, which protect the feeders on the low-voltage side.



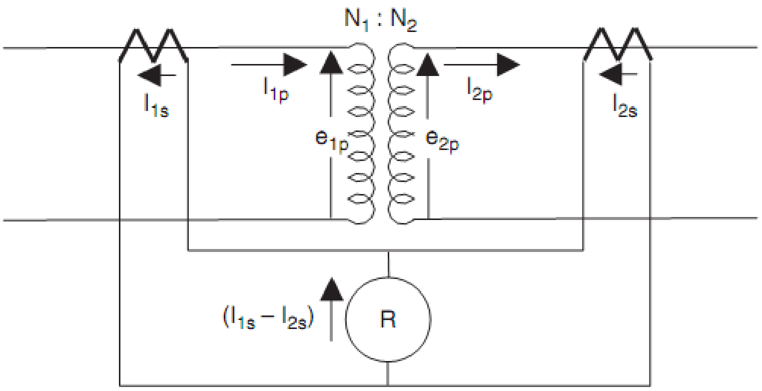
Coordination of transformer overcurrent relay with feeder protection on low side

- <u>Instantaneous relays:</u>

There are several constraints imposed upon the use of instantaneous relays; some of them depend upon the design of the relay. In all cases, of course, the relay must not operate on inrush, or for low-side faults. Peak magnetizing current in a transformer can be as high as 8–10 times peak full-load current. Since the relay will see low-side faults, one must consider these faults when they are fully offset.

4.3.2. Percentage differential protection:

Consider the single-phase, two-winding power transformer shown in Figure 8.3. During normal operation of the transformer, the algebraic sum of the ampere-turns of the primary and the secondary windings must be equal to the MMF required to set up the working flux in the transformer core. if an internal fault develops, this condition is no longer satisfied, and the difference of ils and i2s becomes much larger; in fact, it is proportional to the fault current. The differential current: Id = i_1s – i_2s provides a highly sensitive measure of the fault current. If an overcurrent relay is connected as shown in Figure, it will provide excellent protection for the power transformer.



Differential relay connections

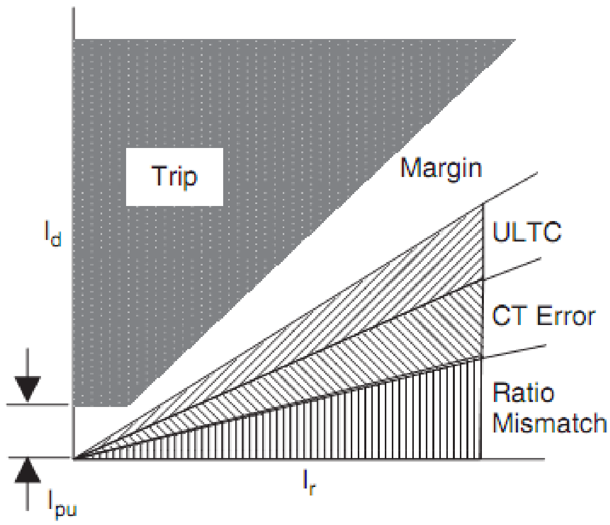
<u>Several practical issues must be considered before a workable differential relay can be implemented:</u>

First, it may not be possible to obtain the CT ratios on the primary and the secondary side which will satisfy the condition N1n1 = N2n2.

Second, the errors of transformation of the two CTs may differ from each other, thus leading to significant differential current when there is normal load flow, or an external fault.

Finally, if the power transformer is equipped with a tap changer, it will introduce a main transformer ratio change when the taps are changed.

A percentage differential relay provides an excellent solution to this problem. In a percentage differential relay, the differential current must exceed a fixed percentage of the 'through' current in the transformer. The through current is defined as the average of the primary and the secondary currents: $i_r = (i_{1s} + i_{2s})/2$ The current (i_r) is known as the restraint current – a name that comes from the electromechanical relay design, where this current produced a restraint torque on the moving disc, while the differential current produced the operating torque. The relay operates when: $i_d \geq K * i_r$
K: slope of the percentage differential characteristic.



