10 A-C GENERATOR AND MOTOR PROTECTION

The remaining chapters deal with the application of protective relays to each of the several elements that make up the electric power system. Although there is quite good agreement among protection engineers as to what constitutes the necessary protection and how to provide it, there are still many differences of opinion in certain areas. This book describes the general practice, giving the pros and cons where there are differences of opinion. Four standard-practice publications deal with the application of protective relays.[1,2,3,4] Manufacturers' publications are also available.[5,6,20] Bibliographies of relaying literature prepared by an AIEE committee provide convenient reference to a wealth of information for more detailed study.[7] Frequent reference will be made here to publications that have been found most informative.

The fact that this book recognizes differences of opinion should not be interpreted as complete approval of the various parallel practices: although it is recognized that there may sometimes be special economic and technical considerations, nevertheless, much can still be done in the way of standardization.

Generator Protection

Except where specifically stated otherwise, the following will deal with generators in *attended* stations, including the generators of frequency converters.

The protection of generators involves the consideration of more possible abnormal operating conditions than the protection of any other system element. In unattended stations, automatic protection against all harmful abnormal conditions should be provided.[1] But much difference of opinion exists as to what constitutes sufficient protection of generators in attended stations. Such difference of opinion is mostly concerning the protection against abnormal operat-

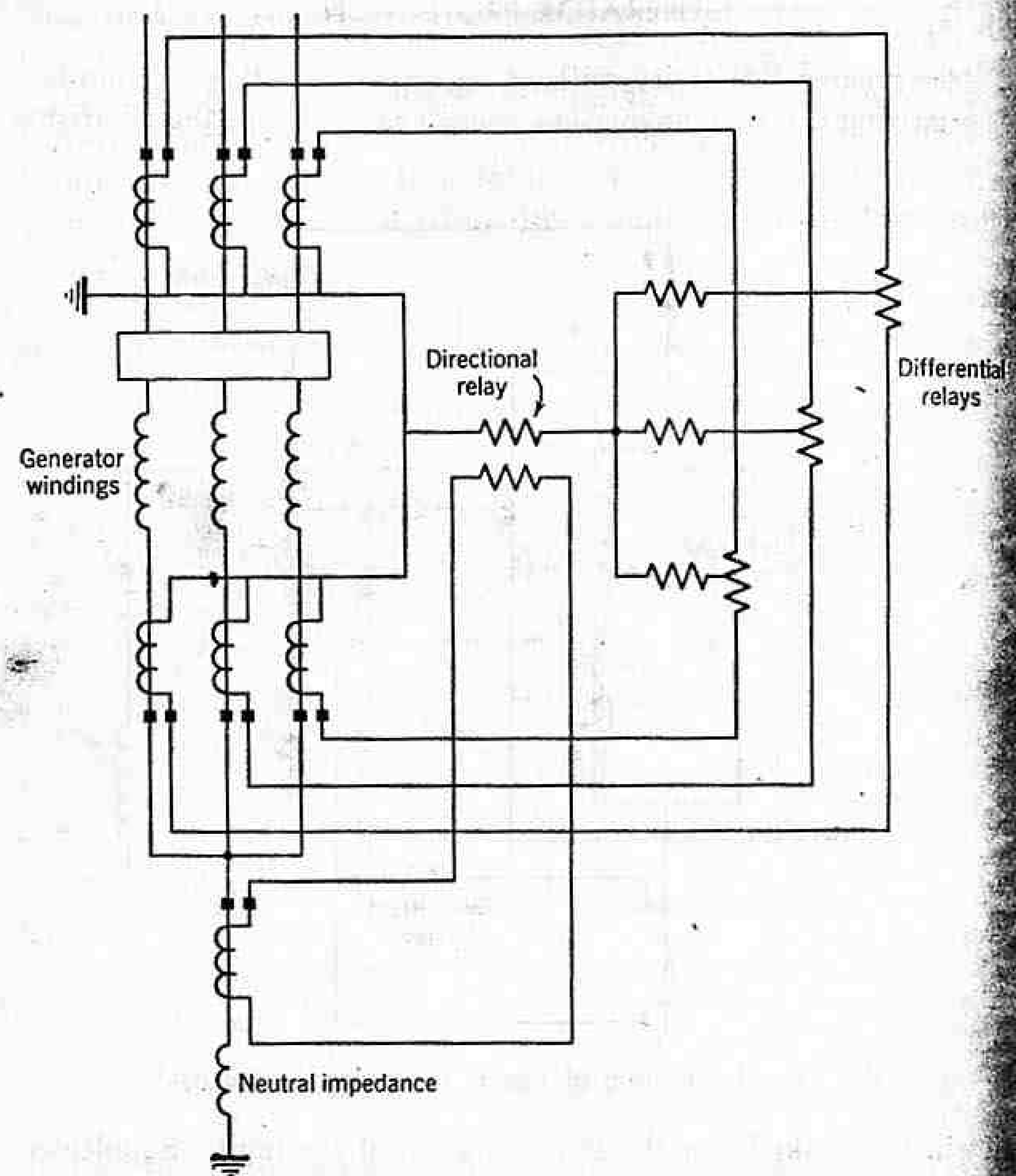

Fig. 13. Sensitive stator ground-fault relaying for generators.

where X_C is the total phase-to-ground-capacity reactance *per phase* of the generator stator windings, the surge protective capacitors or lightning arresters, if used, the leads to the main and station-service power transformers, and the power-transformer windings on the generator side; and N is the open-circuit voltage ratio (or turns ratio) of the high-voltage to the low-voltage windings of the distribution transformer.[20]

The value of R may be less than that given by the foregoing equation. The value of resistance given by the equation will limit the maximum instantaneous value of the transient voltage to ground to about 260% of normal line-to-ground crest value. Further reduction in resistance

will not appreciably reduce the magnitude of the transient voltage. The lower the value of R, the more damage will be done by a ground fault, particularly if the relay is not connected to trip the generator breakers. The relaying sensitivity will decrease as R is decreased, because, as can be seen in Fig. 15, more of the available voltage will be consumed in the positive- and negative-phase-sequence impedances and less in the zero-phase-sequence impedance which determines the magnitude of the relay voltage. This decrease in sensitivity is considered by some people to be an advantage because the relay will be less likely to operate for faults on the low-voltage side of the generator potential transformers, as discussed later. In fact, it has been suggested[21] that for this reason, and also to simplify the calculations by making it unnecessary to determine X_C, a resistor be chosen that will limit the fault current to approximately 15 amperes, neglecting the effect of X_C. In other words,

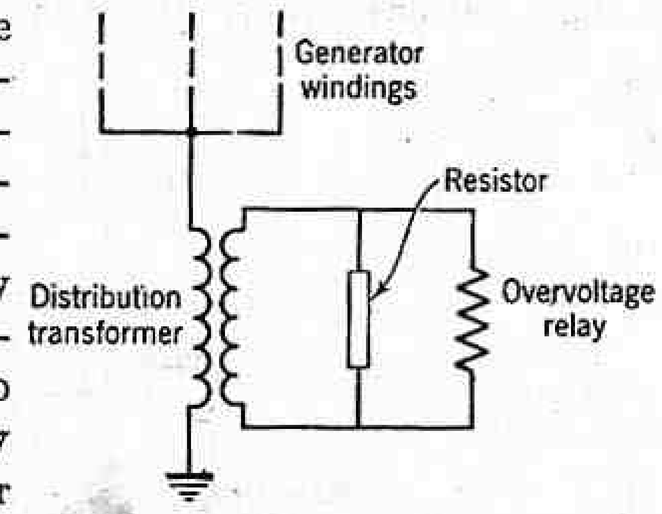

Fig. 14. Stator ground-fault protection of unit generators.

$$R = \frac{10^3 V_G}{15\sqrt{3}\, N^2} \text{ ohms}$$

where V_G is the phase-to-phase-voltage rating of the generator in kilovolts.

It has been suggested that, to avoid large magnetizing-current flow to the distribution transformer when a ground fault occurs, the high-voltage rating of the distribution transformer should be at least 1.5 times the phase-to-neutral-voltage rating of the generator.[20] Its insulation class must fulfill the standard requirements for neutral grounding devices.[22] The low-voltage rating may be 120, 240, or 480 volts, depending on the available or desired voltage rating of the protective relay.

The kva rating to choose for the distribution transformer and for the resistor will depend on whether the user intends to let the overvoltage relay trip the generator main and field breakers or merely sound an alarm. If the relay will merely sound an alarm, the transformer should be continously rated for at least:

$$\text{kva} = \frac{10^3 V_G V_T}{\sqrt{3}\, N^2 R}$$

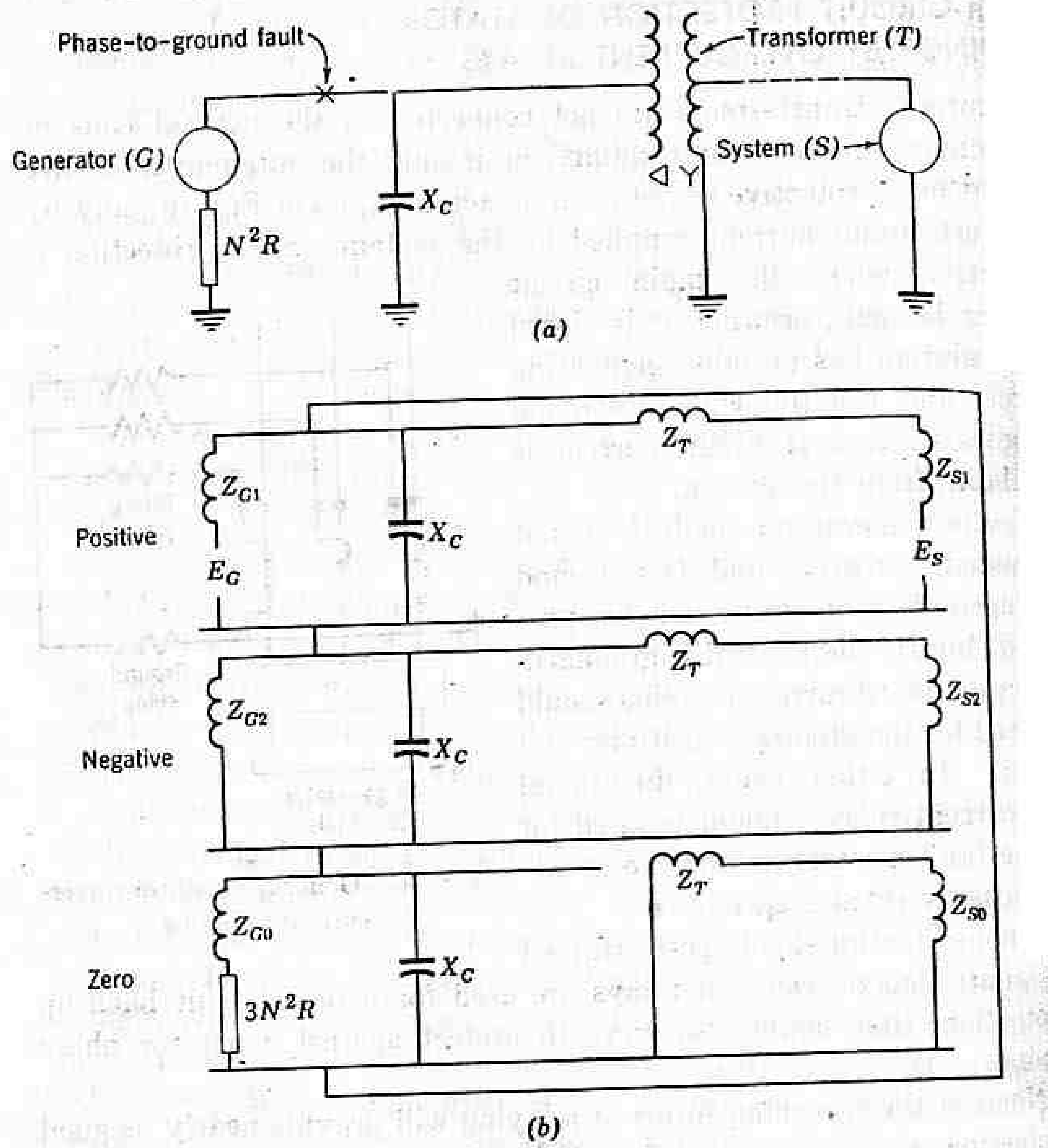

Fig. 15. (a) One-line diagram of a system with a unit generator and a phase-to-ground fault. (b) Phase-sequence diagram for (a).

where V_T is the high-voltage rating of the distribution transformer in kilovolts. Similarly, the continuous rating of the resistor should be at least:

$$\text{kw} = \frac{10^3 V_G^2}{3N^2R}$$

If the relay is arranged to trip the generator breakers, short-time transformer and resistor ratings[23] may be used. For example, a 1-minute-rating transformer would have only 21% of the continuous kva rating, and a 10-minute rating would have 40%. However, the lower the transformer rating, the more inductive reactance the transformer will introduce in series with the grounding resistance; for this reason, the 1-minute rating is the lowest considered desirable. The resistor may have either a 10-second or a 1-minute rating, but the 1-minute rating is generally preferred because it is more conservative and not much more expensive. In fact, continuous-rated resistors may even be economical enough.

It is preferred to have the relay trip the generator main and field breakers. Even though the fault current is very low, some welding of the stator laminations may occur if the generator is permitted to continue operating with a ground fault in its winding.[24] Also, in the presence of the fault, the voltage to ground of other parts of the stator windings will rise to $\sqrt{3}$ times normal; should this cause another ground fault to develop, a phase-to-phase fault might result, and additional damage would be done that would have been avoided had the generator breakers been tripped when the first fault occurred. Furthermore, if split-phase protection is not provided and if the ground relay is not permitted to trip, the generator could develop a turn-to-turn fault and there might be considerable iron burning before the fault could spread to another phase and cause the differential relays to operate. In spite of the foregoing, many power companies are willing to risk the possibility of additional damage until they can conveniently remove the faulty generator from service.

A number of power companies simply connect a potential transformer between the generator neutral and ground without any loading resistor. They have operated this way for years, apparently without any difficulty.[19] An overvoltage relay is used as with the distribution-transformer arrangement. The maximum current that can flow in a ground fault is 71% of that with the distribution-transformer-and-resistor combination if the maximum allowable value of R is used, which is not a significant difference. In either case, the arc energy is sufficient to cause damage if immediate tripping is not done.[25] The potential transformer is considerably smaller and cheaper than the distribution-transformer-and-resistor combination, although either one is relatively inexpensive compared with the equipment protected. The principal disadvantage is that the user cannot be certain whether harmfully high transient overvoltages will occur. The only evidence we have is that such overvoltages can occur—at least under laboratory-controlled circumstances. Therefore, until positive evidence to the contrary is presented, the distribution-transformer-and-resistor combination seems to be safer.

If one prefers to let a generator operate with a ground fault in its stator winding, a ground-fault neutralizer will limit the fault current to the smallest value of any of the arrangements, and at the same time will hold the transient voltage to a lower level.[25] However, it is necessary to be sure that surge-protective capacitors, if used, cannot cause harmfully high overvoltages should a defect cause the capacitances to ground to become unbalanced.[26]

Reference 27 describes a modification of the foregoing methods whereby voltage is introduced between the generator neutral and ground for the purpose of obtaining greater sensitivity. Little, if any, application of this principle exists presently in the United States.

The same overvoltage-relay characteristics are required for any of the foregoing generator-neutral-grounding methods. The relay must be sensitive to fundamental-frequency voltages and insensitive to the third-harmonic and multiples of third-harmonic voltages. The relay may require adjustable time delay so as to be selective with other relays for ground faults on the high-voltage side of the main power transformer for which there may be a tendency to operate owing to capacitance coupling between the power-transformer windings, particularly if the high-voltage winding of the power transformer does not have its neutral solidly grounded;[19,20,25] the ground-fault-neutralizer-grounding arrangement has the greatest operating tendency under such circumstances, and the distribution-transformer arrangement has the least. Time delay is desirable also to provide as good selectivity as possible with potential-transformer fuses for faults on the secondary side of potential transformers connected wye-wye. If the relaying equipment is used only to sound an alarm, a combination of relays may be required to get both good sensitivity and a high continuous-voltage rating.

If grounded-neutral wye-wye potential transformers are connected to the generator leads, it may be impossible to get complete selectivity between the relay and the PT (potential-transformer) fuses for certain ground faults on the low-voltage side of the PT's, depending on the fuse ratings and on the relay sensitivity.[21] In other words, the relay may sometimes operate when there is not enough fault current to blow a fuse. Such lack of coordination might be considered an advantage; the relay will protect the PT's from thermal damage for which the fuses could not protect. To make the relay insensitive enough so that it would not operate for low-voltage ground faults would sacrifice too much sensitivity for generator faults. Of course, if the relay has time delay, it will not operate for a momentary short circuit such as might be caused inadvertently during testing. If the relay is used only to sound an alarm, some selectivity may be sacrificed in the interests of sensitivity; the relay will not operate frequently enough to be a nuisance.

SHORT-CIRCUIT PROTECTION OF STATOR WINDINGS BY OVERCURRENT RELAYS

If current transformers are not connected in the neutral ends of wye-connected generator windings, or if only the outgoing leads are brought out, protective devices can be actuated, as in Fig. 16, only by the short-circuit current supplied by the system. Such protection is ineffective when the main circuit breaker is open, or when it is closed if the system has no other generating source, and the following discussion assumes that short-circuit current is available from the system.

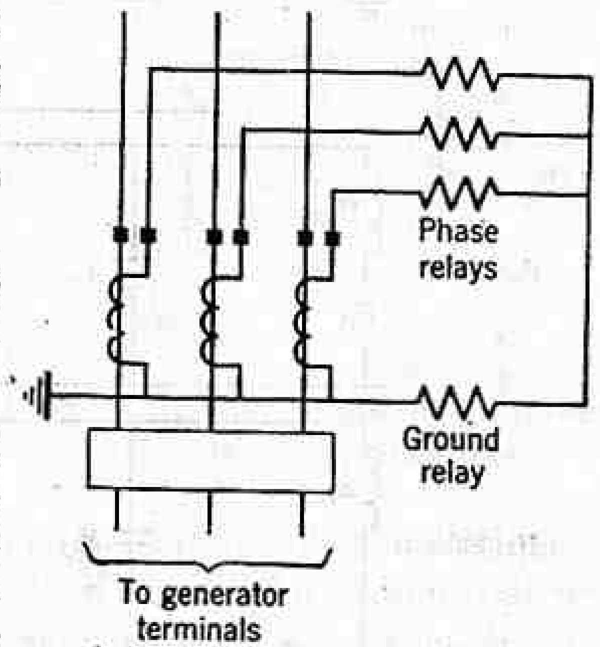

Fig. 16. Generator stator overcurrent relaying.

If the generator's neutral is not grounded, sensitive and fast ground overcurrent protection can be provided; but, if the neutral is grounded, directional overcurrent relaying should be used for the greatest sensitivity and speed. In either event, directional overcurrent relays should be used for phase-fault protection for the greatest sensitivity and speed.

If non-directional voltage-restrained or -controlled overcurrent relays are used for external-fault back-up protection, they could also serve to protect against generator phase faults.

None of the foregoing forms of relaying will provide nearly as good protection as percentage-differential relaying equipment, and they should not be used except when the cost of bringing out the generator leads and installing current transformers and differential relays cannot be justified.

PROTECTION AGAINST STATOR OPEN CIRCUITS

An open circuit or a high-resistance joint in a stator winding is very difficult to detect before it has caused considerable damage. Split-phase relaying may provide such protection, but only the most sensitive equipment will detect the trouble in its early stages.[17] Negative-phase-sequence-relaying equipment for protection against unbalanced phase currents contains a sensitive alarm unit that will alert an operator to the abnormal condition.

It is not the practice to provide protective-relaying equipment purposely for open circuits. Open circuits are most unlikely in well-constructed machines.

STATOR-OVERHEATING PROTECTION

General stator overheating is caused by overloading or by failure of the cooling system, and it can be detected quite easily. Overheating because of short-circuited laminations is very localized, and it is just a matter of chance whether it can be detected before serious damage is done.

The practice is to embed resistance temperature-detector coils or thermocouples in the slots with the stator windings of generators larger than about 500 to 1500 kva. Enough of these detectors are located at different places in the windings so that an indication can be obtained of the temperature conditions throughout the stator.[28] Several of the detectors that give the highest temperature indication are selected for use with a temperature indicator or recorder, usually having alarm contacts; or the detector giving the highest indication may be arranged to operate a temperature relay to sound an alarm.

Supplementary temperature devices may monitor the cooling system; such equipment would give the earliest alarm in the event of cooling-system failure, but it is generally felt that the stator temperature detectors and alarm devices are sufficient.

Figure 17 shows one form of detector-operated relaying equipment using a Wheatstone-bridge circuit and a directional relay. In another form of equipment, the stator current is used to energize the bridge.

"Replica"-type temperature relays may be used with small generators that do not have temperature detectors. Such a relay is energized either directly by the current flowing in one of the stator windings of the machine or indirectly from current transformers in the stator circuit. The relay is arranged with heating and heat-storage elements so as to heat up and cool down as nearly as possible at the same rate as the machine in response to the same variations in the current. A thermostatic element closes contacts at a selected temperature. It will be evident that such a relay will not operate for failure of the cooling system.

The temperature-detector-operated devices are preferred because they respond more nearly to the actual temperature of the stator. The fact that the actual stator copper temperature is higher than the temperature at the detector[29] should be taken into account in the adjustment of the temperature relay. This difference in temperature may be 25°C or more in hydrogen-cooled machines, being greater at the higher hydrogen pressures. Thus, if the permissible copper

temperature is assumed to remain constant with higher loading at higher hydrogen pressure, the temperature-relay setting must be lower. In unattended stations, temperature relays are arranged to reduce

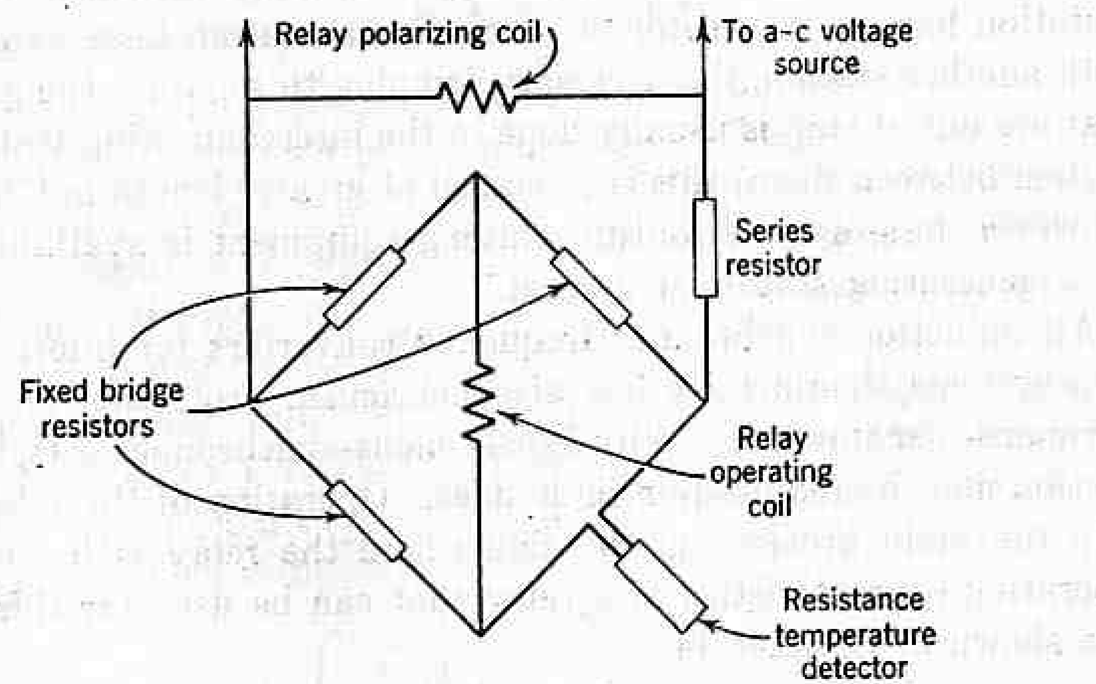

Fig. 17. Stator overheating relaying with resistance temperature detectors.

the load or shut down the unit if it overheats, but in an attended station the relay, if used, merely sounds an alarm. It should not be inferred from the foregoing that a generator may be loaded on the basis of temperature, because such practice is not recommended.

OVERVOLTAGE PROTECTION

Overvoltage protection is recommended for all hydroelectric or gas-turbine generators that are subject to overspeed and consequent overvoltage on loss of load. It is not generally required with steam-turbine generators.

This protection is often provided by the voltage-regulating equipment. If it is not, it should be provided by an a-c overvoltage relay. This relay should have a time-delay unit with pickup at about 110% of rated voltage, and an instantaneous unit with pickup at about 130% to 150% of rated voltage. Both relay units should be compensated against the effect of varying frequency. The relay should be energized from a potential transformer other than the one used for the automatic voltage regulator. Its operation should, preferably, first cause additional resistance to be inserted in the generator or exciter field circuit. Then, if overvoltage persists, the main generator breaker and the generator or exciter field breaker should be tripped.

LOSS-OF-SYNCHRONISM PROTECTION

It is not the usual practice to provide loss-of-synchronism protection at a prime-mover-driven generator. One generator is not likely to lose synchronism with other generators in the same station unless it loses excitation, for which protection is usually provided. Whether a station has one generator or more, if this station loses synchronism with another station, the necessary tripping to separate the generators that are out of step is usually done in the interconnecting transmission system between them; this is discussed at greater length in Chapter 14. However, loss-of-synchronism relaying equipment is available for use at a generating station if desired.

All induction-synchronous frequency converters for interconnecting two systems should have loss-of-synchronism protection on the synchronous-machine side. With synchronous-synchronous sets, such protection may be required on both sides. Operation of the relay should trip the main breaker on the side where the relay is located. The operating characteristics of a relay that can be used for this purpose are shown in Chapter 14.

FIELD GROUND-FAULT PROTECTION

Because field circuits are operated ungrounded, a single ground fault will not cause any damage or affect the operation of a generator in any way. However, the existence of a single ground fault increases the stress to ground at other points in the field winding when voltages are induced in the field by stator transients.[30] Thus, the probability of a second ground occurring is increased. Should a second ground occur, part of the field winding will be by-passed, and the current through the remaining portion may be increased. By-passing part of the field winding will unbalance the air-gap fluxes, and this will unbalance the magnetic forces on opposite sides of the rotor. Depending on what portion of the field is by-passed, this unbalance of forces may be large enough to spring the rotor shaft, and make it eccentric. A calculation of the possible unbalance force for a particular generator gave 40,000 pounds.[31] Cases are on record where the resulting vibration has broken bearing pedestals, allowing the rotor to grind against the stator; such failures caused extensive damage that was costly to repair and that kept the machines out of service for a long time.[31]

The second ground fault may not by-pass enough of the field winding to cause a bad magnetic unbalance, but arcing at the fault

may heat the rotor locally and slowly distort it, thereby causing eccentricity and its accompanying vibration to develop slowly in from 30 minutes to 2 hours.

The safest practice is to use protective-relaying equipment to trip the generator's main and field breakers immediately when the first ground fault occurs, and this practice should certainly be followed in all unattended stations. However, many would rather risk the chance of a second ground fault and its possible consequences in an attended station, in order to keep the machine in service until it is more convenient to shut it down;[9] this group would use protective-relaying—or other—equipment, if any—merely to actuate an alarm or an indication when the first ground fault has occurred.

If a generator is to be permitted to operate with a single ground fault in its field, there should at least be provided automatic equipment for immediately tripping the main and field breakers at an abnormal amplitude of vibration, but at no higher amplitude than necessary to avoid undesired operation on synchronizing or short-circuit transients. Such equipment would minimize the duration of severe vibration should the second ground fault occur at a critical location; obviously, the vibration cannot be stopped instantly because it takes time for the field flux to decay, but this is the best that can be done under the circumstances; the authors of Reference 31 calculated the effect of such prolonged vibration decreasing in amplitude and felt that there was no hazard. However, damage has been known to occur immediately when the second ground occurred and before anything could be done to prevent it. Vibration-detecting equipment should be in service continuously and not be put in service manually after the first ground fault has occurred, because the two ground faults may occur together or in quick succession. In addition, at least an alarm would be desirable, and preferably time-delay automatic tripping of the main and field breakers, at a still lower amplitude of vibration. This lower-set time-delay equipment would minimize the amplitude of vibration caused by rotor distortion because of localized heating. If this lower-set equipment were provided, the high-set vibration equipment could be permitted to shut down the prime mover as well as to trip the main and field breakers. The low-set equipment should preferably not shut down the prime mover; if the vibration is being caused by rotor eccentricity because of local heating, the amplitude might increase to a dangerous amount as the rotor speed decreases, because many generators have a critical speed below normal at which vibration may be materially worse than at normal speed;

instead, it would be preferable to trip the main and field breakers and keep the rotor turning at normal speed for 30 minutes to an hour to cool the rotor and let it straighten itself out.

In spite of the known hazard of extensive damage and a long-time outage, many generators are in service with no automatic protection or even alarm for field grounds, and the majority of the rest have ground-indication equipment only. This can only mean that, during the time that a generator is being operated with one ground in its field, the probability is remote of a second ground occurring and at such a location as to cause immediate damage before an operator can act to correct the condition. The possibility exists, nevertheless, and one should avoid such operation if at all possible.

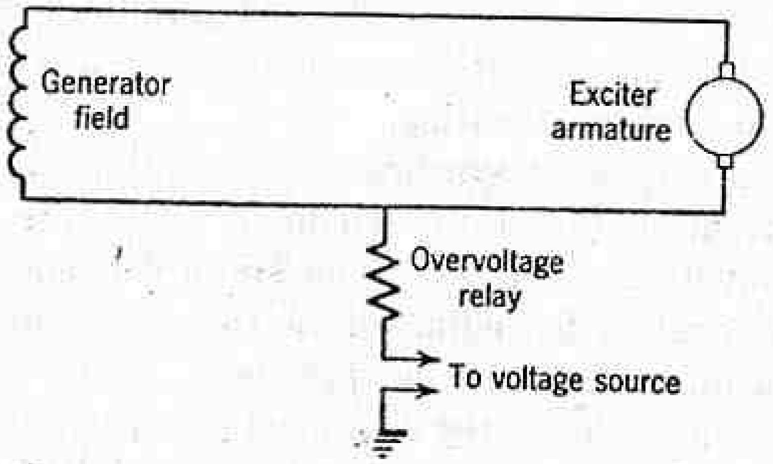

Fig. 18. Generator field ground-fault relaying.

The preferred type of protective-relaying equipment is shown in Fig. 18. Either a-c or d-c voltage may be impressed between the field circuit and ground through an overvoltage relay. A ground anywhere in the field circuit will pick up the relay. If direct current is used, the overvoltage relay can be more sensitive than if alternating current is used; with alternating current, the relay must not pick up on the current that flows normally through the capacitance to ground, and care must be taken to avoid resonance between this capacitance and the relay inductance.

It may be necessary to provide a brush on the rotor shaft that will effectively ground the rotor, especially when a-c voltage is applied.[32] One should not rely on the path to ground through the bearing-oil film for two reasons: (1) the resistance of this path may be high enough so that the relay would not operate if the field became grounded, and (2) even a very small magnitude of current flowing continually through the bearing may pit the surface and destroy the bearing.[33] A brush will probably be required with a steam turbine having steam seals. The brush should be located where it will not

by-pass the bearing-pedestal insulation that is provided to prevent the flow of shaft currents. One should consult the turbine manufacturer before deciding that such a brush is not required.

PROTECTION AGAINST ROTOR OVERHEATING BECAUSE OF UNBALANCED THREE-PHASE STATOR CURRENTS

Unbalanced three-phase stator currents cause double-system-frequency currents to be induced in the rotor iron. These currents will quickly cause rotor overheating and serious damage if the generator is permitted to continue operating with such an unbalance.[34,35,36] Unbalanced currents may also cause severe vibration, but the overheating problem is more acute.

Standards have been established for the operation of generators with unbalanced stator currents.[37] The length of time (T) that a generator may be expected to operate with unbalanced stator currents without danger of being damaged can be expressed in the form:

$$\int_0^T i_2^2\, dt = K$$

where i_2 is the instantaneous negative-phase-sequence component of the stator current as a function of time; i_2 is expressed in per unit based on the generator rating, and K is a constant. K is 30 for steam-turbine generators, synchronous condensers, and frequency-changer sets; K is 40 for hydraulic-turbine generators, and engine-driven generators. If the integrated value is between that given for K and twice this value, the generator "may suffer varying degrees of damage, and an early inspection of the rotor surface is recommended."[37] If the integrated value is greater than twice that given for K, "serious damage should be expected.".

If we let I_2^2 be the average value of i_2^2 over the time interval T, we can express the foregoing relation in the handy form $I_2^2\ T = 30$ or $I_2^2T = 40$, depending on the type of generator. If T is longer than 30 seconds, I_2 may be larger than the foregoing relation would permit, but no general figures can be given that would apply to any machine.[34,36,38]

It has been shown that current-balance relaying equipment operating from the phase currents will operate too quickly for small unbalances and too slowly for large unbalances.[39]

The recommended type of relaying equipment is an inverse-time overcurrent relay operating from the output of a negative-phase-sequence-current filter that is energized from the generator CT's as in Fig. 19.[38,39] The relay's time-current characteristics are of the form $I^2T = K$, so that, with the pickup and time-delay adjustments that are provided, the relay characteristic can be chosen to match closely any machine characteristic. The relay should be connnected to trip the generator's main breaker. Some forms of the relay also include a very sensitive unit to control an alarm for small unbalances.

Extensive studies have shown that, in the majority of cases, the negative-phase-sequence-current relay will properly coordinate with

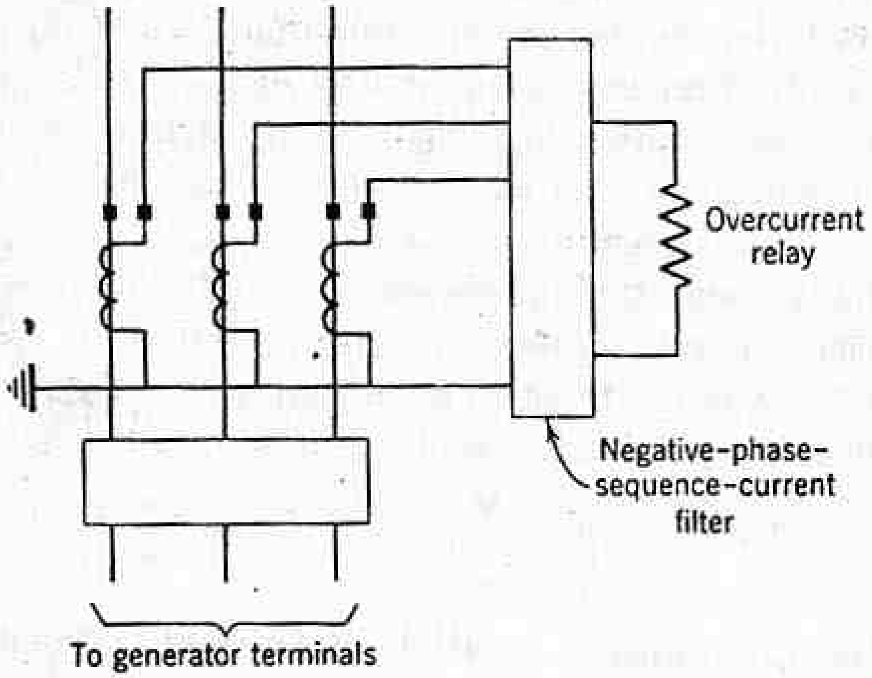

Fig. 19. Negative-phase-sequence-overcurrent relaying for unbalanced stator currents.

other system-relaying equipment.[40,41] Improper coordination is said to be possible where load is supplied at generator voltage and where there are five or more generators in the system. For a unit generator-transformer arrangement, proper coordination is assured.

The fact that the system-relaying equipment will generally operate first might lead to the conclusion that, with modern protective equipment, protection against unbalanced three-phase currents during short circuits is not required.[36,42] This conclusion might be reached also from the fact that there has been no great demand for improvement of the existing forms of protection. The sensitive alarm unit would be helpful to alert an operator in the event of an open circuit under load, for which there may be no other automatic protection. Otherwise, one would apply the negative-phase-sequence-current relay only when the back-up-relaying equipment of the system could not be relied on to remove unbalanced faults quickly enough in the event of primary-relaying failure. However, there are undoubtedly many locations where back-up relaying will not operate for certain faults. Therefore, one should not generalize on this subject but should get the

facts for each application. To determine properly whether additional protection is really necessary is a very complicated study. Where additional protection can be afforded, it should be applied.

LOSS-OF-EXCITATION PROTECTION

When a synchronous generator loses excitation, it operates as an induction generator, running above synchronous speed. Round-rotor generators are not suited to such operation because they do not have amortisseur windings that can carry the induced rotor currents. Consequently, a steam-turbine-generator's rotor will overheat rather quickly from the induced currents flowing in the rotor iron, particularly at the ends of the rotor where the currents flow across the slots through the wedges and the retaining ring, if used. The length of time to reach dangerous rotor overheating depends on the rate of slip, and it may be as short as 2 or 3 minutes. Salient-pole generators invariably have amortisseur windings, and, therefore, they are not subject to such overheating.

The stator of any type of synchronous generator may overheat, owing to overcurrent in the stator windings, while the machine is running as an induction generator. The stator current may be as high as 2 to 4 times rated, depending on the slip. Such overheating is not apt to occur as quickly as rotor overheating.

Some systems cannot tolerate the continued operation of a generator without excitation. In fact, if the generator is not disconnected immediately when it loses excitation, widespread instability may very quickly develop, and a major system shutdown may occur. Such systems are those in which quick-acting automatic generator voltage regulators are not employed. When a generator loses excitation, it draws reactive power from the system, amounting to as much as 2 to 4 times the generator's rated load. Before it lost excitation, the generator may have been delivering reactive power to the system. Thus, this large reactive load suddenly thrown on the system, together with the loss of the generator's reactive-power output, may cause widespread voltage reduction, which, in turn, may cause extensive instability unless the other generators can automatically pick up the additional reactive load immediately.

In a system in which severe disturbances can follow loss of excitation on a given generator, automatic quick-acting protective-relaying equipment should be provided to trip the generator's main and field breakers. An operator does not have sufficient time to act under such circumstances. Where system disturbances definitely will not follow loss of excitation, an operator will usually have at least 2 or 3 minutes in which to act in lieu of automatic tripping. Sometimes an emergency excitation source and manual throw-over are provided that may make it unnecessary to remove a generator from service. However, an operator can usually do nothing except remove the generator from service, unless the operator himself has accidentally removed excitation. If a loss-of-excitation condition should not be recognized and a generator should run without excitation for an unknown length of time, it ought to be shut down and carefully examined for damage

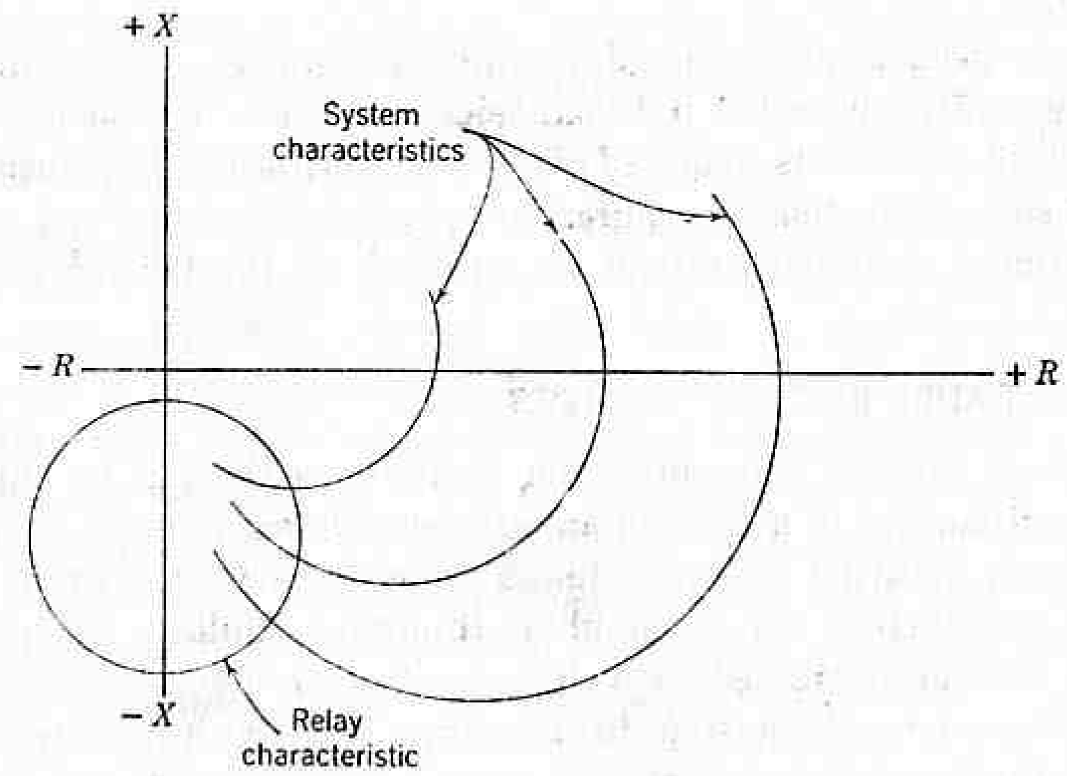

Fig. 20. Loss-of-excitation relay and system characteristics.

before returning it to service. In systems in which severe disturbances may or may not follow loss of excitation in a given generator, the generator must sometimes be tripped when the system does not require it, merely to be sure that the generator will always be tripped when the system *does* require it.

Undercurrent relays connected in the field circuit have been used quite extensively, but the most selective type of loss-of-excitation relay is a directional-distance type operating from the a-c current and voltage at the main generator terminals.[43] Figure 20 shows several loss-of-excitation characteristics and the operating characteristic of one type of loss-of-excitation relay on an R-X diagram. No matter what the initial conditions, when excitation is lost, the equivalent generator impedance traces a path from the first quadrant into a region of the fourth quadrant that is entered only when excitation is severely reduced or lost. By encompassing this region within the relay characteristic, the relay will operate when the generator first starts to slip poles and will trip the field breaker and disconnect the generator from the system before either the generator or the system can be harmed. The generator may then be returned to service immediately when the cause of excitation failure is corrected.

PROTECTION AGAINST ROTOR OVERHEATING BECAUSE OF OVEREXCITATION

It is not the general practice to provide protection against overheating because of overexcitation. Such protection would be provided indirectly by the stator-overheating protective equipment or by excitation-limiting features of the voltage-regulator equipment.

PROTECTION AGAINST VIBRATION

Protective-relaying practices and equipment that are described under the headings "Protection against Rotor Overheating because of Unbalanced Three-Phase Stator Currents" and "Field Ground-Fault Protection" prevent or minimize vibration under those circumstances. If the vibration-detecting equipment recommended under the latter heading is used, it will also provide protection if vibration results from a mechanical failure or abnormality. For a steam turbine, it is the general practice to provide vibration recorders that can also be used if desired to control an alarm or to trip. However, it is not the general practice to trip.

PROTECTION AGAINST MOTORING

Motoring protection is for the benefit of the prime mover or the system, and not for the generator. However, it is considered here because, when protective-relaying equipment is used, it is closely associated with the generator.

Steam Turbines. A steam turbine requires protection against overheating when its steam supply is cut off and its generator runs as a motor. Such overheating occurs because insufficient steam is passing through the turbine to carry away the heat that is produced by windage loss. Modern condensing turbines will even overheat at outputs of less than approximately 10% of rated load.

The length of time required for a turbine to overheat, when its steam is completely cut off, varies from about 30 seconds to about 30 minutes, depending on the type of turbine. A condensing turbine that operates normally at high vacuum will withstand motoring much longer than a topping turbine that operates normally at high back pressure.

Since the conditions are so variable, no single protective practice is clearly indicated. Instead, the turbine manufacturer's recommendations should be sought in each case. The manufacturer will probably have turbine accessories that will provide an alarm or will shut down the equipment, as required.

For a turbine that will not overheat unless its generator runs as a motor, sensitive power-directional-relaying equipment has been widely used. One type of such relaying equipment is able to operate on power flowing into the generator amounting to about 0.5% of the generator's rated full-load watts. In general, the protective equipment should operate on somewhat less than about 3% of rated power. Sufficient time delay should be provided to prevent undesired operation on transient power reversals such as those occurring during synchronizing or system disturbances.

Hydraulic Turbines. Motoring protection may occasionally be desirable to protect an unattended hydraulic turbine against cavitation of the blades. Cavitation occurs on low water flow that might result, for example, from blocking of the trash gates. Protection is not generally provided for attended units. Protection can be provided by power-directional-relaying equipment capable of operating on motoring current of somewhat less than about 2.5% of the generator's full-load rating.

Diesel Engines. Motoring protection for Diesel engines is generally desirable. The generator will take about 15% of its rated power or more from the system, which may constitute an undesirably high load on the system. Also, there may be danger of fire or explosion from unburned fuel. The engine manufacturer should be consulted if one wishes to omit motoring protection.

Gas Turbines. The power required to motor a gas turbine varies from 10% to 50% of full-load rating, depending on turbine design and whether it is a type that has a load turbine separate from that used to drive the compressor. Protective relays should be applied based primarily on the undesirability of imposing the motoring load on the system. There is usually no turbine requirement for motoring protection.

OVERSPEED PROTECTION

Overspeed protection is recommended for all prime-mover-driven generators. The overspeed element should be responsive to machine speed by mechanical, or equivalent electrical, connection; if electrical, the overspeed element should not be adversely affected by generator voltage.

The overspeed element may be furnished as part of the prime mover, of its speed governor, or of the generator; it should operate the speed governor, or whatever other shut-down means is provided, to shut down the prime mover. It should also trip the generator circuit breaker; this is to prevent overfrequency operation of loads connected to the system supplied by the generator, and also to prevent possible overfrequency operation of the generator itself from the a-c system. The overspeed device should also trip the auxiliary breaker where auxiliary power is taken from the generator leads. In certain cases, an overfrequency relay may be suitable for providing both of these forms of protection. However, a direct-connected centrifugal switch is preferred.

The overspeed element should usually be adjusted to operate at about 3% to 5% above the full-load rejection speed. Supplementary overspeed protection is required for some forms of gas turbines. Whether such protection is required for any given turbine, and what its adjustment should be, should be specified by the turbine manufacturer.

EXTERNAL-FAULT BACK-UP PROTECTION

Generators should have provision against continuing to supply short-circuit current to a fault in an adjacent system element because of a primary relaying failure. Simple inverse-time overcurrent relaying is satisfactory for single-phase-to-ground faults. For phase faults, a voltage-restrained or voltage-controlled inverse-time-overcurrent relay—or a single-step distance-type relay with definite time delay—is preferred.

Which of the two general types of phase relay to use depends on the types of relays with which the back-up relays must be selective. Thus, if the adjacent circuits have inverse-time-overcurrent relaying, the voltage-restrained or -controlled inverse-time-overcurrent relay should be used. But, if the adjacent circuits have high-speed pilot or distance relaying, then the distance-type relay should be used.

Inverse-time-overcurrent relays for phase-fault-back-up protection are considered decidedly inferior; owing to the decrement in the short-circuit current put out by a generator, the margin between the maximum-load current and the short-circuit current a short time after the fault current has started to flow is too narrow for reliable protection.

Where cross-compounded generators are involved, external-fault-back-up-relaying equipment need be applied to only one unit.

Negative-phase-sequence-overcurrent-relaying equipment to prevent overheating of the generator rotor as a consequence of prolonged unbalanced stator currents is not here considered a form of external-fault-back-up protection. Instead, such relaying is considered a form of primary relaying, and it is treated as such elsewhere. A back-up relay should have characteristics similar to the relays being backed up, and a negative-phase-sequence-overcurrent relay is not the best for this purpose, apart from the fact that such a relay would not operate for three-phase faults.

When a unit generator-transformer arrangement is involved, the external-fault-back-up relay is generally energized by current and voltage sources on the low-voltage side of the power transformer. Then the connections should be such that the distance-type units measure distance properly for high-voltage faults.

BEARING-OVERHEATING PROTECTION

Bearing overheating can be detected by a relay actuated by a thermometer-type bulb inserted in a hole in the bearing, or by a resistance-temperature-detector relay, such as that described for stator-overheating protection, with the detector embedded in the bearing. Or, where lubricating oil is circulated through the bearing under pressure, the temperature of the oil may be monitored if the system has provision for giving an alarm if the oil stops flowing.

Such protection is provided for all unattended generators where the size or importance of the generator warrants it. Such protection for attended generators is generally only to sound an alarm.

OTHER MISCELLANEOUS FORMS OF PROTECTION

The references given later under the heading "Protection of the Prime Mover" describe other protective features provided for generators and their associated equipment. These forms of protection are generally mechanical and are not generally classified with protective-relaying equipment.

GENERATOR POTENTIAL-TRANSFORMER FUSING AND FUSE BLOWING

Unless special provision is made, the blowing of a potential-transformer fuse may cause certain relays to trip the generator breakers. Such relays are those types employing voltage restraint, such as voltage-controlled or distance-type relays used for loss-of-excitation or external-fault-back-up protection. It is not necessarily a complete loss of voltage that causes such undesired tripping; with a three-phase voltage supply consisting of two or three potential transformers, the blowing of a fuse may change the magnitude and phase relations of certain secondary voltages through the mechanism of the potentiometer

effect of other devices connected to the PT's. Such an effect can cause a relay to operate undesirably when complete loss of voltage would not cause undesired operation.

The proper solution to this problem is not the complete removal of all fuses. The preferred practice is to fuse both primary and secondary circuits.[2] However, the secondary fuses may be omitted from the circuits of relays or other devices where correct operation is so essential that it is "preferable to incur hazards associated with the possible destruction of the PT by a sustained secondary short circuit rather than to risk interruption of the voltage supply to such devices as the result of a momentary short circuit."[2] Advantage is usually taken of this clause not to fuse the secondary, and the record with this practice has been very good. Primary fuses should not be omitted, but they must be chosen so that they will not blow on magnetizing-current inrush or other transients.[44]

When secondary fusing is used because of the better protection that it gives the potential transformers, the exposure of critical devices to the effects of accidental fuse blowing can be minimized by fusing their circuits separately, or by fusing all circuits except those of the critical devices.

When separate secondary fusing is not enough assurance against the consequences of fuse blowing, a voltage-balance relay may be used that compares the magnitudes of the voltages of the voltage source under consideration with the voltages of another source that are always approximately equal to the voltages of the first source unless a fuse blows. Such a relay can be arranged to prevent undesired operation of critical relays and to actuate an alarm when a fuse blows. Not only preventing undesired relay operation but also knowing immediately that a fuse has blown are important. With wye-wye potential transformers, a set of auxiliary PT's connected wye-broken-delta, with a voltage relay energized by the voltage across the open corner of the delta, can be used to open the trip circuit when one or more fuses blow.

STATION AUXILIARY PROTECTION

Power-plant auxiliaries are treated somewhat differently from similar equipment used elsewhere. It is generally felt that they deserve higher-quality protective equipment. At the same time, however, certain so-called "essential" auxiliaries are kept in service under manual supervision during overload conditions that would ordinarily call for tripping.[45,46] Reference 46 stresses the importance of keeping auxiliary motors running during system disturbances, and describes ing conditions, other than short circuits, that do not necessarily re-quire the immediate removal from service of a machine and that might be left to the control of an attendant.

The arguments that are advanced in favor of a minimum amount of automatic protective equipment are as follows: (*a*) the more automatic equipment there is to maintain, the poorer maintenance it will get, and hence it will be less reliable; (*b*) automatic equipment might operate incorrectly and trip a generator undesirably; (*c*) an operator can sometimes avoid removing a generator from service when its removal would be embarrassing. Most of the objection to automatic protective equipment is not so much that a relay will fail to operate when it should, but that it might remove a generator from service unnecessarily. Part of the basis for this attitude is simply fear. Each additional device adds another contact that can trip the generator. The more such contacts there are, the greater is the possibility that one might somehow close when it should not. There is some justification for such fears. Relays have operated improperly. Such improper operation is most likely in new installations before the installation "kinks" have been straightened out. Occasionally, an abnormal operating condition arises that was not anticipated in the design or application of the equipment, and a relay operates undesirably. Cases are on record where cleaning or maintenance personnel accidentally caused a relay to trip a generator. But, if something is known to be basically wrong with a protective relay so that it cannot be relied on to operate properly, it should not be applied, or it should be corrected one way or another. Otherwise, fear alone is not a proper basis for omitting needed protection.

Admittedly, an alert and skillful operator can sometimes avoid removing a generator from service. In general, however, and with all due respect to operators, the natural fear of removing a machine from service unnecessarily could result in serious damage. Operators have been known to make mistakes during emergencies and to trip generators unnecessarily as well as to fail to trip when necessary. Furthermore, during an emergency, an operator has other important things to do for which he is better fitted.

An unnecessary generator outage is undesirable, but one should not try to avoid it by the omission of otherwise desirable automatic protection. It is generally agreed that any well-designed and well-operated system should be able to withstand a short unscheduled outage of the largest generating unit.[9] It is realized that sometimes it may take several hours to make sure that there is nothing wrong with the unit and to return it to service. Nevertheless, if this is the

price one has to pay to avoid the possibility of a unit's being out of service several months for repair, it is worth it. The protection of certain generators against the possibility of extensive damage may be more important than the protection of the service of the system.[9]

The practice is increasing of using centralized control, which requires more automatic equipment and less manual "on the spot" supervision, in order to provide higher standards of service with still greater efficiency.[10] Such practice requires more automatic protective-relaying equipment to provide the protection that was formerly the responsibility of attendants.[8]

SHORT-CIRCUIT PROTECTION OF STATOR WINDINGS BY PERCENTAGE-DIFFERENTIAL RELAYS

It is the standardized practice of manufacturers to recommend differential protection for generators rated 1000 kva or higher,[2] and most of such generators are protected by differential relays.[11] Above 10,000 kva, it is almost universally the practice to use differential relays.[9] Percentage-differential relaying is the best for the purpose, and it should be used wherever it can be justified economically. It is not necessarily the size of a generator that determines how good the protection should be; the important thing is the effect on the rest of the system of a prolonged fault in the generator, and how great the hardship would be if the generator was badly damaged and was out of service for a long time.

The arrangement of CT's and percentage-differential relays is shown in Fig. 1 for a wye-connected machine, and in Fig. 2 for a delta machine. If the neutral connection is made inside the generator and only the neutral lead is brought out and grounded through low impedance, percentage-differential relaying for ground faults only can be provided, as in Fig. 3. The connections for a so-called "unit" generator-transformer arrangement are shown in Fig. 4; notice that the CT's on the neutral side may be used in common by the differential-relaying equipments of the generator and the transformer.

For greatest sensitivity of differential relaying, the CT primary-current rating would have to be equal to the generator's rated full-load current. However, in practice the CT primary-current rating is as much as about 25% higher than full load, so that if ammeters are connected to the CT's their deflections will be less than full scale at rated load. It may be impossible to abide by this rule in Fig. 5; here, the primary-current rating of the CT's may have to be considerably higher than the generator's rated current, because of the higher system current that may flow through the CT's at the breakers.

techniques for accomplishing this. Reference 47 is a collection of several papers on the effect of reduced voltage and frequency on power-plant capabilities. The protection of station auxiliaries will be treated in more detail where the protection of motors, transformers, and busses is described.

PROTECTION OF THE PRIME MOVER

Except for the protection against motoring and overspeed, the protection of the prime mover and its associated mechanical equipment is not treated in this book. References to some excellent papers on this subject, and also on the subject of fire protection, are given in the Bibliography.[8,48]

Motor Protection

This section deals with the protection of attended synchronous motors, induction motors, synchronous condensers, and the motors of frequency converters. Motors in unattended stations must be protected against all harmful abnormal conditions.[1] The protection of very small motors is not specifically described, although the same basic principles apply; this subject is treated in detail in the National Electrical Code.[3] The practices described here for large motors are at least equal to those covered by the Code, and are generally more comprehensive. However, it is recommended that the Code be consulted whenever it applies. The protection of fire-pump motors is not included here, because it is completely described elsewhere.[4]

SHORT-CIRCUIT PROTECTION OF STATOR WINDINGS

Overcurrent protection is the basic type that is used for short-circuit protection of stator windings. The equipment for this type of protection ranges from fuses for motor voltages of 600 volts and lower, through direct-acting overcurrent tripping elements on circuit breakers, to separate overcurrent relays and circuit breakers for voltages of 2200 volts and higher.

Protection should be provided against a fault in any ungrounded conductor between the interrupting device and the motor, including its stator windings. Where fuses or direct-acting tripping devices are used, there must be one protective element in each ungrounded conductor. Where relays and current transformers are used with so-called "a-c tripping" from the output of the current transformers, a CT and relay are required for each ungrounded conductor. However, if battery or capacitor tripping is provided, three current trans-

formers with two phase relays and one ground relay will suffice for a three-phase circuit whether or not the source neutral is grounded.

Motors Other than Essential Service. For all except "essential-service" motors, it is the practice to provide both inverse-time and instantaneous phase and ground overcurrent relays for automatic tripping. The inverse-time phase relays are generally adjusted to pick up at somewhat less than about 4 times rated motor current, but to have enough time delay so as not to operate during the motor-starting period. The instantaneous phase relays are adjusted to pick up a little above the locked-rotor current. The inverse-time ground relays are adjusted to pick up at no more than about 20% of rated current or about 10% of the maximum available ground-fault current, whichever is smaller. The instantaneous ground-relay pickup should be from about 2.5 to 10 times rated current; this relay may be omitted if the maximum available ground-fault current is less than about 4 times rated current, or if the pickup has to be more than about 10 times rated current to avoid undesired tripping during motor starting or external faults. If a CT, like a bushing CT, is used with all three phase conductors of the motor circuit going through the opening in the core, a very sensitive instantaneous overcurrent relay can be used that will operate for ground faults within about 10% of the winding from the neutral end.

Percentage-differential relaying is provided for large motors. It is the practice of manufacturers[2] to recommend such protection for motors of the following ratings: (*a*) 2200 volts to 4999 volts, inclusive, 1500 hp and higher; (*b*) 5000 volts and higher, 501 hp and higher. The advantage of percentage-differential relaying is that it will provide faster and more sensitive protection than overcurrent relaying, but at the same time it will not operate on starting or other transient overcurrents.

References to excellent articles on the subject of industrial-motor protection are given in the Bibliography.[49]

Essential-Service Motors. For essential-service motors, the inverse-time phase overcurrent relays are usually omitted, leaving the instantaneous phase relays, and the inverse-time and instantaneous ground relays, or the differential relays if applicable. The reason for the omission is to trip the motor breaker automatically only for short circuits and not to trip for any other reason. This is because the tripping of such a motor may force a partial or complete shutdown of a generator or other service with which the motor is associated, and hence any unnecessary tripping must be avoided. As will be seen when we consider stator overheating protection, supplementary protection against phase overcurrents less than locked-rotor values is provided.

STATOR-OVERHEATING PROTECTION

All motors need protection against overheating resulting from overload, stalled rotor, or unbalanced stator currents. For complete protection, three-phase motors should have an overload element in each phase; this is because an open circuit in the supply to the power transformer feeding a motor will cause twice as much current to flow in one phase of the motor as in either of the other two phases, as shown in Fig. 21. Consequently, to be sure that there will be an overload ele-

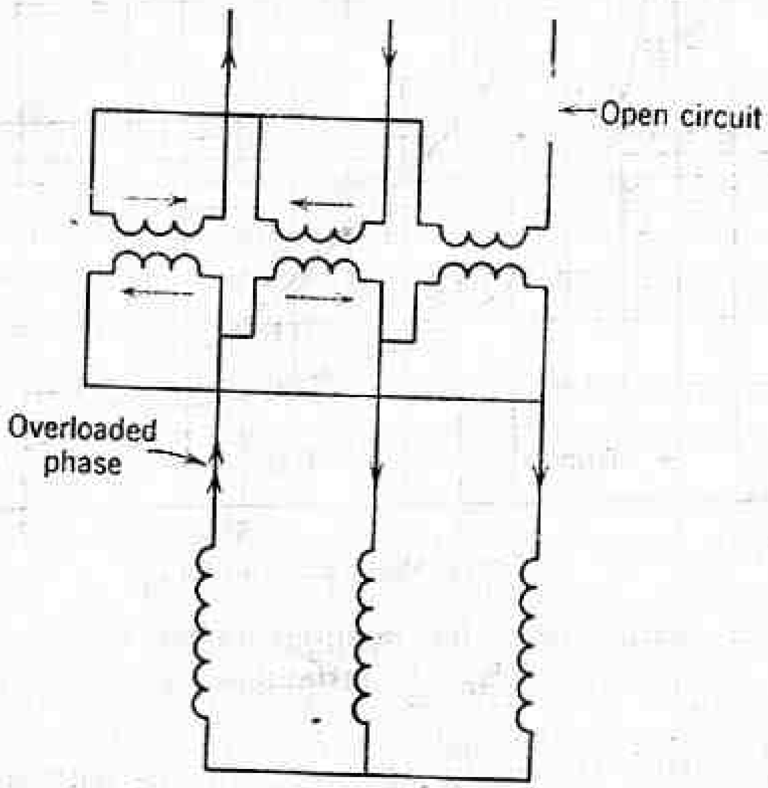

Fig. 21. Illustrating the need for overcurrent protection in each phase.

ment in the most heavily loaded phase no matter which power-transformer phase is open-circuited, one should provide overload elements in all three phases. In spite of the desirability of overload elements in all three phases, motors rated about 1500 hp and below are generally provided with elements in only two phases, on the assumption that the open-phase condition will be detected and corrected before any motor can overheat.

Single-phase motors require an overload element in only one of the two conductors.

Motors Other than Essential Service. Except for some essential-service motors, whose protection will be discussed later, it is the practice for motors rated less than about 1500 hp to provide either

replica-type thermal-overload relays or long-time inverse-time-overcurrent relays or direct-acting tripping devices to disconnect a motor from its source of supply in the event of overload. Which type of relay to use is largely a matter of personal preference. Other things being equal, the replica type will generally provide the best protection because, as shown in Fig. 22, its time-current characteristic more nearly matches the heating characteristic of a motor over the full range of overcurrent; also, it may take into account the heating effect

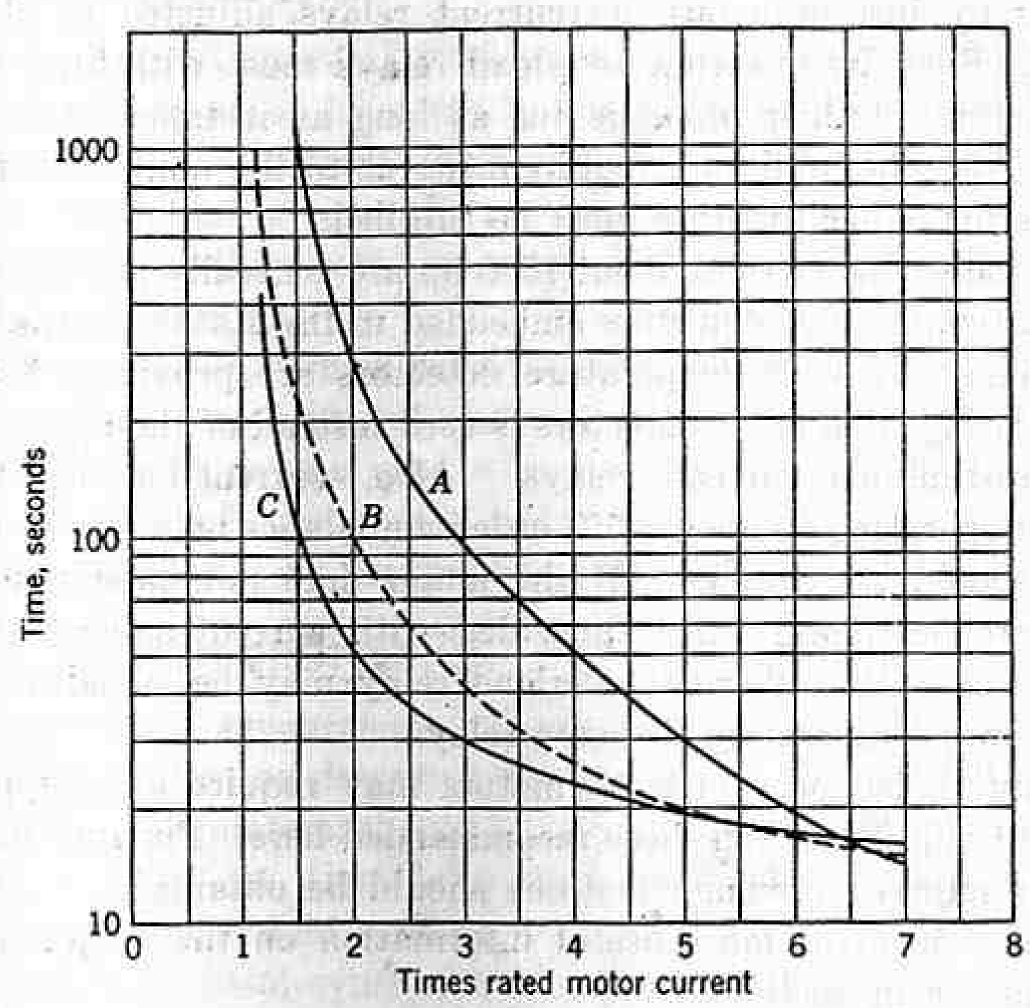

Fig. 22. Typical motor-heating and protective-relay characteristics. *A*, motor; *B*, replica relay; *C*, inverse-time relay.

of the load on the motor before the overload condition occurred. The inverse-time-overcurrent relay will tend to "overprotect" at low currents and to "underprotect" at high currents, as shown in Fig. 22. However, the overcurrent relay is very easy to adjust and test, and it is self-reset. For continuous-rated motors without service factor or short-time overload ratings, the protective relays or devices should be adjusted to trip at not more than about 115% of rated motor current. For motors with 115% service factor, tripping should occur at not more than about 125% of rated motor current. For motors with special short-time overload ratings, or with other service factors, the motor characteristic will determine the required tripping characteristic, but the tripping current should not exceed about 140% of rated motor current. The manufacturer's recommendations should be obtained in each case.

The overload relays will also provide protection in the event of phase-to-phase short circuits, and in practice one set of such relays serves for both purposes wherever possible. A survey of the practice of a number of power companies[45] showed that a single set of long-time inverse-time-overcurrent relays, adjusted to pick up at 125% to 150% of rated motor current, is used for combined short-circuit and overload protection of non-essential auxiliary motors; they are supplemented by instantaneous overcurrent relays adjusted as already described. Such inverse-time overload relays must withstand short-circuit currents without damage for as long as it takes to trip the breaker. Also the minimum requirements as to the number of relays or devices for either function must be fulfilled.

Motors rated higher than about 1500 hp are generally provided with resistance temperature detectors embedded in the stator slots between the windings. If such temperature detectors are provided, a single relay operating from these detectors is used instead of the replica-type or inverse-time-overcurrent relays. Also, current-balance relays capable of operating on about 25% or less unbalance between the phase currents should be supplied. If the motor does not have resistance temperature detectors, but is provided with current-balance relays, a single replica-type thermal overload relay may be substituted for the resistance-temperature-detector relay.

Specially cooled or ventilated motors may require other types of protective equipment than those recommended here. For such motors the manufacturer's recommendations should be obtained.

Reference 50 gives more useful information on the subject of industrial-motor protection.

Essential-Service Motors. The protection recommended for some essential-service motors is based on minimizing the possibility of unnecessarily tripping the motor, even though such practice may sometimes endanger the motor. In other words, long-time inverse-time-overcurrent relays are provided for all motor ratings, but they merely control an alarm and leave tripping in the control of an operator. Then, for motors that can suffer locked rotor, supplementary instantaneous overcurrent relays, adjusted to pick up at about 200% to 300% of rated motor current are used, and their contacts are connected in series with the contacts of the inverse-time-overcurrent relays to trip the motor breaker automatically. The instantaneous relays should be of the high-reset type to be sure that they will reset when the

current returns to normal after the starting inrush has subsided. The protection provided by this type of equipment is illustrated in Fig. 23.

For essential-service motors for which automatic tripping is desired in addition to the alarm for overloads between about 115% of rated current and the pickup of the instantaneous overcurrent relays,

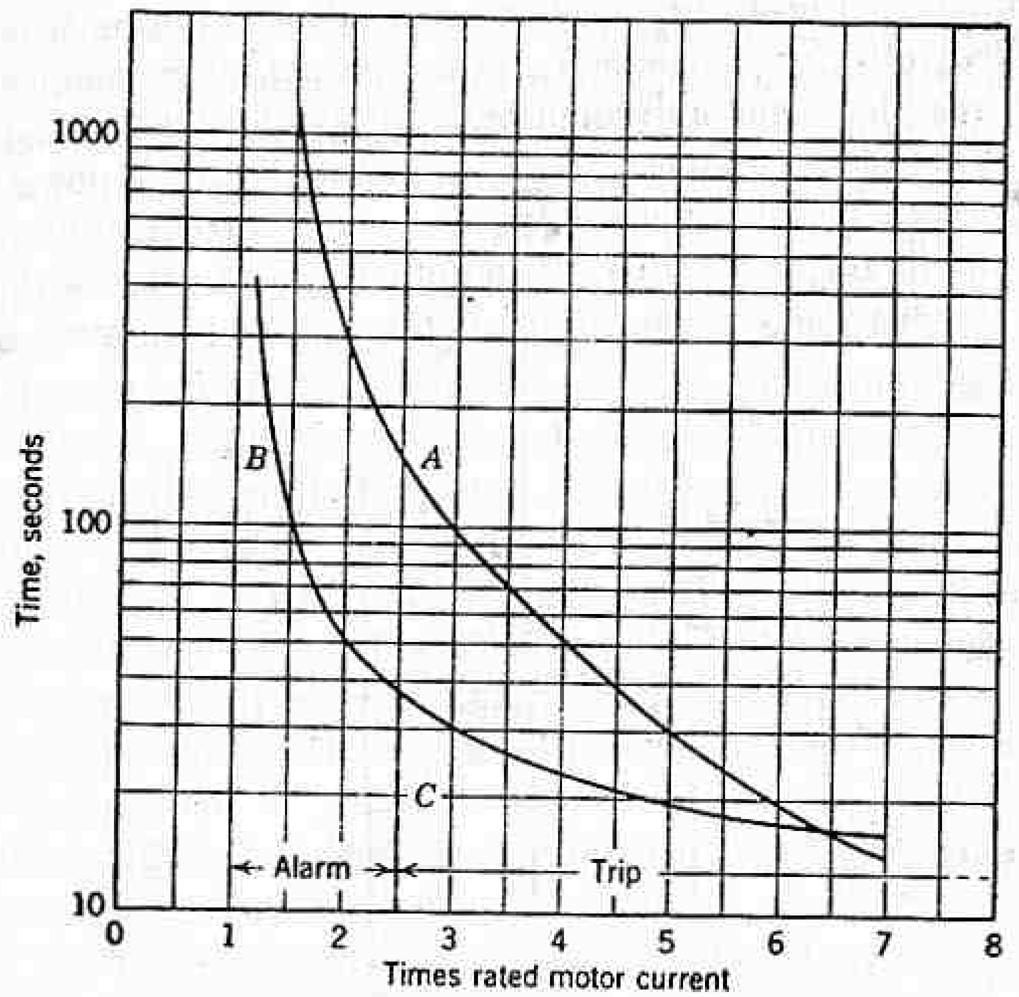

Fig. 23. Protection characteristic for essential-service motors. *A*, motor; *B*, inverse-time relay; *C*, instantaneous relay.

thermal relays of either the replica type or the resistance-temperature-detector type should be used, depending on the size of the motor. Such relays permit operation for overloads as far as possible beyond the point where the alarm will be sounded, but without damaging the motor to the extent that it must be repaired before it can be used again.

ROTOR-OVERHEATING PROTECTION

Squirrel-Cage Induction Motors. The replica-type or the inverse-time-overcurrent relays, recommended for protection against stator overheating, will generally protect the rotor except where high-inertia load is involved; such applications should be referred to the manufacturer for recommendations. Where resistance-temperature-detector relaying is used, a single replica-type or inverse-time-overcurrent relay should be added for rotor protection during starting.

Wound-Rotor Induction Motors. General recommendations for this type of motor cannot be given except that the rotor may not be protected by the stator-overheating protective equipment that has been described. Each application should be referred to the manufacturer for recommendations.

Synchronous Motors. Amortisseur-overheating protection during starting or loss of synchronism should be provided for all "loaded-start" motors. (A loaded-start motor is any motor other than either a synchronous condenser or a motor driving a generator; it includes any motor driving a mechanical load even though automatic unloading means may be employed.) Such protection is best provided by a time-delay thermal overload relay connected in the field-discharge circuit.[31]

Amortisseur-overheating protection is not required for "unloaded-start" motors (synchronous condensers or motors driving generators). An unloaded-start motor is not likely to fail to start on the application of normal starting voltage. Also, loss-of-synchronism protection that is provided either directly or indirectly will provide the necessary protection. An exception to the foregoing is a condenser or a motor that has an oil-lift pump for starting.

Where stator-overheating protection is provided by current-balance-relaying equipment, the amortisseur is indirectly protected also against unbalanced phase currents.

Protection against field-winding overheating because of prolonged overexcitation should be provided for synchronous motors or condensers with automatic voltage regulators without automatic field-current-limiting features. A thermal overload relay with time delay or a relay that responds to an increase in the field-winding resistance with increasing temperature may be used. In an attended station, the relay would merely control an alarm.

LOSS-OF-SYNCHRONISM PROTECTION

All loaded-start synchronous motors should have protection against loss of synchronism, generally arranged to remove the load and the excitation temporarily and to reapply them when permissible. Otherwise, the motor is disconnected from its source.

For unloaded-start motors except the synchronous motor of a frequency converter, the combination of undervoltage protection, loss-of-excitation protection, and the d-c generator overcurrent protection that is generally furnished will provide satisfactory loss-of-synchronism protection. Should additional protection be required, it can be provided by an inverse-time-overcurrent relay energized by the current

the running connection and arranged to trip the main breaker. ...ally, automatic resynchronizing is not required.

All frequency converters interconnecting two systems should have ...of-synchronism protection on the synchronous-machine side. With ...chronous-synchronous sets, protection may be required on both ...es. The protective-relaying equipment should be arranged to trip ... main breaker on its side.

...DERVOLTAGE PROTECTION

All a-c motors except essential-service motors should have protection ...inst undervoltage on at least one phase during both starting and ...ning. For polyphase motors larger than about 1500 hp, polyphase ...ervoltage protection is generally provided.

Wherever possible, the protective equipment should have inverse-...me-delay characteristics.

"Undervoltage release," which provides only temporary shutdown on ...ltage failure and which permits automatic restart when voltage is ...established, should not be used with such equipment as machine ...ols, etc., where such automatic restart might be hazardous to ...rsonnel or detrimental to process or equipment.

...OSS-OF-EXCITATION PROTECTION

All unloaded-start synchronous motors that do not have loss-of-...nchronism protection as described elsewhere, and that do not have ...tomatic voltage regulators, should have loss-of-excitation protection ... the form of a low-set, time-delay-reset undercurrent relay whose ...l is in series with the field winding.

If a motor has loss-of-synchronism protection, amortisseur-over-...ating protection, and stator-overheating protection, these equipments ...directly provide loss-of-excitation protection.

...ELD GROUND-FAULT PROTECTION

The same equipment as that described for generators may be used ... the size or importance of the motor warrants it.

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The way in which the generator neutral is grounded does not influence the choice of percentage-differential relaying equipment when both ends of all windings are brought out. But, if the neutral is not grounded, or if it is grounded through high enough impedance, the differential relays should be supplemented by sensitive ground-fault relaying, which will be described later. Such supplementary

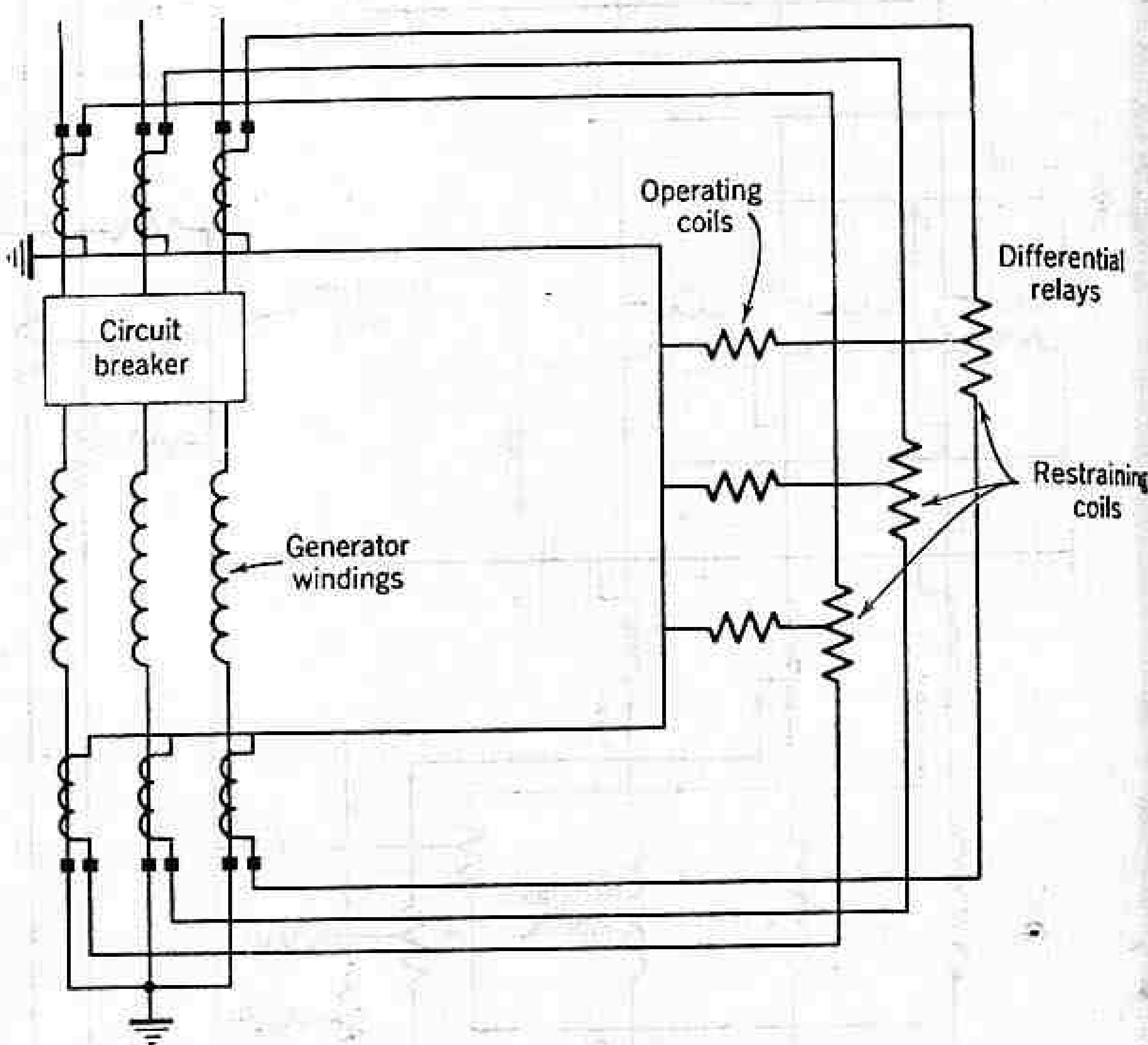


Fig. 1. Percentage-differential relaying for a wye-connected generator.

equipment is generally provided when the ground-fault current that the generator can supply to a single-phase-to-ground fault at its terminals is limited to less than about rated full-load current. Otherwise, the differential relays are sensitive enough to operate for ground faults anywhere from the terminals down to somewhat less than about 20% of the winding away from the neutral, depending on the magnitude of fault current and load current, as shown in Fig. 6, which was obtained from calculations for certain assumed equipment. This is generally considered sensitive enough because, with less than 20% of rated voltage stressing the insulation, a ground fault is most unlikely; in the rare event that a fault did occur, it would simply have to spread

until it involved enough of the winding to operate a relay. To make the percentage-differential relays much more sensitive than they are would make them likely to operate undesirably on transient CT errors during external disturbances.

The foregoing raises the question of CT accuracy and loading. It is generally felt that CT's having an ASA accuracy classification of

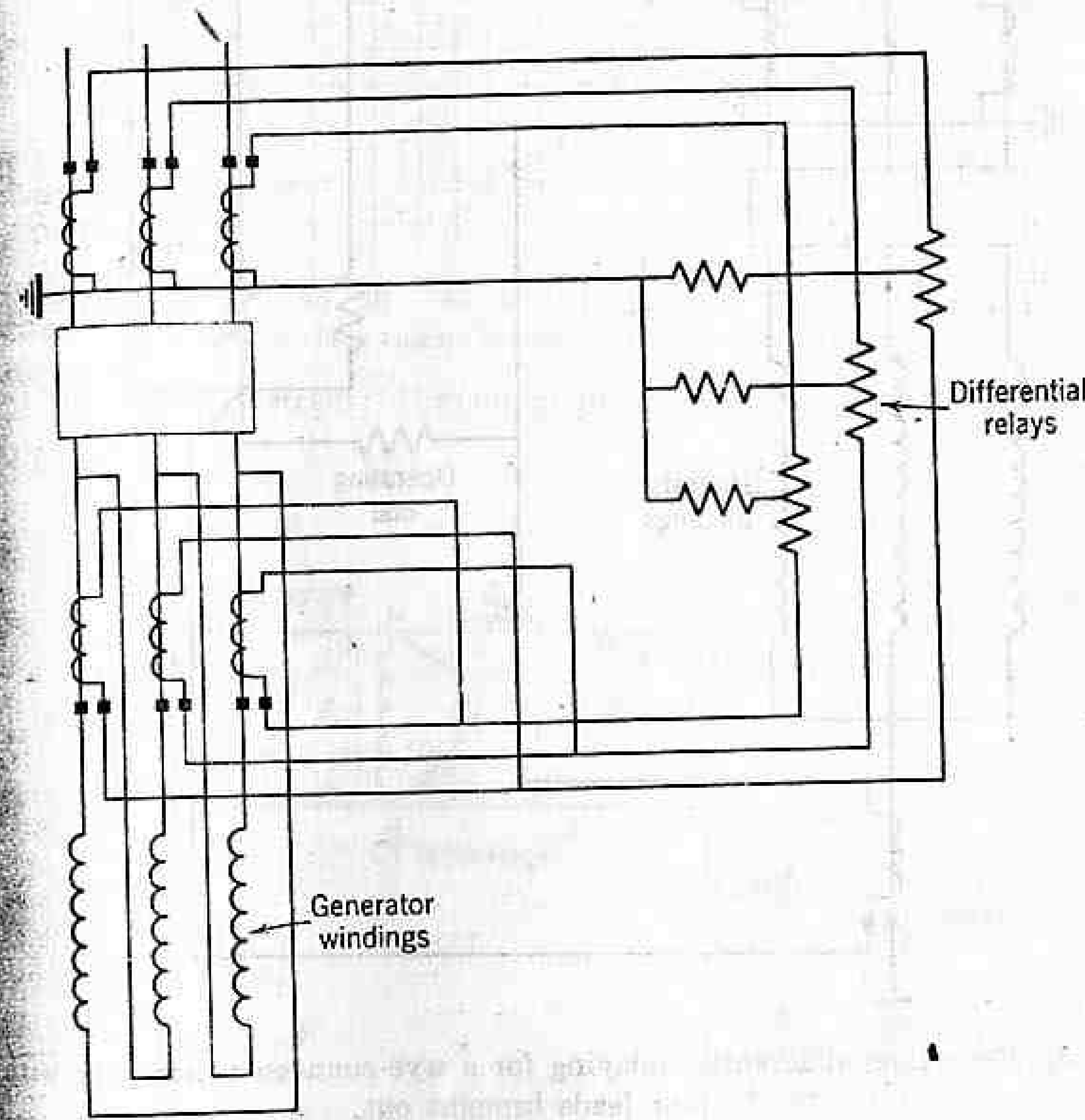


Fig. 2. Percentage-differential relaying for a delta-connected generator.

10H200 or 10L200 are satisfactory if the burdens imposed on the CT's during external faults are not excessive. If variable-percentage-differential relays (to be discussed later) are used, CT's of even lower accuracy classification may be permissible, or higher burdens may be applied. It is the *difference* in accuracy between the CT's (usually of the same type) at opposite ends of the windings that really counts. The difference between their ratio errors should not exceed about one-half of the percent slope of the differential relays for any external fault beyond the generator terminals. Such things as unequal CT secondary lead lengths, or the addition of other burdens in the leads on one side or the other, tend to make the CT's have different errors.

A technique for calculating the steady-state errors of CT's in a differential circuit will be described for the circuit of Fig. 7, where a single phase-to-ground external fault is assumed to have occurred on the

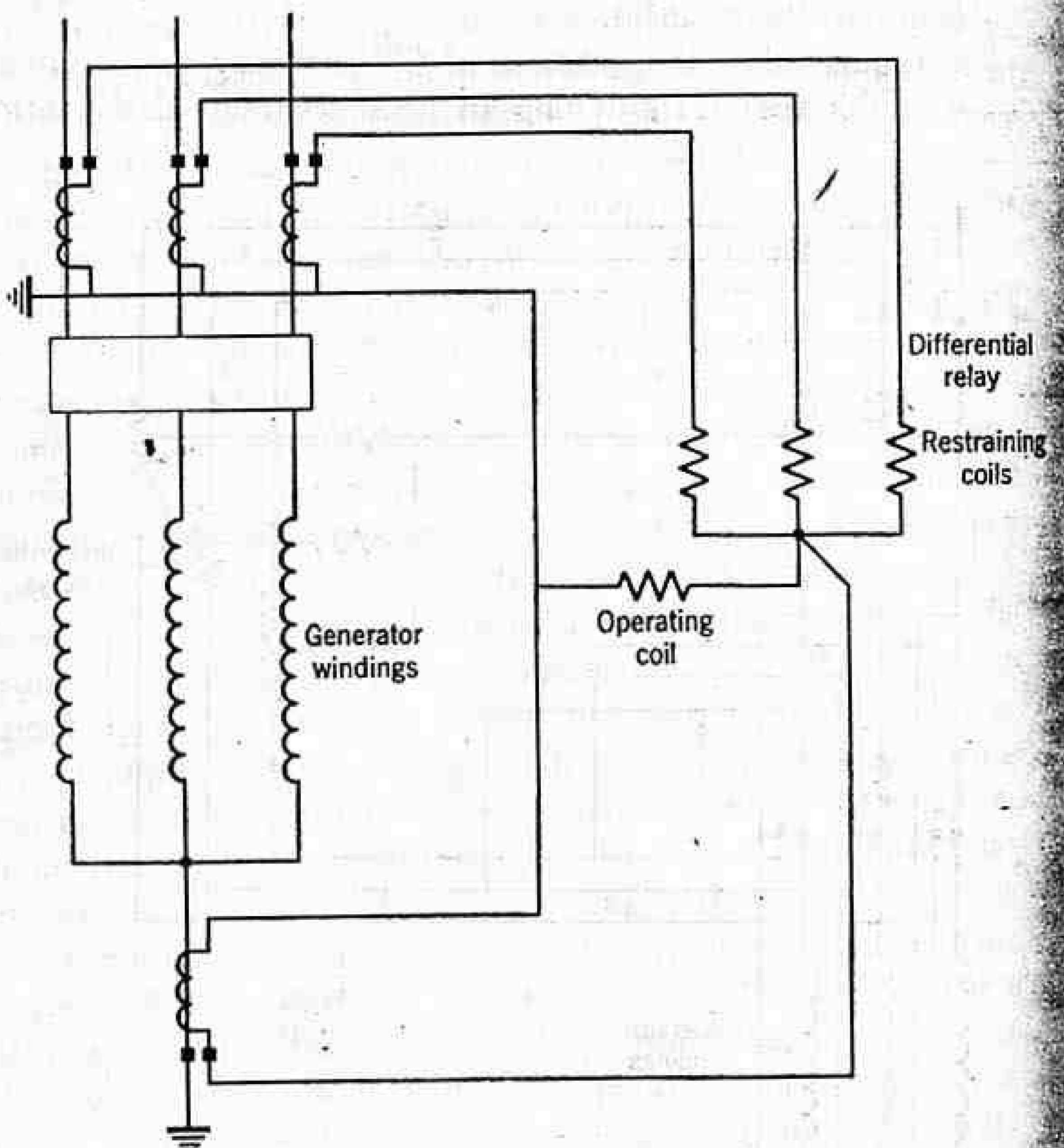


Fig. 3. Percentage-differential relaying for a wye-connected generator with only four leads brought out.

phase shown. The equivalent circuit of each CT is shown in order to illustrate the method of solution. The fact that $(I_{S1} - I_{S2})$ is flowing through the relay's operating coil in the direction shown is the result of assuming that CT_1 is more accurate than CT_2, or in other words that I_{S1} is greater than I_{S2}. We shall assume that I_{S1} and I_{S2} are in phase, and, by Kirchhoff's laws, we can write the voltages for circuit *a-b-c-d-a* as follows:

$$E_1 - I_{S1}(Z_{S1} + 2Z_{L1} + Z_R) - (I_{S1} - I_{S2})Z_0 = 0$$

or

$$(I_{S1} - I_{S2})Z_0 = E_1 - I_{S1}(Z_{S1} + 2Z_{L1} + Z_R)$$

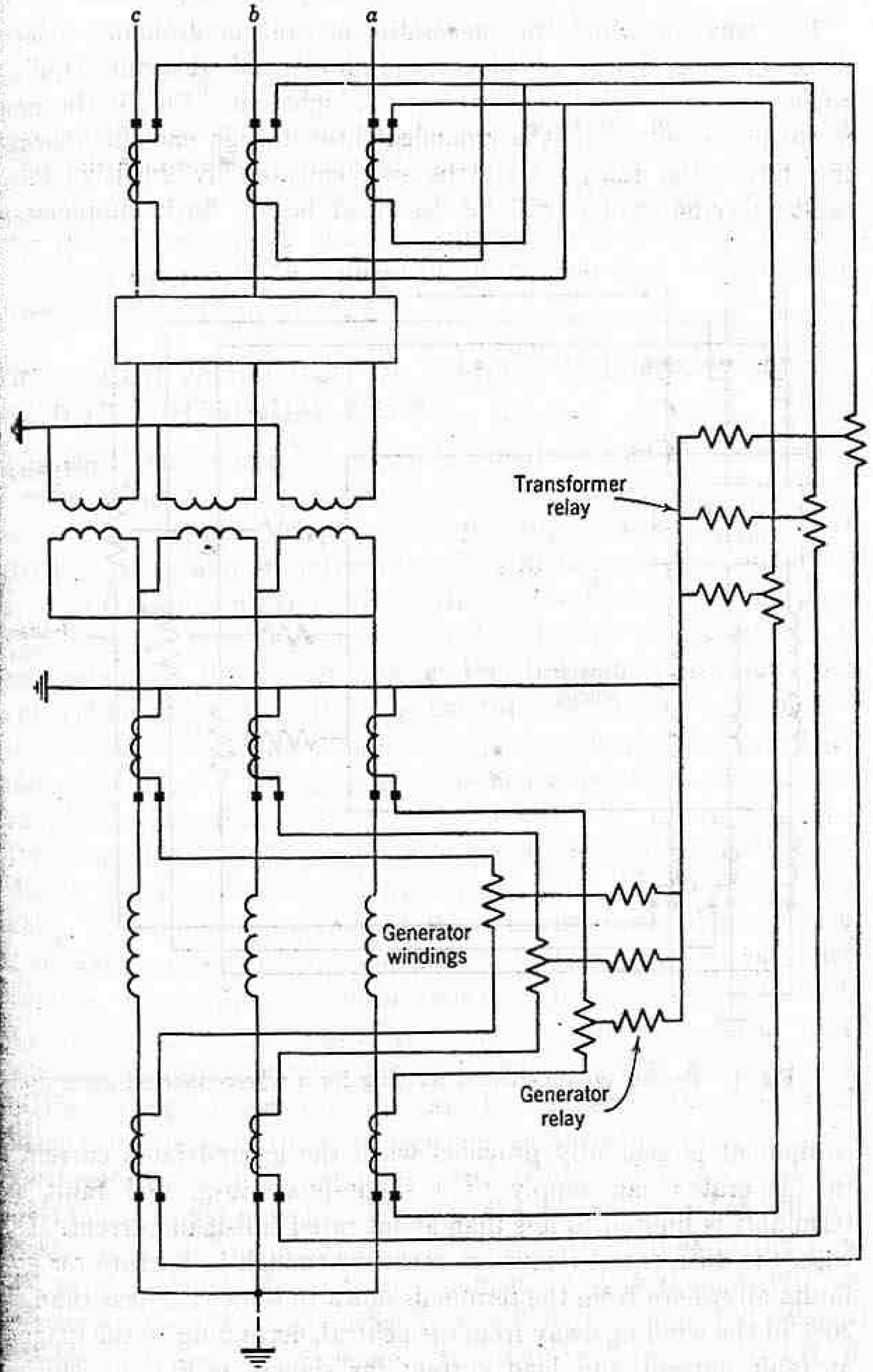


Fig. 4. Percentage-differential relaying for a unit generator and transformer. Note: phase sequence is *a-b-c*.

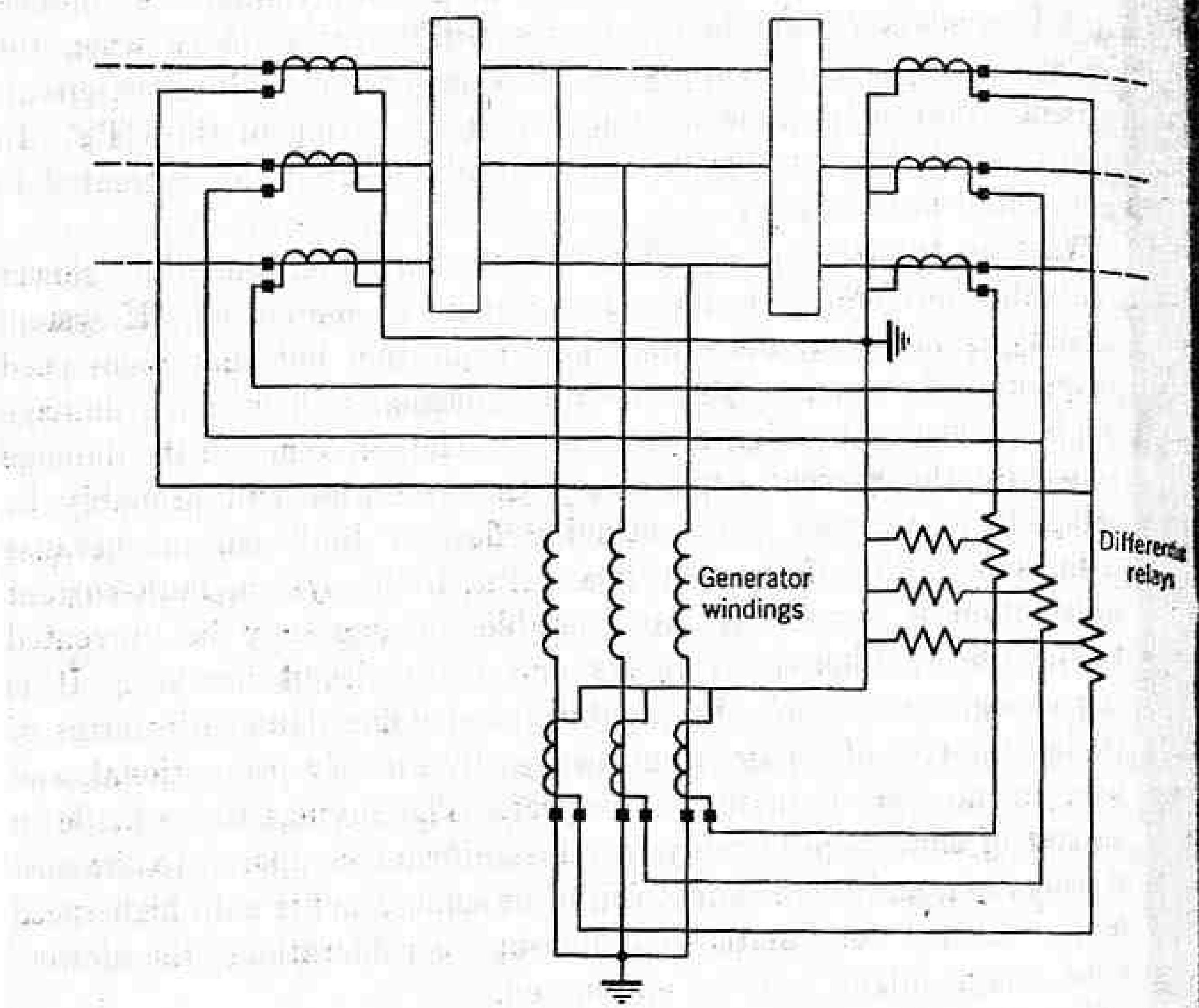


Fig. 5. Generator differential relaying with a double-breaker bus.

Similarly, for the circuit *e-f-d-c-e*, we can write:

$$E_2 - I_{S2}(Z_{S2} + 2Z_{L2} + Z_R) + (I_{S1} - I_{S2})Z_0 = 0$$

or

$$(I_{S1} - I_{S2})Z_0 = I_{S2}(Z_{S2} + 2Z_{L2} + Z_R) - E_2 \qquad (2)$$

For each of the two equations 1 and 2, if we assume a value of the secondary-excitation voltage E, we can obtain a corresponding value of the secondary-excitation current I_e from the secondary-excitation curve. Having I_e, we can get I_S from the relation $I_S = I/N - I_e$, where I is the initial rms magnitude of the fundamental component of primary current. This enables us to calculate the value of $(I_{S1} - I_{S2})$. Finally, the curves of I_{S1} and I_{S2} versus $(I_{S1} - I_{S2})$ for each of the two CT's is plotted on the same graph, as in Fig. 8. For only one value of the abscissa $(I_{S1} - I_{S2})$ will the difference between the two ordinates I_{S1} and I_{S2} be equal to that value of the abscissa, and this is the point that gives us the solution to the problem. Once we know the values of I_{S1} and I_{S2}, we can quickly determine whether the differential relay will operate for the maximum external fault current.