Percentage differential relay characteristic

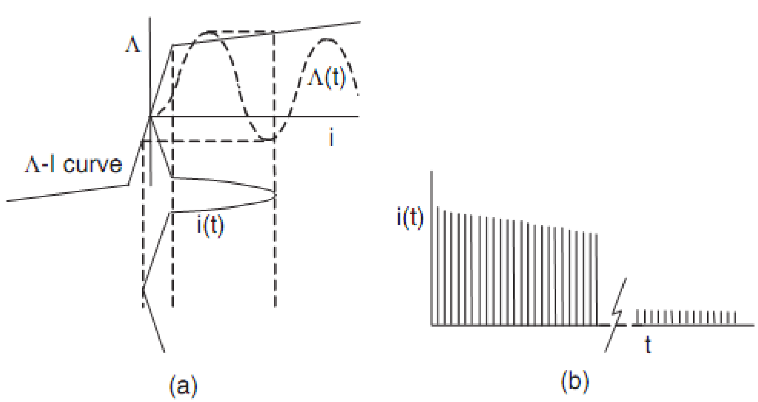
The relay has a small pickup current setting, i.e. the relay does not operate unless the differential current is above this pickup value. The pickup setting is usually set very low: typical values are 0.25 A secondary. This accounts for any residual CT errors at low values of transformer load current.

- <u>Causes of false differential currents:</u>

certain other phenomena cause a substantial differential current to flow, when there is no fault, and these false differential currents are generally sufficient to cause a percentage differential relay to trip, unless some special precautions are taken.

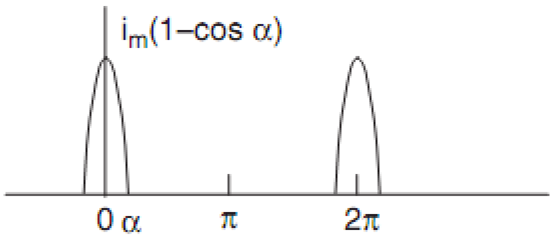
<u>1. Magnetizing inrush current during energization:</u>

Consider the two-slope approximation of a magnetizing characteristic shown in Figure (a). As the flux linkages go above the saturation knee point, a much larger current is drawn from the source. The magnitude of this current is determined by the slope of the magnetizing characteristic in the saturated region, and by the leakage inductance of the transformer.



It should be clear that in most modern transformers very large inrush currents are possible, depending upon the instant of energization, and the remnant flux in the transformer core. Since the inrush current flows only in the primary and not in the secondary winding of the transformer, it is clear that it produces a differential current which is 200% of the restraining current, and would cause a false operation.

2. Harmonic content of the inrush current:



Let the magnetizing characteristic be a vertical line in the V–i plane, and be a straight line with a finite slope in the saturated region This makes the current waveform of Figure(a) acquire the shape shown in Figure➔

As we will see shortly, the false operation of a percentage differential relay for a transformer is prevented by taking advantage of the fact that the inrush current is rich in harmonic components, while the fault current is a pure fundamental frequency component (except for a possible decaying DC component).

The relative magnitude of various harmonic components with respect to the fundamental frequency component front Table up to the 13th harmonic, and for saturation angles of 60◦,90◦ and 120◦.

Table 8.1 Harmonics of the magnetizing inrush current

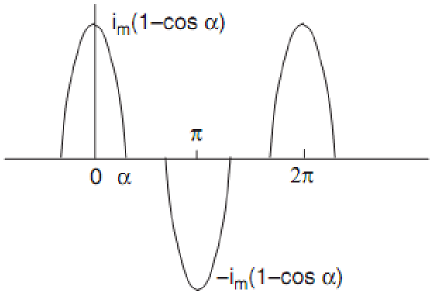
Harmonic	a_n/a_1		
	$\alpha = 60°$	$\alpha = 90°$	$\alpha = 120°$
2	0.705	0.424	0.171
3	0.352	0.000	0.086
4	0.070	0.085	0.017
5	0.070	0.000	0.017
6	0.080	0.036	0.019
7	0.025	0.000	0.006
8	0.025	0.029	0.006
9	0.035	0.000	0.008
10	0.013	0.013	0.003
11	0.013	0.000	0.003
12	0.020	0.009	0.005
13	0.008	0.000	0.002

3.Magnetizing inrush during fault removal:

As the voltage applied to the transformer windings jumps from a low prefault value to the normal (or larger) postfault value, the flux linkages in the transformer core are once again forced to change from a low prefault value to a value close to normal. Depending upon the instant at which the fault is removed, the transition may force a DC offset on the flux linkages, and primary current waveforms similar to those encountered during energization would result. It should be noted that as there is no remnant flux in the core during this process; the inrush is in general smaller than that during the transformer energization.

4. Transformer overexcitation:

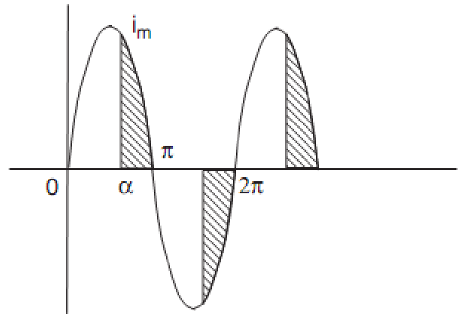
During overexcitation, the transformer flux remains symmetric, but goes into saturation for equal periods in the positive and the negative half periods of the waveform. This condition is illustrated in Figure➔



5. CT saturation:

For certain external faults, where the fault currents are large, it is likely that one of the CTs may saturate.

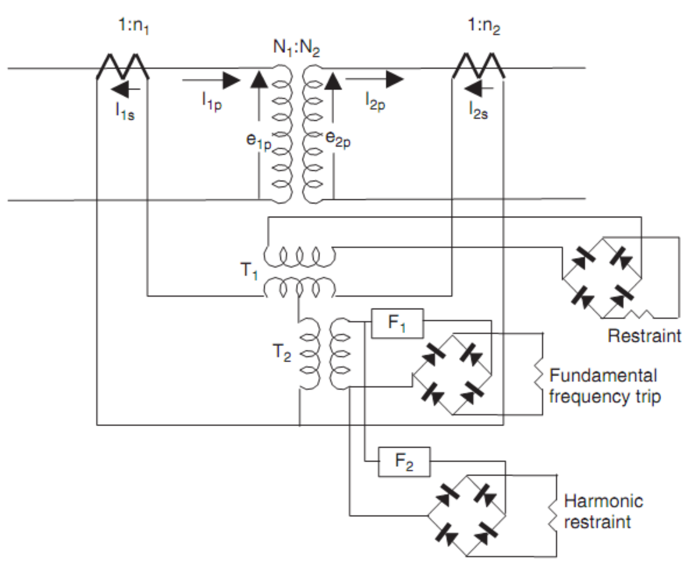
The resulting current waveform of that CT secondary winding is shown in Figure➔. The differential current in the relay will then equal the shaded area, which is the difference between the unsaturated current waveform and the saturated current waveform.



- ## Supervised differential relays:

left inside or around the transformerdesensitizing (or disabling) the differential relay during energization is a poor practice, as it is precisely during the initial energization of the transformer, when the transformer is first energized, or some repair work on the transformer may have been completed, that the transformer is in need of protection. This is to ensure that the repair work has been successfully completed, and no maintenance tools inadvertently.