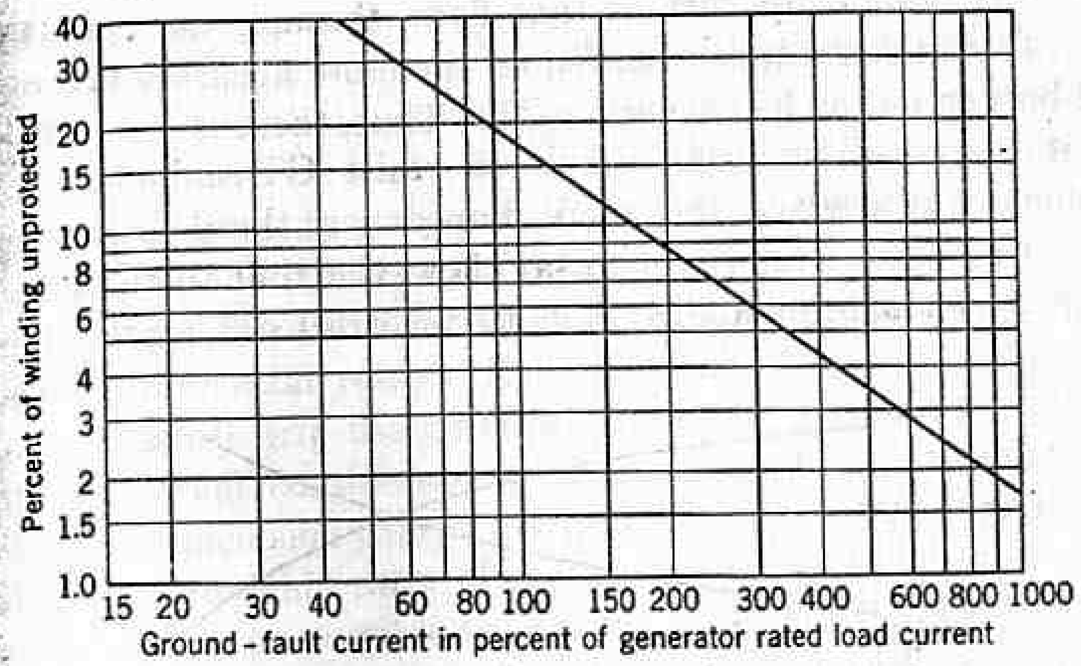


Fig. 6. Percent of winding unprotected for ground faults.

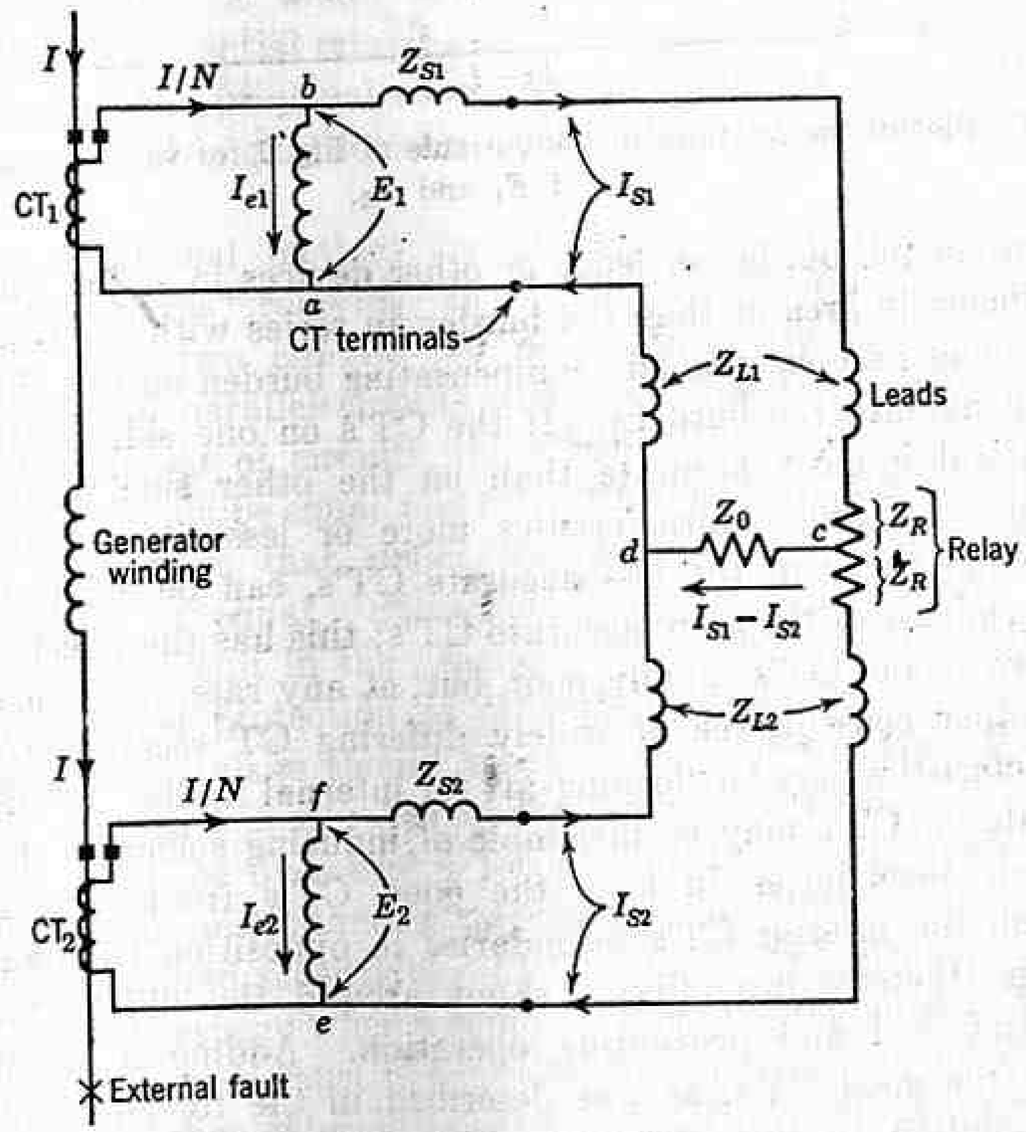


Fig. 7. Equivalent circuit for calculating CT errors in a generator differential circuit.

From the example of Fig. 7, it will become evident that, for an external fault, if there is a tendency for one CT to be more accurate than the other, any current that flows through the operating coil of the relay imposes added burden on the more accurate CT and reduces the burden on the less accurate CT. Thus, there is a natural tendency in a current-differential circuit to resist CT unbalances, and this tendency is greater the more impedance there is in the relay operating coil. This is not to say, however, that there may not sometimes be enough unbalance to cause incorrect differential-relay opera-

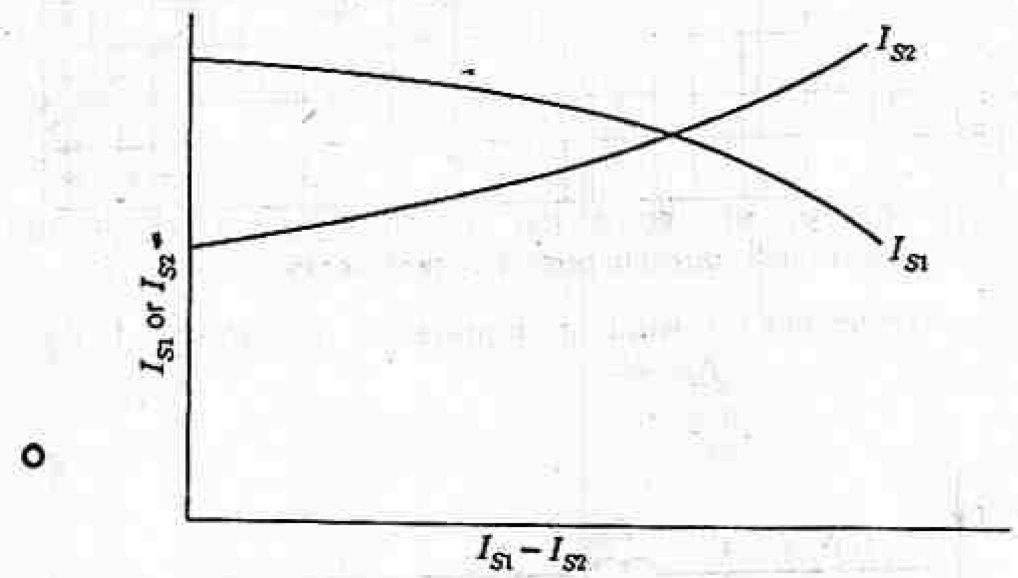


Fig. 8. Plot of the relations of the currents of Fig. 7 for various assumed values of E_1 and E_2.

tion when the burden of leads or other devices in series with one CT is sufficiently greater than the burden in series with the other. If so, it becomes necessary to add compensating burden on one side to more nearly balance the burdens. If the CT's on one side are inherently considerably more accurate than on the other side, shunt burden having saturation characteristics more or less like the secondary-excitation curve of the less accurate CT's, can be connected across the terminals of the more accurate CT's; this has the effect of making the two sets of CT's equally poor, but, at any rate, more nearly alike.

Another consequence of widely differing CT secondary-excitation characteristics may be "locking-in" for internal faults. In such a case, the inferior CT's may be incapable of inducing sufficient rms voltage in their secondaries to keep the good CT's from forcing current through the inferior CT's secondaries in opposition to their induced voltage, thereby providing a shunt around the differential relay operating coil and preventing operation. Adding a shunt burden across the good CT's, as was described in the foregoing paragraph, is a solution to this difficulty. The larger the impedance of the operating coil, the more likely locking-in is to happen. However, circumstances that make it possible are rare.

Chapter 7 described the possibility of harmfully high overvoltages in CT secondary circuits of generator-differential relays when the system is capable of supplying to a generator fault short-circuit current whose magnitude is many times the rating of the CT's. In such cases, it is necessary to use overvoltage limiters, as treated in more detail in Chapter 7.

Whether to use high-speed relays or only the somewhat slower "instantaneous" relays is sometimes a point of contention. If system stability is involved, there may be no question but that high-speed relays must be used. Otherwise, the question is how much damage will be prevented by high-speed relays. The difference in the damage caused by the current supplied by the generator will probably be negligible in view of the continuing flow of fault current because of the slow decay of the field flux. But, if the system fault-current contribution is very large, considerable damage may be prevented by the use of high-speed relays and main circuit breaker. It is easy enough to compare the capabilities of doing damage in terms of I^2t, but the cost of repair is not necessarily directly proportional, and there are no good data in this respect. The savings to be made in the cost of slower-speed relays are insignificant compared to the cost of generators, and there cannot fail to be some benefits with high-speed relays. Except for "match and line-up" considerations, the slower-speed relays might well be eliminated.

Generally, the practice is to have the percentage-differential relays trip a hand-reset multicontact auxiliary relay. This auxiliary relay simultaneously initiates the following: (1) trip main breaker, (2) trip field breaker, (3) trip neutral breaker if provided, (4) shut down the prime mover, (5) turn on CO_2 if provided, (6) operate an alarm and/or annunciator. The auxiliary relay may also initiate the transfer of station auxiliaries from the generator terminals to the reserve source, by tripping the auxiliary breaker. Whether to provide a main-field breaker or only an exciter-field breaker is a point of contention. The tripping of a main-field breaker instead of only an exciter-field breaker will minimize the damage, but there is insufficient evidence to prove whether it is worth the additional expense where other important factors urge the omission of a main-field breaker. Consequently, the practice is divided.

THE VARIABLE-PERCENTAGE-DIFFERENTIAL RELAY

High-speed percentage-differential relays having variable ratio—or percent-slope—characteristics are preferred. At low values of through current, the slope is about 5%, increasing to well over 50% at the high values of through current existing during external faults. This characteristic permits the application of sensitive high-speed relaying equipment using conventional current transformers, with no danger of undesired tripping because of transient inaccuracies in the CT's. To a certain extent, poorer CT's may be used—or higher burdens may be applied—than with fixed-percent-slope relays.

Two different operating principles are employed to obtain the variable characteristic. In both, saturation of the operating element is responsible for a certain amount of increase in the percent slope. In one equipment,[13] saturation alone causes the slope to increase to about 20%; further increase is caused by the effect on the relay response of angular differences between the operating and restraining currents that occur owing to CT errors at high values of external short-circuit current. The net effect of both saturation and phase angle is to increase the slope to more than 50%.

The other equipment[14] obtains a slope greater than 50% for large values of through current entirely by saturation of the operating element. A principle called "product restraint" is used to assure operation for internal short circuits. Product restraint provides restraint sufficient to overcome the effect of any CT errors for external short circuits; for internal short circuits when the system supplies very large currents to a fault, there is no restraint.

PROTECTION AGAINST TURN-TO-TURN FAULTS IN STATOR WINDINGS

Differential relaying, as illustrated in Figs. 1–5, will not respond to faults between turns because there is no difference in the currents at the ends of a winding with shorted turns; a turn fault would have to burn through the major insulation to ground or to another phase before it could be detected. Some of the resulting damage would be prevented if protective-relaying equipment were provided to function for turn faults.

Turn-fault protection has been devised for multicircuit generators, and is used quite extensively, particularly in Canada.[15] In the United States, the government-operated hydroelectric generating stations are the largest users. Because the coils of modern large steam-turbine generators usually have only one turn, they do not need turn-fault protection because turn faults cannot occur without involving ground.

Even though the benefits of turn-fault protection would apply equally well to single-circuit generators, equipment for providing this protection for such generators has not been used, although methods have been suggested;[15,18] as will be seen later, the equipment used for multicircuit generators is not applicable to single-circuit generators.

To justify turn-fault protection, apart from what value it may have as duplicate protection, one must evaluate the savings in damage and outage time that it will provide. In a unit generator-transformer arrangement, considerable saving is possible where the generator operates ungrounded, or where high-resistance grounding or ground-fault-neutralizer grounding is used; if the ground-detecting equipment is not permitted to trip the generator breakers, a turn fault could burn much iron before the fault could spread to another phase and operate the differential relay. Even if the ground-detecting equipment is arranged to trip the generator breakers, it would probably be too slow to prevent considerable iron burning. (The foregoing leads to the further conclusion that if the generator has single-circuit windings with no turn-fault protection, the ground-fault detector should operate as quickly as possible to trip the generator breakers.)

For other than unit generator-transformer arrangements, and where the generator neutral is grounded through low impedance, the justification for turn-fault protection is not so apparent. The amount of iron burning that it would save would not be significant because conventional differential relaying will prevent excessive iron burning.[19] Consequently, the principal saving would be in the cost of the coil-repair job, and it is questionable whether there would be a significant saving there.

The conventional method for providing turn-fault protection is called "split-phase" relaying, and is illustrated in Fig. 9. If there are more than two circuits per phase, they are divided into two equal groups of parallel circuits with a CT for each group. If there is an odd number of circuits, the number of circuits in each of the two groups will not be equal, and the CT's must have different primary-current ratings so that under normal conditions their secondary currents will be equal. Split-phase relaying will operate for any type of short circuit in the generator windings, although it does not provide as good protection as differential relaying for some faults. The split-phase relays should operate the same hand-reset auxiliary tripping relay that is operated by the differential relays.

An inverse-time overcurrent relay is used for split-phase relaying rather than an instantaneous percentage-differential relay, in order to get the required sensitivity. For its use to be justified, split-phase relaying must respond when a single turn is short-circuited. Moreover, the relay equipment must not respond to any transient unbalance that there may be when external faults occur. If percentage restraint were used to prevent such undesired operation, the restraint caused by load current would make the relay too insensitive at full load.

Consequently, time delay is relied on to prevent operation on transients.

Time delay tends somewhat to nullify the principal advantage of turn-fault protection, namely, that of tripping the generator breaker before the fault has had time to develop serious proportions. A supplementary instantaneous overcurrent unit is used together with the

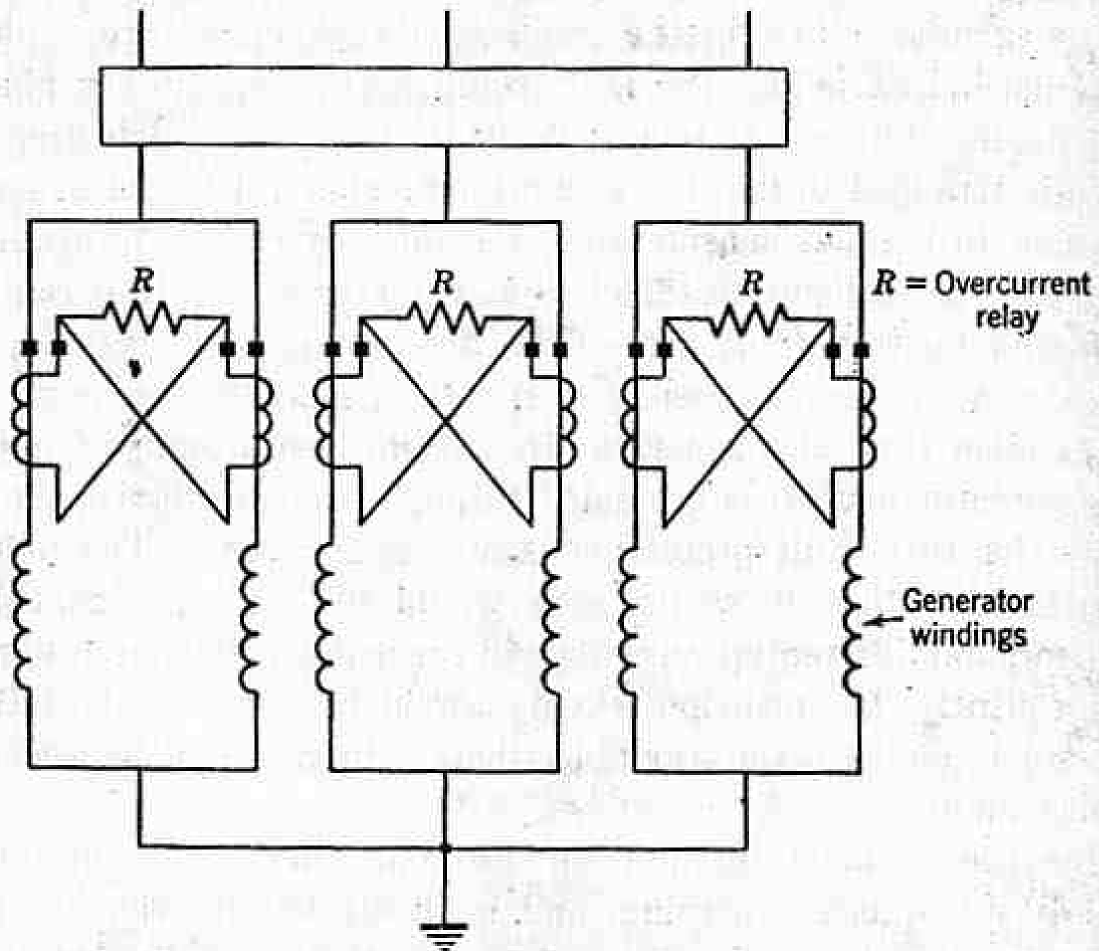


Fig. 9. Split-phase relaying for a multicircuit generator.

inverse-time unit, but the pickup of the instantaneous unit has to be so high to avoid undesired operation on transients that it will not respond unless several turns are short-circuited.

Faster and more sensitive protection can be provided if a double-primary, single-secondary CT, as shown in Fig. 10, is used rather than the two separate CT's shown in Fig. 9.[16] Such a double-primary CT eliminates all transient unbalances except those existing in the primary currents themselves. With such CT's and with close attention to the generator design to minimize normal unbalance, very sensitive instantaneous protection is possible.[17] Such practices have been limited to Canada.

Split-phase relaying at its best could not completely replace over-all differential relaying which is required for protection of the generator circuit beyond the junctions of the paralleled windings. However,

some people feel that if split-phase relaying is used with unit generator-transformer arrangements, it is not necessary to have separate generator-differential relaying if the transformer differential relaying includes the generator in its protective zone. This would be true if the split-phase relaying was instantaneous. The greater sensitivity

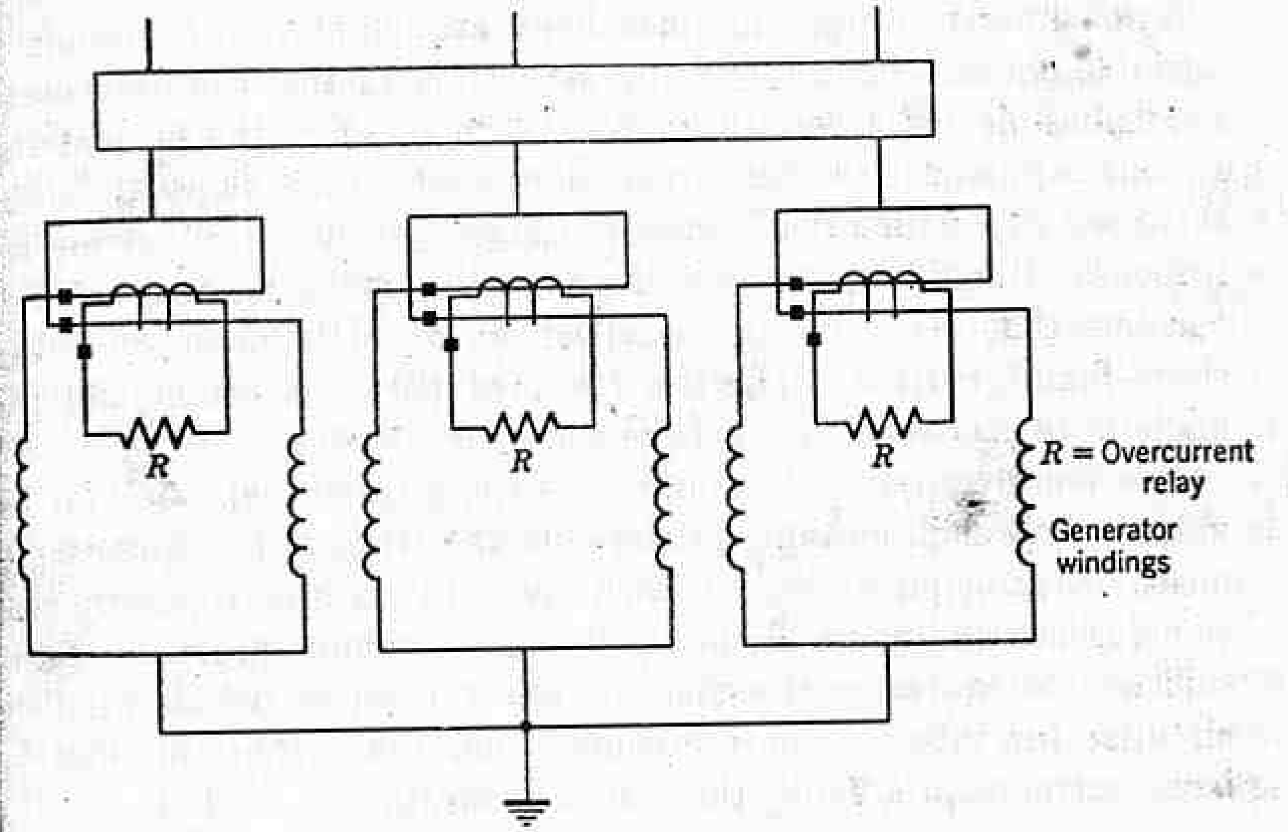


Fig. 10. Split-phase relaying using double-primary current transformers.

of generator-differential relaying is not needed for faults beyond the generator windings. The principal advantage of retaining the generator-differential relaying, apart from the duplicate protection that it affords, is the value of its target indication in helping to locate a fault. However, if split-phase relaying is provided by inverse-time overcurrent relays, generator-differential relaying is recommended because of its higher speed for all except turn faults.

COMBINED SPLIT-PHASE AND OVER-ALL DIFFERENTIAL RELAYING

Figure 11 shows an arrangement that has been used to try to get the benefits of split-phase and over-all differential protection at a saving in current transformers and in relays. However, this arrangement is not as sensitive as the separate conventional split-phase and over-all differential equipments. Sensitivity for turn faults is sacrificed with a percentage-differential relay; with full-load secondary current flowing through the restraining coil, the pickup is considerably higher than with the conventional split-phase equipment, and the equipment will not operate if a single turn is shorted. With the main generator breaker open, the sensitivity for ground faults near the neutral end of the winding that does not have a current transformer may be considerably poorer than with the conventional over-all dif-

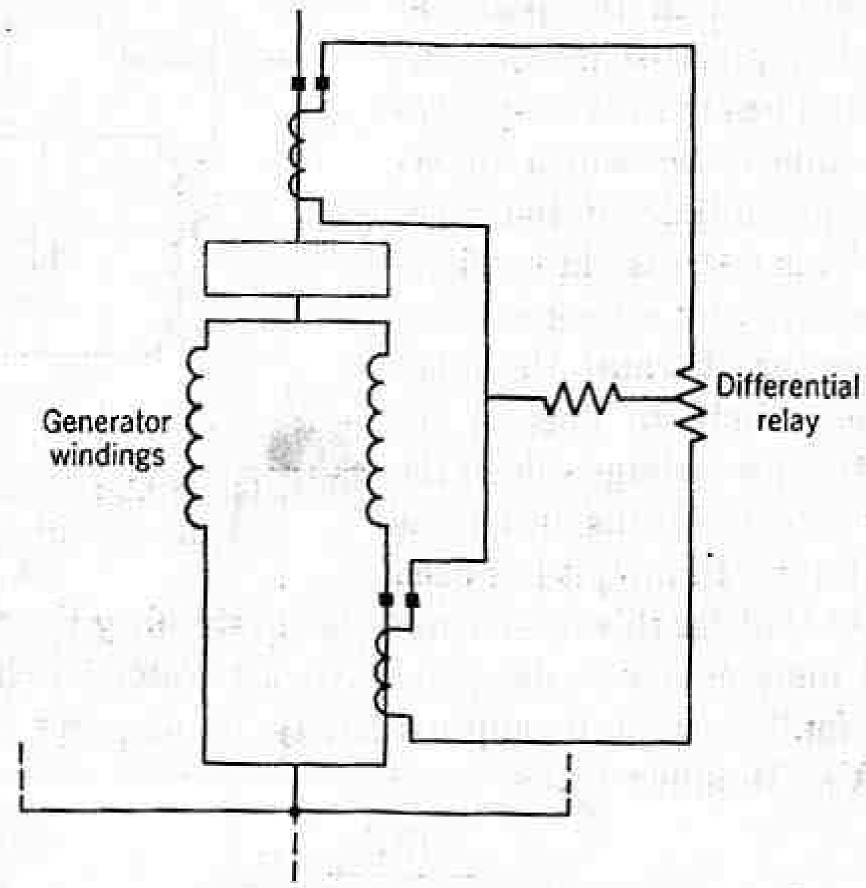


Fig. 11. Combined split-phase and differential relaying (shown for one phase only).

ferential; the current flowing in the winding having the CT is much smaller than one-half of the current flowing in the neutral lead where the over-all differential CT would be. For this reason, the modification shown in Fig. 12 is sometimes used.

SENSITIVE STATOR GROUND-FAULT RELAYING

The protection of unit generator-transformer arrangements is described under the next heading. Here, we are concerned with other than unit arrangements, where the generator's neutral is grounded through such high impedance that conventional percentage-differential relaying equipment is not sensitive enough. The problem here is to get the required sensitivity and at the same time to avoid the possibility of undesired operation because of CT errors with large external-fault currents. Figure 13 shows a solution to the problem: a current-current directional relay is shown whose operating coil is in the neutral of the differential-relay circuit and whose polarizing coil is energized from a CT in the generator neutral. A polarized relay

provides greater sensitivity without excessive operating-coil burden; the polarizing CT may have a low enough ratio so that the polarizing

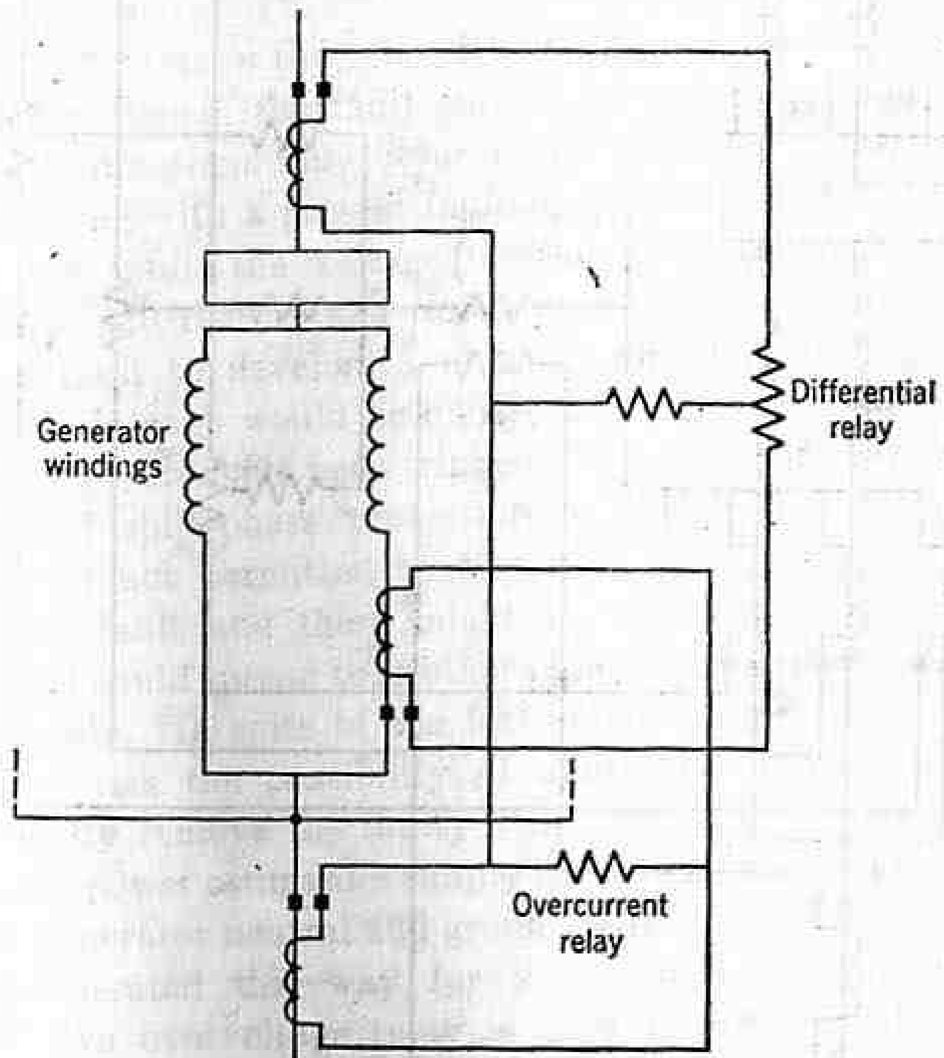


Fig. 12. Modification of Fig. 11 for greater sensitivity.

coil will be "soaked" for the short duration of the fault. Supplementary equipment may sometimes be required to prevent undesired operation because of CT errors during external two-phase-to-ground faults.

STATOR GROUND-FAULT PROTECTION OF UNIT GENERATORS

Figure 14 shows the preferred way[19] to provide ground-fault protection for a generator that is operated as a unit with its power transformer. The generator neutral is grounded through the high-voltage winding of a distribution transformer. A resistor and an overvoltage relay are connected across the low-voltage winding.

It has been found by test that, to avoid the possibility of harmfully high transient overvoltages because of ferroresonance, the resistance of the resistor should be no higher, approximately, than:

$$R = \frac{X_C}{3N^2} \text{ ohms}$$

11 TRANSFORMER PROTECTION

This chapter describes the protection practices for transformers of the following types whose three-phase bank rating is 501 kva and higher:

Power transformers
Power autotransformers
Regulating transformers
Step voltage regulators
Grounding transformers
Electric arc-furnace transformers
Power-rectifier transformers

Contrasted with generators, in which many abnormal circumstances may arise, transformers may suffer only from winding short circuits, open circuits, or overheating. In practice relay protection is not provided against open circuits because they are not harmful in themselves. Nor in general practice, even for unattended transformers, is overheating or overload protection provided; there may be thermal accessories to sound an alarm or to control banks of fans, but, with only a few exceptions, automatic tripping of the transformer breakers is not generally practiced. An exception is when the transformer supplies a definite predictable load. External-fault back-up protection may be considered by some a form of overload protection, but the pickup of such relaying equipment is usually too high to provide effective transformer protection except for prolonged short circuits. There remains, then, only the protection against short circuits in the transformers or their connections, and external-fault back-up protection. Moreover, the practices are the same whether the transformers are attended or not.

Power Transformers and Power Autotransformers

THE CHOICE OF PERCENTAGE-DIFFERENTIAL RELAYING FOR SHORT-CIRCUIT PROTECTION

It is the practice of manufacturers to recommend percentage-differential relaying for short-circuit protection of all power-transformer banks

The direct-current component, present in both magnetizing-inrush and offset fault current, is largely blocked by the differential-current and the through-current transformers, and produces only a slight momentary restraining effect.

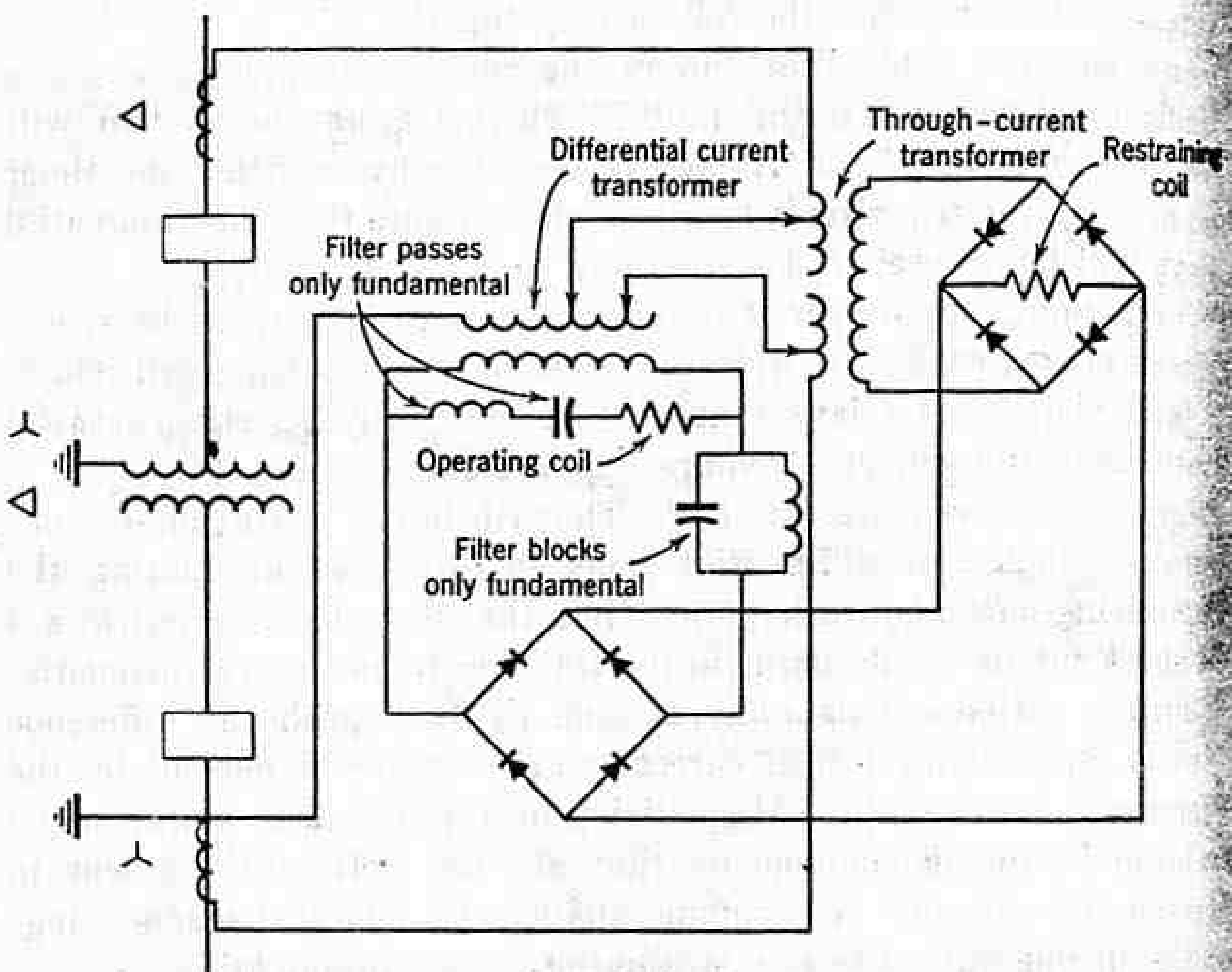


Fig. 11. **Harmonic-current-restraint percentage-differential relay.**

PROTECTION OF PARALLEL TRANSFORMER BANKS

From the standpoint of protective relaying, the operation of two transformer banks in parallel without individual breakers is to be avoided. In order to obtain protection equivalent to that when individual breakers are used, the connections of Fig. 12 would be required. To protect two equally rated banks as a unit, using only CT's on the source sides of the common breakers and a single relay is only half as sensitive as protecting each bank from its own CT's; this is because the CT ratios must be twice as high as if individual CT's were used for each bank, both banks being assumed to have the same rating, and as a result the secondary current for a given fault will be only half as high. If one bank is smaller than the other, its protection will be less than half as sensitive. With more than two banks, the protection is still poorer.

When parallel transformer banks having individual breakers are located some distance away from any generating station, a possibly troublesome magnetizing-current-inrush problem may arise.[11] If one bank is already energized and a second bank is then energized, magnetizing-current inrush will occur—not only to the bank being energized but also to the bank that is already energized. Moreover,

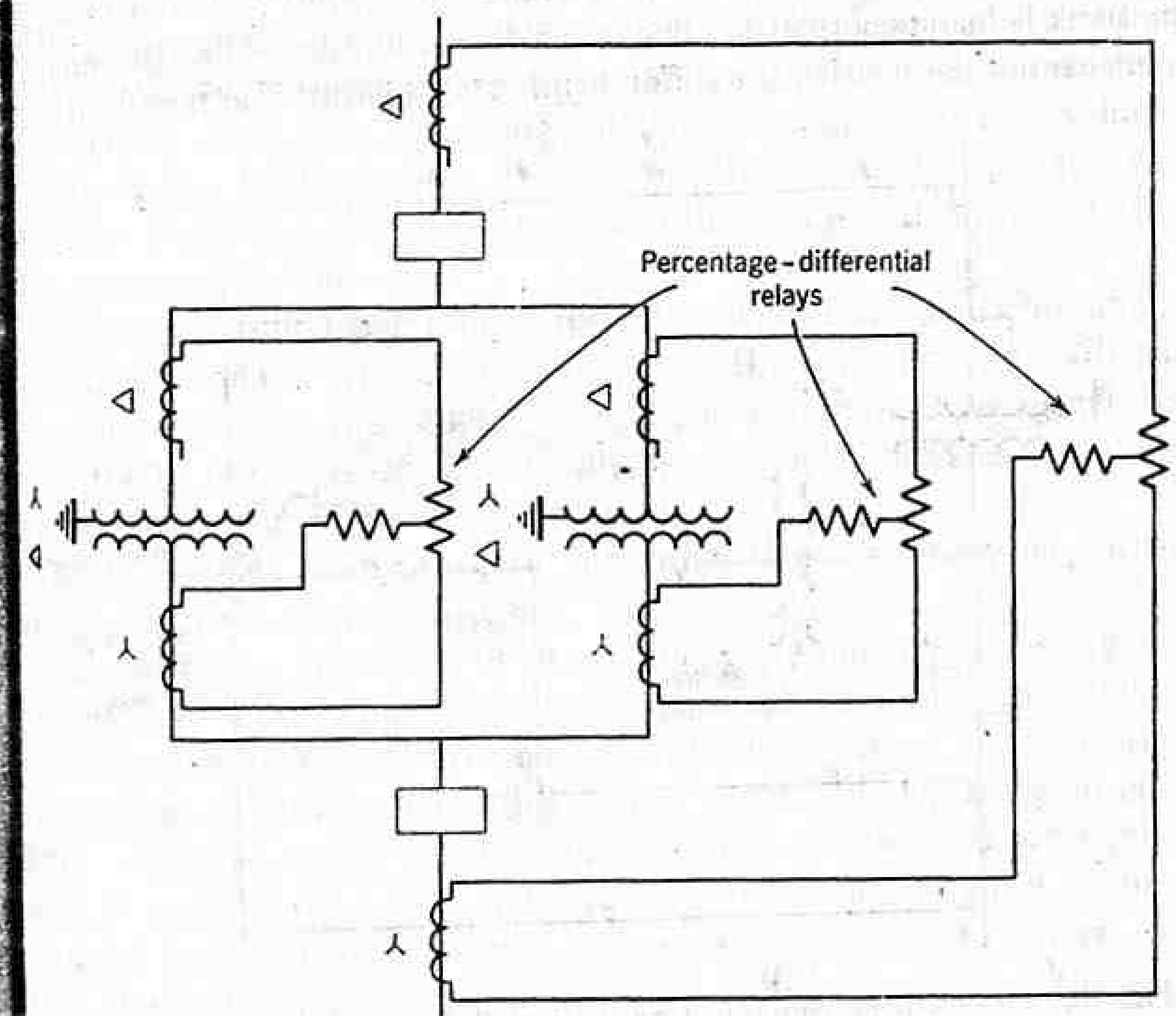


Fig. 12. The protection of parallel transformer banks with common breakers.

the inrush current to both banks will decay at a much slower rate than when a single bank is energized with no other banks in parallel. The magnitude of the inrush to the bank already connected will not be as high as that to the bank being switched, but it can easily exceed twice the full-load-current rating of the bank; the presence of load on the bank will slightly reduce its inrush and increase its rate of decay.

Briefly, the cause of the foregoing is as follows: The d-c component of the inrush current to the bank being energized flows through the resistance of transmission-line circuits between the transformer banks and the source of generation, thereby producing a d-c voltage-drop component in the voltage applied to the banks. This d-c component of voltage causes a build-up of d-c magnetizing current in the already-connected bank, the rate of which is the same as the rate at whi the d-c component of magnetizing current is decreasing in the bank j energized. When the magnitudes of the d-c components in both ban become equal, there is no d-c component in the transmission-li circuit feeding the banks, but there is a d-c component circulati in the loop circuit between the banks. The time constant of this trapp d-c circulating current, depending only on the constants of the lo circuit, is much longer than the time constant of the d-c compone

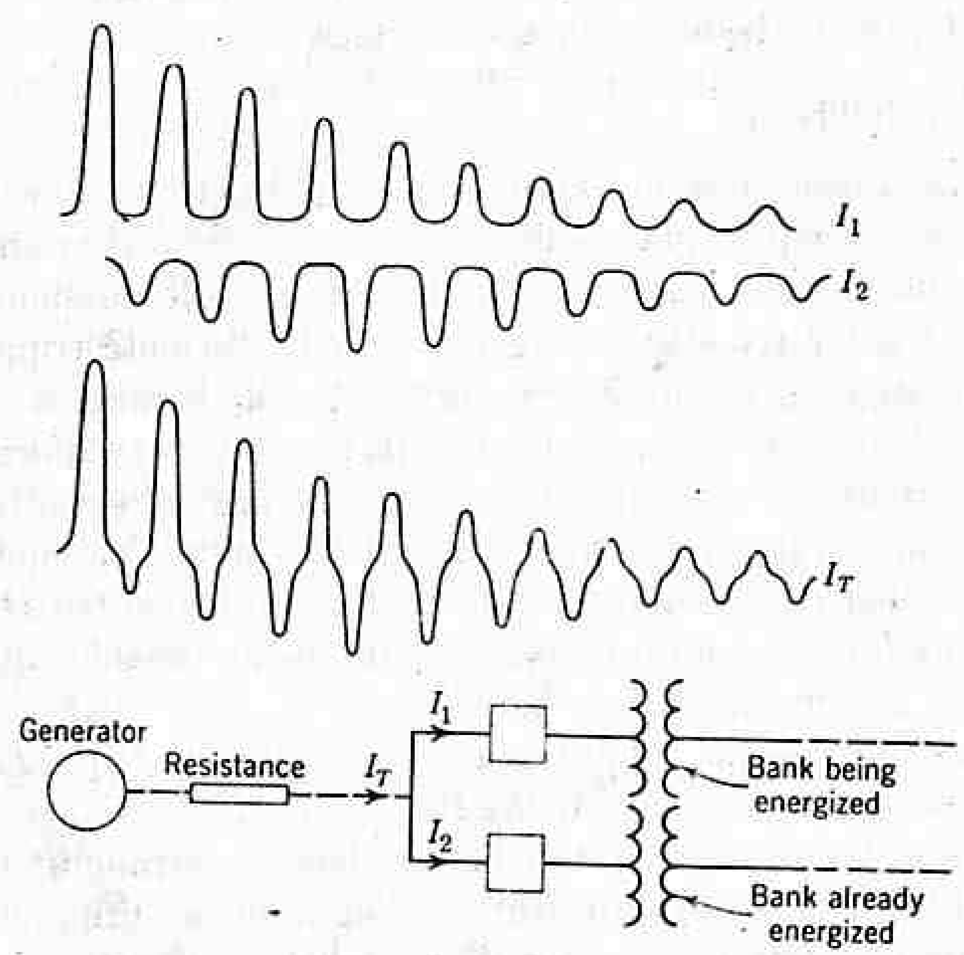


Fig. 13. Prolonged inrush currents with parallel transformers.

in the transmission-line circuit feeding the banks. Figure 13 show the circuits involved and the magnetizing-current components in each circuit.

The significance of the foregoing is two-fold. First, desensitizing means already described for preventing differential-relay operation on magnetizing-current inrush are not effective in the bank that is already energized. Only time delay in the operation of the differential relay will be effective in preventing undesired tripping. However, if the banks are protected by separate relays having tripping suppression or harmonic restraint, no undesired tripping will occur. Second, if the banks are protected as a unit, even the harmonic-current restraint type may cause undesired tripping because, as shown in Fig. 13, the

al-current wave very shortly becomes symmetrical and does not ain the necessary even harmonics required for restraint.

ORT-CIRCUIT PROTECTION WITH OVERCURRENT RELAYS

Overcurrent relaying is used for fault protection of transformers ing circuit breakers only when the cost of differential relaying not be justified. Overcurrent relaying cannot begin to compare differential relaying in sensitivity.

Three CT's, one in each phase, and at least two overcurrent phase ys and one overcurrent ground relay should be provided on each of the transformer bank that is connected through a circuit aker to a source of short-circuit current. The overcurrent relays uld have an inverse-time element whose pickup can be adjusted somewhat above maximum rated load current, say about 150% maximum, and with sufficient time delay so as to be selective with relaying equipment of adjacent system elements during external lts. The relays should also have an instantaneous element whose kup can be made slightly higher than either the maximum short-uit current for an external fault or the magnetizing-current inrush. When the transformer bank is connected to more than one source short-circuit current, it may be necessary for at least some of the rcurrent relays to be directional in order to obtain good protection well as selectivity for external faults.

The overcurrent relays for short-circuit protection of transformers vide also the external-fault back-up protection discussed elsewhere.

AS-ACCUMULATOR AND PRESSURE RELAYS

A combination gas-accumulator and pressure relay, called the uchholz" relay after its inventor, has been in successful service for r 30 years in Europe and for 10 years in Canada.[12] This relay applicable only to a so-called "conservator-type" transformer in ich the transformer tank is completely filled with oil, and a pipe nects the transformer tank to an auxiliary tank, or "conservator," ch acts as an expansion chamber. In the piping between the main k and the conservator are the two elements of the relay. One ment is a gas-collecting chamber in which gas evolved from the breakdown of insulation in the presence of a small electric arc collected; when a certain amount of gas has been collected a con-t closes, usually to sound an alarm. The collected gas may be awn into a gas analyzer to determine what kind of insulation is ng broken down and thereby to learn whether lamination, core-t, or major insulation is being deteriorated. This gas analyzer is system is subjected to the shock of one or more reclosings on a short circuit. It may be necessary to delay reclosing to be sure that the grounding switch is closed first when high-voltage transformer-bushing flashovers occur. That these disadvantages are not always too serious is shown by the fact that about half of the installations in this country use this method.

The other way to trip the distant breaker is with a pilot.[16,18] Any of the types of pilot (wire, carrier-current, or microwave) may be used, depending on the circumstances. In any event, the equipment must be free of the possibility of undesired tripping because of extraneous causes; this is achieved by transmitting a tripping signal that is not apt to be duplicated otherwise. One of the most successful methods is the so-called "frequency-shift" system;[18] not only is this system most reliable but it is also high speed, requiring only about 1 cycles to energize the trip coil of the distant breaker after the transformer-differential relay has closed its tripping contacts. By using two frequency-shift channels, the equipment can be tested without removing it from service.

An inherent advantage of remote tripping over a pilot is that the received tripping signal can also block automatic reclosing. It may be necessary, however, to delay reclosing a few cycles to be sure that reclosing is blocked when high-voltage transformer-bushing flashovers occur.

EXTERNAL-FAULT BACK-UP PROTECTION

A differentially protected transformer bank should have inverse-time-overcurrent relays, preferably energized from CT's other than those associated with the differential relays, to trip fault-side breakers when external faults persist for too long a time. An exception is the transformer bank of a unit generator-transformer arrangement where the generator's external-fault back-up relays provide all the necessary back-up protection. The back-up relays should preferably be operated from CT's located as in Fig. 14; this makes it unnecessary to adjust the relays so as not to operate on magnetizing-current inrush and hence permits greater sensitivity and speed if desired. When the transformer is connected to more than one source of short-circuit current, back-up relays in all the circuits are required, and at least some may need to be directional, as indicated in Fig. 15, for good protection and selectivity. Each set of back-up relays should trip only its associated breaker, also as indicated in Fig. 15.

When a transformer has overcurrent relaying for short-circuit protection because the cost of differential relaying cannot be justified,

the same overcurrent relays are used for back-up protection. It is realized that combining the two functions may work to the disadvantage of one or both, but this is the price that one must pay to minimize the investment.

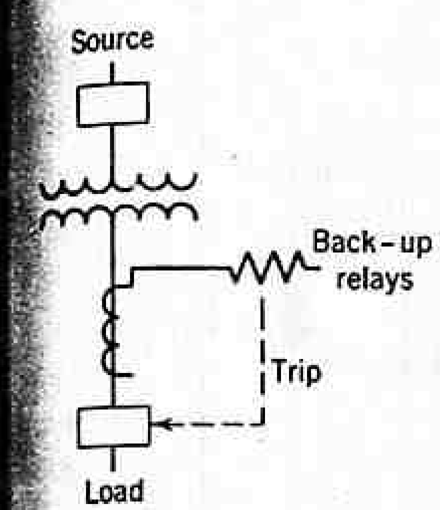


Fig. 14. Back-up relaying for transformer connected to one source.

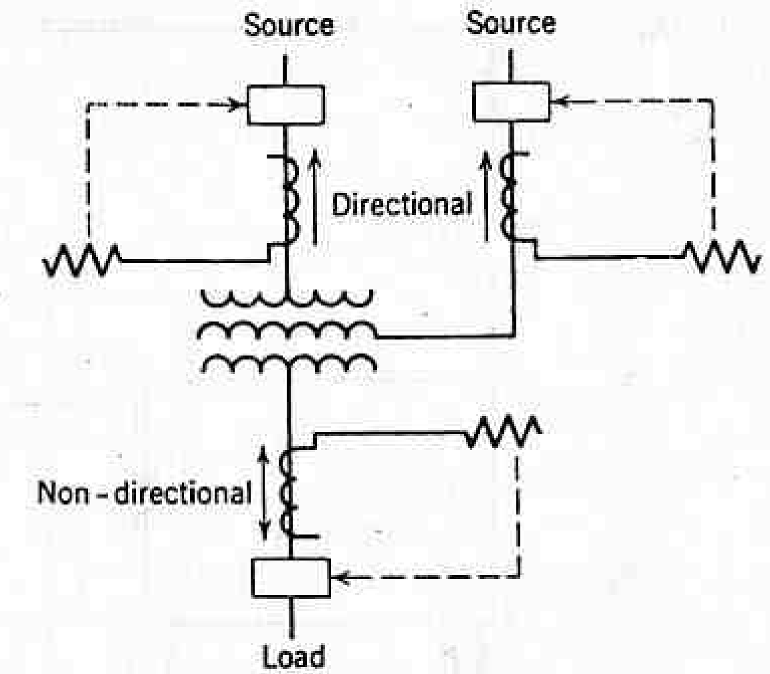


Fig. 15. Back-up relaying with two sources.

Regulating Transformers

Regulating transformers may be of the "in-phase" type or the "phase-shifting" type. The in-phase type provides means for increasing or decreasing the circuit voltage at its location under load without changing the phase angle. The phase-shifting type changes the phase angle and usually also the voltage magnitude—under load.

A regulating transformer may be used alone in a circuit or in conjunction with a power transformer. Or the regulating-transformer function may be built into a power transformer.

PROTECTION OF IN-PHASE TYPE

Figure 16 shows schematically the relay equipment that is recommended for protection against internal short circuits. Percentage-differential relaying, like that for generators, should be used to protect the series winding and its connections to its breakers. If the regulating transformer is close enough to a power transformer in the same circuit, the differential-protection zone of the power transformer may be extended to include the regulating transformer. The percent slope of the differential relay should be high enough to accommodate the full range of voltage change, as already mentioned for tap-changing power transformers.

The exciting windings need separate protective equipment because the equipment protecting the series winding is not sensitive enough

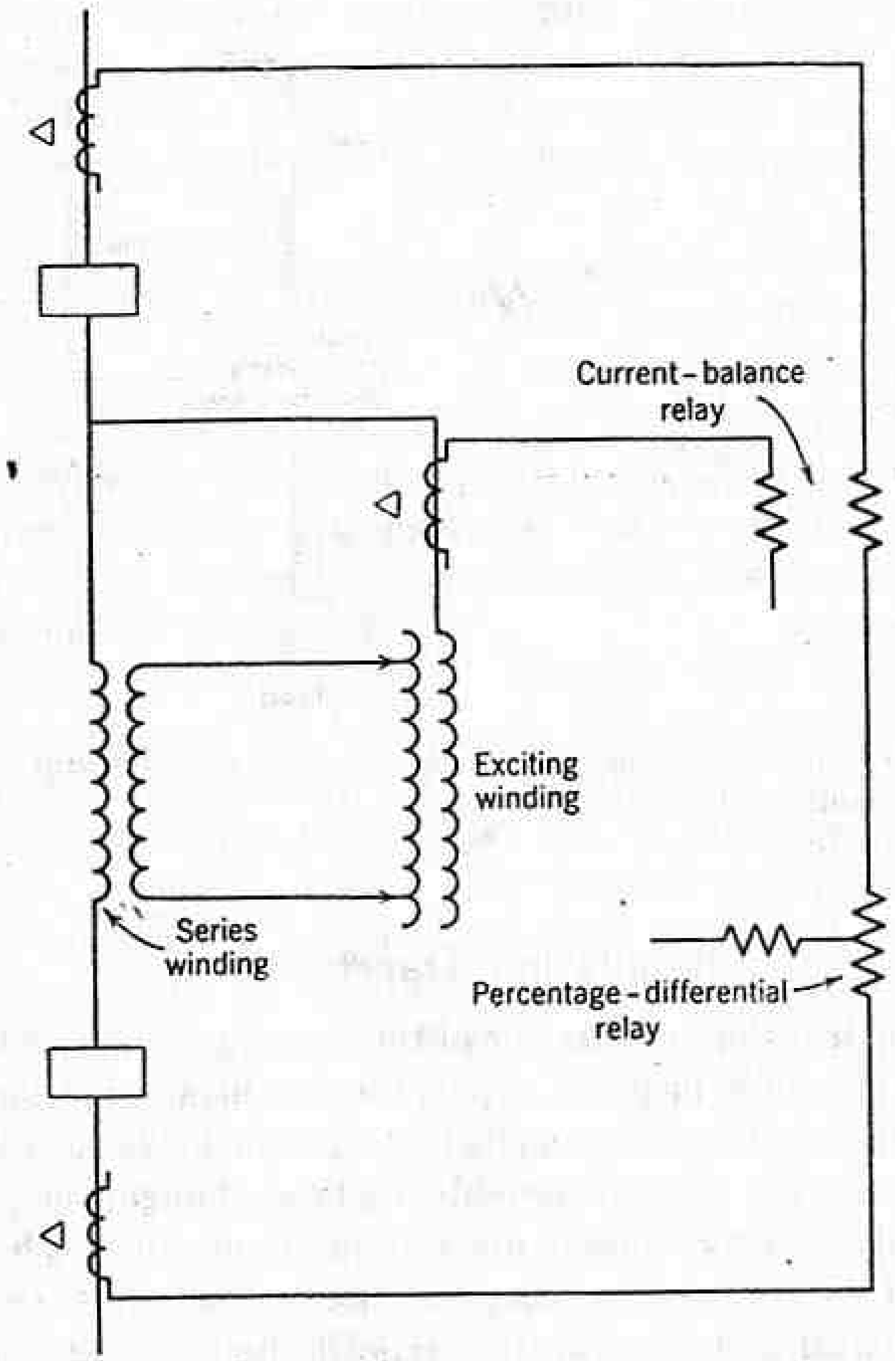
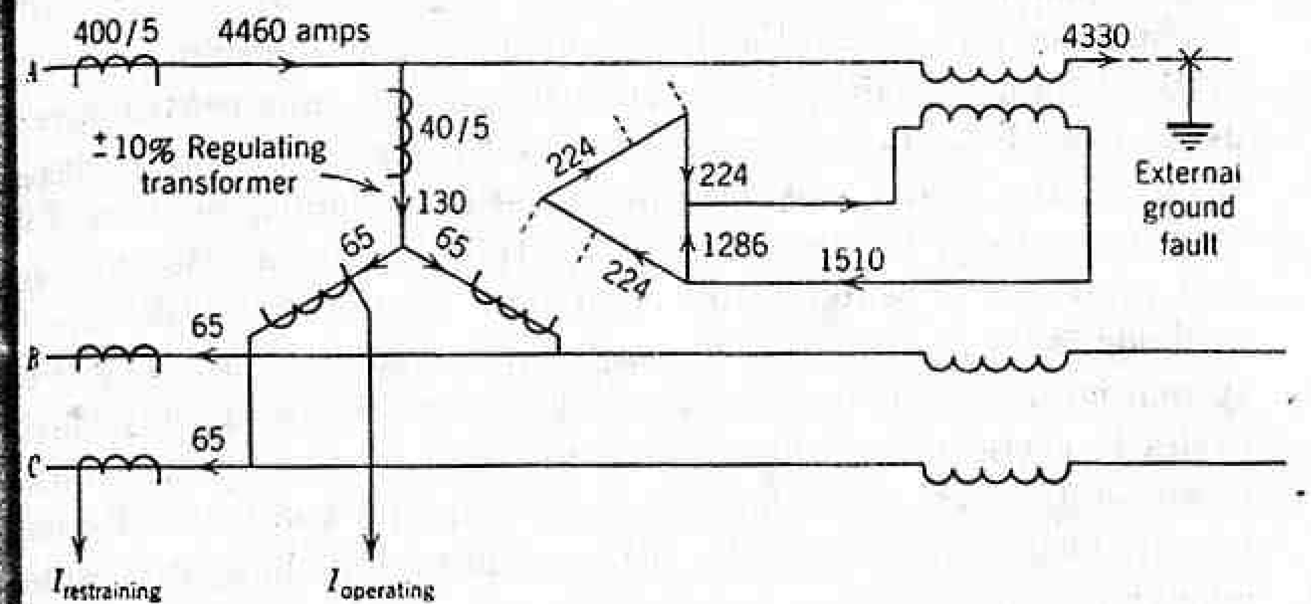


Fig. 16. Protection of an in-phase regulating transformer.

for the exciting windings. This is because the full-load-current rating of the exciting winding is much less than that of the series winding and the short-circuit current is proportionally less; for example, in a regulating transformer that changes the circuit voltage by ±10%, the full-load-current rating of the exciting winding will be 10% of that of the series winding. The situation is the same as that already described for protecting two different-sized power transformers with one differential relay. In practice a current-balance relay protects

the exciting winding, as shown in Fig. 16. So long as there is no fault in the exciting windings, the exciting current of a ±10% transformer will never exceed 10% of the rated series-winding current; the current-balance relay will operate whenever the ratio of exciting-winding current to series-winding current is about 25% higher than the maximum normal ratio under conditions of maximum buck or boost.



With Y CT's

Phase	I_{op}	I_{restr}
A	16.3	55.8
B	8.1	0.8
C	8.1	0.8

With Δ CT's

Phase	I_{op}	I_{restr}
A-B	24.4	56.6
B-C	0	0
C-A	24.4	56.6

Fig. 17. Illustrating why delta-connected CT's are required for regulating-transformer protection.

A very important precaution is that the CT's supplying the current-balance relay must always be delta connected. This is so whether the neutral of the exciting windings is grounded or not. Figure 17 shows the results of a study of an actual application where an external phase-to-ground fault would cause the current-balance relays of phases B and C to operate incorrectly if the CT's were wye connected.

Wherever possible, it is recommended that gas-accumulator and pressure relaying supplement the other protective equipment. Or, if the regulating-transformer tank can be insulated from ground, a grounding protective relay would be recommended because of the more sensitive protection that it would provide.

PROTECTION OF PHASE-SHIFTING TYPE

Wherever possible, the phase-shifting type of regulating transformer is protected in the same manner as the in-phase type. However, with conventional percentage-differential relaying, a 10° phase shift is about all that can be tolerated; such a phase shift requires that the differential relays have about a 40% slope and that relays in two phases operate before tripping is permitted, in order not to trip undesirably for external faults.

When phase shifts of more than about 10° are involved, special forms of relaying equipment are necessary. Certain modifications to conventional differential relaying may sometimes be possible, but the basis for such modifications is too complicated to consider here. Gas-accumulator and pressure relaying take on more importance where over-all differential relaying is not completely adequate. Complete percentage-differential protection can often be provided for wye windings if CT's are made available at both ends of each winding,[19] or differential protection against ground faults only can be provided if CT's at the neutral ends are lacking. Overcurrent relaying can protect against ground faults in a delta winding connected to a grounded-neutral source.

EXTERNAL-FAULT BACK-UP PROTECTION

The external-fault back-up relays of the power transformer or circuit associated with the regulating transformer will provide the necessary back-up protection.

Step Voltage Regulators

If circuit breakers are provided, pressure relaying should be used for regulators whose equivalent physical size is about 1000 kva or more.

Grounding Transformers

Two types of grounding transformer are in general use: (1) the wye-delta transformer, and (2) the zig-zag transformer. The neutral of either type may be grounded directly or through current-limiting impedance. It is assumed here that neither load nor a source of generation is connected to the delta winding of the wye-delta transformer, and that the zig-zag transformer does not have another winding connected to load or generation; should either type have such connections, it would be treated as an ordinary power transformer.

Figure 18 shows the recommended way to protect either type of bank. For external ground faults, only zero-phase-sequence currents flow through the primaries of the delta-connected CT's. Therefore, current will flow only in the external-fault back-up overcurrent relay,

and its time delay should be long enough to be selective with other relays that should operate for external faults. The other three relays will provide protection for short circuits on the grounding-transformer side of the CT's. These relays may be sensitive and quite fast because, except for magnetizing current and small currents that may flow through the relays because of CT errors, current will flow only when short circuits requiring tripping occur. The pickup of the overcurrent relays should be 25% to 50% of the grounding-trans-

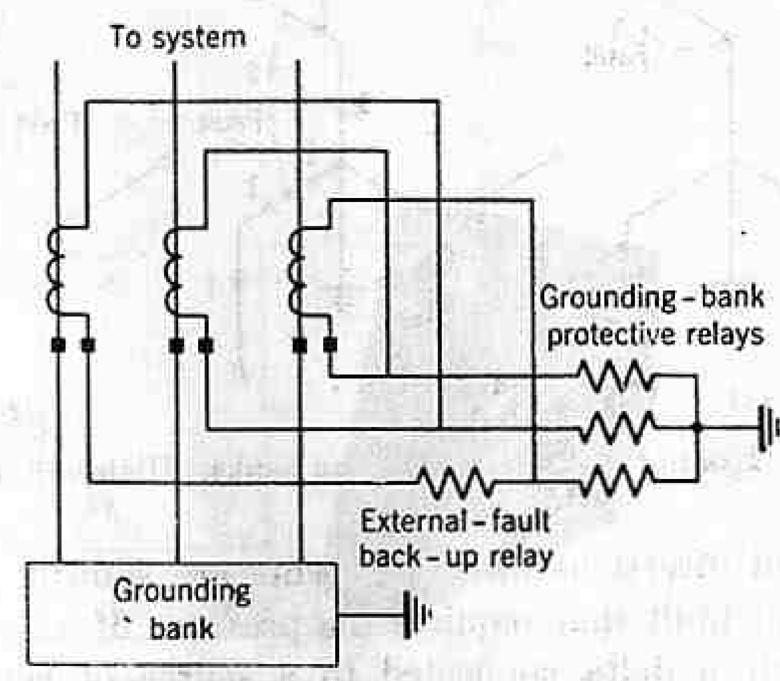


Fig. 18. Grounding-bank protection.

former's continuous-current rating, and the primary-current rating of the CT's should be about the continuous-current rating of the power transformer.

An interesting fact in connection with either type of grounding bank is that, under certain conditions, it is impossible to have certain types of fault in the bank without the short-circuit current's being limited by some magnetizing impedance. For example, certain types of fault can occur without the limiting effect of magnetizing impedance only if there is another grounding bank to provide a zero-phase-sequence-circulating-current path for the currents in the faulted bank; this other grounding bank may or may not have a delta winding connected to a source of generation. Or the fault must occur between certain points of the windings, and the presence of another grounding bank may or may not be necessary. Examples of the foregoing facts are shown in Figs. 19(a), 19(b), and 19(c) for a zig-zag bank. Remember that, unless fault current can flow in windings on the same core in such a way that the ampere-turns cancel, the current will be limited by some magnetizing impedance. However, if enough of a winding is shorted out, considerable overvoltage impressed on the remaining portion would cause large magnetizing currents to flow because of saturation. Figure 19(a) is an example of a type of short circuit where the current is limited by some magnetizing impedance of a winding. Figure 19(b) shows a type of short circuit that can occur without requiring the presence of another grounding bank; here, the fault is assumed to occur between the middle points of the two windings involved, and the relative

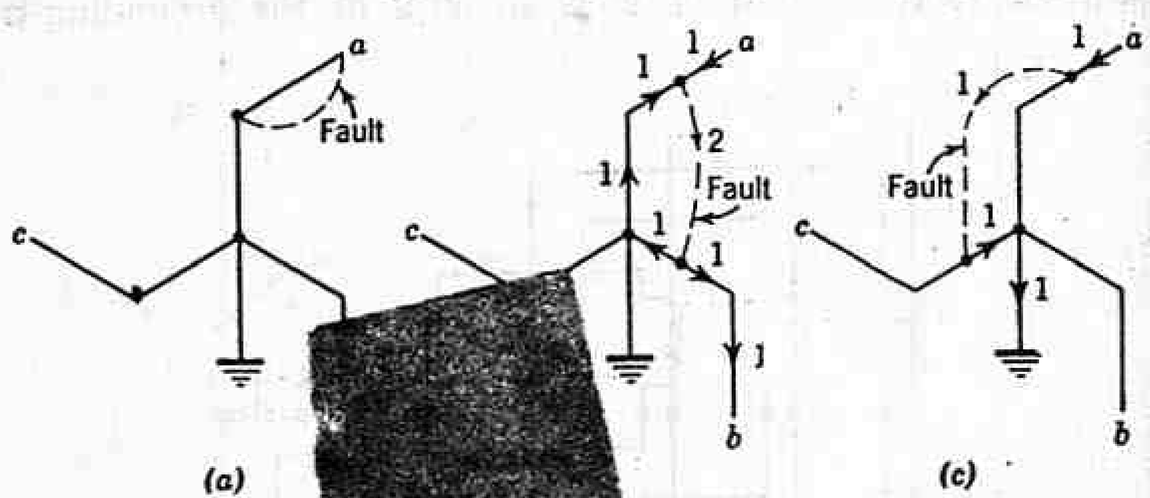


Fig. 19. Exampl[illegible]g banks. High-voltage side.

magnitudes and directions o[illegible]ents are shown. Figure 19(c) shows a type of fault that requires the presence of a grounding bank with or without a delta connected to a source of generation; here again, the fault is between the middle points of the two windings involved. A good exercise for the reader is to trace the flow of current back through the other grounding bank, and also to apply other types of short circuit, to see if there is any way in which current can flow to cancel the ampere-turns on each core involved. Figures 19(a), 19(b), and 19(c) are not the only examples of the three different conditions.

Because faults can occur that will not cause high currents to flow, gas-accumulator relaying, if applicable, would provide valuable supplementary protection.

Electric Arc-Furnace Transformers

Electric arc-furnace power transformers are not protected with percentage-differential relays because of the complications that would be introduced by the very frequent tap changing on the power transformer. Every time a furnace-transformer tap was changed, the low-voltage CT ratio or a tap on the relay would have to be changed.

Also, the connections of the furnace-transformer primary windings are usually changed from delta to wye and back again, which would require changing the CT connections.

Protection against short circuits inside the power transformer should be provided by inverse-time phase (and ground if required) overcurrent relays operating from the current on the high-voltage side of the power transformer. The phase relays should have torque-control coils and should be adjusted to pick up at currents only slightly in excess of the transformer's rated full-load current; they should have time delay only long enough to prevent operation on transformer magnetizing-current inrush. High-speed overcurrent relays on the low-voltage side of the transformer, adjusted to pick up at current slightly above rated full load but slightly below the current that will pick up the high-voltage phase relays, should be arranged to control the operation of the high-voltage phase relays through their torque-control coils so as to permit the high-voltage relays to operate only when the low-voltage relays do not operate. In this way, the high-voltage relays may normally be sensitive and fast so as to provide as good protection to the transformer as it is possible to provide with overcurrent relays, while at the same time avoiding undesired operation on external faults, the most common of which are short circuits in the furnace.

For primary protection against short circuits between the "back-up" breaker and the power transformer, and for back-up protection against faults in the transformer or beyond it, inverse-time phase (and ground if required) overcurrent relays should be provided. These relays should obtain their current from the source side of the back-up breaker. This so-called "back-up" breaker is the breaker that is provided to interrupt short-circuit currents in the transformer or on the high-voltage side, and it may serve several transformers.

Both of the foregoing groups of relays should trip the back-up breaker.

Power-Rectifier Transformers

Inverse-time-overcurrent relays are recommended for internal short-circuit protection. The inverse-time elements should have time-delay adjustment with just sufficient delay to be selective with the d-c protective equipment for external d-c short circuits or overloads. The instantaneous elements should be adjustable so as barely not to operate for low-voltage faults or magnetizing-current inrush, including an allowance for overtravel.

A temperature relay operating in conjunction with a resistance temperature detector should be provided to sound an alarm or trip the transformer breaker as desired.

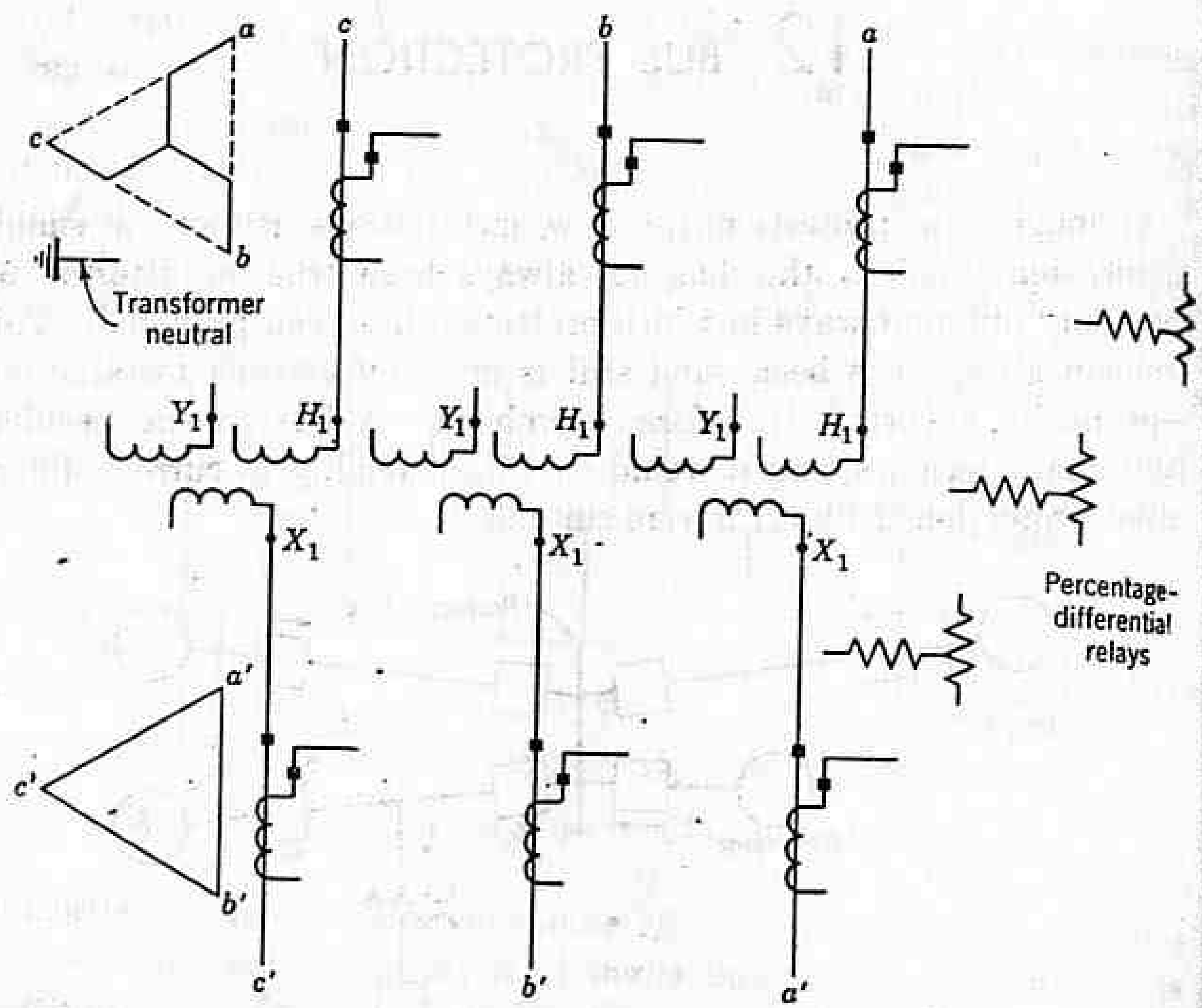


Fig. 20. Illustration for Problem 1.

Problems

1. Given three single-phase power transformers having windings as shown in Fig. 20. Complete the connections of the power transformers so as to obtain a zig-zag connection on the high-voltage side and a delta connection on the low-voltage side, using the partial connections shown, the voltage diagrams to be as shown. Connect the CT's to the percentage-differential relays so as to obtain protection of the transformer bank for internal faults but so that undesired tripping will not occur for external faults. Assume a 1/1 turn ratio between each pair of power-transformer windings, and assume that any desired ratio is available for the CT's. Add the CT-secondary ground connection.

2. Given a wye-delta power transformer protected as shown in Fig. 21. An external three-phase fault occurs, and fault currents flow through the transformer with the magnitudes as shown. Will the differential relay operate to trip?

3. Repeat Problem 2 except with a three-phase fault between the high-voltage breaker and the transformer. Assume that the system supplies 4000 amperes three-phase to the fault, the current supplied by the power transformer being the same as in Problem 2.

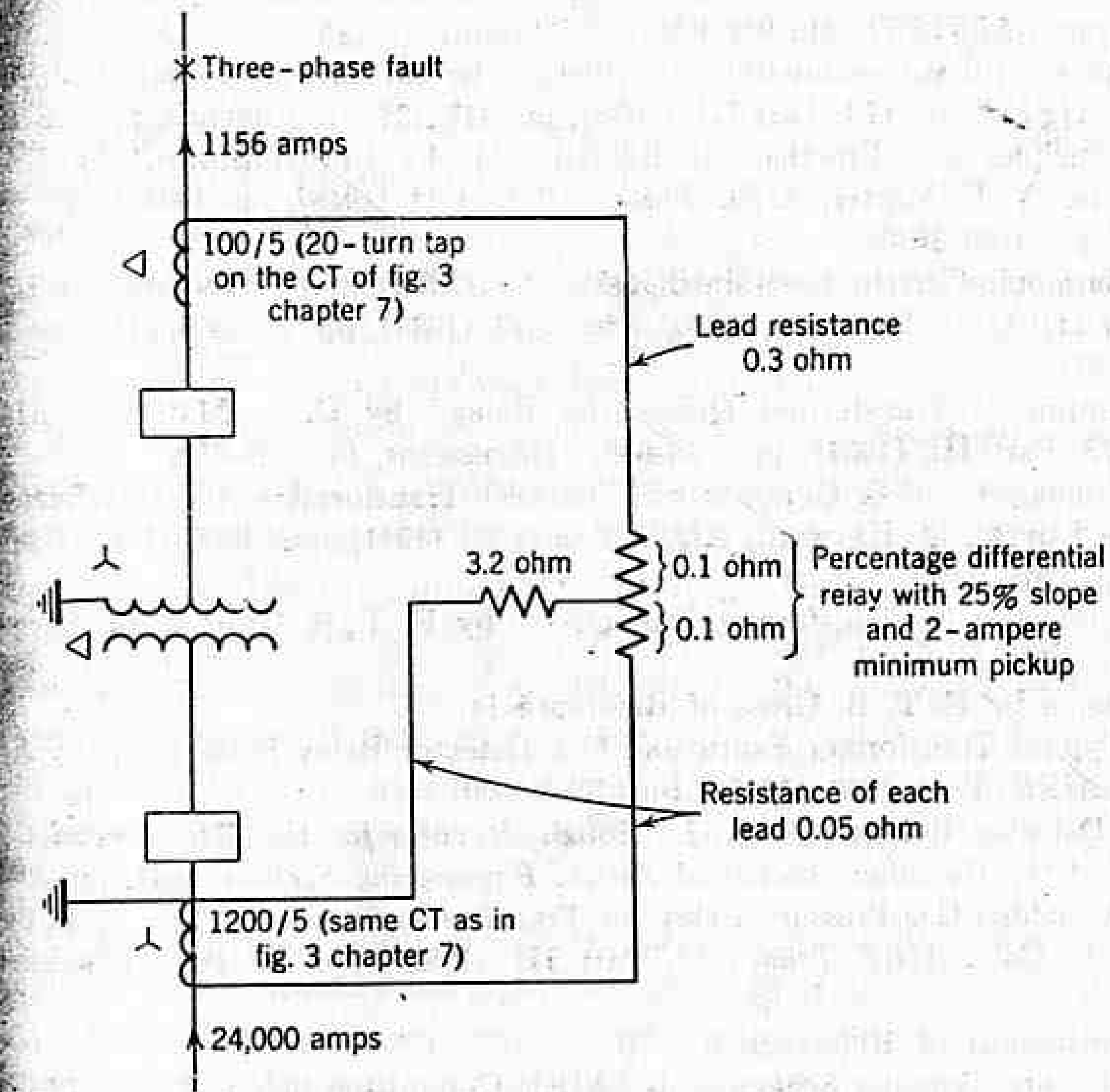


Fig. 21. Illustration for Problems 2 and 3.

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whose three-phase rating is 1000 kva and higher.[1] A survey of a large number of representative power companies showed that a minority favored differential relaying for as low as 1000-kva banks, but that they were practically unanimous in approving differential relaying for banks rated 5000 kva and higher.[2] To apply these recommendations to power autotransformers, the foregoing ratings should be taken as the "equivalent physical size" of autotransformer banks, where the equivalent physical size equals the rated capacity times $[1 - (V_L/V_H)]$, and where V_L and V_H are the voltage ratings on the low-voltage and high-voltage sides, respectively.

The report of an earlier survey[3] included a recommendation that circuit breakers be installed in the connections to all windings when banks larger than 5000 kva are connected in parallel. The more recent report is not very clear on this subject, but nothing has transpired that would change the earlier recommendation. The protection of parallel banks without separate breakers and the protection of a single bank in which a transmission line terminates without a high-voltage breaker will be considered later.

The differential relay should operate a hand-reset auxiliary that will trip all transformer breakers. The hand-reset feature is to minimize the likelihood of a transformer breaker being reclosed inadvertently, thereby subjecting the transformer to further damage unnecessarily.

Where transmission lines with high-speed distance relaying terminate on the same bus as a transformer bank, the bank should have high-speed relaying. Not only is this required for the same reason that the lines require it, but also it permits the second-zone time of the distance relays "looking" toward the bus to be set lower and still be selective.

CURRENT-TRANSFORMER CONNECTIONS FOR DIFFERENTIAL RELAYS

A simple rule of thumb is that the CT's on any wye winding of a power transformer should be connected in delta, and the CT's on any delta winding should be connected in wye. This rule may be broken, but it rarely is; for the moment let us assume that it is inviolate. Later, we shall learn the basis for this rule. The remaining problem is how to make the required interconnections between the CT's and the differential relay.

Two basic requirements that the differential-relay connections must satisfy are: (1) the differential relay must not operate for load or external faults; and (2) the relay must operate for severe enough internal faults.

If one does not know what the proper connections are, the procedure is first to make the connections that will satisfy the requirement of not tripping for external faults. Then, one can test the connections for their ability to provide tripping for internal faults.

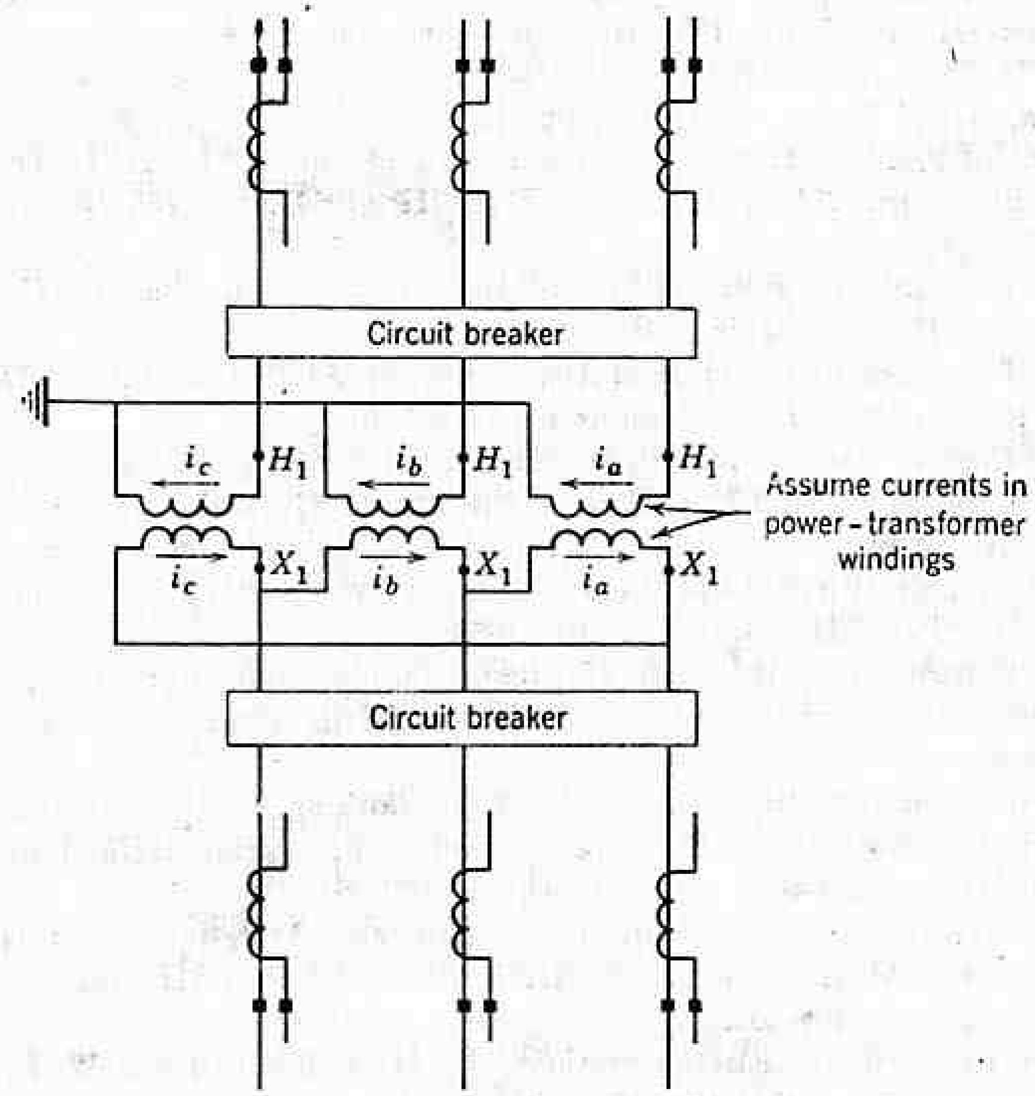


Fig. 1. Development of CT connections for transformer differential relaying, first step.

As an example, let us take the wye-delta power transformer of Fig. 1. The first step is arbitrarily to assume currents flowing in the power-transformer windings in whichever directions one wishes, but to observe the requirements imposed by the polarity marks that the currents flow in opposite directions in the windings on the same core, as shown in Fig. 1. We shall also assume that all the windings have the same number of turns so that the current magnitudes are equal, neglecting the very small exciting-current component. (Once the proper connections have been determined, the actual turn ratios can very easily be taken into account.)

On the basis of the foregoing, Fig. 2 shows the currents that flow in the power-transformer leads and the CT primaries for the general external-fault case for which the relay must not trip. We are assuming that no current flows into the ground from the neutral of the wye winding; in other words, we are assuming that the three-phase currents add vectorially to zero.

The next step is to connect one of the sets of CT's in delta or in wye, according to the rule of thumb already discussed; it does not matter how the connection is made, i.e., whether one way or reversed.

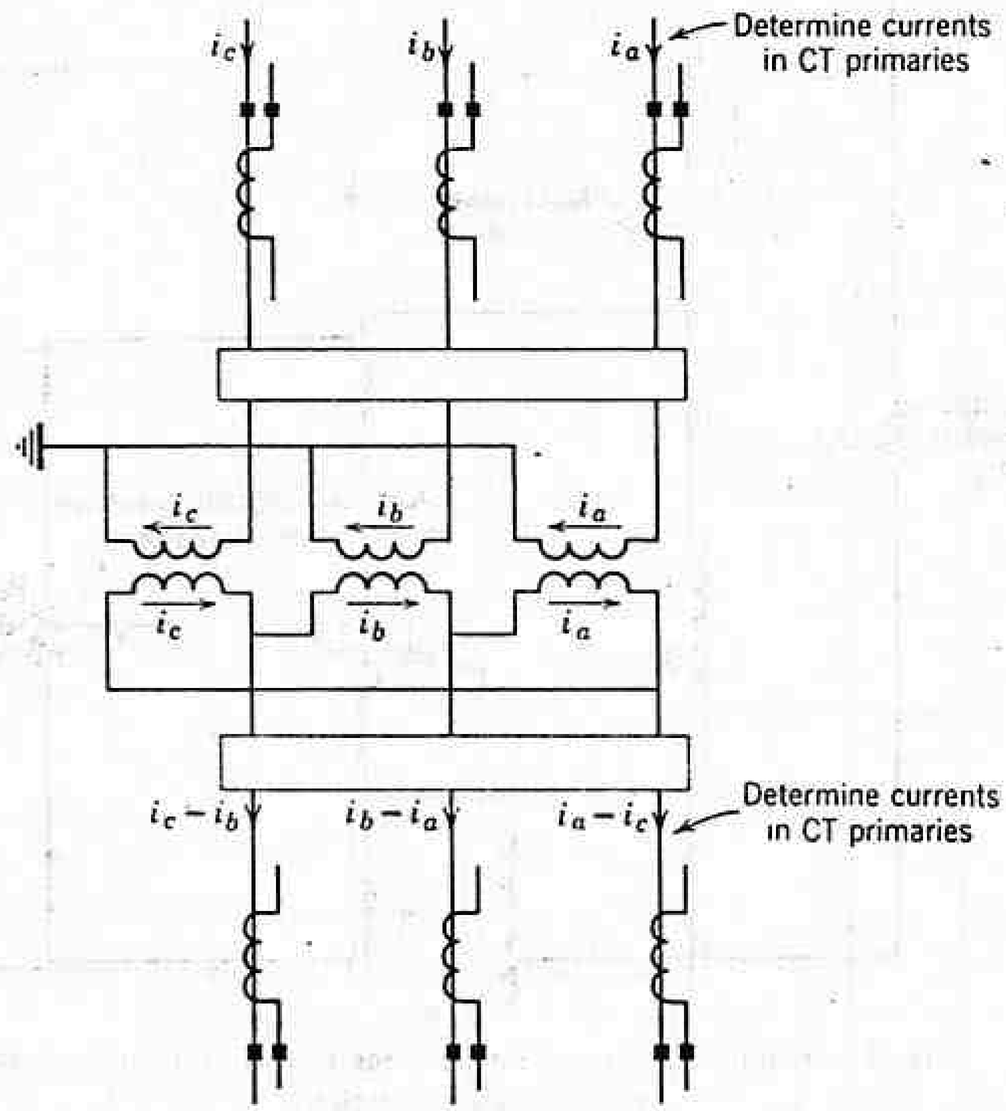


Fig. 2. Development of CT connections for transformer differential relaying, second step.

Then, the other set of CT's must be connected also according to the rule, but, since the connections of the first set of CT's have been chosen, it does matter how the second set is connected; this connection must be made so that the secondary currents will circulate between the CT's as required for the external-fault case. A completed connection diagram that meets the requirements is shown in Fig. 3. The connections would still be correct if the connections of both sets of CT's were reversed.

Proof that the relay will tend to operate for internal faults will not be given here, but the reader can easily satisfy himself by drawing current-flow diagrams for assumed faults. It will be found that

protection is provided for turn-to-turn faults as well as for faults between phases or to ground if the fault current is high enough.

We shall now examine the rule of thumb that tells us whether to connect the CT's in wye or in delta. Actually, for the assumption

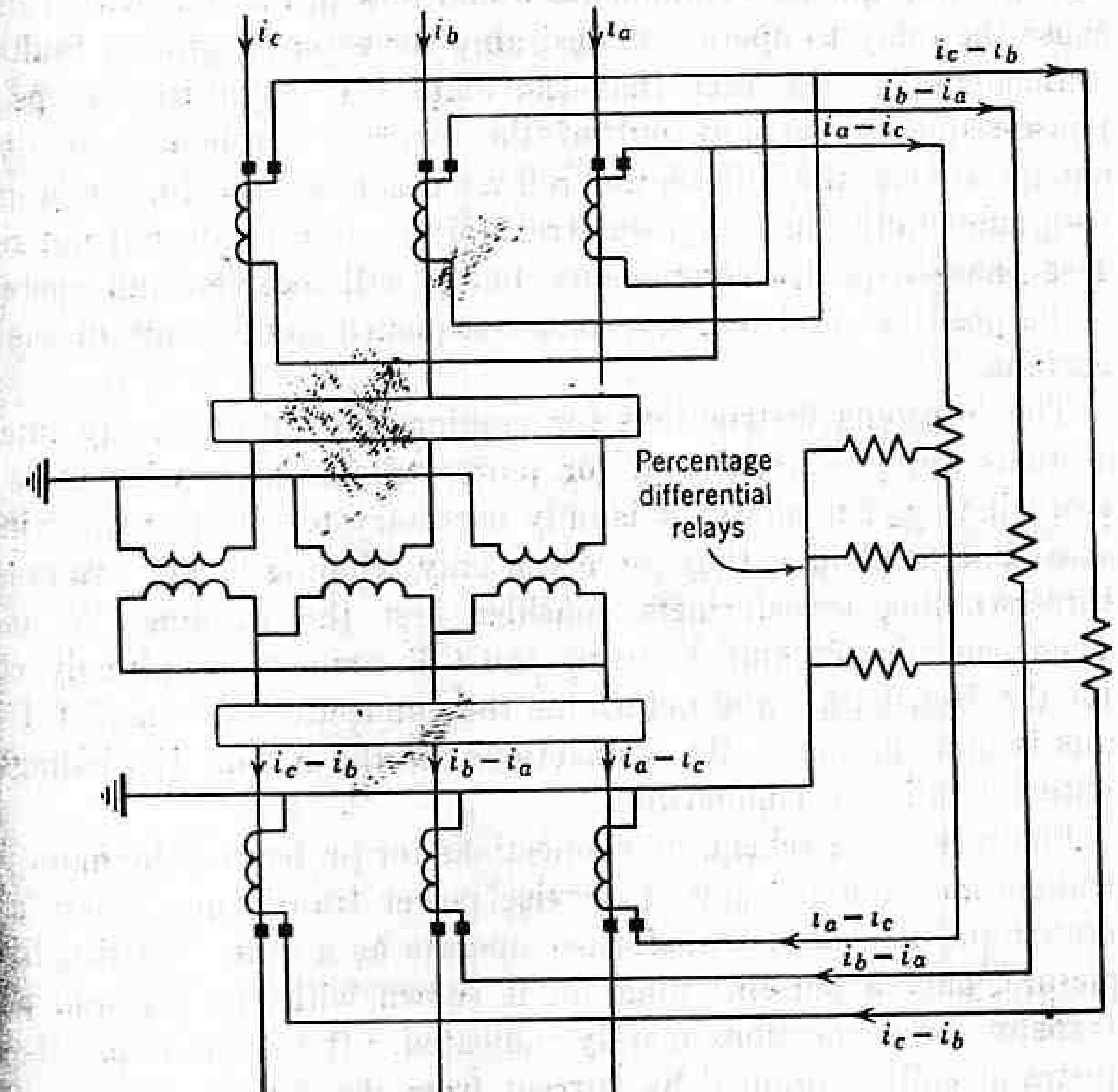


Fig. 3. Completed connections for percentage-differential relaying for two-winding transformer.

made in arriving at Fig. 2, namely, that the three-phase currents add vectorially to zero, we could have used wye-connected CT's on the wye side and delta-connected CT's on the delta side. In other words, for all external-fault conditions except ground faults on the wye side of the bank, it would not matter which pair of CT combinations was used. Or, if the neutral of the power transformer was not grounded, it would not matter. The significant point is that, when ground current can flow in the wye windings for an external fault, we must use the delta connection (or resort to a "zero-phase-sequence-current shunt" that will be discussed later). The delta CT connection circulates the zero-phase-sequence components of the currents inside the delta and thereby keeps them out of the external connections to the relay. This is necessary because there are no zero-phase-sequence components of current on the delta side of the power transformer for a ground fault on the wye side; therefore, there is no possibility of the zero-phase-sequence currents simply circulating between the sets of CT's and, if the CT's on the wye side were not delta connected, the zero-phase-sequence components would flow in the operating coils and cause the relay to operate undesirably for external ground faults.

Incidentally, the fact that the delta CT connection keeps zero-phase-sequence currents out of the external secondary circuit does not mean that the differential relay cannot operate for single-phase-to-ground faults in the power transformer; the relay will not receive zero-phase-sequence components, but it will receive—and operate on—the positive- and negative-phase-sequence components of the fault current.

The foregoing instructions for making the CT and relay interconnections apply equally well for power transformers with more than two windings per phase; it is only necessary to consider two windings at a time as though they were the only windings. For example, for three-winding transformers consider first the windings H and X. Then, consider H and Y, using the CT connections already chosen for the H winding, and determine the connections of the Y CT's. If this is done properly, the connections for the X and Y windings will automatically be compatible.

Figure 4 shows schematic connections for protecting the main power transformer and the station-service power transformer where a generator and its power transformer operate as a unit. To simplify the picture, only a one-line diagram is shown with the CT and power-transformer connections merely indicated. It will be noted that one restraint coil is supplied by current from the station-service-bus side of the breaker on the low-voltage side of the station-service power transformer in parallel with the CT in the neutral end of the generator winding; this is to obtain the advantage of overlapping adjacent protective zones around a circuit breaker, as explained in Chapter 1. A separate differential relay is used to protect the station-service power transformer because the relay protecting the main power transformer is not sensitive enough to provide this protection; with a steam-turbine generator, the station-service bank is no larger than about 10% of the size of the main bank, and, consequently, the CT's used for the main bank have ratios that are about 10 times as large as would be desired for the most sensitive protection of the station-service transformer. With a hydroelectric-turbine generator, the

station-service transformer is more nearly 1% of the size of the main transformer; consequently, the impedance of the station-service transformer is so high that a fault on its low-voltage side cannot operate the relay protecting the main transformer even if the CT's are omitted from the low-voltage side of the station-service transformer; therefore,

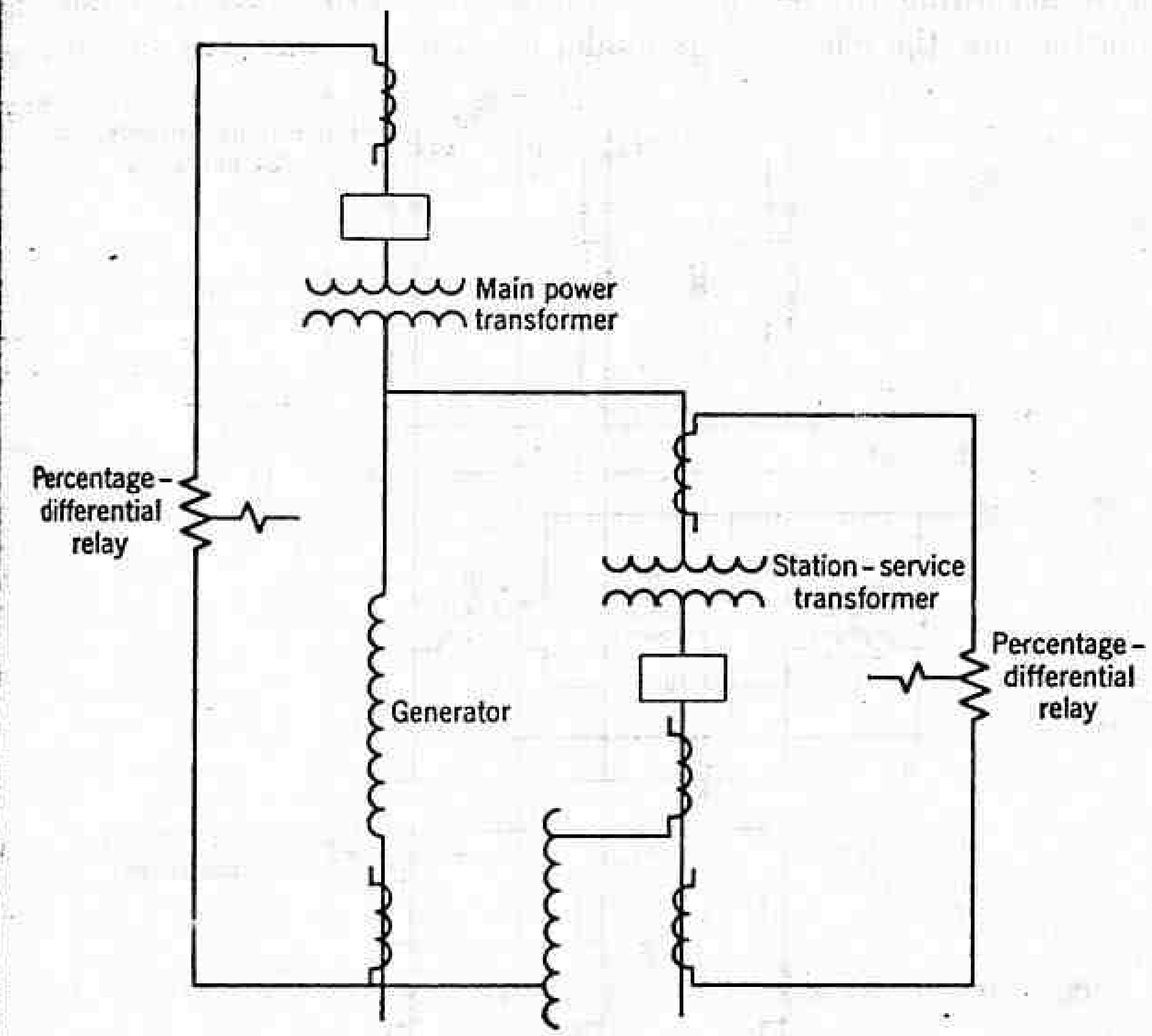


Fig. 4. Schematic connections for main and station-service-transformer protection.

for hydroelectric generators it is the practice to omit these CT's and to retain separate differential protection for the station-service bank. In order to minimize the consequential damage should a station-service-transformer fault occur, separate high-speed percentage-differential relaying should be used on the station-service transformer as for the main power transformer.