The method currently in use on large transformers is based upon using the harmonic characterization of the inrush and overexcitation currents. The differential current is almost purely sinusoidal when the transformer has an internal fault, whereas it is full of harmonics when the magnetizing inrush current is present, or when the transformer is overexcited. Thus, the differential current is filtered with filters tuned to an appropriate set of harmonics, and the output of the filters is



Harmonic restraint percentage differential relay. F_1 is a pass filter and F_2 is a block filter for the fundamental frequency

used to restrain the differential relay.

A harmonic restraint function that uses all the harmonics for restraint may be in danger of

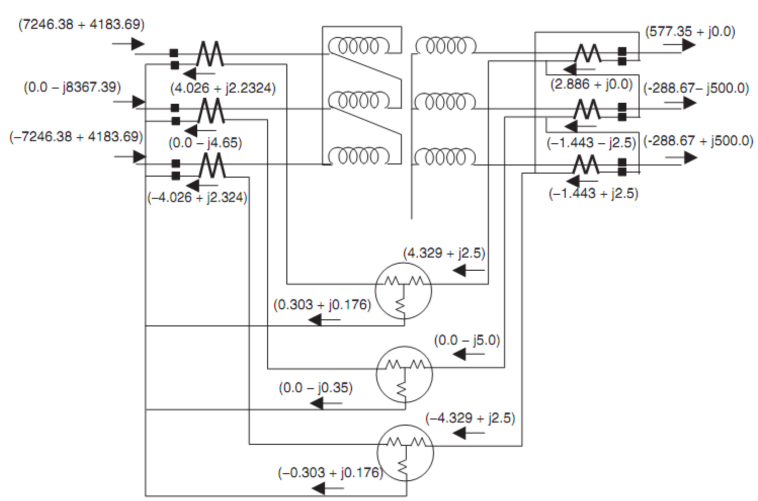
preventing a trip for an internal fault if the CTs should saturate, saturated CTs produce a predominant third harmonic in the current. Care should be taken to make sure that the third harmonic component produced in a saturated CT secondary current during an internal fault is not of sufficient magnitude to block tripping of the differential relay. Some modern relays use second and fifth harmonics for restraint so that the relay is prevented from tripping for inrush and overexcitation, but is not blocked from tripping for internal faults with CT saturation.

4.3.3. Three-phase transformer protection:

Under normal load conditions, the currents in the primary and secondary windings are in phase, but the line currents on the wye and delta sides of the three-phase transformer are out of phase by 30^0.
This phase shift causes a standing differential current, even when the turns ratio of the main transformer is correctly taken into account.
Solution is that the current transformers on the wye side of the power transformer are connected in delta, and the current transformers on the delta side of the power transformer are connected in wye.

it is also necessary to adjust the turns ratios of the CTs so that the delta connection on the wye side of the power transformer produces relay currents that are numerically matched with the relay currents produced by the wye-connected CTs. Thus, the delta CT winding currents must be (1/√3) times the wye CT currents.

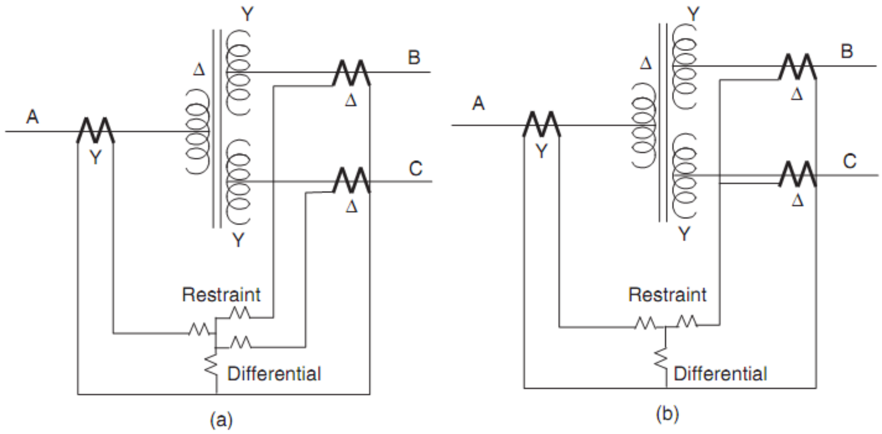
It should be noted that the CTs on the wye side of the power transformer are connected in such a manner that the currents in the relays are exactly in phase, and very small currents flow in the differential windings the three relays during normal conditions. The currents are calculated with due attention given to the polarity markings on the CT windings.



Connections for a three-phase differential relay. Note the polarity markings on the CTs. Relay taps will further reduce the differential currents

4.3.4. Multi-winding transformer protection:

three-phase transformers, similar considerations hold for single-phase transformers as well. Consider the three-winding transformer shown in Figure ➔. One winding is assumed to be delta connected, while the other two are assumed to be wye connected.



Protection of a three-winding transformer with (a) a three-winding relay and (b) a two-winding

The CTs must of course be connected in wye on the delta side and in delta on the wye side of the power transformer.

The CT ratios are chosen so that when any two windings are in service, equal secondary currents are produced.

It is interesting to note that under certain conditions a two-winding differential relay can be used to protect a three-winding transformer. If the transformer is connected to a source only on oneside, the other two winding CTs could be paralleled to produce a net secondary current, which can then be used in a two-winding protection scheme.

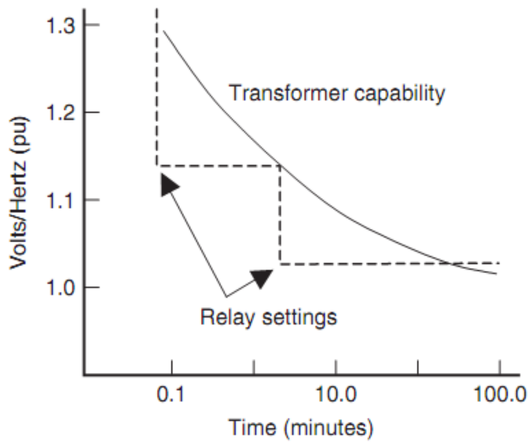
4.3.5. Volts-per-hertz protection:

Transformer cores are normally subjected to flux levels approaching the knee point in their magnetizing characteristic. Typically, the rated voltage at rated frequency may be 10% below the saturation level. If the core flux should exceed the saturation level, the flux patterns in the core and the surrounding structure would change, and significant flux levels may be reached in the transformer tank and other structural members. As these are not laminated, very high eddy currents are likely to result, producing severe damage to the transformer.

As the flux is proportional to the voltage, and inversely proportional to the operating frequency, the significant relaying quantity is the ratio of the per unit voltage to the per unit frequency.

A typical capability curve is shown in Figure ➔.

Many volts/hertz relays have two settings, a lower setting for alarm and a higher setting which may be used for tripping.



Volts/hertz capability of transformers, and relay settings

4.3.6. Nonelectrical protection:

- Pressure devices:

A very sensitive form of transformer protection is provided by relays based upon a mechanical principle of operation :

When a fault occurs inside an oil-filled transformer tank, the fault arc produces gases, which create pressure waves inside the oil. In the ‘conservator’ type of tank construction, which is more common in Europe, the pressure wave created in the oil is detected by a pressure vane in the pipe which connects the transformer tank with the conservator. The movement of the vane is detected by a microswitch, which can be used to sound an alarm, or trip the transformer. This type of a relay is known as a Buchholz relay, named after its inventor.

In the presence of gas pressure relays, the differential relays can be made less sensitive. Indeed, one may attempt reclosing on those faults which cause the operation of the differential relay, but not of the pressure relay.

- Temperature devices:

The temperature devices actuate alarms to a central dispatching office, to alert the operators, who can either remotely unload the transformer by opening the circuit breaker, or can dispatch an operator to the station. The hot-spot sensors are also commonly used to start and stop cooling fans and pumps. In extreme cases, when it is not possible to remotely remove the load, or send an operator to the station, an extreme high alarm will trip the bank.