Figure 5 shows the usual way to protect a Scott-connected bank. This arrangement would not protect against a ground fault on phase b', but, since this is on the low-voltage side where a ground-current source is unlikely, such a possibility is of little significance. A more practical objection to Fig. 5, but still of secondary significance, is that, for certain turn-to-turn or phase-to-phase faults, only one relay unit can operate. This is contrasted with the general practice of providing three relay units to protect three-phase banks where, for any phase-to-phase fault, two relay units can operate, thereby giving double assurance that at least one unit will cause tripping. However, since

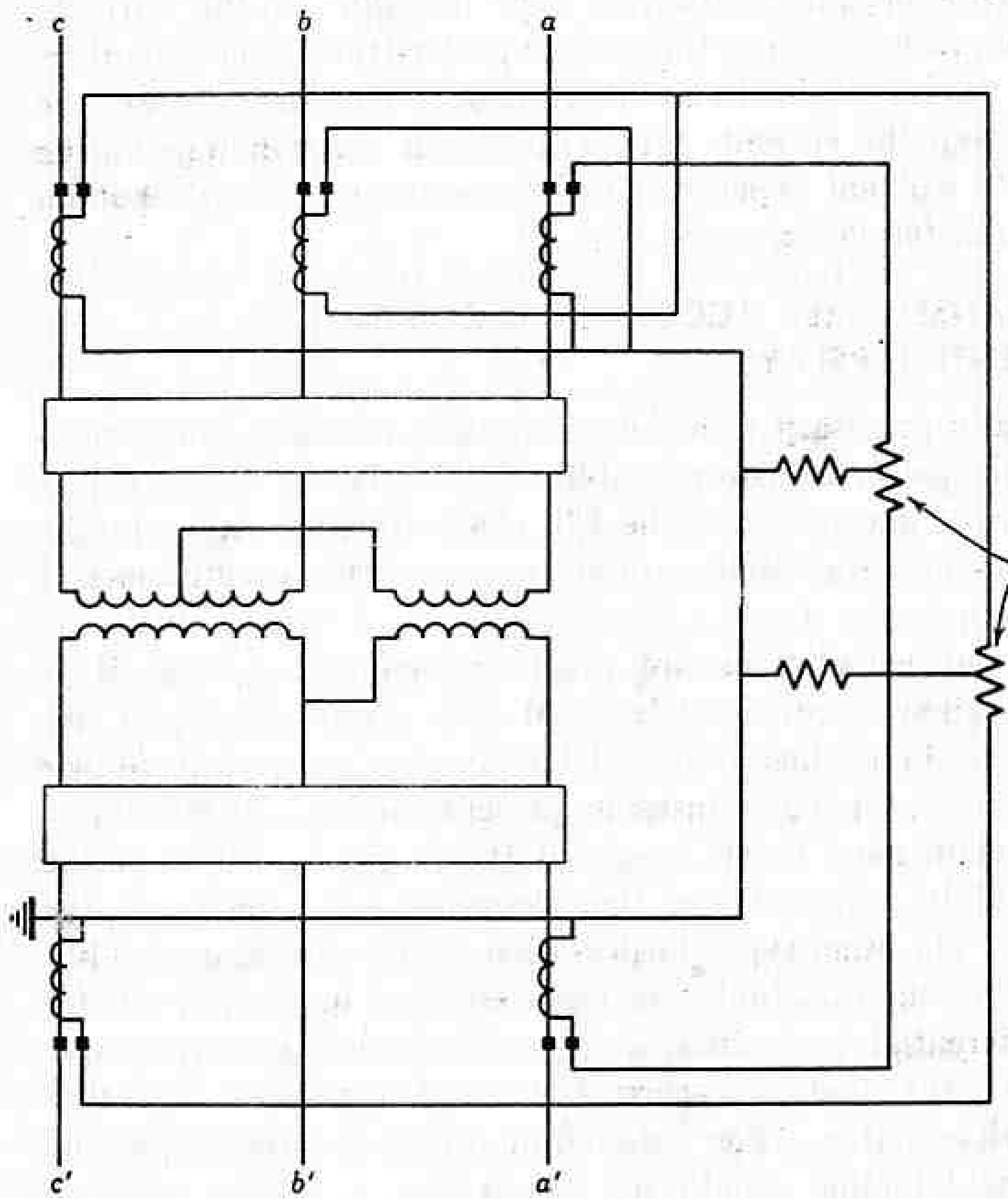


Fig. 5. Usual method of protecting a Scott-connected bank.

Scott-connected banks are used only at or near the load, it is questionable if the added cost of slightly more reliable protection can be justified. An alternative that does not have the technical disadvantages of Fig. 5 is shown in Fig. 6. Reference to other forms of Scott-connected bank and their differential protection is given in the Bibliography.[4]

Differentially connected CT's should be grounded at only one point. If more than one set of wye-connected CT's is involved, the neutrals

should be interconnected with insulated wire and grounded at only one point. If grounds are made at two or more different points, even to a low-resistance ground bus, fault currents flowing in the ground or ground bus may produce large differences of potential between

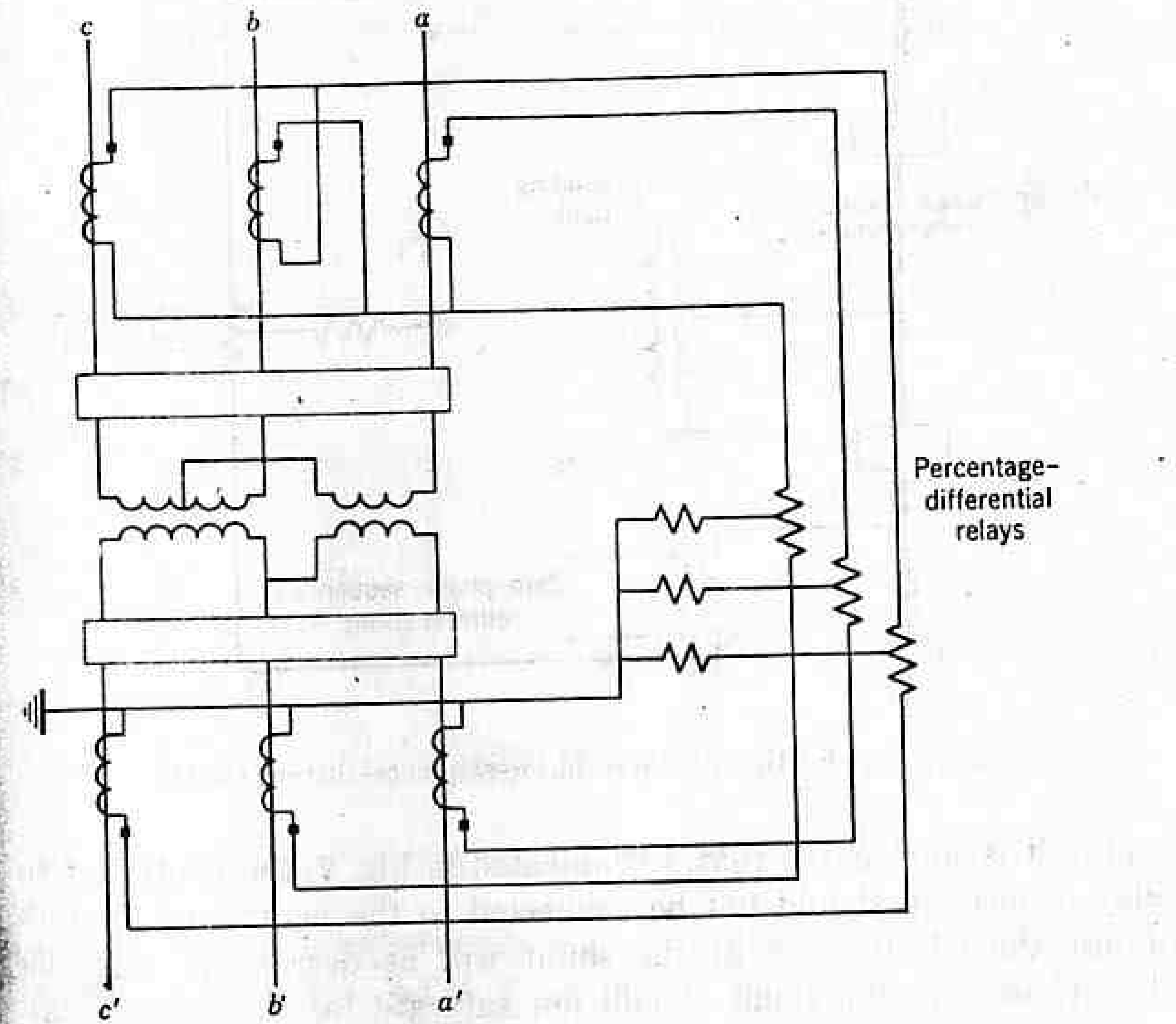


Fig. 6. Alternative protection of a Scott-connected bank.

the CT grounds, and thereby cause current to flow in the differential circuit. Such a flow of current might cause undesired tripping by the differential relays or damage to the circuit conductors.

THE ZERO-PHASE-SEQUENCE-CURRENT SHUNT

The zero-phase-sequence-current shunt was described in Chapter 7. Such a shunt is useful where it is necessary to keep the zero-phase-sequence components of current out of the external secondary circuits of wye-connected CT's. Such a shunt would permit one to connect the CT's in wye on the wye side of a power transformer and in delta on the delta side. Advantage is seldom taken of this possibility because there is usually no hardship in using the conventional connections, and in fact the conventional connections are usually preferred. The shunt is occasionally useful for the application of Fig. 7, where a grounding transformer on the delta side of a wye-delta power transformer is to be included within the zone of protection of the main

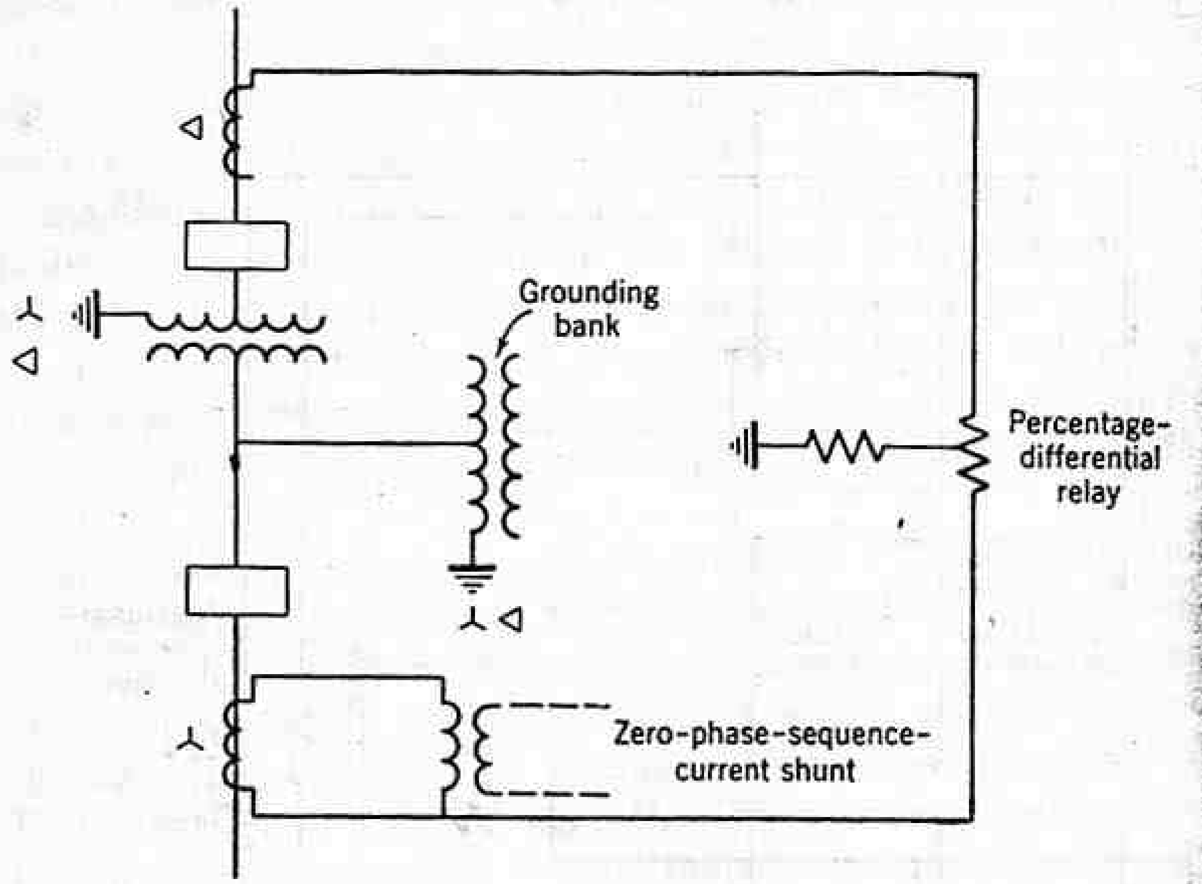


Fig. 7. Application of a zero-phase-sequence-current shunt.

bank. It is emphasized that, as indicated in Fig. 7, the neutral of the relay connection should not be connected to the neutral of the CT's or else the effectiveness of the shunt will be decreased. Also, the CT's chosen for the shunt should not saturate for the voltages that can be impressed on them when large phase currents flow.

CURRENT-TRANSFORMER RATIOS FOR DIFFERENTIAL RELAYS

Most differential relays for power-transformer protection have taps or are used with auxiliary autotransformers having taps, to compensate for the CT ratios not being exactly as desired. Where there is a choice of CT ratio, as with relaying-type bushing CT's, the best practice is to choose the highest CT ratio that will give a secondary current as nearly as possible equal to the lowest-rated relay tap. The purpose of this is to minimize the effect of the connecting circuit between the CT's and the relay (for the same reason that we use high voltage to minimize transmission-line losses). For whatever relay tap is used, the current supplied to the relay under maximum

load conditions should be as nearly as possible equal to the continuous rating for that tap; this assures that the relay will be operating at its maximum sensitivity when faults occur. If the current supplied is only half the tap rating, the relay will be only half as sensitive, etc.

When choosing CT ratios for power transformers having more than two windings per phase, one should assume that each winding can carry the total rated phase load. The proper matching of the CT ratios and relay or autotransformer taps depends on the current-transformation ratios between the various power-transformer windings and not on their full-load-current ratings. This is because the relations between the currents that will flow in the windings during external faults will not depend on their rated-current values but on the current-transformation ratios.

CURRENT-TRANSFORMER ACCURACY REQUIREMENTS FOR DIFFERENTIAL RELAYS

It is generally necessary to make certain CT accuracy calculations when applying power-transformer differential relays. These calculations require a knowledge of the CT characteristics either in the form of ratio-correction-factor curves or secondary-excitation and impedance data.

Two types of calculations are generally required. First, it is necessary to know approximately what CT errors to expect for external faults. Percentage-differential relays for power-transformer protection generally have adjustable percent slopes. This subject will be treated in more detail later, but the knowledge of what the CT errors will be is one factor that determines the choice of the percent slope. The other type of calculation is to avoid the possibility of locking-in for internal faults, as was described in Chapter 10 for generator differential protection; such a calculation is particularly necessary with the "harmonic-current-restraint" relay, a type that will be described later. For detailed application procedures, the manufacturers' bulletins should be followed.

The example given in Chapter 10 of a method for calculating steady-state CT errors in a generator differential-relay circuit is also applicable to the power-transformer relay, with minor exceptions. The fact that some CT's may be in delta introduces a slight complication, but the circuit calculation is still simple.

A study based on certain equipment of the manufacturer with whom the author is associated showed the minimum requirements for bushing CT's to be as in the accompanying table. The fact that relaying-type bushing CT's may be operated on their lowest turns-ratio tap makes

Number of Secondary Turns	ASA Accuracy Rating (Full Winding)
120	10L200
240	10L400
400	10L400
600	10L400
800	10L800
1000	10L800
1200	10L800

it necessary that the rating of the full winding be higher than if the full winding were used.

CHOICE OF PERCENT SLOPE FOR DIFFERENTIAL RELAYS

Percentage-differential relays are generally available with different percent slopes; they may have adjustment so that a single relay can have any one of several slopes. The purpose of the percent-slope characteristic is to prevent undesired relay operation because of "unbalances" between CT's during external faults arising from an accumulation of unbalances for the following reasons: (1) tap-changing in the power transformer; (2) mismatch between CT currents and relay tap ratings; and (3) the difference between the errors of the CT's on either side of the power transformer. Many power transformers have taps that will give $\pm X\%$ change in transformation ratio. It is the practice to choose CT ratios and relay or autotransformer taps to balance the currents at the midpoint of the tap-changing range; on that basis, the most unbalance that can occur from this cause is $X\%$. The maximum unavoidable mismatch between CT currents and relay tap ratings is one-half of the difference between two relay tap ratings, expressed in percent. The percent difference between CT errors must be determined for the external fault that produces the greatest error; the best that we can do is to calculate this on a steady-state basis. We should assume that all three unbalances are in the same direction to get the total maximum possible unbalance. Then add at least 5% to this value, and the new total is the minimum percent slope that should be used.

PROTECTING A THREE-WINDING TRANSFORMER WITH A TWO-WINDING PERCENTAGE-DIFFERENTIAL RELAY

Unless there is a source of generation back of only one side of a power transformer, a two-winding percentage-differential relay should not be used to protect a three-winding transformer. Figure 8 shows that, when a two-winding relay is used, the CT secondaries on two

sides of the power transformer must be paralleled. If there is a source of generation back of one of these sides, the conditions shown by the arrows of Fig. 8 could exist. For an external fault on the other side there may be sufficient unbalance between the CT currents, either

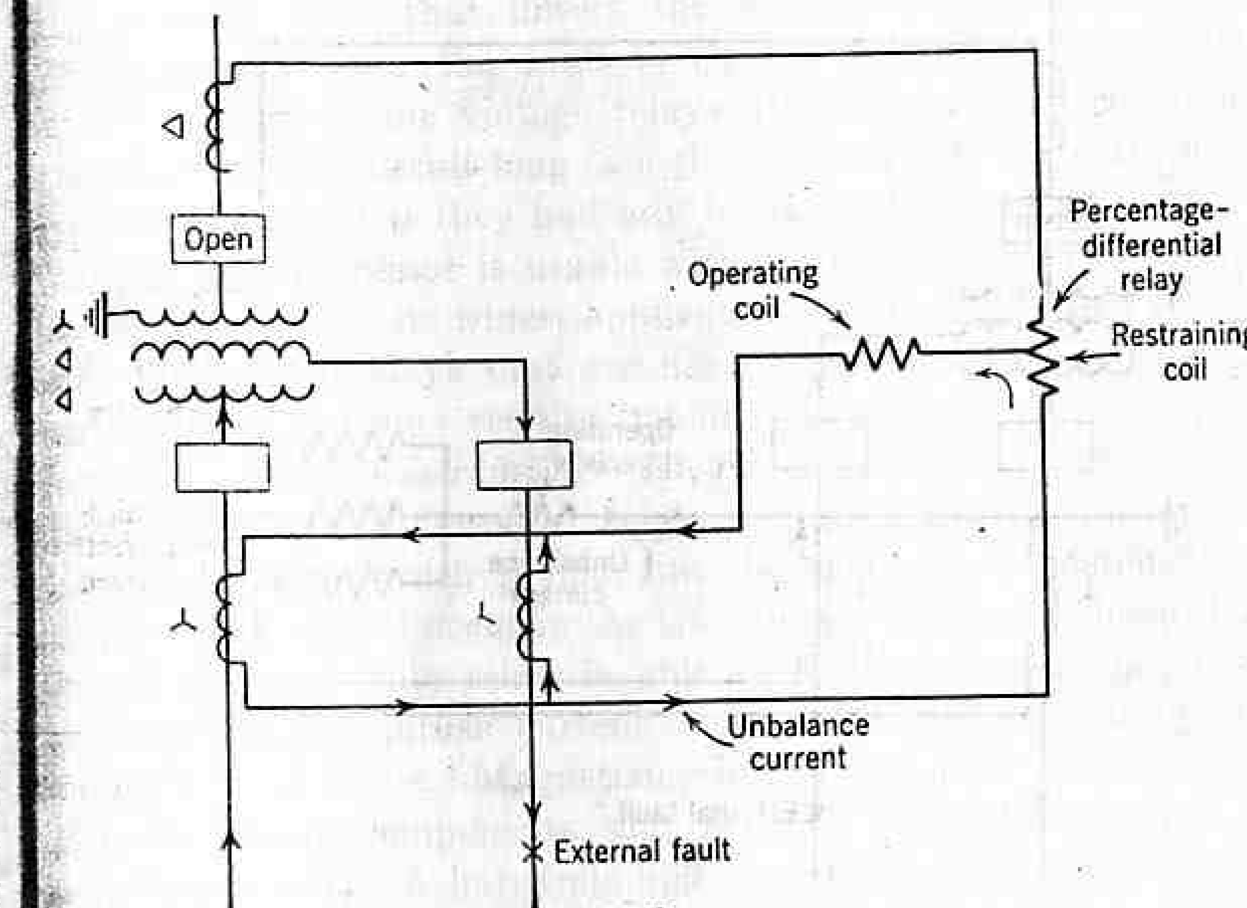


Fig. 8. A misapplication of a two-winding transformer differential relay.

because of mismatch or errors or both, to cause the differential relay to operate undesirably. The relay would not have the benefit of through-current restraint, which is the basis for using the percentage-differential principle. Instead, only the unbalance current would flow in all of the operating coil and in half of the restraining coil; in effect, this constitutes a 200% unbalance, and it is only necessary that the unbalance current be above the relay's minimum pickup for the relay to operate.

Of course, if the two sides where CT's are paralleled in Fig. 8 supply load only and do not connect to a source of generation, a two-winding relay may be used with impunity.

Figure 9 shows that, if a three-winding relay is used, there will always be through-current restraint to restrain the relay against undesired operation.

A further advantage of a three-winding relay with a three-winding transformer is that, where relay types are involved having taps for matching the CT secondary currents, it is often unnecessary to use any auxiliary CT's. Thus, a three-winding relay may even be used with advantage where a two-winding relay might suffice. There is no disadvantage, other than a slight increase in cost, in using a three-winding relay on a two-winding transformer; no harm is done if one of the restraint circuits is left unconnected.

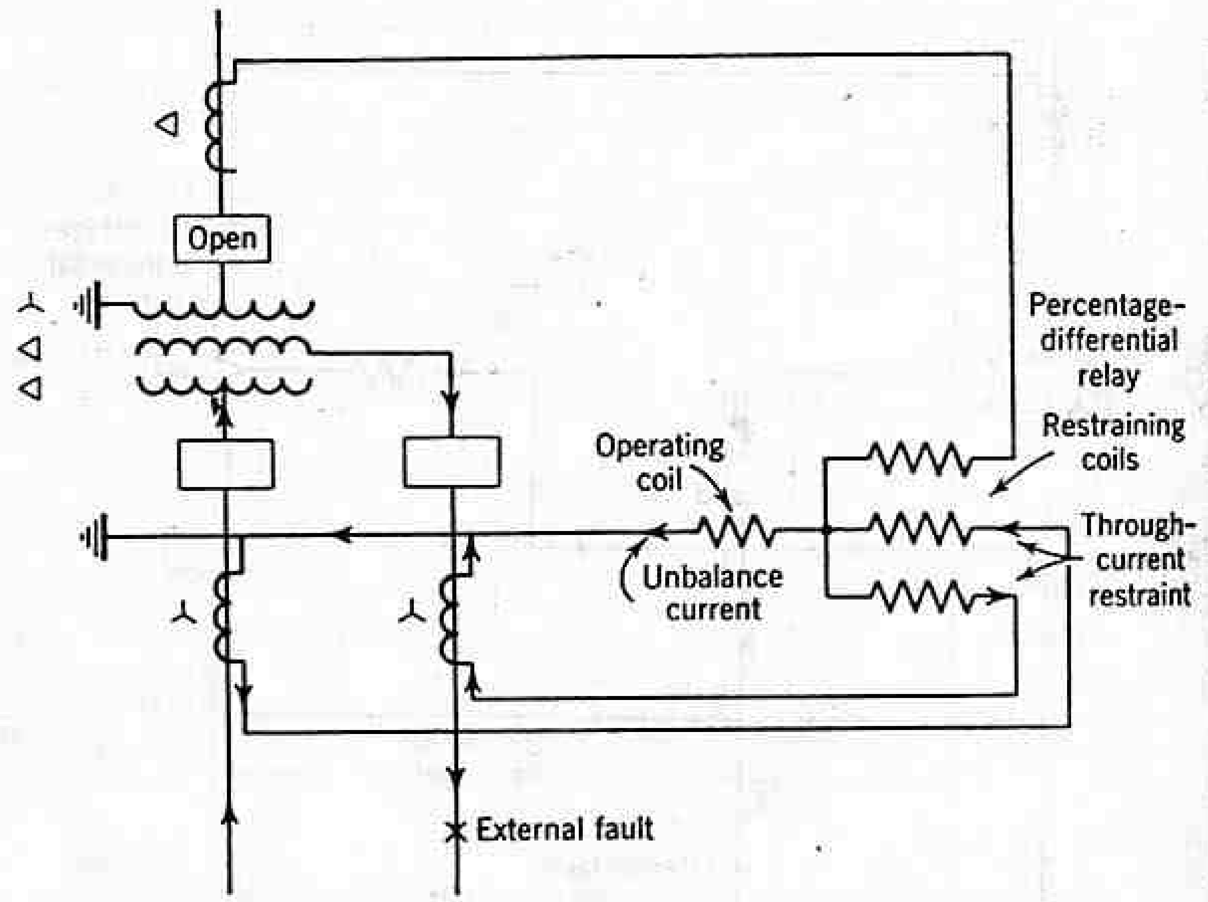


Fig. 9. Illustrating the advantage of a three-winding relay with a three-winding transformer.

EFFECT OF MAGNETIZING-CURRENT INRUSH ON DIFFERENTIAL RELAYS

The way in which CT's are connected and the way in which CT ratios and relay taps are chosen for differential relaying neglect the power-transformer exciting-current component. Actually, this component causes current to flow in the relay's operating coil, but it is so small under normal load conditions that the relay has no tendency to operate. However, any condition that calls for an instantaneous change in flux linkages in a power transformer will cause abnormally large magnetizing currents to flow, and these will produce an operating tendency in a differential relay.[5,6,7]

The largest inrush and the greatest relay-operating tendency occur when a transformer bank has been completely de-energized and then a circuit breaker is closed, thereby applying voltage to the windings on one side with the windings on the other side still disconnected

from load or source. Reference 5 gives data as to the magnitudes and durations of such inrush currents. Considerably smaller but still possibly troublesome inrushes occur when a transformer with connected load is energized[7] or when a short circuit occurs or is disconnected.[8]

Another troublesome inrush problem will be discussed later under the heading "Protection of Parallel Transformer Banks."

The occasional tripping because of inrush when a transformer is energized is objectionable because it delays putting the transformer into service. One does not know but that the transformer may have a fault in it. Consequently, the safest thing to do is to make the necessary tests and inspection to locate the trouble, if any, and this takes considerable time.

Percentage-differential relays operating with time delay of about 0.2 second or more will often "ride over" the inrush period without operating. Where high-speed relays are required, it is generally necessary to use relay equipment that is especially designed to avoid undesired tripping on the inrush current.

Three methods that are used for preventing operation on inrush current will now be described.

Desensitizing. One type of desensitizing equipment consists of an undervoltage relay with "*b*" contacts and having time-delay pickup and reset; these contacts are connected in series with a low-resistance resistor that shunts the operating coil of the differential relay in each phase. This is shown schematically in Fig. 10 for the differential relay of one phase. The undervoltage relay is energized from a potential transformer connected to the power-transformer leads between the power transformer and its low-voltage breaker. When the power transformer is de-energized, the undervoltage relay resets, and its contacts complete the shunt circuit across the operating coil of the differential relay. The undervoltage relay will not pick up and open its contacts until a short time after the power transformer has been energized, thereby desensitizing the differential relay during the magnetizing-current-inrush period. During normal operation of the power transformer, the desensitizing circuit is open, thereby not interfering with the differential-relay sensitivity should a fault occur in the power transformer. Should a transformer fault occur that would reset the undervoltage relay, its time delay would prevent desensitizing the differential relay until after it had had more than sufficient time to operate if it was going to do so.

One disadvantage of such a desensitizing method is that it might delay tripping should a short circuit occur during the magnetizing-inrush period while the differential relay is desensitized. If the fault were severe enough to lower the voltage sufficiently so that the desensitizing relay could not pick up, tripping would depend on the current being high enough to operate the differential relay in its desensitized state. This is a rather serious disadvantage in view of the fact that one of the most likely times for a fault to occur is when the bank is being energized. The other disadvantage is that this equipment cannot desensitize the differential relay against the possibility of

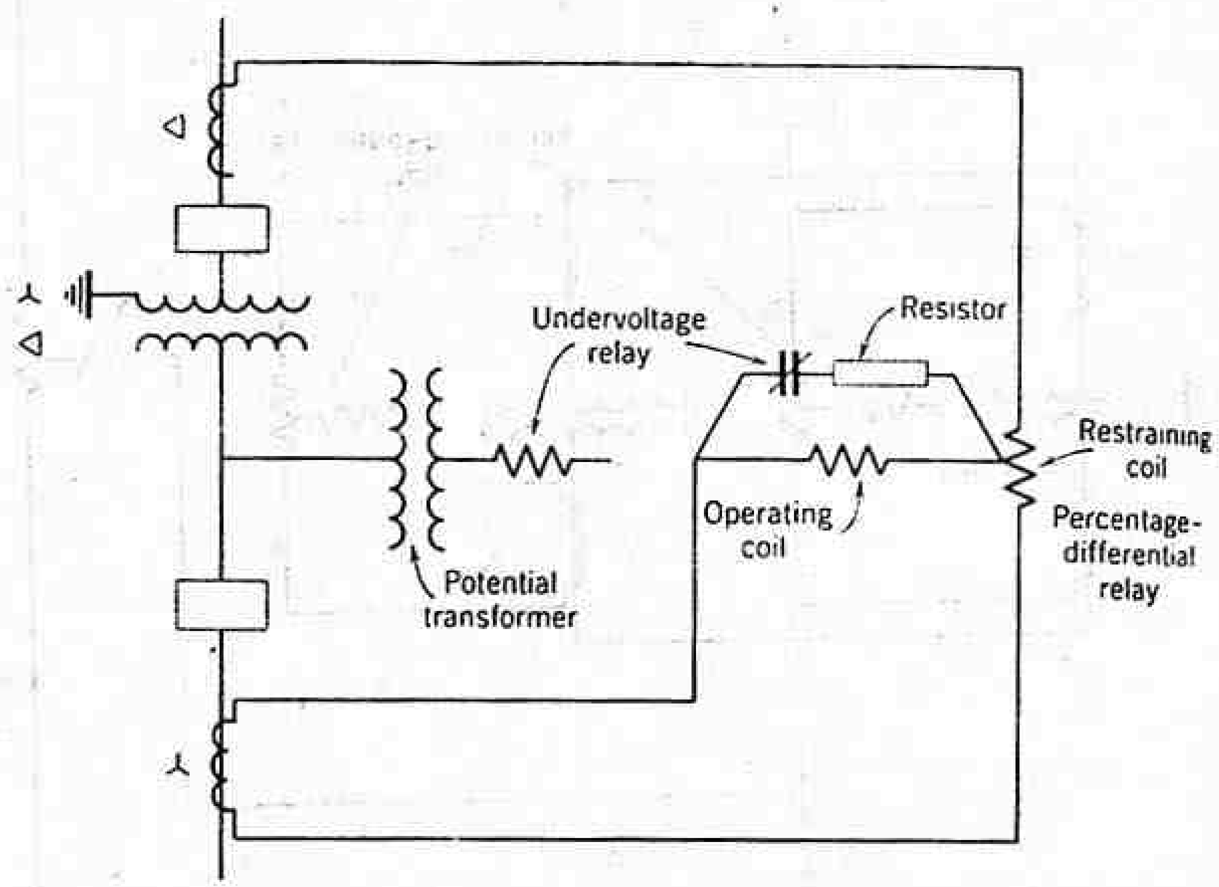


Fig. 10. Desensitizing equipment to prevent differential-relay tripping on magnetizing inrush.

undesired operation during the magnetizing inrush after the clearing of an external fault. This is not so serious a disadvantage because desensitizing of the type described here is used only with relays having about 0.2-second time delay, and there is practically no problem of tripping on voltage recovery with such relays.

Tripping Suppressor.[9] An improvement over the desensitizing principle is called the "tripping suppressor." Three high-speed voltage relays, connected to be actuated by either phase-to-phase or phase-to-neutral voltage, control tripping by the percentage-differential relays. If all three voltage relays pick up during the inrush period, thereby indicating either a sound transformer or one with very low fault current, a timer is energized that closes its "*a*" contact in the tripping circuit of the differential relays after enough time delay so that

tripping on inrush alone would not occur. But, for any fault that will operate a differential relay and also reduce the voltage enough so that at least one voltage relay will not pick up, tripping occurs immediately. In other words, tripping is delayed only for very-low-current faults that affect the voltage only slightly.

Any external fault that lowers the voltage enough to cause a significant inrush when the fault is cleared from the system will reset one or more of the voltage relays, thereby resetting the timer and opening the trip circuit long enough to assure that the differential relays will have reset if they had any tendency to operate.

The tripping suppressor is usable with either high-speed or slower differential relays, but its widest application is with high-speed relays. In fact, high-speed relays that are not inherently selective between inrush and fault currents require tripping suppressors.

Harmonic-Current Restraint.[10] The principle of "harmonic-current restraint" makes a differential relay self-desensitizing during the magnetizing-current-inrush period, but the relay is not desensitized if a short circuit should occur in the transformer during the magnetizing-inrush period. This relay is able to distinguish the difference between magnetizing-inrush current and short-circuit current by the difference in wave shape. Magnetizing-inrush current is characterized by large harmonic components that are not noticeably present in short-circuit current. A harmonic analysis of a typical magnetizing-inrush-current wave was as shown in the accompanying table.

Harmonic Component	Amplitude in Percent of Fundamental
2nd	63.0
3rd	26.8
4th	5.1
5th	4.1
6th	3.7
7th	2.4

Figure 11 shows how the relay is arranged to take advantage of the harmonic content of the current wave to be selective between faults and magnetizing inrush.

Figure 11 shows that the restraining coil will receive from the through-current transformer the rectified sum of the fundamental and harmonic components. The operating coil will receive from the differential-current transformer only the fundamental component of the differential current, the harmonics being separated, rectified, and fed back into the restraining coil.

12 BUS PROTECTION

Although bus protection for new installations is now a simple application problem, this has not always been true, as attested by the many different ways in which protection has been provided. This problem always has been—and still is in many existing installations —primarily a current-transformer problem. A bus has no peculiar fault characteristics, and it would lend itself readily to current-differential protection if its CT's were suitable.

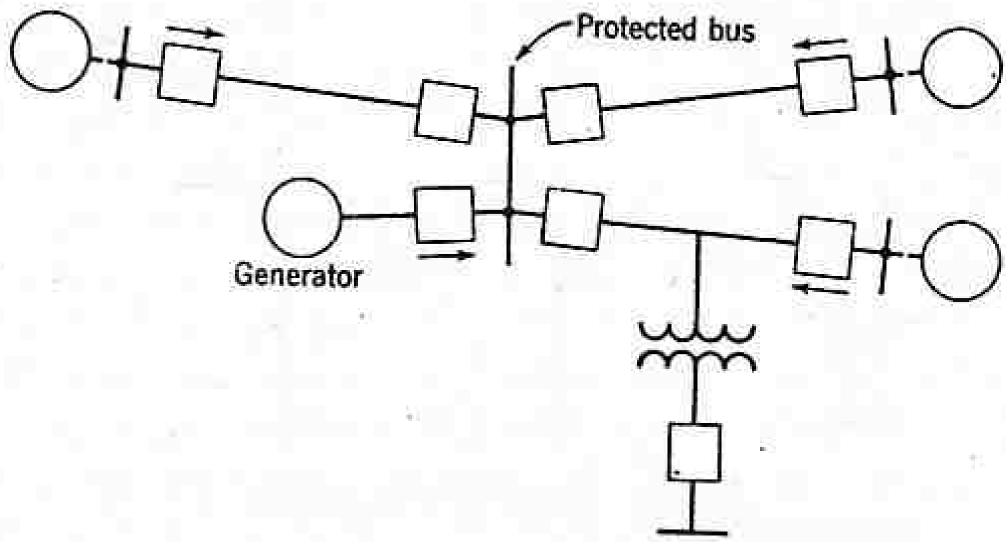


Fig. 1. Bus protection by back-up relays.

Before considering the more modern equipments for bus protection, let us first examine the various forms of protection that have been used and that are still in service; new uses for some of these may still be found infrequently today.

PROTECTION BY BACK-UP RELAYS

The earliest form of bus protection was that provided by the relays of circuits over which current was supplied to a bus, at locations such as shown by the arrows on Fig. 1. In other words, the bus was included within the back-up zone of these relays. This method was relatively slow speed, and loads tapped from the lines would be in-

The correct practice is to interconnect the neutrals of all differentially connected CT's with the same kind of *insulated* wire as that used for the other CT interconnections. Then, the neutral interconnection is grounded at *one point only*. Since the grounding is for the protection of personnel, the best place to make the ground is at the differential-relay panel where connection is made to the neutral of wye-connected relay coils.

The reason why the ground should be made at only one point is to avoid improper relay operation and damage to the CT interconnections. If grounds are made at two or more locations, circulating currents may be caused to flow in the differential circuit because of differences of potential between the grounding points, owing to the flow of large ground currents during ground faults.

AUTOMATIC RECLOSING OF BUS BREAKERS

A few installations of outdoor automatic substations, whose busses are not enclosed, employ automatic reclosing of the bus breakers. In at least one installation, a single circuit connected to a generating source is first reclosed and, if it stays in, the remaining circuits are then reclosed—all automatically. Somewhat the same philosophy applies to outdoor open busses as to transmission lines, namely, that many faults will be non-persisting if quickly cleared, and, hence, that automatic reclosing will usually be successful. However, substations are generally better protected against lightning than lines, and their exposure to lightning is far less. Hence, one can expect that a larger percentage of bus faults will be persisting.

PRACTICES WITH REGARD TO CIRCUIT-BREAKER BY-PASSING

Most users of bus-differential protection take the bus protective-relaying equipment completely out of service, either automatically or manually, and do not substitute any other equipment for temporary protection, when circuit breakers are to be by-passed for maintenance purposes or when any other abnormal set-up is to be made.[7] Of course, the bus still has time-delay protection because the back-up equipment in the circuits connected to the bus should function for bus faults.

Others use a wide diversity of temporary forms of bus relaying.[7]

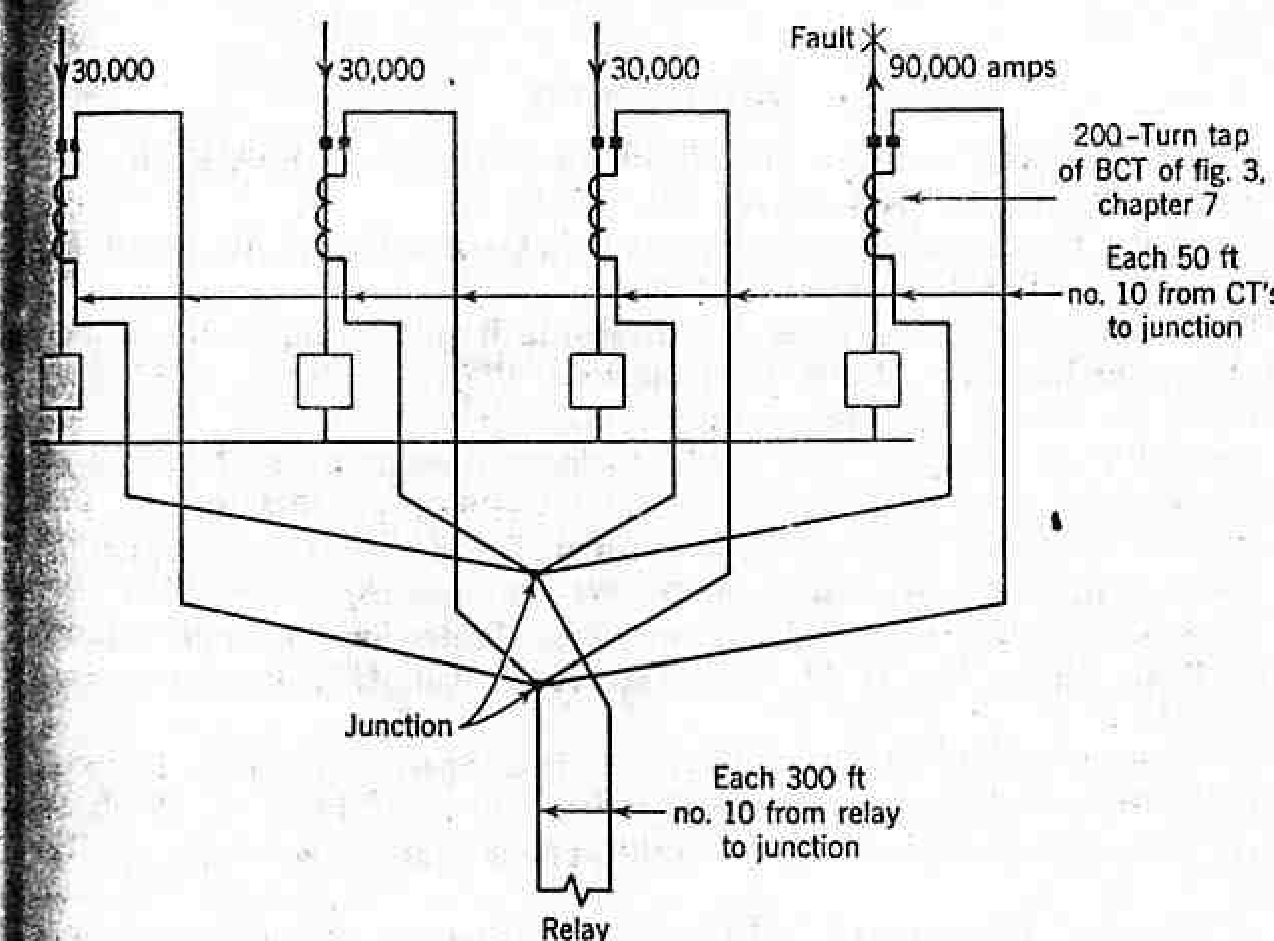
ONCE-A-SHIFT TESTING OF DIFFERENTIAL-RELAYING EQUIPMENT

Most power companies make maintenance checks once every 6 to 12 months or longer, but a few follow the practice of testing their bus-differential-relaying CT secondary circuits every shift for open circuits or short circuits. This can be done with permanently in-

lled testing equipment arranged to measure current in the relay rating coils, and to superimpose on the circuit a testing current voltage, as required. Where fault detectors are employed to super- tripping, the equipment is sometimes arranged to sound an alarm CT circuit should open and cause a differential relay to operate.

Such testing is felt by some to be particularly desirable where the ferential relay's pickup is high enough so that the relays will not erate on the current that they will get during normal load condi- ns if an open circuit or a short circuit should occur in a CT ondary circuit. Such trouble would not be discovered until after relays had operated undesirably for an external fault or had iled to operate for a bus fault.

Of course, the only difference between bus-differential CT circuits d the CT circuits of relaying equipment protecting other system ements is that for the bus there are more CT's involved and that larger part of the power system is affected. It is not that the bus uipment is inferior to the other, but that the consequences of failure e more serious.



g. 14. Illustration for problem. Assume resistance of no. 10 wire is 1.018 ohms per 1000 ft at 25° C.

Problem

Given a bus-differential-relaying equipment as shown in Fig. 14, using -ampere inverse-time-overcurrent relays whose time-current characteristics are shown in Fig. 3 of Chapter 3. The total short-circuit current to a bus fault under minimum generating conditions will be 5000 amperes; and it has been decided to adjust the relays to pick up at 2400 amperes (12-ampere tap). For an external three-phase fault involving the current magnitudes and directions as shown, the breaker in the faulty circuit will interrupt the flow of short-circuit current in 0.3 second by virtue of other protective relaying equipment not shown.

In view of the large magnitude of external-fault current, it is suspected that the differential relays may tend to operate, and, if so, they are to be adjusted to have a 0.5-second time delay so as to be selective with the faulty-feeder relaying equipment. What time-lever setting should be chosen for this purpose?

Assume that each CT in the faulty feeder saturates completely so as to have no secondary-current output, and that the total output current of the other CT's divides between the saturated CT's and the relays. Take into account the fact that the other CT's will have ratio error, and for this purpose assume that their primary currents are symmetrical. Also, take into account the fact that the relay coils saturate and, hence, that their impedance decreases as shown in the acompanying table when current of large magnitude flows in each coil.

Multiple of Pickup Current (4-amp. tap)	Coil Impedance, ohms
1	0.3
3	0.15
10	0.08
20	0.07

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terrupted unnecessarily, but it was otherwise effective. Some preferred this method to one in which the inadvertent operation of a single relay would trip all the connections to the bus.

THE FAULT BUS[1]

The fault-bus method consists of insulating the bus-supporting structure and its switchgear from ground; interconnecting all the framework, circuit-breaker tanks, etc.; and providing a single ground connection through a CT that energizes an overcurrent relay, as illustrated schematically in Fig. 2. The overcurrent relay controls a multicontact auxiliary relay that trips the breakers of all circuits

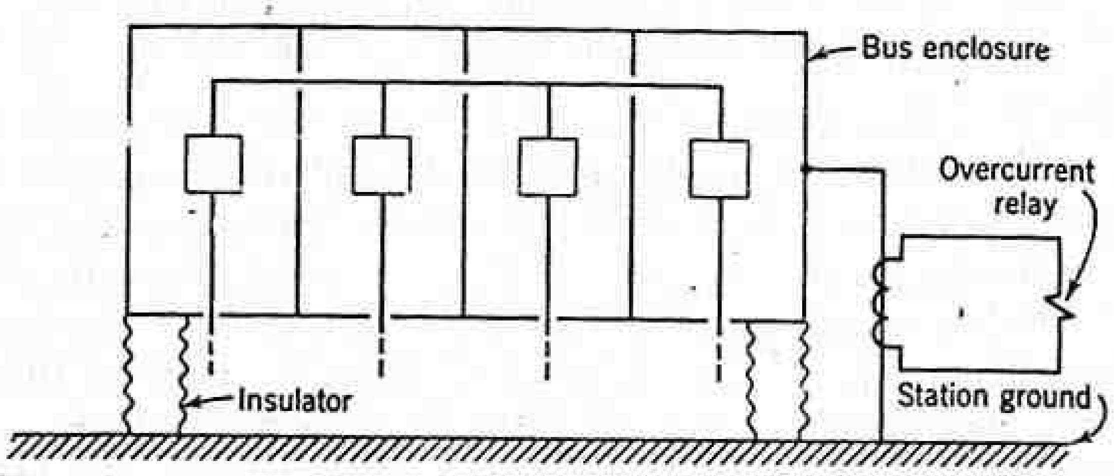


Fig. 2. Schematic diagram of the fault-bus method of protection.

connected to the bus. The maximum effectiveness is obtained by this method when the switchgear is of the isolated-phase construction, in which event all faults will involve ground. However, it is possible to design other types of switchgear with special provisions for making ground faults the most probable. Of course, if interphase faults not involving ground can occur, and if CT's and conventional differential relaying have to be used for protection against such faults, the fault-bus method would probably not be justified.

This method is most applicable to new installations, particularly of the metal-clad type, where provision can be made for effective insulation from ground. It has been more favored for indoor than for outdoor installations. Certain existing installations may not be adaptable to fault-bus protection, owing to the possibility of other paths for short-circuit current to flow to ground through concrete-reinforcing rods or structural steel. It is necessary to insulate cable sheaths from the switchgear enclosure or else cable ground-fault currents may find their way to ground through the fault-bus CT and improperly trip all the switchgear breakers. An external flashover of an entrance bushing will also improperly trip all breakers, unless

the bushing support is insulated from the rest of the structure and independently grounded.

If a sectionalized bus structure is involved, the housing of each section must be insulated from adjoining sections, and separate fault-bus relaying must be employed for each section. The fault-bus method does not provide overlapping of protective zones around circuit breakers; and, consequently, supplementary relaying is required to protect the regions between bus sections.

Some applications have used a fault-detecting overcurrent relay, energized from a CT in the neutral of the station-grounding transformer or generator, with its contact in series with that of the fault-bus relay, to guard against improper tripping in the event that the fault-bus relay should be operated accidentally; without some such provision, the accidental grounding of a portable electric tool against the switchgear housing might pass enough current through the fault-bus ground to operate the relay and trip all the breakers, unless the pickup of the relay was higher than the current that it could receive under such a circumstance.

Consideration should be given to the possibility of people being able to make contact between the switchgear housing and ground, to avoid the possibility of contact with high voltage should a ground fault occur; although the ground connection would have very low impedance, high current flowing through it could produce dangerously high voltage. This requirement also makes it desirable to ground all relay, meter, and control circuits to the switchgear housing rather than by means of a separate connection to the station ground.

DIRECTIONAL-COMPARISON RELAYING

The principle of "directional comparison" used for transmission-line relaying has been adapted to bus protection in order to avoid the problem of matching current-transformer ratings and characteristics.[2] Basically, the contacts of directional relays in all source circuits and the contacts of overcurrent relays in purely load circuits are interconnected in such a way that, if fault current flows toward the bus, the equipment will operate to trip all bus breakers unless sufficient current is flowing away from the bus in any circuit.

This principle has been used only with ground relays, on the basis that most bus faults start as ground faults, or at least that they very quickly involve ground. This greatly reduces the cost of the equipment over that if phase relays were also used; even so, it is still more costly than most relaying equipments for bus protection. Of course, if it saves investment in new current transformers and their installation cost, it would be economically attractive.

The principal disadvantage of this type of equipment is the greater maintenance required and the greater probability of failure to operate because of the large number of contacts in series in the trip circuit. Another disadvantage is that connections from the current transformers in all the circuits must be run all the way to the relay panel. Of course, if only ground relays were used, only two connections to the CT's of each circuit would be required. If phase relays were used, they would depend on bus voltage for polarization, and, therefore, they might not operate for a metallic short circuit that reduced the voltage practically to zero.

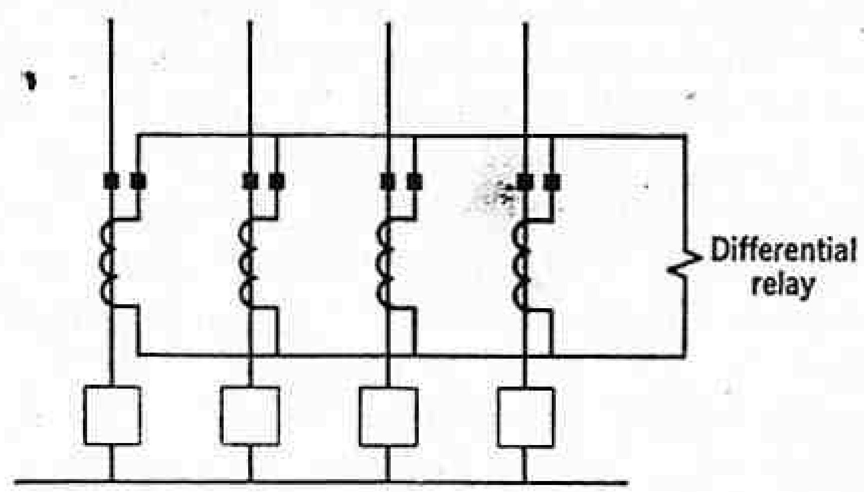


Fig. 3. Bus protection by current-differential relaying.

CURRENT-DIFFERENTIAL RELAYING WITH OVERCURRENT RELAYS

The principle of current-differential relaying has been described. Figure 3 shows its application to a bus with four circuits. All the CT's have the same nominal ratio and are interconnected in such a way that, for load current or for current flowing to an external fault beyond the CT's of any circuits, no current should flow through the relay coil, assuming that the CT's have no ratio or phase-angle errors. However, the CT's in the faulty circuit may be so badly saturated by the total fault current that they will have very large errors; the other CT's in circuits carrying only a part of the total current may not saturate so much and, hence, may be quite accurate. As a consequence, the differential relay may get a very large current, and, unless the relay has a high enough pickup or a long enough time delay or both, it will operate undesirably and cause all bus breakers to be tripped.

The greatest and most troublesome cause of current-transformer saturation is the transient d-c component of the short-circuit current.

It is easy to determine if the CT's in the faulty circuit will be badly saturated by a fault-current wave having a d-c component, by using the following approximate formula:

$$B_{max} = \frac{(\sqrt{2})(10^8)R_2 I_1 T N_1}{A N_2^2}$$

where B_{max} = maximum flux density in CT core in lines per square inch.
R_2 = resistance of CT-secondary winding and leads up to, but not including, the relay circuit, in ohms.
I_1 = rms magnitude of symmetrical component of primary fault current in amperes.
T = time constant of primary d-c component in seconds.
A = cross-sectional area of CT core in square inches.
N_1 = number of primary turns (=1 for bushing CT's).
N_2 = number of secondary turns.

For values of B_{max} greater than about 100,000 lines per square inch, there will be saturation in modern CT's, and for values greater than about 125,000 lines there will be appreciable saturation, the degree being worse the higher the value of B_{max}. For instantaneous relays, B_{max} should be no more than about 40,000 lines because the residual flux can be as high as about 60,000 lines. For CT's that are 10 or 15 years old, about 77,500 lines represents saturation flux density.

Considering the effect of the d-c time constant, it will become evident that the nearer a bus is to the terminals of a generator, the greater will be the CT saturation. Typical d-c time constants for different circuit elements are:

Generators	0.3 second
Transformers	0.04 second
Lines	0.01 second

It makes a tremendous difference, therefore, whether the fault-current magnitude is limited mostly by line impedance or by generator impedance.

If the d-c component will not badly saturate the CT's, it is a relatively simple matter to calculate the error characteristics of the CT's by the methods already described, and to find out how much current will flow in the differential relay. Knowing this magnitude of current and the magnitude for which the differential relay must operate for bus faults, one can choose the pickup and time settings that will give the best protection to the bus and still provide selectivity for external faults.

But, if the d-c saturation is severe, and it usually is, the problem is much more difficult, particularly if instantaneous relaying is desired. Two methods of analysis have been presented. One is a method for first calculating the differential current and then determining the response of an overcurrent relay to this current.[3] The other is a method whereby the results of a comprehensive study can be applied directly to a given installation for the purpose of estimating the response of an overcurrent relay.[4] Because of the approximations and the uncertainties involved (and probably also because of the

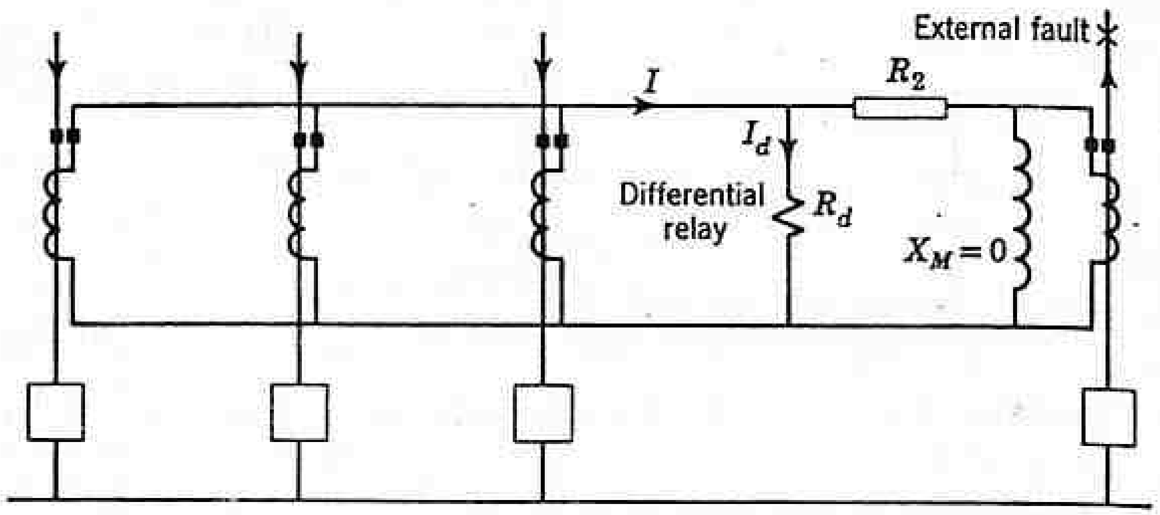


Fig. 4. Distribution of current for an external fault.

labor involved), neither of these two methods is used very extensively, but, together with other investigations, they provide certain very useful guiding principles.

Perhaps the most useful information revealed by these and other[5,6] studies is the effect of resistance in the differential branch on the magnitude of current that can flow in that branch. Figure 4 is a one-line diagram of the CT's and differential relay for a bus with four feeders, showing an external short circuit on one of the feeders. Figure 4 shows the equivalent circuit of the CT in the feeder having the short circuit. If that CT is assumed to be so completely saturated that its magnetizing reactance is zero, neglecting the air-core mutual reactance, the secondary current (I) from all the other CT's will divide between the differential branch and the saturated CT secondary, and the rms value of the differential current (I_d) will be no higher than:

$$I_d = I\left(\frac{R_2}{R_d + R_2}\right)$$

where R_2 includes the secondary-winding resistance of the CT in the faulty circuit. The effect of relay-coil saturation must be taken into account in using this relation. Of course, the differential current

will quickly decrease as the fault-current wave becomes symmetrical. However, studies have shown that, depending on the circuit resistances, the rms value of the differential current (I_d) can momentarily approach the fault-current magnitude (I) expressed in secondary terms. Where this is possible, instantaneous overcurrent relays are not applicable unless sufficient resistance can be added to the differential branch. The amount of such additional resistance should not be enough to cause too high voltages when very high currents flow to a bus fault. Nor should the resistance be so high that the CT's could not supply at least about 1.5 times pickup current under minimum bus-fault-current conditions. If we assume the CT's in the faulty circuit to be so badly saturated that their magnetizing reactance is zero, and that all the other CT's maintain their nominal ratio, the division of current between the differential relays and the secondaries of the saturated CT's, and the effects of adding resistance to the differential branch, may be calculated assuming symmetrical sinusoidal currents; the results will be conservative in that the differential relays will not have as great an operating tendency as the calculations would indicate.

The foregoing furnishes a practical rule for obtaining the best possible results with any current-differential-relaying application. This rule is to make the junction point of the CT's at a central location with respect to the CT's and to use as large-diameter wire as practical for the interconnections. The fact that the CT secondary windings have appreciable resistance makes it impractical to try to go too far toward reducing the lead resistance. Resistance in the leads from the junction point to the differential relays is beneficial to a certain extent, as already mentioned.

Another rule that is generally followed is to choose CT ratings so that the maximum magnitude of external-fault current is less than about 20 times the CT rating.[7] Some allow this multiple to go to 30 or more, and others[8] try to keep it below 10. In an existing installation with multiratio bushing CT's, use the highest turns ratio.

To prevent differential-relay operation should a CT open-circuit, the relay pickup is often made no less than about twice the load current of the most heavily loaded circuit;[8] if the magnitude of ground-fault current is sufficiently limited by neutral-grounding impedance, lower pickup may be required and additional fault-detecting means may be required to prevent operation should a CT open-circuit, such as by the use of an overcurrent relay energized from a CT in the grounded-neutral source, and with its "a" contacts in series with the trip circuit.

Some instantaneous overcurrent relays are used for current-differential relaying, but inverse-time induction-type overcurrent relays are the most common; the induction principle makes these relays less responsive to the d-c and harmonic components of the differential current resulting from CT errors because of saturation. Time delay is most helpful to delay differential-relay operation long enough for the transient differential current due to CT errors to subside below the relay's pickup; from 0.2 second to 0.5 second is sufficient for most applications. The fact that a relay will overtravel after the current has dropped below the pickup value should be taken into account.

Where not all the CT's are of the same ratio, sometimes the practice is to provide current-differential relaying only for ground faults. To accomplish this, auxiliary CT's are connected in the neutral of the CT's of each circuit, and the ratios of these auxiliary CT's are chosen to compensate for the differences in ratio of the main CT's. The ratio accuracy of such auxiliary CT's should be investigated to determine their suitability. Of course, auxiliary CT's might be used to permit phase-fault relaying, but it would be much more expensive. In general, auxiliary CT's should be avoided whenever possible.

PARTIAL-DIFFERENTIAL RELAYING

Partial-differential relaying is a modification of current-differential relaying whereby only the CT's in generating-source (either local or distant) circuits are paralleled, as illustrated in Fig. 5. This is not done because of any advantage to be gained by omitting the other CT's in the purely load circuits, but either because there are no CT's to be used or because those that are available are not suitable for complete current-differential relaying.

Two types of partial-differential relaying have been used, one type employing overcurrent relays and the other employing distance relays. The protection provided by the overcurrent type is much like that provided by back-up relays in the individual source circuits. The overcurrent type must have enough time delay to be selective with the relays of the load circuits for external faults in these circuits. Also, it must have a pickup higher than the total maximum-load current of all source circuits. The only advantages of partial-differential relaying with overcurrent relays are (1) that local protective equipment is provided for bus protection, and (2) that back-up protection is provided for the load circuits.

A second type of partial-differential-relaying equipment uses distance relays.[9,10] This type is applicable where all the load circuits have current-limiting reactors, as illustrated in Fig. 6. So long as two or more of the load circuits are not paralleled a short distance from the bus, the reactors introduce enough reactance into the cir-

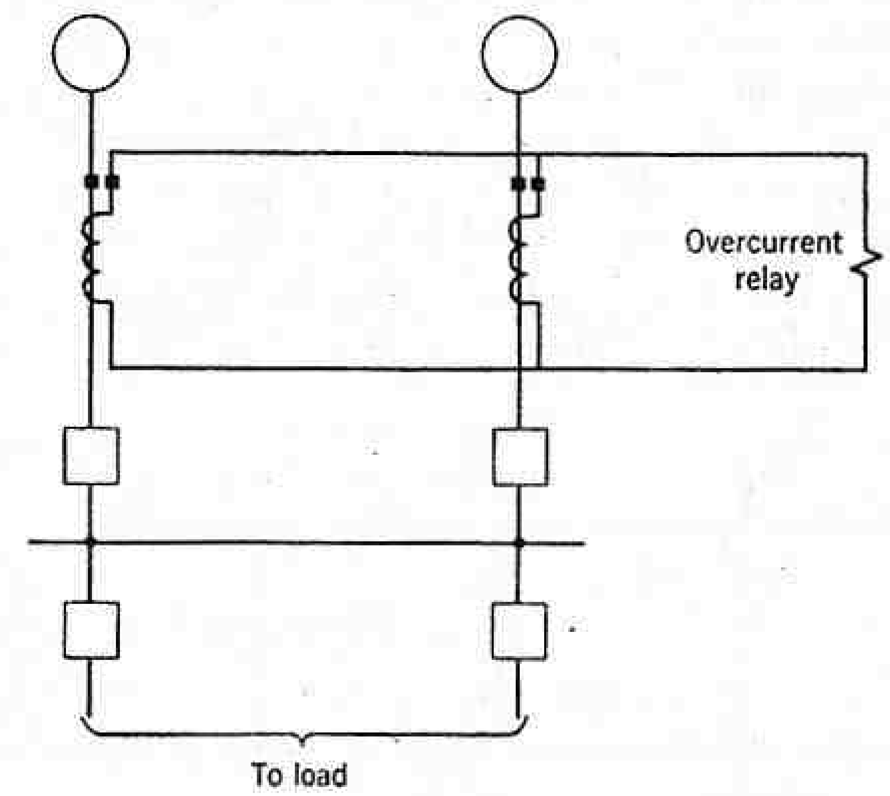


Fig. 5. Partial-differential relaying with overcurrent relays.

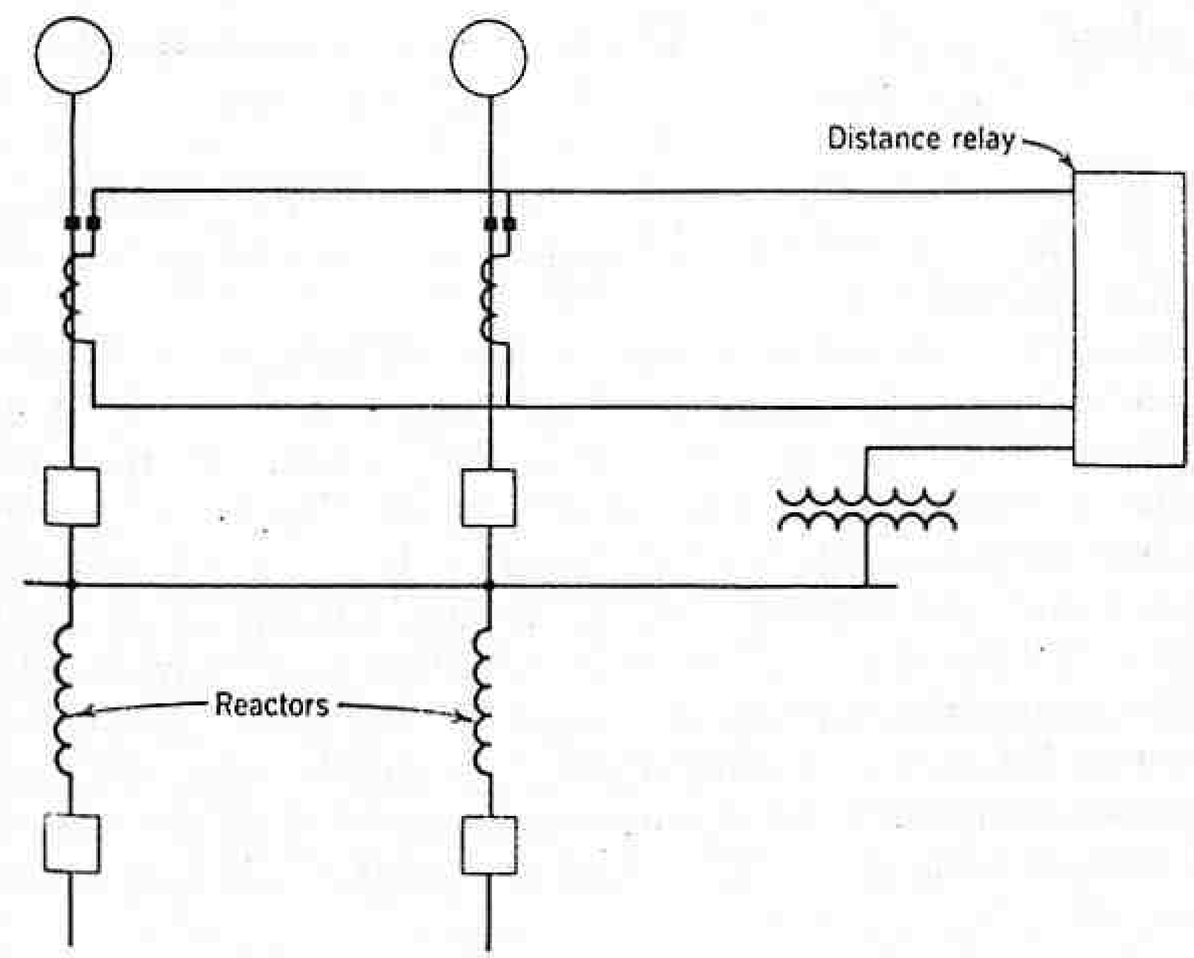


Fig. 6. Partial-differential relaying with distance relays.

cuits so that the distance relays can select between faults on the bus side and faults on the load side of the reactors. In some actual applications, only ground distance relays have been used on the basis that all bus faults will involve ground sooner or later. Because a fault in one of the source circuits that badly saturates its CT's will tend to cause the distance relays to operate undesirably, such a possibility must be carefully investigated. Otherwise, this type of relaying can be both fast and sensitive.

One application has been described in which distance relays were used for station-service bus protection and there were no reactors in the load circuits.[10] Instead, selectivity with the load-circuit relays was obtained by adding a short time delay to the operating time of the distance relays.

CURRENT-DIFFERENTIAL RELAYING WITH PERCENTAGE-DIFFERENTIAL RELAYS

As in differential relaying for generators and transformers, the principle of percentage-differential relaying is a great improvement over overcurrent relays in a differential CT circuit. The problem of providing enough restraining circuits has been largely solved by so-called "multirestraint" relays.[5] By judicious grouping of circuits and by the use of two relays per phase where necessary, sufficient restraining circuits can generally be provided. Further improvement in selectivity is provided by the "variable-percentage" characteristic,[5] like that described in connection with generator protection; with this characteristic, one should make sure that very high internal-fault currents will not cause sufficient restraint to prevent tripping.

This type of relaying equipment is available with operating times of the order of 3 to 6 cycles (60-cycle basis). It is not suitable where high-speed operation is required.

As in current-differential relaying with overcurrent relays, the problem of calculating the CT errors is very difficult. The use of percentage restraint and the variable-percentage characteristic make the relay quite insensitive to the effects of CT error. Nevertheless, it is recommended that each application be referred to the manufacturer together with all the necessary data.

A disadvantage of this type of equipment is that all CT secondary leads must be run to the relay panel.

VOLTAGE-DIFFERENTIAL RELAYING WITH "LINEAR COUPLERS"

The problem of CT saturation is eliminated at its source by air-core CT's called "linear couplers."[11] These CT's are like bushing CT's but they have no iron in their core, and the number of secondary turns is much greater. The secondary-excitation characteristic of

these CT's is a straight line having a slope of about 5 volts per 1000 ampere-turns. Contrasted with conventional CT's, linear couplers may be operated without damage with their secondaries open-circuited. In fact, very little current can be drawn from the secondary, because so much of the primary magnetomotive force is consumed in magnetizing the core.

The foregoing explains why the linear couplers are connected in a voltage-differential circuit, as shown schematically in Fig. 7. For normal load or external-fault conditions, the sum of the voltages in-

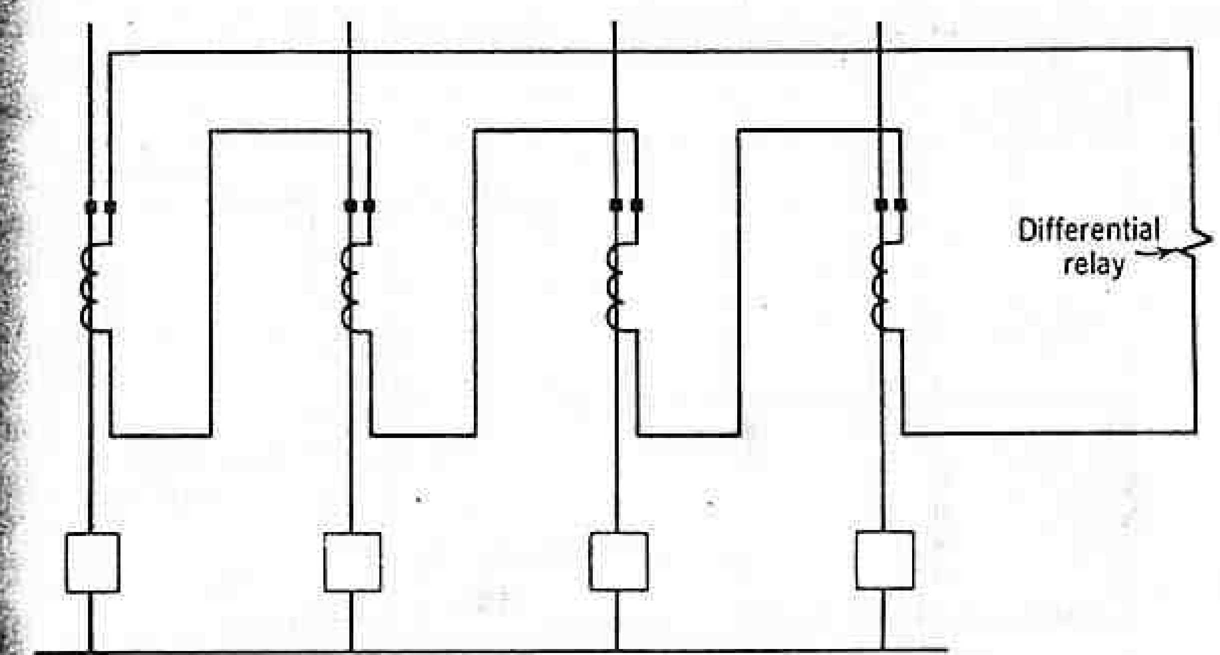


Fig. 7. Bus protection with voltage-differential relaying.

duced in the secondaries is zero, except for the very small effects of manufacturing tolerances, and there is practically no tendency for current to flow in the differential relay.

When a bus fault occurs, the voltages of the CT's in all the source circuits add to cause current to flow through all the secondaries and the coil of the differential relay. The differential relay, necessarily requiring very little energy to operate, will provide high-speed protection for a relatively small net voltage in the differential circuit.

The application of the linear-coupler equipment is most simple, requiring only a comparison of the possible magnitude of the differential voltage during external faults, because of differences in the characteristics of individual linear couplers, with the magnitude of the voltage when bus faults occur under conditions for which the fault-current magnitude is the lowest. Except when ground-fault current is severely limited by neutral impedance, there is usually no selectivity problem. When such a problem exists, it is solved by the use of additional more-sensitive relaying equipment, including a supervising relay that permits the more-sensitive equipment to operate only for a single-phase-to-ground fault.[12]

CURRENT-DIFFERENTIAL RELAYING WITH OVERVOLTAGE RELAYS

A type of high-speed relaying equipment employing current-differential relaying with overvoltage relays also eliminates the problem of current-transformer saturation, but in a different manner from that described using linear couplers. With this equipment, conventional bushing CT's (or other CT's with low-impedance secondaries) are used, and they are differentially connected exactly as for current-differential relaying already described; the only difference is that overvoltage rather than overcurrent relays are used.[13]

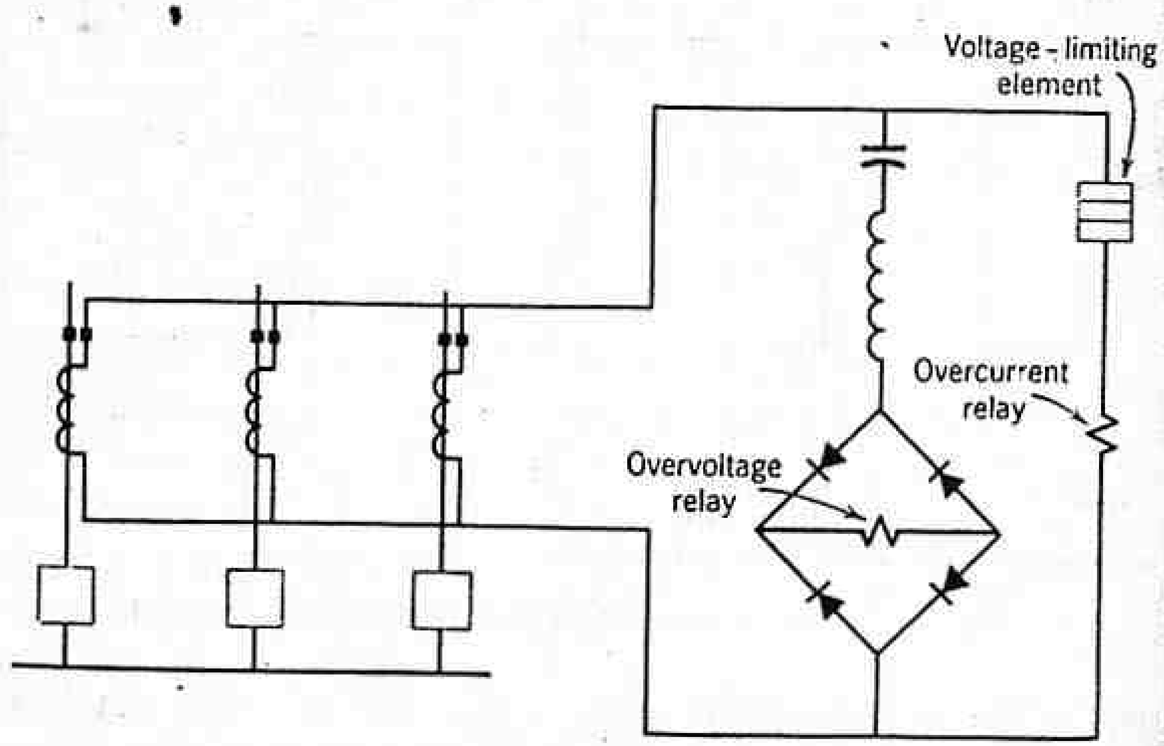


Fig. 8. Bus protection using current-differential relaying with overvoltage relays.

In effect, this equipment carries to the limit the beneficial principle already described of adding resistance to the differential branch of the circuit. However, in this equipment, the impedance of the overvoltage-relay's coil is made to appear to the circuit as resistance by virtue of a full-wave rectifier, as illustrated in Fig. 8. Hence, the efficiency of the equipment is not lowered as it would be if a series resistor were used.

The capacitance and inductance, shown in series with the rectifier circuit, are in series resonance at fundamental system frequency; the purpose of this is to make the relay responsive to only the fundamental component of the CT secondary current so as to improve the relay's

selectivity. It has the disadvantage, however, of slowing the voltage-relay's response slightly, but this is not serious in view of the high-speed operation of an overcurrent-relay element now to be described.

Because the effective resistance of the voltage-relay's coil circuit is so high, being approximately 3000 ohms, a voltage-limiting element must be connected in parallel with the rectifier branch, or else excessively high CT secondary voltages would be produced when bus faults occurred. As shown in Fig. 8, an overcurrent-relay unit in series with the voltage limiter provides high-speed operation for bus faults involving high-magnitude currents. Since the overcurrent unit is relied on only for high-magnitude currents, its pickup can easily be made high enough to avoid operation for external faults.

The procedure for determining the necessary adjustments and the resulting sensitivity to low-current bus faults is very simple and straightforward, requiring only a knowledge of the CT secondary excitation characteristics and their secondary impedance.

For the best possible results, all CT's should have the same rating, and should be a type, like a bushing CT with a distributed secondary winding, that has little or no secondary leakage reactance.

COMBINED POWER-TRANSFORMER AND BUS PROTECTION

Figure 9 shows a frequently encountered situation in which a circuit breaker is omitted between a transformer bank and a low-voltage bus. If the low-voltage bus supplies purely load circuits without any back-feed possible from generating sources, the CT's in all the load circuits may be paralleled and the transformer-differential relay's zone of protection may be extended to include the bus.

Figure 10 shows two parallel high-voltage lines feeding a power-transformer bus with no circuit breaker between the transformer and the bus. As shown in the figure, a three-winding type of percentage-differential relay will provide good protection for the bus and the transformer.

In Fig. 11, the two high-voltage lines are from different stations and may constitute an interconnection between parts of a system. Consequently, much higher load currents may flow through these circuits than the rated load current of the power transformer. Therefore, the CT ratios in the high-voltage circuits may have to be much higher than one would desire for the most sensitive protection of the power transformer. And therefore, the protective scheme of Fig. 10, though generally applicable, is not as sensitive to transformer faults as the arrangement of Fig. 11. Bushing CT's can generally be added to most power transformers, but it is considerably less expensive and less

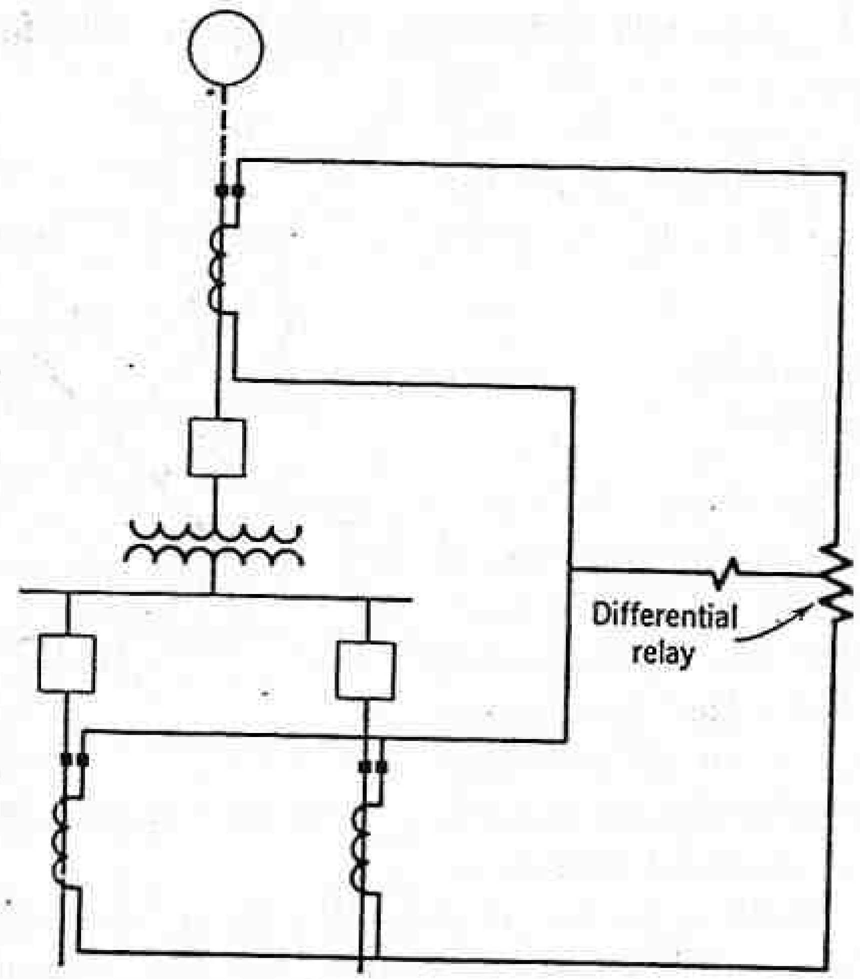


Fig. 9. Combined transformer and bus protection with a two-winding percentage-differential relay.

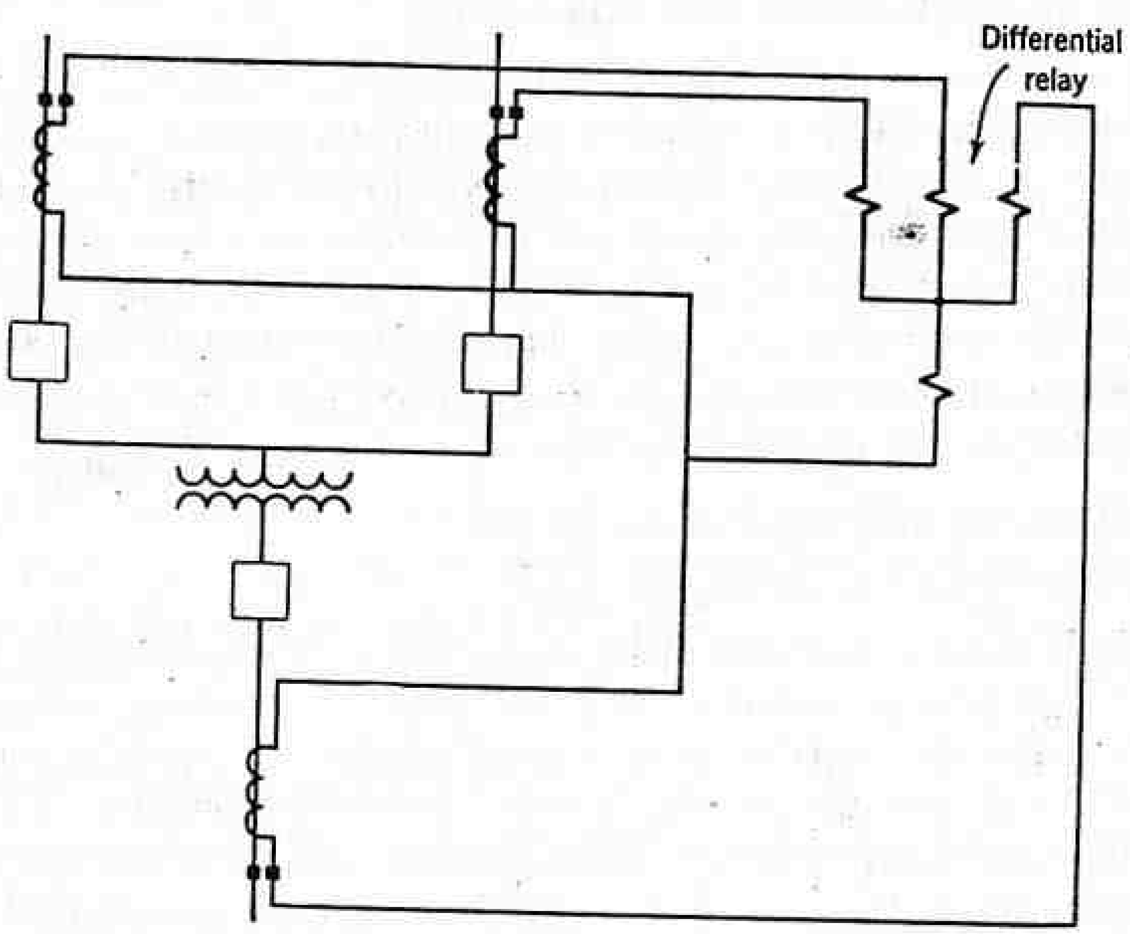


Fig. 10. Combined transformer and bus protection with a three-winding percentage-differential relay.

troublesome if the power transformers are purchased with the two sets of CT's already installed. It is almost axiomatic that, whenever circuit breakers are to be omitted on the high-voltage side of power transformers, two sets of bushing CT's should be provided on the

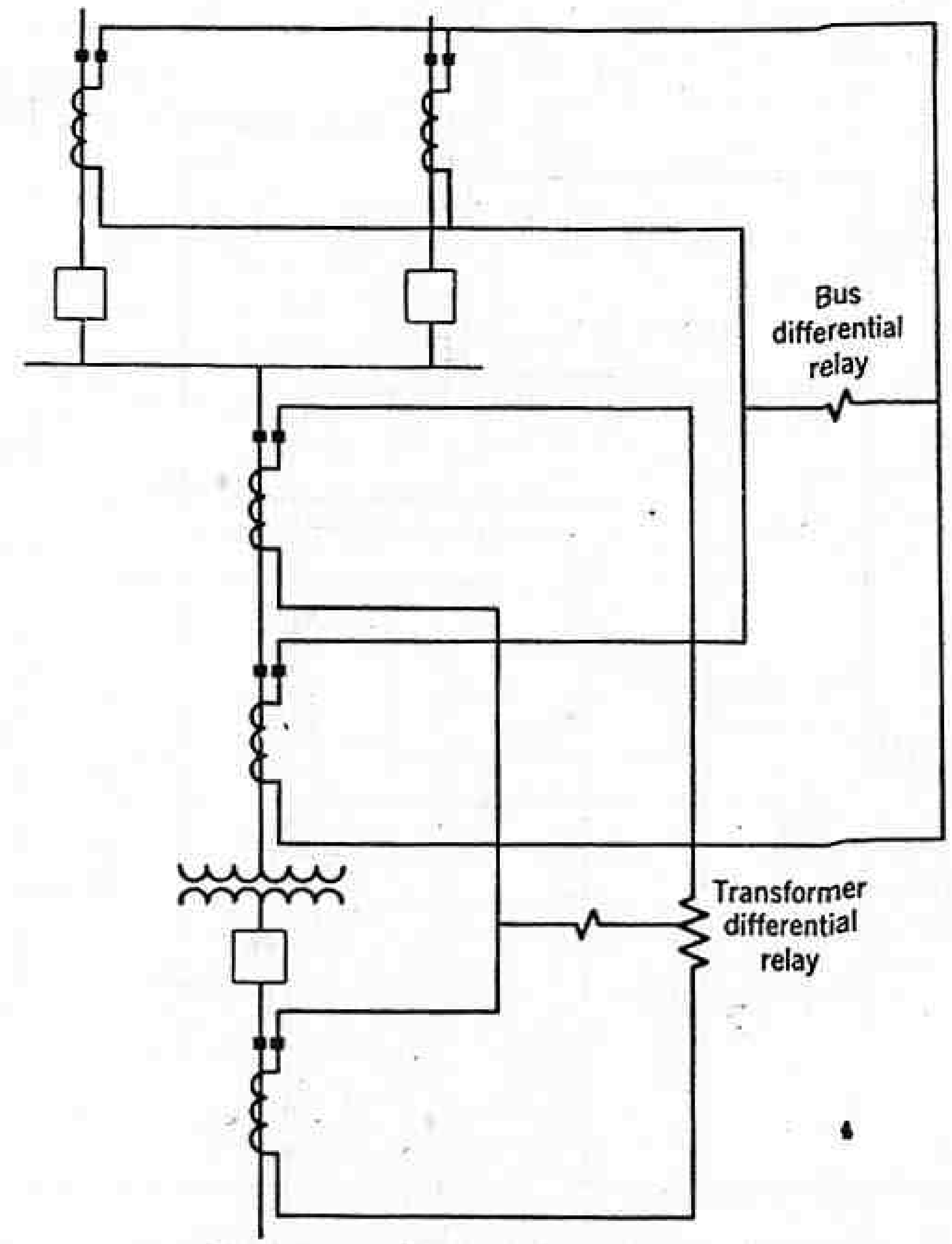


Fig. 11. Preferred alternative to Fig. 10 when high-voltage lines are from different stations.

transformer high-voltage bushings. The arrangement of Fig. 11 can be extended to accommodate more high-voltage lines or more power transformers, although, as stated in Chapter 11, it is not considered good practice to omit high-voltage breakers when two or more power-transformer banks rated 5000 kva or higher are paralleled.

Figure 12 shows a protective arrangement that has been used for the combination of two power transformers as shown. It could not be extended to accommodate any more transformers or high-voltage circuits, and it does not provide as sensitive protection as the arrangement of Fig. 11, but it saves one set of bushing CT's and a set of bus-differential relays.

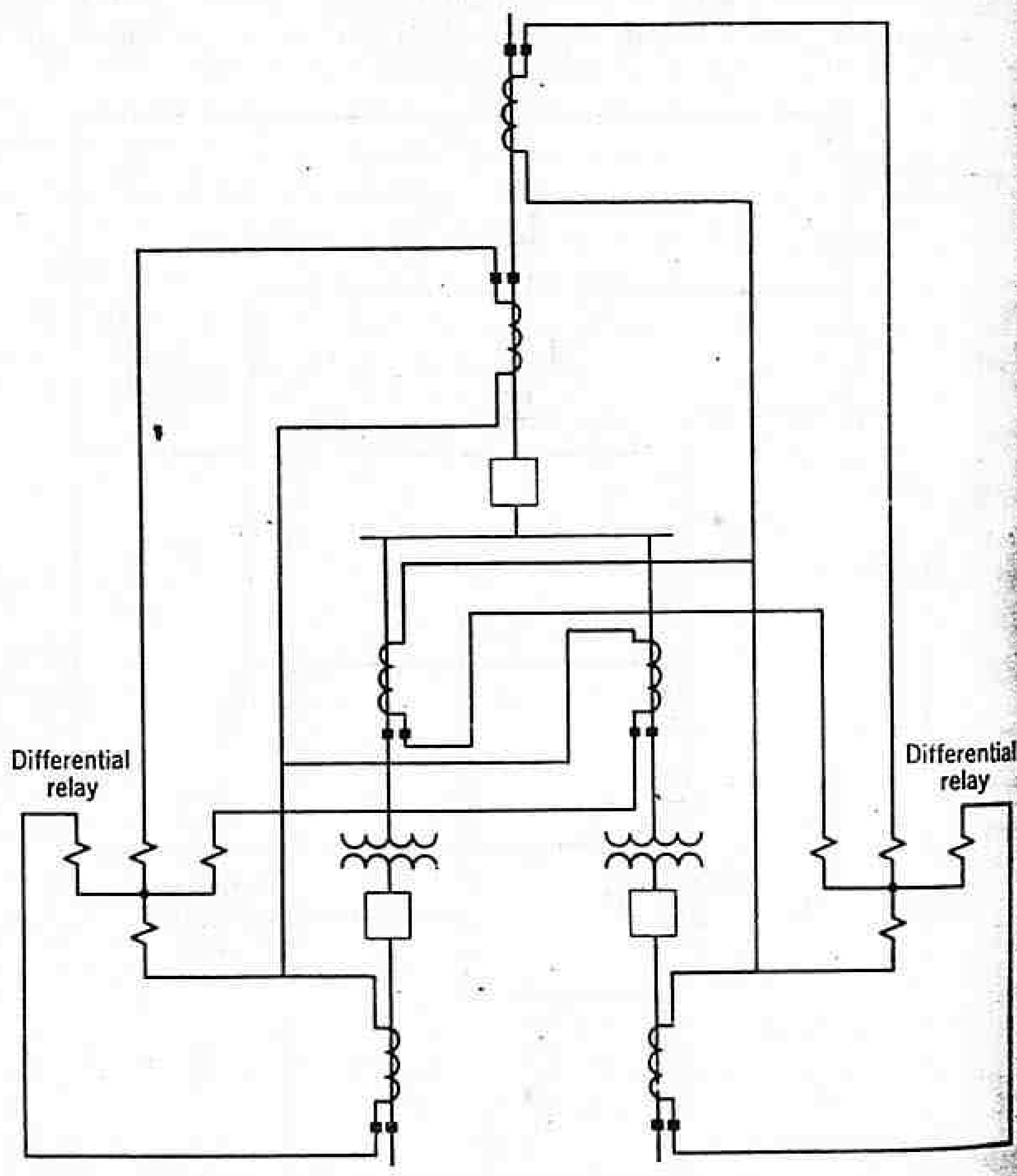


Fig. 12. Complete protection of two transformers and a bus with two three-winding percentage-differential relays.

RING-BUS PROTECTION

No separate relaying equipment is provided for a ring bus. Instead, the relaying equipments of the circuits connected to the bus include the bus within their zones of protection, as illustrated in Fig. 13. The relaying equipment of each circuit is indicated by a box lettered to correspond to the protected circuit, and is energized by the parallel-connected CT's in the branches that feed the circuit.

A separate voltage supply is required for the protective relays of each circuit. Also, the CT ratios must be suitable for the largest magnitude of load current that might flow around the ring, which might be too high for the desired protection of a given circuit.

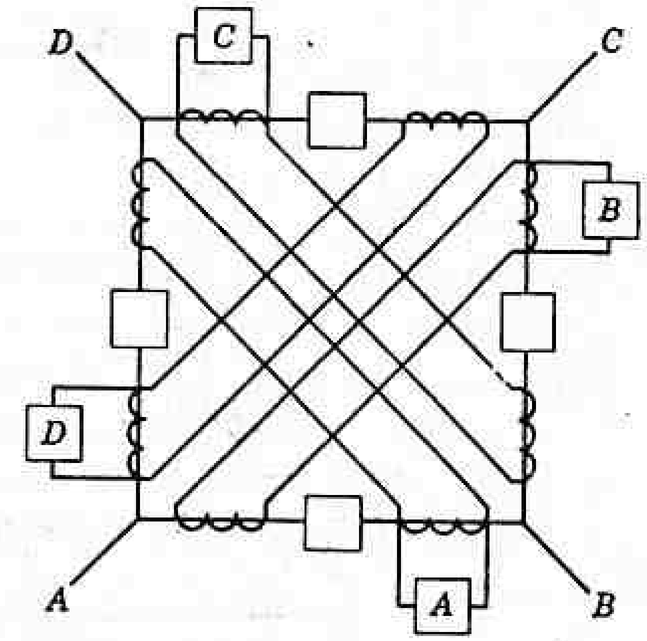


Fig. 13. Protection of a ring bus.

THE VALUE OF BUS SECTIONALIZING

Although the design of busses does not fall in the category of bus relaying, it is well to keep in mind that bus sectionalizing helps to minimize interference with service when a bus fault occurs. For some busses, sectionalizing is an essential feature of design if stability is to be maintained after a bus fault. With bus sectionalizing, each bus section can be protected separately, and the likelihood of a fault in one section interfering with the service of another section is thereby minimized.

BACK-UP PROTECTION FOR BUS FAULTS

If one or more bus breakers fail to trip in the event of a bus fault, back-up protection is provided by the relaying equipments at the far ends of the circuits that continue to feed current directly to the fault.

Occasionally, relaying equipment is provided at a bus location for back-up protection of adjoining circuits. This is done only when it is impossible to provide the desired back-up protection in the conventional manner described in Chapter 1. This matter is treated further under the subject of line protection.

GROUNDING THE SECONDARIES OF DIFFERENTIALLY CONNECTED CT'S

The intent here is to emphasize the fact that differentially connected CT's should be grounded *at only one point.*[14] In spite of the fact that various publications have warned against separately grounding the CT's of each circuit, the survey reported in Reference 7 found separate grounding to be practiced by many. Metering practices have been so strongly ingrained that people have replaced grounds that were purposely omitted from differentially connected CT's.

13 LINE PROTECTION WITH OVERCURRENT RELAYS

Lines are protected by overcurrent-, distance-, or pilot-relaying equipment, depending on the requirements. Overcurrent relaying is the simplest and cheapest, the most difficult to apply, and the quickest to need readjustment or even replacement as a system changes. It is generally used for phase- and ground-fault protection on station-service and distribution circuits in electric utility and in industrial systems, and on some subtransmission lines where the cost of distance relaying cannot be justified. It is used for primary ground-fault protection on most transmission lines where distance relays are used for phase faults, and for ground back-up protection on most lines having pilot relaying for primary protection. However, distance relaying for ground-fault primary and back-up protection of transmission lines is slowly replacing overcurrent relaying. Overcurrent relaying is used extensively also at power-transformer locations for external-fault back-up protection, but here, also, there is a trend toward replacing overcurrent with distance relays.

It is generally the practice to use a set of two or three overcurrent relays for protection against interphase faults and a separate overcurrent relay for single-phase-to-ground faults. Separate ground relays are generally favored because they can be adjusted to provide faster and more sensitive protection for single-phase-to-ground faults than the phase relays can provide. However, the phase relays alone are sometimes relied on for protection against all types of faults. On the other hand, the phase relays must sometimes be made to be inoperative on the zero-phase-sequence component of ground-fault current. These subjects will be treated in more detail later.

Overcurrent relaying is well suited to distribution-system protection for several reasons. Not only is overcurrent relaying basically simple and inexpensive but also these advantages are realized in the greatest degree in many distribution circuits. Very often, the relays do not

need to be directional, and then no a-c voltage source is required. Also, two phase relays and one ground relay are permissible. And finally, tripping reactor or capacitor tripping (described elsewhere) may be used.

In electric-utility distribution-circuit protection, the greatest advantage can be taken of the inverse-time characteristic because the fault-current magnitude depends mostly on the fault location and is practically unaffected by changes in generation or in the high-voltage transmission system. Not only may relays with extremely inverse curves be used for this reason but also such relays provide the best selectivity with fuses and reclosers. However, if ground-fault-current magnitude is severely limited by neutral-grounding impedance, as is often true in industrial circuits, there is little or no advantage to be gained from the inverse characteristic of a ground relay.

Inverse-time relaying is supplemented by instantaneous relaying wherever possible. Speed in clearing faults minimizes damage and thereby makes automatic reclosing more likely to be successful.

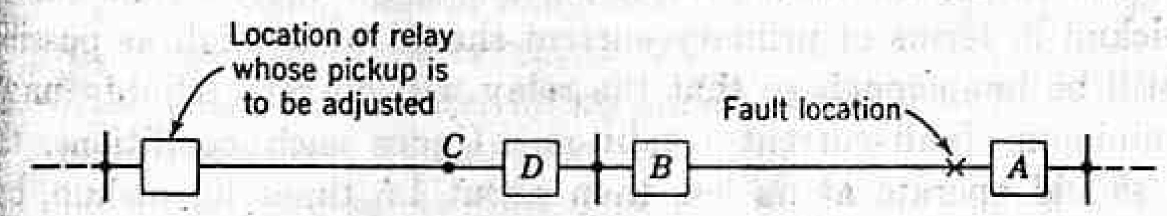


Fig. 1. The fault location for adjusting the pickup for back-up protection.

HOW TO SET INVERSE-TIME-OVERCURRENT RELAYS FOR COORDINATION

The first step is to choose the pickup of the relay so that it will (1) operate for all short circuits in its own line, and (2) provide back-up protection for short circuits in immediately adjoining system elements under certain circumstances. For example, if the adjoining element is a line section, the relay is set to pick up at a current somewhat less than it receives for a short circuit at the far end of this adjoining line section under minimum generating—or other—conditions that would cause the least current flow at the relay location. This is illustrated in Fig. 1.

For a phase relay, a phase-to-phase fault would be assumed since it causes less current to flow than does any other fault not involving ground. However, a phase relay must not be so sensitive that it will pick up under emergency conditions of maximum load over the line from which it receives its current. For a ground relay, a single-phase-to-ground fault would be assumed; load current is not a factor in the relay cannot be used with a polyphase directional relay to get the necessary contact separation, because there is no suitable voltage source to operate the auxiliary relay; the lack of such a voltage source is why a-c tripping is used.

A set of three single-phase directional-overcurrent relays can often be used to provide protection against single-phase-to-ground faults as well as against interphase faults. Polyphase directional relays may not be used for this purpose unless the minimum ground-fault current is more than 3 times the maximum load current.

Some users want to test the relays of each phase separately so that, if a fault occurs during testing, the relays of the other two phases can provide protection. This requires single-phase relays.

A minor advantage of single-phase relays is that they provide somewhat more flexibility in the layout of panels.

The advantage of a polyphase directional relay is that it is less subject to occasional misoperation than single-phase relays. For a certain fault condition, one of three single-phase relays may develop torque in the tripping direction when tripping would be undesirable; if the current in that one relay was high enough to operate the overcurrent unit, improper tripping would result. Since a polyphase directional relay operates on the net torque of its three elements, a reversed torque in one element can be overbalanced by the other two elements, and a correct net torque usually results. The subject of directional-relay misoperation is treated in the following section.

HOW TO PREVENT SINGLE-PHASE DIRECTIONAL-OVERCURRENT-RELAY MISOPERATION DURING GROUND FAULTS

Under certain circumstances, single-phase directional-overcurrent relays for phase-fault protection may cause undesired tripping for ground faults in the non-tripping direction. Such undesired tripping can be prevented if one only knows when special preventive measures are necessary.

The zero-phase-sequence components of ground-fault current produce the misoperating tendency. All these components are in phase, and, when wye-connected current transformers are used, these components always produce contact-closing torque in one of the three directional units no matter in which direction the current may be flowing. Generally, the other fault-current components are able to "swamp" the effect of the zero-phase-sequence components. But, when the fault current is largely composed of zero-phase-sequence component, misoperation is most likely.

Figure 11 shows the basic type of application where undesired tripping is most apt to occur. Let us assume that the directional units of the relays are intended to permit tripping only for faults to the left of the relay location, as indicated by the arrow. However, a ground fault to the right, as shown, will cause at least one directional unit to close its contact and permit tripping by its overcurrent unit. Whether the overcurrent unit will actually trip its breaker will depend on its pickup and time settings, and on whether it gets enough current to operate before the fault is removed from the system by some other relay that is supposed to operate for this fault. Failure to trip when tripping is desired is not a problem.

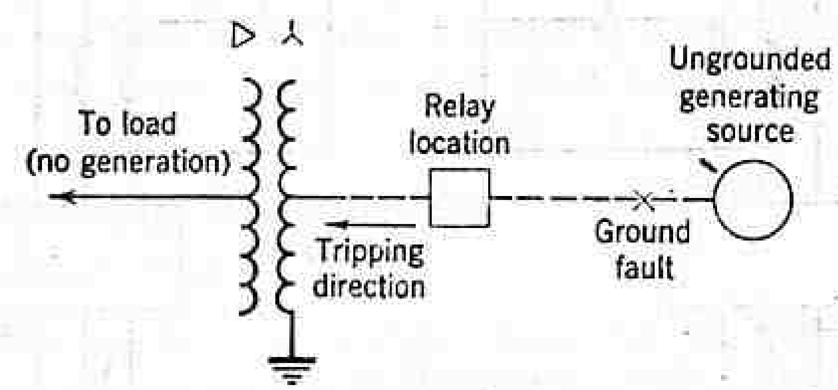


Fig. 11. A situation where single-phase directional-overcurrent relays may misoperate.

Misoperation can occur also for conditions *approaching* those of Fig. 11.[8] In other words, misoperation may still occur if there is a small source of generation at the load end of Fig. 11. In general, one should examine the possibility of misoperation whenever the zero-phase-sequence impedances from the ground-fault location back to the sources of generation on either side of the fault are not approximately in the same complex ratio as the corresponding positive-phase-sequence impedances. Thus, in addition to the situation of Fig. 11, if one side of a system is grounded through resistance and the other side through reactance, misoperation is possible.

The likelihood of misoperation is greatest when the phase relays are used also for ground-fault protection, and particularly when the relays have to be more sensitive because the ground-fault current is limited by neutral impedance.

To prevent misoperation for the situation shown in Fig. 11, the phase relays should be prevented from responding to the zero-phase-sequence component of current. This can be done with a zero-phase-sequence shunt using three auxiliary current transformers, as shown in Fig. 12. It is emphasized that the neutral of the phase relays should not be connected to the CT neutral or else part of the effectiveness of the shunt will be lost. Delta-connecting the secondaries of the main current transformers would also remove the zero-phase-sequence component, but it introduces other misoperating tendencies, and it does not provide the required source of energization for ground relays. The 90-degree or quadrature connection of the phase relays should be used.

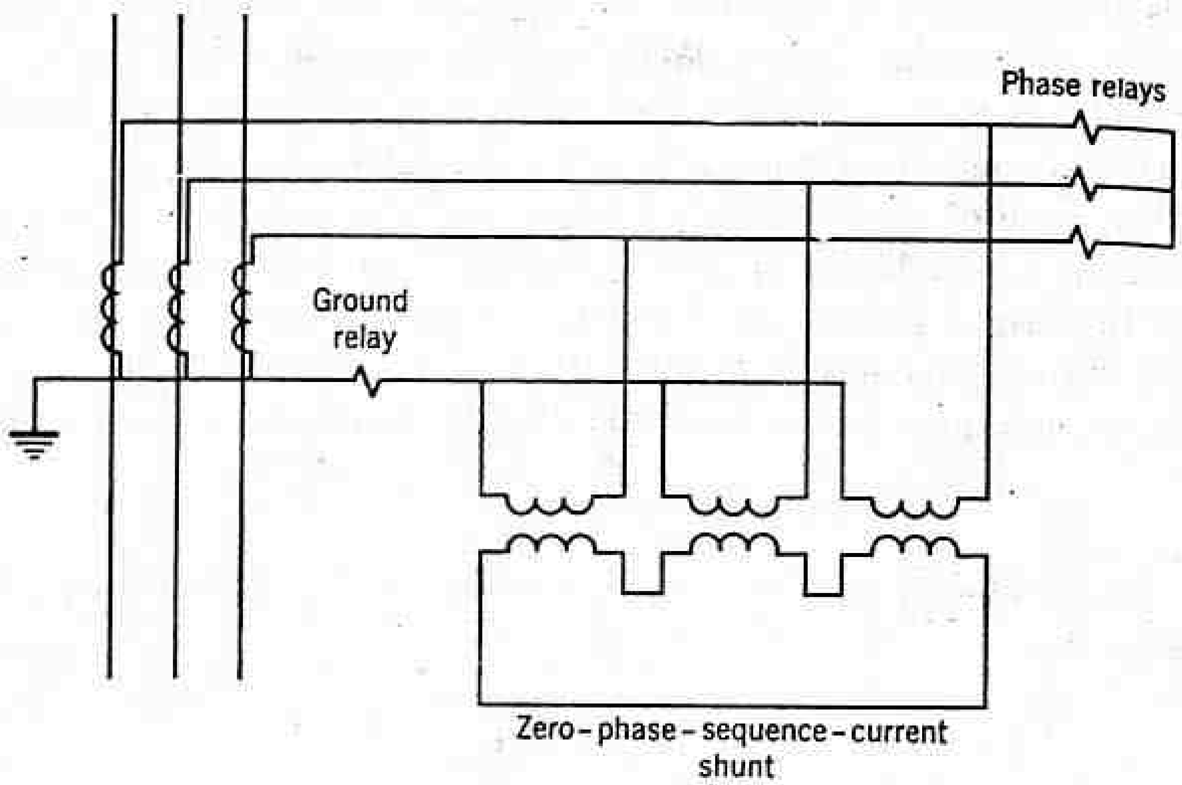


Fig. 12. Application of a zero-phase-sequence-current shunt.

The phase relays will still be able to respond to ground faults if the current magnitude is large enough, and if positive-phase-sequence components are present in the fault current. However, it is generally preferable to use separate directional-overcurrent ground relays for ground-fault protection because faster tripping can thereby be obtained. Where only zero-phase-sequence current can flow, as at the relay location of Fig. 11, separate ground relays must be used.

ADJUSTMENT OF GROUND VERSUS PHASE RELAYS

The satisfactory adjustment of ground overcurrent relays is generally easier to achieve than that of phase overcurrent relays in any system, including complicated loop systems. The principal reason for this is that the zero-phase-sequence impedance of lines (except single-phase cables) is approximately 2 to 5.5 times the positive-phase-sequence impedance, which provides two beneficial effects: (1) the magnitude of zero-phase-sequence current varies much more with fault location, and (2) the magnitude of the zero-phase-sequence current is not so much affected by changes in generating capacity.

These effects make it possible to take greater advantage of the inverse-time characteristic, and particularly of the very inverse characteristic; and also they aid the application of instantaneous overcurrent relays. Another simplification with ground relaying is that the pickup does not have to be higher than load current, because ground relays are not energized during normal load conditions, except in some distribution systems where ground current flows normally because of unbalanced phase-to-ground loading. (For other reasons to be discussed later there are limits as to how sensitive ground relays may be.) Finally, two-winding wye-delta or delta-wye power transformers are open circuits in the system so far as ground relays are concerned; in other words, except for the effect of CT errors, a ground-overcurrent relay cannot reach through such a transformer for any kind of fault on the other side. This minimizes the selectivity problem because it restricts the "reach" of the ground relays. The foregoing are the reasons why, when it is necessary to use distance relays for interphase faults, inverse-time and instantaneous overcurrent relaying are often satisfactory for ground faults.

An excellent coverage of the whole subject of ground-fault protection of transmission lines is in Reference 9.

EFFECT OF LIMITING THE MAGNITUDE OF GROUND-FAULT CURRENT

Current-limiting impedance in the grounded neutrals of generators or power transformers may be desirable from the standpoint of limiting the severity of a phase-to-ground short circuit. If carried too far, however, such practice tends to jeopardize the application of ground relaying where fast and selective operation is required.

Two problems must be considered. The first problem is that of obtaining sufficient sensitivity without danger of misoperation because of CT errors when large phase-fault currents flow. As explained later, an overcurrent relay in the neutral of wye-connected CT's will receive a current, even though a fault may not involve ground, if residual flux or d-c offset current in a CT of one phase causes it to have a different ratio error from a CT in another phase during a fault that involves large phase currents. The more sensitive the ground relay has to be in order to operate on the severely restricted phase-to-ground-fault currents, the more likely it is to operate on this CT error current.

The second problem when ground-fault current is limited by neutral impedance is to obtain prompt and selective tripping. The effect of limiting the ground-fault current by neutral impedance is to reduce the difference in magnitude of ground-fault current for faults at different locations. If there is little or no difference in the fault current for nearby or for distant faults, the inverse-time characteristic is of little use. The result is that selectivity must be obtained on the basis of time alone. Where several line sections are in series, the tripping time must be increased a fixed amount for each line section, the nearer a fault is to the source of fault current. As a consequence, faults adjacent to the source may not be cleared in less than several seconds, and during such a relatively long time the fault might involve other phases, thus causing a severe shock to the system.

It has been found from experience that a good rule of thumb is not to limit the ground-fault current of the generator or transformer to less than about its rated full-load current. Even this might be objectionable on some systems. The best procedure is to study the effect of limiting the current in each individual case.

Ground relays that are much more sensitive than phase relays may misoperate when simultaneous grounds exist at two different locations on different phases. Actually, this constitutes a phase-to-phase fault on the system, and the fault-current magnitude will be that for phase-to-phase faults. However, the ground relays of the circuits having these faults will operate as though a ground fault existed but at much higher speed than they would operate for ground faults because the current is so much higher. It is possible that these ground relays may operate faster than the phase relays that should operate, and the wrong breakers might be tripped because the ground relays might not be selective with each other at these higher currents.[10]

TRANSIENT CT ERRORS

The principal problem introduced by transient CT errors is the effect on fast and sensitive overcurrent ground relays. The troublesome effect, often called "false residual current," is that large transient currents flow through the ground-relay coils in the CT neutral when there is no actual ground-fault current in the CT primaries. This happens because the CT's have different errors because of unequal d-c offset in the primary currents or because of different amounts of residual magnetism. As a consequence, if ground-fault current is severely limited by neutral impedance and one needs to use very sensitive ground relays to detect ground faults reliably, the relays should have time delay or else they may operate undesirably on high-current interphase faults.

Such false residual current can be reduced appreciably by the addition of resistance to the CT neutral circuit if the relay burden is

not already high enough to limit the current. The same mechanism applies as with current-differential relaying for bus protection, described in Chapter 12. The addition of such resistance tends to equalize the CT errors. However, the best solution is a CT whose magnetic circuit encircles all three phase conductors.[11]

Although not properly includable as consequences of transient CT errors, many other transient and steady-state conditions may cause ground-relay misoperation. Two of these—open phases and simultaneous ground faults at different locations—are described further in this chapter. The others are comprehensively treated in Reference 12. For these, as well as for transient CT errors, a solution that usually works is to make the ground relays less sensitive.

When none of the suggested solutions to false residual current can be used, it is possible to provide equipment that will permit a ground relay to close a circuit only if fault current is flowing in only one phase, such as, for example, by the relay described in Reference 13. However, this may be too heroic a solution for a distribution circuit.

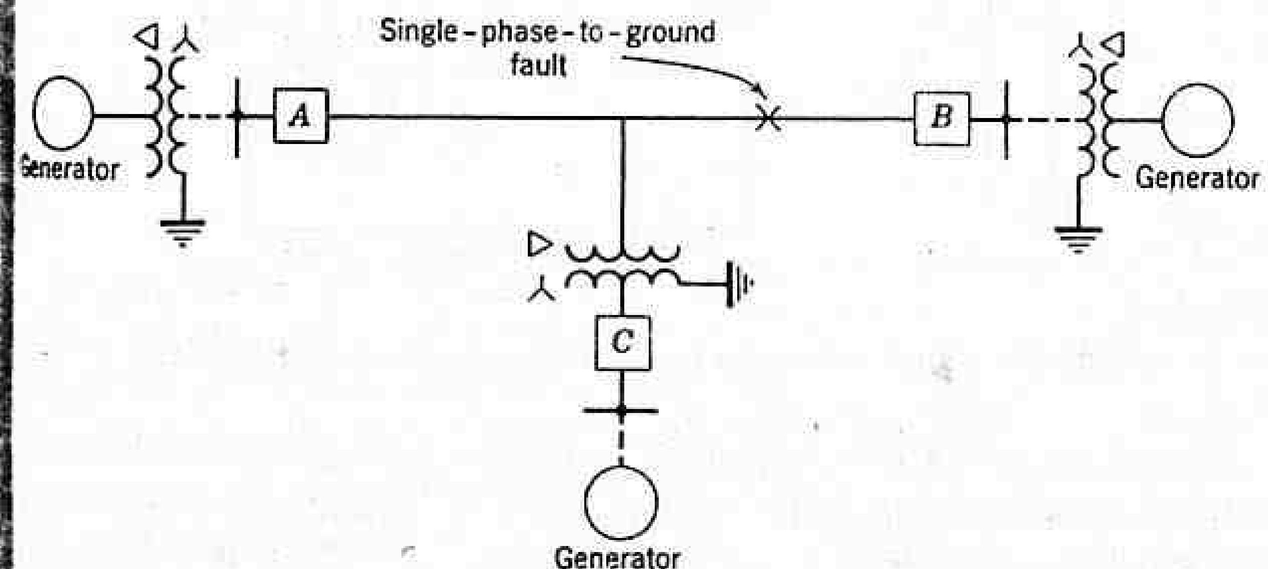


Fig. 13. Illustrating the possibility of ungrounded-neutral operation with a ground fault on the line.

DETECTION OF GROUND FAULTS IN UNGROUNDED SYSTEMS

The operation of other than distribution systems completely ungrounded is recognized as poor practice, and hence ground relaying in such systems is not usually a consideration. However, through circumstance, a portion of a system containing a source of generation may become disconnected from the rest of the system, and a condition of ungrounded operation may result. Consider the situation of Fig. 13 which is encountered quite frequently. Figure 13 shows a delta-wye power transformer tapped to a transmission line. A single-phase-to-ground fault on the line would cause the prompt tripping of breakers

A and *B*. If we assume that breaker *C* did not trip by the operation of its phase relays before breakers *A* and *B* had tripped, the line section would still be left connected to the tapped station with no means for opening breaker *C*. So long as the fault remained single-phase-to-ground, there would be no current of short-circuit magnitude flowing at *C* after breakers *A* and *B* had opened; only charging currents would flow. But, if the fault was of a persistent nature, as, for example, if a conductor had fallen to the ground, it is highly desirable that breaker *C* open automatically.

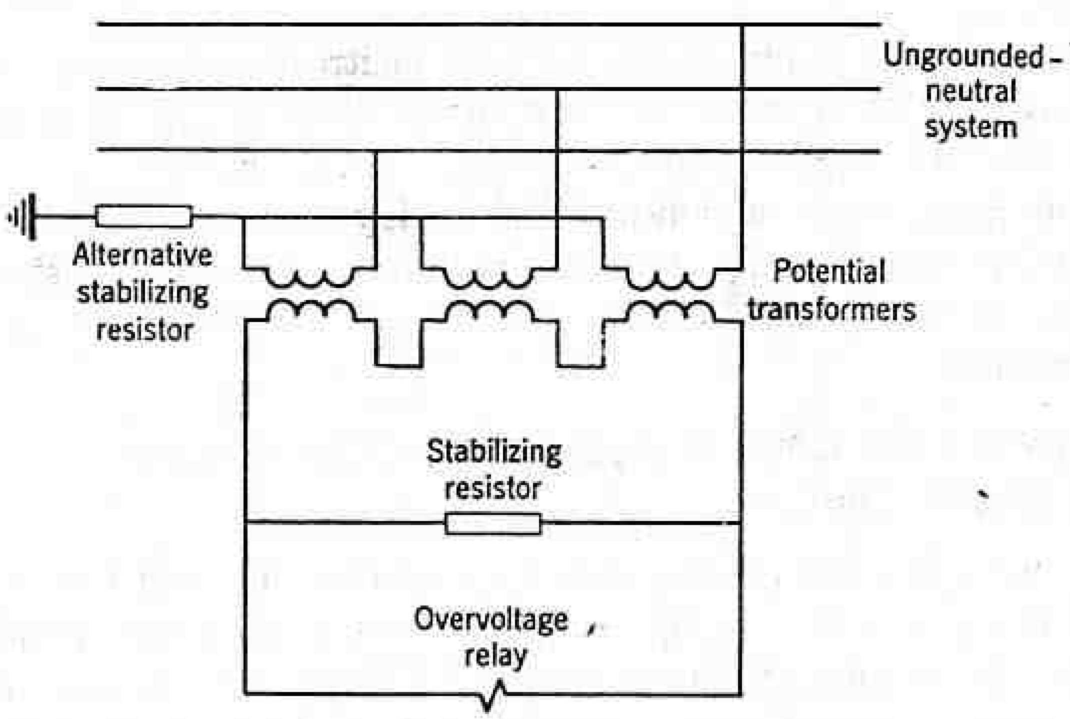


Fig. 14. A wye-broken-delta potential-transformer connection to detect a ground fault on an ungrounded-neutral system.

The presence of a ground fault on an ungrounded-neutral system can be detected through the use of a wye-broken-delta potential transformer with an overvoltage relay connected across the opening in the delta, as illustrated in Fig. 14, or the wye windings of Fig. 14 may be connected to the system indirectly through the secondary of a wye-wye potential transformer, both of whose neutrals are grounded.

This potential-transformer connection will be recognized as being that described in Chapter 8 for obtaining a polarizing voltage for ground directional relays. When such a connection is used on an ungrounded system, the burden placed across the break in the delta should be greater than a certain minimum value, or else an unstable neutral condition (ferroresonance) may develop that would indicate the presence of a ground fault when no fault existed.[14] However, it has been found that occasionally the required burden is higher than that recommended in Reference 14, and is so high that it will quickly

thermally overload the potential transformers. A promising solution in such cases appears to be a resistor in series with the grounded neutral of the wye windings, as shown in Fig. 14.

An alternative to Fig. 14 is one high-voltage potential transformer connected between one phase and ground, and one induction-type voltage relay with double-throw contacts. For this method to work, it is necessary that there be sufficient and well-enough-balanced capacitance to ground to establish the neutral of the three-phase system approximately at ground potential. The relay would be provided with a stiff enough control spring so that neither contact would be closed under normal-voltage conditions. Should a ground fault occur on the phase to which the potential transformer was connected, the voltage on the relay would drop and the relay would close its undervoltage "*b*" contact. Should a ground fault occur on either of the other two phases, the relay voltage would rise and cause the overvoltage "*a*" contact to close. With such a relay arranged to trip a breaker on the closing of either contact, some provision must be made to permit reclosing the breaker if such reclosing is desired even though voltage has not been restored to the circuit to which the potential transformer is connected. Here, as in Fig. 14, sufficient stabilizing load should be connected to the potential-transformer secondary or inserted in series with the primary to prevent ferroresonance.[15] If a capacitance potential device were used, it would avoid this ferroresonance problem.

EFFECT OF GROUND-FAULT NEUTRALIZERS ON LINE RELAYING

Ground-fault neutralizers, or "Petersen coils," do not affect the choice of phase relays for line protection. When provision is made to short-circuit the neutralizer automatically after the expiration of a definite time if the ground fault is still present, ground relays are applied on the basis of solidly grounded-neutral operation.

Ordinarily, the ground relays will have no tendency to operate until after the neutralizer has been shorted, but rarely there may be a tendency to misoperate at certain locations before the neutralizer is shorted. Figure 15 shows a one-line diagram of a portion of a system, and the corresponding zero-phase-sequence diagram, to illustrate the cause of such a misoperating tendency. Although the total zero-phase-sequence current (I_0) may be zero or very small, the magnitudes of the currents flowing in certain branches of the zero-phase-sequence network can be large. The current through the neutralizer will be nearly equal to the normal phase-to-neutral voltage divided by the neutralizer's impedance. The total capacitance current is approximately equal in magnitude to the neutralizer current, but reversed in phase.

Ground-relay misoperation is possible in the branches where large capacitance current flows, such as at location P of Fig. 15. All the capacitance current in the network to the right of location P flows through this location. A ground directional relay at P is arranged not

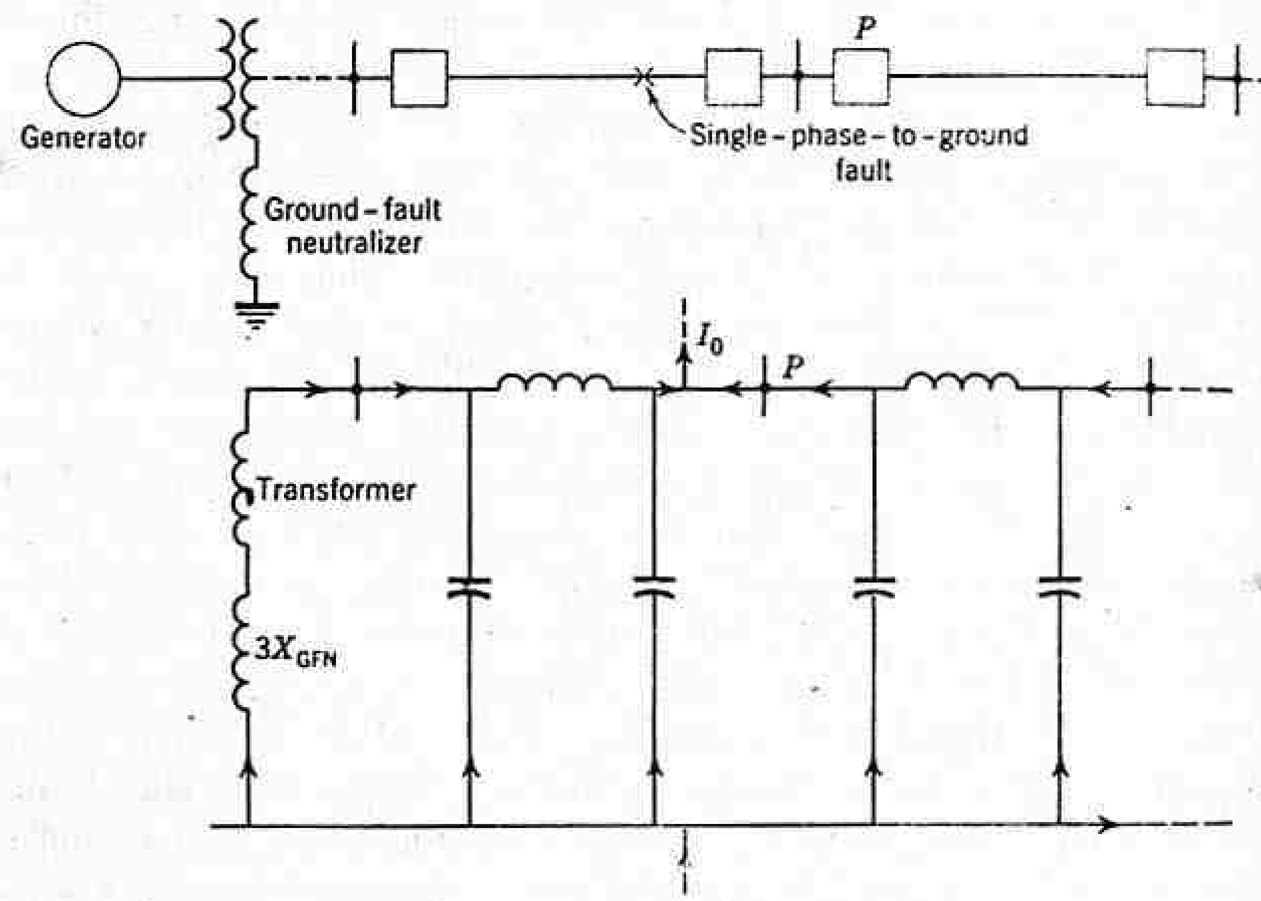


Fig. 15. System and zero-phase-sequence-network diagram illustrating tendency of ground relays to misoperate in the presence of a ground-fault neutralizer.

to operate when lagging current flows in the direction of the arrow. But capacitance, or leading, current flowing in the direction of the arrow will cause relay operation if the current is above the relay pickup. ~~This~~ tendency to misoperate can usually be corrected by increasing the relay's pickup slightly.

The more neutralizers there are at different points in the system, the less will be the charging current at any one location, and the tendency for ground relays to misoperate on charging current will be reduced.

The practice of attempting to use very sensitive relays to obtain selective ground-relay operation without shorting neutralizers is to be discouraged in general. Such practice may be successful with radial lines, but in loop circuits it is not reliable.[16] If one objects to shorting neutralizers on the basis that destructive short-circuit currents may flow, one can always insert sufficient resistance in the neutralizer short circuit to limit the magnitude of the current and still permit enough to flow for reliable selective relay operation.

An application problem is frequently encountered when ground-

fault neutralizers have been applied to a system where the line conductors are not sufficiently transposed. The consequence is that, owing to unbalanced phase-to-neutral capacitances, a net phase-to-neutral charging current returns through the earth and the neutralizer coil, and flows continuously. In the zero-phase-sequence circuit, this current path is essentially a series-resonant circuit, and large zero-phase-sequence voltages will exist continuously for relatively low currents in the series-resonant circuit. If these voltages are large enough, they will tend to cause overheating of relay voltage-polarizing coils. (In the same system, but with solidly grounded neutrals, there is no series-resonant circuit, and the voltages are small enough to be negligible.)

Aside from not applying ground-fault neutralizers to such a system, the only solution is to be sure that the continuous ratings of ground-relay polarizing-coil circuits are high enough so that overheating will not occur, which may mean special relays or relays with decreased sensitivity. Incidentally, the ground-fault neutralizers must also be capable of withstanding the current that will flow through them continuously.

THE EFFECT OF OPEN PHASES NOT ACCOMPANIED BY A SHORT CIRCUIT

An open phase not accompanied by a short circuit may be caused by the blowing of a fuse, or by faulty contacts in a circuit breaker. Or an open-phase condition may exist for a short time because of non-simultaneous circuit-breaker-pole closing or opening, or because of single-phase switching.

This subject is too extensive to treat here in all its various aspects. In general, only ground relays are apt to operate undesirably, although sometimes the phase relays of balanced-current relaying may also operate undesirably. However, ground relays, being generally sensitive enough to operate on less than normal load current, are more apt to be the offenders. This subject is treated in more detail in Reference 12.

The operating tendencies of various types of relays can be determined from a study of the phase-sequence currents that flow during open-phase conditions. Consider the system diagram of Fig. 16. If one phase is open-circuited at the location shown in Fig. 16, the phase-sequence diagrams for the open phase are as shown in Fig. 17.

If two phases are open-circuited at the location shown in Fig. 16, the phase-sequence diagrams for the phase that is not open-circuited are shown in Fig. 18.

The arrows of Figs. 17 and 18 show the direction of current flow in the various phase-sequence networks. Note that all these currents are of load-current magnitude, their size depending on the magnitude of load current flowing before the open-phase condition occurred.

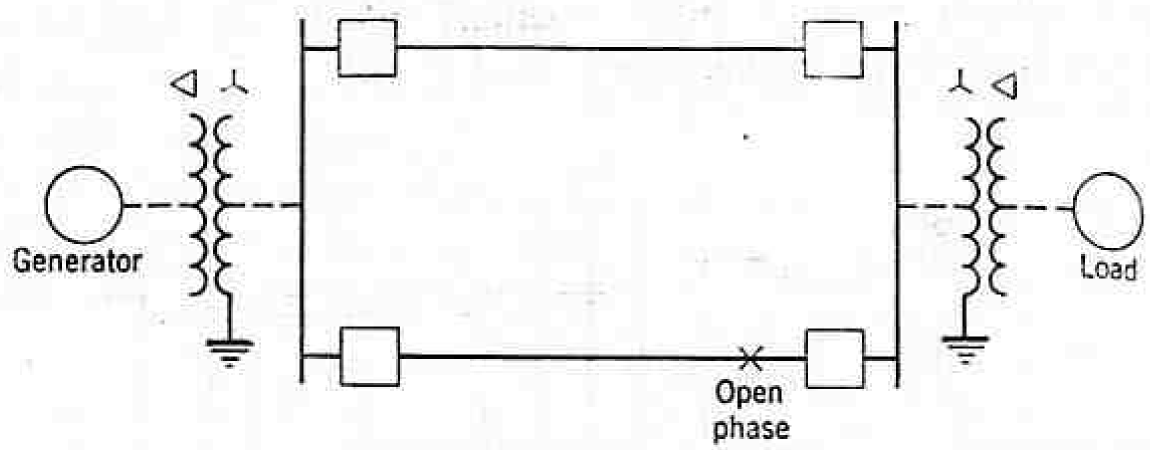


Fig. 16. Relay operation resulting from open phases.

The operating tendency of current-polarized directional-ground relays can be analyzed quite simply from Figs. 17 and 18 by remembering that the relays can trip when zero-phase-sequence current flows

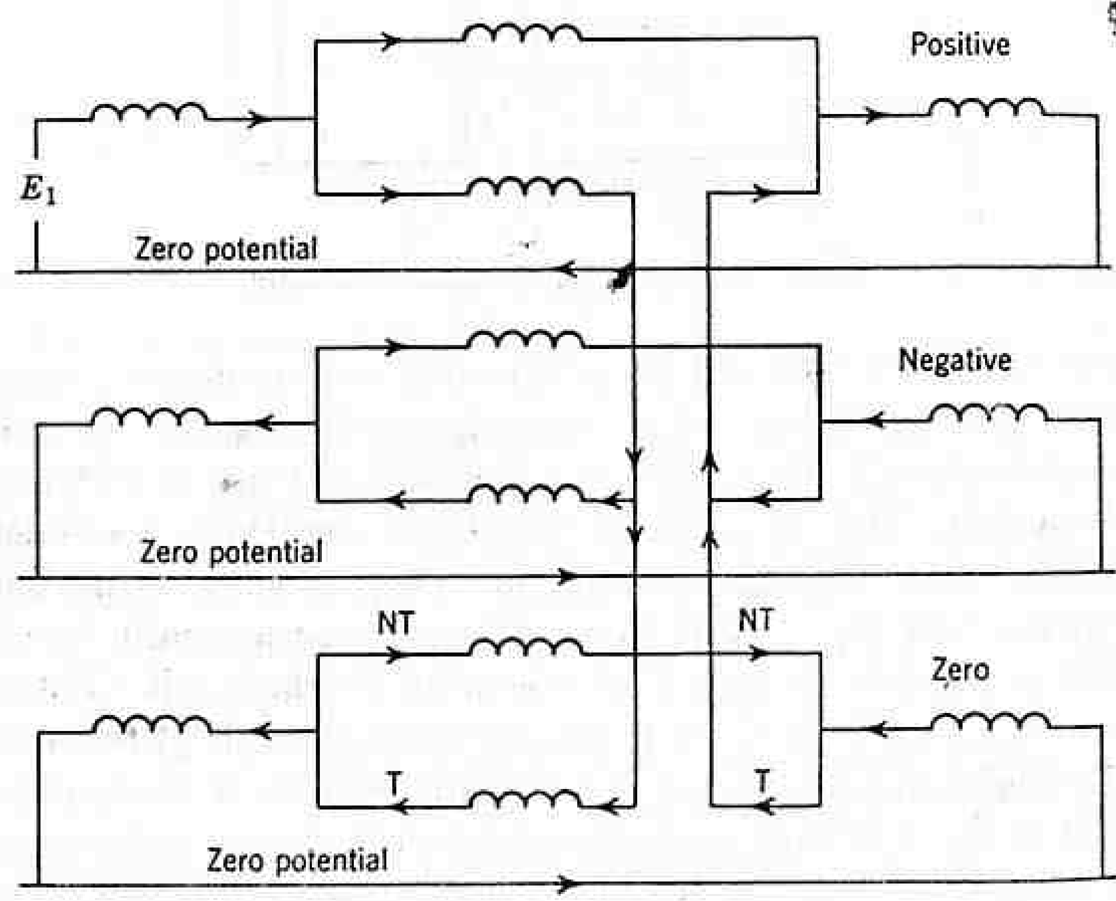


Fig. 17. Phase-sequence diagrams of the open phase when one phase is open.

out of the zero potential bus and into a line at a given location. A reversal of both of these directions also produces a tripping tendency. Based on this fact, Figs. 17 and 18 are labeled T (trip) and NT (not trip) at the ends of the lines to indicate the operating tendencies of the ground directional relays at those locations.

The operation of voltage-polarized ground directional relays obtaining voltage from a bus source will be the same as for current-polarized relays. However, if voltage is obtained from the line side of the

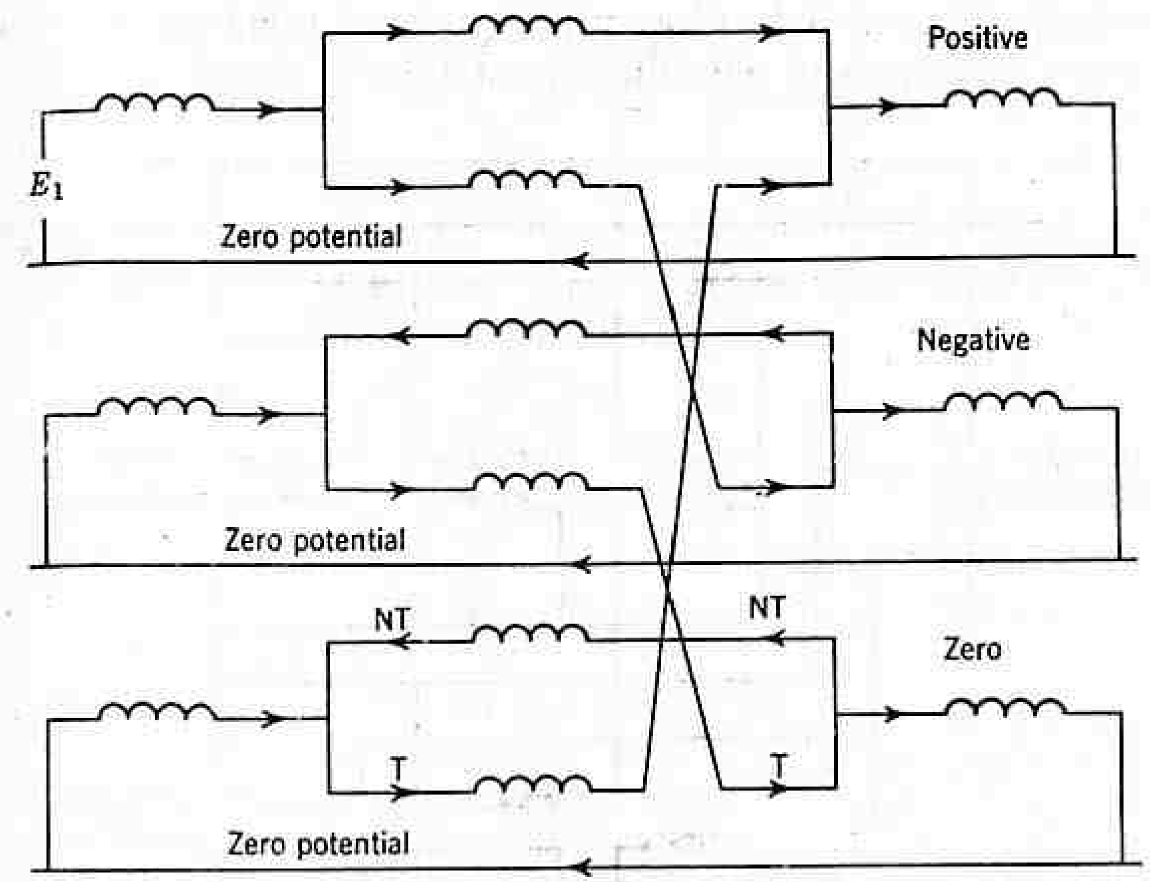


Fig. 18. Phase-sequence diagrams of the closed phase when two phases are open.

breakers, as with coupling-capacitor potential devices, an open circuit between a bus and the voltage source of a given relay will produce an operating tendency opposite to that shown on Figs. 17 and 18 for the relay at that location.

The effect that has been most troublesome, actually, is the transient effect on high-speed ground relays of non-simultaneous circuit-breaker-pole closing or opening. It has been necessary to employ induction types and sometimes to increase the pickup of the relays in order to avoid undesirable operation.

THE EFFECT OF OPEN PHASES ACCOMPANIED BY SHORT CIRCUITS

If a line conductor breaks, and one or both ends fall to the ground, we have simultaneous faults of two different types—an open-circuit and a phase-to-ground short circuit. Such faults can be analyzed by the method of symmetrical components.[17] However, it is rarely, if ever, that one has to make such an analysis because the presence of the short circuit takes command of the situation, and the proper protective relays operate to remove the short circuit from the system, the situation caused by the open circuit also being relieved.

POLARIZING THE DIRECTIONAL UNITS OF GROUND RELAYS

Directional units of ground relays may be polarized from certain zero-phase-sequence-current or voltage sources, or from both simultaneously.[18] Chapter 8 describes voltage-polarization sources utilizing potential transformers or capacitance potential devices.

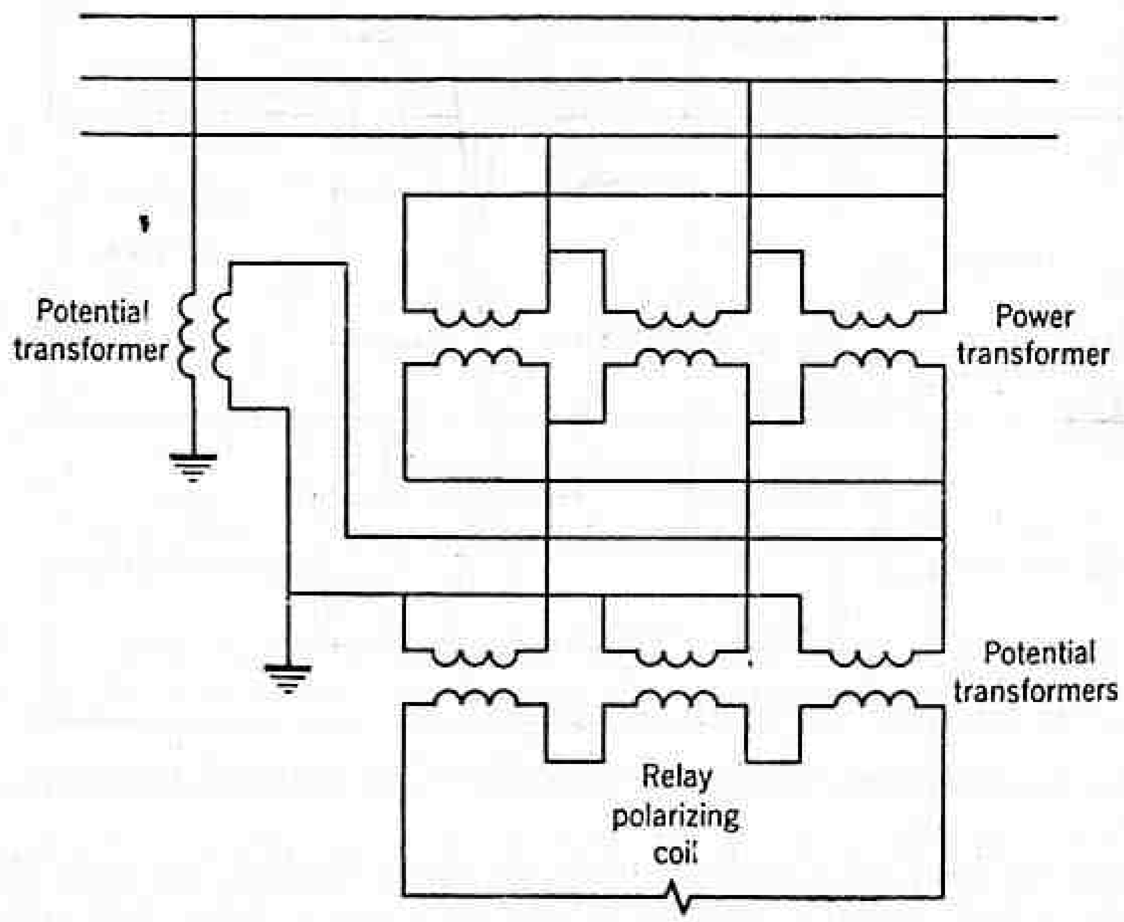


Fig. 19. Low-tension polarizing voltage for directional units of ground relays.

Figure 19 shows a method, not described in Chapter 8, for obtaining polarizing voltage from the low-voltage side of a delta-delta power-transformer bank, using only one high-voltage potential transformer to establish the neutral on the low-voltage side.[19] The same principle can be applied to a delta-wye transformer bank if the necessary auxiliary potential transformers are used to compensate for the 30° phase shift of voltages.

The voltage obtained by the method of Fig. 19 has an error caused by the voltage regulation in the transformer bank, owing to load current flowing from the high-voltage side to the low-voltage side, or caused by positive- and negative-phase-sequence currents flowing toward the fault if there is a source of generation connected to the

low-voltage side. This error is not great enough to cause concern for large values of zero-phase-sequence voltage, but for low values it might cause a directional relay to misoperate. Magnetizing-current inrush to the bank also could cause misoperation if the relay was a high-speed type. For these reasons, this kind of a polarizing source is not considered suitable for high-speed directional relays. It may be used with inverse-time directional-overcurrent relays.

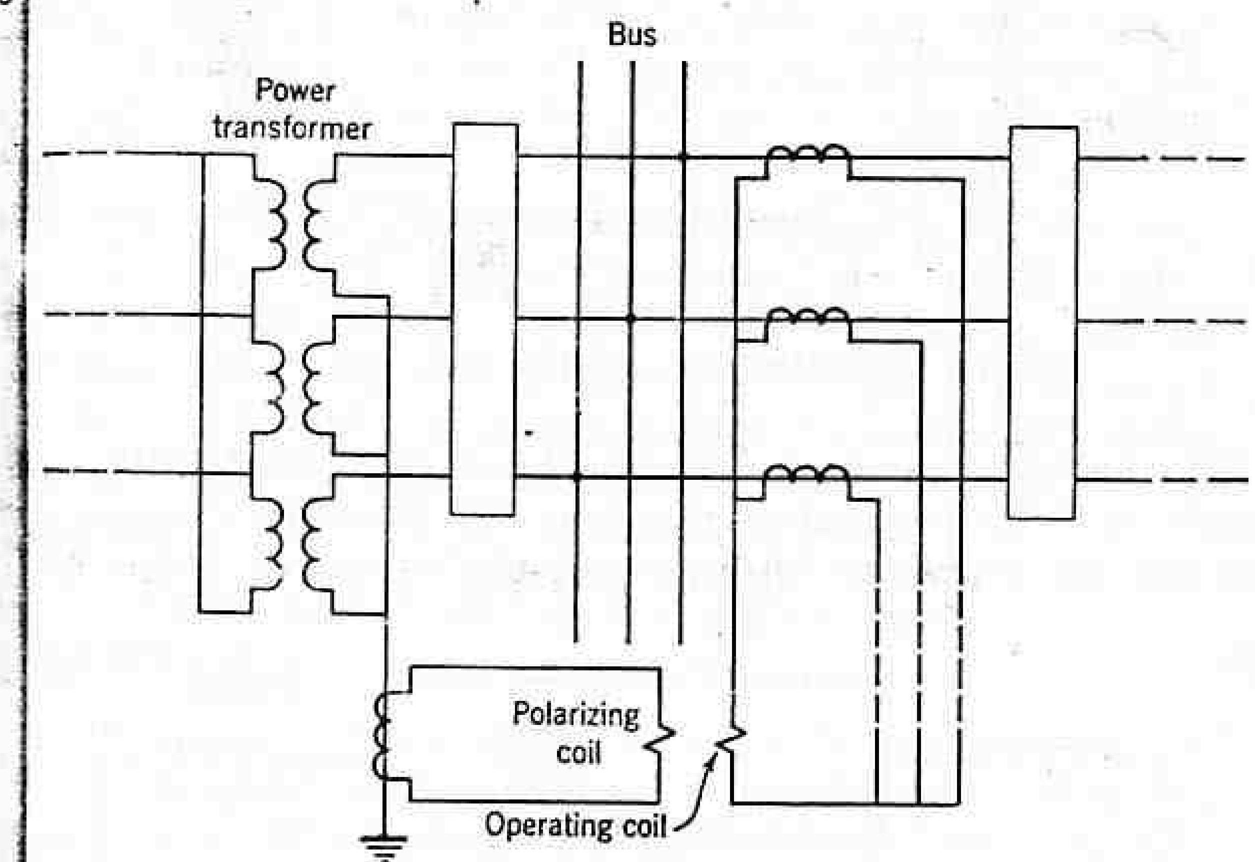


Fig. 20. Current polarization from power-transformer-neutral current.

Figure 20 shows how current polarization can be obtained from the grounded-neutral current of a three-phase power-transformer bank. As mentioned in Chapter 8 in connection with the use of voltage from the low-voltage side of a transformer bank, one should consider the reliability of a single transformer bank as a polarizing medium in view of the fact that it will be out of service occasionally for maintenance, or possibly for repair because of an internal fault. Polarizing current from paralleled CT's in the grounded neutrals of two or more transformer banks is considered sufficiently reliable if the banks have separate circuit breakers so that one bank will always be in service.

With a three-winding wye-delta-wye power-transformer bank, polarizing CT's should be put in the grounded neutrals of both wye windings and paralleled. The ratios of these two CT's should be inversely proportional to the voltage ratings of the wye windings.

As an alternative to the neutral CT's with either two- or three-winding transformers, a single CT in series with one of the delta windings may be used if these windings do not supply external load or are not connected to a generating source. If there are external connections to the delta, three CT's are required, one in each of the three windings. These CT's should be paralleled, as shown in Fig. 21, in such a way that their output is proportional to 3 times the zero-phase-sequence component of current circulating in the delta when a ground fault occurs.

As a second alternative to the neutral CT's, the neutral current of wye-connected CT's in series with the wye windings may be used,

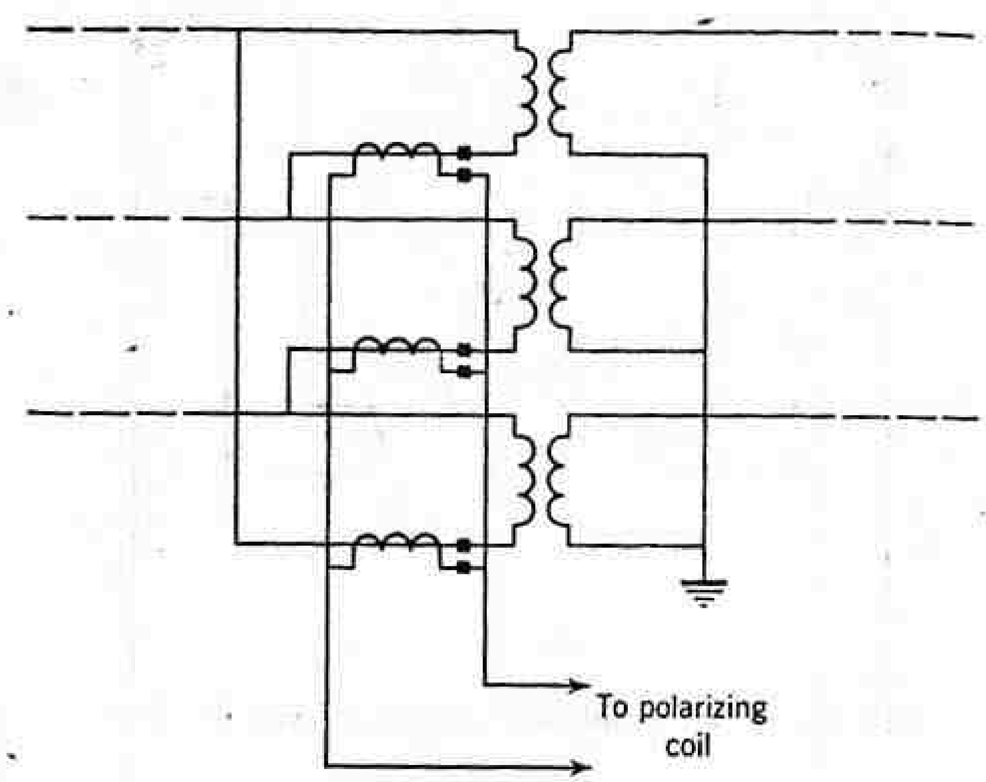


Fig. 21. Current polarization from a loaded power-transformer delta.

as in Fig. 22. In the three-winding power transformer, the ratios of these CT's should be inversely proportional to the voltage ratings of the wye windings, as when neutral CT's are used. This alternative is not exactly equivalent to neutral CT's because of the possibility of false residual current, and, therefore, it should not be used with high-speed relays.

In an autotransformer bank with a delta tertiary, either of the two alternatives to the neutral CT's may be employed. It is generally not permissible to use a CT in the neutral because the neutral current for a low-voltage fault may be reversed from the neutral current for a high-voltage fault. Infrequently, the distribution of fault currents is such that a neutral CT may be used; however, one should realize that the conditions might change as system changes are made.

The primary-current rating of a neutral or delta-winding CT used

r polarizing directional units of ground relays should be such that e polarizing and operating coils of a directional unit get about the me current magnitudes for any fault for which it must operate.

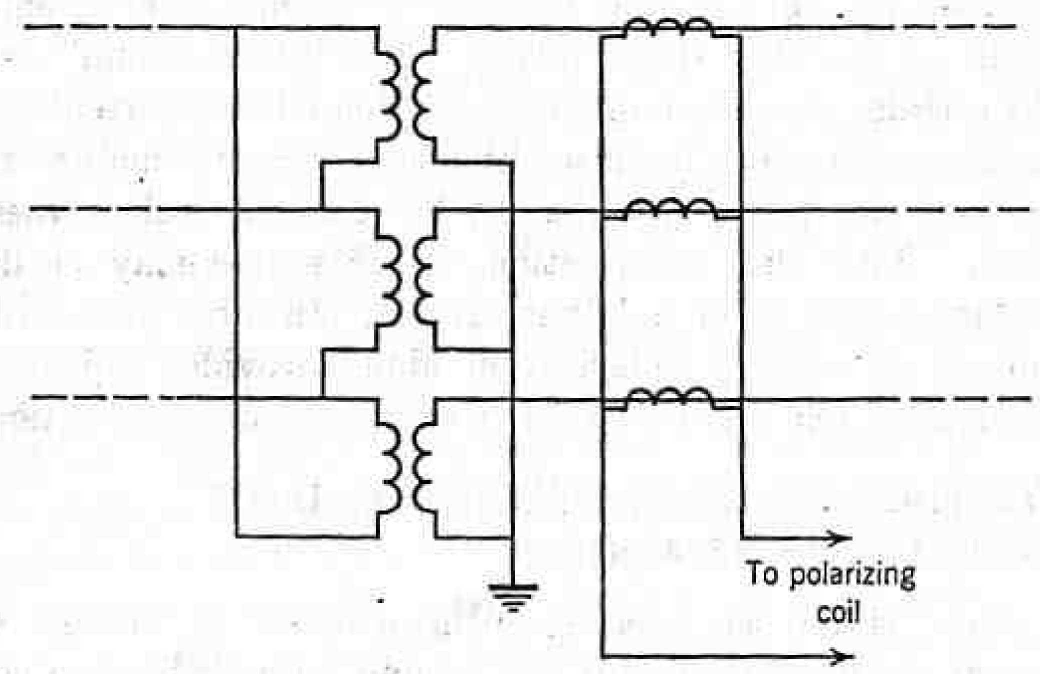
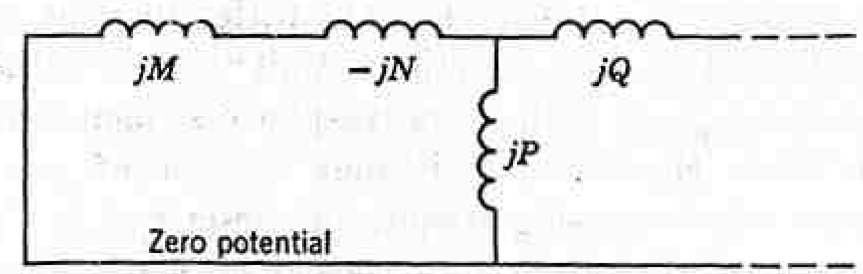


Fig. 22. Alternative to Fig. 20.

his is more important for the so-called "directional-ground" relays hose published characteristics hold only if one current does not iffer too much from the other.



g. 23. Zero-phase-sequence diagram illustrating a case where polarization by the methods of Figs. 20 to 22 will cause misoperation.

In rare cases, such as that illustrated in Fig 23, none of the regoing methods of current polarization may be used. Such cir-umstances may exist when one branch (N) of the equivalent circuit f a three-winding power transformer or autotransformer has nega-ive reactance and when the zero-phase-sequence reactance of the ystem (M) connected to this negative branch is less than the re-ctance of the negative branch. In other words, on the side of this anch, the total zero-phase-sequence reactance including this branch f the transformer ($M + N$) is negative. Then, if this total negative actance is smaller than the positive reactance of the branch repre-nting the delta winding (P), all conditions are satisfied to make unsuitable any of the current-polarizing methods that have been described. When these circumstances exist, it becomes necessary either to use voltage polarization or, possibly, a special combination of currents.[20]

Directional relays are available that are arranged for polarization simultaneously by voltage and current.[18] Apart from simplifying the problem of stocking spare relays, "dual polarization," as it is called, has certain functional advantages. Sometimes, current or voltage alone is unsatisfactory because either source may sometime be disconnected from the system and thereby be rendered useless when it is still needed. With dual polarization, either source may be disconnected so long as the other is left in service. In other circumstances, either voltage or current polarization alone provides objectionably weak polarization but the two together assure strong polarization.

NEGATIVE-PHASE-SEQUENCE DIRECTIONAL UNITS FOR GROUND-FAULT RELAYING

When there is no zero-phase-sequence-current or voltage source for polarizing the directional unit of a ground relay, it is often possible to use a negative-phase-sequence directional unit if separate ground relaying is required. However, one must be sure that sufficient negative-phase-sequence current and voltage will be available to assure reliable operation of the directional unit for all conditions for which it must operate. In some systems that are grounded through impedance, the negative-phase-sequence quantities may be too small.

A negative-phase-sequence directional unit may be either a simple directional unit supplied with negative-phase-sequence current and voltage from filter circuits[21] or it may consist of two polyphase directional units with opposing torques, as described in Chapter 9.

Another advantage of negative-phase-sequence directional units is that they are not affected by mutual induction between paralleled circuits when ground faults occur. Chapter 15 shows that directional relays with zero-phase-sequence polarization may operate undesirably under such circumstances.

In spite of any advantages the negative-phase-sequence relay may have, it is used only as a last resort, because the zero-phase-sequence relay is simpler and easier to test, and because it produces more reliable torque under all conditions where it is applicable.

CURRENT-BALANCE AND POWER-BALANCE RELAYING

Prior to the introduction of high-speed distance and pilot relaying, current-balance and power-balance relaying were used extensively

for the protection of parallel lines. Aside from instantaneous overcurrent relaying, they were the only available forms of instantaneous relaying for transmission lines. Their present-day usage for new installations is rare, but many old installations are still in service, and occasionally a new one is justified.

Current-balance relaying is illustrated in Fig. 24 for one phase of a pair of three-phase parallel lines. Two overcurrent-type current-

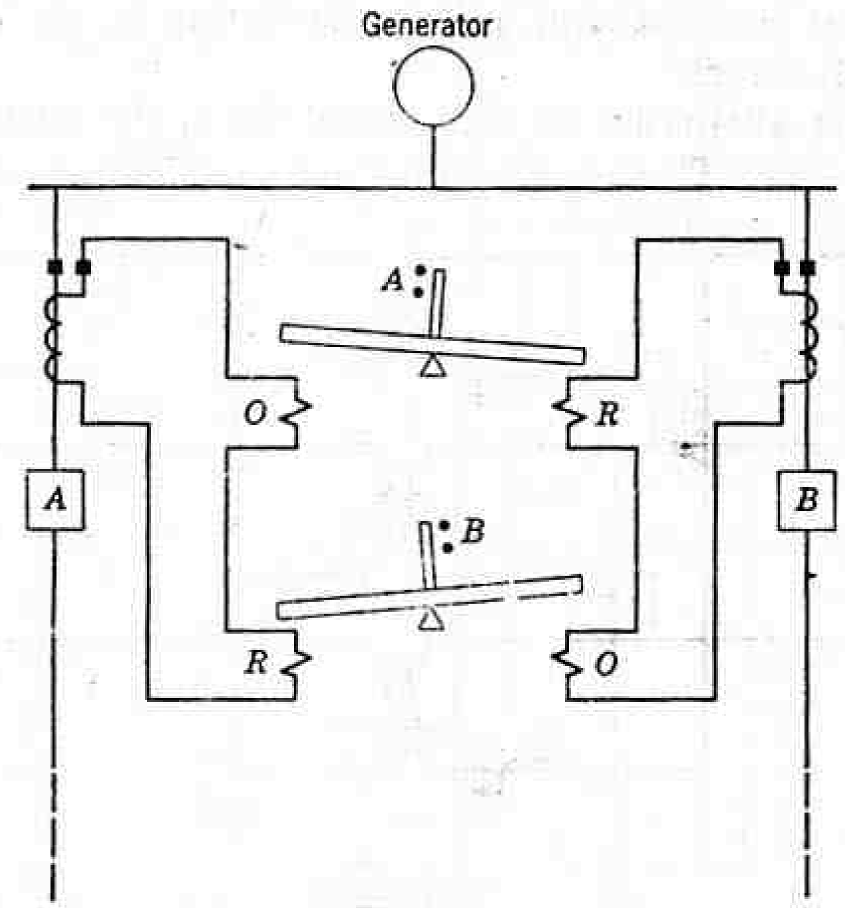


Fig. 24. Current-balance relaying of parallel lines.

balance units are shown schematically, having operating coils O and restraining coils R. One unit has contacts A that trip breaker A, and the other unit has contacts B for tripping breaker B. The trip circuits are not shown, but they are arranged so that tripping of either breaker can occur only when both breakers are closed. Furthermore, each phase-relay unit is restrained either by its control spring or by voltage (not shown) so that it will not operate with operating-coil current corresponding to maximum load and no restraining current (or, in other words, it will not operate when only one line is closed and carrying maximum load). This restraint is necessary with this type of relay to prevent immediate undesirable tripping when a line is being returned to service and one end is closed while the other end is open. Such restraint is unnecessary on a current-balance ground relay obtaining current from the CT neutrals, because normally there is no neutral current.

Power-balance-relaying is illustrated in Fig. 25. As shown, the CT's of each corresponding phase of the two parallel lines are cross-connected, and the current coil of a directional relay is differentially connected across the CT interconnections. While the currents flowing into the two lines are equal vectorially, no current will flow in the directional-relay coil, the currents merely circulating between the two CT's. If the current in one line becomes larger than that of the other, current will flow in one direction through the relay coil. If

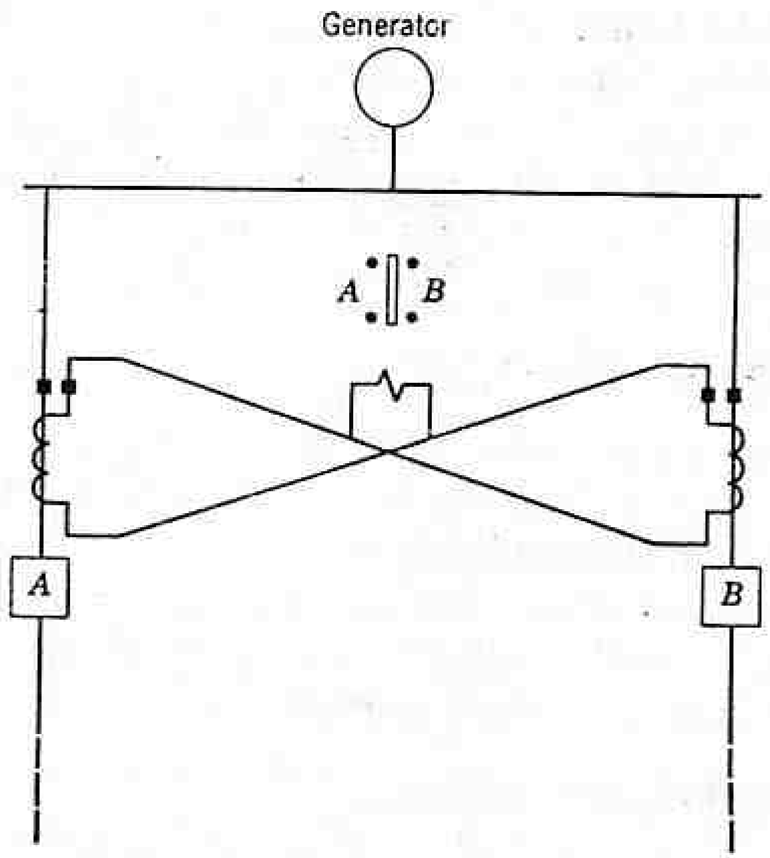


Fig. 25. Power-balance relaying of parallel lines.

the current of the other line is larger, the current will flow in the other direction. Thus, the relay will close one or the other of its double-throw contacts to trip the breaker of the line having the larger current. Instead of the single relay shown in Fig. 25, two relays may be used, contact A being on one, and contact B on the other. As described for current-balance relaying, the trip circuits are arranged so that both breakers must be closed before either can be tripped. Supplementary overcurrent relays connected in series with the directional-relay current coils provide a sensitivity adjustment.

Power-balance relaying can be used at either end of parallel lines, as contrasted with current-balance relaying, which can be used only where there is a connection to a source of short-circuit current. If there is no such source at one end of a pair of parallel lines, the magnitudes of the currents in the two lines are equal at that end for a fault on one line, and hence a relay that compares only the magnitudes of the currents would not operate. The power-balance equipment compares not only magnitude but also the phase relation of the currents in the two lines, and, since the direction of current flow in one line is reversed from that in the other line at the load end, this equipment will operate to trip the faulty line. The only reason for ever using current-balance relaying is that it is somewhat simpler and less expensive, especially if no voltage restraint is involved and since supplementary overcurrent relays are not required to establish the sensitivity.

Both current-balance and power-balance relaying are effective only while both lines are in service. For single-line operation, supplementary relaying is required. This supplementary relaying is also required to provide back-up protection for faults in adjoining lines or other system elements, since the current- or power-balance relaying will not operate for faults outside the two parallel lines. Unless relaying comparable to that provided by distance relays is used for single-line operation, faults during single-line operation will not be cleared nearly so quickly as when both lines are in service; and, if fast clearing is required for single-line operation, current-balance or power-balance relaying cannot be justified. The only exception to this is for protection against single-phase-to-ground faults for which distance relaying may not be economically feasible; then, current-balance or power-balance relaying will minimize the likelihood of a single-phase-to-ground fault on one line developing into a fault involving the other line, when both lines are close together.

AUTOMATIC RECLOSING

Experience has shown that 70% to 95% of all high-voltage transmission-, subtransmission-, and distribution-line faults are non-persisting if the faulty circuit is quickly disconnected from the system. This is because most line faults are caused by lightning, and, if the ensuing arcing at the fault is not allowed to continue long enough to badly damage conductors or insulators, the line can be returned to service immediately.[22] Where the fault persists after the first trip and closure, experience has shown it to be desirable to try as many as two or three more reclosures before keeping the line out of service until the trouble can be found and repaired.

Automatic reclosing is generally applied to all types of circuits. Subtransmission lines having overcurrent relaying usually have multi-reclosure equipment, with supplementary "synchronism-check" equipment at one end if it is likely that the line may sometime be the only choice of a ground-relay's pickup except in a distribution system where there is ground current normally because of unbalanced loading. If there are two or more adjoining line sections, the fault should be assumed at the end of the section that causes the least current to flow at the location of the relay being adjusted.

Because of the effect of parallel circuits not shown, less current will flow at the relay location of Fig. 1 if breaker A is closed than if A is open. If satisfactory adjustment can be obtained with A closed, so much the better. However, the relay under consideration is being adjusted to operate if breaker B fails to open; it is not generally assumed that breaker A will also fail to open. There may be some occasions when one will wish to assume simultaneous equipment failures at different locations, but it is not the usual practice. Hence, it is permissible to assume that breaker A has opened, which is usually very helpful and may even be necessary.

Under certain circumstances, the relay will get less current for a phase-to-phase fault at C with breaker D closed and under minimum generating conditions than for the fault location shown in Fig. 1 with A open; the relay must be able to operate for this condition also.

In order to use the most inverse portion of the relay's time curves, the pickup in terms of primary current should be as high as possible and still be low enough so that the relay will operate reliably under the minimum fault-current condition. Under such conditions, the relay should operate at no less than about 1.5 times its pickup, but as near to that value as conveniently possible. The reason for this rule is that, closer to the pickup current, the torque is so low that a small increase in friction might prevent operation or it might increase the operating time too much. It may be that the CT ratio and the relay's range of adjustment do not permit adjusting for so low a multiple of pickup; in that event the only recourse, aside from changing the CT or the relay, is to use the highest possible pickup for which the relay can be adjusted.

To assure selectivity under all circumstances, the pickup of a given relay should be somewhat higher than that of other relays nearer to the fault and with which the given relay must be selective.

Because the impedance of generators increases from subtransient to synchronous as time progresses from the instant that a short circuit occurs, the question naturally arises as to which value of impedance to use in calculating the magnitude of short-circuit current for protective-relaying purposes where overcurrent relaying is involved. The answer to this question depends on the operating speed of the relay under consideration, on the amount by which generator impedance affects

the magnitude of the short-circuit current, and on the particular relay setting involved. Usually, the impedance that limits the magnitude of the short-circuit current contains so much transformer and line impedance that the effect of changing generator impedance is negligible; one can always determine this effect in any given application. For relays near a large generating station that furnishes most of the short-circuit current, synchronous impedance would be best for determining the pickup of a relay for back-up purposes—particularly if the operating time of the relay was to be as long as a second or two. On the other hand, the pickup of a high-speed relay near such a generating station would be determined by the use of transient—or possibly even subtransient—impedance. Ordinarily, however, transient impedance will be found most suitable for all purposes—particularly for subtransmission or distribution circuits where overcurrent relays are generally used; there is enough transformer and line impedance between such circuits and the generating stations so that the effect of changing generator impedance is negligible. In fact, for distribution circuits, it is frequently sufficiently accurate to assume a source impedance that limits the current to the source-breaker interrupting capacity on the high-voltage side of a power transformer feeding such a circuit; in other words, only slightly more total impedance than that of the transformer itself and of the circuit to be protected is assumed.

Whether to take into account the effect of arc and ground resistance depends on what one is interested in. Arc resistance may or may not exist. Occasionally, a metallic fault with no arcing may occur. When one is concerned about the maximum possible value of fault current, he should assume no arc resistance unless he is willing to chance the possibility of faulty relay operation should a fault occur without resistance. Thus, as will be seen later, for choosing the pickup of instantaneous overcurrent relays or the time-delay adjustment for inverse-time relays, it is more conservative to assume no arc resistance.

When one is choosing the pickup of inverse-time relays, the effect of arc resistance should be considered This is done to a limited extent when one arbitrarily chooses a pickup current lower than the current at which pickup must surely occur, as recommended in the foregoing material; however, this pickup may not be low enough. In view of the fact that an arc may lengthen considerably in the wind, and thereby greatly increase its resistance, it is a question how far to go in this respect. At least, one should take into account the resistance of the arc, when it first occurs, whose length is the shortest distance between conductors or to ground. Beyond this, what one tie between certain generating stations. Synchronism-check equipment is relay equipment that permits a circuit breaker to be closed only if the parts to be connected by the breaker are in synchronism. On radial lines, there is no need for synchronism check.

In distribution systems in which selectivity with branch-circuit fuses is involved, multireclosure is also used.[23] Instantaneous and inverse-time overcurrent relays are arranged so that, when a fault occurs, the instantaneous relays operate to trip the breaker before a branch-circuit fuse can blow, and the breaker is then immediately reclosed. However, after the first tripout, the instantaneous relays are automatically cut out of service so that if the fault should persist the inverse-time relays would have to operate to trip the breaker. This gives time for the branch-circuit fuse of the faulty circuit to blow, if we assume that the fault is beyond this fuse. In this way, the cost of replacing blown branch-circuit fuses is minimized, and at the same time the branch-circuit outage is also minimized. If the breaker is not tripped within a certain time after reclosure, the instantaneous relays are automatically returned to service.

When industrial loads are to be fed from lines with automatic reclosing, certain problems exist that must be solved before automatic reclosing can be safely permitted. They have to do with the possible loss of synchronism between the utility and the industrial plant that makes it necessary to cut the plant loose from the utility before the utility's breakers reclose. At the same time, the industrial plant may have to resort to some "load shedding" of unessential loads so as to be able to supply its essential load from its own generating source. These problems, as well as other problems of industrial-plant protection, are discussed at length and solutions are given in the material under Reference 24.

RESTORATION OF SERVICE TO DISTRIBUTION FEEDERS AFTER PROLONGED OUTAGES

Large economies can be effected in the design and operation of distribution circuits and related equipment by taking advantage of the diversity between loads. Under normal operating conditions, the actual load on a distribution feeder will generally be considerably less than the total rating of the power-utilization equipment served by the feeder. When such a feeder is quickly reclosed after the clearing of a fault, the inrush current will not greatly exceed the normal load current, and the current will quickly return to normal. But after such a feeder has been out of service long enough so that the normal "off" period of all loads, such as electric furnaces, refrigerators, water

heaters, pumps, air conditioners, etc., has been exceeded, all these loads will be thrown on together with no diversity between them. The total inrush current to all the electric motors involved, added to the current of other loads, may be several times the normal peak-load current, decaying to approximately 1.5 times the normal peak-load current after several seconds.[25] This subject has been called "cold-load restoration" or "cold-load pickup."

Protective relaying for such feeders is faced with the problem of selecting between such inrush currents and the current to a fault at or beyond the next automatic sectionalizing point. An induction-type extremely inverse-time-overcurrent relay, having a time-current curve closely matching that of a fuse down to an operating time of approximately 0.1 second, has given some relief for such an application. However, the best solution seems to be automatic sectionalizing on prolonged loss of voltage, and time-staggered automatic reclosing on the return of voltage.

COORDINATING WITH FUSES

When overcurrent relays must be selective with fuses, the relay that will provide such selectivity and still be the fastest for faults for which it must operate is the extremely inverse type just described for cold-load restoration. Occasionally it may be necessary to add a delay of a few cycles, in the form of an auxiliary relay, to maintain selectivity at very high fault currents.

A-C AND CAPACITOR TRIPPING

Some installations, particularly in distribution systems, cannot justify the expense and the maintenance of a storage battery and its charging equipment solely for use with protective-relaying equipment of one or two circuits. Then "a-c tripping" or "capacitor tripping" may be used if they are applicable.

In one type of a-c tripping equipment, a reactor, called a "tripping reactor," is permanently connected in series with the coil of each overcurrent relay in the CT secondary circuit. The circuit breaker has a separate trip coil for each overcurrent relay. Each trip coil is connected across a tripping reactor through the contact of the corresponding overcurrent relay. Figure 26 shows the connections when three relays are involved. This method of tripping is applicable when the rms voltage drop through a reactor is sufficiently high during a short circuit to actuate the reactor's corresponding trip-coil mechanism should its overcurrent relay close its contact. Reactors of various ratings are available for producing the required voltage whenever the current is high enough to close the relay contacts. However, owing to limitations in the ability of CT's to produce sufficient rms voltage at low primary currents, this method of tripping is effective only for short-circuit currents of the order of rated load current or higher. Saturation of the tripping reactor limits the rms voltage to a safe value at high fault currents, and a shunt resistor, not shown in Fig. 26, holds down the crest value of voltage.

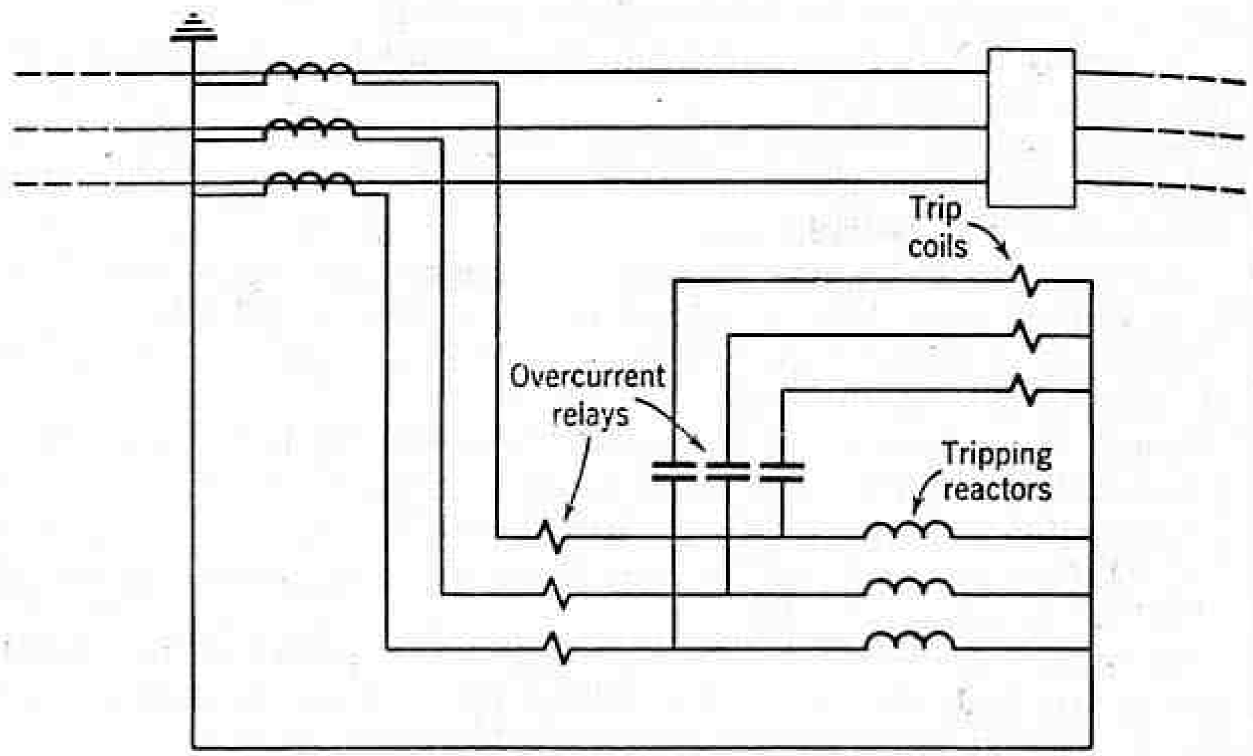


Fig. 26. A-c tripping with tripping reactors.

When the fault current for a single-phase-to-ground short circuit is less than the pickup of the phase overcurrent relays, phase-to-phase voltage from the secondary of a potential transformer may be used for tripping by a ground overcurrent relay in conjunction with a separate voltage trip coil. For a single-phase-to-ground fault, the phase-to-phase voltage will usually be large enough so that reliable tripping will be assured. A-c voltage can be used for tripping by other types of protective relays that operate for other than short circuits, or, in other words, when the voltage is not badly affected.

A-c tripping is inferior principally in its limited sensitivity for interphase faults, and also because of more severe relay contact duty which requires more maintenance. Also, the burden imposed on the CT's is high, and, unless the CT's are good enough to support this burden, the relaying sensitivity will be poor. Because of the high burden, accurate metering cannot be provided from the same CT's. A minor limitation is that single-phase relays must be used; a polyphase directional relay having but one contact could not be used because there would not be a suitable source for operating an auxiliary relay to provide the necessary additional contacts.

Capacitor tripping uses the stored energy of a charged capacitor to actuate a trip-coil mechanism. The capacitor is charged through a rectifier from a-c voltage obtained from the system. Its principal advantage over a-c tripping is greater sensitivity for interphase faults. Also, it permits the use of polyphase relays that do not need auxiliary relays, although an additional capacitor tripping device has been used to operate an auxiliary tripping relay. Its principal disadvantage is that the circuit-breaker trip mechanism gets only one impulse and not a steady force as with a-c tripping; this fact makes some people feel that the breaker requires a more "hair-triggered" trip mechanism, and consequently that it is apt to be less reliable.

Problem

Given a simple loop system as shown in Fig. 27, where the impedances are in percent based on the rating of one of the generators. Adjust overcurrent relays having time characteristics of Chapter 3, Fig. 3, for the protection of all the lines

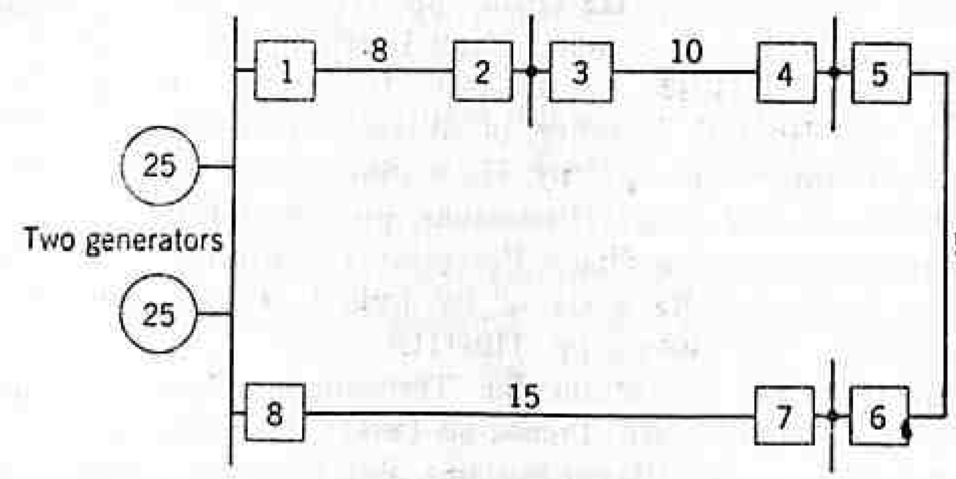


Fig. 27. Illustration for problem.

against phase faults, assuming and indicating directional elements, wherever necessary, by an arrow pointing in the tripping direction. Neglect the fact that the pickup should be well above load current. Make your adjustments on the basis of per unit primary current, assuming that any desired pickup can be obtained.

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should do depends on the operating time of the relay under consideration and the wind velocity. The characteristics of an arc are considered later.

Ground resistance concerns us only for ground faults. It is in addition to arc resistance. This subject is considered later also, along with arc resistance.

For ground relays on lines between which there is mutual induction, this mutual induction should be taken into account in calculating the magnitude of current for single-phase-to-ground faults. In some studies, this will show that selectivity cannot be obtained when it would otherwise appear to be possible.

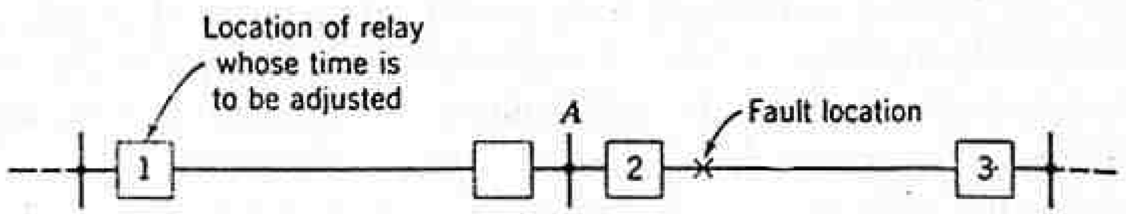

Fig. 2. The fault location for adjusting for selectivity.

The second step in the adjustment of inverse-time-overcurrent relays is to adjust the time delay for obtaining selectivity with the relays of the immediately adjoining system elements. This adjustment should be made for the condition for which the maximum current would flow at the relay location. This condition would exist for a short circuit just beyond the breaker in an adjoining system element. This is illustrated in Fig. 2. Under certain circumstances, more current will flow at the relay location if breaker 3 is open. For adjusting a phase relay, a three-phase fault would be assumed; and for a ground relay a single-phase-to-ground fault would be assumed. In either event, one would use the fault current for maximum generating conditions and for any likely switching condition that would make the current at 1 most nearly equal to the current at 2. For example, when there are other sources of short-circuit current connected to bus A, if it is considered a practical operating condition to assume them to be disconnected, they should be so assumed.

The adjustment for selectivity is made under maximum fault-current conditions because, if selectivity is obtained under such conditions, it is certain to be obtained for lower currents. This will be seen by examining the time-current curves of any inverse-time overcurrent relay, such as Fig. 3 of Chapter 3, and observing that the time spacing between any two curves increases as the multiple of pickup decreases. Hence, if there is sufficient time spread at any given multiple of

pickup, the spread will be more than sufficient at a lower multiple. The foregoing assumes that relays having the same time-current characteristics are involved. Relays with different characteristics are to be avoided.

This brings us to the question of how much difference there must be between the operating times of two relays in order that selectivity will be assured. Let us examine the elements involved in the answer to this question by using the example of Fig. 2. For the fault as shown in Fig. 2, the relay located at breaker 2 must close its contacts, and breaker 2 must trip and interrupt the flow of short-circuit current before the relay at breaker 1 can close its contacts. Furthermore, since the relay at breaker 1 may "overtravel" a bit after the flow of short-circuit current ceases, provision should also be made for this overtravel. We can express the required operating time of the relay at 1 in terms of the operating time of the relay at 2 by the following formula:

$$T_1 = T_2 + B_2 + O_1 + F$$

where T_1 = operating time of relay at 1.
T_2 = operating time of relay at 2.
B_2 = short-circuit interrupting time of breaker at 2.
O_1 = overtravel time of relay at 1.
F = factor-of-safety time.

The overtravel time will be different for different overcurrent relays and for different multiples of pickup, but, for the inverse-time types generally used, a value of about 0.1 second may be used. The factor-of-safety time is at the discretion of the user; this time should provide for normally expected variations in all the other times. A value of 0.2 to 0.3 second for overtravel plus the factor of safety will generally be sufficient; lower values may be used where accurate data are available.

We are now in a position to examine Fig. 3 wherein time-versus-distance curves are shown for relays that have been adjusted as described in the foregoing. The time S, called the "selective-time interval," is the sum of the breaker, overtravel, and factor-of-safety times. A vertical line drawn through any assumed fault location will intersect the operating-time curves of various relays and will thereby show the time at which each relay would operate if the short-circuit current continued to flow for that length of time.

The order in which the relays of Fig. 3 are adjusted is to start with the relay at breaker 1 and work back to the relay at breaker 4. This will become evident when one considers that the selectivity adjustment of each relay depends on the adjustment of the relay with which it must select. For cases like that shown in Fig. 3, we can generalize and say that one starts adjustment at the relay most distant electrically from the source of generation, and then works back toward the generating source.

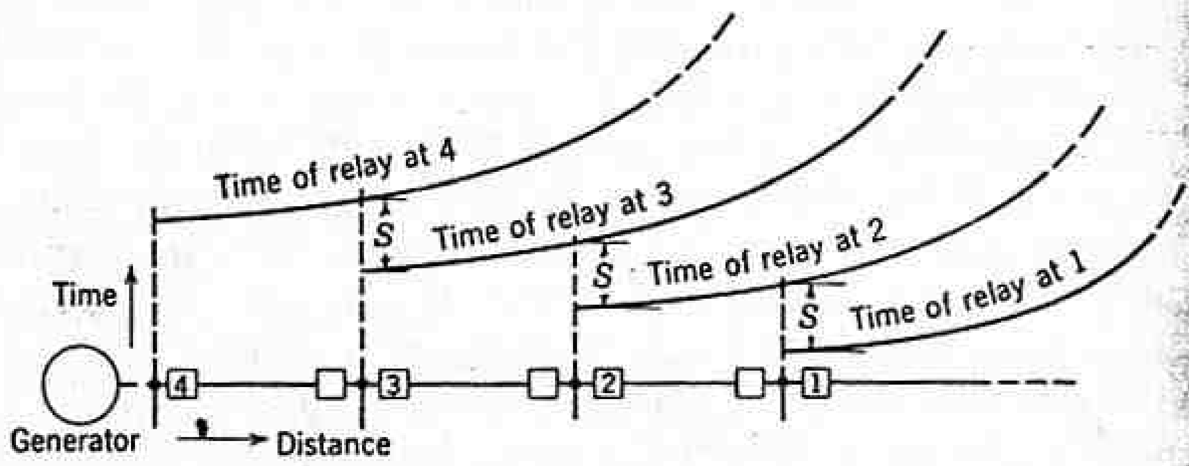

Fig. 3. Operating time of overcurrent relays with inverse-time characteristics.

ARC AND GROUND RESISTANCE

Although there is much difference of opinion on the interpretation of test data, the maximum value of rms volts per foot of arc length given by any of the data[1,2,3] for all arc currents greater than 1000 rms amperes is about 550. For currents below 1000 amperes, the formula $V = 8750/I^{0.4}$ gives the maximum reported value of rms volts per foot (V) for any rms value of arc current (I); from this formula, values considerably higher than 550 will be obtained at low currents. Actually, this formula gives a fairly good average of all the available data for any value of arc current, as will be seen by plotting superimposed the data of Fig. 1 of Reference 1, Fig. 5 of Reference 2, and the foregoing formula which is obtained from the formula given in Reference 3. However, because this average value is only about half of the maximum reported in Reference 1 for currents larger than 1000 amperes, it is more conservative not to use this average for such current values when one is interested in the maximum arc resistance.

To take into account the lengthening of the arc by wind, the approximate formula $L = 3vt + L_0$ may be used, where:

L = length of arc, in feet.
v = wind velocity, in miles per hour.
t = time, in seconds after the arc was first struck.
L_0 = initial arc length, i.e., the shortest distance between conductors or across insulator, in feet.

It will be evident that there are limits to which this formula may be applied because there are limits to the amount an arc may stretch without either restriking or being extinguished. Reference 2 gives several sets of data showing how the arc voltage increased during field tests.

Ground resistance is resistance in the earth. This resistance is in addition to that of an arc. When overhead ground wires are not used, or when they are insulated from the towers or poles, the ground resistance is the tower- or pole-footing resistance at the location where the ground fault has occurred plus the resistance of the earth back to the source. Electric utilities have measured data on such footing resistance. When overhead ground wires are connected to steel towers or to grounding connections on wood poles, the effect is somewhat as though all footing resistances were connected in parallel, which makes the resulting footing resistance negligible. Published zero-phase-sequence-impedance data do not include the effect of tower-footing resistance.

Occasionally, a conductor breaks and falls to the ground. The ground-contact resistance of such a fault may be much higher than tower-footing resistance where relatively low resistance is usually obtained with ground rods or counterpoises. The contact resistance depends on the geology of a given location, whether the ground is wet or dry, and, if dry, how high the voltage is; it takes a certain amount of voltage to break down the surface insulation.

Ground resistance can range over such wide limits that the only practical thing to do is to use measured values for any given locality. An example of extremely high ground resistance and the method of relaying is given in Reference 4.

In one system,[5] advantage was taken of ground resistance to decrease the rms magnitude of ground-fault current and to greatly shorten the time constant of its d-c component in order to reduce the interrupting stress on circuit breakers. However, such practice should be avoided in general.

EFFECT OF LOOP CIRCUITS ON OVERCURRENT-RELAY ADJUSTMENTS

Figure 3 best serves the purpose of illustrating how selectivity is provided with inverse-time-overcurrent relays. But, lest it mislead one by oversimplifying the problem, it is well to realize that, except for some parts of distribution systems, Fig. 3 does not truly represent most actual systems where loops are the rule and radial circuits are the exception. The principles involved and the general results obtained in the application and adjustment of overcurrent relays are correctly shown by reference to Fig. 3, but the difficulties in arriving at suitable adjustment in an actual system are minimized. This consideration is important because it is often the deciding factor that leads one to choose distance or pilot relaying in preference to overcurrent relaying.

When we studied the method of setting inverse-time-overcurrent relays, we saw that the relay most distant electrically from the generating source was adjusted first, and that one then worked back toward the generating source. The same procedure would be followed in the simple loop system illustrated in Fig. 4. The order in which the relays "looking" one way around the loop would be adjusted is

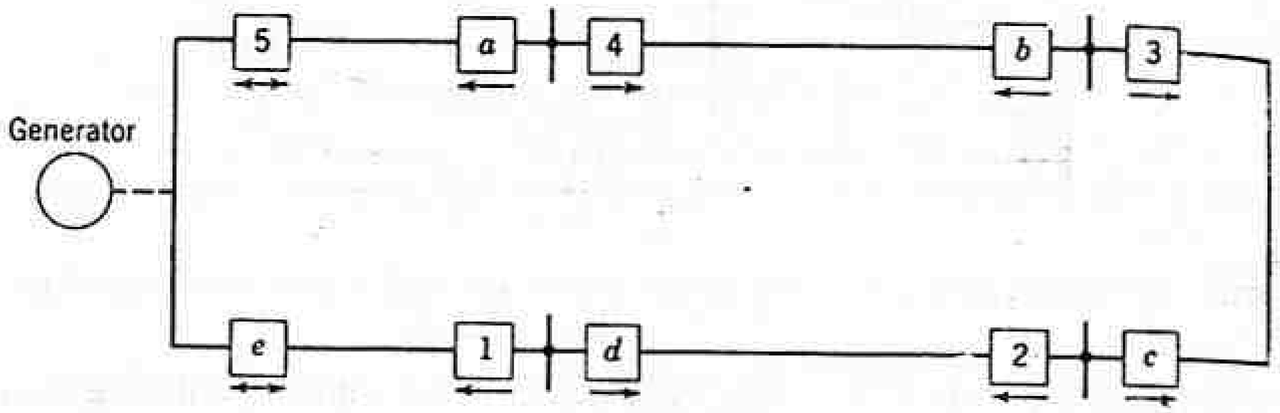

Fig. 4. The order for adjusting relays in a simple loop system.

1–2–3–4–5, and looking the other way, *a–b–c–d–e*. Directional overcurrent relays would usually be employed as indicated by the single-ended arrows that point in the direction of fault-current flow for which the relays should trip. Only at locations *e* and 5 can fault current flow only in the same direction as that for which tripping is desired, and the relays there may be non-directional as indicated by the double-headed arrows. The first relay to be adjusted in each of the two groups can be made as sensitive and as fast as possible because the current flow at the relay location will decrease to zero as faults are moved from the relay location to the generator bus, and hence there is no problem of selectivity for those relays. The phase relay at 1, for example, must receive at least 1.5 times its pickup current for a phase-to-phase fault at the far end of its line with the breaker at *e* open, and with minimum generation. Of course, no phase overcurrent relay should be so sensitive that it will pick up on maximum load.

Occasionally, the short-circuit current that can flow in the non-tripping direction is so small in comparison with the current that can flow in the tripping direction that certain relays need not be directional,

the system itself having a directional characteristic. But, if a relay can pick up on the magnitude of current that flows in the non-tripping direction, it is wise to make the relay directional or else the problem of obtaining selectivity under all possible conditions is needlessly complicated; and a future change in the system or its operation may demand directional relays anyway.

The first complication in adjusting overcurrent relays in loop circuits arises when generators are located at the various stations around the loop. The problem then is where to start. And, finally, when circuits of one loop form a part of other loops, the problem is most difficult. The trial-and-error method is the only way to proceed with such circuits. In fact, some such systems cannot be relayed selectively by inverse-time-overcurrent relays without operating the system with certain breakers normally open, and closing them only in emergencies. Supplementary instantaneous overcurrent relaying will sometimes give relief in such cases, as will be described later. Of course, such systems are not created in their entirety; they develop slowly, and the relaying problems arise each time that a change is made.