4.4. INTRODUCTION TO BUS PROTECTION:

bus protection has been the most difficult protection to implement because of the severity of an incorrect operation on the integrity of the system. A bus is one of the most critical system elements. It is the connecting point of a variety of elements and a number of transmission lines, and any incorrect operation would cause the loss of all of these elements. This would have the same disastrous effect as a large number of simultaneous faults. However, without bus protection, if a bus fault should occur, the remote terminals of lines must be tripped. In effect, this could create a worse situation than the loss of all of the elements at the bus itself for two reasons:

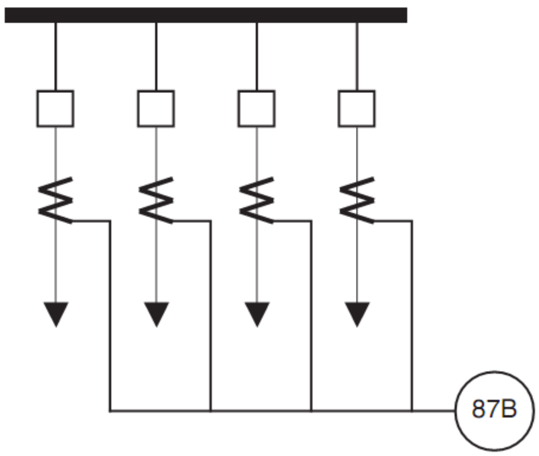
1. The loss of the remote ends will also result in the loss of intermediate loads.
2. As systems become stronger it is increasingly difficult for the remote ends to see all faults owing to infeeds.

The major problem with bus protection has been unequal core saturation of the current transformers (CTs). This unequal core saturation is due to the possible large variation of current magnitude and residual flux in the individual transformers used in the system. In particular, for a close-in external fault, one CT will receive the total contribution from the bus while the other CTs will only see the contribution of the individual lines. The basic requirement is that the total scheme will provide the degree of selectivity necessary to differentiate between an internal and an external fault.

- Protection of substation buses is almost universally accomplished by differential relaying.

Differential relaying with overcurrent relays requires connecting CTs in each phase of each circuit in parallel with an overcurrent relay for that phase as Figure➔

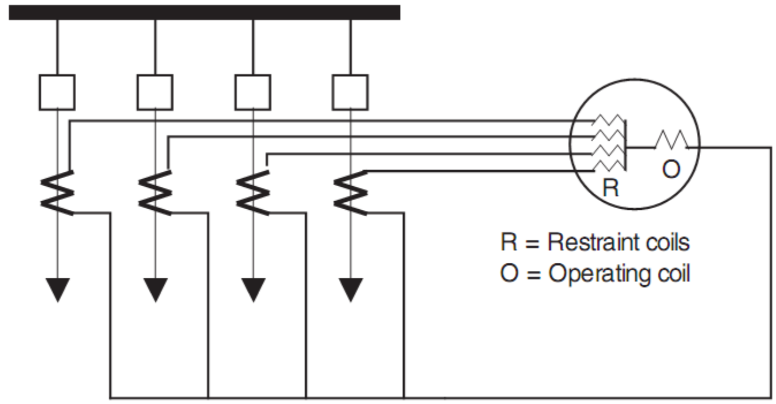
- When conditions are normal, the bridge is balanced and no current flows through the relay operating coil.
- When an external fault occurs, if all of the CTs reproduce the primary current accurately, thebridge is balanced as in normal case and no current flows in the relay operating coil.
- When an internal fault occurs, this balance, as we would expect, is also disrupted and current flows through the operating coil.