EFFECT OF SYSTEM ON CHOICE OF INVERSENESS OF RELAY CHARACTERISTIC

The less change there is in the magnitude of short-circuit current with changes in connected generating capacity, etc., for a fault at a given location, the more benefit can be obtained from greater inverseness. This is particularly true in distribution circuits where short-circuit-current magnitude is practically independent of normal changes in generating capacity. In such circuits one can use the very inverse—or extremely inverse—overcurrent relays to advantage.

In systems, such as many industrial systems, where the magnitude of the ground-fault current is severely limited by neutral-grounding impedance, little or no advantage can be taken of the inverseness of a ground-relay's characteristic; the relays might just as well have definite-time characteristics. This would also be true even where no neutral impedance was used if the sum of the arc and ground resistance was high enough, no matter where the fault should happen to occur.

Later, under the heading "Restoration of Service to Distribution Feeders after Prolonged Outages," the need for the extremely inverse characteristic is described. This characteristic is also useful in areas of a distribution system adjacent to where fuses and reclosers begin to replace relays and circuit breakers, because the extremely inverse characteristic will coordinate with fuses and reclosers.

THE USE OF INSTANTANEOUS OVERCURRENT RELAYS

Instantaneous overcurrent relays are applicable if the fault-current magnitude under maximum generating conditions about triples as a fault is moved toward the relay location from the far end of the line. This will become evident by referring to Fig. 5 where the symmetrical fault-current magnitude is plotted as a function of fault location along a line for three-phase faults and for phase-to-phase faults, if we assume that the fault-current magnitude triples as the fault is moved

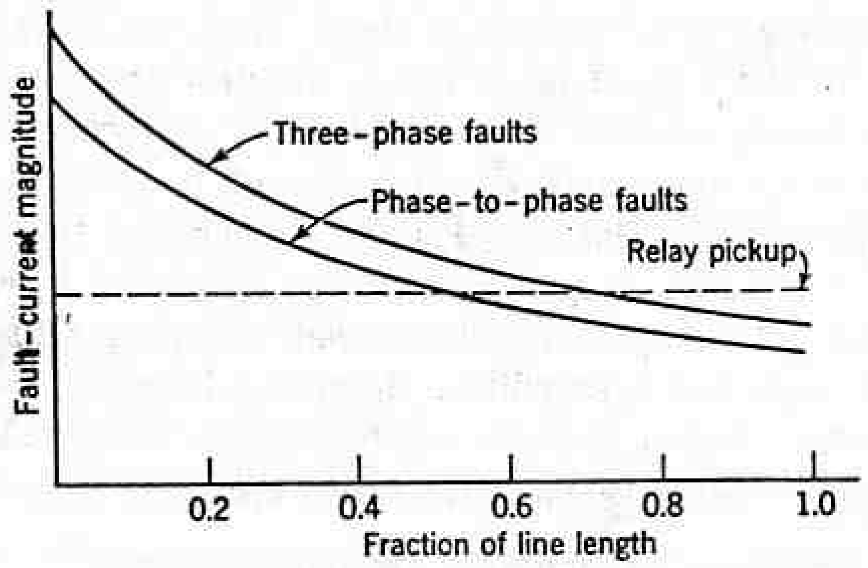

Fig. 5. Performance of instantaneous overcurrent relays.

from the far end of the line to the relay location. The pickup of the instantaneous relay is shown to be 25% higher than the magnitude of the current for a three-phase fault at the end of the line; the relay should not pick up at much less current or else it might overreach the end of the line when the fault-current wave is fully offset. In a distribution circuit, the relay could be adjusted to pick up at somewhat lower current because the tendency to overreach is less. For the condition of Fig. 5, it will be noted that the relay will operate for three-phase faults out to 70% of the line length and for phase-to-phase faults out to 54%. If the ground-fault current is not limited by neutral impedance, or if the ground resistance is not too high, a similar set of characteristics for ground faults would probably show somewhat more than 70% of the line protected; this is because the ground-fault current usually increases at a higher rate as the fault is moved toward the relay. The technique of Fig. 5 may be used for any other conditions to determine the effectiveness of instantaneous overcurrent relaying, including the effect on fault-current magnitude because of changes in generation, etc.

The shaded area of Fig. 6 shows how much instantaneous overcurrent

relaying reduces the over-all relaying time for most faults. Even if such reduction is obtained only under maximum generating conditions, and if instantaneous relays were not even operable under minimum generating conditions, the use of supplementary instantaneous relays is considered to be worth while because they are relatively so inexpensive.

With instantaneous overcurrent relaying at both ends of a line, simultaneous tripping of both ends is obtained under maximum generating conditions for faults in the middle portion of the line. For

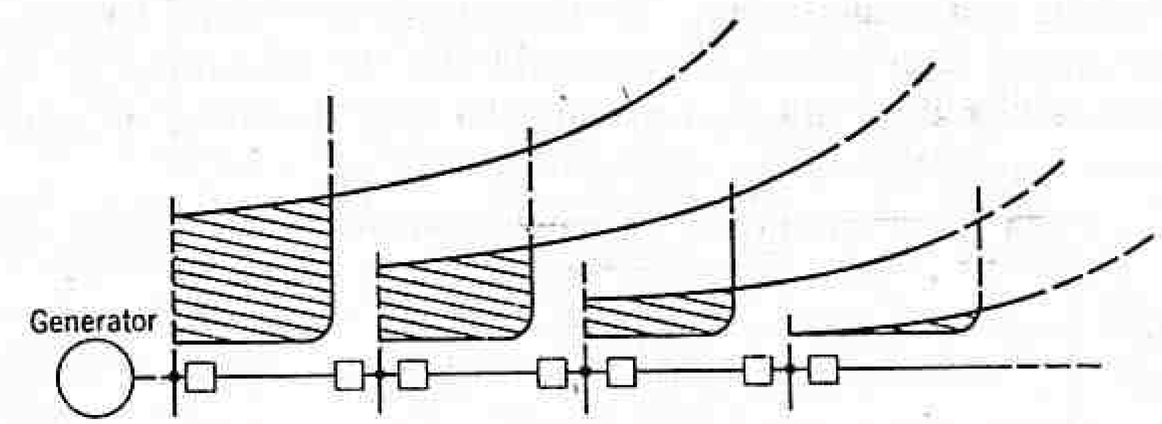

Fig. 6. Reduction in tripping time by the use of instantaneous overcurrent relays.

faults near the ends of the line, sequential instantaneous tripping will often occur, i.e., the end nearest the fault will trip instantly and then the magnitude of the current flowing to the fault from the other end will usually increase sufficiently to pick up the instantaneous overcurrent relays there.

When the magnitude of fault current depends only on the fault location, instantaneous overcurrent relaying is like distance relaying[6] except that the overcurrent relays cannot generally be as sensitive as distance relays.

AN INCIDENTAL ADVANTAGE OF INSTANTANEOUS OVERCURRENT RELAYING

A useful advantage that can sometimes be taken of instantaneous overcurrent relaying is illustrated in Fig. 7. Without instantaneous overcurrent relaying at breaker 2, the inverse-time-overcurrent relays at 1 would have the dashed time curve so as to obtain the selective time interval *ab* with respect to the inverse-time relays at breaker 2. With instantaneous overcurrent relays at 2, the inverse-time relays at 1 need only be selective with the inverse-time relays at 2 for faults at and beyond the point where the instantaneous relays stop operating, as shown by *cd*. This permits speeding up the relays at 1 from the dashed to the solid curve, which is sometimes very useful, or even necessary when complicated loop circuits are involved. Of course, under minimum generating conditions when the instantaneous relays may not operate, one must be sure that selectivity between

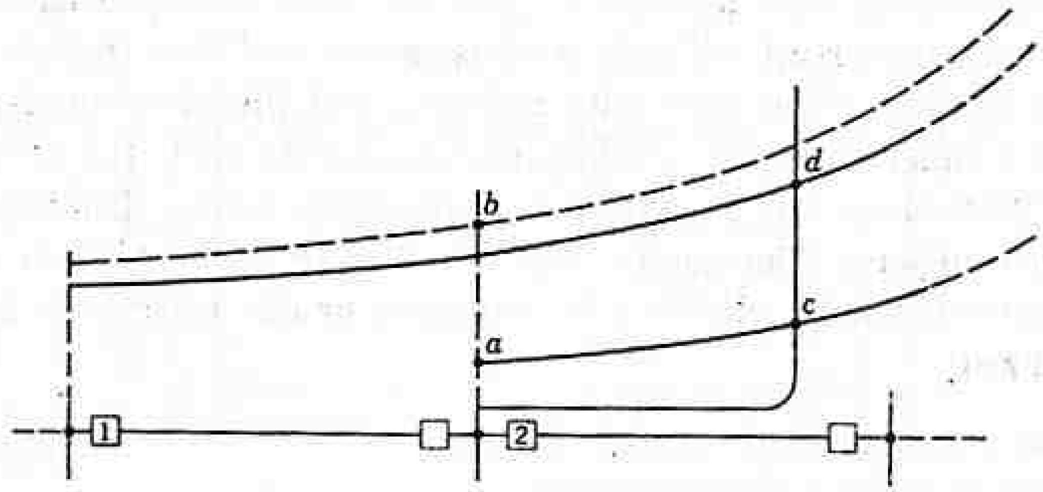

Fig. 7. Illustrating an additional advantage of instantaneous overcurrent relays.

the inverse-time relays is obtained. The fact that selectivity is not obtained between the inverse-time relays for faults just beyond the relay at 2 for maximum generating conditions is unimportant so long as selectivity is obtained down to the pickup current of the instantaneous relays.

OVERREACH OF INSTANTANEOUS OVERCURRENT RELAYS

"Overreach" is the tendency of a relay to pick up for faults farther away than one would expect if he neglected the effect of offset in the fault-current wave. Magnetic-attraction relays are more affected by offset waves than induction relays, and some induction relays are more affected than others. Certain induction relays can be designed to be unaffected by offset waves.

"Percent overreach" is a term that describes the degree to which the overreach tendency exists, and it has been defined as follows:

$$\text{Percent overreach} = 100\left(\frac{A - B}{A}\right)$$

where A = the relay's pickup current, in steady-state rms amperes.
B = the steady-state rms amperes which, when fully offset initially, will just pick up the relay.

In relays that have a tendency to overreach, the percent overreach increases as the ratio of reactance to resistance of the fault-current-limiting impedance increases, or, in other words, as the time constant of the d-c component of the fault current increases. The slower the

decay of the d-c component, the sooner will the integrated force acting on the relay cause it to pick up; and the sooner the relay tends to pick up, the lower may be the rms component of the fault current and still cause pickup. If the fault-current wave were continually fully offset, the rms component for pickup would be the smallest. It may be evident from the foregoing that, other things being equal, the faster a relay is, the greater will its percent overreach be. The maximum percent overreach would be 50% for a relay that was fast

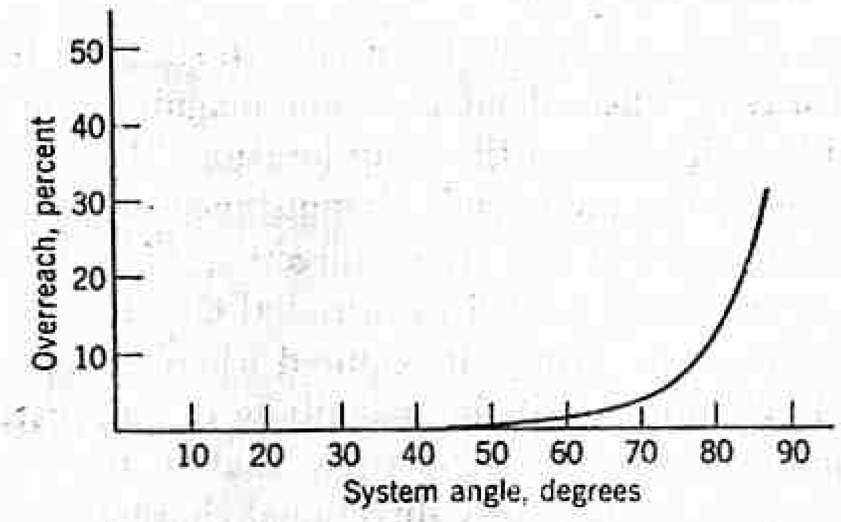

Fig. 8. Overreach characteristic of a certain instantaneous overcurrent relay.

enough to respond to the instantaneous magnitude of current. Since the rms value of a fully offset sine wave is $\sqrt{3}$ times that if the wave were symmetrical, the maximum value of percent overreach is 42% for relays that are not fast enough to respond to the instantaneous magnitude of current. Figure 8 shows how the percent overreach of a certain relay increases as the system angle ($\tan^{-1} X/R$) increases. Because X/R in a distribution circuit is only about 1 or 2, the tendency to overreach is negligible.

To allow accurately for overreach when choosing the pickup of an instantaneous overcurrent relay, one must have a percent-overreach curve for the relay, like that of Fig. 8. Then, solving the foregoing equation for A, we obtain:

$$A = \frac{100B}{(100 - \text{Percent overreach})}$$

Thus, with an overcurrent relay that has a 15% overreach for a fault whose steady-state component of current is 10 amperes, if the relay is not to operate for that fault, A must exceed:

$$\frac{100 \times 10}{100 - 15}\ \text{amperes} = 11.8\ \text{amperes}$$

When percent-overreach data are not available, it will usually be satisfactory to make the pickup about 25% higher than the maximum value of symmetrical fault current for which the relay must not operate. This will provide for overreach and also for some error in the data on which the setting is based.

The tendency of an instantaneous overcurrent relay to overreach on offset waves can be minimized by a so-called "transient shunt."[1] This device is described in Chapter 14 in connection with its use with distance relays for the same purpose.

THE DIRECTIONAL FEATURE

Overcurrent relaying is made directional to simplify the problem of obtaining selectivity when about the same magnitude of fault current can flow in either direction at the relay location. It would be impossible to obtain selectivity under such circumstances if overcurrent relays could trip their breakers for either direction of current flow. The directional feature is not needed for a radial circuit with a generating source at only one end. Nor is it required where short-circuit current can flow in either direction if the magnitude of current that can flow in the tripping direction is several times that in the other direction; here, the system has a sufficiently directional characteristic. However, it is best to install directional relays, even if the directional feature is not presently needed, because system changes are likely to make directional relays necessary.

All directional-overcurrent relays should have the directional-control feature, as described in Chapter 3, whereby the overcurrent unit cannot begin to operate until the directional unit operates for current flow in the direction for which the overcurrent unit should operate. Here, again, this feature is not always required, but need for it may develop in the near future.

Occasionally, voltage-restrained directional units are desirable for use with phase overcurrent relays. This need arises when the magnitude of fault current in the direction for which an overcurrent relay must trip its breaker can be about the same as—or even somewhat less than—the maximum load current that might flow in the same direction. Voltage-restrained directional units also minimize the likelihood of undesired tripping when severe power swings occur. Such directional units should also provide directional control.

The terms "directional-overcurrent" and "directional-ground," as applied to ground relays with directional characteristics, are used by some people to denote two different types of relays. The term "directional-overcurrent" denotes a relay with separate directional and overcurrent units, and the term "directional-ground" denotes a directional unit with adjustable pickup and time-delay characteristics that combines the directional and overcurrent functions. The directional-overcurrent type is generally preferred because, although it imposes somewhat more burden on its CT's and also takes up somewhat more panel space, it is much easier to adjust. This is because only the line-current magnitude affects its operation both as to sensitivity and time delay; its directional unit is so sensitive and fast that its effect may be ignored. The sensitivity and speed of the directional-ground type is a function of the product of the line current, the polarizing current or voltage, and the phase angle between them. The two types are not simply interchangeable, and it is best to standardize on one or the other and not to mix them in a system, or else selectivity may be jeopardized.

USE OF TWO VERSUS THREE RELAYS FOR PHASE-FAULT PROTECTION

The consideration of two versus three relays for phase-fault protection arises because of a desire to save the expense of one CT and one relay, or at least of one relay, in applications where only the bare minimum expense can be tolerated for the protection of a certain line. The considerations involved in such practices are as follows.

Non-Directional Relaying. Non-directional-overcurrent phase-fault relaying can be provided by two relays energized from CT's in two of the three phases. However, protection will not necessarily be provided if the CT's in all circuits are not located in the same phases, as illustrated in Fig. 9. The system shown in Fig. 9 is assumed to be ungrounded. Simultaneous ground faults on different phases of two different circuits will constitute a phase-to-phase fault on the system, and yet neither overcurrent relay will operate.

Whether the system neutral is grounded or not, complete protection against phase and ground faults, even in the situation of Fig. 9, is provided if three CT's are used with two phase relays and one ground relay as illustrated in Fig. 10.

If a wye-delta or a delta-wye power-transformer bank lies between the relays and a phase-to-phase fault, the magnitude of the current in one of the phases at the relay location will be twice as great as in either of the other two phases. If only two relays are used, neither relay will get this larger current for a fault between one pair of the three possible pairs of phases that may be faulted on the other side of the bank. This fact should be taken into account in choosing the pickup and time settings.

If the fault-current magnitude for a phase-to-phase fault is of the same order as the load current, the effect of load current adding to

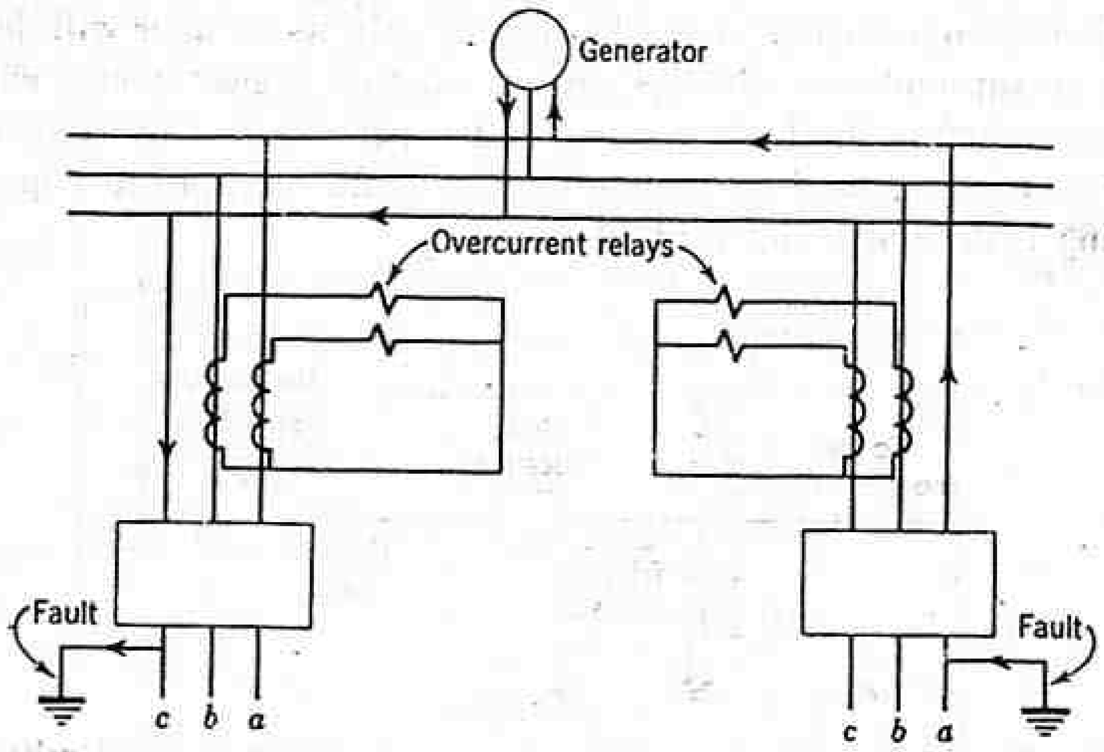

Fig. 9. A case of lack of protection with two overcurrent relays.

fault current in one phase and subtracting from it in another phase should be considered. This affects the pickup and time settings in a manner similar to that of an intervening power-transformer bank.

Three CT's and three phase relays are used wherever economically justifiable to avoid the foregoing difficulties because at least one relay will always operate for all interphase faults; and, except for the special conditions just described, two relays will operate, thereby giving double assurance of protection for much less than double the cost.

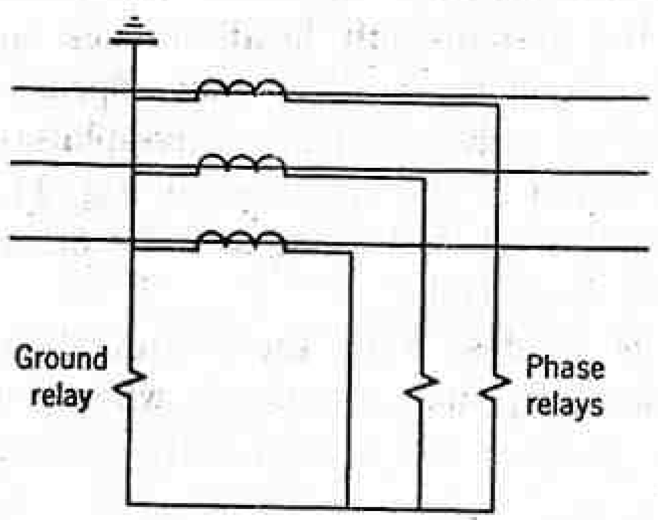

Fig. 10. Complete protection with two phase relays and one ground relay.

Directional Relaying. Directional-overcurrent phase-fault relaying is subject to the considerations described for non-directional-overcurrent relaying in so far as overcurrent units are concerned. In addition, there are the following considerations.

In a non-grounded system, two single-phase relays may generally be used if one is sure that the relays of all circuits are energized by

currents from the same phases. Otherwise, grounds could occur on different phases of two different circuits, as in Fig. 9, thereby imposing a phase-to-phase fault on the system, and no protection would be provided. Directional-overcurrent relays for ground-fault protection are not usable on non-grounded systems, and, therefore, they could not alleviate this possible difficulty in the same way that non-directional ground-overcurrent relays do.

If directional phase relaying is to be used in two phases of a grounded-neutral system, ground relays must be provided for protection against ground faults. Then, the only question is if one or the other of the two phase relays will always operate for a phase-to-phase fault in the tripping direction.

If the magnitude of fault current for phase-to-phase faults is not several times the load-current magnitude, three single-phase directional-overcurrent relays should be used to assure tripping when desired. However, this problem involves more than just the number of relays required; the relays may operate to trip undesirably as well as to fail to trip when desired. Therefore, not only are three relays necessary but also voltage restraint on the directional units to keep them from operating undesirably. If three relays were not required for other reasons, they would be required as soon as voltage restraint is used. (This is why it is never the practice to use only two distance relays.)

With only two directional-overcurrent relays, the quadrature connection should be used. This is the best assurance that one of the two relays will always operate under the borderline conditions existing when faults occur close to the relay location.

SINGLE-PHASE VERSUS POLYPHASE DIRECTIONAL-OVERCURRENT RELAYS

Single-phase directional-overcurrent relays are generally preferred for protection against interphase faults. The main reason for this is that the very desirable feature of "directional control" is more simply and reliably obtained with single-phase directional-overcurrent relays than with a polyphase directional relay in combination with single-phase overcurrent relays. The directional-unit contact of a single-phase directional-overcurrent relay controls the operation of the overcurrent unit directly; an intermediate auxiliary relay is required when a polyphase directional unit is used.

Single-phase directional-overcurrent relays must be used when a-c tripping is involved, because separate contacts must be available for connection in each of the three CT secondary circuits. An auxiliary

14 LINE PROTECTION WITH DISTANCE RELAYS

Distance relaying should be considered when overcurrent relaying is too slow or is not selective. Distance relays are generally used for phase-fault primary and back-up protection on subtransmission lines, and on transmission lines where high-speed automatic reclosing is not necessary to maintain stability and where the short time delay for end-zone faults can be tolerated. Overcurrent relays have been used generally for ground-fault primary and back-up protection, but there is a growing trend toward distance relays for ground faults also.

Single-step distance relays are used for phase-fault back-up protection at the terminals of generators, as described in Chapter 10. Also, single-step distance relays might be used with advantage for back-up protection at power-transformer banks, but at the present such protection is generally provided by inverse-time overcurrent relays.

Distance relays are preferred to overcurrent relays because they are not nearly so much affected by changes in short-circuit-current magnitude as overcurrent relays are, and, hence, are much less affected by changes in generating capacity and in system configuration. This is because, as described in Chapter 9, distance relays achieve selectivity on the basis of impedance rather than current.

THE CHOICE BETWEEN IMPEDANCE, REACTANCE, OR MHO

Because ground resistance can be so variable, a ground distance relay must be practically unaffected by large variations in fault resistance. Consequently, reactance relays are generally preferred for ground relaying.

For phase-fault relaying, each type has certain advantages and disadvantages. For very short line sections, the reactance type is preferred for the reason that more of the line can be protected at high speed. This is because the reactance relay is practically un-

affected by arc resistance which may be large compared with the line impedance, as described elsewhere in this chapter. On the other hand, reactance-type distance relays at certain locations in a system are the most likely to operate undesirably on severe synchronizing-power surges unless additional relay equipment is provided to prevent such operation.

The mho type is best suited for phase-fault relaying for longer lines, and particularly where severe synchronizing-power surges may occur. It is the least likely to require additional equipment to prevent tripping on synchronizing-power surges.[1] When mho relaying is adjusted to protect any given line section, its operating characteristic encloses the least space on the R-X diagram, which means that it will be least affected by abnormal system conditions other than line faults; in other words, it is the most selective of all distance relays. Because the mho relay is affected by arc resistance more than any other type, it is applied to longer lines. The fact that it combines both the directional and the distance-measuring functions in one unit with one contact makes it very reliable.

The impedance relay is better suited for phase-fault relaying for lines of moderate length than for either very short or very long lines. Arcs affect an impedance relay more than a reactance relay but less than a mho relay. Synchronizing-power surges affect an impedance relay less than a reactance relay but more than a mho relay. If an impedance-relay characteristic is offset, so as to make it a modified-impedance relay, it can be made to resemble either a reactance relay or a mho relay but it will always require a separate directional unit.

There is no sharp dividing line between areas of application where one or another type of distance relay is best suited. Actually, there is much overlapping of these areas. Also, changes that are made in systems, such as the addition of terminals to a line, can change the type of relay best suited to a particular location. Consequently, to realize the fullest capabilities of distance relaying, one should use the type best suited for each application. In some cases much better selectivity can be obtained between relays of the same type, but, if relays are used that are best suited to each line, different types on adjacent lines have no appreciable adverse effect on selectivity.

THE ADJUSTMENT OF DISTANCE RELAYS

Chapter 9 shows that phase distance relays are adjusted on the basis of the positive-phase-sequence impedance between the relay location and the fault location beyond which operation of a given relay unit should stop. Ground distance relays are adjusted in the objectionable also because less of the line will be protected at high speed, but it can be tolerated if necessary.

When a single line terminates in a power transformer with a low-voltage generating source, transformer-drop compensation offers no benefit unless it is so accurate that more than 90% of the transformer drop can be safely compensated, which is not apt to be the case. In practice compensation is not used, but the reach of the distance relays is adjusted for 80% to 90% of the sum of the transformer impedance plus the line impedance. Thus, if we adjust for 90%,

$$R = 0.9(Z_T + Z_L)$$

The amount of the line (R_L) that is protected with this reach is:

$$\begin{aligned} R_L &= 0.9(Z_T + Z_L) - Z_T \\ &= 0.9Z_L - 0.1Z_T \end{aligned}$$

If low-tension voltage is to be obtained from one low-tension side of a three-winding power-transformer bank having generating sources on both low-tension sides, it becomes necessary to use two sets of transformer-drop compensators. The details of this application are presented in Reference 9.

It will probably be evident from the foregoing that low-tension voltage for distance relays is an inferior alternative to high-tension voltage.[10] It will not permit the full capabilities of the relays to be realized, and, unless great care is taken in the adjustment of the equipment, it may even cause faulty operation.

USE OF LOW-TENSION CURRENT

Where a suitable current-transformer source of current for distance relays is not available in the high-voltage circuit to be protected, a source on the low-voltage side of an intervening power-transformer bank may be used. This practice is usually followed for external-fault back-up relays of unit generator-transformer arrangements. Low-tension current may infrequently be used where a line terminates in a power-transformer bank with no high-voltage breaker. In either of such circumstances, the possibility of losing the current source is not a consideration, as with a low-tension-voltage source, because the current source is not needed when the transformer bank is out of service.

When low-tension current is used where a line terminates in a transformer bank without a high-voltage breaker, it is theoretically possible that occasionally the distance relays might operate undesirably on magnetizing-current inrush. If such operation is possible, it can be avoided, if desired, by the addition of supplementary equipment that will open the trip circuit during the inrush period; such equipment uses the harmonic components of the inrush current in a manner similar to that of the harmonic-current-restraint relay described in Chapter 11 for power-transformer protection. However, there is really no need for concern. The probability of getting enough inrush current to operate a distance relay is quite low. In those infrequent cases in which a distance relay does operate to trip the transformer breaker, one may merely reclose the breaker and it probably will not trip again; this is permissible so long as the transformer-differential relay has not operated. As mentioned in Chapter 11, tripping on magnetizing-current inrush is objectionable only because one cannot be sure if it was actually an inrush or a fault that caused tripping; but, if the transformer-differential relay has not operated, one can be sure that it was not a transformer fault.

To use low-tension current, it is necessary to supply the relays with the same current components as when high-tension current is used. It will be seen from Chapter 9 that phase distance relays use the difference between the currents of the phases from which their voltage is obtained. (When high-tension current is used, this phase-difference —or so-called "delta"—current is obtained either by connecting the high-voltage CT's in delta or by providing two current coils on the magnetic circuits of each relay and passing the two phase currents through these coils in opposite directions. The two-coil type of relay has the advantage of permitting the CT's to be connected in wye; this is preferred because it avoids auxiliary CT's when the wye connection is needed for ground relaying.)

Figure 13 shows the current connections for one of the three distance relays used for inter-phase-fault protection; these connections are for a two-coil type of relay that uses the high-tension voltage V_{ab}. The connections A are the connections if high-tension CT's are available, and B and C are alternative low-tension connections. The power transformer is assumed to have the standard connections described in Chapter 8 for the voltage phase sequence a-b-c. The terminals of the two coils are labeled for each connection so that the three connections can be related. If we assume that each relay coil has N turns, the ampere-turns for each connection are as in the accompanying table. The significant thing about the three ampere-

Connection	Ampere-Turns
A	$(I_a - I_b)N$
B	$3(I_a - I_b)N$
C	$2(I_a - I_b)N$

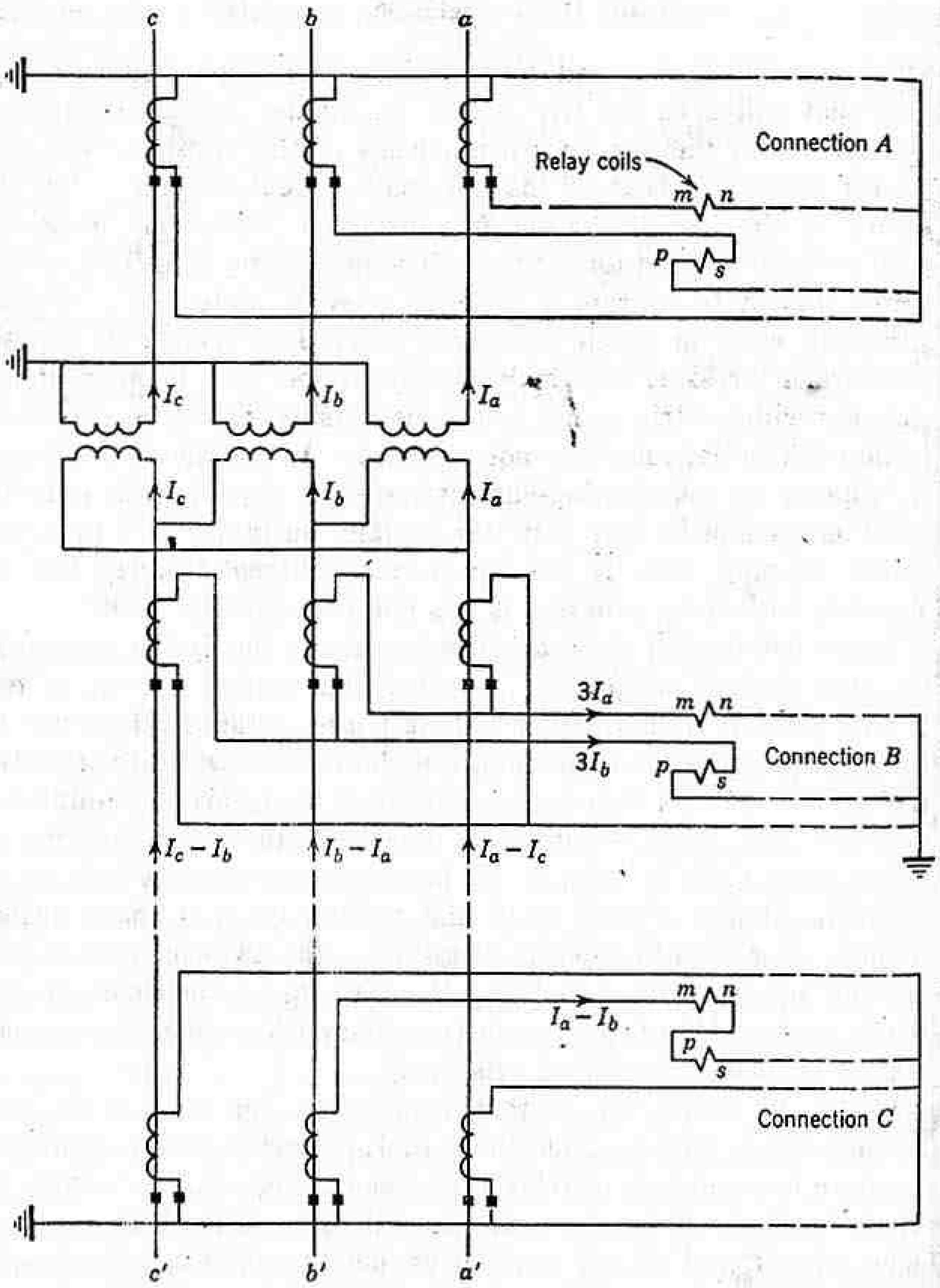

Fig. 13. Low-tension-current connections for a two-coil distance relay.

turns expressions is that all of them contain $(I_a - I_b)$ as required for proper distance measurement. That the ampere-turns of B and C are, respectively, 3 times and 2 times those of A is merely a consequence of the unity transformation ratios assumed for the power transformer and the CT's. However, connection C is different from the other two in that, if balanced three-phase currents of the same

magnitude are supplied to the terminals of relays connected as in A (or B) and C, the ampere-turns of the relays of C will be $2/\sqrt{3}$ times the ampere-turns of the relays of A (or B). Since the adjustment procedure for such relays is usually given for the connections of A, the difference in ampere-turns can be taken care of by assuming that

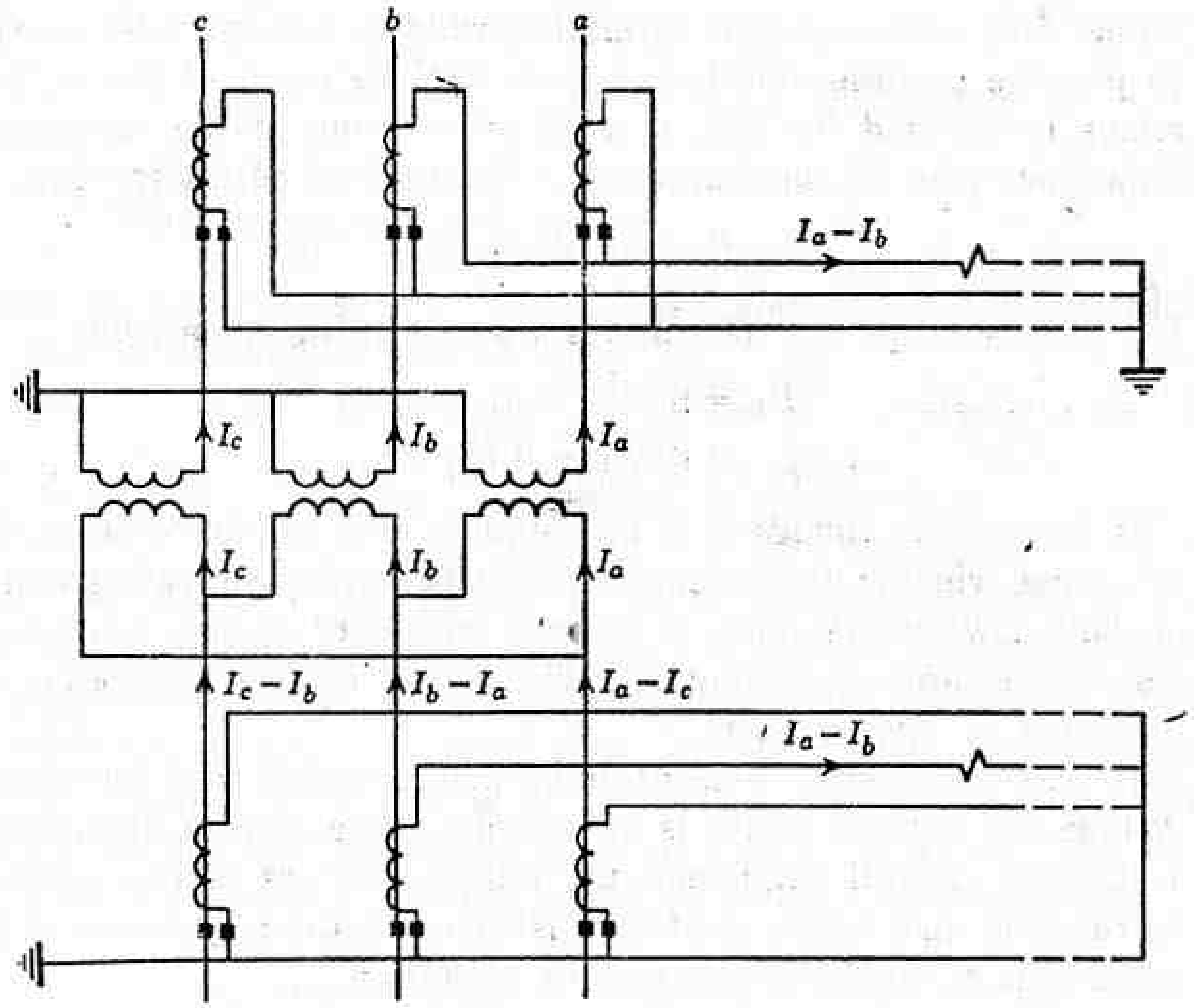

Fig. 14. Low-tension-current connections for a single-coil distance relay.

the magnitude of the current supplied to C is $2/\sqrt{3}$ times that supplied to A, or, in other words, that the CT ratio for C is $\sqrt{3}/2$—or 87%—of its actual value. The actual CT ratio for any connection is the ratio of the high-voltage-circuit phase-current magnitude to the relay phase-current magnitude under normal balanced three-phase conditions.

Figure 14 shows the high-tension and low-tension current connections for a single-coil type of distance relay. The CT ratio is the same as that defined in the preceding paragraph.

EFFECT OF POWER-TRANSFORMER MAGNETIZING-CURRENT INRUSH ON DISTANCE-RELAY OPERATION

The effect of power-transformer magnetizing-current inrush on distance-relay operation is also discussed under the heading "Use of

Low-Tension Current." It is the purpose here to consider the case of inrush to the HV windings of the transformers at the far end or ends of a line.

The writer does not know of any cases of tests, theoretical studies, or actual trouble in this respect. Therefore, it is concluded that, if the possibility of distance-relay misoperation exists, it must be extremely remote. The most severe inrush that can occur in existing conventional power transformers would be less likely to operate a distance relay than would a three-phase fault on the other side of the transformer bank. This is because the rms magnitude of the initial inrush current is generally less than that of the fault current. Furthermore, the inrush contains harmonic currents to which certain relays do not respond as well as to the fundamental components. The high-speed zone of a distance relay is not permitted to reach through transformers at the far ends of a line, and, therefore, if any relay unit is to operate it would have to be either the second- or third-zone unit. These units generally have enough time delay so that the inrush will have subsided considerably before a unit could operate, which further lessens the likelihood of their operation. And, finally, the distance relays in question will usually get only a part of the inrush current in those cases in which misoperation would be most objectionable, such as when energizing a transformer bank tapped to an important line. Therefore, there is little wonder that this subject is not cause for concern.

THE CONNECTIONS OF GROUND DISTANCE RELAYS

Reference 11 shows that for accurate distance measurement, a ground relay may be supplied with a phase-to-neutral voltage and the sum of the corresponding phase current and an amount proportional to the zero-phase-sequence current. If there is another line nearby that can induce voltage in the line under consideration when a ground fault occurs anywhere, there must also be added to the phase current an amount proportional to the zero-phase-sequence current of the other line. The addition of these zero-phase-sequence-current quantities is called "current compensation." Reference 11 also describes an alternative to current compensation called "voltage compensation," whereby the voltage is compensated by zero-phase-sequence-voltage quantities. Compensation is necessary because variations in the distribution of zero-phase-sequence current relative to the distribution of positive- and negative-phase-sequence current would otherwise cause objectionable errors in distance measurement.

Ground distance relays can also be energized by zero-phase-sequence-

voltage drop and zero-phase-sequence current to measure distance by measuring the zero-phase-sequence impedance.[12]

OPERATION WHEN PT FUSES BLOW

Distance relays that are capable of operating on less than normal load current may operate to trip their breaker when a potential-transformer fuse blows. In one system, blown fuses caused more undesired tripping than any other thing until suitable fusing was provided.[13]

Since potential transformers are generally energized from a bus and supply voltage to the relays of several lines, it is advisable to provide separate voltage circuits for the relays of each line and to fuse them separately if fusing is to be used at all. With separate fusing, trouble in the circuit of one set of relays will not blow the fuses of another circuit. The principal objection to bus PT's is that "all the eggs are in one basket"; but, with separately fused circuits, this objection is largely eliminated.

Neon lamps should be used for pilot indication of the voltage supply to each set of distance relays.

When the relays do not have to operate on less than load current, instantaneous overcurrent units can be used to prevent tripping for a blown fuse during normal load conditions. The overcurrent-relay contacts are in series with the trip circuit. Undesired tripping is still possible should a fault occur before the blown fuse has been replaced; it is to minimize this possibility that the indicating lamps are recommended. If the ground-fault current is high enough, a single set of three instantaneous overcurrent relays can be used separately from the distance relays to prevent undesired tripping by either the phase or ground relays; otherwise, a single ground overcurrent relay would be used for the ground relays.

PURPOSEFUL TRIPPING ON LOSS OF SYNCHRONISM

When generators have gone out of synchronism, all ties between them should be opened to maintain service and to permit the generators to be resynchronized. The separation should be made only at such locations that the generating capacity and the loads on either side of the point of separation will be evenly matched so that there will be no interruption to the service.[14] Distance relays at those locations are sometimes suitable for tripping their breakers on loss of synchronism, and in some systems they are used for this purpose in addition to their usual protective functions. However, as mentioned in Chapter 9, additions or removals of generators or lines during normal operation will often change the response of certain distance relays to loss of synchronism. Therefore, each application should be examined to see if certain distance relays can always be relied on to trip.

A completely reliable method of tripping at preselected locations is available.[15] This relaying equipment contains two angle-impedance units as described in Chapter 4, an overcurrent unit, and several auxiliary relays. It is a single-phase equipment, which is all that is necessary because loss of synchronism is a balanced three-phase phenomenon. The two angle-impedance units use the same one of the three combinations of current and voltage used by phase distance relays for short-circuit protection. Figure 15 shows the operating

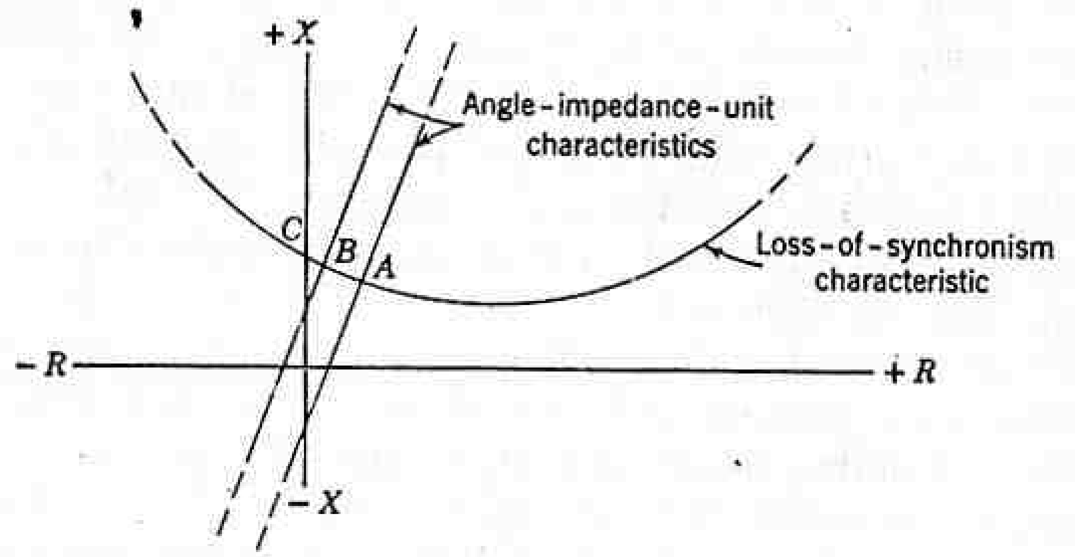

Fig. 15. Relay for tripping on loss of synchronism.

characteristics of the two angle-impedance units on an R-X diagram, together with a loss-of-synchronism characteristic for the relay's location on a tie line connecting the generators that have lost synchronism. The significant feature of the equipment is that the two angle-impedance units divide the diagram into the three regions A, B, and C. As the impedance changes during loss of synchronism, the point representing this impedance moves along the loss-of-synchronism characteristic from region A into B and then into C, or from C into B and then into A, depending on which generators are running the faster. As the point crosses the operating characteristic of an angle-impedance unit, the unit reverses its direction of torque and closes a contact to pick up an auxiliary relay. As the impedance point moves into one region after another, a chain of auxiliary relays picks up, one after the other. When the third region is entered, the last auxiliary relay of the chain picks up and trips its breaker. There are two such chains—one for each direction of movement—and the

contacts of the two last auxiliary relays of the chains are connected in parallel so that either one can trip the breaker.

The purpose of the overcurrent unit is to prevent tripping during hunting between the generators at light load. This condition is represented by movement along a portion of the loss-of-synchronism characteristic diametrically opposite to the portion shown in Fig. 15. Such movement would also fulfill the requirements for tripping that have been described. Relatively very little current flows during hunting at light load compared with the high current flowing when generators pass through the 180° out-of-phase position which is in the B region on the portion of the loss-of-synchronism characteristic shown in Fig. 15. Therefore, the overcurrent unit's pickup can be adjusted so that the equipment will select between hunting and loss of synchronism.

No other condition can cause the impedance point to move successively through the three regions, and therefore the equipment is completely selective.

Changes in a system cannot cause the equipment to fail so long as there is enough current to operate the overcurrent unit when synchronism is lost. The loss-of-synchronism characteristic may shift up or down on the R-X diagram, or the characteristic may change from one of overexcitation to one of underexcitation, without adversely affecting the operation of the equipment.

When tripping is desired at a location where the current is too low to actuate a loss-of-synchronism relay, remote tripping is necessary over a suitable pilot channel from a location where a loss-of-synchronism relay can be actuated.[16]

When two or more loss-of-synchronism relays are used at different locations, one or more of these relays may need a supplementary single-step distance unit because the overcurrent units may not provide the desired additional selectivity.

The locations where tripping is desired on loss of synchronism may change from time to time as the relations between load and generation change. Under such circumstances, it is desirable to have installations of loss-of-synchronism-relay equipments at several locations so that the load dispatcher can select the equipments to be made operative during any period.

In lieu of complete freedom to choose the best locations to separate parts of a system when synchronism is lost, it may be necessary to resort to some automatic "load shedding." By such means, non-essential load can be dropped automatically either directly when the tie breakers are tripped or indirectly through the operation of relays such as the underfrequency type. This subject is treated in detail in Reference 24 of Chapter 13.

BLOCKING TRIPPING ON LOSS OF SYNCHRONISM

Tripping at certain locations is required when generators lose synchronism, but it should be limited to those locations only. If distance relays at any other locations have a tendency to trip, supplementary relaying equipment should be used to block tripping there. Also, wherever tripping can occur during severe power swings when a system is recovering from the effects of a shock, such as that caused

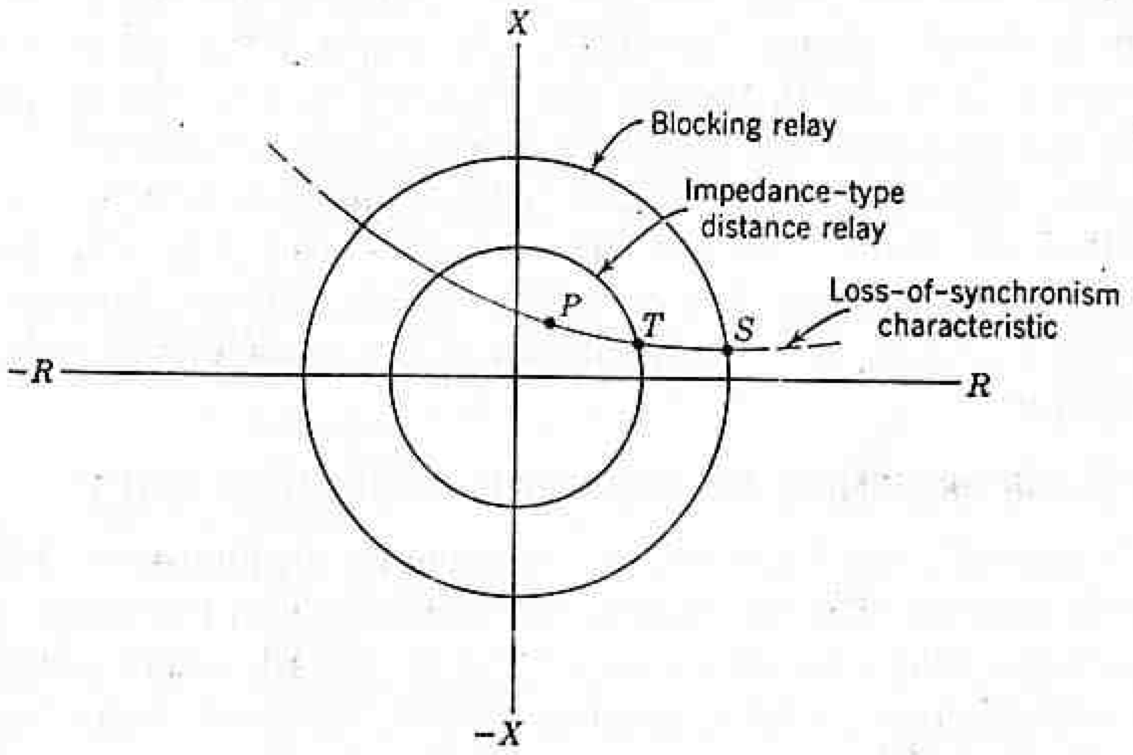

Fig. 16. Relay characteristics of equipment of Fig. 17.

by a short circuit, equipment to block tripping is most desirable; tripping a sound line that is carrying synchronizing power would very likely cause instability.

The method by which tripping on loss of synchronism can be blocked is very ingenious.[17] Consider the R-X diagram of Fig. 16. The point P represents the impedance for a three-phase fault well within the operating characteristic of an impedance-type distance relay. Assuming that the loss-of-synchronism characteristic passes through P, the problem, then, is to devise a selective relaying equipment that will permit tripping when the fault represented by P occurs, but not when loss of synchronism reaches a stage that is also represented by P. The way in which this selection is made is based on the fact that the change in impedance from the operating conditions just before the fault is instantaneous, whereas the change in impedance during loss of synchronism is relatively slow. The method used for recognizing this difference is to encircle the distance-relay characteristic with a blocking-relay characteristic such as that shown on Fig. 16. (For balanced three-phase conditions, such as those during loss of synchronism, all three phase distance relays see the same impedance; therefore, the one characteristic represents all three relays.) Then, a control circuit is provided so that, if the blocking relay operates sufficiently ahead of a distance relay, as when the impedance is changing from S to T, the distance-relay trip circuit will be opened. But, if the impedance changes instantly to any value such as P inside the distance-relay characteristic, the trip circuit will not be opened.

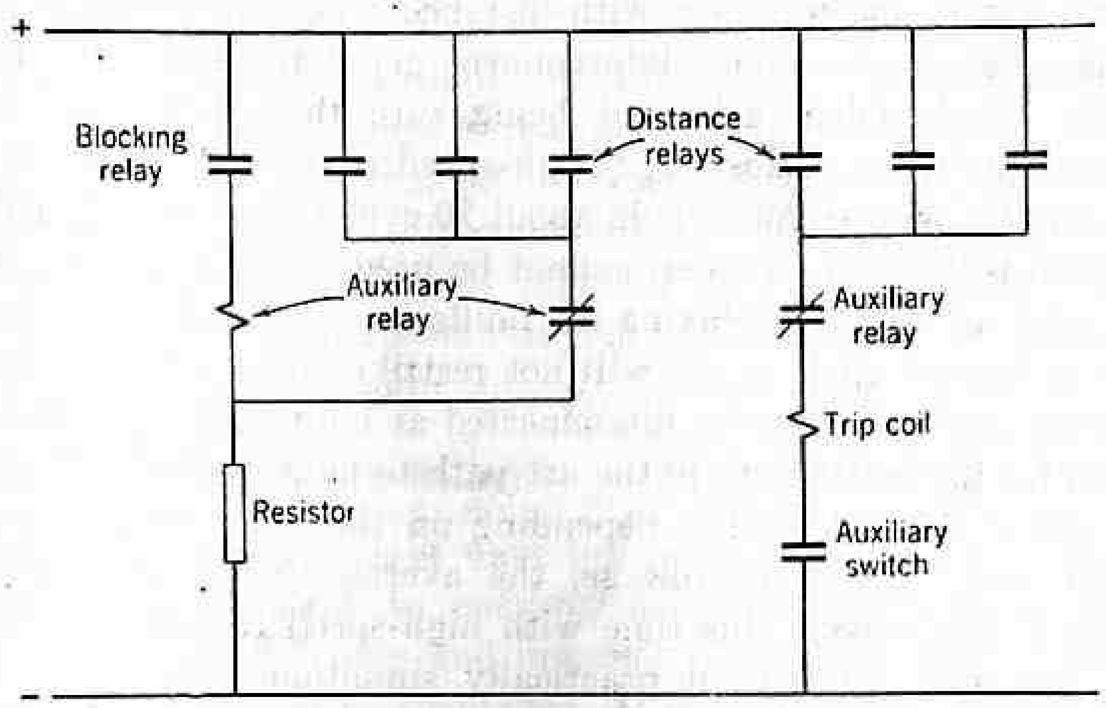

Fig. 17. Equipment for blocking tripping on loss of synchronism.

The circuit for blocking tripping is shown in Fig. 17. If the blocking relay closes its contact to energize the coil of the auxiliary relay before any distance relay closes its contact to short out the auxiliary-relay coil, the auxiliary relay will pick up and open its contact in the trip circuit. The subsequent closing of a distance-relay contact in the circuit around the auxiliary-relay coil will be ineffective because the auxiliary relay will have opened its contact in this circuit. The auxiliary relay is given a little time delay to pick up so as to be sure that it will not pick up when a fault occurs requiring tripping, and the distance and blocking relays close contacts practically together.

The blocking relay may be an impedance type or a mho type so long as its characteristic encircles the characteristic of the distance relays whose tripping is to be blocked. In practice the blocking relay is single phase. At one time, some considered three blocking relays necessary because a fault might still be on the system when blocking was required. Today, this is thought to be an unnecessary complication because of the general use of relatively high-speed relays. A single-phase blocking relay is permissible because loss of synchronism is a balanced three-phase phenomenon. The blocking relay uses the same voltage-and-current combination as one of the phase distance relays. Ground distance relays using phase-to-neutral voltage and compensated phase current could also tend to trip, and, therefore, their tripping should also be blocked.

AUTOMATIC RECLOSING

Chapter 13 introduces the subject of automatic reclosing and describes the practices with overcurrent relaying. Here, we are concerned with the practices with distance relaying. Lines protected by distance relays usually interconnect generating sources. Consequently, the problem arises of being sure that both ends are in synchronism before reclosing. "High-speed reclosing," defined here as reclosing the breaker contacts in about 20 cycles after the trip coil was energized to trip the breaker, cannot be used because of the inherent time delay of distance relaying for faults near the ends of a line. In order to be sure that an arc will not restrike when reclosing the line breakers, the line has to be disconnected at both ends for a time long enough for the ionized gas in the arc path to be dispersed. This takes from about 6 to 16 cycles, depending on the magnitude of the arc current and the system voltage, the average being about 8 to 10 cycles.[18] To provide this time with high-speed reclosing, both ends of a line must be tripped practically simultaneously. Since, with distance relays, one end may trip 6 to 12 cycles or more ahead of the other, depending on the intermediate-time adjustment, this additional time must be added to the reclosing cycle. In other words, about the fastest permissible reclosing time with distance relays is 26 to 32 cycles or longer. The only exceptions are lines with wye-delta power transformers at both ends; there simultaneous high-speed tripping is possible.

Because of the foregoing reclosing times and also the fact that inverse-time-overcurrent relays are generally used for ground-fault protection, such lines require synchronism check, as described in Chapter 13. Of course, one end of a line can be reclosed without synchronism check. Synchronism check is unnecessary if there are enough other interconnections between the generating sources that the line interconnects so that one can be sure that both sides will always be in synchronism. Automatic reclosing can be very harmful if it causes the connection of parts of a system that are out of synchronism; this is known to have been the "last straw" that caused a major system shutdown.

It is usually the practice to provide one immediate (which is slower than high-speed) reclosure followed by 2 or 3 time-delay reclosures and then lockout if the fault persists.

When a line ends in a power-transformer bank with no high-voltage breaker, but with a grounding switch for remote tripping in the event of a transformer-bank fault, automatic reclosing of the remote breaker is affected. Some users adjust ground-distance relays' first-zone reach to 80% to 90% of the line (i.e., not to reach to the transformer) in order that the first-zone unit will not operate when the grounding switch is closed. Then, automatic reclosing is permitted only if a first-zone unit operates, thereby avoiding reclosing on the grounding switch and a transformer fault. If a three-phase grounding switch is used, the high-speed zone of the remote distance relays may be permitted to reach into the transformer bank; this will permit automatic reclosure on the grounding switch without harming the transformer, which may be permissible if the shock to the system is not too great.

EFFECT OF PRESENCE OF EXPULSION PROTECTIVE GAPS

It is generally necessary to delay tripping by the high-speed zone of distance relaying if a line is equipped with expulsion protective gaps. A minimum relay-operating time of 2 or 3 cycles is usually sufficient to prevent high-speed-relay tripping while an expulsion protective gap is functioning. This additional delay in the tripping time is provided by the addition of an auxiliary relay. The tripping circuit should be carried through the protective-relay contacts to avoid undesired tripping because of overtravel of the auxiliary relay.

EFFECT OF A SERIES CAPACITOR

A series capacitor can upset the basic premises on which the principles of distance and directional relaying are founded. These premises are (1) that the ratio of voltage to current at a relay location is a measure of the distance to a fault, and (2) that fault currents are approximately reversed in phase only for faults on opposite sides of a relay location. A series capacitor introduces a discontinuity in the ratio of voltage to current, and particularly in the reactance component of that ratio, as a fault is moved from the relay location toward and beyond a series capacitor. One can easily visualize the effect by plotting the impedance points on an R-X diagram. As a fault is moved from the relay side of the capacitor to the other side, the capacity reactance subtracts from the accumulated line reactance between the relay and the fault. As a consequence, the fault may appear to be much closer to the relay location or it may even have the appearance to some relays of being back of the relay location.

One way that series capacitors are used[19] minimizes their adverse effect on distance relays. A single capacitor bank is chosen to compensate no more than about half of the reactance of a given line section; if a higher degree of compensation is used, the capacitors are divided into two or more banks located at different places along a line. Also, a protective gap is provided across each capacitor bank, and this gap flashes over immediately when a fault occurs and effectively shorts out the capacitor bank while fault current flows. In other words, the capacitor banks are in service normally, are shorted out while a fault exists, and are returned to service immediately when the faulty line section is tripped.

Where capacitors are located otherwise, it will probably be necessary to add slight time delay to the distance-relay trip circuit. For fault currents that are too low to flash over the capacitor gap, it may be necessary to use phase-comparison relaying, probably with greater-than-normal sensitivity.

COST-REDUCTION SCHEMES FOR DISTANCE RELAYING

Many ways have been suggested for reducing the cost of high-speed distance relaying so that its use on lower-voltage circuits could be justified. What has been sought is a "class of protection somewhere in the middle ground between the cost, performance, and complexity of overcurrent and conventional 3-zone distance relays."[20] These schemes may be classified as follows:

(*a*) Abbreviated relays.[20]

(*b*) Three conventional relays for phase faults and three conventional relays for ground faults, except that certain units are used in common.[21]

(*c*) Three conventional relays for both phase and ground faults by means of "current and voltage switching."[22]

(*d*) One conventional relay for phase faults and/or one conventional relay for ground faults by means of current and voltage switching.[12,23]

(*e*) One conventional relay for both phase and ground faults by means of current and voltage switching.[22]

Current and voltage switching is a means for automatically connecting the relay to the proper current and voltage sources so that it will measure distance correctly for any fault that occurs.

With the possible exception of (*e*), all these schemes are in use in this country, although none of them very extensively. The greater the departure from the conventional arrangement of three phase and three ground relays, the poorer is the quality of relaying. They either have more time delay, are harder to apply, are less accurate, or require more frequent maintenance. Voltage switching may not be permitted with capacitance potential devices because of the errors that result from changing the burden. It is probably economically feasible to standardize on one intermediate arrangement, but there is little justification for much more.

To complete the list, other combinations of units should be included, most of which may be classified as "abbreviated" relays. They consist of various combinations of units like those used in conventional high-speed relays.[7] Such relays supplement existing relays for speeding up the protection. For example, three single-step directional-distance relays might supplement directional-overcurrent inverse-time relays; this would provide high-speed relaying for 80% to 90% of a line plus inverse-time-overcurrent relaying for the remainder of the line and for back-up protection.

ELECTRONIC DISTANCE RELAYS

Electronic distance relays have been extensively tested[24] that are functionally equivalent to conventional electromechanical distance relays, but that are faster and impose considerably lower burden on a-c sources of current and voltage. At the same time, they are more shock resistant. Their greater speed is most effective when they are used in conjunction with a carrier-current or microwave pilot. When they are used alone, it is still necessary to have some time delay for faults near the ends of a line, which tends to reduce the advantage of a higher-speed first-zone unit.

The lower-burden characteristic of electronic relays may contribute to less expensive current and voltage transformers, and therefore may increase the use of such relays even though the greater speed may not be required.

Apart from differences in physical characteristics, the basic principles of electromechanical distance relays and their application apply equally well to electronic distance relays.

Problems

1. Referring to Fig. 18, it has been determined that load transfer from *A* to *B* or from *B* to *A* prevents setting a distance relay at either *A* or *B* with a

greater ohmic reach than just sufficient to protect a 100-ohm, 2-terminal line with a 25% margin (i.e., third-zone reach = 125 ohms).

a. What is the apparent impedance of the fault at X_1 to the relay at A? Can the relay at A see the fault before the breaker at B has tripped?

b. Can the relay at B see the fault at X_1 before the breaker at A has tripped? Why?

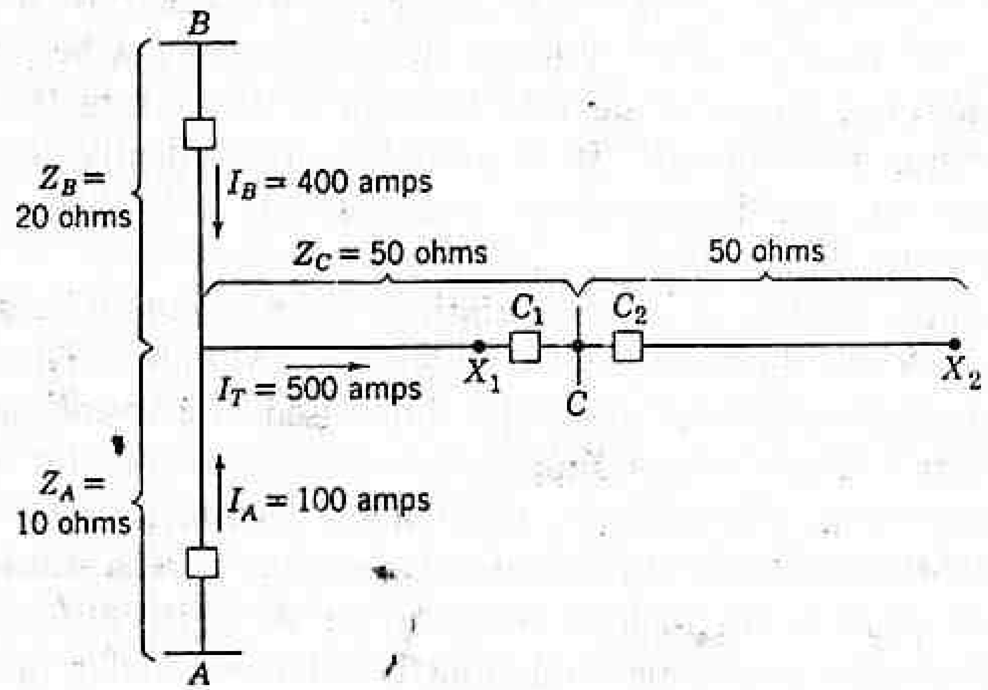

Fig. 18. Illustration for Problem 1.

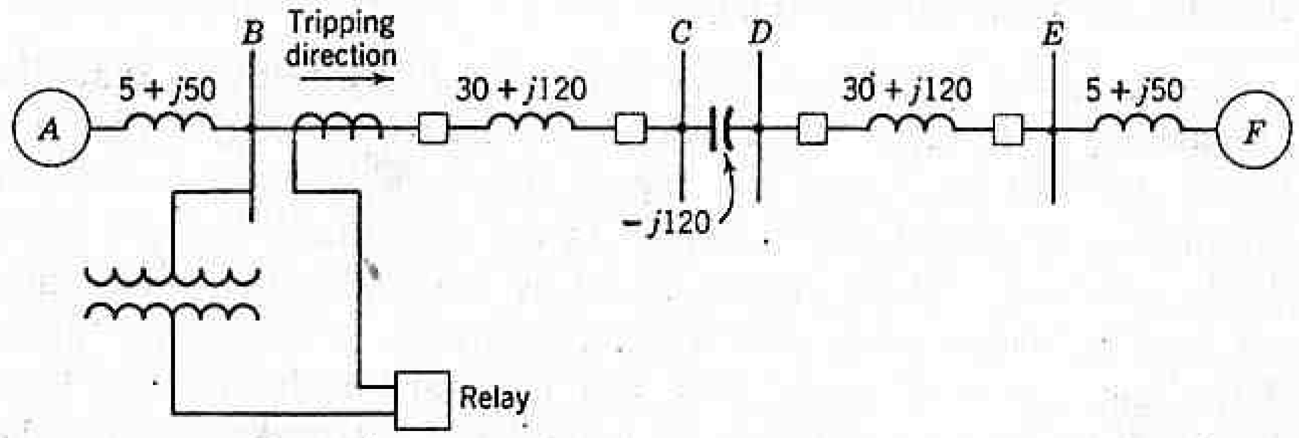

Fig. 19. Illustration for Problem 2.

c. If, for a fault at X_2, breaker C_2 fails to open, will the fault be cleared by relays at A and B? Assume the same relative fault-current magnitudes as for *a* and *b*.

d. By what means can the fault at X_2 be cleared?

2. Show the positive-phase-sequence impedances of the line sections and series capacitor of Fig. 19 on an R-X diagram as seen by phase distance relays at B, neglecting the effect of a protective gap across the capacitor. Comment on the use of distance and directional relays at B.

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23. "Distance Relay Protection for Subtransmission Lines Made Economical," by L. J. Audlin and A. R. van C. Warrington, *AIEE Trans.*, *62* (1943), pp. 574–578. Discussions, pp. 976–979.

24. "Field Experience—Electronic Mho Distance Relay," by H. C. Barnes and R. H. Macpherson, *AIEE Trans.*, *72*, Part III (1953), pp. 857–864. Discussions, p. 865.

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same way, although some types may respond to the zero-phase-sequence impedance. This impedance, or the corresponding distance, is called the "reach" of the relay or unit. For purposes of rough approximation, it is customary to assume an average positive-phase-sequence-reactance value of about 0.8 ohm per mile for open transmission-line construction, and to neglect resistance. Accurate data are available in textbooks devoted to power-system analysis.[2]

To convert primary impedance to a secondary value for use in adjusting a phase or ground distance relay, the following formula is used:

$$Z_{\text{sec}} = Z_{\text{pri}} \times \frac{\text{CT ratio}}{\text{VT ratio}}$$

where the CT ratio is the ratio of the high-voltage phase current to the relay phase current, and the VT ratio is the ratio of the high-voltage phase-to-phase voltage to the relay phase-to-phase voltage—all under balanced three-phase conditions. Thus. for a 50-mile, 138-kv line with 600/5 wye-connected CT's, the secondary positive-phase-sequence reactance is about $50 \times 0.8 \times \frac{600}{5} \times \frac{115}{138{,}000} = 4.00$ ohms.

It is the practice to adjust the first, or high-speed, zone of distance relays to reach to 80% to 90% of the length of a two-ended line or to 80% to 90% of the distance to the nearest terminal of a multi-terminal line. There is no time-delay adjustment for this unit.

The principal purpose of the second-zone unit of a distance relay is to provide protection for the rest of the line beyond the reach of the first-zone unit. It should be adjusted so that it will be able to operate even for arcing faults at the end of the line. To do this, the unit must reach beyond the end of the line. Even if arcing faults did not have to be considered, one would have to take into account an underreaching tendency because of the effect of intermediate current sources, and of errors in: (1) the data on which adjustments are based, (2) the current and voltage transformers, and (3) the relays. It is customary to try to have the second-zone unit reach to at least 20% of an adjoining line section; the farther this can be extended into the adjoining line section, the more leeway is allowed in the reach of the third-zone unit of the next line-section back that must be selective with this second-zone unit.

The *maximum* value of the second-zone reach also has a limit. Under conditions of maximum overreach, the second-zone reach should be short enough to be selective with the second-zone units of distance relays on the shortest adjoining line sections, as illustrated in Fig. 1.

Transient overreach need not be considered with relays having a high ratio of reset to pickup because the transient that causes overreach will have expired before the second-zone tripping time. However, if the ratio of reset to pickup is low, the second-zone unit must be set either (1) with a reach short enough so that its overreach will not extend beyond the reach of the first-zone unit of the adjoining line

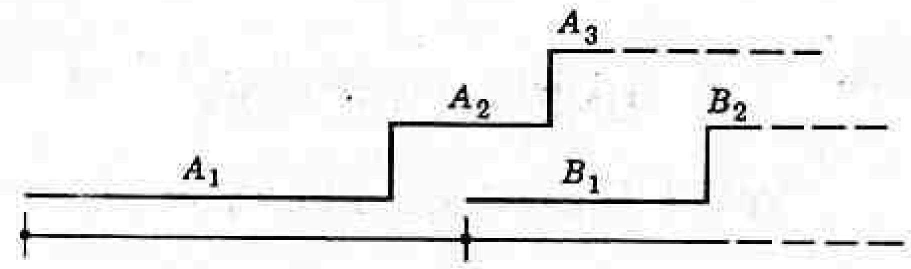

Fig. 1. Normal selectivity adjustment of second-zone unit.

section under the same conditions, or (2) with a time delay long enough to be selective with the second-zone time of the adjoining section, as shown in Fig. 2. In this connection, any underreaching tendencies of the relays on the adjoining line sections must be taken

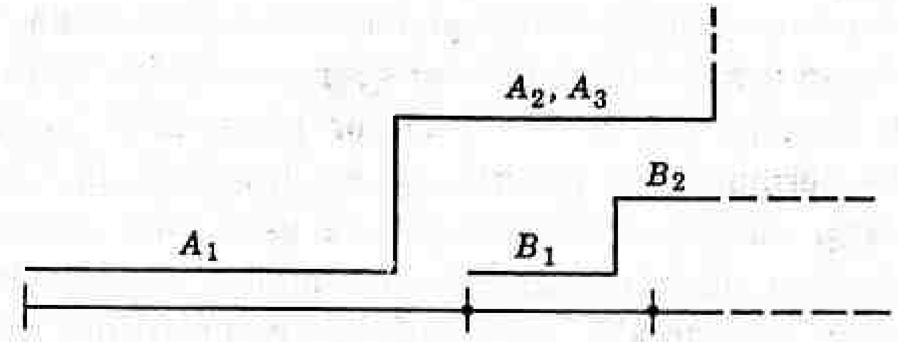

Fig. 2. Second-zone adjustment with additional time for selectivity with relay of a very short adjoining line section.

into account. When an adjoining line is so short that it is impossible to get the required selectivity on the basis of reach, it becomes necessary to increase the time delay, as illustrated in Fig. 2. Otherwise, the time delay of the second-zone unit should be long enough to provide selectivity with the slowest of (1) bus-differential relays of the bus at the other end of the line, (2) transformer-differential relays of transformers on the bus at the other end of the line, or (3) line relays of adjoining line sections. The interrupting time of the circuit breakers of these various elements will also affect the second-zone time. This second-zone time is normally about 0.2 second to 0.5 second.

The third-zone unit provides back-up protection for faults in adjoining line sections. So far as possible, its reach should extend beyond the end of the longest adjoining line section under the conditions that cause the maximum amount of underreach, namely, arcs

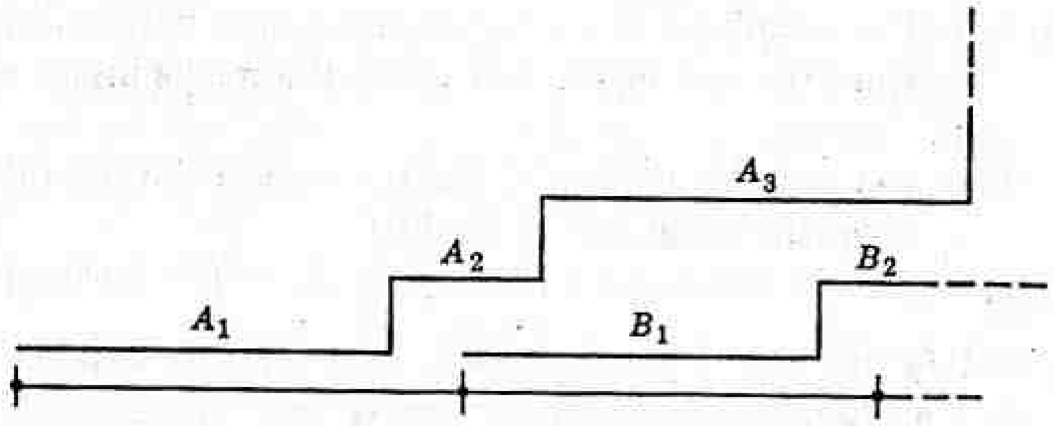

Fig. 3. Normal selectivity adjustment of third-zone unit.

and intermediate current sources. Figure 3 shows a normal back-up characteristic. The third-zone time delay is usually about 0.4 second to 1.0 second. To reach beyond the end of a long adjoining line and

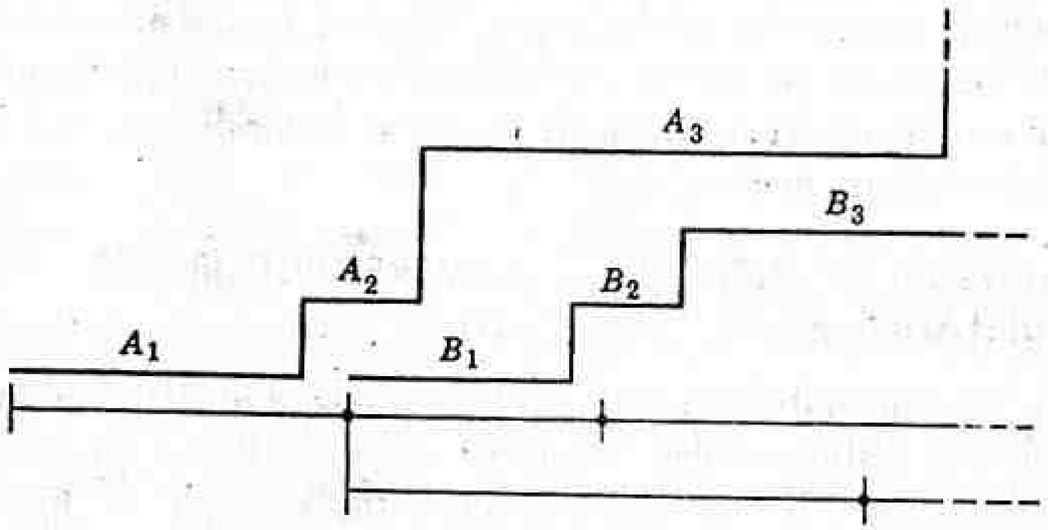

Fig. 4. Third-zone adjustment with additional time for selectivity with relay of a short adjoining line and to provide back-up protection for a long adjoining line.

still be selective with the relays of a short line, it may be necessary to get this selectivity with additional time delay, as in Fig. 4.

When conditions of Fig. 4 exist, the best solution is to use the type of back-up relaying described later under the heading "The Effect of Intermediate Current Sources on Distance-Relay Operation." Then, one has only the problem of adjusting the first- and second-zone units.

Under no circumstances should the reach of any unit be so long that the unit would operate for any load condition or would fail to reset for such a condition if it had previously operated for any reason. To determine how near a distance relay may be to operating under

a maximum load condition, in lieu of more accurate information, it is the practice to superimpose the relay's reset characteristic on an R-X diagram with the point representing the impedance when the equivalent generators either side of the relay location are 90° out of phase. This is done by the method described in Chapter 9 for drawing the loss-of-synchronism characteristic. Stability can be maintained with somewhat more than a 90° displacement, but 90° is nearly the limit and is easy to depict, as described in Chapter 9.

THE EFFECT OF ARCS ON DISTANCE-RELAY OPERATION

Chapter 9 shows the effect of fault or arc resistance on the appearance of different kinds of short circuits when plotted on an R-X diagram in terms of the voltages and currents used by distance relays. Chapter 13 gives data from which arc resistance can be estimated for plotting such fault characteristics on the R-X diagram. It is only necessary, then, to superimpose the characteristic of any distance relay in order to see what its response will be.

The critical arc location is just short of the point on a line at which a distance relay's operation changes from high-speed to intermediate time or from intermediate time to back-up time. We are concerned with the possibility that an arc within the high-speed zone will make the relay operate in intermediate time, that an arc within the intermediate zone will make the relay operate in back-up time, or that an arc within the back-up zone will prevent relay operation completely. In other words, the effect of an arc may be to cause a distance relay to underreach.

For an arc just short of the end of the first- or high-speed zone, it is the initial characteristic of the arc that concerns us. A distance relay's first-zone unit is so fast that, if the impedance is such that the unit can operate immediately when the arc is struck, it will do so before the arc can stretch appreciably and thereby increase its resistance. Therefore, we can calculate the arc characteristic for a length equal to the distance between conductors for phase-to-phase faults, or across an insulator string for phase-to-ground faults. On the other hand, for arcs in the intermediate-time or back-up zones, the effect of wind stretching the arc should be considered, and then the operating time for which the relay is adjusted has an important bearing on the outcome.

Tending to offset the longer time an arc has to stretch in the wind when it is in the intermediate or back-up zones is the fact that, the farther an arcing fault is from a relay, the less will its effect be on the relay's operation. In other words, the more line impedance there of no intermediate current source. Then, they will not overreach and operate undesirably. Of course, when current flows from an intermediate source, the relays will "underreach," i.e., they will not operate for faults as far away as one might desire, but this is to be preferred to overreach.

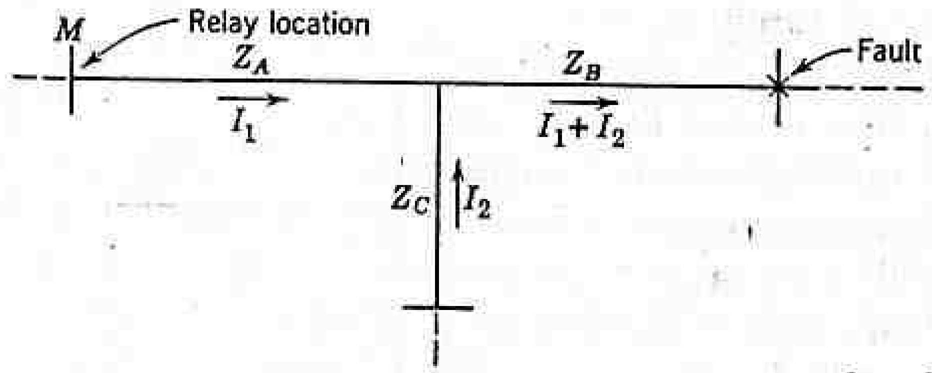

Fig. 6. Illustrating the effect of intermediate current sources on distance-relay operation.

Because of the effect of intermediate current sources, the full capabilities of distance relaying cannot be realized on multiterminal lines. It is the practice to adjust the high-speed zone of the relays at a given terminal to reach 80% to 90% of the distance to the nearest terminal, neglecting the effect of an intermediate current source. Thus, in Fig. 6, the maximum reach of the high-speed zone of the relays at M would be 80% to 90% of $Z_A + Z_B$ or of $Z_A + Z_C$, whichever was smaller. Neglecting the effect of an arc, if this maximum reach of the high-speed zone is less than Z_A, it will become evident that intermediate current cannot affect the high-speed-zone reach; if the maximum reach is greater than Z_A, intermediate current will cause the reach to approach Z_A as a minimum limit. If the second-zone reach is made to include double the impedance of the common branch, tripping will always be assured although it might be sequential.[4]

Back-up protection of the conventional type described in Chapter 1 is often impossible in the presence of intermediate current sources. In Fig. 7, consider the problem of adjusting relays at A to provide back-up for the fault location shown, in the event that breaker B fails to trip for any reason. The problem is similar whether inverse-time or distance relays are involved at A. The magnitude of the fault current flowing at A, or the impedance measured by a distance relay at A, may vary considerably, depending on the magnitude of fault current fed into the intermediate station from other sources. The range of such variations must be taken into account in determining the back-up adjustment. In some extreme cases, the apparent impedance between A and the fault may be such as to put the fault

beyond the reach of the relays at A. Obviously, this problem may apply also to the relays in the other lines except the faulted one.

A solution that has been resorted to, when a fault can be beyond the reach of conventional back-up relays, is to have the back-up unit of the relaying equipment of each line at the intermediate station operate a timer which, after a definite time, will energize a multicontact auxiliary tripping relay to trip all the breakers connected to the bus of the intermediate station.[5] Admittedly, this solution violates one of the fundamental principles of back-up protection by assuming that the failure to trip is owing only to failure in the

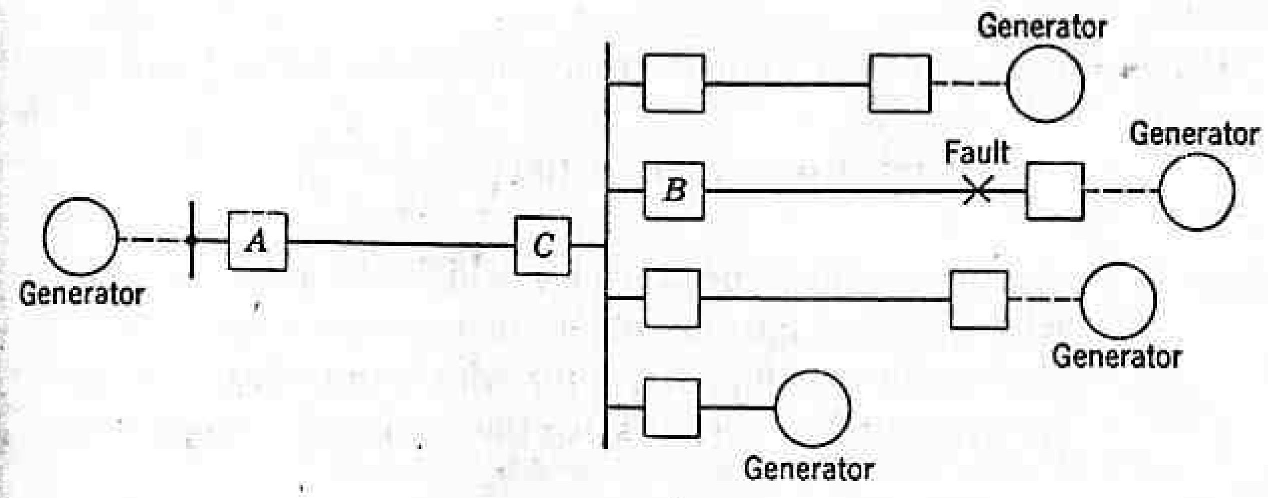

Fig. 7. A situation in which conventional back-up relaying is inadequate.

breaker or in the tripping circuit between the relay and the breaker; it assumes that the protective-relaying equipment or the source of tripping voltage will not fail. However, it is a practical solution, and it has been considered worth the risk. A more reliable arrangement is to use separate CT's and protective relays to energize the multicontact tripping relay, employing only the battery in common. It is also possible to have the back-up relay first try to trip the breaker of the faulty line before tripping all the other breakers.[5]

The back-up elements of mho-type distance relays can be made to operate for faults in the direction opposite to the conventional back-up direction. In fact, the reversed back-up direction, called "reversed third zone," is normally provided when mho-type distance relays are used with directional-comparison carrier-current-pilot relaying. This feature gives some relief in the problem of reaching far enough to provide back-up protection for adjoining line sections, since the back-up elements, being closer to these adjoining line sections, do not have to reach so far. Referring to Fig. 7, for example, if the back-up elements located at breaker C are arranged to operate for current flow toward the fault, their reach can be reduced by the distance is between the relay and the fault, the less change there will be in the total impedance when the arc resistance is added. On the other hand, the farther away an arc is, the higher its apparent resistance will be because the current contribution from the relay end of the line will be smaller, as considered later.

A small reduction in the high-speed-zone reach because of an arc is objectionable, but it can be tolerated if necessary. One can always use a reactance-type or modified-impedance-type distance relay to minimize such reduction.[3] The intermediate-zone reach must not be

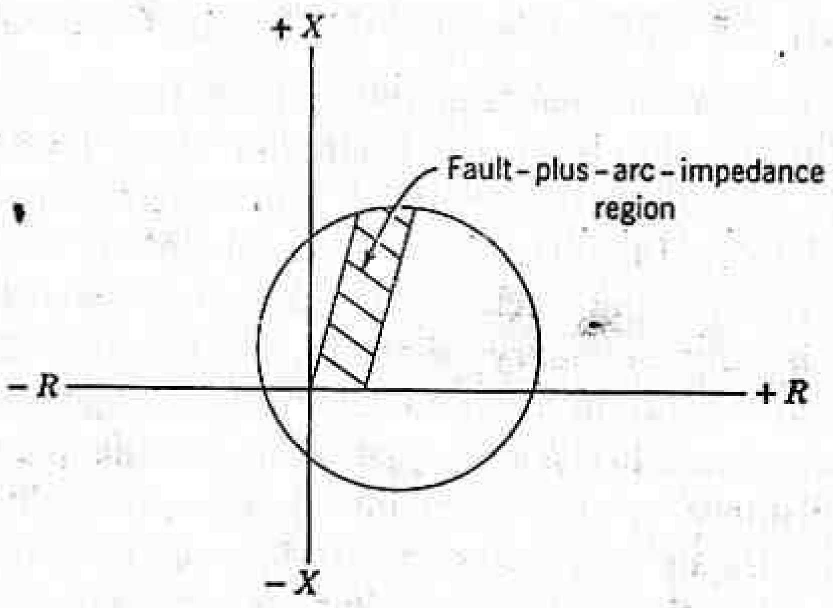

Fig. 5. Offsetting relay characteristic to minimize susceptibility to arcs.

reduced by an arc to the point at which relays of the next line back will not be selective; of course, they too will be affected by the arc, but not so much. Reactance-type or modified-impedance-type distance relays are useful here also for assuring the minimum reduction in second-zone reach. Figure 5 shows how an impedance or mho characteristic can be offset to minimize its susceptibility to an arc. One can also help the situation by making the second-zone reach as long as possible so that a certain amount of reach reduction by an arc is permissible. Conventional relays do not use the reactance unit for the back-up zone; instead, they use either an impedance unit, a modified-impedance unit, or a mho unit. If failure of the back-up unit to operate because of an arc extended by the wind is a problem, the modified-impedance unit can be used or the mho—or "starting"—unit characteristic can also be shifted to make its operation less affected by arc resistance. The low-reset characteristic of some types of distance relay is advantageous in preventing reset as the wind stretches out an arc.

Although an arc itself is practically all resistance, it may have a

capacitive-reactance or an inductive-reactance component when viewed from the end of a line where the relays are. The impedance of an arc (Z_A) has the appearance:

$$Z_A = \frac{(I_1 + I_2)}{I_1} R_A = R_A + \frac{I_2}{I_1} R_A$$

where I_1 = the complex expression for the current flowing into the arc from the end of the line where the relays under consideration are.

I_2 = the complex expression for the current flowing into the arc from the other end of the line.

R_A = the arc resistance with current $(I_1 + I_2)$ flowing into it.

If I_1 and I_2 are out of phase, Z_A will be a complex number. Therefore, even a reactance-type distance relay may be adversely affected by an arc. This effect is small, however, and is generally neglected.

Of more practical significance is the fact that, as shown by the equation, the arc resistance will appear to be higher than it actually is, and it may be very much higher. After the other end of the line trips, the arc resistance will be higher because the arc current will be lower. However, its appearance to the relays will no longer be magnified, because I_2 will be zero. Whether its resistance will appear to the relays to be higher or lower than before will depend on the relative and actual magnitudes of the currents before and after the distant breaker opens.

THE EFFECT OF INTERMEDIATE CURRENT SOURCES[4] ON DISTANCE-RELAY OPERATION

An "intermediate-current source" is a source of short-circuit current between a distance-relay location and a fault for which distance-relay operation is desired. Consider the example of Fig. 6. The true impedance to the fault is $Z_A + Z_B$, but, when the intermediate current I_2 flows, the impedance appears to the distance relays as $Z_A + Z_B + (I_2/I_1) Z_B$; in other words, the fault appears to be farther away because of the current I_2. This effect has been called the "mutual impedance" effect. It will be evident that, if I_1 and I_2 are out of phase, the impedance $(I_2/I_1) Z_B$ will have a different angle from Z_B.

If the distance relays are adjusted to operate for a fault at a given location when a given value of I_2 flows, they will operate for faults beyond that location for smaller values of I_2. Therefore, it is the practice to adjust distance relays to operate as desired on the basis of no intermediate current source. Then, they will not overreach and operate undesirably. Of course, when current flows from an intermediate source, the relays will "underreach," i.e., they will not operate for faults as far away as one might desire, but this is to be preferred to overreach.

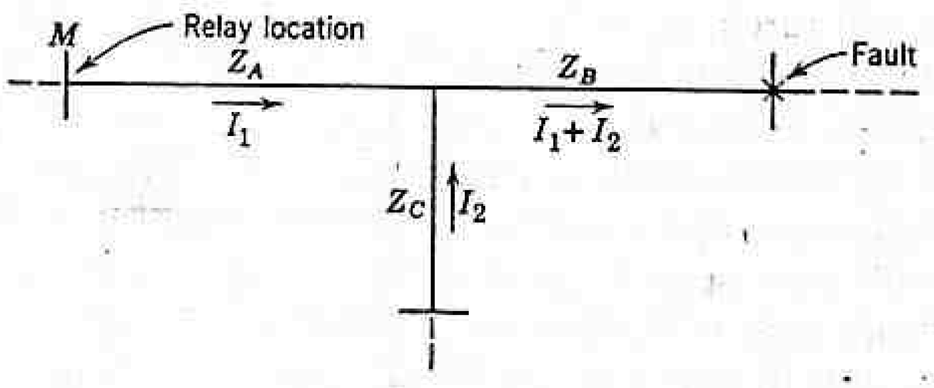

Fig. 6. Illustrating the effect of intermediate current sources on distance-relay operation.

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Back-up protection of the conventional type described in Chapter 1 is often impossible in the presence of intermediate current sources. In Fig. 7, consider the problem of adjusting relays at A to provide back-up for the fault location shown, in the event that breaker B fails to trip for any reason. The problem is similar whether inverse-time or distance relays are involved at A. The magnitude of the fault current flowing at A, or the impedance measured by a distance relay at A, may vary considerably, depending on the magnitude of fault current fed into the intermediate station from other sources. The range of such variations must be taken into account in determining the back-up adjustment. In some extreme cases, the apparent impedance between A and the fault may be such as to put the fault

beyond the reach of the relays at A. Obviously, this problem may apply also to the relays in the other lines except the faulted one.

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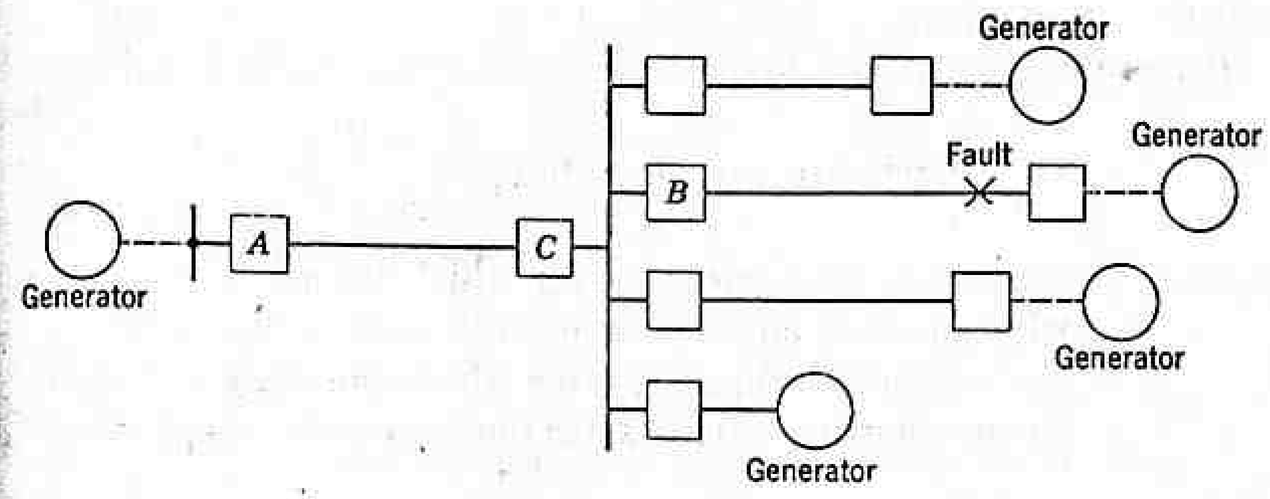

Fig. 7. A situation in which conventional back-up relaying is inadequate.

breaker or in the tripping circuit between the relay and the breaker; it assumes that the protective-relaying equipment or the source of tripping voltage will not fail. However, it is a practical solution, and it has been considered worth the risk. A more reliable arrangement is to use separate CT's and protective relays to energize the multicontact tripping relay, employing only the battery in common. It is also possible to have the back-up relay first try to trip the breaker of the faulty line before tripping all the other breakers.[5]

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Various other solutions have been resorted to, depending on how many different possibilities of failure one may wish to anticipate.[6]

OVERREACH BECAUSE OF OFFSET CURRENT WAVES

Distance relays have a tendency to overreach, similar to that described in Chapter 13 for overcurrent relays, when the fault current contains a d-c offset. Other things being equal, the tendency to overreach is greatest in magnetic-attraction types of distance relays, and particularly in the impedance type where the contact-closing torque is generated by current alone. The tendency is the least with induction-type relays.

"Percent overreach" for distance relays has been defined as follows:

$$\text{Percent overreach} = 100\left(\frac{Z_o - Z_s}{Z_s}\right)$$

where Z_o = the maximum impedance for which the relay will operate with an offset current wave, for a given adjustment.

Z_s = the maximum impedance for which the relay will operate for symmetrical currents, for the same adjustment as for Z_o.

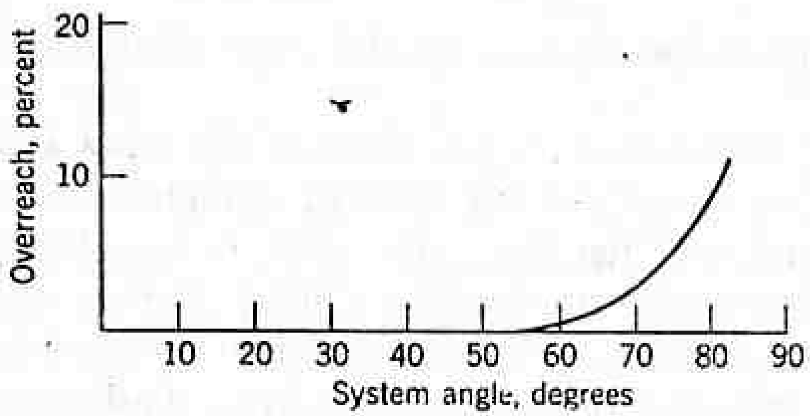

Fig. 8. Overreach characteristic of a certain distance relay.

As for overcurrent relays, the percent overreach increases as the system angle ($\tan^{-1} X/R$) increases. This angle increases with higher-voltage lines because the greater spacing between conductors makes the inductive reactance higher. Figure 8 shows a curve of percent overreach versus the system angle for one type of distance relay.

The overreach of a distance relay is of concern usually only for the first- or high-speed zone. The reaches of the intermediate and back-up zones are usually not nearly as critical as the reach of the first zone. Also, the intermediate and back-up-zone time delays are

long enough for the offset to die out and to permit a distance unit to reset if it has overreached and if it is a type of unit whose reset is practically equal to its pickup.

The greater the first-zone overreach, the less of the line may the first zone be adjusted to protect. If the current wave were always fully offset, one could adjust the relay, relying on overreach, so as to protect the desired portion of the line at high speed. But the current wave will rarely be fully offset; it will usually have little offset. Therefore, one cannot depend on overreach, and less than the desired portion of the line will usually be protected at high speed. If the relays at both ends of the line are considered, and if each protects P percent of the line from its end at high speed, only the middle ($2P - 100$) percent of the line is protected at high speed at both ends simultaneously.

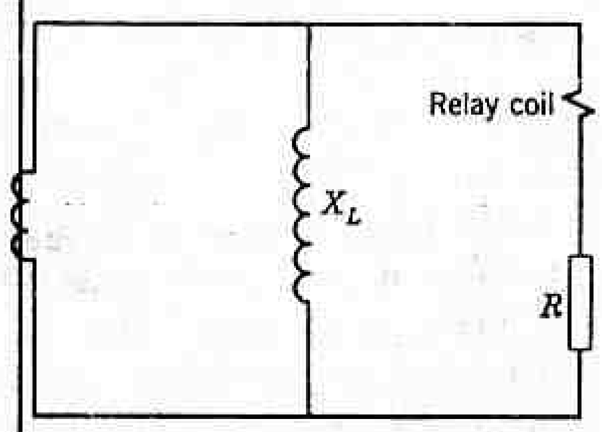

Fig. 9. A transient shunt to minimize overreach.

A device called a "transient shunt," shown in Fig. 9, has been used to minimize overreach with relays whose overreach might otherwise be objectionable.[7] The inductive reactor (X_L) is designed to have a very low resistance component so as to provide a low-impedance by-pass for the d-c component; the reactance is made high to block out most of the symmetrical a-c component. The resistor (R) in series with the relay coil may or may not be needed, depending on the impedance characteristic of the relay coil; the resistor is used, when necessary, to avoid a transient in the relay circuit that would occur if X/R of the relay circuit approached X/R of X_L.

OVERREACH OF GROUND DISTANCE RELAYS FOR PHASE FAULTS

Reference 8 shows that if phase-to-neutral voltage and compensated phase current are used, one of the three ground distance relays may overreach for phase-to-phase or two-phase-to-ground faults. This is not a transient effect like overreach because of offset waves; it is a consequence of the fact that such ground relays do not measure distance correctly for interphase faults. (Phase distance relays do not measure distance correctly for single-phase-to-ground faults, but, fortunately, they tend to underreach.) For this reason, it is necessary to use supplementary relaying equipment that will either permit tripping only when a single-phase-to-ground fault occurs or block tripping by the relay that tends to overreach.

USE OF LOW-TENSION VOLTAGE

Chapter 8 shows the connections of potential transformers for obtaining the proper voltages. It is emphasized that a low-tension source is not reliable unless there are two or more paralleled power-transformer banks with separate breakers; with only one bank, the source will be lost if this bank is taken out of service.

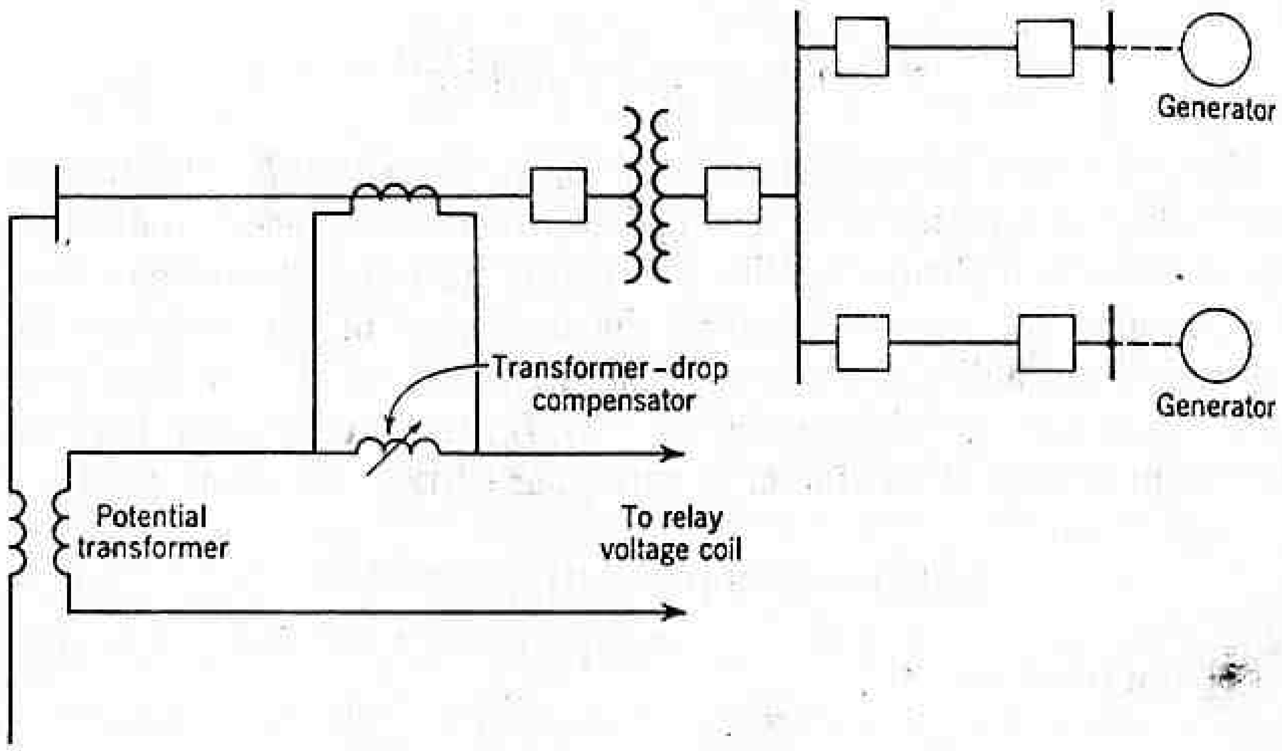

Fig. 10. Transformer-drop compensator for distance relays.

Whenever two or more high-voltage lines are connected to generating sources, as in Fig. 10, "transformer-drop compensation" should be used. For reasons to be given later, it is not sufficient merely to provide the relays with voltages that correspond in phase to the high-tension voltages that would be used if they were available; it is further necessary to correct for the voltage rise or drop in the transformer bank. In other words, by means of transformer-drop compensation, we take into account the fact that, in terms of per unit quantities:

$$V_H = V_L - I_T Z_T$$

where V_H = the high-tension voltage.

V_L = the low-tension voltage.

I_T = the current flowing from the low-tension side toward the high-tension side.

Z_T = the transformer impedance.

Figure 10 shows schematically how the low-tension current is used to produce a voltage that is added to the low-tension voltage in order to provide the relays with a voltage corresponding in phase and magnitude to that on the high-voltage side. Reference 9 gives detailed descriptions of actual connections.

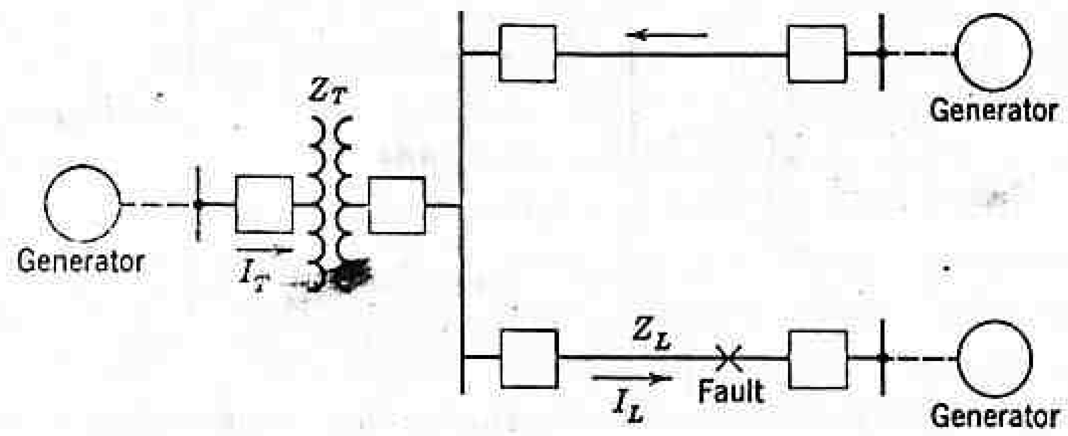

Fig. 11. Illustrating the need for transformer-drop compensation.

Transformer-drop compensation is required for Fig. 10 whether or not a generating source may be connected to the low-voltage side of the transformer bank. Synchronous motors may be considered such a source. Consider Fig. 11 in which a source is assumed to exist. Without transformer-drop compensation, and for a fault at the end of the line, the relays would see an impedance:

$$Z = \frac{I_T Z_T + I_L Z_L}{I_L} = \frac{I_T}{I_L} Z_T + Z_L$$

where Z_L is the per unit line impedance. It will be realized that I_T/I_L can be any value from zero to unity, depending on how the system is being operated; consequently, without transformer-drop compensation, the distance relays must be adjusted for $I_T/I_L = 0$ so as not to overreach. Then, for other values of I_T/I_L the relays will underreach, and underreaching is objectionable because less of the line is protected at high speed. With transformer-drop compensation, most of the first term is eliminated and the relays see practically the correct impedance Z_L, regardless of I_T/I_L, thus minimizing underreaching.

Even if there is never to be a source of generation on the low-voltage side, transformer-drop compensation is still necessary if there are two high-voltage lines either of which may be connected to a generating source. Consider the case of Fig. 12 in which a fault has occurred on the low-voltage side, and some load current continues to flow in line A on the high-voltage side. Without transformer-drop compensation, one or more of the relays of A would be likely to operate because there might be little or no voltage restraint but sufficient voltage for polarization to cause undesired tripping. Compensation would eliminate such a possibility. This possibility exists only when there are two or more high-voltage lines either of which may be connected to a generating source at its far end; otherwise, load current could not flow as in Fig. 12.

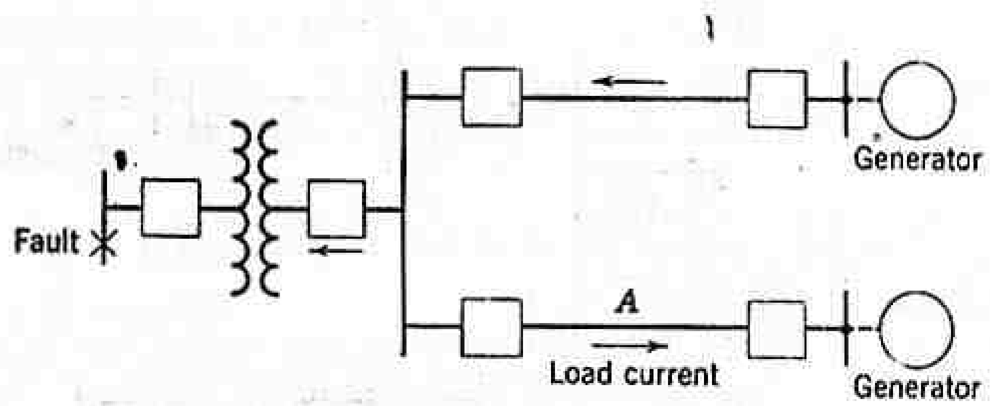

Fig. 12. Another instance in which transformer-drop compensation is needed.

Great care must be taken to avoid overcompensation. If the transformer drop is overcompensated, and if a short circuit that reduced the high-tension voltage to zero should occur on the protected line at the end where transformer-drop compensation is used, the relay voltage would be reversed in phase. This would prevent operation of the relays of the faulted line and would cause undesired operation of the relays of other lines supplying current to the fault. In order to avoid the possibility of overcompensation, the transformer drop should be undercompensated by an amount sufficiently large to take into account the effect of errors in the equipment and in the data on which the calculations are based.

Errors in compensation also affect the reach of the distance relays, and must be carefully considered so as to avoid overreach. In practice the high-speed reach of distance relays is adjusted to about 80% to 90% of the sum of the uncompensated part of the transformer impedance plus the line impedance for a fault at the far end of the line. In other words, if we use 90%,

$$R = 0.9\left[\frac{(1-C)I_TZ_T + I_LZ_L}{I_L}\right]$$

where R = the high-speed reach of the distance relays.
C = the fraction of the total transformer drop that is intended to be compensated, neglecting any errors in the compensation.

I_T, Z_T, I_L, and Z_L are as previously defined. The *actual* uncompensated part of the effective transformer impedance, taking into account the effect of error, is:

$$Z_{TU} = [(1-C) - EC]\frac{I_TZ_T}{I_L}$$

where E = the fractional error in C, being positive when the actual compensation is greater than C.

Therefore, the amount of the line (R_L) that is actually protected when the relay is adjusted for reach R is:

$$R_L = R - Z_{TU}$$

$$= [-0.1(1-C) + EC]\frac{I_TZ_T}{I_L} + 0.9Z_L$$

Now, it would be undesirable for R_L to exceed $0.9Z_L$ because we need $0.1Z_L$ as a factor of safety against overreaching because of other reasons that are always applicable whether we have transformer-drop compensation or not. Therefore, the first term of the equation for R_L must be practically zero or be negative. If we let the first term be zero, we lose the significance of I_TZ_T/I_L; so let us assume that the first term is 10% of our factor of safety, or $0.01Z_L$. In other words:

$$0.01Z_L = [-0.1(1-C) + EC]\frac{I_TZ_T}{I_L}$$

Solving for E we get:

$$E = \frac{Z_LI_L}{100C(Z_TI_T)} + 0.1\frac{(1-C)}{C}$$

Let $Z_LI_L/Z_TI_T = N$. Then:

$$E = \frac{0.01N + 0.1(1-C)}{C}$$

For any value of compensation, this equation gives the maximum positive error in the compensation that we can tolerate without having the relay's reach exceed 91% of the line length. An error of about ±3% is reasonable to expect, which permits about 80% to 90% compensation.

Negative compensation error will cause underreaching. This is

15 LINE PROTECTION WITH PILOT RELAYS

Pilot relaying is the best type for line protection. It is used whenever high-speed protection is required for all types of short circuits and for any fault location. For two-terminal lines, and for many multiterminal lines, all the terminal breakers are tripped practically simultaneously, thereby permitting high-speed automatic reclosing. The combination of high-speed tripping and high-speed reclosing permits the transmission system to be loaded more nearly to its stability limit, thereby providing the maximum return on the investment.

The continuing trend of increasing circuit-breaker-interrupting capabilities is increasing the allowable magnitude of short-circuit current. It is quite possible that damage rather than stability may dictate high-speed relaying in some cases.

Pilot relaying is used on some multiterminal lines where high-speed tripping and reclosing are not essential, but where the configuration of the circuit makes it impossible for distance relaying to provide even the moderate speed that may be required.

Some lines are too short for any type of distance relay. For such lines, it is not merely a matter of getting a distance relay with a lower minimum ohmic adjustment; the ohmic errors would be so high as compared with the ohms being measured that such relaying would be impractical.

Critical loads may require high-speed tripping beyond the capabilities of distance relays.[1]

For these reasons, it is the practice to use pilot relaying for most high-voltage transmission lines and for many subtransmission and distribution circuits. Therefore, it becomes necessary to choose between wire pilot, carrier-current pilot, and microwave pilot.[2] If either of the last two is indicated, one has to choose further between phase comparison and directional comparison, or a combination of the tripping relay to operate. The best solution to this problem is directional blocking relays.

Miscellaneous Problems of Coordinating Blocking and Tripping Sensitivities. It is necessary that the coordination between blocking

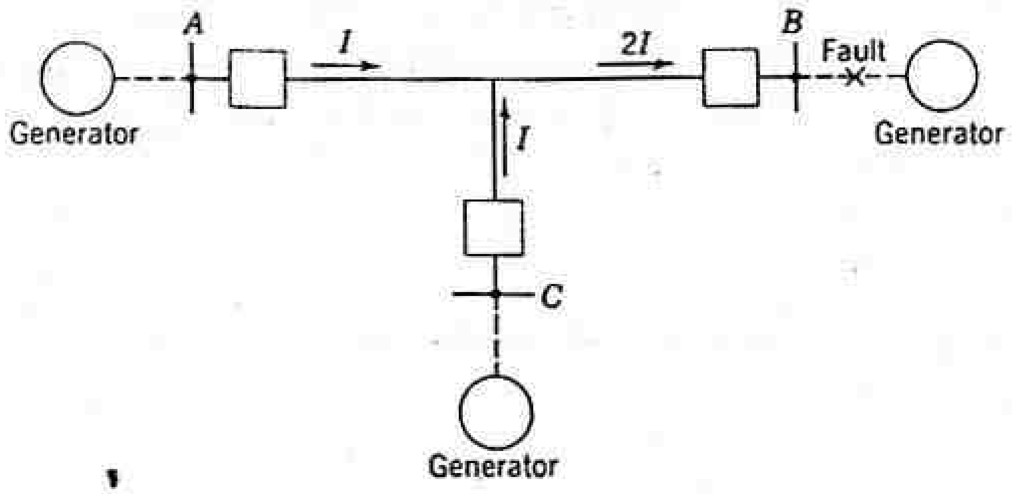

Fig. 11. Directional-comparison blocking relays get twice as much current as tripping relays.

and tripping sensitivities be carefully analyzed not only for multi-terminal operation but also when a line is operated with one or more terminals open. Owing to elimination of intermediate current sources,

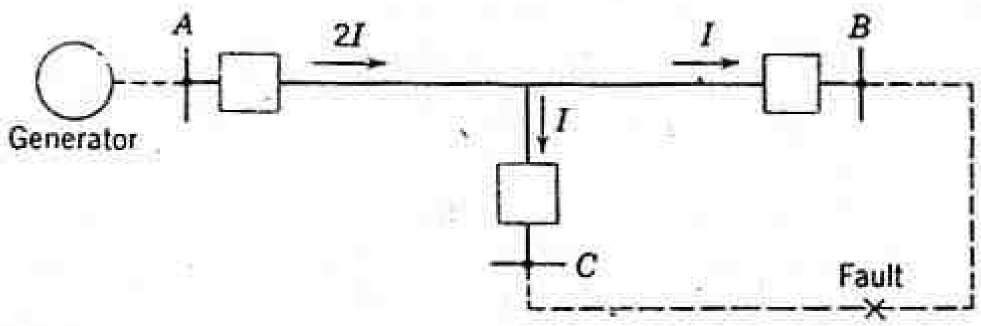

Fig. 12. Directional-comparison tripping relays get twice as much current as blocking relays.

such operation may increase the reach of the tripping relays at one terminal; one must be sure that these relays do not outreach the blocking relays at another terminal.

Figures 11 and 12 show two extreme operating conditions for a three-terminal line, so far as the relative blocking and tripping sensitivities are concerned. For Fig. 11, the blocking relays at terminal B get twice as much current as the tripping relays at A or C; for Fig. 12, the blocking relays at B and C get only half as much current as the tripping relays at A. Even greater extremes could exist for a line with more than three terminals.

Need for a Blinder on the Loss-of-Synchronism Blocking Relay. If the phase tripping relays at terminal A of Fig. 13 cannot operate

to trip until after terminal B has tripped for the fault location P, a supplementary angle-impedance relay should be used to provide a "blinder" for the loss-of-synchronism blocking relay. The need for

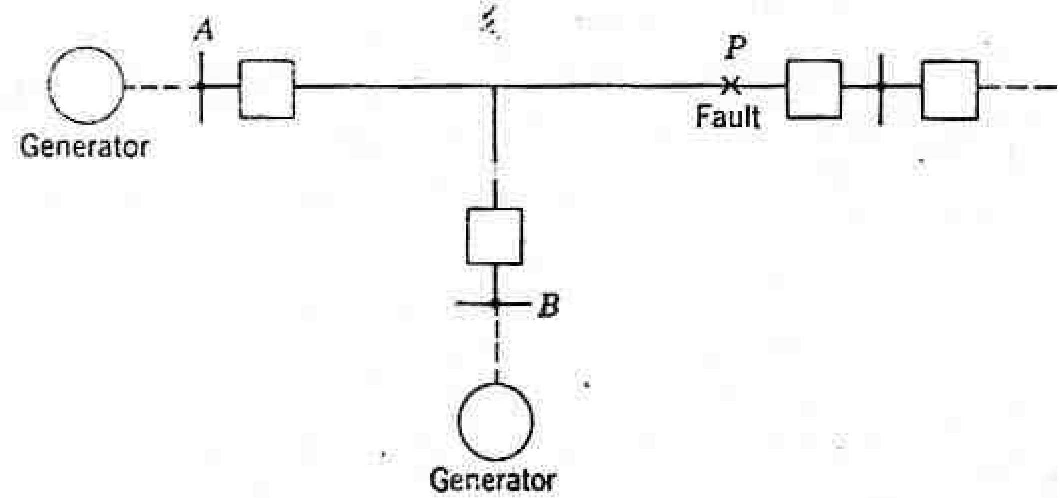

Fig. 13. Situation in which the loss-of-synchronism blocking relay will block tripping for an internal fault.

this blinder is shown in Fig. 14. The point P_1 represents the way the fault first appears to the tripping and blocking relays at A, and the point P_2 represents the appearance of the fault after B has tripped.

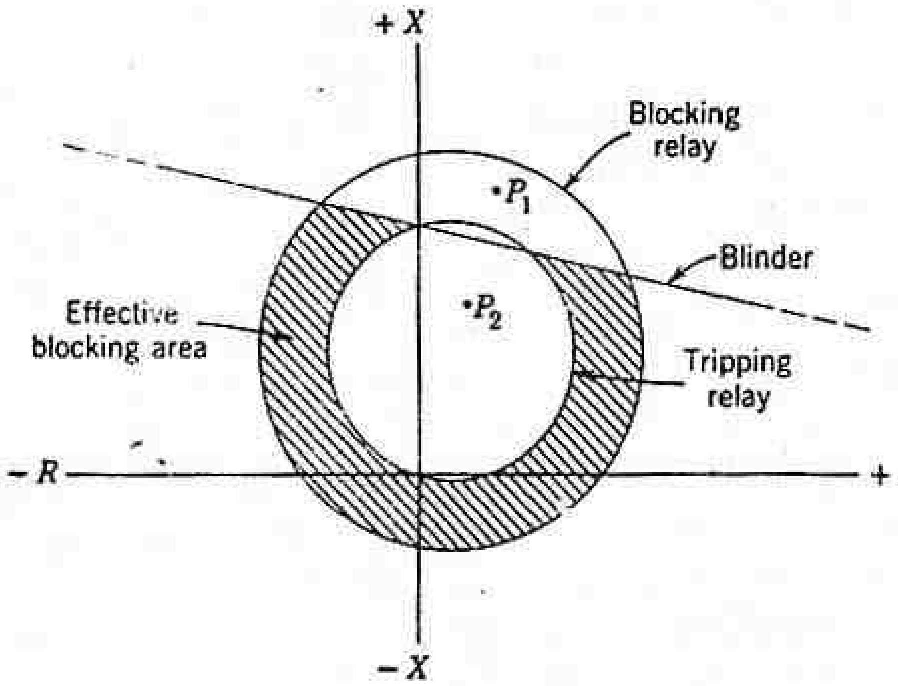

Fig. 14. R-X diagram of the conditions of Fig. 13.

It will be noted that this sequence will establish local blocking at A by the loss-of-synchronism relay, and, consequently, that tripping there can only occur in third-zone time.

Figure 14 shows how the blinder characteristic modifies the operating characteristic of the blocking relay so that when the fault first occurs it will not fulfill the requirement for the second step in the sequence of operations necessary to set up loss-of-synchronism blocking. The effective blocking area is shown cross-hatched.

Blocking-Terminal Equipment at Load Terminals. At terminals behind which there is no source of generation, only blocking equipment may be required. Such equipment is required if the high-speed relays at any of the main terminals are sensitive enough to operate for a low-voltage fault at such a load terminal. The blocking-terminal equipment consists of instantaneous overcurrent relays, energized from CT's on the high-voltage side of the power-transformer bank, and carrier-current transmitting and receiving equipment. The overcurrent relays start the transmission of carrier current to block tripping at the main terminals for low-voltage faults at the load terminal or for magnetizing-current inrush to the load-terminal power-transformer bank.

As described for phase-comparison relaying, remote tripping from a blocking-terminal power-transformer differential relay to the breakers at the main terminals can be accomplished over the carrier-current channel.[5]

EFFECT OF TRANSIENTS

Directional-comparison relaying using high-speed ground relays energized from zero-phase-sequence quantities is exposed to more possibilities of misoperation than is phase-comparison relaying. Reference 6 describes a host of things that tend to fool such ground relays. However, conventional directional-comparison-relaying equipments have certain features, developed as a result of experience, that minimize any tendency toward misoperation. Such features are: (1) limited sensitivity, (2) slight time delay in auxiliary relays, and (3) "transient blocking" or the prolongation of a carrier-current blocking signal for several cycles after a relay operates to try to shut it off. Also, induction-type directional units in both the carrier-starting and the tripping functions make the units unresponsive to transients in only one of the operating quantities.

Ground distance relays, that respond to positive-phase-sequence impedance, for controlling carrier-current transmission and for tripping eliminate the problem of misoperation on transients.

Combined Phase and Directional Comparison

Directional-comparison relaying using directional-ground relays may operate undesirably if there is sufficient mutual induction with a

neighboring power circuit.[6] The directional-ground relays misoperate because their polarization is adversely affected, as will be described later. This would seem to indicate the desirability of phase-comparison relaying which would be unaffected by mutual induction. If phase comparison was completely applicable, it would be a good solution. However, occasionally it does not have sufficient sensitivity for phase faults, although it would be entirely satisfactory for ground faults. Under these circumstances combined phase- and directional-comparison relaying is chosen. The directional-comparison principle is used for phase faults and the phase-comparison principle is used for ground faults. Because the carrier-current transmitter and receiver are employed in common, the equipment is only a little more expensive than directional comparison alone. Incidentally, the phase-comparison ground-fault equipment is less affected by most of the transient conditions that affect directional-ground relays.

If ground distance relays were used in the directional-comparison equipment instead of directional-ground relays, it would be unnecessary to resort to combined phase- and directional-comparison equipment. However, it would be somewhat more expensive, but it would provide better back-up protection.

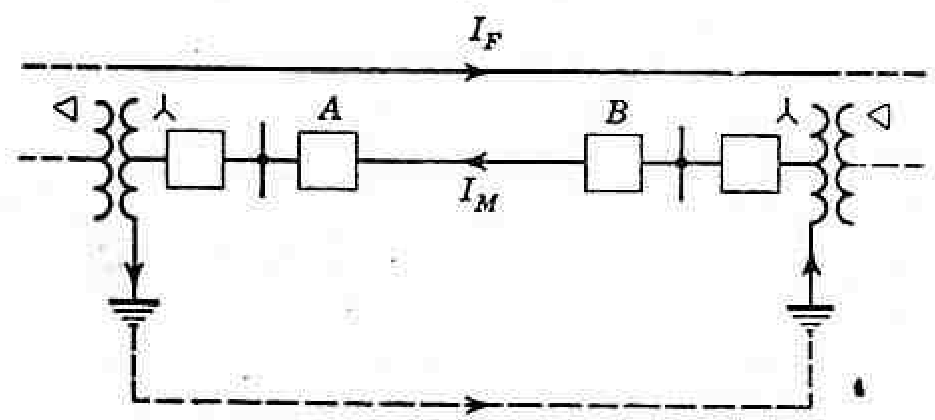

Fig. 15. Illustrating the cause of undesired directional-ground-relay operation resulting from mutual induction.

THE EFFECT OF MUTUAL INDUCTION ON DIRECTIONAL-GROUND RELAYS

Figure 15 illustrates the fundamental principle involved in the undesired operation of directional-ground relays. As shown in Fig. 15, fault current I_F flowing in a nearby line causes current I_M to flow by mutual induction in the line under consideration. The induced current circulates through grounded-neutral power-transformer banks at the ends of the line and the earth, as shown. The difficulty is that directional-ground relays at both ends of the line tend to operate under such circumstances. At location B, the polarizing current flows from the ground into the neutral of the grounded power transformer and from the bus into the line; this is the same as for a ground fault on the line for which directional-ground relays are intended to operate. The fact that, at end A, both the currents are reversed with respect to the directions at B also produces a tripping tendency. The same operating tendencies would exist if the relays were voltage-polarized. In

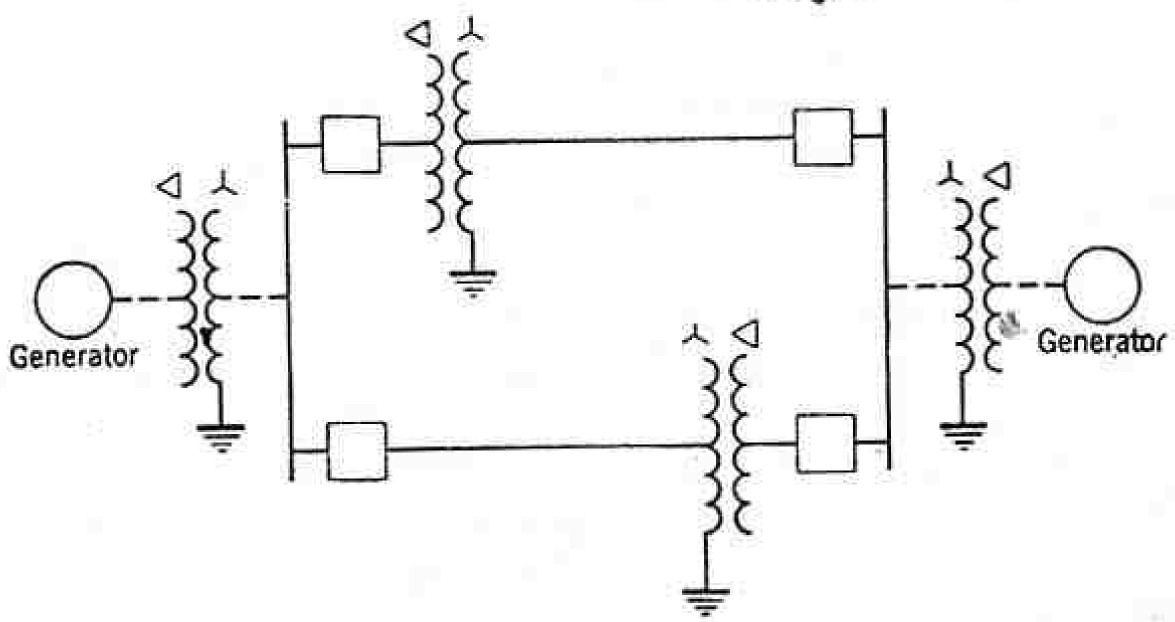

Fig. 16. Parallel circuits subject to mutual induction that are electrically independent so far as zero-phase-sequence currents are concerned.

other words, the phase of the polarizing quantity is not independent of the direction of current flow in the line, as it is when a short circuit occurs in the line or beyond either end.

One can immediately see the significance of the foregoing circumstances when directional-comparison pilot relaying is involved. Since the directional-ground relays at both ends of the circuit have a tripping tendency, if the induced current is high enough to pick up the relays, the circuit will be tripped undesirably.

The conditions of Fig. 15 are extreme in view of the fact that the line section in which induced current flows cannot directly contribute short-circuit current to the other circuit. However, it is not an impossible situation. It can exist whenever electrically independent circuits are closely paralleled, or in a case such as that illustrated in Fig. 16. Although these two circuits are paralleled at their ends, they are independent so far as zero-phase-sequence currents are concerned.

Situations that are more apt to be encountered are illustrated in Fig. 17. It is only necessary in either case of Fig. 17 that the breaker of the faulty line be open at the end where the lines are normally

paralleled, in order to have the condition that can produce an undesirable tripping tendency of the directional-ground relays of the sound line. This breaker may be open either because it was tripped by its protective relays immediately when the fault occurred and before the breaker at the other end could trip, or because the line had been open at both ends and the breaker at the other end was reclosed first on a

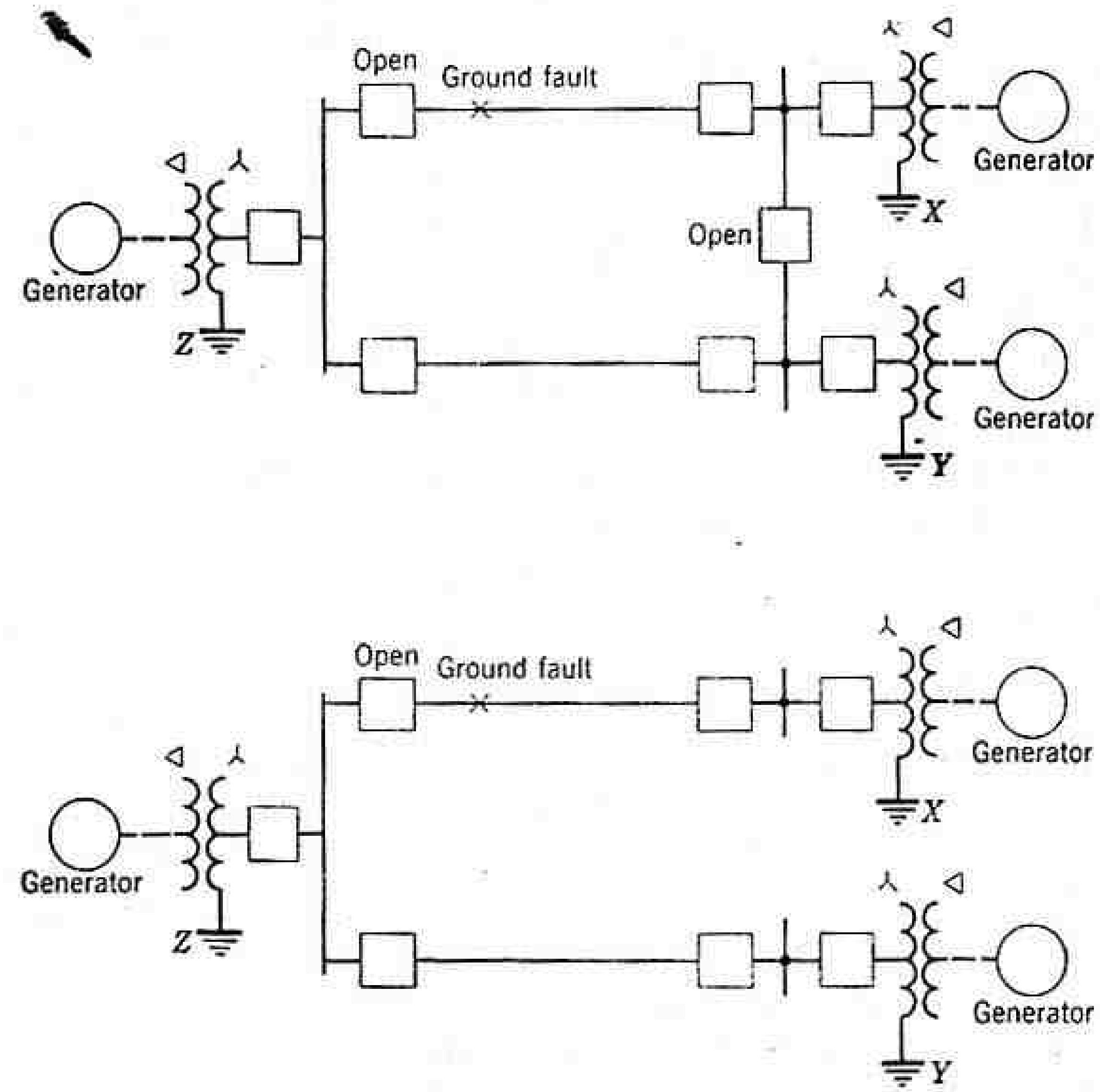

Fig. 17. Situations in which lines are directly paralleled at one end only.

persisting fault. Not only would the directional elements at both ends of the sound line permit tripping, but the current magnitudes may be large enough so that selectivity would not be obtained.

Sometimes it is even unnecessary that the breaker in the faulty line of Fig. 17 be open. If the effect of mutual induction is great enough, it can overcome the tendency of the unfaulted line to supply current to the fault, and actually reverse the direction of its current.

Apart from phase-comparison relaying or directional ground distance relays, other solutions to the problem can sometimes be found. The zero-phase-sequence current or voltage at the ends of the faulted circuit may be enough greater than at the corresponding ends of the unfaulted circuit so that a relay can be interposed that balances the corresponding quantities and permits only the circuit to trip that has the larger quantity. Another possible solution is to parallel the CT's in the neutrals of the power transformers, as, for example, at X and Y of Fig, 17, and to use the resulting current to polarize the directional-ground relays of both lines at that end. At the other end of the circuits of Fig. 17, a CT in the neutral of the one power-transformer bank shown at Z would suffice for the directional-ground relays of both lines; or voltage polarization might be used at this end.

Should the line terminals be too far apart at one end, as when two lines run close to one another for part of their length and then diverge, it would be impossible to employ the alternatives to phase-comparison relaying that have been described. One remaining alternative would be to determine if the magnitude of the zero-phase-sequence current or voltage at the ends of the lines could not be used alone to permit operation, subject to directional control, only if the magnitude was high enough. Another possibility is to take advantage of the fact that the phase-to-neutral voltages of the circuit in which the induced current flows are usually not as low during the induced-current condition as they are while a ground fault exists on the line itself.

It was mentioned in Chapter 13 that a negative-phase-sequence directional-ground relay would not be affected by mutual induction. However, such a relay has other disadvantages, as mentioned also, that make it desirable to seek some other alternative.

All-Electronic Directional-Comparison Equipment

All-electronic directional-comparison equipment, including electronic phase distance and directional-ground relays, has been in service since 1953.[16] The average operating time of this equipment is ⅝ cycle with a maximum of 1.0 cycle, as compared with 1.0 to 3.0 cycles for conventional electromechanical relay equipment.

Such operating speeds eventually become necessary, not only to maintain stability when faults occur but also to minimize the damage from ever-increasing concentrations of short-circuit current.

The application procedures and problems are the same as those described for the electromechanical equipment.

Microwave

A microwave pilot is used for relaying only when the relaying equipment can share the channel with enough other services; it is not

economically justifiable for relaying alone if carrier current or wire pilot is applicable.[17]

Microwave is entirely suitable although it is not as reliable as carrier current for protective-relaying purposes; this is partly because of the complex circuitry and the large number of tubes involved, and also because of the large number of services on the same microwave channel. When repeater stations are necessary, the complexity practically doubles with further loss of reliability. Of course, one should realize that the requirements of protective relaying as to reliability are in certain respects more severe than the requirements of other services that use the microwave channel. Any lapse in the signal when a fault occurs is unacceptable.

Microwave has certain theoretical advantages over carrier current because it is dissociated from the power line,[18] but its only real advantage is in connection with remote tripping, which will be considered later. Occasionally, microwave is useful where the attenuation would be too high for carrier current, such as on a power-cable circuit, but even there microwave would probably not be selected unless there were many other uses in addition to protective relaying.

The same relaying equipments that are used with a carrier-current pilot are also used with a microwave pilot. Therefore, the application considerations are the same so far as the relaying equipment is concerned.

THE MICROWAVE CHANNEL

The microwave channel is a line-of-sight-radio system operating on a frequency band in the United States assigned by the Federal Communications Commission in the range from 950 to 30,000 megacycles.[19] Such a system requires that a straight line from one antenna to another be above intervening objects, preferably by about 50 feet. This usually limits the distance between antennae to about 20 to 50 miles, depending on the topography of the land. Where a longer channel is required, one or more "repeater stations" may be necessary. One repeater station doubles the base channel equipment, except that only one additional tower is necessary; hence, the cost of a microwave channel is dependent on its length.

It is the practice to use standby equipment automatically switched into service in the event that the regular equipment fails.

For protective relaying that cannot tolerate even a moment's outage when a fault occurs, operation from a power-system a-c source is not acceptable. It is necessary to provide an a-c generator operating from the station battery, or d-c-operated equipment. This becomes more of a problem at a repeater station where a suitable battery source would not otherwise be available.

For protective-relaying purposes, the practice is to modulate the microwave frequency directly by any of the usual methods, such as, for example, by a so-called "tone." Such a tone is a single-frequency voltage in the audio range or above. Tones above the audio range are preferred because the time constants of their filter circuits are shorter, and therefore it is unnecessary to delay tripping to allow time for the receiver output to build up sufficiently to block tripping.

REMOTE TRIPPING

The principal advantage of microwave for protective relaying is that the presence of a fault on the protected line will not interfere with the transmission of a remote-tripping signal. For the protection of three-terminal lines, there are circumstances when the relays at a given terminal cannot operate to trip their breakers until after the breakers trip at another terminal. With microwave, the first relays to operate can cause the transmission of a tripping signal to another terminal and thereby eliminate part of the time delay in the sequential tripping of this other terminal.[20]

This ability to perform remote tripping without hindrance by a fault makes possible the use of a different principle for line protection.[18] To apply this principle, it is first necessary that the high-speed-tripping zones of the relays at all terminals overlap for all types of fault in such a way that, for any fault, the relays of at least one terminal will always operate at high speed. Then, if each terminal is arranged to transmit a trip signal to each other terminal, practically simultaneous high-speed tripping will occur at all terminals; the remote tripping will be delayed about 2 to 3 cycles. Of course, each terminal is still free to trip at high speed independently of the remote-tripping equipment whenever a fault occurs within that terminal's high-speed-tripping zone. This principle eliminates the need for blocking relays, as required by directional comparison, but it often requires distance relays for phase- and ground-fault protection. Where remote tripping is required for multiterminal applications, this type of relaying would have its greatest application; otherwise, the added time delay for certain faults would discourage its general usage where simultaneous high-speed tripping is possible with directional comparison.

Incidentally, the foregoing principle can be applied to a wire-pilot system by the use of tones.

High-Speed Reclosing

High-speed automatic reclosing of transmission-line breakers after they have tripped to clear a fault is generally possible only with pilot relaying, because only pilot relaying is able to cause all line terminals to trip at high speed and practically simultaneously. With such high-speed tripping and reclosing, generators do not have time to swing very far out of phase, and therefore no synchronism check is necessary before reclosing. The experience with such high-speed reclosing (or "ultra-high-speed reclosing," as it is sometimes called) has been excellent.[21]

Generally, all three phases are tripped and reclosed for any kind of fault. Infrequently, however, such three-phase switching cannot be used, but it is possible to use single-phase switching to advantage.[22] Such a possibility exists when there is only one line connecting a hydroelectric generating station to its system. If about 25% or more of the load on the generating station is dropped when a line is tripped, the generators will speed up too rapidly to permit high-speed reclosing. But for single-phase-to-ground faults, if only the faulty phase is tripped and reclosed, stability can often be maintained; for any other kind of fault, all three phases are tripped but are not reclosed. Single-phase switching can be performed with conventional relaying equipment by the addition of "phase-selector" relays.[23]

High-speed reclosing is permitted only when high-speed tripping is caused by the operation of the pilot equipment or the first-zone units of distance relays. When tripping is caused by any other units, automatic reclosing is blocked until released locally by an operator or remotely by supervisory control.

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Review Problems

1. A system short-circuit study is to be made. What quantities should be obtained for studying the application of protective relays? What other data are required to apply (*a*) overcurrent relays, (*b*) pilot relays, and (*c*) distance relays?

2. Name and describe briefly the various methods for obtaining selectivity.

3. Discuss the factors governing the choice of transmission-line-relaying equipment. Which type would lend itself best to standardization, and why?

4. Given a breaker with 1200/5 bushing CT's having the secondary-excitation characteristic of Fig. 3 of Chapter 7. What would the ASA accuracy classification be for the 40-turn tap (ratio 200/5)? Assume the tap winding to be fully distributed.

5. On what basis is it permissible to superimpose system and relay characteristics on the same *R-X* diagram for the purpose of studying relay response?

6. Under what circumstance is distance relaying affected by short-circuit-current magnitude?

7. Show the complete CT and relay connections for applying percentage-

differential protection to the power transformer of Fig. 18. Draw the three-phase voltage vector diagrams for both sides of the power transformer.

8. Discuss the virtues of high-speed relaying.

9. Write "true" or "false" after each of the following:

(a) Overcurrent relays with more-inverse curves are better to use when the generating capacity changes more from time to time.

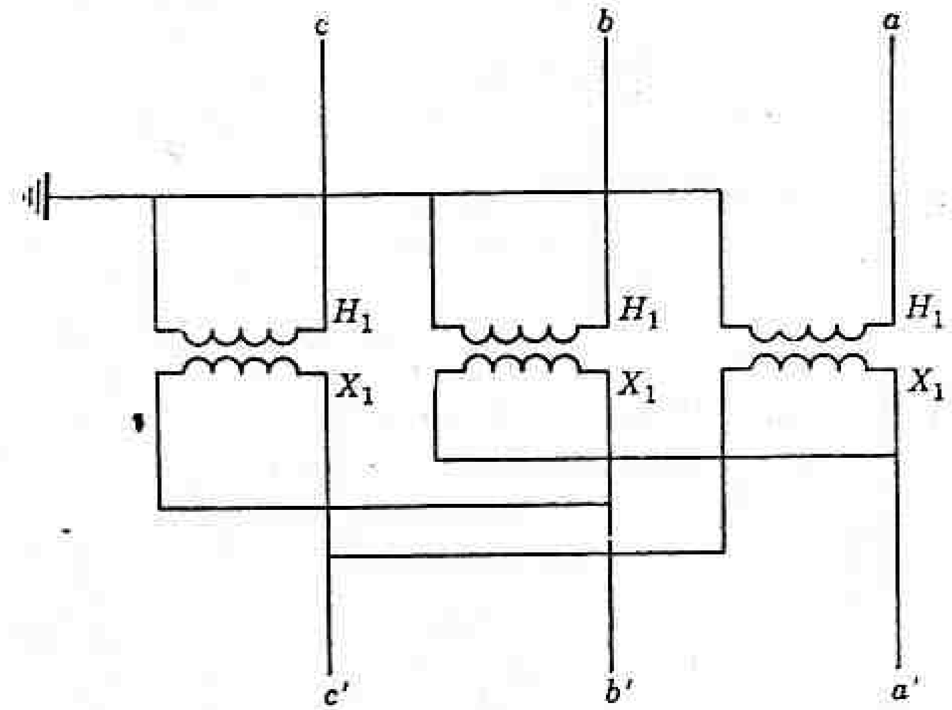

Fig. 18. Illustration for Review Problem 7.

(b) Instantaneous overcurrent relays are more applicable on the longer lines.

(c) Mho-type distance relays are more likely to operate undesirably on power swings than other types of distance relays.

(d) Any distance relay—no matter where it is located—will trip on loss of synchronism.

(e) Sensitive, high-speed bus protection can always be obtained with differentially connected overcurrent relays.

(f) In attended stations, it is not the practice to let transformer overload relays trip the transformer breakers.

(g) Back-up relaying is not a substitute for good maintenance.

two. In addition to any of these, some form of remote tripping may be required. The application considerations of these various equipments will now be discussed.

Wire-Pilot Relaying

Chapter 5 tells why d-c wire-pilot relaying has largely given way to a-c types. In this chapter, we shall consider the application of only the a-c types.

Wire-pilot relaying is used on low-voltage circuits, and on high-voltage transmission lines when a carrier-current pilot is not economically justifiable. For the protection of certain power-cable circuits, wire pilot may be used because the cable-circuit attenuation is too high for carrier current. For short lines, a-c wire-pilot relaying is the most economical form of high-speed relaying.

Generally, wire pilots no longer than about 5 to 10 miles are used, but there are a few in service as long as about 27 miles.[3] As mentioned in Chapter 5, the technical limitations on the length of a pilot circuit are its resistance and shunt capacitance. Compensating reactors are sometimes used when the shunt capacitance is too high. A pilot circuit that is rented from the telephone company may be much longer than the transmission line for whose protection it is to be used, because such telephone circuits seldom run directly between the line terminals. Therefore, in borderline cases, one should find out the actual resistance and capacitance before deciding to use wire pilot. Other requirements imposed on the wire-pilot circuit are described in Chapter 5.

In general, wire-pilot relaying is not considered as reliable as carrier-current-pilot relaying, mostly because many of the wire-pilot circuits that are used are not very reliable. The pilot circuit represents so much exposure to the possibility of trouble that great care should be taken in its choice and protection.

OBTAINING ADEQUATE SENSITIVITY

Apart from making sure that associated equipment is suitable for the application, the principal step in the application procedure is to determine if the available adjustments of the relaying equipment are such that the necessary sensitivity and speed are assured. Manufacturers' bulletins describe how to do this when one knows the maximum and minimum fault-current magnitudes for phase and ground faults at either end of the line.

It is advisable not to adjust the equipment to have much greater

sensitivity than is required or else, in so doing, the CT's may be burdened excessively. With excessive burden, the over-all sensitivity may be poorer, as illustrated by Problem 2 of Chapter 7.

If the phase-fault currents are high enough to permit it, it is advisable to adjust the phase-fault pickup to be at least 25% higher than maximum load current. Then, the equipment will not trip its breakers undesirably on load current should the pilot wires become open-circuited or short-circuited. Undesirable tripping could still occur for an external fault, unless supervising equipment is used to forestall such tripping.

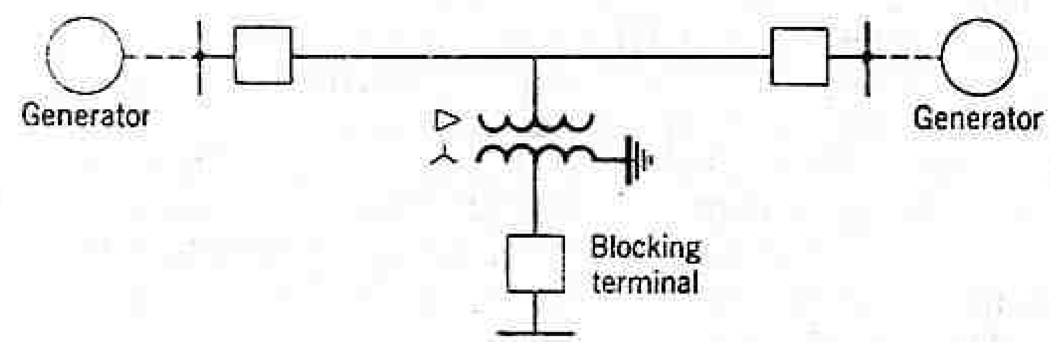

Fig. 1. Illustrating a blocking-terminal application.

THE PROTECTION OF MULTITERMINAL LINES

When there are sources of generation back of more than two terminals, or if there are grounded-neutral wye-delta power-transformer banks at more than two terminals, the application requires a careful study of the available short-circuit currents under various generating conditions to determine if the necessary sensitivity can be assured. The more source terminals there are, the less sensitive will the protection be.[4]

When there are sources of generation back of only two terminals as in Fig. 1, the problem is much simplified. A terminal that has no source of generation is treated as a so-called "blocking" terminal. Instantaneous overcurrent relays energized from CT's on the high-voltage side of each blocking terminal are connected either to open-circuit or to short-circuit the pilot wires, depending on the type of wire-pilot relaying used, to block tripping at the main terminals for a low-voltage fault at the blocking terminal. The operating time of the tripping relays at the main terminals must be coordinated with that of the blocking-terminal relays. The overcurrent-relay contacts operate in the secondary of an insulating transformer, as in Fig. 2. It is necessary to energize the blocking relays from high-voltage CT's so that tripping at the source terminals will also be blocked for magnetizing-current inrush. The blocking relays should not be sensitive enough to operate on the current fed back to high-voltage faults by motors on the low-voltage side of the blocking terminal, or else tripping at the main terminals will be delayed.

Blocking-terminal equipment will not trip the local breaker for high-voltage line faults; such tripping may be necessary if automatic reclosing is used at the source terminals of the line and if there are motors at the blocking terminal that might be damaged by such reclosing. If high-speed reclosing is used at the source terminals, the

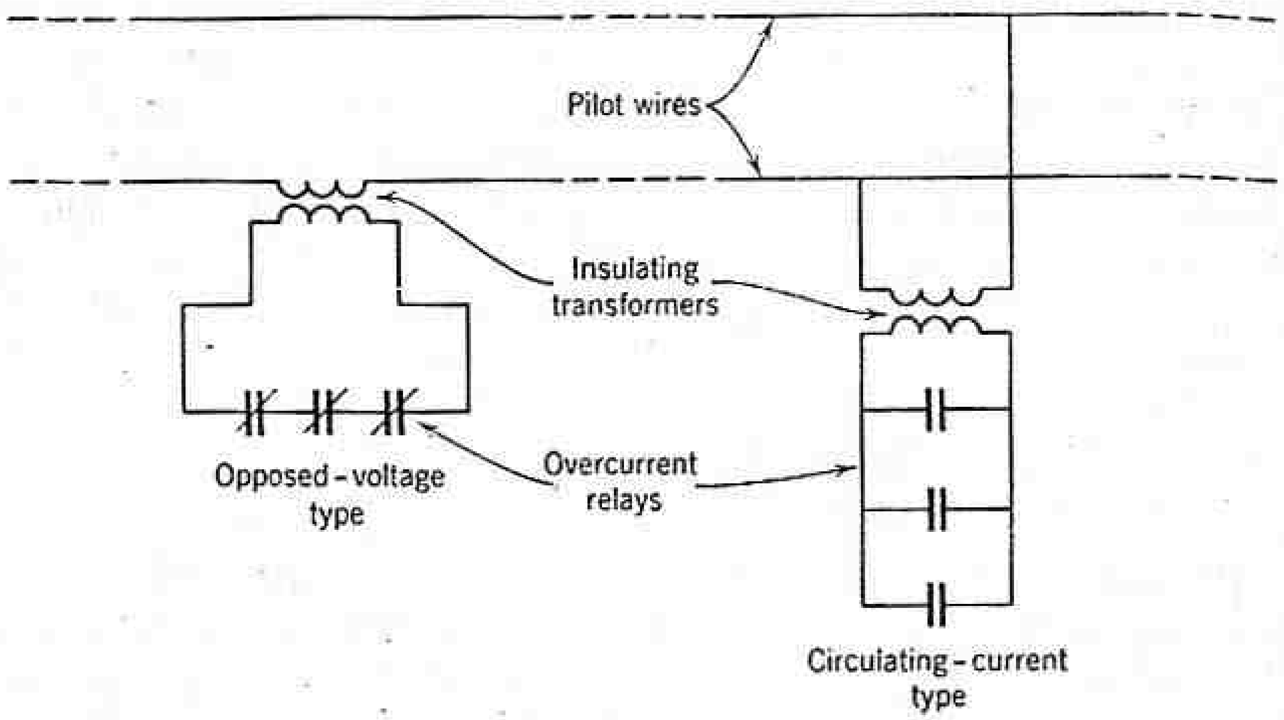

Fig. 2. Blocking-terminal technique.

breaker at the blocking terminal must be tripped, when necessary, by remote tripping from both source terminals. If the automatic reclosing is slow enough, the breaker could be tripped by local undervoltage or underfrequency relays.

If a blocking-terminal power-transformer bank is large enough to justify differential relaying, remote tripping of the source terminals for transformer faults would be used if there were no high-voltage breakers at the blocking terminal, as is usually true.[5] Otherwise, the bank would be protected only by fuses on the high-voltage side.

For the blocking-terminal technique to be permissible, the total load current of all blocking terminals on the line must be less than the current required to operate the wire-pilot relays at one source terminal of the line witn the breaker at the other source terminal open.

If the power-transformer banks are small enough at the load terminals behind which there is no generation, the wire-pilot relays at the source terminals could be adjusted not to operate for low-voltage faults at the load terminals. This would also probably prevent opera-

tion on magnetizing-current inrush, particularly if the ground-fault pickup could be made high enough.[6] This would eliminate the need for any blocking-terminal equipment.

A multiterminal line can sometimes be well protected against ground faults with wire-pilot relaying, even though adequate phase-fault protection is impossible. This is because line taps are usually made through delta-wye power-transformer banks, and they are open circuits so far as zero-phase-sequence currents on the high-voltage side are concerned. Therefore, if the wire-pilot relays are arranged to receive only the CT neutral current, such a multiterminal line may be treated as a two-terminal line. Good protection against phase faults on such a line can often be provided by distance relays because the impedance of the transformer at each tap is so high that the distance relays can usually be adjusted to protect 80% to 90% of the line without reaching through any of the transformers.

CURRENT-TRANSFORMER REQUIREMENTS

Conventional a-c wire-pilot relays have variable percentage-differential characteristics that permit large CT ratio errors at high magnitudes of external-fault currents. Usually, it is only necessary to be sure that the CT's are able to supply the required current to operate the relays at high speed when internal faults occur. This is a matter involving the relay burdens for the sensitivity taps used, the pilot-wire resistance, and the characteristics of the CT's.

The equipment may also contain adjustment to compensate for the nominal CT ratio at one terminal differing from that at another terminal. In borderline cases, this adjustment might increase a tendency to operate undesirably for external faults because of transient differences between CT errors; therefore, in general, the same nominal CT ratios at all terminals are preferred.

If a line terminates in a power-transformer bank with no high-voltage breaker, the relaying equipment should be energized from high-voltage CT's—generally bushing CT's in the transformer bank. If low-voltage CT's were used, they would have to be connected so as to compensate for the phase shift caused by the power transformer and, possibly, to remove zero-phase-sequence components. The objection to low-voltage CT's is that the relaying equipment will operate to trip undesirably on magnetizing-current inrush either when the transformer bank is energized or when system disturbances occur. To avoid such objectionable operation would require additional relaying equipment. Also, some types of a-c wire-pilot relays would not respond to faults between a particular pair of phases.

BACK-UP PROTECTION

Wire-pilot relaying does not provide back-up protection. Separate overcurrent or distance relays are used for this purpose. When wire-pilot relaying is applied to an existing line, it is often the practice to use the existing relaying equipment for back-up protection.

Distance relays may be used for back-up protection even though the line is too short to use distance relays for primary protection. In such a case, the high-speed zone would be made inoperative.

When directional-overcurrent relays are used for back-up protection, the requirements on the voltage source are the least severe, and uncompensated low-tension voltage can be used. It will be noted that the conventional type of a-c wire-pilot-relaying equipment does not use any a-c voltage.

Carrier-Current-Pilot Relaying

Carrier-current-pilot relaying is the best and most commonly used kind of relaying for high-voltage lines. A report[7] showed that this kind of relaying is in service on lines whose voltage is as low as 33 kv. It is applicable in some form to any aerial line. Carrier-current-pilot relaying is preferred to wire-pilot relaying because it is somewhat more reliable and is more widely applicable. Consisting entirely of terminal equipment, it is completely under the control of the user, as contrasted with rented wire pilot. Also, the carrier-current pilot lends itself more conveniently to joint usage by other services such as emergency telephony and remote trip.

AUTOMATIC SUPERVISION OF THE CARRIER-CURRENT CHANNEL

When carrier-current-pilot relaying was first introduced, the reliability of vacuum tubes was not as good as it is now, and some users felt the need for automatic equipment to supervise the pilot channel. Today, users are content to rely on the manual tests that are made daily at various regular intervals because the carrier-current channel has proved to be a very reliable element of the protective equipment.[7]

CARRIER-CURRENT ATTENUATION

Every proposed application should be studied to be sure that the losses, or attenuation, in the carrier-current channel will be within the allowable limits of the equipment.[8] Manufacturers' publications specify these limits and describe how to calculate the attenuation in each element of the channel.[9]

The protection of multiterminal lines requires very careful scrutiny of the attenuation. Depending on the length of line tapped from the main line, "reflections" from a tap may cause excessive attenuation unless the carrier-current frequency is very carefully chosen. If this length is ¼, ¾, 5/4, 7/4, 9/4, etc., wavelengths, excessive attenuation may be expected. Sometimes, only a test with carrier current of different frequencies will supply the required information.[10] In extreme cases, it is necessary to install line traps in the taps to eliminate reflections.

Power cable causes very high carrier-current attenuation, particularly where sheath-bonding transformers are used. Also, the so-called "mismatch," or discontinuity in the impedance characteristic of the channel where power cable connects to overhead line, causes high loss.[11] It is usually possible to use carrier current only on short lengths of cable, and then only with frequencies near the low end of the range. Because of the foregoing, wire pilot, or even microwave pilot, is sometimes used where carrier current might otherwise be preferred.

USE OF CARRIER CURRENT TO DETECT SLEET ACCUMULATION

The carrier-current channel provides a method for determining when sleet accumulation requires sleet melting to be started. This method has had varied reception among electric utilities.[12] It is generally agreed that the method indicates sleet accumulation, but it will also occasionally give false indication during fog, mist, or rain. Those who use this method of sleet detection feel that the extra cost incurred as a result of going through the sleet-melting process unnecessarily because of such false indications is small and is justified on a "fail-safe" basis.

The method of detecting sleet accumulation is based on the fact that the attenuation of a transmission line increases as sleet accumulates on the line. Figure 3 shows the effect of attenuation on the magnitude of the output from the carrier-current receiver. Normal operation is represented by the point A. The safety factor in the equipment, when it is properly applied, is sufficient so that under the most adverse atmospheric conditions, including sleet, the attenuation would not greatly exceed that represented by the point B. Therefore, the reliability of the equipment is assured under all conditions. Now, when it is desired to detect sleet accumulation, the operator at one end of the line causes carrier current to be transmitted, and the operator at one end or the other presses a button to introduce attenuation into the transmitter or receiver circuit so as to advance the normal operating position from A to B. Then, the receiver output decreases rapidly for any additional attenuation due to sleet. When conditions appear to be favorable for sleet, such a test at frequent intervals will detect increases in sleet accumulation. Such information must be

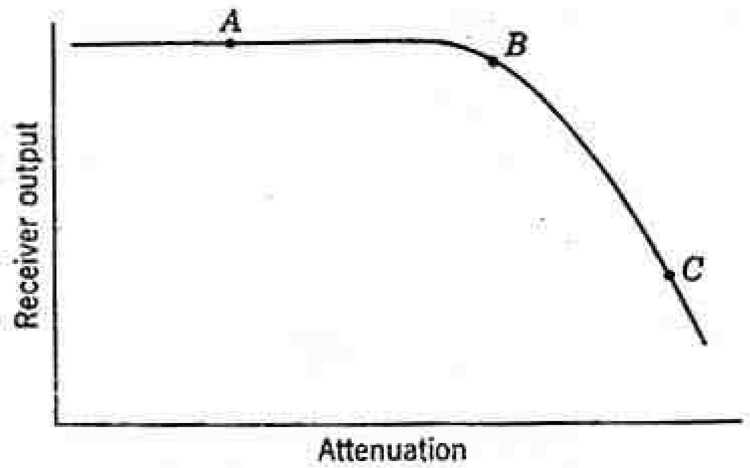

Fig. 3. Effect of attenuation on the strength of the receiver-output signal.

coordinated with visual observation and experience before the receiver-output readings have any useful meaning.

This sleet-detection feature also detects accumulation of dirt or salt on the line insulators, and deterioration of vacuum tubes. It is used for this purpose by many companies that do not use it for sleet detection.

TYPES OF RELAYING EQUIPMENT

The three types of carrier-current-pilot-relaying equipment in regular use are phase comparison, directional comparison, and combined phase and directional comparison. Each of them will be treated in the following material.

Phase Comparison

Phase-comparison relaying is much like a-c wire-pilot relaying. It is the simplest conventional type of carrier-current-pilot-relaying equipment. However, its best application is to two-terminal lines; multiterminal-line applications require very careful examination, and the sensitivity of the protection is quite inferior to that for two-terminal lines. Even for two-terminal lines, the phase-fault sensitivity of phase comparison is not as good as that of directional comparison.

The ideal application of phase comparison is to a two-terminal line that one is sure will not be tapped later, and where the fault-current

magnitudes are high enough to assure high-speed tripping under all likely conditions of system operation.

The fact that phase-comparison relaying does not use a-c voltage (except for testing) may or may not be an advantage, depending on the type of back-up relaying that is used. If distance relays are used for back-up, the same quality of voltage source is required as for directional-comparison relaying. It is only when overcurrent relaying (possibly directional) is used for back-up protection that phase-comparison relaying enjoys any advantage from not using a-c voltages.

Phase-comparison relaying is unaffected by mutual induction from neighboring power circuits. This is an advantage over directional comparison. This subject is treated in more detail later under the heading "Combined Phase and Directional Comparison."

The fact that any back-up-relaying equipment that may be used is entirely separate from the phase-comparison equipment is an advantage of phase comparison. One equipment may be taken out of service for maintenance without disturbing the other in any way.

An excellent comparison of phase and directional-comparison relaying is given in Reference 13.

OBTAINING ADEQUATE SENSITIVITY

Apart from making sure that the carrier-current attenuation is not too high, and that associated equipment is suitable for the application, the principal step in the application procedure is to determine if the available adjustments of the relaying equipment are such that the necessary sensitivity and speed are assured. Manufacturers' bulletins describe how to do this when one knows the maximum and minimum fault-current magnitudes for phase and ground faults at either end of the line.

It is advisable not to adjust the equipment to have much greater sensitivity than is required or else, in so doing, the CT's may be burdened excessively. With excessive burden, the over-all sensitivity might be poorer, as illustrated by Problem 2 of Chapter 7. Or, if the ground-fault sensitivity is too high, the equipment might misoperate on "false residual currents"[6] caused by CT errors because of external-fault current having a large d-c offset, or because of differences in residual flux.

In practice the equipment is usually adjusted so that carrier current is not generated unless the phase-fault current exceeds the maximum load current. The purpose of this is to prolong the life of the vacuum tubes and to make the carrier-current channel available for other services when it is not required for relaying. Because the pickup of the tripping fault detectors must be higher than the pickup of the blocking fault detectors, the tripping pickup will be still higher above maximum load; in fact, the *reset* value of the tripping fault detectors must be a safe margin above the pickup of the blocking fault detectors. With such adjustment, failure of the carrier-current channel will not cause undesired tripping under load; however, undesired tripping could occur for an external fault if the channel failed.

THE PROTECTION OF MULTITERMINAL LINES

The more terminals there are with sources of generation back of them, the less sensitive will the protection be. This is illustrated with

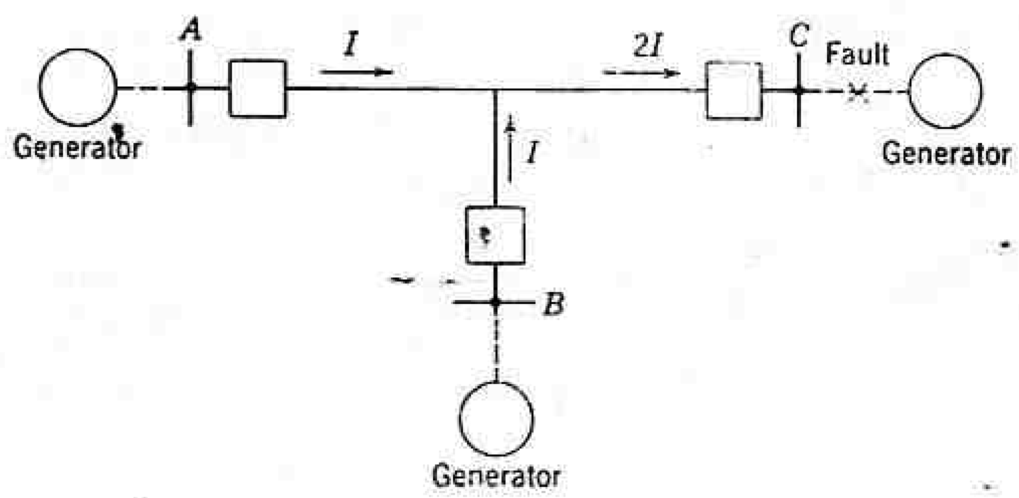

Fig. 4. Illustrating the reduction of sensitivity of phase-comparison relaying on multiterminal lines.

the help of Fig. 4 for a three-terminal line. Should equal magnitudes of fault current be fed into terminals A and B for an external fault beyond C, the pickup of the tripping fault detectors at C would have to be more than twice as high as the carrier-current-starting, or blocking, fault detectors at A and B. And, if the blocking fault detectors are adjusted to reset at more than the maximum full-load current, the tripping fault detectors at C will have to be adjusted to pick up at about 3 times maximum load.[14] Remember that phase-comparison relaying is not directional and that one terminal will operate to trip whenever its current is high enough unless it receives a blocking carrier-current signal from another terminal. The worst case is with equal currents entering at A and B. If one can be sure that these currents will not be equal, the tripping-fault-detector pickup at C can be lowered.

In general, the pickup adjustments of the fault detectors do not have to be the same at all terminals, but the pickup of the blocking fault detector having the highest pickup must be lower than the reset of the tripping fault detector having the lowest pickup.

Occasionally, in order to get the required tripping sensitivity, it may be considered justifiable to increase the blocking sensitivity to the point at which carrier current is transmitted continually when full-load current is flowing. In that event, vacuum-tube life will be shortened and the carrier-current channel cannot be used for any other services.

Another way of avoiding high pickup of the tripping fault detectors for situations like Fig. 4 is to use directional relays to control tripping at places like terminal C. However, this kind of solution will not work

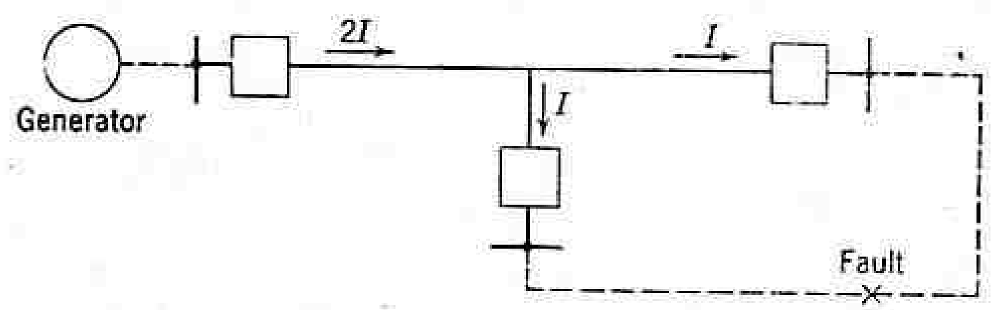

Fig. 5. A situation in which directional relaying will not prevent reduced sensitivity.

for the situation illustrated by Fig. 5 where the same problem exists, but at a terminal where the large current is flowing in the tripping direction.

At a load terminal, back of which there is no source of generation, and where there is no power-transformer neutral grounding on the high-voltage side, blocking-terminal equipment consisting of instantaneous overcurrent relays and a carrier-current transmitter can be used to block tripping at the main terminals for faults in the load circuits. Of course, this is necessary only if the main-terminal equipment is sensitive enough to operate for low-voltage faults at a load terminal. The phase-sequence network, comparer, etc., that are used in the equipment at the main terminals are not necessary, since no tripping function is provided at the blocking terminal. To block tripping at the main terminals, the overcurrent relays simply turn on carrier that is transmitted continuously and not every other half cycle. The blocking relays should be energized from CT's on the high-voltage side of the load-terminal power-transformer bank so that tripping will be blocked on magnetizing-current inrush. If the power transformer is wye-delta and grounded on the wye side, a ground overcurrent relay would be required to shut off carrier for ground faults on the high-voltage side.

If tripping at a blocking terminal is required to avoid damage to large motors when automatic reclosing is used at the main terminals, such tripping will probably have to be provided by local underfrequency relays. Remote tripping by carrier current over the protected line from the main terminals to such a load terminal could not be assured unless the tripping of the main terminals will extinguish an arcing phase-to-ground fault that might be on the phase to which the carrier-current equipment is coupled. Synchronous motors, acting as generators, might be able to generate sufficient voltage to maintain an arc through the capacitance to ground of the unfaulted conductors. Some users have installed equipment that relies on transmitting sufficient carrier current for remote tripping past an arcing ground fault on the coupling phase, but such operation cannot be assured in gen-

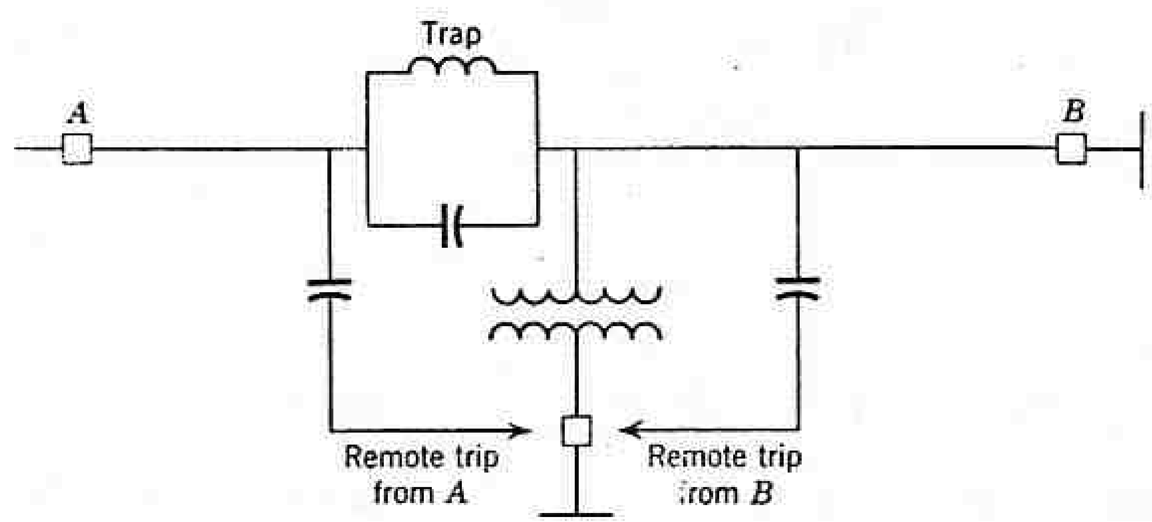

Fig. 6. Method of avoiding interference by a fault with remote tripping.

eral. One solution is to use phase-to-phase coupling for the remote-trip signal, or to transmit this signal over another line section if the lines are parallel. Another solution that has been used is shown in Fig. 6; no matter where the fault is, one main terminal or the other can cause remote tripping.

Remote tripping from power-transformer differential relays at a load terminal to the breakers at the main terminals can be done over the carrier-current channel.[5] Whenever remote tripping for transformer faults is undertaken, a line trap should be inserted in the coupling phase between the coupling capacitor and the power transformer, so that power-transformer faults to ground on the coupling phase cannot short-circuit the carrier-current-transmitter output.

A multiterminal line can sometimes be well protected against ground faults even though adequate phase-fault protection is impossible. This is because line taps are usually made through delta-wye power-transformer banks, which are open circuits so far as zero-phase-sequence currents on the high-voltage side are concerned. Therefore, if only ground relaying equipment is used and arranged to receive only

the CT neutral current, such a multiterminal line may be treated as a two-terminal line.

BACK-UP PROTECTION

Phase-comparison relaying does not provide back-up protection. This should be provided by phase distance relays and either overcurrent or distance ground relays. When phase-comparison relaying is applied to an existing line, it is often the practice to use the existing relaying equipment for back-up protection.

Conventional back-up relaying will be inadequate when intermediate current sources supply so much current to a fault that the fault is put beyond the reach of the back-up relays. Such a problem and its solution are described in Chapter 14 under the heading "The Effect of Intermediate Current Sources on Distance-Relay Operation." In such a situation it will be at the discretion of the user whether, in addition to the special back-up equipment, conventional back-up equipment is also applied to provide primary relaying while the phase-comparison equipment is being maintained or repaired.

Directional Comparison

Directional-comparison relaying is the most widely applicable type, and therefore it lends itself best to standardization programs. The only circumstance in which directional comparison is not applicable is when there is sufficient mutual induction with another line and when directional ground relays are used instead of ground distance relays; this is treated at greater length later under "Combined Phase and Directional Comparison."

In general, apart from considerations of carrier-current attenuation, the application of directional-comparison relaying is largely a matter of applying phase distance and directional-ground or ground distance relays. This is because, as mentioned in Chapter 6, conventional equipment uses certain units in common for carrier-current-pilot primary relaying and for back-up relaying. In fact, if a line is now protected by phase distance relays and ground overcurrent or distance relays, one may merely need to add some supplementary relays plus the carrier-current equipment to apply directional-comparison carrier-current-pilot relaying; the supplementary relays and carrier-current equipment provide the blocking function while the existing relays provide the tripping function. Of course, completely separate relaying could be used, but it would be more expensive.

RELATION BETWEEN SENSITIVITIES OF TRIPPING AND BLOCKING UNITS FOR TWO-TERMINAL LINES

The principal application procedure is to be sure that the correct relations are obtained between the operating ranges of the blocking and tripping units. This is seldom a problem for a two-terminal line. Figure 7 shows the relative operating ranges of the blocking and tripping units at both ends of a two-terminal line for, say, phase faults. The significant observation is that, for external faults beyond either end of the line, the blocking units must reach out farther than the

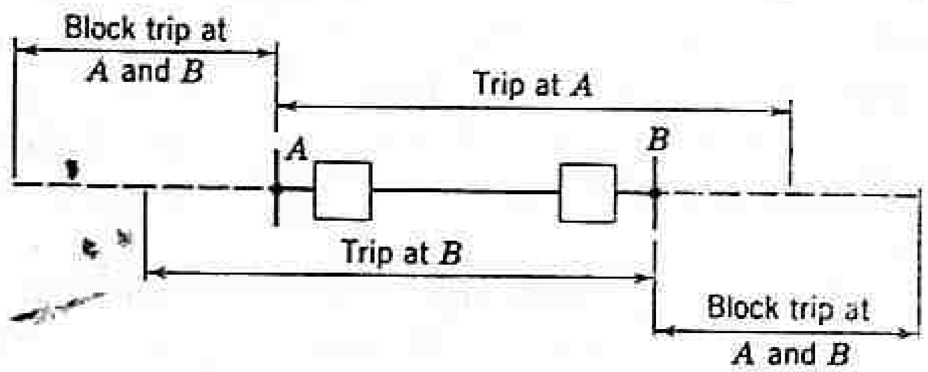

Fig. 7. Relative operating ranges of directional-comparison blocking and tripping units.

tripping units to be certain that, if there is any tendency to trip, it will surely be blocked. The tripping range for phase faults will be the operating range of the second- or third-zone distance-relay units, depending on the type of equipment.

The only time there is any problem adjusting the blocking units is when their range has to be so great that they might operate on load current, or that having operated for a fault they might not reset on load current. In such situations, it becomes necessary to use additional units called "blinders." These units are angle-impedance distance-relay units, one of which would be used with each blocking relay. The contacts of the two relays of each group would be connected in parallel so that both would have to open to start carrier. Figure 8 shows the operating characteristics of both relays and the point representing the load condition that makes blinders necessary. The resulting blocking region is shown cross-hatched. Blinders with impedance-type distance relays are shown because this type of relay is the most likely to require blinders for this purpose.

Incidentally, such blinders have been used also to prevent *tripping* on load current where distance relays have been applied to unusually long lines.

When low-tension voltage is used, transformer-drop compensation

not so necessary as when distance relays are used alone. The only time that transformer-drop compensation would be beneficial would be when the carrier-current equipment is out of service and complete reliance for protection is being placed on the distance relays. Such

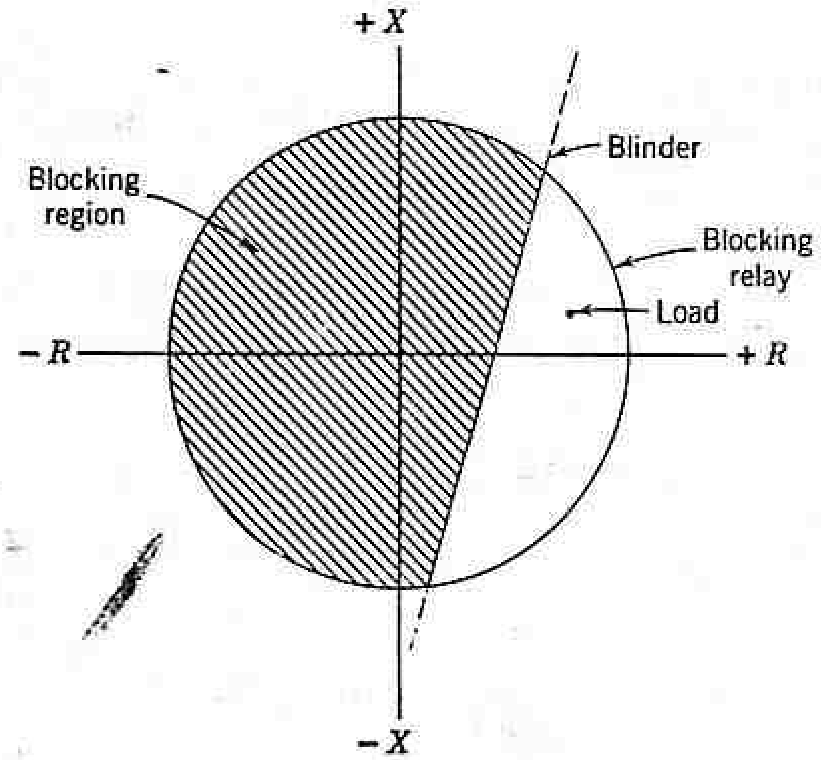

Fig. 8. A blinder to prevent blocking on load current.

circumstances occupy so little of the total time that the additional complications of transformer-drop compensation are not justified.

The problem of obtaining the correct relations between the tripping and blocking units for multiterminal-line applications, along with other related problems, is treated next.

THE PROTECTION OF MULTITERMINAL LINES

Directional-comparison relaying is applicable to any multiterminal line. However, under some circumstances proper operation will not be obtained without a very careful choice of the type of equipment and of the blocking- and tripping-relay adjustments.[4,15] And sometimes simultaneous high-speed tripping at all terminals will not be obtained. Therefore, one should be familiar with these circumstances so as to be able to avoid them, if possible, in the early stages of system planning. These circumstances will now be described.

Current Flow Out of One Terminal for an Internal Fault. In Fig. 9, directional-comparison relaying cannot trip for an internal fault if the current flowing out of the line at A is higher than the blocking-relay pickup there. This situation may exist for phase faults or ground faults or both. If it is not permissible to raise the blocking-relay pickup so as to avoid this situation, tripping must wait until the back-up relays at B trip their breaker, after which high-speed tripping can occur at the other two terminals. For phase faults, the distance relays at B will operate at high speed, and sequential high-speed tripping of all other terminals can follow if there is enough fault current, and if other features of the equipment do not introduce time delay. For ground faults, the tripping of breaker B will be delayed slightly unless ground distance or instantaneous overcurrent ground relays are used.

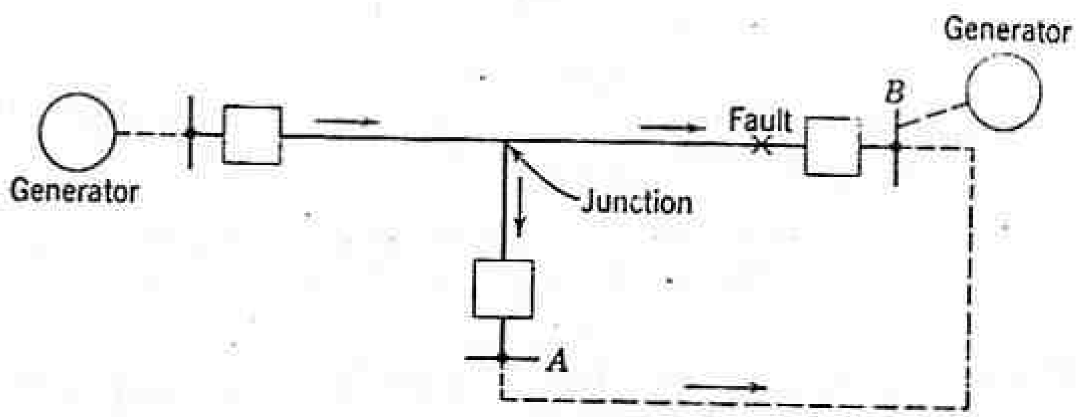

Fig. 9. Situation in which directional comparison blocks tripping for an internal fault.

Remote tripping from breaker B to the other terminals by means of carrier current over the protected line is not a reliable way to avoid sequential tripping, unless this type of difficulty occurs only for faults not involving ground. Or, if it occurs only for ground faults, phase-to-phase coupling could be used. Although some users are relying on getting sufficient remote-tripping signal past a phase-to-ground fault on the coupling phase, satisfactory results cannot be assured in general. Occasionally, another line section can be used for carrying the remote-tripping signal. Obviously, remote tripping would be practical if microwave were used instead of carrier current.

Insufficient Current for Tripping. Apart from there being too small a source of short-circuit current back of a terminal, other circumstances can make the current so low—or the apparent impedance to the fault so high—as to prevent or at least to delay tripping.

For the circumstance of Fig. 9, if the fault is closer to the junction, the current at A will be: (1) in the blocking direction but too low to operate a blocking relay, (2) zero, or (3) in the tripping direction but too low to operate a tripping relay. For any of these, tripping at the other terminals would not be blocked, but tripping at A would have to wait until the breakers at B had tripped, assuming that there would then be a redistribution of enough fault current at A to cause tripping there.

Another circumstance in which the fault current may be too low is shown in Fig. 10. Here, the intermediate current, or "mutual impedance effect," as it is sometimes called, may prevent tripping at both B and C. Furthermore, the tripping of the breakers at A may not relieve the inability to trip at breakers B and C, so that even sequential tripping may not be possible.

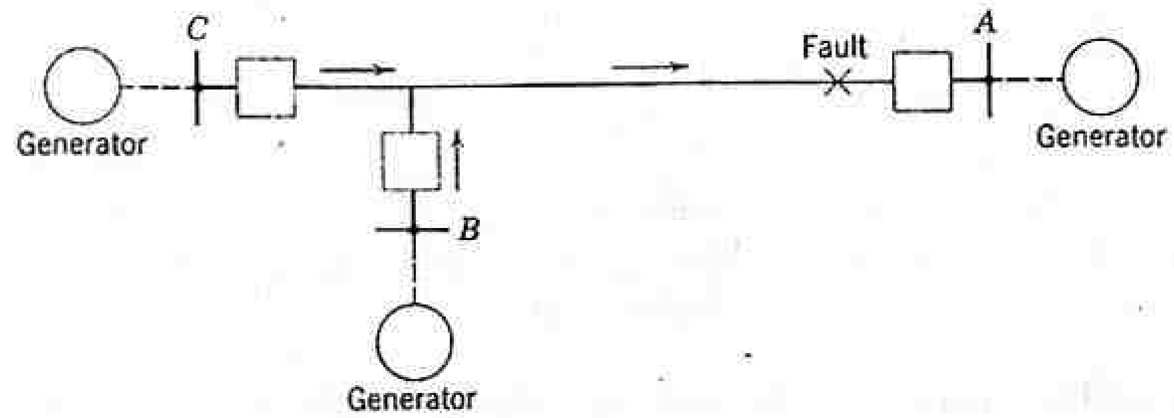

Fig. 10. Insufficient current for tripping.

As stated before, remote tripping is not a complete solution to the problem. Instantaneous undervoltage carrier-starting or tripping relays are a solution if their adjustments can be coordinated with those of the other relays.[2]

Shortcomings of Non-Directional Blocking Relays. Some directional-comparison equipments use non-directional overcurrent or impedance relays to start carrier. Occasionally, such equipments block tripping for an internal fault because the current or apparent impedance falls between the pickup of the blocking and tripping relays at the *same* terminal. Basically, the pickup adjustment of the blocking relays at a given terminal has to coordinate with the pickup adjustments of tripping relays at the other terminals. However, when non-directional blocking relays are used, coordination must also be obtained between the pickup adjustments of blocking and tripping relays at the *same* terminal. Such a circumstance can exist when there is insufficient current or too high an apparent impedance to cause tripping at a given terminal until after another terminal has tripped, as in one of the preceding cases. However, if a blocking relay at the given terminal should operate, it would block tripping at the other terminals; this situation would persist until a back-up relay operated to cause tripping at another terminal that would permit the given

1 THE PHILOSOPHY OF PROTECTIVE RELAYING

What is Protective Relaying?

We usually think of an electric power system in terms of its more impressive parts—the big generating stations, transformers, high-voltage lines, etc. While these are some of the basic elements, there are many other necessary and fascinating components. Protective relaying is one of these.

The role of protective relaying in electric-power-system design and operation is explained by a brief examination of the over-all background. There are three aspects of a power system that will serve the purposes of this examination. These aspects are as follows:

A. Normal operation.
B. Prevention of electrical failure.
C. Mitigation of the effects of electrical failure.

The term "normal operation" assumes no failures of equipment, no mistakes of personnel, nor "acts of God." It involves the minimum requirements for supplying the existing load and a certain amount of anticipated future load. Some of the considerations are:

A. Choice between hydro, steam, or other sources of power.
B. Location of generating stations.
C. Transmission of power to the load.
D. Study of the load characteristics and planning for its future growth.
E. Metering.
F. Voltage and frequency regulation.
G. System operation.
H. Normal maintenance.

The provisions for normal operation involve the major expense for equipment and operation, but a system designed according to this aspect alone could not possibly meet present-day requirements. Electrical equipment failures would cause intolerable outages. There must be additional provisions to minimize damage to equipment and interruptions to the service when failures occur.

Two recourses are open: (1) to incorporate features of design aimed at preventing failures, and (2) to include provisions for mitigating the effects of failure when it occurs. Modern power-system design employs varying degrees of both recourses, as dictated by the economics of any particular situation. Notable advances continue to be made toward greater reliability. But also, increasingly greater reliance is being placed on electric power. Consequently, even though the probability of failure is decreased, the tolerance of the possible harm to the service is also decreased. But it is futile—or at least not economically justifiable—to try to prevent failures completely. Sooner or later the law of diminishing returns makes itself felt. Where this occurs will vary between systems and between parts of a system, but, when this point is reached, further expenditure for failure prevention is discouraged. It is much more profitable, then, to let some failures occur and to provide for mitigating their effects.

The type of electrical failure that causes greatest concern is the short circuit, or "fault" as it is usually called, but there are other abnormal operating conditions peculiar to certain elements of the system that also require attention. Some of the features of design and operation aimed at preventing electrical failure are:

A. Provision of adequate insulation.
B. Coordination of insulation strength with the capabilities of lightning arresters.
C. Use of overhead ground wires and low tower-footing resistance.
D. Design for mechanical strength to reduce exposure, and to minimize the likelihood of failure causable by animals, birds, insects, dirt, sleet, etc.
E. Proper operation and maintenance practices.

Some of the features of design and operation for mitigating the effects of failure are:

A. Features that mitigate the immediate effects of an electrical failure.
   1. Design to limit the magnitude of short-circuit current.[1]
      a. By avoiding too large concentrations of generating capacity.
      b. By using current-limiting impedance.
   2. Design to withstand mechanical stresses and heating owing to short-circuit currents.
   3. Time-delay undervoltage devices on circuit breakers to prevent dropping loads during momentary voltage dips.
   4. Ground-fault neutralizers (Petersen coils).
B. Features for promptly disconnecting the faulty element.
   1. Protective relaying.
   2. Circuit breakers with sufficient interrupting capacity.
   3. Fuses.

C. Features that mitigate the loss of the faulty element.
   1. Alternate circuits.
   2. Reserve generator and transformer capacity.
   3. Automatic reclosing.
D. Features that operate throughout the period from the inception of the fault until after its removal, to maintain voltage and stability.
   1. Automatic voltage regulation.
   2. Stability characteristics of generators.
E. Means for observing the effectiveness of the foregoing features.
   1. Automatic oscillographs.
   2. Efficient human observation and record keeping.
F. Frequent surveys as system changes or additions are made, to be sure that the foregoing features are still adequate.

Thus, protective relaying is one of several features of system design concerned with minimizing damage to equipment and interruptions to service when electrical failures occur. When we say that relays "protect," we mean that, together with other equipment, the relays help to minimize damage and improve service. It will be evident that all the mitigation features are dependent on one another for successfully minimizing the effects of failure. *Therefore, the capabilities and the application requirements of protective-relaying equipments should be considered concurrently with the other features.*[2] This statement is emphasized because there is sometimes a tendency to think of the protective-relaying equipment after all other design considerations are irrevocably settled. Within economic limits, an electric power system should be designed so that it can be adequately protected.

The Function of Protective Relaying

The function of protective relaying is to cause the prompt removal from service of any element of a power system when it suffers a short circuit, or when it starts to operate in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system. The relaying equipment is aided in this task by circuit breakers that are capable of disconnecting the faulty element when they are called upon to do so by the relaying equipment.

Circuit breakers are generally located so that each generator, transformer, bus, transmission line, etc., can be completely disconnected from the rest of the system. These circuit breakers must have sufficient capacity so that they can carry momentarily the maximum short-circuit current that can flow through them, and then interrupt this current; they must also withstand closing in on such a short circuit and then interrupting it according to certain prescribe standards.[3]

Fusing is employed where protective relays and circuit breaker are not economically justifiable.

Although the principal function of protective relaying is to mitigat the effects of short circuits, other abnormal operating conditions aris that also require the services of protective relaying. This is par ticularly true of generators and motors.

A secondary function of protective relaying is to provide indicatio of the location and type of failure. Such data not only assist i expediting repair but also, by comparison with human observatio and automatic oscillograph records, they provide means for analyz ing the effectiveness of the fault-prevention and mitigation feature including the protective relaying itself.

Fundamental Principles of Protective Relaying

Let us consider for the moment only the relaying equipment fo the protection against short circuits. There are two groups of suc equipment—one which we shall call "primary" relaying, and th other "back-up" relaying. Primary relaying is the first line of de fense, whereas back-up relaying functions only when primary relayin fails.

PRIMARY RELAYING

Figure 1 illustrates primary relaying. The first observation i that circuit breakers are located in the connections to each powe system element. This provision makes it possible to disconnect onl a faulty element. Occasionally, a breaker between two adjacent ele ments may be omitted, in which event both elements must be dis connected for a failure in either one.

The second observation is that, without at this time knowing ho it is accomplished, a separate zone of protection is established aroun each system element. The significance of this is that any failu occurring within a given zone will cause the "tripping" (i.e., opening of all circuit breakers within that zone, and only those breakers.

It will become evident that, for failures within the region wher two adjacent protective zones overlap, more breakers will be trippe than the minimum necessary to disconnect the faulty element. Bu if there were no overlap, a failure in a region between zones woul not lie in either zone, and therefore no breakers would be tripped The overlap is the lesser of the two evils. The extent of the overla

is relatively small, and the probability of failure in this region is low; consequently, the tripping of too many breakers will be quite infrequent.

Finally, it will be observed that adjacent protective zones of Fig. 1 overlap *around a circuit breaker*. This is the preferred practice

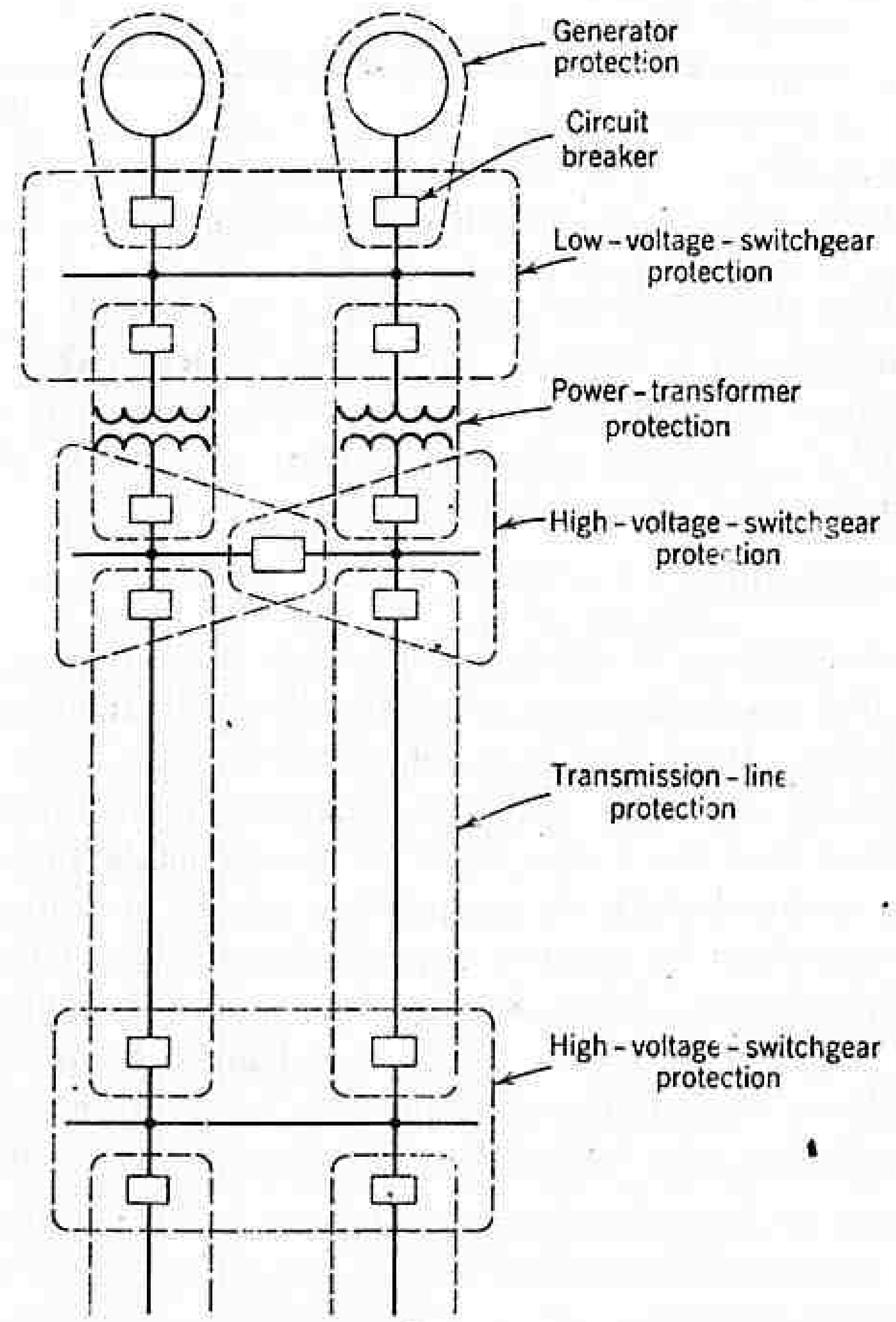

Fig. 1. One-line diagram of a portion of an electric power system illustrating primary relaying.

because, for failures anywhere except in the overlap region, the minimum number of circuit breakers need to be tripped. When it becomes desirable for economic or space-saving reasons to overlap on one side of a breaker, as is frequently true in metal-clad switchgear, the relaying equipment of the zone that overlaps the breaker must be arranged to trip not only the breakers within its zone but also one or more breakers of the adjacent zone, in order to completely disconnect certain faults. This is illustrated in Fig. 2, where it can be seen that, for a short circuit at X, the circuit breakers of zone B, including breaker C, will be tripped; but, since the short circuit is outside zone A, the relaying equipment of zone B must also trip certain breakers in zone A if that is necessary to interrupt the flow of short-circuit current from zone A to the fault. This is not a disadvantage for a fault at X, but the same breakers in zone A will be tripped unnecessarily for other faults in zone B to the right of breaker C. Whether this unnecessary tripping is objectionable will depend on the particular application.