Differential with overcurrent relays

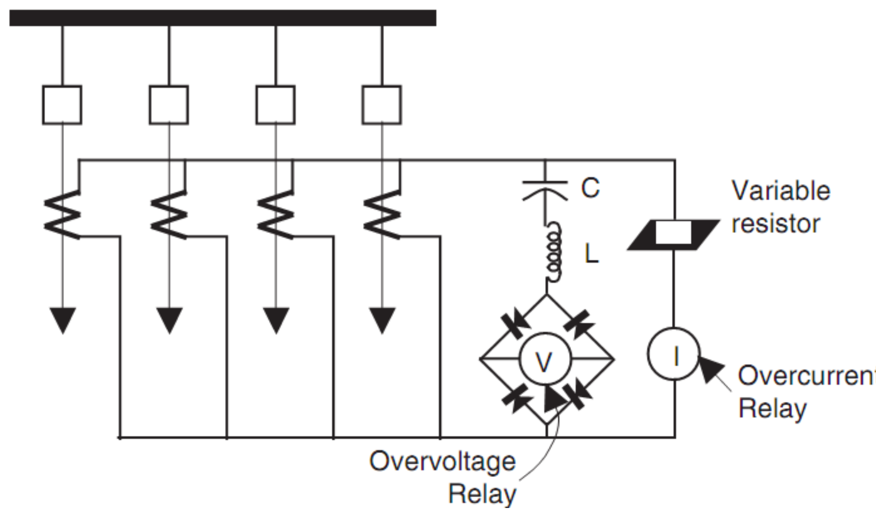
To minimize possible incorrect operations, the overcurrent relay may be set less sensitive and/or with time delay.

it is common to use a percentage differential relay. These relays have restraint and operating circuits as shown in Figure ➔
Only one operating coil per phase is required, but one restraint winding for each phase of each circuit is necessary.
The required current to operate the relay is proportional to the current flowing in the restraint windings.



Percentage differential relay

Even with the use of percentage differential relays, the problem of the completely saturated CT for a close-in external fault still exists. To overcome this problem, the most commonly used bus differential relay, particularly on extra high voltage (EHV) buses, is the high-impedance voltage differential relay.
This relay design circumvents the effects of CT saturation during external faults by assuming complete saturation for the worst external fault and calculating the error voltage across the operating coil. The connection for this relay is the same as shown in Figure➔



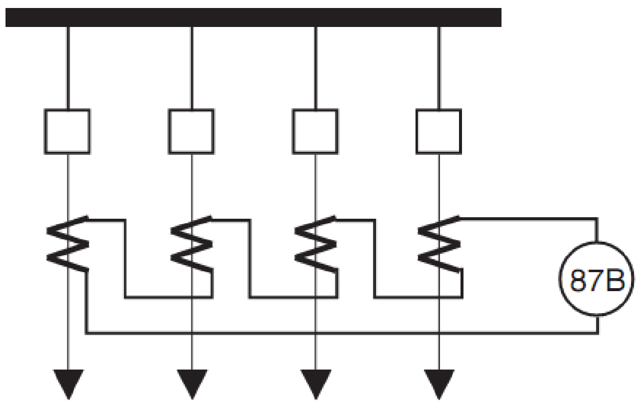
The L–C circuit in series with the overvoltage relay is tuned to 60 Hz to prevent the overvoltage relay from mis-operating on DC offset or harmonics.

- <u>Directional comparison:</u>

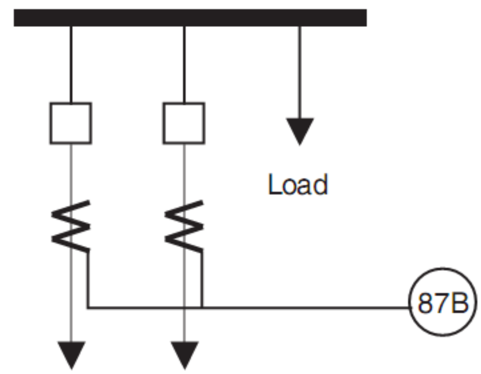
there are a number of directional relays that can compare the direction of current flow in each circuit connected to the bus. If the current flow in one or more circuits is away from the bus, an external fault exists. If the current flow in all of the circuits is into the bus, an internal bus fault exists. The timer is required to provide contact coordination. Since all of the directional relays are connected in series, it is essential that they all have an opportunity to close before a trip signal is initiated.
particularly at high-magnitude fault currents. The relay application and settings must be reviewed whenever system changes are made near the protected bus.