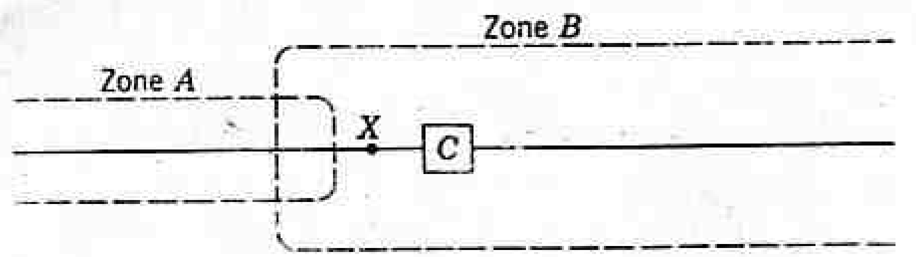

Fig. 2. Overlapping adjacent protective zones on one side of a circuit breaker.

BACK-UP RELAYING

Back-up relaying is employed only for protection against short circuits. Because short circuits are the preponderant type of power-system failure, there are more opportunities for failure in short-circuit primary relaying. Experience has shown that back-up relaying for other than short circuits is not economically justifiable.

A clear understanding of the possible causes of primary-relaying failure is necessary for a better appreciation of the practices involved in back-up relaying. When we say that primary relaying may fail, we mean that any of several things may happen to prevent primary relaying from causing the disconnection of a power-system fault. Primary relaying may fail because of failure in any of the following:

A. Current or voltage supply to the relays.
B. D-c tripping-voltage supply.
C. Protective relays.
D. Tripping circuit or breaker mechanism.
E. Circuit breaker.

It is highly desirable that back-up relaying be arranged so that anything that might cause primary relaying to fail will not also cause failure of back-up relaying. It will be evident that this requirement is completely satisfied only if the back-up relays are located so that they do not employ or control anything in common with the primary relays that are to be backed up. So far as possible, the practice is to locate the back-up relays at a different station. Consider, for example, the back-up relaying for the transmission line section EF of Fig. 3. The back-up relays for this line section are normally arranged to trip breakers A, B, I, and J. Should breaker E fail to trip for a fault on the line section EF, breakers A and B are tripped; breakers A and B and their associated back-up-relaying equipment, being physically apart from the equipment that has failed, are not likely to be simultaneously affected as might be the case if breakers C and D were chosen instead.

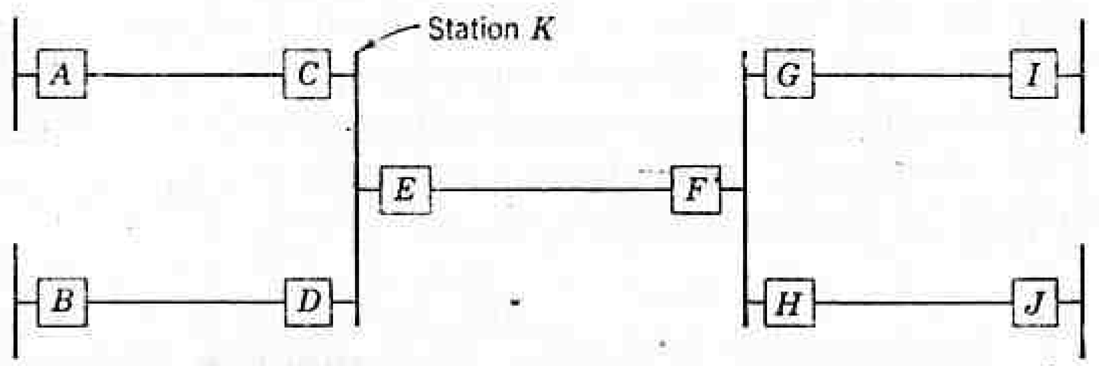

Fig. 3. Illustration for back-up protection of transmission line section EF.

The back-up relays at locations A, B, and F provide back-up protection if bus faults occur at station K. Also, the back-up relays at A and F provide back-up protection for faults in the line DB. In other words, the zone of protection of back-up relaying extends in one direction from the location of any back-up relay and at least overlaps each adjacent system element. Where adjacent line sections are of different length, the back-up relays must overreach some line sections more than others in order to provide back-up protection for the longest line.

A given set of back-up relays will provide incidental back-up protection of sorts for faults in the circuit whose breaker the back-up relays control. For example, the back-up relays that trip breaker A of Fig. 3 may also act as back-up for faults in the line section AC. However, this duplication of protection is only an incidental benefit and is not to be relied on to the exclusion of a conventional back-up arrangement when such arrangement is possible; to differentiate between the two, this type might be called "duplicate primary relaying."

A second function of back-up relaying is often to provide primary protection when the primary-relaying equipment is out of service for maintenance or repair.

It is perhaps evident that, when back-up relaying functions, a larger part of the system is disconnected than when primary relaying operates correctly. This is inevitable if back-up relaying is to be made independent of those factors that might cause primary relaying to fail. However, it emphasizes the importance of the second requirement of back-up relaying, that it must operate with sufficient time delay so that primary relaying will be given enough time to function if it is able to. In other words, when a short circuit occurs both primary relaying and back-up relaying will normally start to operate, but primary relaying is expected to trip the necessary breakers to remove the short-circuited element from the system, and back-up relaying will then reset without having had time to complete its function. When a given set of relays provides back-up protection for several adjacent system elements, the slowest primary relaying of any of those adjacent elements will determine the necessary time delay of the given back-up relays.

For many applications, it is impossible to abide by the principle of complete segregation of the back-up relays. Then one tries to supply the back-up relays from sources other than that supply the primary relays of the system element in question, and to trip other breakers. This can usually be accomplished; however, the same tripping battery may be employed in common, to save money and because it is considered only a minor risk. This subject will be treated in more detail in Chapter 14.

In extreme cases, it may even be impossible to provide any back-up protection; in such cases, greater emphasis is placed on the need for better maintenance. In fact, even with complete back-up relaying there is still much to be gained by proper maintenance. When primary relaying fails, even though back-up relaying functions properly the service will generally suffer more or less. Consequently, back-up relaying is not a proper substitute for good maintenance.

PROTECTION AGAINST OTHER ABNORMAL CONDITIONS

Protective relaying for other than short circuits is included in the category of primary relaying. However, since the abnormal conditions requiring protection are different for each system element no universal overlapping arrangement of relaying is used as in short-circuit protection. Instead, each system element is independently provided with whatever relaying is required, and this relaying is arranged to trip the necessary circuit breakers which may in some cases be different from those tripped by the short-circuit relaying. As previously mentioned, back-up relaying is not employed because experience has not shown it to be economically justifiable. Frequently however, back-up relaying for short circuits will function when other abnormal conditions occur that produce abnormal currents or voltages, and back-up protection of sorts is thereby incidentally provided.

Functional Characteristics of Protective Relaying

SENSITIVITY, SELECTIVITY, AND SPEED

"Sensitivity," "selectivity," and "speed" are terms commonly used to describe the functional characteristics of any protective-relaying equipment. All of them are implied in the foregoing considerations of primary and back-up relaying. Any relaying equipment must be sufficiently *sensitive* so that it will operate reliably, when required, under the actual condition that produces the least operating tendency. It must be able to *select* between those conditions for which prompt operation is required and those for which no operation, or time-delay operation, is required. And it must operate at the required *speed*. How well any protective-relaying equipment fulfills each of these requirements must be known for each application.

The ultimate goal of protective relaying is to disconnect a faulty system element as quickly as possible. Sensitivity and selectivity are essential to assure that the proper circuit breakers will be tripped, but speed is the "pay-off." The benefits to be gained from speed will be considered later.

RELIABILITY

That protective-relaying equipment must be reliable is a basic requirement. When protective relaying fails to function properly, the allied mitigation features are largely ineffective. Therefore, it is essential that protective-relaying equipment be inherently reliable, and that its application, installation, and maintenance be such as to assure that its maximum capabilities will be realized.

Inherent reliability is a matter of design based on long experience, and is much too extensive and detailed a subject to do justice to here. Other things being equal, simplicity and robustness contribute to reliability, but they are not of themselves the complete solution. Workmanship must be taken into account also. Contact pressure is an important measure of reliability, but the contact materials and the provisions for preventing contact contamination are fully as important. These are but a few of the many design considerations that could be mentioned.

The proper application of protective-relaying equipment involves the proper choice not only of relay equipment but also of the associated apparatus. For example, lack of suitable sources of current and voltage for energizing the relays may compromise, if not jeopardize, the protection.

Contrasted with most of the other elements of an electric power system, protective relaying stands idle most of the time. Some types of relaying equipment may have to function only once in several years. Transmission-line relays have to operate most frequently, but even they may operate only several times per year. This lack of frequent exercising of the relays and their associated equipment must be compensated for in other ways to be sure that the relaying equipment will be operable when its turn comes.

Many electric utilities provide their test and maintenance personnel with a manual that experienced people in the organization have prepared and that is kept up to date as new types of relays are purchased. Such a manual specifies minimum test and maintenance procedure that experience has shown to be desirable. The manual is prepared in part from manufacturers' publications and in part from the utility's experience. As a consequence of standardized techniques, the results of periodic tests can be compared to detect changes or deterioration in the relays and their associated devices. Testers are encouraged to make other tests as they see fit so long as they make the tests required by the manual. If a better testing technique is devised, it is incorporated into the manual. Some organizations include information on the purpose of the relays, to give their people better appreciation of the importance of their work. Courses may be given, also. Such activity is highly recommended. Unless a person is thoroughly acquainted with relay testing and maintenance he can do more harm than good, and he might better leave the equipment alone.

In some cases, actual field tests are made after installation and after careful preliminary testing of the individual relays. These field tests provide an excellent means for checking the over-all operation of all equipment involved.

Careful maintenance and record keeping, not only of tests during maintenance but also of relay operation during actual service, are the best assurance that the relaying equipment is in proper condition. Field testing is the best-known way of checking the equipment prior to putting it in service, but conditions may arise in actual service that were not anticipated in the tests. The best assurance that the relays are properly applied and adjusted is a record of correct operation through a sufficiently long period to include the various operating conditions that can exist. It is assuring not only when a particular

relaying equipment trips the proper breakers when it should for a given fault but also when other relaying equipments properly refrain from tripping.

Are Protective Practices Based on the Probability of Failure?

Protective practices are based on the probability of failure to the extent that present-day practices are the result of years of experience in which the frequency of failure undoubtedly has played a part. However, the probability of failure seldom if ever enters directly into the choice of a particular type of relaying equipment except when, for one reason or another, one finds it most difficult to apply the type that otherwise would be used. In any event, the probability of failure should be considered only together with the consequences of failure should it occur. It has been said that the justification for a given practice equals the likelihood of trouble times the cost of the trouble. Regardless of the probability of failure, no portion of a system should be entirely without protection, even if it is only back-up relaying.

Protective Relaying versus a Station Operator

Protective relaying sometimes finds itself in competition with station operators or attendants. This is the case for protection against abnormal conditions that develop slowly enough for an operator to have time to correct the situation before any harmful consequences develop. Sometimes, an alert and skillful operator can thereby avoid having to remove from service an important piece of equipment when its removal might be embarrassing; if protective relaying is used in such a situation, it is merely to sound an alarm. To some extent, the preference of relying on an operator has a background of some unfortunate experience with protective relaying whereby improper relay operation caused embarrassment; such an attitude is understandable, but it cannot be supported logically. Where quick and accurate action is required for the protection of important equipment, it is unwise to rely on an operator. Moreover, when trouble occurs, the operator usually has other things to do for which he is better fitted.

Undesired Tripping versus Failure to Trip When Desired

Regardless of the rules of good relaying practice, one will occasionally have to choose which rule may be broken with the least embarrassment. When one must choose between the chance of undesired or unnecessary tripping and failure to trip when tripping is desired, the best practice is generally to choose the former. Experience has shown that, where major system shutdowns have resulted from one or the other, the failure to trip—or excessive delay in tripping—has been by far the worse offender.

The Evaluation of Protective Relaying

Although a modern power system could not operate without protective relaying, this does not make it priceless. As in all good engineering, economics plays a large part. Although the protection engineer can usually justify expenditures for protective relaying on the basis of standard practice, circumstances may alter such concepts and it often becomes necessary to evaluate the benefits to be gained. It is generally not a question of whether protective relaying can be justified, but of how far one should go toward investing in the best relaying available.

Like all other parts of a power system, protective relaying should be evaluated on the basis of its contribution to the best economically possible service to the customers. The contribution of protective relaying is to help the rest of the power system to function as efficiently and as effectively as possible in the face of trouble.[2] How protective relaying does this is as follows. By minimizing damage when failures occur, protective relaying minimizes:

A. The cost of repairing the damage.
B. The likelihood that the trouble may spread and involve other equipment.
C. The time that the equipment is out of service.
D. The loss in revenue and the strained public relations while the equipment is out of service.

By expediting the equipment's return to service, protective relaying helps to minimize the amount of equipment reserve required, since there is less likelihood of another failure before the first failure can be repaired.

The ability of protective relaying to permit fuller use of the system capacity is forcefully illustrated by system stability. Figure 4 shows how the speed of protective relaying influences the amount of power that can be transmitted without loss of synchronism when short circuits occur.[4] More load can be carried over an existing system by speeding up the protective relaying. This has been shown to be a relatively inexpensive way to increase the transient stability limit.[5] Where stability is a problem, protective relaying can often be evaluated

against the cost of constructing additional transmission lines or switching stations.

Other circumstances will be shown later in which certain types of protective-relaying equipment can permit savings in circuit breakers and transmission lines.

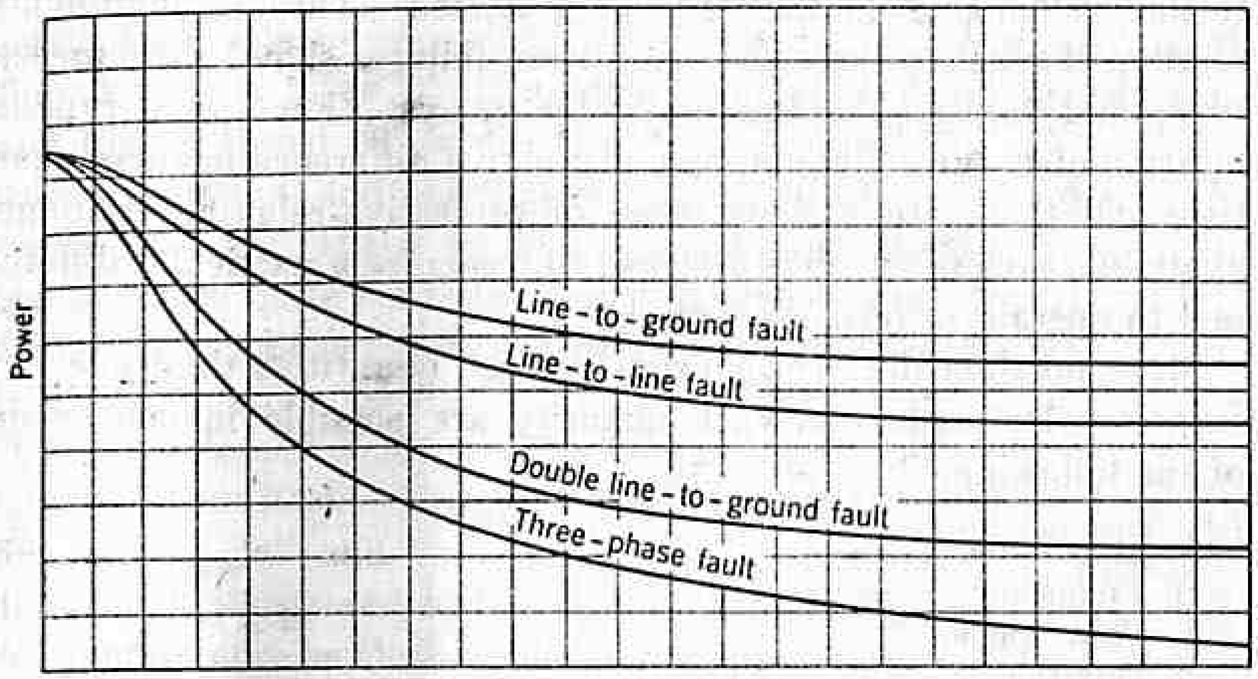

Fig. 4. Curves illustrating the relation between relay-plus-breaker time and the maximum amount of power that can be transmitted over one particular system without loss of synchronism when various faults occur.

The quality of the protective-relaying equipment can affect engineering expense in applying the relaying equipment itself. Equipment that can still operate properly when future changes are made in a system or its operation will save much future engineering and other related expense.

One should not conclude that the justifiable expense for a given protective-relaying equipment is necessarily proportional to the value or importance of the system element to be directly protected. A failure in that system element may affect the ability of the entire system to render service, and therefore that relaying equipment is actually protecting the service of the entire system. Some of the most serious shutdowns have been caused by consequential effects growing out of an original failure in relatively unimportant equipment that was not properly protected.

How Do Protective Relays Operate?

Thus far, we have treated the relays themselves in a most impersonal manner, telling what they do without any regard to how they do it.

This fascinating part of the story of protective relaying will be told in much more detail later. But, in order to round out this general consideration of relaying and to prepare for what is yet to come, some explanation is in order here.

All relays used for short-circuit protection, and many other types also, operate by virtue of the current and/or voltage supplied to them by current and voltage transformers connected in various combinations to the system element that is to be protected. Through individual or relative changes in these two quantities, failures signal their presence, type, and location to the protective relays. For every type and location of failure, there is some distinctive difference in these quantities, and there are various types of protective-relaying equipments available, each of which is designed to recognize a particular difference and to operate in response to it.[6]

More possible differences exist in these quantities than one might suspect. Differences in each quantity are possible in one or more of the following:

A. Magnitude.
B. Frequency.
C. Phase angle.
D. Duration.
E. Rate of change.
F. Direction or order of change.
G. Harmonics or wave shape.

Then, when both voltage and current are considered in combination, or relative to similar quantities at different locations, one can begin to realize the resources available for discriminatory purposes. It is a fortunate circumstance that, although Nature in her contrary way has imposed the burden of electric-power-system failure, she has at the same time provided us with a means for combat.

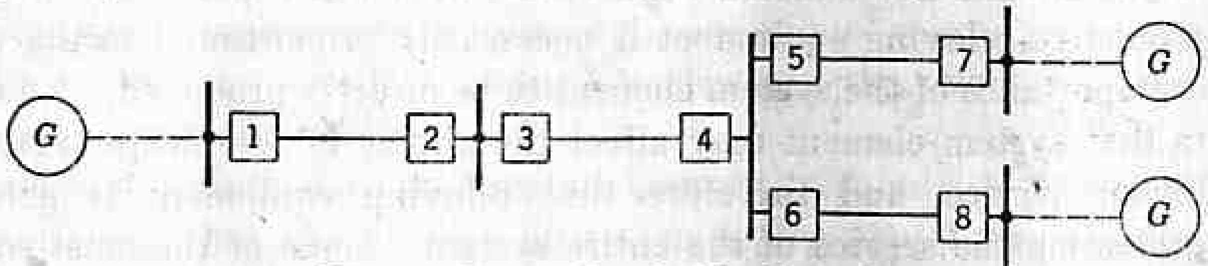

Fig. 5. Illustration for Problem 2.

Problems

1. Compare protective relaying with insurance.
2. The portion of a power system shown by the one-line diagram of Fig. 5, with generating sources back of all three ends, has conventional primary and back-up relaying. In each of the listed cases, a short circuit has occurred and certain circuit breakers have tripped as stated. Assume that the tripping of these breakers was correct under the circumstances. Where was the short circuit? Was there any failure of the protective relaying, including breakers, and if so, what failed? Assume only one failure at a time. Draw a sketch showing the overlapping of primary protective zones and the exact locations of the various faults.

Case	Breakers Tripped
a	4, 5, 8
b	3, 7, 8
c	3, 4, 5, 6
d	1, 4, 5, 6
e	4, 5, 7, 8
f	4, 5, 6

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2 FUNDAMENTAL RELAY-OPERATING PRINCIPLES AND CHARACTERISTICS

Protective relays are the "tools" of the protection engineer. As in any craft, an intimate knowledge of the characteristics and capabilities of the available tools is essential to their most effective use. Therefore, we shall spend some time learning about these tools without too much regard to their eventual use.

General Considerations

All the relays that we shall consider operate in response to one or more electrical quantities either to close or to open contacts. We shall not bother with the details of actual mechanical construction except where it may be necessary for a clear understanding of the operation. One of the things that tend to dismay the novice is the great variation in appearance and types of relays, but actually there are surprisingly few fundamental differences. Our attention will be directed to the response of the few basic types to the electrical quantities that actuate them.

OPERATING PRINCIPLES

There are really only two fundamentally different operating principles: (1) electromagnetic attraction, and (2) electromagnetic induction. Electromagnetic-attraction relays operate by virtue of a plunger being drawn into a solenoid, or an armature being attracted to the poles of an electromagnet. Such relays may be actuated by d-c or by a-c quantities. Electromagnetic-induction relays use the principle of the induction motor whereby torque is developed by induction in a rotor; this operating principle applies only to relays actuated by alternating current, and in dealing with those relays we shall call them simply "induction-type" relays.

DEFINITIONS OF OPERATION

Mechanical movement of the operating mechanism is imparted to a contact structure to close or to open contacts. When we say that a relay "operates," we mean that it either closes or opens its contacts—whichever is the required action under the circumstances. Most relays have a "control spring," or are restrained by gravity, so that they assume a given position when completely de-energized; a contact that is closed under this condition is called a "closed" contact, and one that is open is called an "open" contact. This is standardized nomenclature, but it can be quite confusing and awkward to use. A much better nomenclature in rather extensive use is the designation "*a*" for an "open" contact, and "*b*" for a "closed" contact. This nomenclature will be used in this book. The present standard method for showing "*a*" and "*b*" contacts on connection diagrams is illustrated in Fig. 1. Even though an "*a*" contact may be closed under normal operating conditions, it should be shown open as in Fig. 1; and similarly, even though a "*b*" contact may normally be open, it should be shown closed.

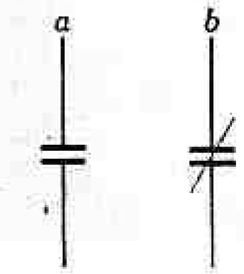

Fig. 1. Contact symbols and designations.

When a relay operates to open a "*b*" contact or to close an "*a*" contact, we say that it "picks up," and the smallest value of the actuating quantity that will cause such operation, as the quantity is slowly increased from zero, is called the "pickup" value. When a relay operates to close a "*b*" contact, or to move to a stop in place of a "*b*" contact, we say that it "resets"; and the largest value of the actuating quantity at which this occurs, as the quantity is slowly decreased from above the pickup value, is called the "reset" value. When a relay operates to open its "*a*" contact, but does not reset, we say that it "drops out," and the largest value of the actuating quantity at which this occurs is called the "drop-out" value.

OPERATION INDICATORS

Generally, a protective relay is provided with an indicator that shows when the relay has operated to trip a circuit breaker. Such "operation indicators" or "targets" are distinctively colored elements that are actuated either mechanically by movement of the relay's operating mechanism, or electrically by the flow of contact current, and come into view when the relay operates. They are arranged to be reset manually after their indication has been noted, so as to be ready for the next operation. One type of indicator is shown in line offset from the origin and perpendicular to the maximum positive-torque position of the current. This line is the plot of the relation:

$$I \cos (\theta - \tau) = \text{constant}$$

which is obtained when the magnitude of V is assumed to be constant, and it is the dividing line between the development of net positive and negative torque in the relay. Any current vector whose head lies in the positive-torque area will cause pickup; the relay will not pick up, or it will reset, for any current vector whose head lies in the negative-torque area.

For a different magnitude of the reference voltage, the operating characteristic will be another straight line parallel to the one shown and related to it by the expression:

$$VI_{\min} = \text{constant}$$

where $I_{\min}$, as shown in Fig. 17, is the smallest magnitude of all current vectors whose heads terminate on the operating characteristic. $I_{\min}$ is called "the minimum pickup current," although strictly speaking the current must be slightly larger to cause pickup. Thus, there is an infinite possible number of such operating characteristics, one for each possible magnitude of the reference voltage.

The operating characteristic will depart from a straight line as the phase angle of the current approaches 90° from the maximum-torque phase angle. For such large angular departures, the pickup current becomes very large, and magnetic saturation of the current element requires a different magnitude of current to cause pickup from the one that the straight-line relation would indicate.

The operating characteristic for current-current or voltage-voltage directional relays can be similarly shown.

THE "CONSTANT-PRODUCT" CHARACTERISTIC

The relation $VI_{\min} = \text{constant}$ for the current-voltage relay (and similar expressions for the others) is called the "constant-product" characteristic. It corresponds closely to the pickup current or voltage of a single-quantity relay and is used as the basis for plotting the time characteristics. This relation holds only so long as saturation does not occur in either of the two magnetic circuits. When either of the two quantities begins to exceed a certain magnitude, the quantity producing saturation must be increased beyond the value indicated by the constant-product relation in order to produce net positive torque.

EFFECT OF D-C OFFSET AND OTHER TRANSIENTS

The effect of transients may be neglected with inverse-time relays, but, with high-speed relays, certain transients may have to be guarded against either in the design of the relay or in its application. Generally, an increase in pickup or the addition of one or two cycles (60-cycle-per-second basis) time delay will avoid undesired operation. This subject is much too complicated to do justice to here. Suffice it to say, trouble of this nature is extremely rare and is not generally a factor in the application of established relay equipments.

THE EFFECT OF FREQUENCY

Directional relays are affected like single-quantity relays by changes in frequency of both quantities. The angle of maximum torque is affected, owing to changes in the X/R ratio in circuits containing inductance or capacitance. The effect of slight changes in frequency such as are normally encountered, however, may be neglected. If the frequencies of the two quantities supplied to the relay are different, a sinusoidal torque alternating between positive and negative will be produced; the net torque for each torque cycle will be zero, but, if the frequencies are nearly equal and if a high-speed relay is involved, the relay may respond to the reversals in torque.

TIME CHARACTERISTICS

Disc-type relays are used where inverse-time characteristics are desired, and cup-type or loop-type relays are used for high-speed operation. When time delay is desired, it is often provided by another relay associated with the directional relay.

The Universal Relay-Torque Equation

As surprising as it may seem, we have now completed our examination of all the essential fundamentals of protective-relay operation. All relays yet to be considered are merely combinations of the types that have been described. At this point, we may write the universal torque equation as follows:

$$T = K_1 I^2 + K_2 V^2 + K_3 VI \cos (\theta - \tau) + K_4$$

By assigning plus or minus signs to certain of the constants and letting others be zero, and sometimes by adding other similar terms, the operating characteristics of all types of protective relays can be expressed.

Various factors that one must generally take into account in applying the different types have been presented. Little or no quantitative data have been given because it is of little consequence for a clear understanding of the subject. Such data are easily obtained for any particular type of relay; the important thing is to know how to use such data. In the following chapters, by applying the fundamental principles that have been given here, we shall learn how the various types of protective relays operate.

Problems

1. A 60-cycle single-phase directional relay of the current-voltage type has a voltage coil whose impedance is $230 + j560$ ohms. When connected as shown in Fig. 18, the relay develops maximum positive torque when load of a leading power factor is being supplied in a given direction.

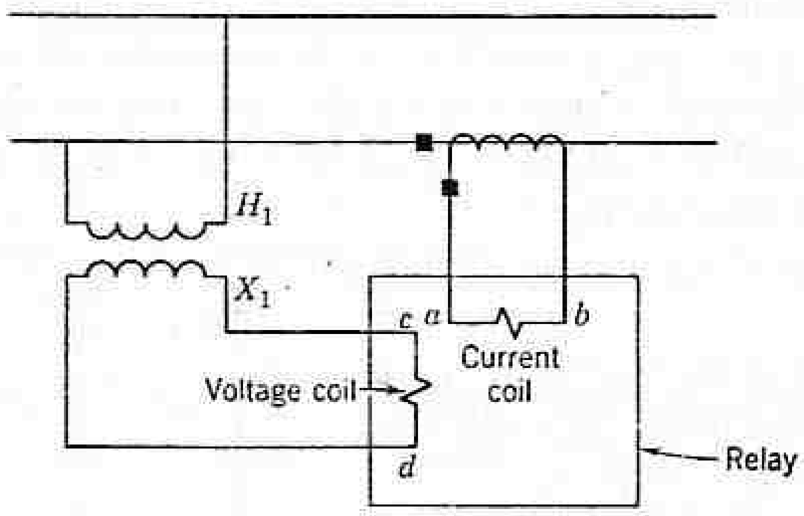

Fig. 18. Illustration for Problem 1.

It is desired to modify this relay so that it will develop maximum positive torque for load in the same direction as before, but at 45° lagging power factor. Moreover, it is desired to maintain the same minimum pickup current as before. Draw a connection diagram similar to that given, showing the modifications you would make, and giving quantitative values. Assume that the relay has a symmetrical structure. R = 197.5 Ω   C = 2.69 μF

2. Given an induction-type directional relay in which the frequency of one flux is n times that of the other. Derive the equation for the torque of this relay at any instant if at zero time the relay is developing maximum torque.

3. What will the torque equation of an induction-type directional relay be if one flux is direct current and the other is alternating current?

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Fig. 2. Electrically operated targets are generally preferred because they give definite assurance that there was a current flow in the contact circuit. Mechanically operated targets may be used when the closing of a relay contact always completes the trip circuit where

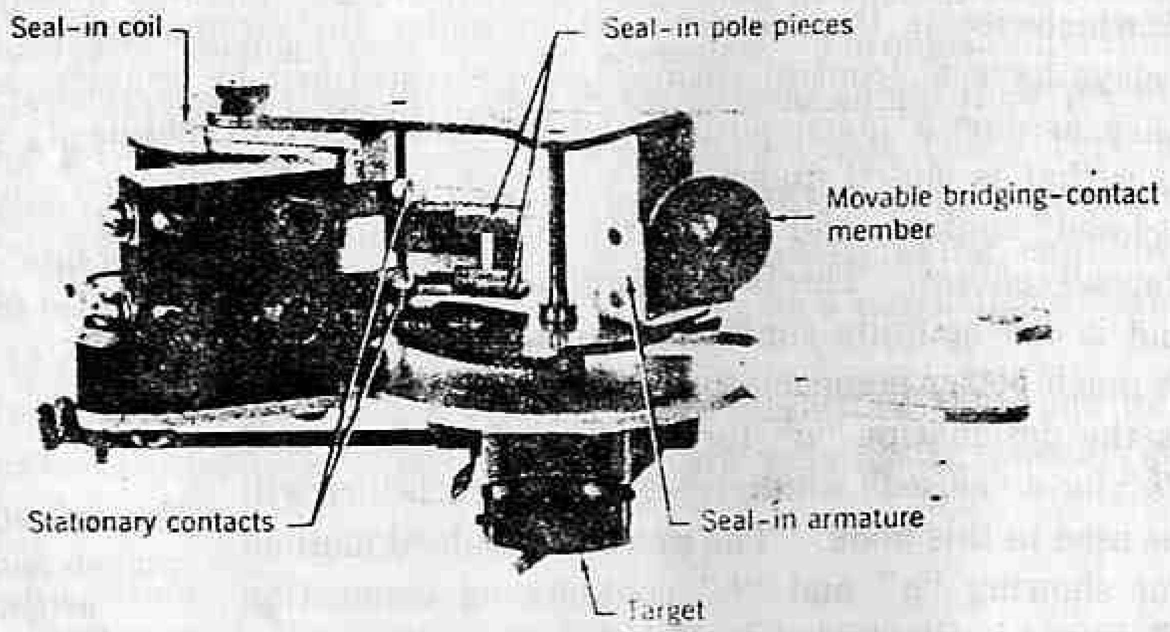

Fig. 2. One type of contact mechanism showing target and seal-in elements.

tripping is not dependent on the closing of some other series contact. A mechanical target may be used with a series circuit comprising contacts of other relays when it is desired to have indication that a particular relay has operated, even though the circuit may not have been completed through the other contacts.

SEAL-IN AND HOLDING COILS, AND SEAL-IN RELAYS

In order to protect the contacts against damage resulting from a possible inadvertent attempt to interrupt the flow of the circuit-breaker trip-coil current, some relays are provided with a holding mechanism comprising a small coil in series with the contacts; this coil is on a small electromagnet that acts on a small armature on the moving-contact assembly to hold the contacts tightly closed once they have established the flow of trip-coil current. This coil is called a "seal-in" or "holding" coil. Figure 2 shows such a structure. Other relays use a small auxiliary relay whose contacts by-pass the protective-relay contacts and seal the circuit closed while tripping current flows. This seal-in relay may also display the target. In either case, the circuit is arranged so that, once the trip-coil current starts to flow, it can be interrupted only by a circuit-breaker auxiliary switch that is connected in series with the trip-coil circuit and that opens when the breaker opens. This auxiliary switch is defined as an "a" contact. The circuits of both alternatives are shown in Fig. 3.

Figure 3 also shows the preferred polarity to which the circuit-breaker trip coil (or any other coil) should be connected to avoid corrosion because of electrolytic action. No coil should be connected

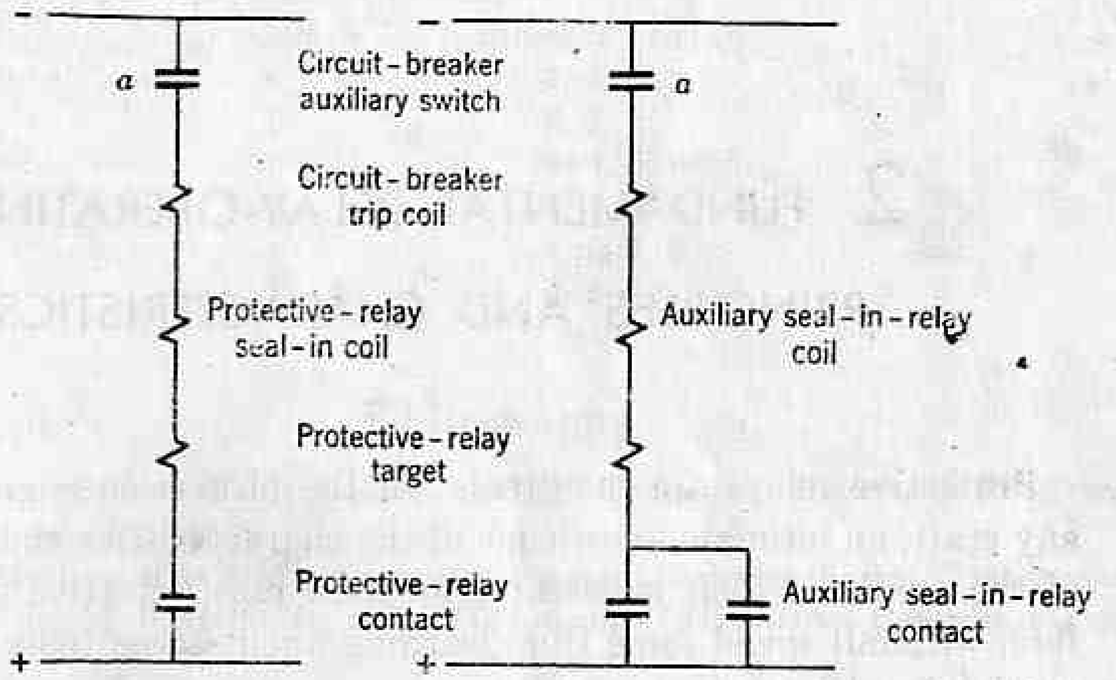

Fig. 3. Alternative contact seal-in methods.

only to positive polarity for long periods of time; and, since here the circuit breaker and its auxiliary switch will be closed normally while the protective-relay contacts will be open, the trip-coil end of the circuit should be at negative polarity.

ADJUSTMENT OF PICKUP OR RESET

Adjustment of pickup or reset is provided electrically by tapped current coils or by tapped auxiliary potential transformers or resistors; or adjustment is provided mechanically by adjustable spring tension or by varying the initial air gap of the operating element with respect to its solenoid or electromagnet.

TIME DELAY AND ITS DEFINITIONS

Some relays have adjustable time delay, and others are "instantaneous" or "high speed." The term "instantaneous" means "having no intentional time delay" and is applied to relays that operate in a minimum time of approximately 0.1 second. The term "high speed" connotes operation in less than approximately 0.1 second and usually in 0.05 second or less. The operating time of high-speed relays is usually expressed in cycles based on the power-system frequency; for example, "one cycle" would be $1/60$ second in a 60-cycle system. Originally, only the term "instantaneous" was used, but, as relay speed was increased, the term "high speed" was felt to be necessary in order to differentiate such relays from the earlier, slower types. This book will use the term "instantaneous" for general reference to either instantaneous or high-speed relays, reserving the term "high-speed" for use only when the terminology is significant.

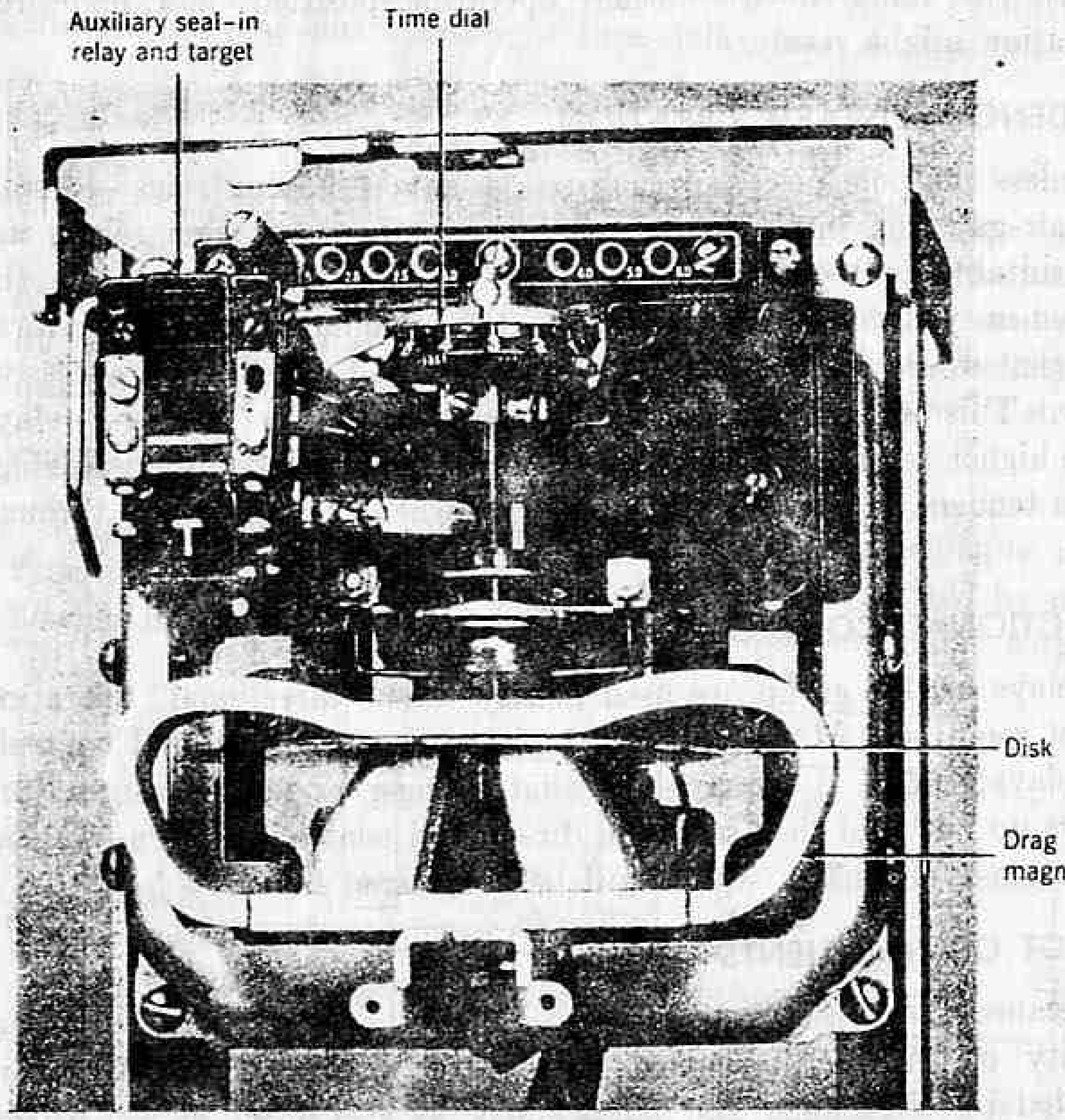

Fig. 4. Close-up of an induction-type overcurrent unit, showing the disc rotor and the drag magnet.

Occasionally, a supplementary auxiliary relay having fixed time delay may be used when a certain delay is required that is entirely independent of the magnitude of the actuating quantity in the protective relay.

Time delay is obtained in induction-type relays by a "drag magnet," which is a permanent magnet arranged so that the relay rotor cuts the flux between the poles of the magnet, as shown in Fig. 4. This produces a retarding effect on motion of the rotor in either direction. In other relays, various mechanical devices have been used, including dash pots, bellows, and escapement mechanisms.

The terminology for expressing the shape of the curve of operating time versus the actuating quantity has also been affected by developments throughout the years. Originally, only the terms "definite time" and "inverse time" were used. An inverse-time curve is one in which the operating time becomes less as the magnitude of the actuating quantity is increased, as shown in Fig. 5. The more pro-

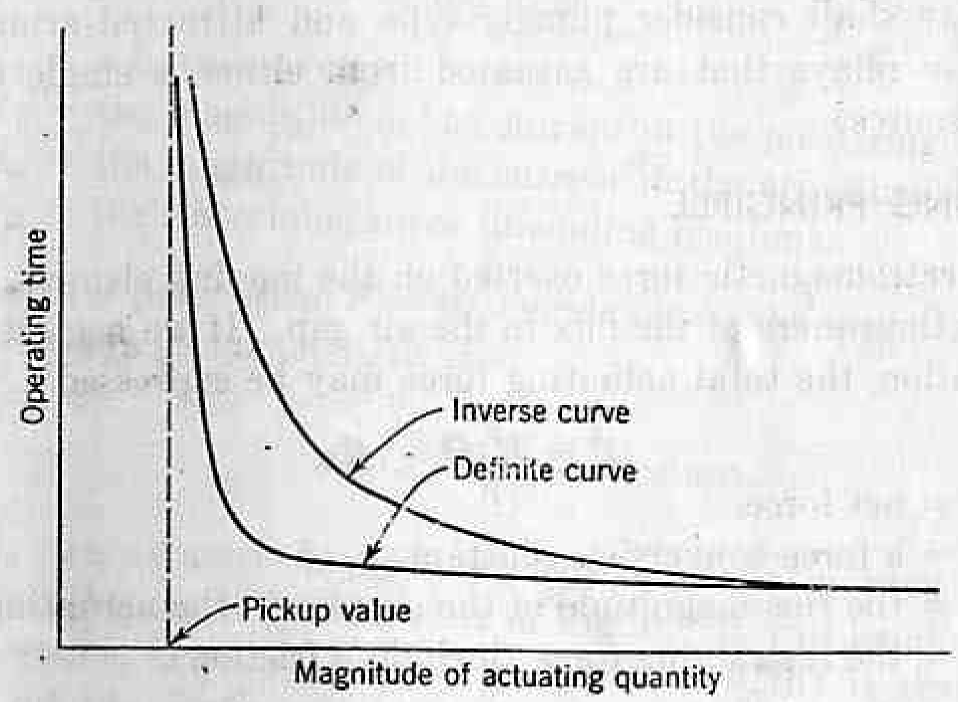

Fig. 5. Curves of operating time versus the magnitude of the actuating quantity.

nounced the effect is, the more inverse is the curve said to be. Actually, all time curves are inverse to a greater or lesser degree. They are most inverse near the pickup value and become less inverse as the actuating quantity is increased. A definite-time curve would strictly be one in which the operating time was unaffected by the magnitude of the actuating quantity, but actually the terminology is applied to a curve that becomes substantially definite slightly above the pickup value of the relay, as shown in Fig. 5.

As a consequence of trying to give names to curves of different degrees of inverseness, we now have "inverse," "very inverse," and "extremely inverse." Although the terminology may be somewhat confusing, each curve has its field of usefulness, and one skilled in the use of these relays has only to compare the shapes of the curves to know which is best for a given application. This book will use the term "inverse" for general reference to any of the inverse curves, reserving the other terms for use only when the terminology is significant.

Thus far, we have gained a rough picture of protective relays in general and have learned some of the language of the profession.

References to complete standards pertaining to circuit elements and terminology are given in the bibliography at the end of this chapter.[1] With this preparation, we shall now consider the fundamental relay types.

Single-Quantity Relays of the Electromagnetic-Attraction Type

Here we shall consider plunger-type and attracted-armature-type a-c or d-c relays that are actuated from either a single current or voltage source.

OPERATING PRINCIPLE

The electromagnetic force exerted on the moving element is proportional to the square of the flux in the air gap. If we neglect the effect of saturation, the total actuating force may be expressed:

$$F = K_1 I^2 - K_2,$$

where F = net force.
K_1 = a force-conversion constant.
I = the rms magnitude of the current in the actuating coil.
K_2 = the restraining force (including friction).

When the relay is on the verge of picking up, the net force is zero, and the operating characteristic is:

$$K_1 I^2 = K_2,$$

or

$$I = \sqrt{\frac{K_2}{K_1}} = \text{constant}$$

RATIO OF RESET TO PICKUP

One characteristic that affects the application of some of these relays is the relatively large difference between their pickup and reset values. As such a relay picks up, it shortens its air gap, which permits a smaller magnitude of coil current to keep the relay picked up than was required to pick it up. This effect is less pronounced in a-c than in d-c relays. By special design, the reset can be made as high as 90% to 95% of pickup for a-c relays, and 60% to 90% of pickup for d-c relays. Where the pickup is adjusted by adjusting the initial air gap, a higher pickup calibration will have a lower ratio of reset to pickup. For overcurrent applications where such relays are often used, the relay trips a circuit breaker which reduces the current to zero, and hence the reset value is of no consequence. However, if

a low-reset relay is used in conjuction with other relays in such a way that a breaker is not always tripped when the low-reset relay operates, the application should be carefully examined. When the reset value is a low percentage of the pickup value, there is the possibility that an abnormal condition might cause the relay to pick up (or to reset), but that a return to normal conditions might not return the relay to its normal operating position, and undesired operation might result.

TENDENCY TOWARD VIBRATION

Unless the pole pieces of such relays have "shading rings" to split the air-gap flux into two out-of-phase components, such relays are not suitable for continuous operation on alternating current in the picked-up position. This is because there would be excessive vibration that would produce objectionable noise and would cause excessive wear. This tendency to vibrate is related to the fact that a-c relays have higher reset than d-c relays; an a-c relay without shading rings has a tendency to reset every half cycle when the flux passes through zero.

DIRECTIONAL CONTROL

Relays of this group are used mostly when "directional" operation is not required. More will be said later about "directional control" of relays; suffice it to say here that plunger or attracted-armature relays do not lend themselves to directional control nearly as well as induction-type relays, which will be considered later.

EFFECT OF TRANSIENTS

Because these relays operate so quickly and with almost equal facility on either alternating current or direct current, they are affected by transients, and particularly by d-c offset in a-c waves. This tendency must be taken into consideration when the proper adjustment for any application is being determined. Even though the steady-state value of an offset wave is less than the relay's pickup value, the relay may pick up during such a transient, depending on the amount of offset, its time constant, and the operating speed of the relay. This tendency is called "overreach" for reasons that will be given later.

TIME CHARACTERISTICS

This type of relay is inherently fast and is used generally where time delay is not required. Time delay can be obtained, as previously stated, by delaying mechanisms such as bellows, dash pots, or escapements. Very short time delays are obtainable in d-c relays by encircling the magnetic circuit with a low-resistance ring, or "slug" as it is sometimes called. This ring delays changes in flux, and it can be positioned either to have more effect on air-gap-flux increase if time-delay pickup is desired, or to have more effect on air-gap-flux decrease if time-delay reset is required.

Directional Relays of the Electromagnetic-Attraction Type

Directional relays of the electromagnetic-attraction type are actuated by d-c or by rectified a-c quantities. The most common use of such relays is for protection of d-c circuits where the actuating quantity is obtained either from a shunt or directly from the circuit.

OPERATING PRINCIPLE

Figure 6 illustrates schematically the operating principle of this type of relay. A movable armature is shown magnetized by current flowing in an actuating coil encircling the armature, and with such

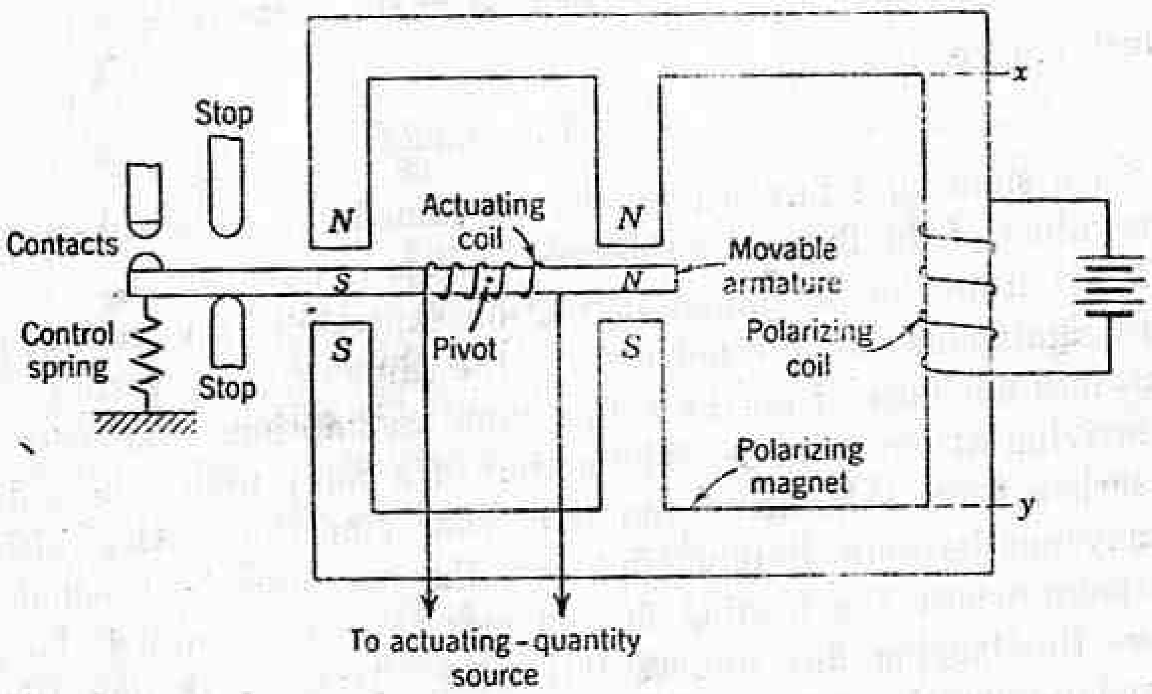

Fig. 6. Directional relay of the electromagnetic-attraction type.

polarity as to close the contacts. A reversal of the polarity of the actuating quantity will reverse the magnetic polarities of the ends of the armature and cause the contacts to stay open. Although a "polarizing," or "field," coil is shown for magnetizing the polarizing magnet, this coil may be replaced by a permanent magnet in the section between x and y. There are many physical variations pos-

sible in carrying out this principle, one of them being a construction similar to that of a d-c motor.

The force tending to move the armature may be expressed as follows, if we neglect saturation:

$$F = K_1 I_p I_a - K_2,$$

$$F = \text{net force}$$

where K_1 = a force-conversion constant.
I_p = the magnitude of the current in the polarizing coil.
I_a = the magnitude of the current in the armature coil.
K_2 = the restraining force (including friction).

At the balance point when $F = 0$, the relay is on the verge of operating, and the operating characteristic is:

$$I_p I_a = \frac{K_2}{K_1} = \text{constant}$$

I_p and I_a are assumed to flow through the coils in such directions that a pickup force is produced, as in Fig. 6. It will be evident that, if the direction of either I_p or I_a (but not of both) is reversed, the direction of the force will be reversed. Therefore, this relay gets its name from its ability to distinguish between opposite directions of actuating-coil current flow, or opposite polarities. If the relative directions are correct for operation, the relay will pick up at a constant magnitude of the product of the two currents.

If permanent-magnet polarization is used, or if the polarizing coil is connected to a source that will cause a constant magnitude of current to flow, the operating characteristic becomes:

$$I_a = \frac{K_2}{K_1 I_p} = \text{constant}$$

I_a still must have the correct polarity, as well as the correct magnitude, for the relay to pick up.

EFFICIENCY

This type of relay is much more efficient than hinged-armature or plunger relays, from the standpoint of the energy required from the actuating-coil circuit. For this reason, such directional relays are used when a d-c shunt is the actuating source, whether directional action is required or not. Occasionally, such a relay may be actuated from an a-c quantity through a full-wave rectifier when a low-energy a-c relay is required.

RATIO OF CONTINUOUS THERMAL CAPACITY TO PICKUP

As a consequence of greater efficiency, the actuating coil of this type of relay has a high ratio of continuous current or voltage capacity to the pickup value, from the thermal standpoint.

TIME CHARACTERISTICS

Relays of this type are instantaneous in operation, although a slug may be placed around the armature to get a short delay.

Induction-Type Relays—General Operating Principles

Induction-type relays are the most widely used for protective-relaying purposes involving a-c quantities. They are not usable with d-c quantities, owing to the principle of operation. An induction-type relay is a split-phase induction motor with contacts. Actuating force is developed in a movable element, that may be a disc or other form of rotor of non-magnetic current-conducting material, by the interaction of electromagnetic fluxes with eddy currents that are induced in the rotor by these fluxes.

THE PRODUCTION OF ACTUATING FORCE

Figure 7 shows how force is produced in a section of a rotor that is pierced by two adjacent a-c fluxes. Various quantities are shown

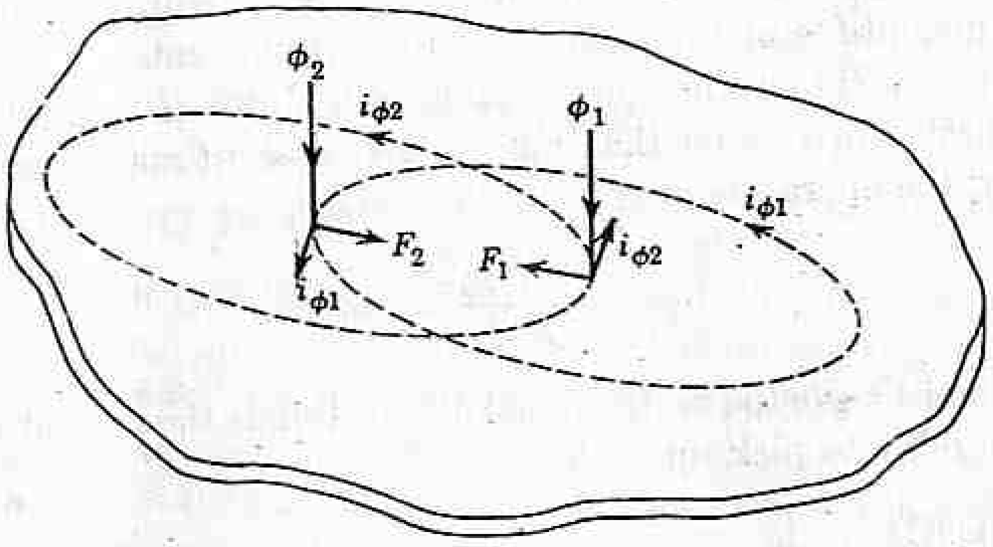

Fig. 7. Torque production in an induction relay.

at an instant when both fluxes are directed downward and are increasing in magnitude. Each flux induces voltage around itself in the rotor, and currents flow in the rotor under the influence of the two voltages. The current produced by one flux reacts with the other flux, and vice versa, to produce forces that act on the rotor.

The quantities involved in Fig. 7 may be expressed as follows:

$$\phi_1 = \Phi_1 \sin \omega t$$

$$\phi_2 = \Phi_2 \sin (\omega t + \theta),$$

where θ is the phase angle by which ϕ_2 leads ϕ_1. It may be assumed with negligible error that the paths in which the rotor currents flow have negligible self-inductance, and hence that the rotor currents are in phase with their voltages:

$$i_{\phi 1} \propto \frac{d\phi_1}{dt} \propto \Phi_1 \cos \omega t$$

$E = N\frac{d\phi}{}$

$i = \frac{E}{R}$

$$i_{\phi 2} \propto \frac{d\phi_2}{dt} \propto \Phi_2 \cos (\omega t + \theta)$$

We note that Fig. 7 shows the two forces in opposition, and consequently we may write the equation for the net force (F) as follows:

$$F = (F_2 - F_1) \propto (\phi_2 i_{\phi 1} - \phi_1 i_{\phi 2}) \qquad (1)$$

Substituting the values of the quantities into equation 1, we get:

$$F \propto \Phi_1\Phi_2 [\sin (\omega t + \theta) \cos \omega t - \sin \omega t \cos (\omega t + \theta)] \qquad (2)$$

which reduces to:

$$F \propto \Phi_1\Phi_2 \sin \theta \qquad (3)$$

Since sinusoidal flux waves were assumed, we may substitute the rms values of the fluxes for the crest values in equation 3.

Apart from the fundamental relation expressed by equation 3, it is most significant that the net force is the same *at every instant.* This fact does not depend on the simplifying assumptions that were made in arriving at equation 3. The action of a relay under the influence of such a force is positive and free from vibration. Also, although it may not be immediately apparent, the net force is directed from the point where the leading flux pierces the rotor toward the point where the lagging flux pierces the rotor. It is as though the flux moved across the rotor, dragging the rotor along.

In other words, actuating force is produced in the presence of out-of-phase fluxes. One flux alone would produce no net force. There must be at least two out-of-phase fluxes to produce any net force, and the maximum force is produced when the two fluxes are 90° out of phase. Also, the direction of the force—and hence the direction of motion of the relay's movable member—depends on which flux is leading the other.

A better insight into the production of actuating force in the induction relay can be obtained by plotting the two components of the expression inside the brackets of equation 2, which we may call the "per-unit net force." Figure 8 shows such a plot when θ is assumed to be 90°. It will be observed that each expression is a double-frequency sinusoidal wave completely offset from the zero-force axis.

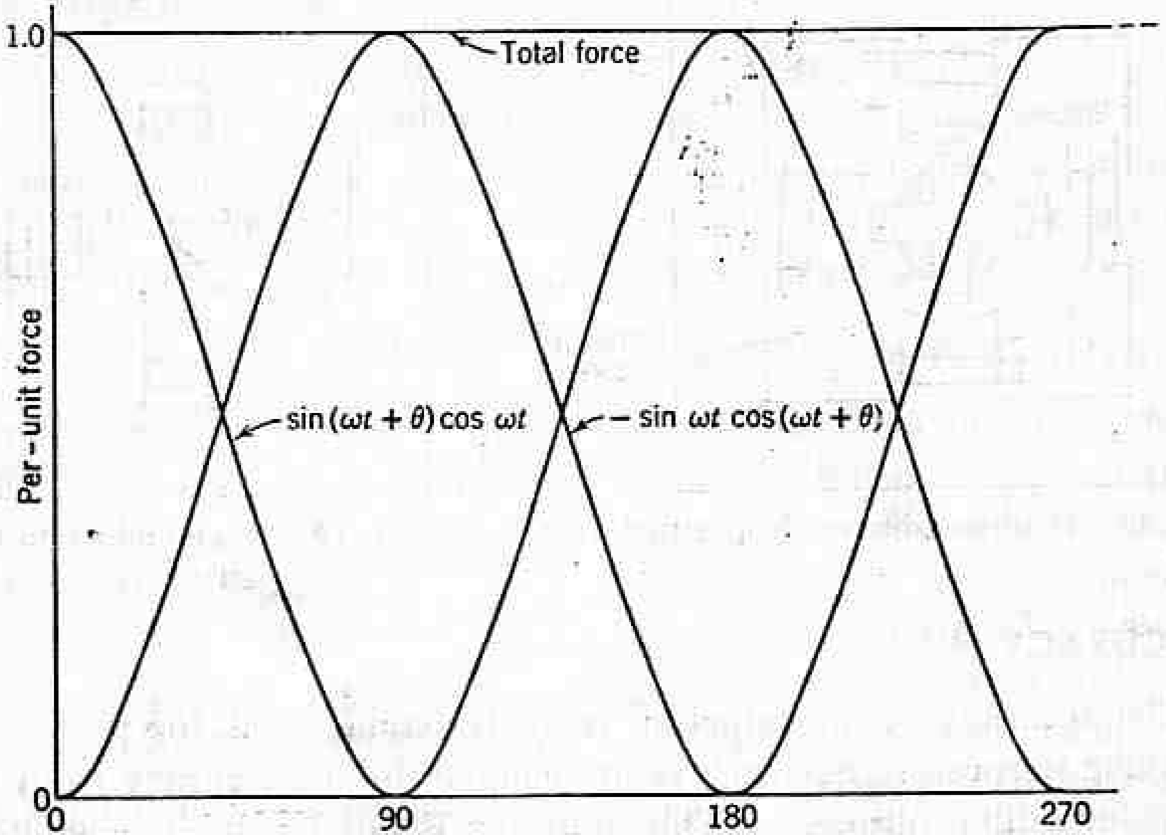

Fig. 8. Per-unit net force.

The two waves are displaced from one another by 90° in terms of fundamental frequency, or by 180° in terms of double frequency. The sum of the instantaneous values of the two waves is 1.0 at every instant. If θ were assumed to be less than 90°, the effect on Fig. 8 would be to raise the zero-force axis, and a smaller per-unit net force would result. When θ is zero, the two waves are symmetrical about the zero-force axis, and no net force is produced. If we let θ be negative, which is to say that ϕ_2 is lagging ϕ_1, the zero-force axis is raised still higher and net force in the opposite direction is produced. However, for a given value of θ, the net force is the same at each instant.

In some induction-type relays one of the two fluxes does not react with rotor currents produced by the other flux. The force expression for such a relay has only one of the components inside the brackets of equation 2. The *average* force of such a relay may still be expressed by equation 3, but the instantaneous force is variable, as

shown by omitting one of the waves of Fig. 8. Except when θ is 90° lead or lag, the instantaneous force will actually reverse during parts of the cycle; and, when $\theta = 0$, the average negative force equals the average positive force. Such a relay has a tendency to vibrate, particularly at values of θ close to zero.

Reference 2 of the bibliography at the end of this chapter gives more detailed treatment of induction-motor theory that applies also to induction relays.

TYPES OF ACTUATING STRUCTURE

The different types of structure that have been used are commonly called: (1) the "shaded-pole" structure; (2) the "watthour-meter" structure; (3) the "induction-cup" and the "double-induction-loop" structures; (4) the "single-induction-loop" structure.

Shaded-Pole Structure. The shaded-pole structure, illustrated in Fig. 9, is generally actuated by current flowing in a single coil on a magnetic structure containing an air gap. The air-gap flux produced by this current is split into two out-of-phase components by a

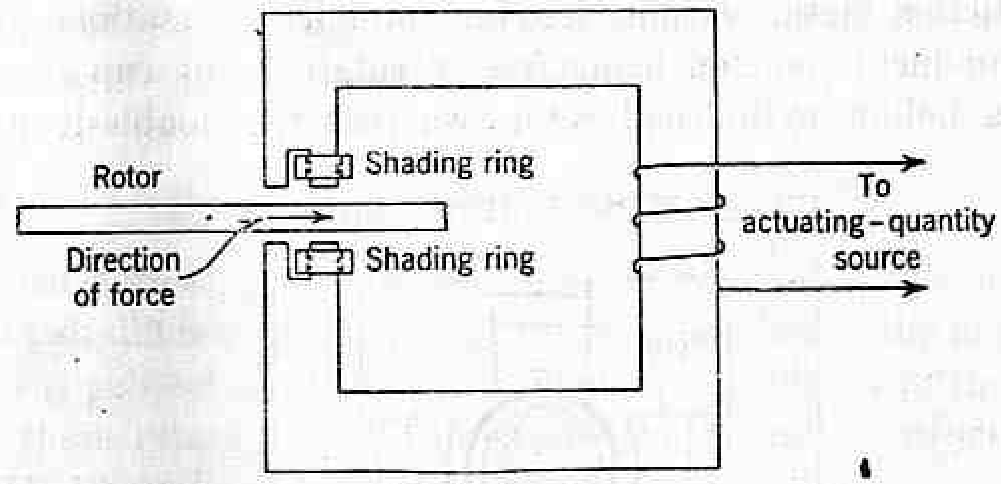

Fig. 9. Shaded-pole structure.

so-called "shading ring," generally of copper, that encircles part of the pole face of each pole at the air gap. The rotor, shown edgewise in Fig. 9, is a copper or aluminum disc, pivoted so as to rotate in the air gap between the poles. The phase angle between the fluxes piercing the disc is fixed by design, and consequently it does not enter into application considerations. *

The shading rings may be replaced by coils if control of the operation of a shaded-pole relay is desired. If the shading coils are short-circuited by a contact of some other relay, torque will be produced; but, if the coils are open-circuited, no torque will be produced because there will be no phase splitting of the flux. Such torque control is employed where "directional control" is desired, which will be described later.

* pass through

Watthour-Meter Structure. This structure gets its name from the fact that it is used for watthour meters. As shown in Fig. 10, this structure contains two separate coils on two different magnetic circuits, each of which produces one of the two necessary fluxes for driving the rotor, which is also a disc.

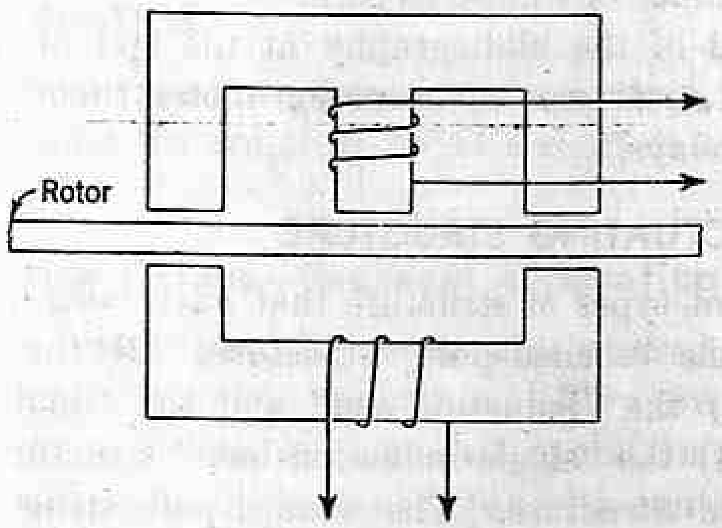

Fig. 10. Watthour-meter structure.

Induction-Cup and Double-Induction-Loop Structures. These two structures are shown in Figs. 11 and 12. They most closely resemble an induction motor, except that the rotor iron is stationary, only the rotor-conductor portion being free to rotate. The cup structure employs a hollow cylindrical rotor, whereas the double-loop structure

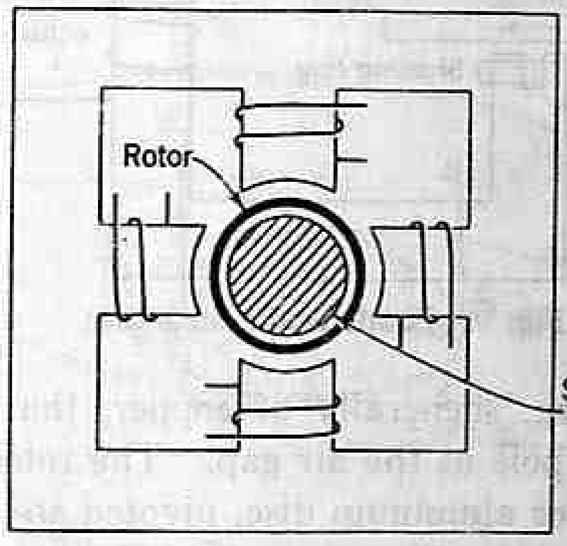

Fig. 11. Induction-cup structure.

employs two loops at right angles to one another. The cup structure may have additional poles between those shown in Fig. 11. Functionally, both structures are practically identical.

These structures are more efficient torque producers than either the shaded-pole or the watthour-meter structures, and they are the type used in high-speed relays.

Single-Induction-Loop Structure. This structure, shown in Fig. 13, is the most efficient torque-producing structure of all the induction types that have been described. However, it has the rather serious disadvantage that its rotor tends to vibrate as previously described for a relay in which the actuating force is expressed by only one component inside the brackets of equation 2. Also, the torque varies somewhat with the rotor position.

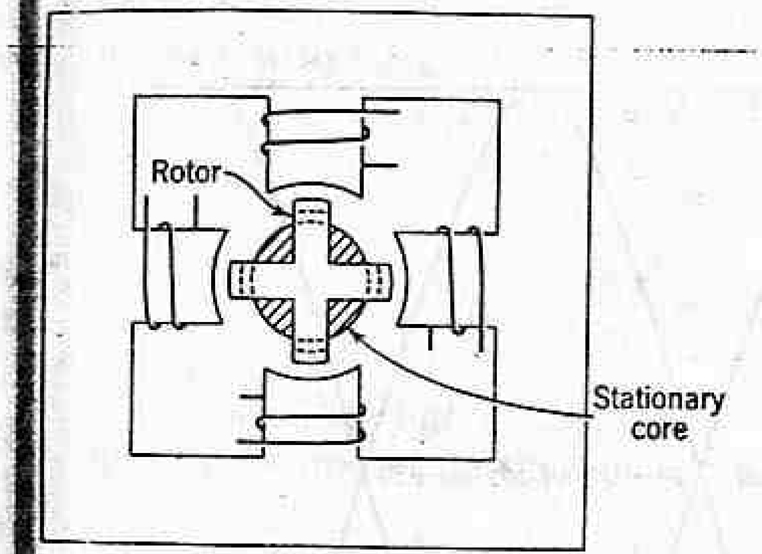

Fig. 12. Double-induction-loop structure.

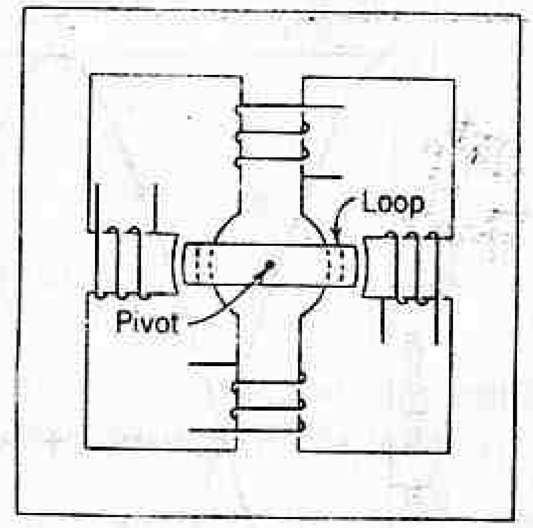

Fig. 13. Single-induction-loop structure.

ACCURACY

The accuracy of an induction relay recommends it for protective-relaying purposes. Such relays are comparable in accuracy to meters used for billing purposes. This accuracy is not a consequence of the induction principle, but because such relays invariably employ jewel bearings and precision parts that minimize friction.

Single-Quantity Induction Relays

A single-quantity relay is actuated from a single current or voltage source. Any of the induction-relay actuating structures may be used. The shaded-pole structure is used only for single-quantity relays. When any of the other structures is used, its two actuating circuits are connected in series or in parallel; and the required phase angle between the two fluxes is obtained by arranging the two circuits to have different X/R (reactance-to-resistance) ratios by the use of auxiliary resistance and/or capacitance in combination with one of the circuits. Neglecting the effect of saturation, the torque of all such relays may be expressed as:

$$T = K_1 I^2 - K_2$$

where I is the rms magnitude of the total current of the two circuits.

The phase angle between the individual currents is a design constant and it does not enter into the application of these relays.

If the relay is actuated from a voltage source, its torque may be expressed as:

$$T = K_1V^2 - K_2$$

where V is the rms magnitude of the voltage applied to the relay.

TORQUE CONTROL

Torque control with the structures of Figs. 10, 11, 12, or 13 is obtained simply by a contact in series with one of the circuits if they are in parallel, or in series with a portion of a circuit if they are in series.

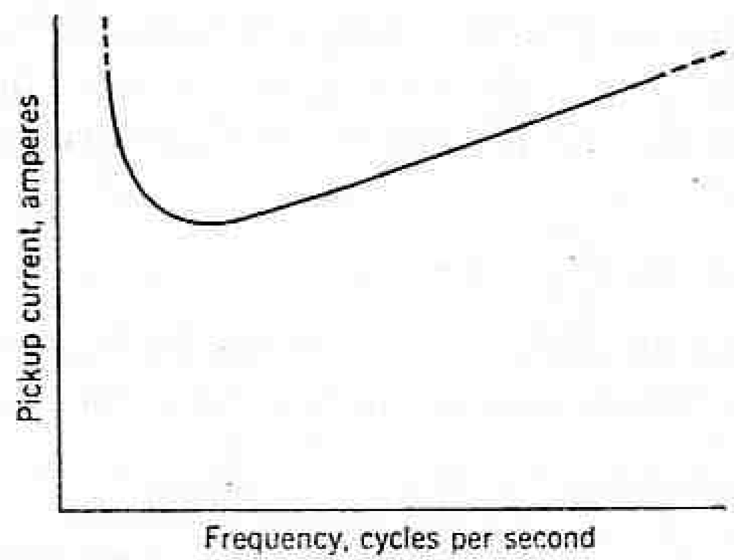

Fig. 14. Effect of frequency on the pickup of a single-quantity induction relay.

EFFECT OF FREQUENCY

The effect of frequency on the pickup of a single-quantity relay is shown qualitatively by Fig. 14. So far as possible a relay is designed to have the lowest pickup at its rated frequency. The effect of slight changes in frequency normally encountered in power-system operation may be neglected. However, distorted wave form may produce significant changes in pickup and time characteristics. This fact is particularly important in testing relays at high currents; one should be sure that the wave form of the test currents is as good as that obtained in actual service or else inconsistent results will be obtained.[3]

EFFECT OF D-C OFFSET

The effect of d-c offset may be neglected with inverse-time single-quantity relays. High-speed relays may or may not be affected depending on the characteristics of their circuit elements. Generally the pickup of high-speed relays is made high enough to compensate for any tendency to "overreach," as will be seen later, and no attempt is made to evaluate the effect of d-c offset.

RATIO OF RESET TO PICKUP

The ratio of reset to pickup is inherently high in induction relays because their operation does not involve any change in the air gap of the magnetic circuit. This ratio is between 95% and 100%, friction and imperfect compensation of the control-spring torque being the only things that keep the ratio from being 100%. Moreover, this ratio is unaffected by the pickup adjustment where tapped current coils provide the pickup adjustment.

RESET TIME

Where fast automatic reclosing of circuit breakers is involved, the reset time of an inverse-time relay may be a critical characteristic in obtaining selectivity. If all relays involved do not have time to reset completely after a circuit breaker has been tripped and before the breaker recloses, and if the short circuit that caused tripping is re-established when the breaker recloses, certain relays may operate too quickly and trip unnecessarily. Sometimes the drop-out time may also be important with high-speed reclosing.

TIME CHARACTERISTICS

Inverse-time curves are obtained with relays whose rotor is a disc and whose actuating structure is either the shaded-pole type or the watthour-meter type. High-speed operation is obtained with the induction-cup or the induction-loop structures.

Directional Induction Relays

Contrasted with single-quantity relays, directional relays are actuated from two different independent sources, and hence the angle θ of equation 3 is subject to change and must be considered in the application of these relays. Such relays use the actuating structures of Figs. 10, 11, 12, or 13.

TORQUE RELATIONS IN TERMS OF ACTUATING QUANTITIES

Current-Current Relays. A current-current relay is actuated from two different current-transformer sources. Assuming no saturation, we may substitute the actuating currents for the fluxes of equation 3, and the expression for the torque becomes:

$$T = K_1I_1I_2 \sin\theta - K_2 \tag{4}$$

where I_1 and I_2 = the rms values of the actuating currents.

θ = the phase angle between the rotor-piercing fluxes produced by I_1 and I_2.

An actuating current is not in phase with the rotor-piercing flux that it produces, for the same reason that the primary current of a trans-

3 CURRENT, VOLTAGE, DIRECTIONAL, CURRENT (OR VOLTAGE)- BALANCE, AND DIFFERENTIAL RELAYS

Chapter 2 described the operating principles and characteristics of the basic relay elements. All protective-relay types are derived either directly from these basic elements, by combining two or more of these elements in the same enclosing case or in the same circuit with certain electrical interconnections, or by directly adding the torques of two or more such elements to control a single set of contacts. Various external connections and auxiliary equipments are employed that may tend to obscure the true identity of the elements and make the equipment appear complicated. However, if one will examine the equipment, he will invariably recognize the basic elements.

General Protective-Relay Features

Certain features and capabilities apply generally to all types of protective relays. These will be discussed briefly before we consider the various types of relays.

CONTINUOUS AND SHORT-TIME RATINGS

All relays carry current- and/or voltage-coil ratings as a guide to their proper application. For relays complying with present standards, the continuous rating specifies what a relay will withstand under continuous operation in an ambient temperature of 40° C. Relays having current coils also carry a 1-second current rating, since such relays are usually subjected to momentary overcurrents. Such relays should not be subjected to currents in excess of the 1-second rating without the manufacturer's approval because either thermal or mechanical damage may result. Overcurrents lower than the 1-second rating value are permissible for longer than 1 second, so long as the I^2t value of the 1-second rating is not exceeded. For example, if a relay will withstand 100 amperes for 1 second, it will withstand $100\sqrt{\frac{1}{2}}$ amperes for 2 seconds. It is not always safe to assume that a relay will withstand any current that it can get from current trans-

formers for as long as it takes a circuit breaker to interrupt a short circuit after the relay has operated to trip the circuit breaker. Also, should a relay fail to succeed in tripping a circuit breaker, thermal damage should be expected unless back-up relays can stop the flow of short-circuit current soon enough to prevent such damage.

CONTACT RATINGS

Protective-relay contacts are rated on their ability to close and to open inductive or non-inductive circuits at specified magnitudes of circuit current and a-c or d-c circuit voltage. As stated in Chapter 2, protective relays that trip circuit breakers are not permitted to interrupt the flow of trip-coil current, and hence they require only a circuit-closing and momentary current-carrying rating. If a breaker fails to trip, the contacts of the relay will almost certainly be damaged. The circuit-opening rating is applicable only when a protective relay controls the operation of another relay, such as a timing relay or an auxiliary relay; in such a case, the protective relay should not have a holding coil or else it may not be able to open its contacts once they have closed. If a seal-in relay is used, the current taken by the controlled relay must be less than the pickup of the seal-in relay.

When a relay of the "over-and-under" type with "*a*" and "*b*" contacts is used to control the operation of some other device, the relay can be relieved of any circuit-breaking duty by the arrangement of Fig. 1. When the protective relay picks up, it causes an auxiliary relay to pick up and seal itself in around the protective-relay contacts. Other auxiliary-relay contacts may be used, as shown, for control purposes, thereby relieving the protective-relay contacts of this duty. When the protective relay resets, it shorts the auxiliary-relay coil, thereby causing the auxiliary relay to reset.

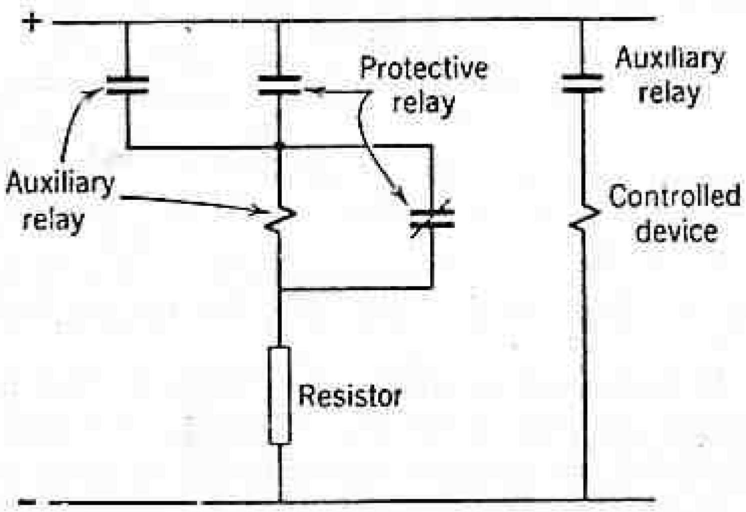

Fig. 1. Control circuit for relay of the "over-and-under" type.

HOLDING-COIL OR SEAL-IN-RELAY AND TARGET RATINGS

Two different current ratings are generally available either in the same relay or in different relays. The higher current rating is for use less and less noticeable at the higher values of current. The rel will pick up for ratios of I_1 to I_2 represented by points above th operating characteristic.

Such an operating characteristic is specified by expressing in perce the ratio of I_1 to I_2 required for pickup when the relay is operati on the straight part of the characteristic, and by giving the minimu pickup value of I_1 when I_2 is zero. I_1 is called the "operating

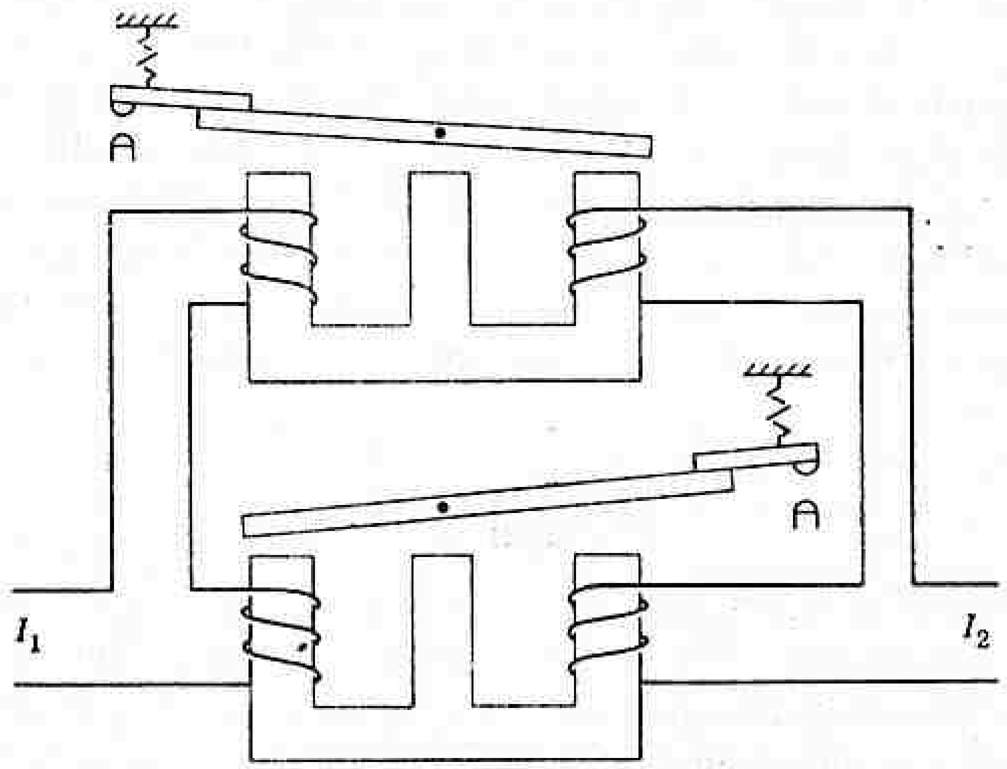

Fig. 11. A two-element current-balance relay.

current since it produces positive, or pickup, torque; I_2 is called th "restraining" current. By proportioning the number of turns on th operating and the restraining coils, one can obtain any desire "percent slope," as it is sometimes called.

Should it be desired to close an "a" contact circuit when either c two currents exceeds the other by a given percentage, two elemen are used, as illustrated schematically in Fig. 11. For some applica tions, the contacts of the two elements may be arranged to tri different circuit breakers, depending on which element operates.

By these means, the currents in the different phases of a circuit, i different circuit branches of the same phase, or between correspondin phases of different circuits, can be compared. When applied betwe circuits where the ratio of one of the currents to the other neve exceeds a certain amount except when a short circuit occurs in one o the circuits, a current-balance relay provides inherently selecti protection.

Although the torque equations were written on the assumption th

the phase angle between the two balanced quantities had no effect, the characteristics of such relays may be somewhat affected by the phase angle. In other words, the actual torque relation may be:

$$T = K_1 I_1^2 - K_2 I_2^2 + K_3 I_1 I_2 \cos (\theta - \tau)$$

where the effect of the control spring is neglected, and where θ and τ are defined as for directional relays. The constant K_3 is small, the production of directional torque by the interaction between the induced currents and stray fluxes of the two elements being incidental

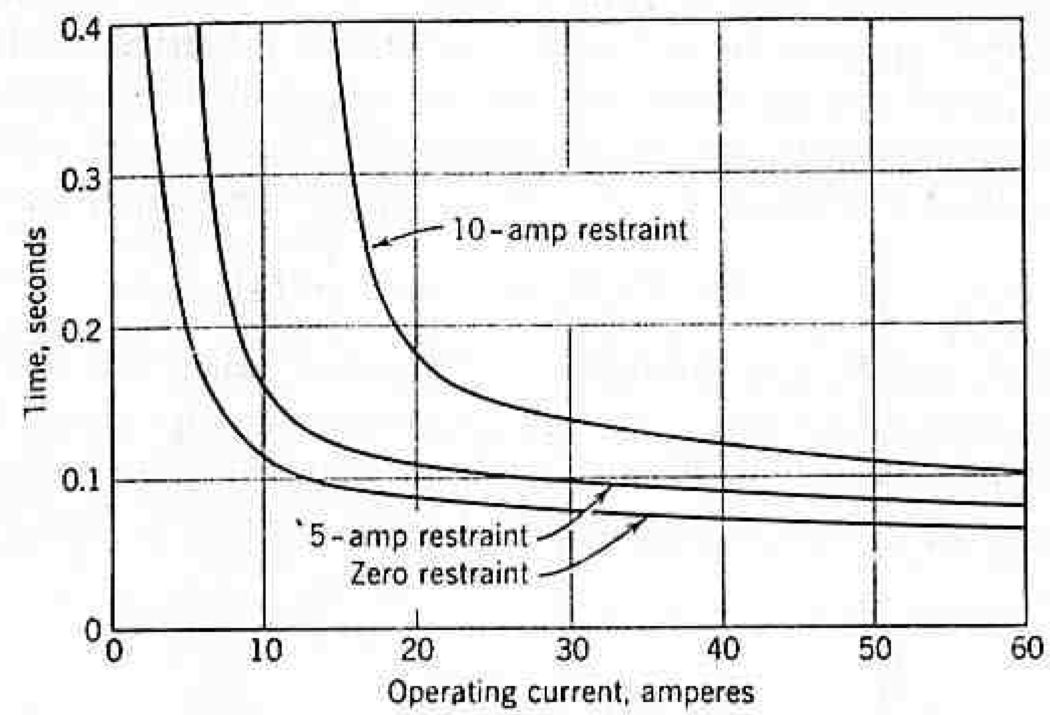

Fig. 12. Time-current curves of a current-balance relay.

and often purposely minimized by design. With only rare exceptions, the directional effect can be neglected. It is mentioned here in passing merely for completeness of the theoretical considerations. It will not be mentioned again when other relays that balance one quantity against another are considered, but the effect is sometimes there nevertheless.

It will be evident that the characteristics of a voltage-balance relay may be expressed as for the current-balance relay if we substitute V_1 and V_2 for I_1 and I_2. Also, whereas the current-balance relay operates when one current exceeds a normal value in comparison with the other current, the voltage-balance relay is generally arranged to operate when one voltage drops below a normal value.

Relays are available having high-speed characteristics or inverse-time characteristics with or without an adjustable time dial. A typical set of time curves is shown in Fig. 12, where the effect of different values of restraining currents on the shape of the time curve is shown for one time adjustment. Such curves cannot be plotted on a multipl of-pickup basis because the pickup is different for each value of r straining current. It will be noted that each curve is asymptotic the pickup current for the given value of restraining current.

High-speed relays may operate undesirably on transient unbalanc if the percent slope is too nearly 100%, and for this reason such rela may require higher percent-slope characteristics than inverse-tim relays.

DIRECTIONAL TYPE

The directional type of current-balance relay uses a current-curre directional element in which the polarizing quantity is the vect difference of two currents, and the actuating quantity is the vect sum of the two currents. If we assume that the currents are in phas and neglect the effect of the control spring, the torque is:

$$T = K_1 (I_1 + I_2)(I_1 - I_2)$$

where I_1 and I_2 are rms values. Therefore, when the two curren are in phase and are of equal magnitude, no operating torque developed. When one current is larger than the other, torque is d veloped, its direction depending on which current is the larger. I

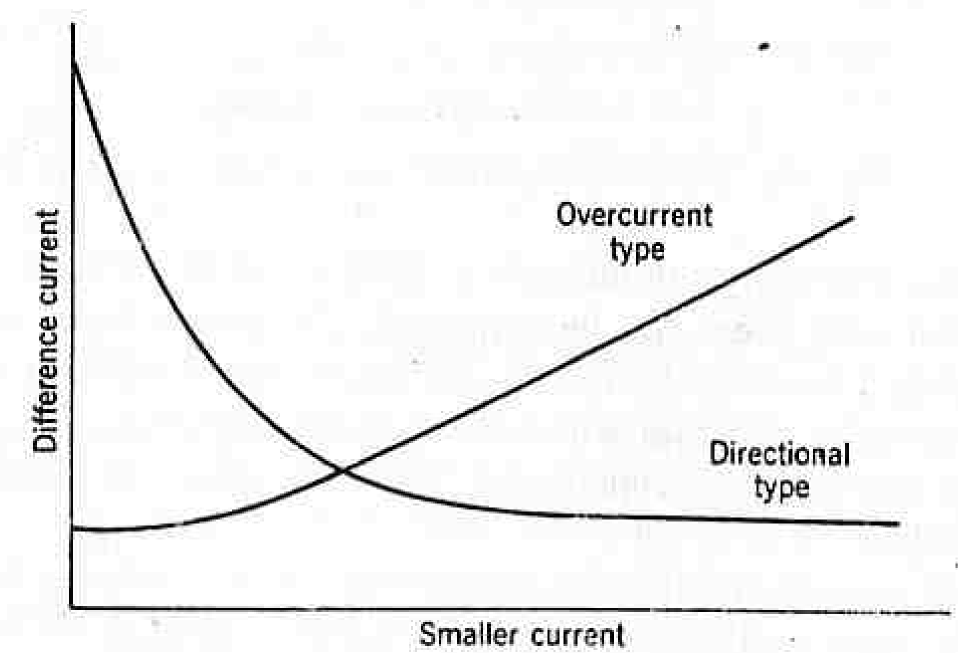

Fig. 13. Comparison of current-balance-relay characteristics

the two currents are 180° out of phase, the direction of torque for given unbalance will be the same as when the currents are in phas as can be seen by changing the sign of either current in the torq equation. This type of relay may have double-throw contacts bo of which are normally open, the control spring being arranged

produce restraint against movement in either direction from the midposition.

This relay is not a current-balance relay in the same sense as the overcurrent type, as shown by a comparison of their operating characteristics in Fig. 13. The directional type is more sensitive to unbalance when the two currents are large, and is less sensitive when they are small. This is advantageous under one circumstance and disadvantageous under another. For parallel-line protection, which is the principal use of the directional type, auxiliary means are not required to prevent undesirable operation on load currents during switching; this is because the pickup is inherently higher when one line is out of service, at which time one of the two currents is zero. On the other hand, the directional type is more apt to operate undesirably on transient current-transformer unbalances when short circuits occur beyond the ends of the parallel lines; this is because the relay is more sensitive to current unbalance under high-current conditions when the errors of current transformers are apt to be greatest.

Differential Relays

Differential relays take a variety of forms, depending on the equipment they protect. The definition of such a relay is "one that operates when the vector difference of two or more similar electrical quantities exceeds a predetermined amount."[2] It will be seen later that almost any type of relay, when connected in a certain way, can be made to operate as a differential relay. In other words, it is not so much the relay construction as the way the relay is connected in a circuit that makes it a differential relay.

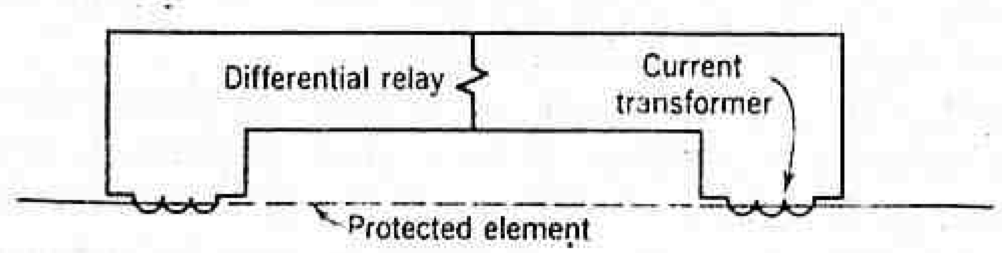

Fig. 14. A simple differential-relay application.

Most differential-relay applications are of the "current-differential" type. The simplest example of such an arrangement is shown in Fig. 14. The dashed portion of the circuit of Fig. 14 represents the system element that is protected by the differential relay. This system element might be a length of circuit, a winding of a generator, a portion of a bus, etc. A current transformer (CT) is shown in each connection to the system element. The secondaries of the CT's a interconnected, and the coil of an overcurrent relay is connect across the CT secondary circuit. This relay could be any of t a-c types that we have considered.

Now, suppose that current flows through the primary circuit eith to a load or to a short circuit located at X. The conditions will as in Fig. 15. If the two current transformers have the same rati

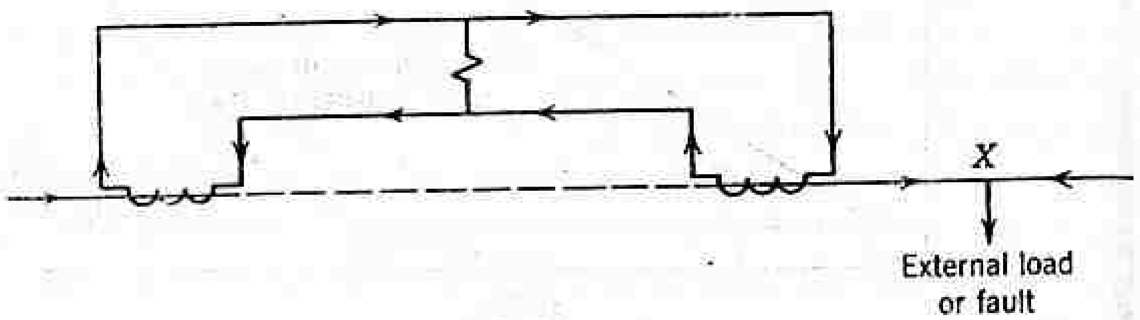

Fig. 15. Conditions for an external load or fault.

and are properly connected, their secondary currents will merely ci culate between the two CT's as shown by the arrows, and no curre will flow through the differential relay.

But, should a short circuit develop anywhere between the t CT's, the conditions of Fig. 16 will then exist. If current flows the short circuit from both sides as shown, the sum of the CT seconda currents will flow through the differential relay. It is not necessa that short-circuit current flow to the fault from both sides to cau secondary current to flow through the differential relay. A flow

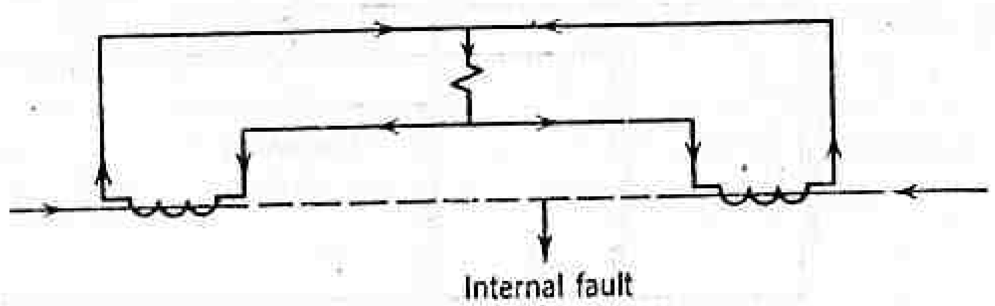

Fig. 16. Conditions for an internal fault.

one side only, or even some current flowing out of one side whil larger current enters the other side, will cause a differential curre In other words, the differential-relay current will be proportional the vector difference between the currents entering and leaving t protected circuit; and, if the differential current exceeds the rela pickup value, the relay will operate.

It is a simple step to extend the principle to a system element hav several connections. Consider Fig. 17, for example, in which th

connections are involved. It is only necessary, as before, that all the CT's have the same ratio, and that they be connected so that the relay receives no current when the total current leaving the circuit element is equal vectorially to the total current entering the circuit element.

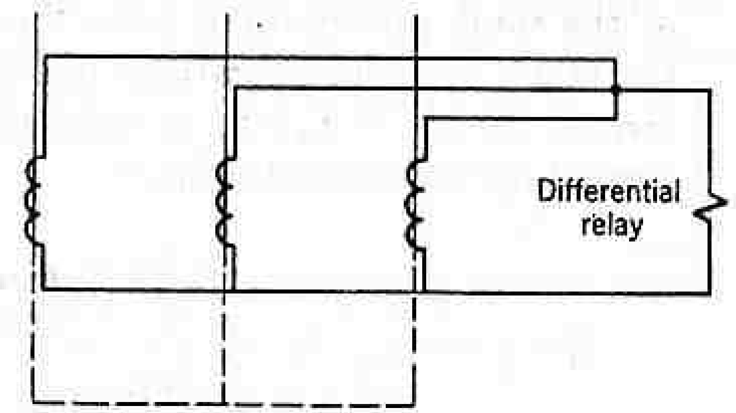

Fig. 17. A three-terminal current-differential application.