- <u>Partial differential protection:</u>

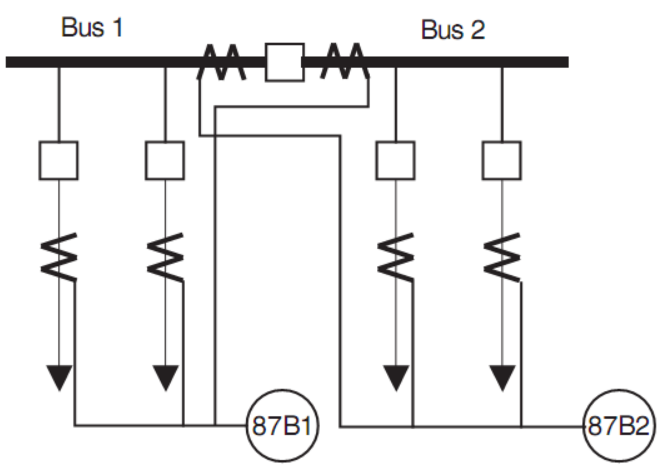
Figures show a variety of bus configurations that have significant impact on the connections and settings of the bus differential.



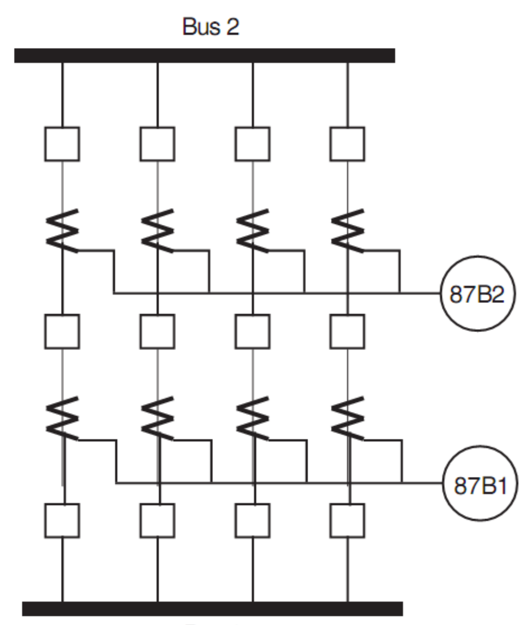
Partial bus differential



Transformer and bus differential



Two-bus relaying



Breaker-and-a-half bus differential

5. RELAYING FOR SYSTEM PERFORMANCE

The traditional goal of protective devices is to protect power system equipment. This is achieved by detecting a fault or undesirable performance and taking corrective action which in most cases involves tripping appropriate circuit breakers.

It is as well to recognize that the built-in, inherent strength of the power system is the best defense against catastrophic failures.

However, if the system is already stressed for whatever reason, such as equipment outages, heavier than normal loads, extreme weather, etc., this corrective action may exacerbate the situation and result in wide- area outages.

As discussed above, a conventional protection scheme is dedicated to a specific piece of equipment (line, transformer, generator, bus bar, etc.). However, a different concept must be developed which would apply to the overall power system or a strategic part of it in order to preserve system stability, maintain overall system connectivity and/or avoid serious equipment damage during major events.

To protect the integrity of the power system or strategic portions thereof, as opposed to conventional protection systems that are dedicated to specific power system elements.

Typical of such schemes are:

1. underfrequency load shedding
2. undervoltage load shedding
3. out-of-step tripping and blocking
4. congestion mitigation
5. Static var compensator (SVC)/static compensator (STATCOM) control
6. dynamic braking
7. generator runback
8. black start of gas turbines
9. system separation.