The principle can still be applied where a power transformer is involved, but, in this case, the ratios and connections of the CT's on opposite sides of the power transformer must be such as to compensate for the magnitude and phase-angle change between the power-transformer currents on either side. This subject will be treated in detail when we consider the subject of power-transformer protection.

A most extensively used form of differential relay is the "percentage-differential" type. This is essentially the same as the overcurrent type of current-balance relay that was described earlier, but it is connected in a differential circuit, as shown in Fig. 18. The

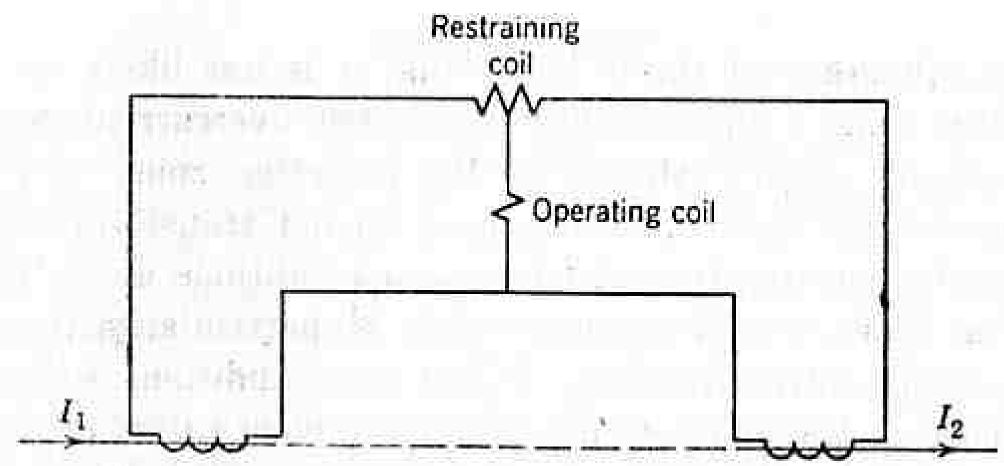

Fig. 18. A percentage-differential relay in a two-terminal circuit.

differential current required to operate this relay is a variable quantity, owing to the effect of the restraining coil. The differential current in the operating coil is proportional to $I_1 - I_2$, and the equivalent current in the restraining coil is proportional to $(I_1 + I_2)/2$; since the operating coil is connected to the midpoint of the restraining coil; in other words, if we let N be the number of turns on the restraining coil, the total ampere-turns are $I_1N/2 + I_2N/2$, which is the same as if $(I_1 + I_2)/2$ were to flow through the whole coil. The operating characteristic of such a relay is shown in Fig. 19. Thus, except for th slight effect of the control spring at low currents, the ratio of th differential operating current to the average restraining current is fixed percentage, which explains the name of this relay. The ter "through" current is often used to designate I_2, which is the portio of the total current that flows through the circuit from one end t the other, and the operating characteristics may be plotted using I instead of $(I_1 + I_2)/2$, to conform with the ASA definition for percentage differential relay.[2]

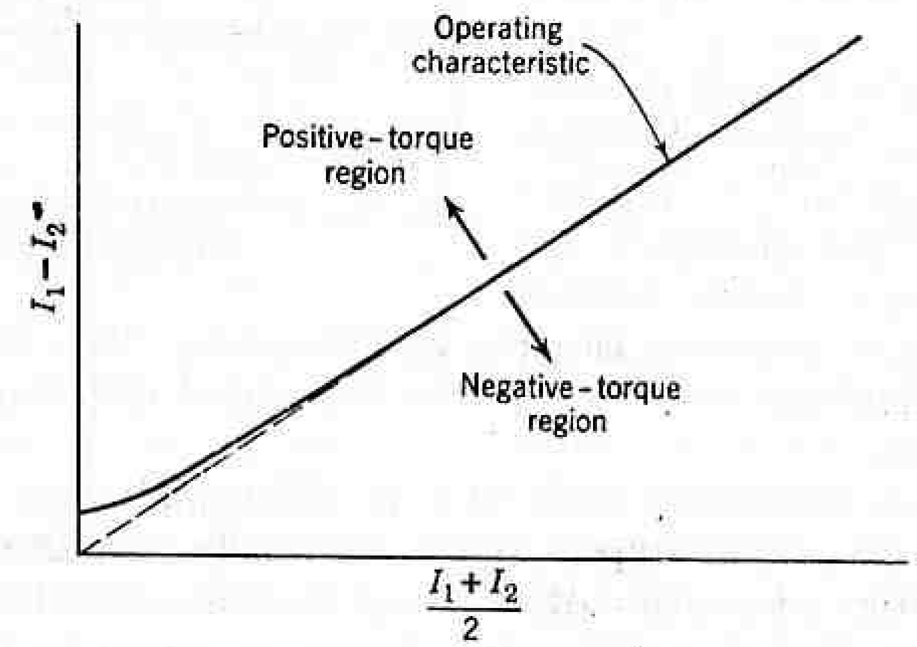

Fig. 19. Operating characteristic of a percentage-differential relay.

The advantage of this relay is that it is less likely to operate in correctly than a differentially connected overcurrent relay when short circuit occurs external to the protected zone. Current tran formers of the types normally used do not transform their primar currents so accurately under transient conditions as for a short tim after a short circuit occurs. This is particularly true when th short-circuit current is offset. Under such conditions, supposedly ide tical current transformers may not have identical secondary curren owing to slight differences in magnetic properties or to their havi different amounts of residual magnetism, and the difference curre may be greater, the larger the magnitude of short-circuit curre Even if the short-circuit current to an external fault is not offset, t CT secondary currents may differ owing to differences in the C types or loadings, particularly in power-transformer protection. Sin the percentage-differential relay has a rising pickup characteristic the magnitude of through current increases, the relay is restrain against operating improperly.

Figure 20 shows the comparison of a simple overcurrent relay with a percentage-differential relay under such conditions. An overcurrent relay having the same minimum pickup as a percentage-differential

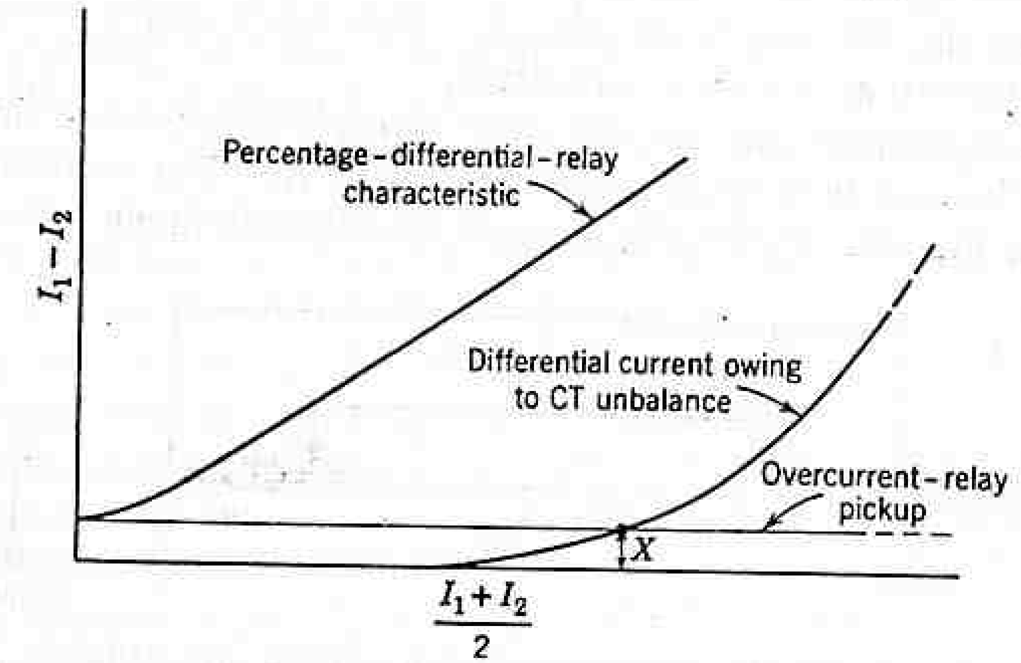

Fig. 20. Illustrating the value of the percentage-differential characteristic.

relay would operate undesirably when the differential current barely exceeded the value X, whereas there would be no tendency for the percentage-differential relay to operate.

Percentage-differential relays can be applied to system elements having more than two terminals, as in the three-terminal application of Fig. 21. Each of the three restraining coils of Fig. 21 has the

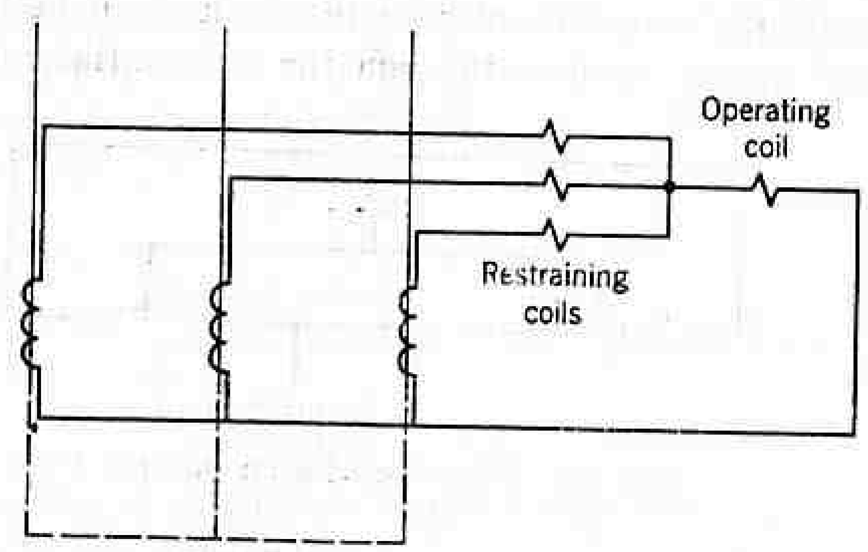

Fig. 21. Three-terminal application of a percentage-differential relay.

same number of turns, and each coil produces restraining torque independently of the others, and their torques are added arithmetically. The percent-slope characteristic for such a relay will vary with the distribution of currents between the three restraining coils.

Percentage-differential relays are usually instantaneous or hi speed. Time delay is not required for selectivity because the pe centage-differential characteristic and other supplementary featu to be described later make these relays virtually immune to the effe of transients when the relays are properly applied.

The adjustments provided with some percentage-differential rela will be described in connection with their application.

Several other types of differential-relay arrangements could mentioned. One of these uses a directional relay. Another has ad tional restraint obtained from harmonics and the d-c component the differential current. Another type uses an overvoltage relay stead of an overcurrent relay in the differential circuit. Spec current transformers may be used having little or no iron in th magnetic circuit to avoid errors in transformation caused by the d component of offset current waves. All these types are extensio of the fundamental principles that have been described, and they w be treated later in connection with their specific applications.

There has been great activity in the development of the different relay because this form of relay is inherently the most selective all the conventional types. However, each kind of system eleme presents special problems that have thus far made it impossible devise a differential-relaying equipment having universal applicati

Problems

1. Given a polyphase directional relay, each element of which develops ma mum torque when the current in its current coil leads the voltage across voltage coil by 20°.

Assuming that the constant in the torque equation is 1.0, and neglecting spring torque, calculate the total torque for each of the three conventional conn tions for the following voltages and currents:

$$V_{bc} = 90 + j0$$
$$V_{ab} = -30 + j50$$
$$V_{ca} = -60 - j50$$
$$I_a = 25 + j7$$
$$I_b = -15 - j18$$
$$I_c = -2 + j10$$

2. Figure 22 shows a percentage-differential relay applied for the protection a generator winding. The relay has a 0.1-ampere minimum pickup and a 10 slope (defined as in Fig. 19). A high-resistance ground fault has occurred as sho near the grounded-neutral end of the generator winding while the generator carrying load. As a consequence, the currents in amperes flowing at each end of the generator winding have the magnitudes and directions as shown on Fig. 22. Assuming that the CT's have a 400/5-ampere ratio and no inaccuracies, will the relay operate to trip the generator breaker under this condition? Would the relay operate at the given value of fault current if the generator were carrying no load with its breaker open? On the same diagram, show the relay operating characteristic and the points that represent the operating and restraining currents in the relay for the two conditions.

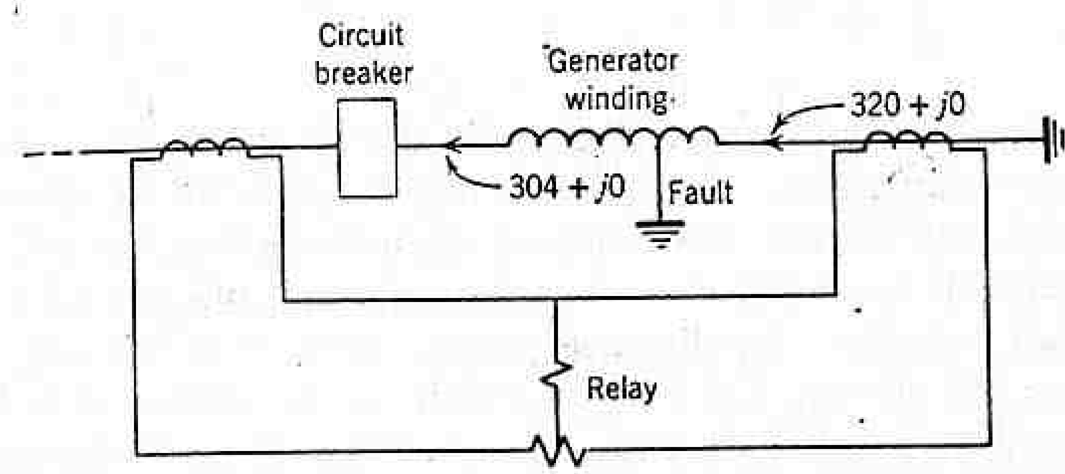

Fig. 22. Illustration for Problem 2.

3. Given two circuits carrying a-c currents having rms values of I_1 and I_2, respectively. Show a relay arrangement that will pick up on a constant magnitude of the arithmetic (not vector) sum of I_1 and I_2.

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when the protective relay trips a circuit breaker directly, and the lower current rating is for use when the relay trips a circuit breaker indirectly through an auxiliary relay. In either event, one should be sure that the rating is low enough so that reliable seal-in and target operation will be obtained should two or more protective relays close contacts together, thereby dividing the total available trip-circuit current between the parallel protective-relay-contact circuits. Also, depending on the tripping speed of the breaker, the trip-circuit current may not have time to build up to its steady-state value. The resistances of the seal-in and target coils are given to permit one to calculate the trip-circuit currents.

BURDENS

The impedance of relay-actuating coils must be known to permit one to determine if the relay's voltage- or current-transformer sources will have sufficient capacity and suitable accuracy to supply the relay load together with any other loads that may be imposed on the transformers. These relay impedances are listed in relay publications. This subject will be treated further when we examine the characteristics of voltage and current transformers.

Overcurrent, Undercurrent, Overvoltage, and Undervoltage Relays

Overcurrent, undercurrent, overvoltage, and undervoltage relays are derived directly from the basic single-quantity electromagnetic-attraction or induction types described in Chapter 2. The prefix "over" means that the relay picks up to close a set of "*a*" contacts when the actuating quantity exceeds the magnitude for which the relay is adjusted to operate. Similarly, the prefix "under" means that the relay resets to close a set of "*b*" contacts when the actuating quantity decreases below the reset magnitude for which the relay is adjusted to operate. Some relays have both "*b*" and "*a*" contacts, and the prefix before the actuating quantity in their name is "over-and-under." In protective-relay terminology, a "current" relay is one whose actuating source is a current in a circuit supplied to the relay either directly or from a current transformer. A "voltage" relay is one whose actuating source is a voltage of the circuit obtained either directly or from a voltage transformer.

Because all these relays are derived directly from the single-quantity types described in Chapter 2, there is no need to consider further their principle of operation.

ADJUSTMENT

Pickup or Reset. Most overcurrent relays have a range of adjustment to make them adaptable to as wide a range of application circumstances as possible. The range of adjustment is limited, however, because of coil-space limitations and to simplify the relay construction. Hence, various relays are available, each having a different range of adjustment. The adjustment of plunger or attracted-armature relays may be by adjustment of the initial air gap, adjustment of restraining-spring tension, adjustable weights, or coil taps. The adjustment of current-actuated induction relays is generally by coil taps, and that of voltage-actuated relays by taps on series resistors or by auxiliary autotransformer taps.

Voltage relays and undercurrent relays do not generally have as wide a range of adjustment because they are expected to operate within a limited range from the normal magnitude of the actuating quantity. The normal magnitude does not vary widely because relay ratings are usually chosen with respect to the ratios of current and voltage transformers so that the relay current is normally slightly less than rated relay current and the relay voltage is approximately rated relay voltage, regardless of the application.

Time. Except for the "over-and-under" types, the operating time of inverse-time induction relays is usually adjustable by choosing the amount of travel of the rotor from its reset position to its pickup position. It is accomplished by adjustment of the position of the reset stop. A so-called "time lever" or "time dial" with an evenly divided scale provides this adjustment.

The slight increase in restraining torque of the control spring, as the reset stop is advanced toward the pickup position, is compensated for by the shape of the disc. A disc whose periphery is in the form of a spiral, or a disc having a fixed radius but with peripheral slots, the bottoms of which are on a spiral, provides this compensation by varying the active area of the disc between the poles. Similarly, holes of different diameter may be used. As the disc turns toward the pickup position when the reset stop is advanced, or whenever the relay operates to pick up, the increase in the amount of the disc area between the poles of the actuating structure causes an increase in the electrical torque that just balances the increase in the control-spring torque.

When a bellows is used for producing time delay, adjustment is made by varying the size of an orifice through which the air escapes from the bellows.

TIME CHARACTERISTICS

A typical time curve for a high-speed relay is shown in Fig. 2. It will be noted that this is an inverse curve, but that a 3-cycle (60-cycle-per-second basis) operating time is achieved only slightly above the pickup value, which permits the relay to be called "high speed."

Figure 3 shows a family of inverse-time curves of one widely used induction-type relay. A curve is shown for each major division of the adjustment scale. Any intermediate curves can be obtained by interpolation since the adjustment is continuous

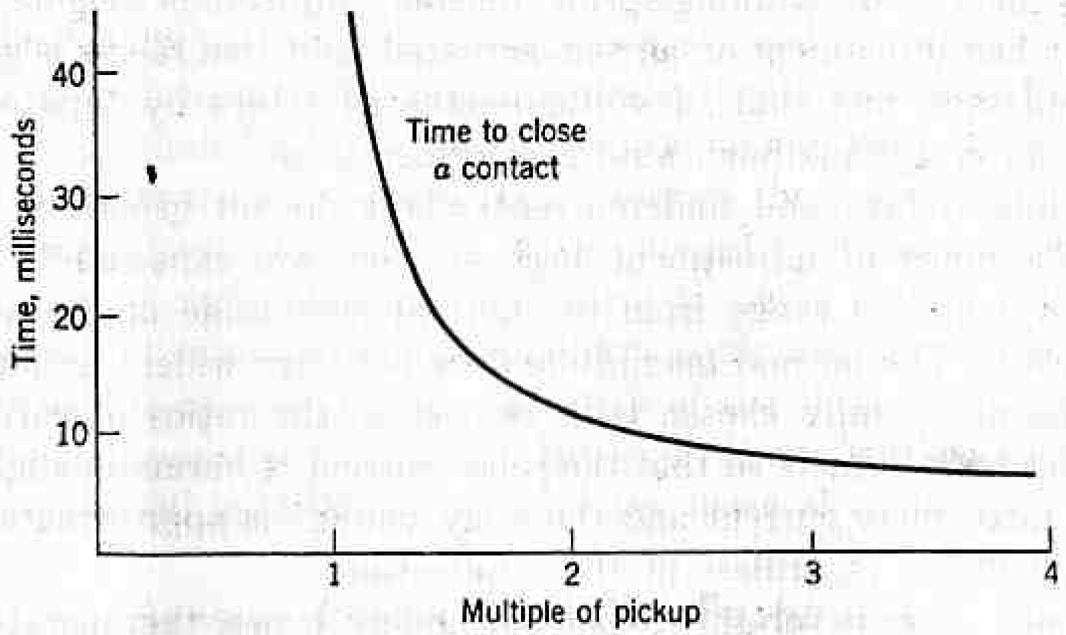

Fig. 2. Time curve of a high-speed relay.

It will be noted that both Fig. 2 and Fig. 3 are plotted in terms of multiples of the pickup value, so that the same curves can be used for any value of pickup. This is possible with induction-type relays where the pickup adjustment is by coil taps, because the ampere-turns at pickup are the same for each tap. Therefore, at a given multiple of pickup, the coil ampere-turns, and hence the torque, are the same regardless of the tap used. Where air-gap or restraining-spring pickup adjustment is used, the shape of the time curve varies with the pickup.

One should not rely on the operation of any relay when the magnitude of the actuating quantity is only slightly above pickup, because the net actuating force is so low that any additional friction may prevent operation, or may increase the operating time. Even though the relay closes its contacts, the contact pressure may be so low that contamination of the contact surface may prevent electrical contact. This is particularly true in inverse-time relays where there may not be much impact when the contacts close. It is the practice

to apply relays in such a way that, when their operation must be reliable, their actuating quantity will be at least 1.5 times pickup. For this reason, some time curves are not shown for less than 1.5 times pickup.

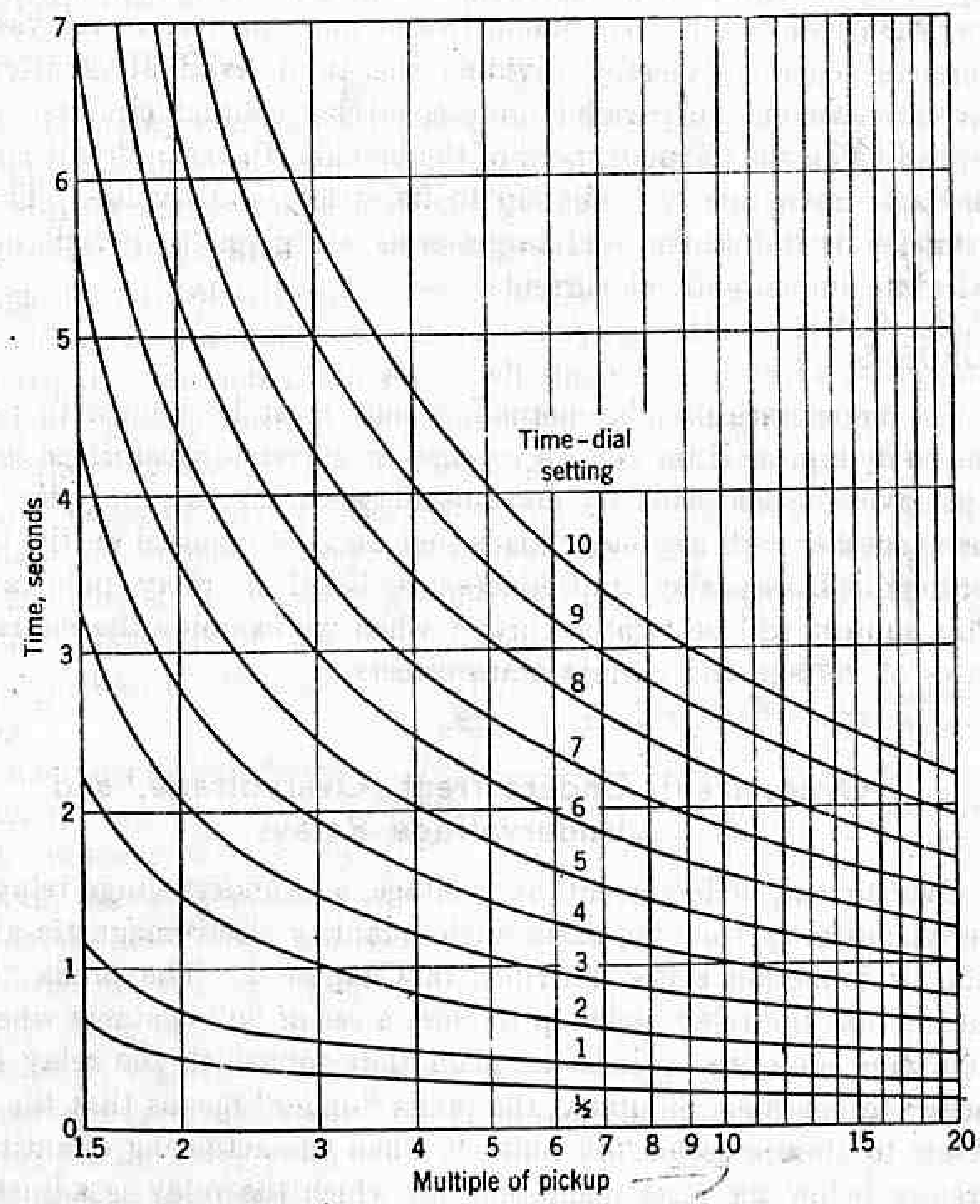

Fig. 3. Inverse-time curves.

The time curves of Fig. 3 can be used to estimate not only how long it will take the relay to close its contacts at a given multiple of pickup and for any time adjustment but also how far the relay disc will travel toward the contact-closed position within any time interval. For example, assume that the No. 5 time-dial adjustment is used, and that the multiple of pickup is 3. It will take the relay 2.45 seconds to close its contacts. We see that in 1.45 seconds, the relay would close its contacts if the No. 3 time-dial adjustment were used. In other words, in 1.45 seconds, the disc travels a distance corresponding to 3.0 time-dial divisions, or three-fifths of the total distance to close the contacts.

This method of analysis is useful to estimate whether a relay will pick up, and, if so, what its time delay will be when the magnitude of the actuating quantity is changing as, for example, during the current-inrush period when a motor is starting. The curve of the rms magnitude of current versus time can be studied for short successive time intervals, and the disc travel during each interval can be found for the average current magnitude during that interval. For each successive interval, the disc should be assumed to start from the position that it had reached at the end of the preceding interval.

For the most effective use of an inverse-time relay, its pickup should be chosen so that the relay will be operating on the most inverse part of its time curve over the range of magnitude of the actuating quantity for which the relay must operate. In other words, the minimum value of the actuating quantity for which the relay must operate should be at least 1.5 times pickup, but not too much more. This will become more evident when we consider the application of these relays.

The time curves illustrated in manufacturers' publications are average curves, and the time characteristics of individual relays vary slightly from the published curves. Ordinarily, this variation will be negligible, but, when the most accurate adjustment of a relay is required, it should be determined by test.

OVERTRAVEL

Owing to inertia of the moving parts, motion will continue when the actuating force is removed. This characteristic is called "overtravel." Although overtravel occurs in all relays, its effect is usually important only in time-delay relays, and particularly for inverse-time overcurrent relays, where selectivity is obtained on a time-delay basis. The basis for specifying overtravel is best described by an example, as follows. Suppose that, for a given adjustment and at a given multiple of pickup, a relay will pick up and close its contacts in 2.0 seconds. Now suppose that we make several tests by applying that same multiple of pickup for time intervals slightly less than 2.0 seconds, and we find that, if the time interval is any longer than 1.9 seconds, the relay will still close its contacts. We would say, then, that the overtravel is 0.1 second. The higher the multiple of pickup, the longer the overtravel time will be. However, a constant overtravel time of

approximately 0.1 second is generally assumed in the application of inverse-time relays; the manner of its use will be described when we consider the application of these relays.

RESET TIME

For accurate data, the manufacturer should be consulted. The reset time will vary directly with the time-dial adjustment. The method of analysis described under "Time Characteristics" for estimating the amount of disc travel during short time intervals, combined with the knowledge of reset time, will enable one to estimate the operation of inverse-time relays during successive application and removal of the actuating quantity, as when a motor is "plugged," or when a circuit is tripped and then automatically reclosed on a fault several times, or during power surges accompanying loss of synchronism.

COMPENSATION FOR FREQUENCY OR TEMPERATURE CHANGES IN VOLTAGE RELAYS

A voltage relay may be provided with a resistor in series with its coil circuit to decrease changes in pickup by decreasing the effect of changes in coil resistance with heating. Such a resistor will also help to decrease the effect on the characteristics of change in frequency. A series capacitor may be used to obtain series resonance at normal frequency when operation on harmonics is to be avoided.

COMBINATION OF INSTANTANEOUS AND INVERSE-TIME RELAYS

Frequently, an instantaneous relay and an inverse-time relay are furnished in one enclosing case because the two functions are so often required together. The two relays are independently adjustable, but are actuated by the same quantity, and their "*a*" contacts may be connected in parallel.

D-C Directional Relays

Such relays are derived directly from the basic electromagnetic-attraction type described in Chapter 2. The various types and their capabilities are as follows.

CURRENT-DIRECTIONAL RELAYS

The current-directional relay is identical with the basic type described in Chapter 2. It is used for protection in d-c power circuits, its armature coil being connected either directly in series with the circuit or across a shunt in series with the circuit, so that the relay will respond to a certain direction of current flow. Such relays may be polarized either by a permanent magnet or by a field coil connected to be energized by the voltage of the circuit. A field coil would be used if the relay were calibrated to operate in terms of the magnitude of power (watts) in the circuit.

With adjustable calibration, the relay would also have overcurrent (or overpower) or undercurrent (or underpower) characteristics, or both, in addition to being directional.

VOLTAGE-DIRECTIONAL RELAYS

Voltage-directional relays are the same as current-directional relays except for the number of turns and the resistance of the armature coil, and possibly except for the polarizing source. Such relays are used in d-c power circuits to respond to a certain polarity of the voltage across the circuit or across some part of the circuit. If the relay is intended to respond to reversal of the circuit-voltage polarity, it is polarized by a permanent magnet, there being no other suitable polarizing source unless a storage battery is available for the purpose. Otherwise, either permanent-magnet polarization or a field coil energized from the circuit voltage would be used.

When such a relay is connected across a circuit breaker to permit closing the breaker only when the voltage across the open breaker has a certain polarity, the relay may be called a "differential" relay because it operates only in response to a predetermined difference between the magnitudes of the circuit voltages on either side of the breaker.

VOLTAGE-AND-CURRENT-DIRECTIONAL RELAYS

The voltage-and-current-directional relay has two armature coils. Such a relay, for example, controls the closing and opening of a circuit breaker in the circuit between a d-c generator and a bus to which another source of voltage may be connected, so as to avoid motoring of the generator. The voltage armature coil is connected across the breaker and picks up the relay to permit closing the breaker only if the generator voltage is a certain amount greater than the bus voltage. The current armature coil is connected in series with the circuit, or across a shunt, and resets the relay to trip the breaker whenever a predetermined amount of current starts to flow from the bus into the generator.

VOLTAGE-BALANCE-DIRECTIONAL RELAYS

A relay with two voltage coils encircling the armature may be used to protect a three-wire d-c circuit against unbalanced voltages. The

two coils are connected in such a way that their magnetomotive forces are in opposition. Such a relay has double-throw contacts and two restraining springs to provide calibration for movement of the armature in either direction. When one voltage exceeds the other by a predetermined amount, the armature will move one way to close one set of contacts; if the other voltage is the higher, the armature will close the other set of contacts.

Such a relay may also be used to respond to a difference in circuit-voltage magnitudes on either side of a circuit breaker, instead of the single-coil type previously described.

CURRENT-BALANCE-DIRECTIONAL RELAYS

A relay like a voltage-balance type except with two current coils encircling the armature may be used for current-balance protection of a three-wire d-c circuit, or to compare the loads of two different circuits.

DIRECTIONAL RELAYS FOR VACUUM-TUBE OR RECTIFIED A-C CIRCUITS

Both the single-coil and the two-coil types of voltage relays previously described have been used to respond to the output of vacuum-tube or rectifying circuits. Such relays are generally called "polarized" relays, the term "directional" having no significance since the actuating quantity is always of the same polarity; the directional type of relay is used only for its high sensitivity. A relay used for this purpose may be polarized by a permanent magnet or from a suitable d-c source such as a station battery.

Another sometimes-useful characteristic of a d-c directional relay actuated from a rectified a-c source is that the torque of the relay is proportional to the first power of the actuating quantity. Thus, if two or more armature coils should be energized from different rectified a-c quantities, the relay torque would be proportional to the arithmetic sum (or difference, if desired) of the rms values of the a-c quantities, regardless of the phase angles between them. Such operation cannot be obtained with a-c relays.

POLARIZING MAGNET VERSUS FIELD COIL

Except where a permanent magnet is the only suitable polarizing source available, a field coil is generally preferred. It has already been said that a field coil is required if a relay is to respond to watts. A coil provides more flexibility of adjustment since series resistors can be used to vary the polarizing mmf. Also, it is necessary to remove polarization to permit some types of relays to reset after they have operated, and this requires a field coil.

SHUNTS

The rating of a shunt and the resistance of the leads from the shunt to a current-directional relay affect the calibration of the relay. It is customary to specify the rating of the shunt and the resistance of the leads necessary for a given range of calibration of the relay.

TIME DELAY

As mentioned in Chapter 2, d-c directional relays are inherently fast. For some applications, an auxiliary time-delay relay is necessary to prevent undesired operation on momentary reversals of the actuating quantity.

A-C Directional Relays

In Chapter 2, a-c directional relays were said to be able to distinguish between the flow of current in one direction or the other in an a-c circuit by recognizing differences in the phase angle between the current and the polarizing quantity. We shall see that the ability to distinguish between the flow of current in one direction or the other depends on the choice of the polarizing quantity and on the angle of maximum torque, and that all the variations in function provided by a-c directional relays depend on these two quantities. This will become evident on further examination of some typical types.

POWER RELAYS

Relays that must respond to power are generally used for protecting against conditions other than short circuits. Such relays are connected to be polarized by a voltage of a circuit, and the current connections and the relay characteristics are chosen so that maximum torque in the relay occurs when unity-power-factor load is carried by the circuit. The relay will then pick up for power flowing in one direction through the circuit and will reset for the opposite direction of power flow.

If a single-phase circuit is involved, a directional relay is used having maximum torque when the relay current is in phase with the relay voltage. The same relay can be used on a three-phase circuit if the load is sufficiently well balanced; in that event, the polarizing voltage must be in phase with the current in one of the three phases at unity-power-factor load. (For simplicity, the term "phase" will

be used frequently where the term "phase conductor" would be more strictly correct.) Such an in-phase voltage will be available if phase-to-neutral voltage is available; otherwise, a connection like that in

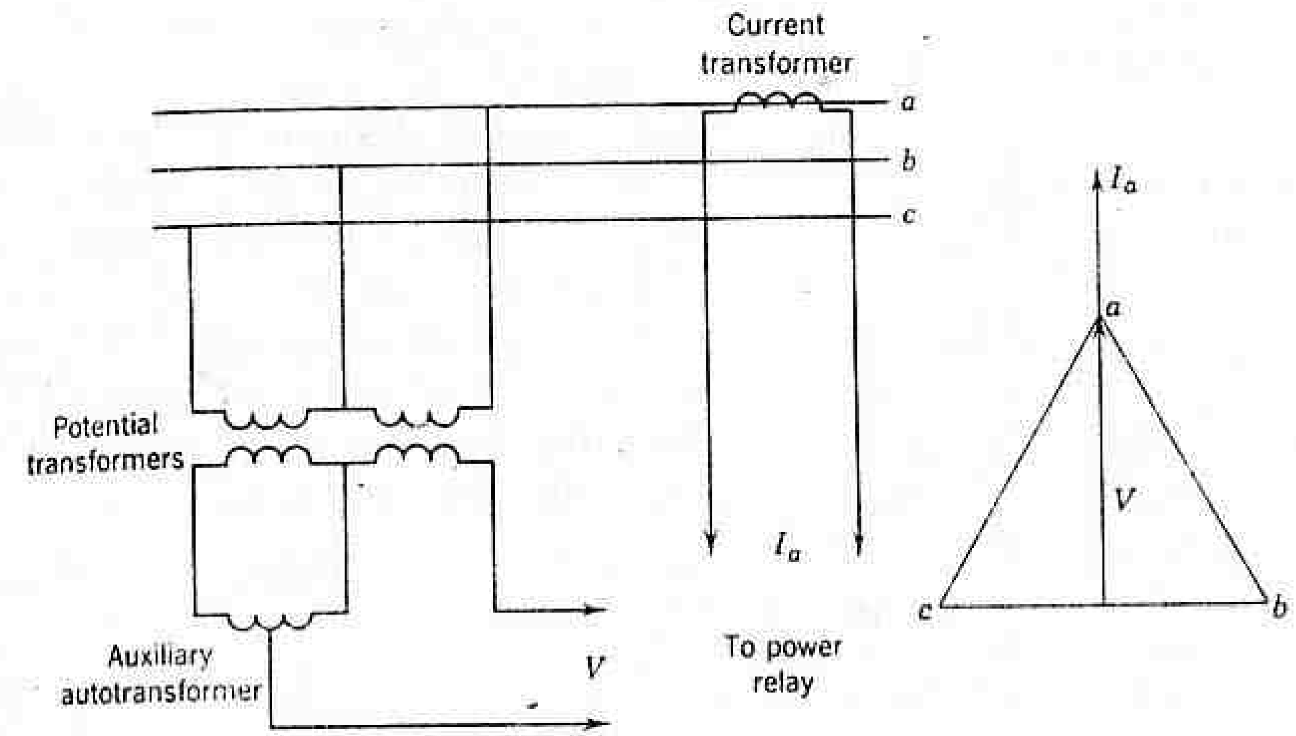

Fig. 4. Connections and vector diagram for a power relay where phase-to-neutral voltage is not available.

Fig. 4 will provide a suitable polarizing voltage. Or, a relay having maximum torque when its current leads its voltage by 30° can be connected to use V_{ac} and I_a, as in Fig. 5.

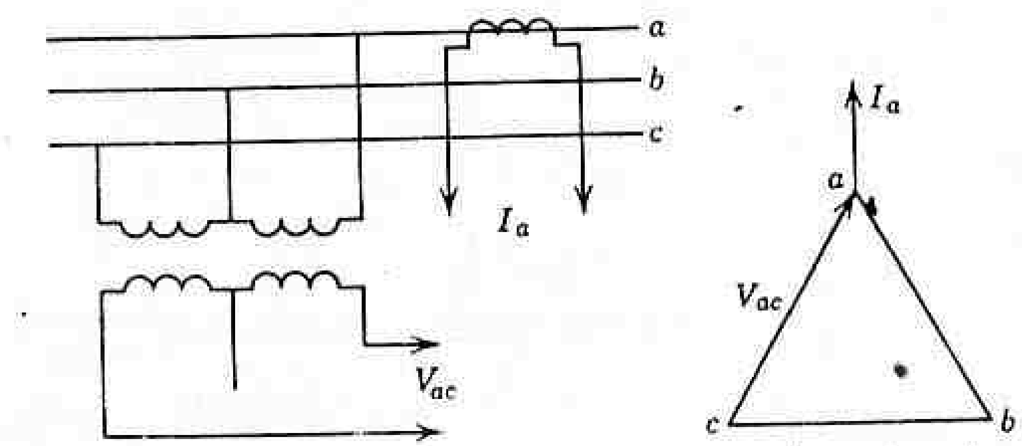

Fig. 5. Connections and vector diagram for a power relay using phase-to-phase voltage.

The conventions and nomenclature used throughout this book in dealing with three-phase voltage and current vector diagrams is shown in Fig. 6. The voltages of Fig. 6 are defined as follows:

$$V_{ab} = V_a - V_b$$
$$V_{bc} = V_b - V_c$$
$$V_{ca} = V_c - V_a$$

From these definitions, it follows that:

$$V_{ba} = -V_{ab} = V_b - V_a$$
$$V_{cb} = -V_{bc} = V_c - V_b$$
$$V_{ac} = -V_{ca} = V_a - V_c$$

When the load of a three-phase circuit may be sufficiently unbalanced so that a single-phase relay will not suffice, or when a very low minimum pickup current is required, a polyphase relay is used, having, actually or in effect, three single-phase relay elements whose torques are added to control a single set of contacts. The actuating quantities of such a relay may be any of several combinations, the following being frequently used:

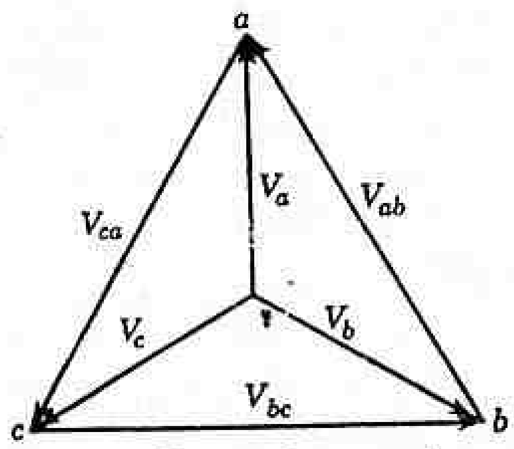

Fig. 6. Conventions and nomenclature for three-phase voltage vector diagrams.

Element No.	Voltage	Current
1	V_{ac}	I_a
2	V_{cb}	I_c
3	V_{ba}	I_b

However it may be accomplished, a power relay will distinguish between the flow of power in one direction or the other by developing positive (or pickup) torque for one direction, and negative (or reset) torque for the other. The unity-power-factor component of the current will reverse as the direction of power flow reverses, as illustrated in Fig. 7 for a relay connected as in Fig. 5.

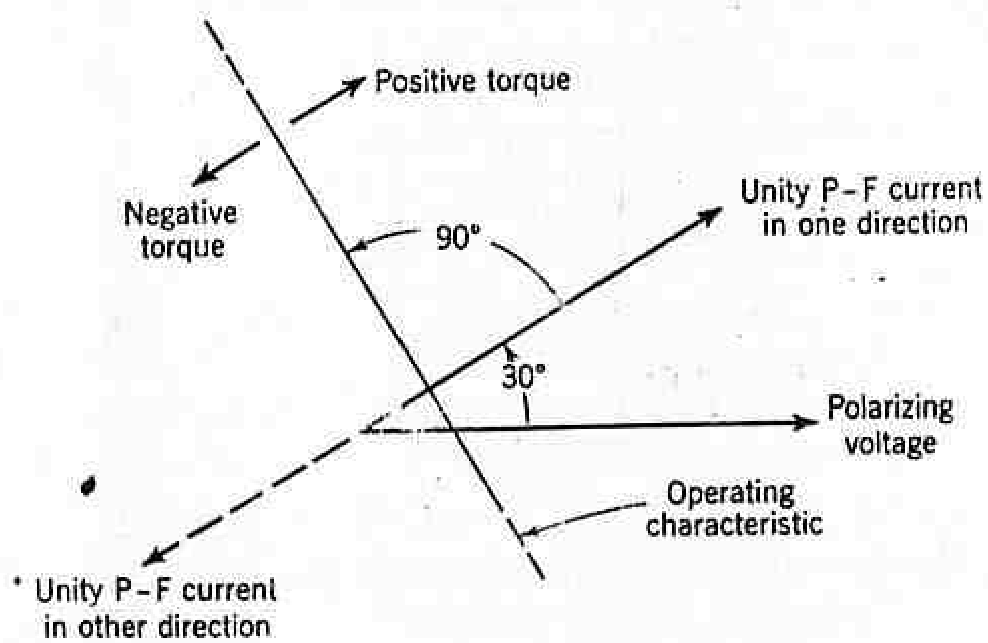

Fig. 7. A typical power-relay operating characteristic.

Power relays are used generally for responding to a certain direction of current flow under approximately balanced three-phase conditions and for approximately normal voltage magnitudes. Consequently, any combination of voltage and current may be used so long as the relay has the necessary angle of maximum torque so that maximum torque will be developed for unity-power-factor current in the three-phase system.

Power relays are available having adjustable minimum pickup currents. They may be calibrated either in terms of minimum pickup amperes at rated voltage or in terms of minimum pickup watts. Therefore, such relays may be adjusted to respond to any desired amount of power being supplied in a given direction. In effect, these relays are watthour meters with their dial mechanisms replaced by contacts, and having a control spring. Some power relays have actually been constructed directly from watthour-meter parts.

Power relays usually have time-delay characteristics to avoid undesired operation during momentary power reversals, such as generator synchronizing-power surges or power reversals when short circuits occur. This time delay may be an inherent inverse-time characteristic of the relay itself, or it may be provided by a separate time-delay relay.

DIRECTIONAL RELAYS FOR SHORT-CIRCUIT PROTECTION

Because short circuits involve currents that lag their unity-power-factor positions, usually by large angles, it is desirable that directional relays for short-circuit protection be arranged to develop maximum torque under such lagging-current conditions. The technique for obtaining any desired maximum-torque adjustment was described in Chapter 2. The problem is straightforward for a single-phase circuit. Exactly the same technique can be applied to three-phase circuits, but there are a number of possible solutions, and not all of them are good. The problem is somewhat different from that with power relays. With power relays, we are dealing with approximately balanced three-phase conditions, and where the polarizing voltage is maintained approximately at its normal value; any of the alternative ways of obtaining maximum torque at unity-power-factor-load current is equally acceptable from a functional standpoint. If three-phase short circuits were the only kind with which we had to contend, any of the many possible arrangements for obtaining maximum torque at a given angle would also be equally acceptable. But the choice of connections for obtaining correct directional discrimination for unbalanced short circuits (i.e., phase-to-phase, phase-to-ground, and two-phase-to-ground) is severely restricted.

Three conventional current-and-voltage combinations that are used for phase relays are illustrated by the vector diagrams of Fig. 8, in which the quantities shown are for one of three single-phase relays or for one of the three elements of a polyphase relay. The other

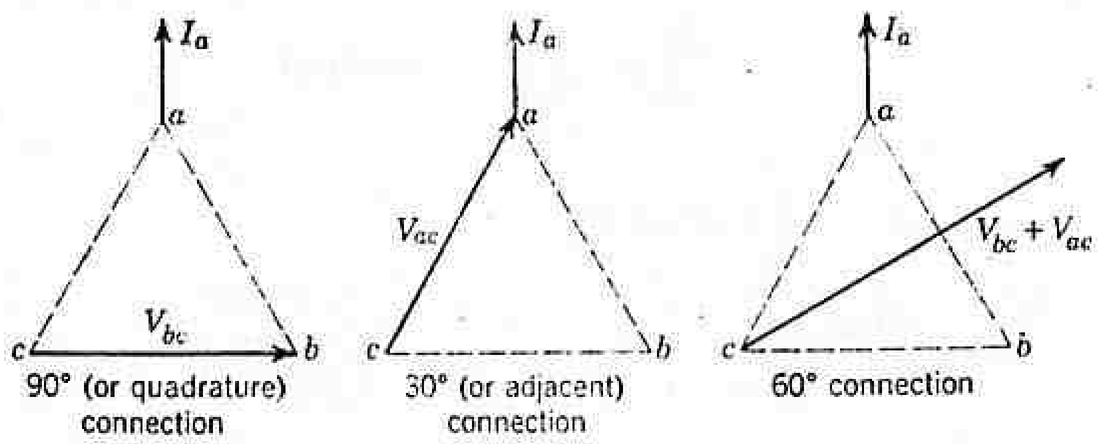

Fig. 8. Conventional connections of directional phase relays.

two relays or elements would use the other two corresponding voltage-and-current combinations. The names of these three combinations, as given in Fig. 8, will be recognized as describing the phase relation of the current-coil current to the polarizing voltage under balanced three-phase unity-power-factor conditions.

The relations shown in Fig. 8 are for the relay or element that provides directional discrimination when short circuits occur involving phases a and b. Note that the voltage V_{ab} is not used by the relay or element on which dependence for protection is placed. For such a short circuit, one or both of the other two relays will also develop torque. It would be highly undesirable if one of these others should develop contact-closing torque when the conditions were such that it would cause unnecessary tripping of a circuit breaker. It is to avoid this possibility, and yet to assure operation when it is required, that the many possible alternative connections are narrowed down to the three shown. Even with these, there are circumstances when incorrect operation is sometimes possible unless additional steps are taken to avoid it; this whole subject will be treated further when we consider the application of such relays to the protection of lines. It will probably be evident, however, that, since in a polyphase relay the torques of the three elements are added, it is only necessary that the net torque be in the right direction to avoid undesired operation. The bibliography[1] gives reference material for further study of polyphase directional-relay connections and their effect on relay behavior, but it is a bit advanced, in view of our present status.

With directional relays for protection against short circuits involving ground, there is no problem similar to that just described for phase relays. As will be seen later, only a single-phase relay is necessary, and the connections are such that, no matter which phase is involved, the quantities affecting relay operation have the same phase relation. Moreover, a ground relay is unaffected by other than ground faults because, for such other faults, the actuating quantities are not present unless the CT's (current transformers) fail to transform their currents accurately.

Except for circuit arrangements for providing the desired maximum-torque relations, a directional relay for ground protection is essentially the same as a single-phase directional relay for phase-fault protection. Such relays are available with or without time delay, and for current or voltage polarization, or for polarization by both current and voltage simultaneously.

Directional relays for short-circuit protection are generally used to supplement other relays. The directional relays permit tripping only for a certain direction of current flow, and the other relays determine (1) if it is a short circuit that is causing the current to flow, and (2) if the short circuit is near enough so that the relays should trip their circuit breaker. Such directional relays have no intentional time delay, and their pickup is non-adjustable but low enough so that the directional relays will always operate when their associated relays must operate. Some directional relays combine the directional with the fault-detecting and locating function; then, the directional relay will have adjustable pickup and either instantaneous or inverse-time characteristics.

Some directional relays have adjustment of their maximum-torque angle to permit their use with various connections of voltage-transformer sources, or to match their maximum-torque angle more accurately to the actual fault-current angle.

DIRECTIONAL-OVERCURRENT RELAYS

Directional-overcurrent relays are combinations of directional and overcurrent relay units in the same enclosing case. Any combination of directional relay, inverse-time overcurrent relay, and instantaneous overcurrent relay is available for phase- or ground-fault protection.

"Directional control" is a design feature that is highly desirable for this type of relay. With this feature, an overcurrent unit is inoperative, no matter how large the current may be, unless the contacts of the directional unit are closed. This is accomplished by connecting the directional-unit contacts in series with the shading-coil circuit or with one of the two flux-producing circuits of the overcurrent unit. When this circuit is open, no operating torque is developed in the overcurrent unit. The contacts of the overcurrent unit alone are in the trip circuit.

Without directional control, the contacts of the directional and overcurrent units would merely be connected in series, and there would be a possibility of incorrect tripping under certain circumstances. For example, consider the situation when a very large current, flowing to a short circuit in the non-tripping direction, causes the overcurrent unit to pick up. Then, suppose that the tripping of some circuit breaker causes the direction of current flow to reverse. The directional unit would immediately pick up and undesired tripping would result; even if the overcurrent unit should have a tendency to reset, there would be a race between the closing of the directional-unit contacts and the opening of the overcurrent-unit contacts.

Separate directional and overcurrent units are generally preferred because they are easier to apply than directional relays with inherent time characteristics and adjustable pickup. The operating time with separate units is simply a function of the current in the overcurrent unit; the pickup and time delay of the directional unit are so small that they can be neglected. But the operating time of the directional relay is a function of the product of its actuating and polarizing quantities and of the phase angle between them. However, the relay composed of separate directional and overcurrent units is somewhat larger, and it imposes somewhat more burden on its current-transformer source.

Current (or Voltage) - Balance Relays

Two basically different types of current-balance relay are used. Based on the production of actuating torque, one may be called the "overcurrent" type and the other the "directional" type.

OVERCURRENT TYPE

The overcurrent type of current-balance relay has one overcurrent element arranged to produce torque in opposition to another overcurrent element, both elements acting on the same moving structure. Figure 9 shows schematically an electromagnetic-attraction "balanced-beam" type of structure. Another commonly used structure is an induction-type relay having two overcurrent elements acting in opposition on a rotor.

If we neglect the negative-torque effect of the control spring, the torque equation of either type is:

$$T = K_1 I_1^2 - K_2 I_2^2$$

When the relay is on the verge of operating, the net torque is zero, and:

$$K_1 I_1^2 = K_2 I_2^2$$

Therefore, the operating characteristic is:

$$\frac{I_1}{I_2} = \sqrt{\frac{K_2}{K_1}} = \text{constant}$$

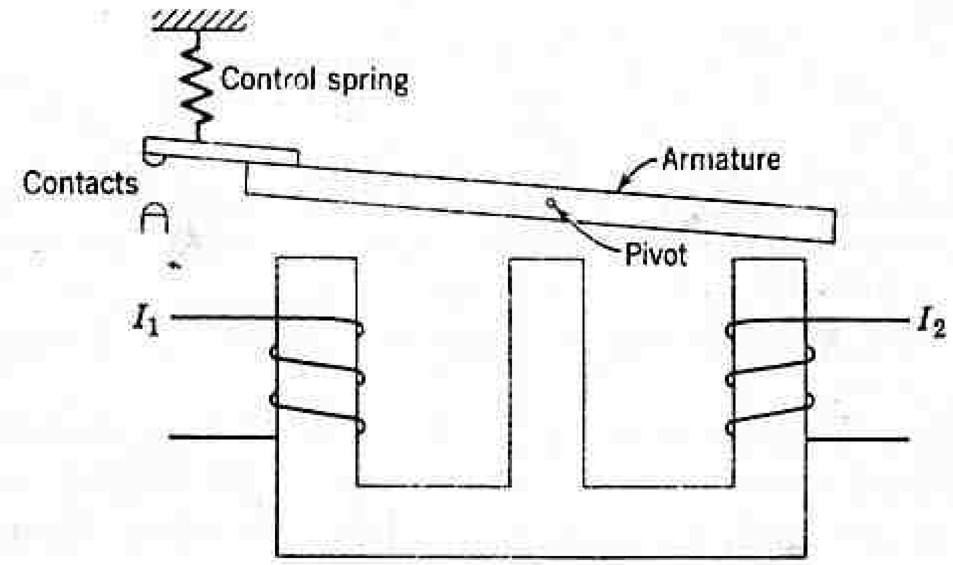

Fig. 9. A balanced-beam type of current-balance relay.

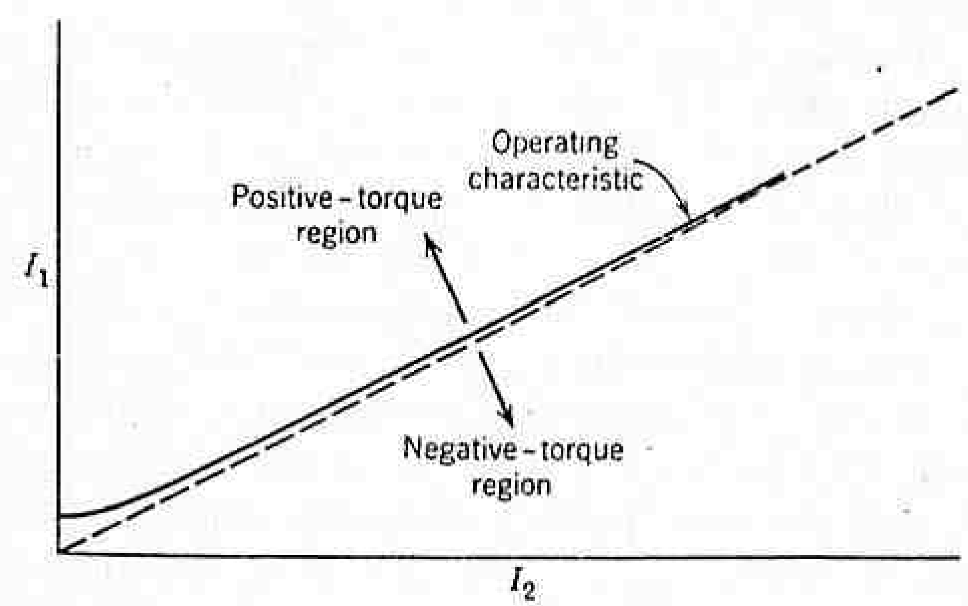

Fig. 10. Operating characteristic of a current-balance relay.

The operating characteristic of such a relay, including the effect of the control spring, is shown in Fig. 10.

The effect of the control spring is to require a certain minimum value of I_1 for pickup when I_2 is zero, but the spring effect becomes

4 DISTANCE RELAYS

Perhaps the most interesting and versatile family of relays is th distance-relay group. In the preceding chapter, we examined relay in which one current was balanced against another current, and w saw that the operating characteristic could be expressed as a ratio o the two currents. In distance relays, there is a balance betwe voltage and current, the ratio of which can be expressed in terms o impedance. Impedance is an electrical measure of distance alon a transmission line, which explains the name applied to this grou of relays.

The Impedance-Type Distance Relay

Since this type of relay involves impedance-type units, let us fir became acquainted with them. Generally speaking, the term "im pedance" can be applied to resistance alone, reactance alone, or combination of the two. In protective-relaying terminology, howeve an impedance relay has a characteristic that is different from that o a relay responding to any component of impedance. And hence, th term "impedance relay" is very specific.

In an impedance relay, the torque produced by a current element balanced against the torque of a voltage element. The current ele ment produces positive (pickup) torque, whereas the voltage eleme produces negative (reset) torque. In other words, an impedance rela is a voltage-restrained overcurrent relay. If we let the control-sprin effect be $-K_3$, the torque equation is:

$$T = K_1 I^2 - K_2 V^2 - K_3$$

where I and V are rms magnitudes of the current and voltage, respe tively. At the balance point, when the relay is on the verge o operating, the net torque is zero, and

$$K_2 V^2 = K_1 I^2 - K_3$$

Dividing by $K_2 I^2$, we get:

$$\frac{V^2}{I^2} = \frac{K_1}{K_2} - \frac{K_3}{K_2 I^2}$$

$$\frac{V}{I} = Z = \sqrt{\frac{K_1}{K_2} - \frac{K_3}{K_2 I^2}}$$

It is customary to neglect the effect of the control spring, since its effect is noticeable only at current magnitudes well below those normally encountered. Consequently, if we let K_3 be zero, the preceding equation becomes:

$$Z = \sqrt{\frac{K_1}{K_2}} = \text{constant}$$

In other words, an impedance relay is on the verge of operating at a given constant value of the ratio of V to I, which may be expressed as an impedance.

The operating characteristic in terms of voltage and current is shown in Fig. 1, where the effect of the control spring is shown as causing a noticeable bend in the characteristic only at the low-current end. For all practical purposes, the dashed line, which represents a

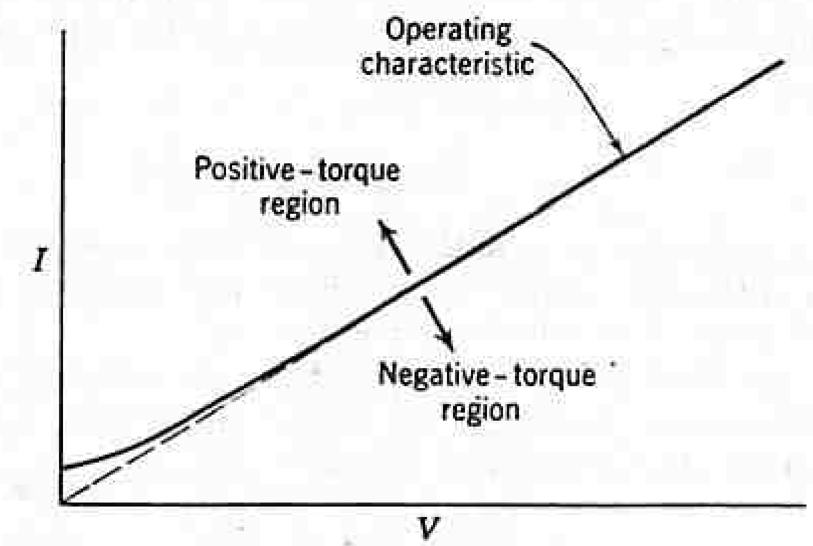

Fig. 1. Operating characteristic of an impedance relay.

constant value of Z, may be considered the operating characteristic. The relay will pick up for any combination of V and I represented by a point above the characteristic in the positive-torque region, or, in other words, for any value of Z less than the constant value represented by the operating characteristic. By adjustment, the slope of the operating characteristic can be changed so that the relay will respond to all values of impedance less than any desired upper limit.

A much more useful way of showing the operating characteristic distance relays is by means of the so-called "impedance diagram" "R-X diagram." Reference 1 provides a comprehensive treatment this method of showing relay characteristics. The operating chara teristic of the impedance relay, neglecting the control-spring effe is shown in Fig. 2 on this type of diagram. The numerical value

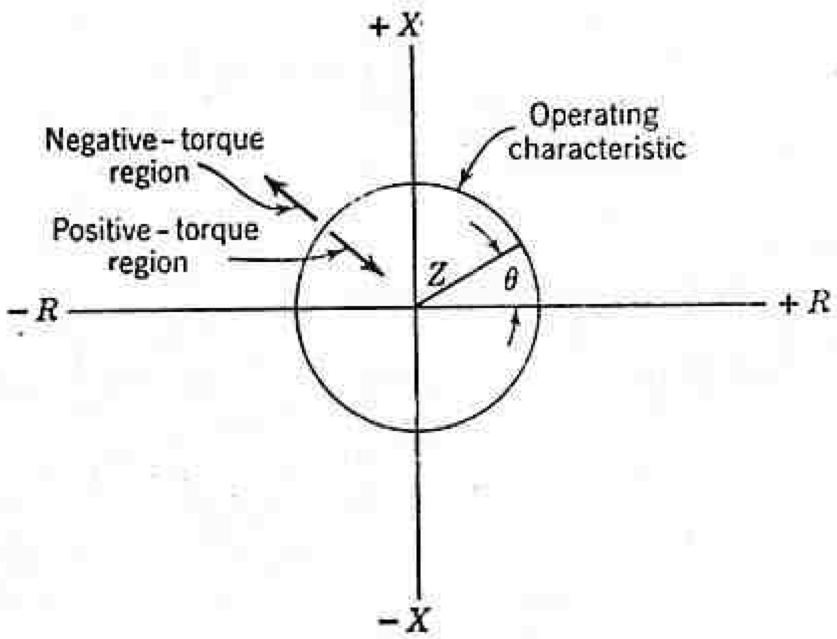

Fig. 2. Operating characteristic of an impedance relay on an R-X diagram.

the ratio of V to I is shown as the length of a radius vector, such Z, and the phase angle θ between V and I determines the position the vector, as shown. If I is in phase with V, the vector lies along t $+R$ axis; but, if I is 180 degrees out of phase with V, the vector li along the $-R$ axis. If I lags V, the vector has a $+X$ componen and, if I leads V, the vector has a $-X$ component. Since the operati of the impedance relay is practically or actually independent of t phase angle between V and I, the operating characteristic is a cir with its center at the origin. Any value of Z less than the radius the circle will result in the production of positive torque, and a value of Z greater than this radius will result in negative torq regardless of the phase angle between V and I.

At very low currents where the operating characteristic of Fig departs from a straight line because of the control spring, the eff on Fig. 2 is to make the radius of the circle smaller. This does n have any practical significance, however, since the proper applicati of such relays rarely if ever depends on operation at such l currents.

Although impedance relays with inherent time delay are encounter occasionally, we shall consider only the high-speed type. The oper ing-time characteristic of a high-speed impedance relay is sho

qualitatively in Fig. 3. The curve shown is for a particular value of current magnitude. Curves for higher currents will lie under this curve, and curves for lower currents will lie above it. In general, however, the operating times for the currents usually encountered in

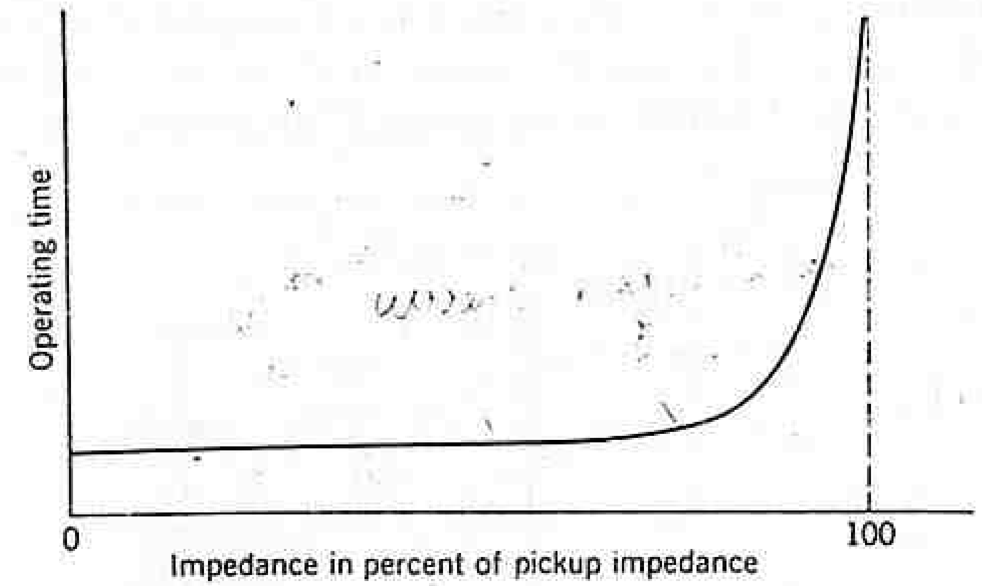

Fig. 3. Operating-time-versus-impedance characteristic of a high-speed impedance relay for one value of current.

normal applications of distance relays are so short as to be within the definition of high speed, and the variations with current are neglected. In fact, even the increase in time as the impedance approaches the pickup value is often neglected, and the time curve is shown simply as in Fig. 4.

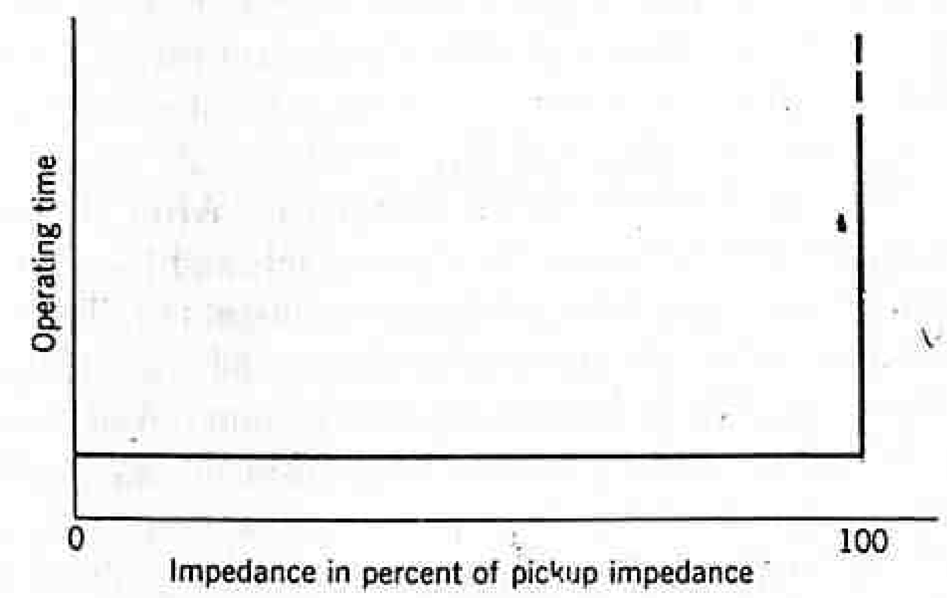

Fig. 4. Simplified representation of Fig. 3.

Various types of actuating structure are used in the construction of impedance relays. Inverse-time relays use the shaded-pole or the watt-metric structures. High-speed relays may use a balance-beam magnetic-attraction structure or an induction-cup or double-loop structure.

For transmission-line protection, a single-phase distance relay the impedance type consists of a single-phase directional unit, thr high-speed impedance-relay units, and a timing unit, together wi the usual targets, seal-in unit, and other auxiliaries. Figure 5 sho very schematically the contact circuits of the principal units. T three impedance units are labeled Z_1, Z_2, and Z_3. The operati characteristics of these three units are independently adjustable. the R-X diagram of Fig. 6, the circle for Z_1 is the smallest, the cir for Z_3 is the largest, and the circle for Z_2 is intermediate. It will

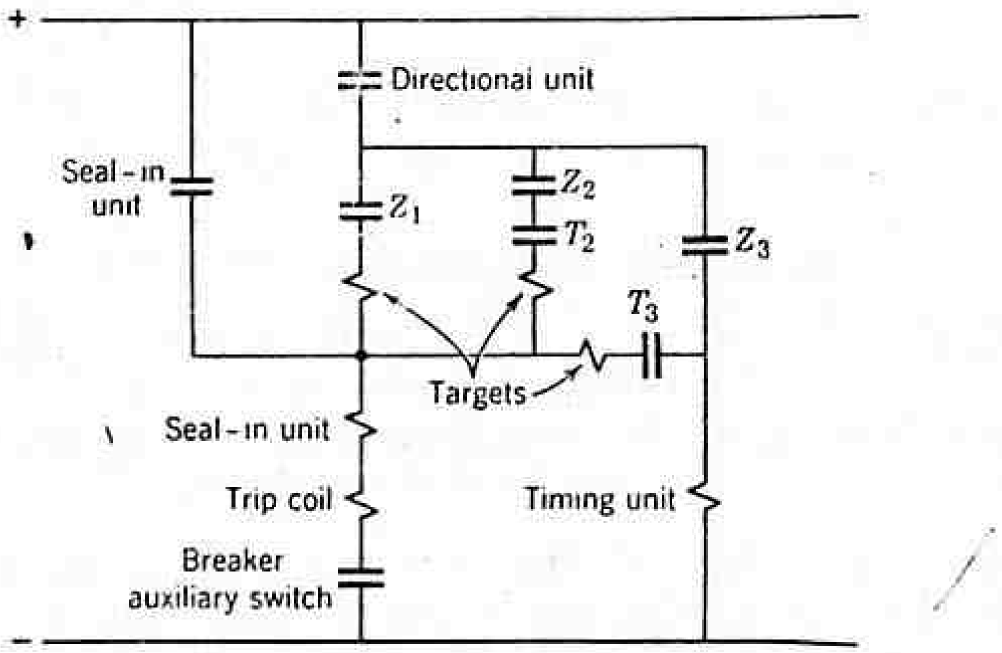

Fig. 5. Schematic contact-circuit connections of an impedance-type distance relay.

evident, then, that any value of impedance that is within the circle will cause all three impedance units to operate. The operati of Z_1 and the directional unit will trip a breaker directly in a ve short time, which we shall call T_1. Whenever Z_3 and the directio unit operate, the timing unit is energized. After a definite del the timing unit will first close its T_2 contact, and later its T_3 conta both time delays being independently adjustable. Therefore, it c be seen that a value of impedance within the Z_2 circle, but outsi the Z_1 circle, will result in tripping in T_2 time. And finally, a val of Z outside the Z_1 and Z_2 circles, but within the Z_3 circle, will res in tripping in T_3 time.

It will be noted that, if tripping is somehow blocked, the rel will make as many attempts to trip as there are characteristic circ around a given impedance point. However, use may not be made this possible feature.

Figure 6 shows also the relation of the directional-unit operati characteristic to the impedance-unit characteristics on the same R

diagram. Since the directional unit permits tripping only in its positive-torque region, the inactive portions of the impedance-unit characteristics are shown dashed. The net result is that tripping will occur only for points that are both within the circles and above the directional-unit characteristic.

Because this is the first time that a simple directional-unit characteristic has been shown on the R-X diagram, it needs some explanation. Strictly speaking, the directional unit has a straight-line

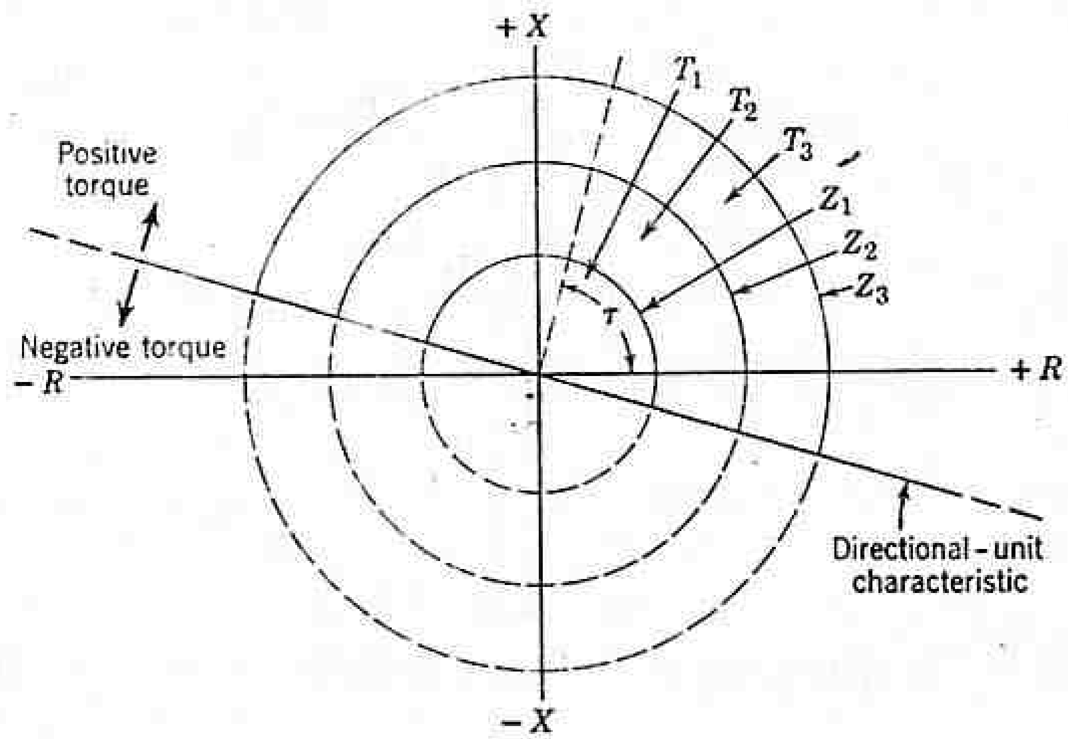

Fig. 6. Operating and time-delay characteristics of an impedance-type distance relay.

operating characteristic, as shown, only if the effect of the control spring is neglected, which is to assume that there is no restraining torque. It will be recalled that, if we neglect the control-spring effect, the torque of the directional unit is:

$$T = K_1 VI \cos(\theta - \tau)$$

When the net torque is zero,

$$K_1 VI \cos(\theta - \tau) = 0$$

Since K_1, V, or I are not necessarily zero, then, in order to satisfy this equation,

$$\cos(\theta - \tau) = 0$$

or

$$(\theta - \tau) = \pm 90°$$

Hence, $\theta = \tau \pm 90°$ describes the characteristic of the relay. In other words, the head of any radius vector Z at 90° from the angle of maximum torque lies on the operating characteristic, and this de-scribes the straight line shown on Fig. 6, the particular value of having been chosen for reasons that will become evident later.

We should also develop the operating characteristic of a direction relay when the control-spring effect *is* taken into account. The torq equation as previously given is:

$$T = K_1VI \cos(\theta - \tau) - K_2$$

At the balance point, the net torque is zero, and hence:

$$K_1VI \cos(\theta - \tau) = K_2$$

But $I = V/Z$, and hence:

$$\frac{V^2}{Z} \cos(\theta - \tau) = \frac{K_2}{K_1}$$

or

$$Z = \frac{K_1}{K_2} V^2 \cos(\theta - \tau)$$

This equation describes an infinite number of circles, one for each val of V, one circle of which is shown in Fig. 7 for the same relay co nections and the same value of τ as in Fig. 6. The fact that som

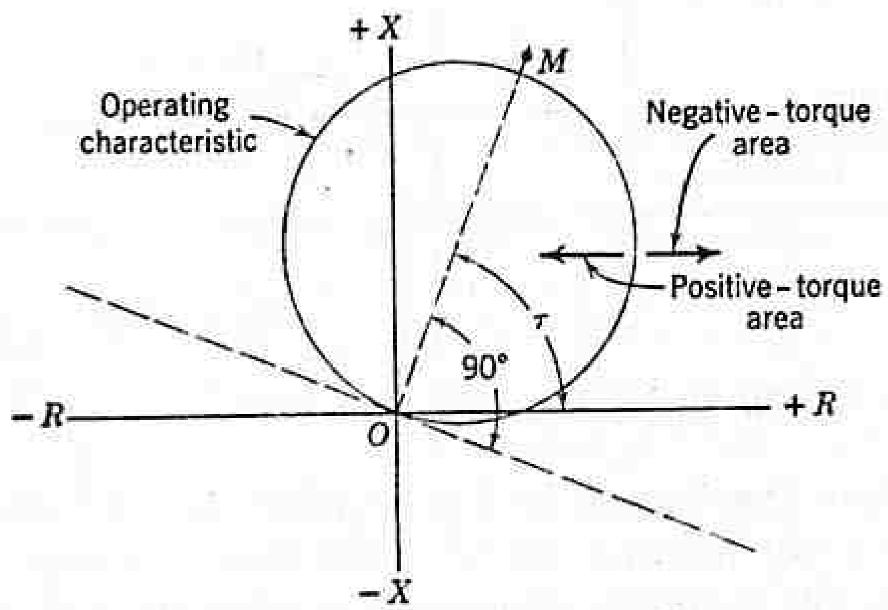

Fig. 7. The characteristics of a directional relay for one value of voltage.

values of θ will give negative values of Z should be ignored. Nega tive Z has no significance and cannot be shown on the R-X diagram.

The centers of all the circles will lie on the dashed line directe from O through M, which is at the angle of maximum torque. Th diameter of each circle will be proportional to the square of th voltage. At normal voltage, and even at considerably reduced voltage

the diameter will be so large that for all practical purposes we may assume the straight-line characteristic of Fig. 6.

Looking somewhat ahead to the application of distance relays for transmission-line protection, we can show the operating-time-versus-impedance characteristic as in Fig. 8. This characteristic is generally

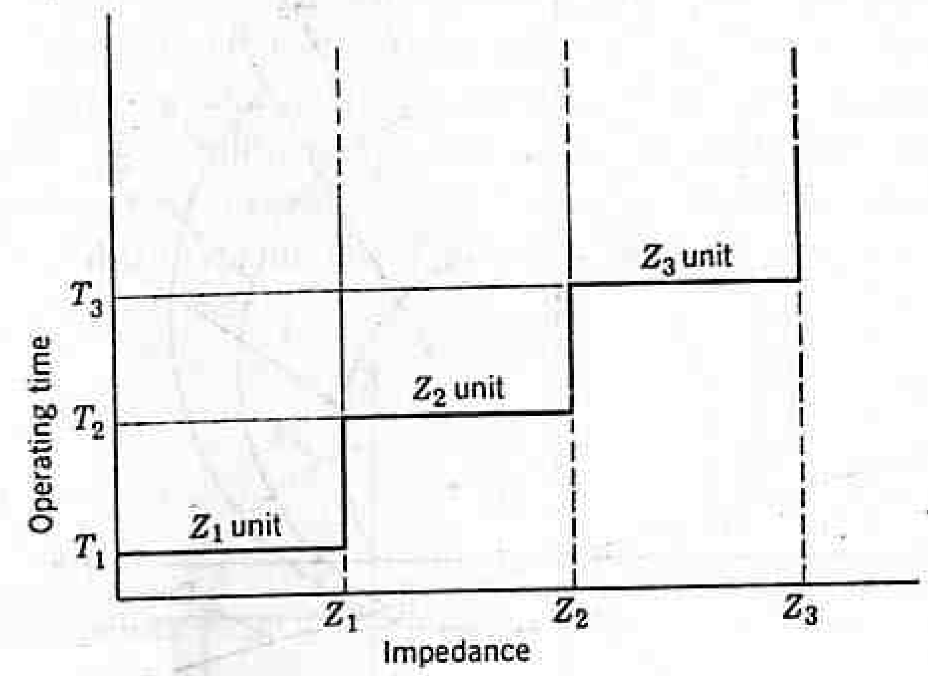

Fig. 8. Operating time versus impedance for an impedance-type distance relay.

called a "stepped" time-impedance characteristic. It will be shown later that the Z_1 and Z_2 units provide the primary protection for a given transmission-line section, whereas Z_2 and Z_3 provide back-up protection for adjoining busses and line sections.

The Modified Impedance-Type Distance Relay

The modified impedance-type distance relay is like the impedance type except that the impedance-unit operating characteristics are shifted, as in Fig. 9. This shift is accomplished by what is called a "current bias," which merely consists of introducing into the voltage supply an additional voltage proportional to the current,[2] making the torque equation as follows:

$$T = K_1I^2 - K_2(V + CI)^2$$

The term $(V + CI)$ is the rms magnitude of the vector addition of V and CI, involving the angle θ between V and I as well as a constant angle in the constant C term. This is the equation of a circle whose center is offset from the origin, as shown in Fig. 9. By such biasing, a characteristic circle can be shifted in any direction from the origin, and by any desired amount, even to the extent that the origin is outside the circle. Slight variations may occur in the biasing, owing to saturation of the circuit elements. For this reason, it is not the prac-

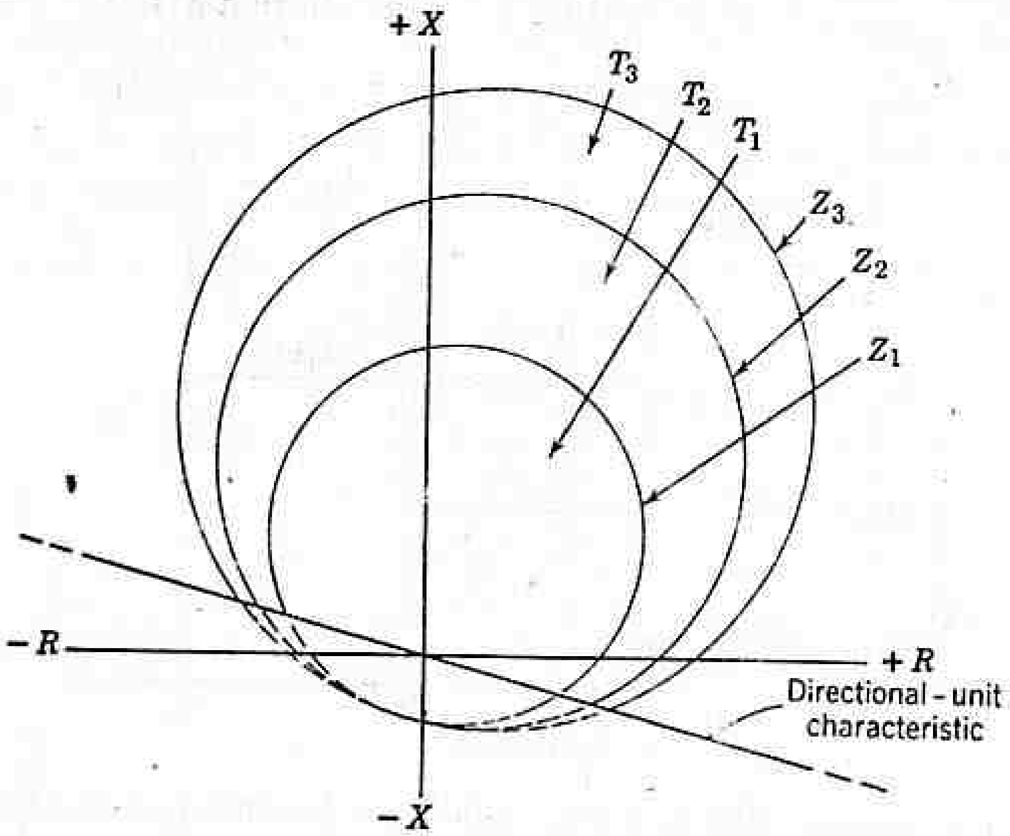

Fig. 9. Operating characteristic of a modified impedance-type distance relay.

tice to try to make the circles go through the origin, and therefore a separate directional unit is required as indicated in Fig. 9.

Since this relay is otherwise like the impedance-type relay already described, no further description will be given here.

The Reactance-Type Distance Relay

The reactance-relay unit of a reactance-type distance relay has, in effect, an overcurrent element developing positive torque, and a current-voltage directional element that either opposes or aids the overcurrent element, depending on the phase angle between the current and the voltage. In other words, a reactance relay is an overcurrent relay with directional restraint. The directional element is arranged to develop maximum negative torque when its current lags its voltage by 90°. The induction-cup or double-induction-loop structures are best suited for actuating high-speed relays of this type.

If we let the control-spring effect be $-K_3$, the torque equation is:

$$T = K_1I^2 - K_2VI \sin \theta - K_3$$

where θ is defined as positive when I lags V. At the balance point, the net torque is zero, and hence:

$$K_1I^2 = K_2VI \sin \theta + K_3$$

Dividing both sides of the equation by I^2, we get:

$$K_1 = K_2 \frac{V}{I} \sin \theta + \frac{K_3}{I^2}$$

or

$$\frac{V}{I} \sin \theta = Z \sin \theta = X = \frac{K_1}{K_2} - \frac{K_3}{K_2I^2}$$

If we neglect the effect of the control spring,

$$X = \frac{K_1}{K_2} = \text{constant}$$

In other words, this relay has an operating characteristic such that all impedance radius vectors whose heads lie on this characteristic have a constant X component. This describes the straight line of Fig. 10. The significant thing about this characteristic is that the resistance

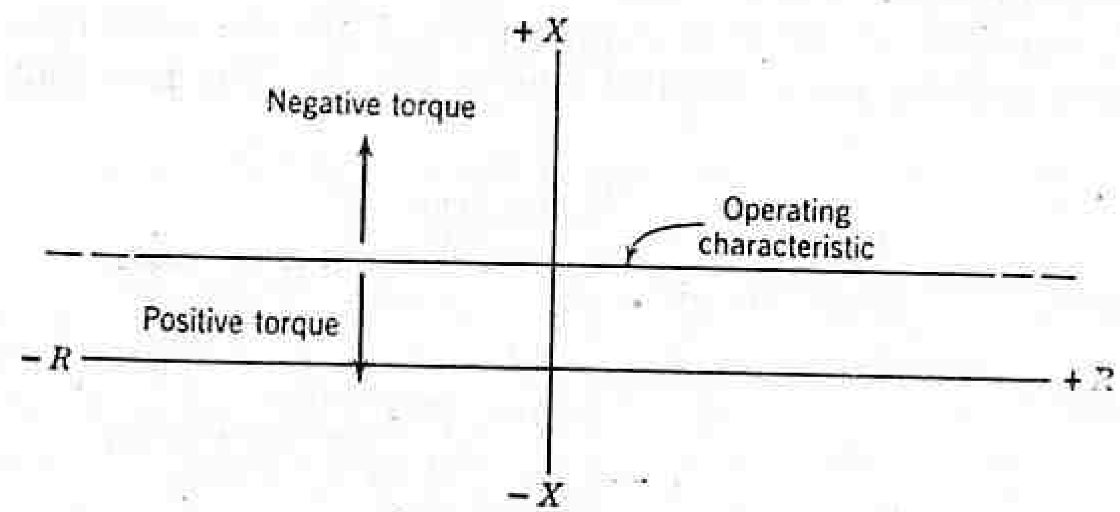

Fig. 10. Operating characteristic of a reactance relay.

component of the impedance has no effect on the operation of the relay; the relay responds solely to the reactance component. Any point below the operating characteristic—whether above or below the R axis—will lie in the positive-torque region.

Taking into account the effect of the control spring would lower the operating characteristic toward the R axis and beyond at very low values of current. This effect can be neglected in the normal application of reactance relays.

It should be noted in passing that, if the torque equation is of the general form $T = K_1I^2 - K_2\,VI \cos(\theta - \tau) - K_3$, and if τ is made some value other than 90°, a straight-line operating characteristi will still be obtained, but it will not be parallel to the R axis. Thi general form of relay has been called an "angle-impedance" relay.

A reactance-type distance relay for transmission-line protectio could not use a simple directional unit as in the impedance-type rela because the reactance relay would trip under normal load conditio at or near unity power factor, as will be seen later when we conside what different system-operating conditions "look" like on the R-X diagram. The reactance-type distance relay requires a directiona

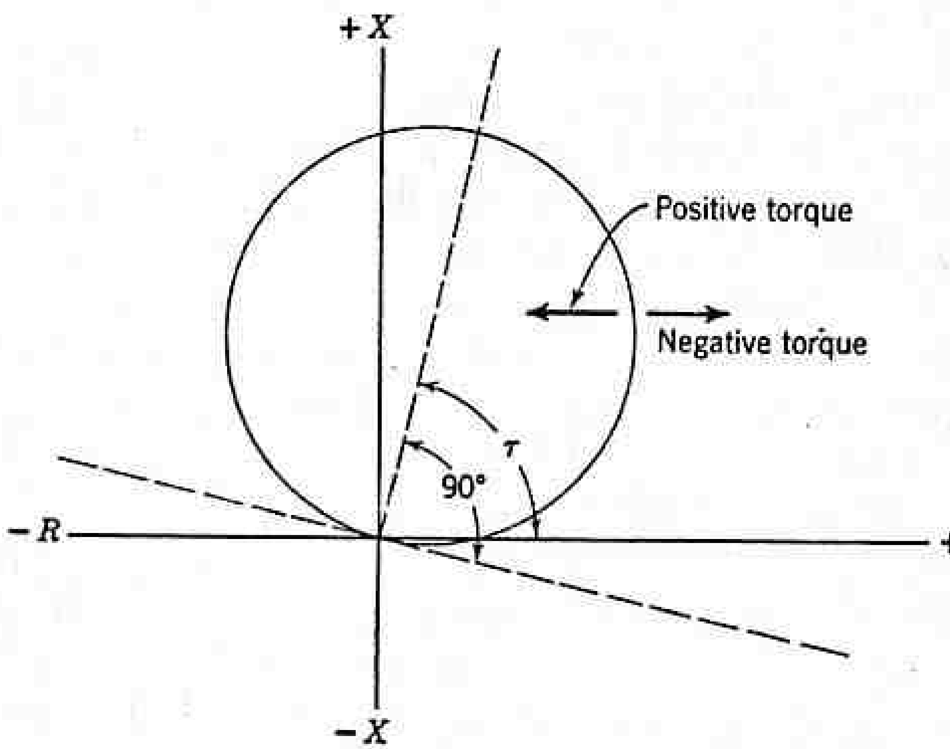

Fig. 11. Operating characteristic of a directional relay with voltage restraint.

unit that is inoperative under normal load conditions. The type o unit used for this purpose has a voltage-restraining element that op poses a directional element, and it is called an "admittance" or "mho unit or relay. In other words, this is a voltage-restrained direction relay. When used with a reactance-type distance relay, this unit h also been called a "starting unit." If we let the control-spring effe be $-K_3$, the torque of such a unit is:

$$T = K_1 VI \cos(\theta - \tau) - K_2 V^2 - K_3$$

where θ and τ are defined as positive when I lags V. At the balan point, the net torque is zero, and hence:

$$K_2 V^2 = K_1 VI \cos(\theta - \tau) - K_3$$

Dividing both sides by $K_2 VI$, we get:

$$\frac{V}{I} = Z = \frac{K_1}{K_2}\cos(\theta - \tau) - \frac{K_3}{K_2 VI}$$

If we neglect the control-spring effect,

$$Z = \frac{K_1}{K_2}\cos(\theta - \tau)$$

It will be noted that this equation is like that of the directional relay when the control-spring effect is included, but that here there is no voltage term, and hence the relay has but one circular characteristic.

The operating characteristic described by this equation is shown in Fig. 11. The diameter of this circle is practically independent of voltage or current, except at very low magnitudes of current or voltage when the control-spring effect is taken into account, which causes the diameter to decrease.

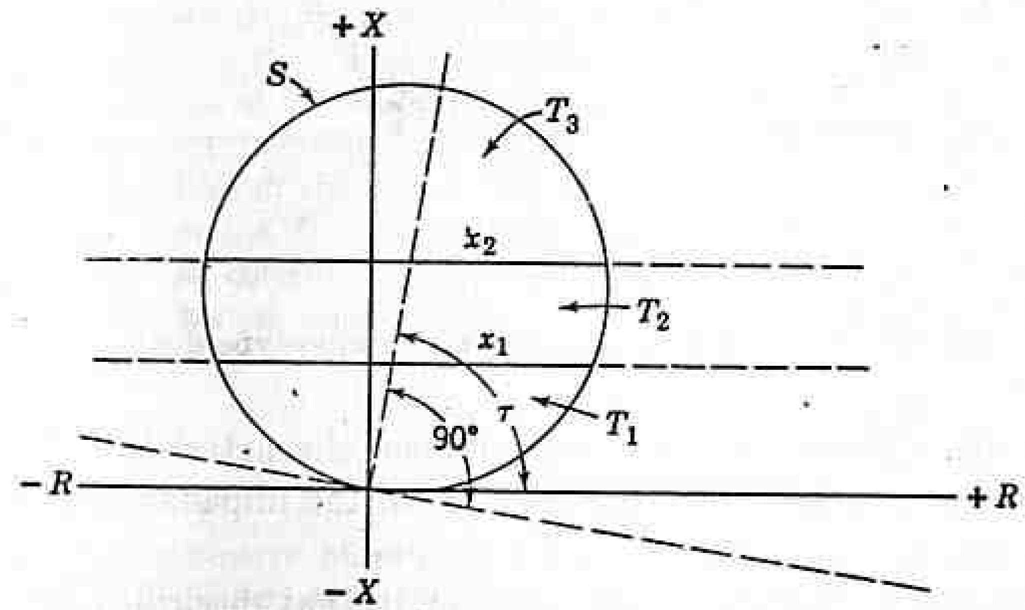

Fig. 12. Operating characteristics of a reactance-type distance relay.

The complete reactance-type distance relay has operating characteristics as shown in Fig. 12. These characteristics are obtained by arranging the various units as described in Fig. 5 for the impedance-type distance relay. It will be observed here, however, that the directional or starting unit (S) serves double duty, since it not only provides the directional function but also provides the third step of distance measurement with inherent directional discrimination.

The time-versus-impedance characteristic is the same as that of Fig. 8.

The Mho-Type Distance Relay

The mho unit has already been described, and its operating characteristic was derived in connection with the description of the starting unit of the reactance-type distance relay. The induction-cylinder or double-induction-loop structures are used in this type of relay.

The complete distance relay for transmission-line protection is composed of three high-speed mho units (M_1, M_2, and M_3) and a timing unit, connected in a manner similar to that shown for an impedance-type distance relay, except that no separate directional unit is required, since the mho units are inherently directional.[3] The operating characteristic of the entire relay is shown on Fig. 13.

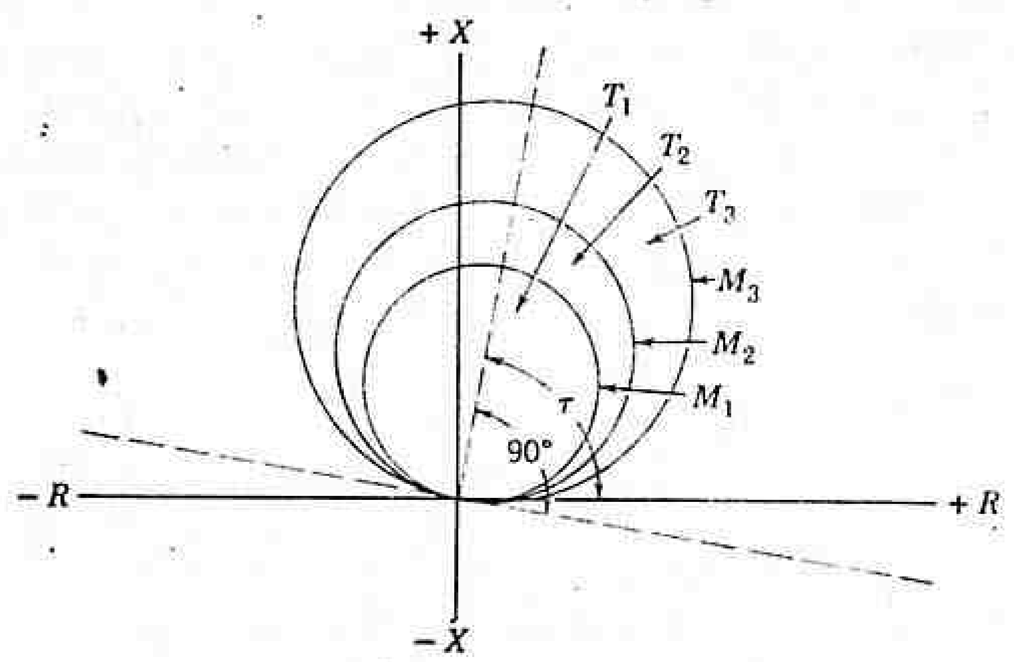

Fig. 13. Operating characteristics of a mho-type distance relay.

The operating-time-versus-impedance characteristic of the mho-type distance relay is the same as that of the impedance-type distance relay, Fig. 8.

By means of current biasing similar to that described for the offset impedance relay, a mho-relay characteristic circle can be offset so that either it encircles the origin of the R-X diagram or the origin is outside the circle.

General Considerations Applicable to All Distance Relays

OVERREACH

When a short circuit occurs, the current wave is apt to be offset initially. Under such conditions, distance relays tend to "overreach," i.e., to operate for a larger value of impedance than that for which they are adjusted to operate under steady-state conditions. This tendency is greater, the more inductive the impedance is. Also, the tendency is greater in electromagnetic-attraction-type relays than in

induction-type relays. The tendency to overreach is minimized in the design of the relay-circuit elements, but it is still necessary to compensate for some tendency to overreach in the adjustment of the relays. Compensation for overreach as well as for inaccuracies in the current and voltage sources is obtained by adjusting the relays to operate at 10% to 20% lower impedance than that for which they would otherwise be adjusted. This will be further discussed when we consider the application of these relays.

MEMORY ACTION

Relays in which voltage is required to develop pickup torque, such as mho-type relays or directional units of other relays, may be provided with "memory action." Memory action is a feature that can be obtained by design in which the current flow in a voltage-polarizing coil does not cease immediately when the voltage on the high-voltage side of the supply-voltage transformer is instantly reduced to zero. Instead, the stored energy in the voltage circuit causes sinusoidal current to flow in the voltage coil for a short time. The frequency of this current and its phase angle are for all practical purposes the same as before the high-tension voltage dropped to zero, and therefore the relay is properly polarized since, in effect, it "remembers" the voltage that had been impressed on it. It will be evident that memory action is usable only with high-speed relays that are capable of operating within the short time that the transient polarizing current flows. It will also be evident that a relay must have voltage applied to it initially for memory action to be effective; in other words, memory action is ineffective if a distance relay's voltage is obtained from the line side of a line circuit breaker and the breaker is closed when there is a short circuit on the line.

Actually, it is a most rare circumstance when a short circuit reduces the relay supply voltage to zero. The short circuit must be exactly at the high-voltage terminals of the voltage transformer, and there must be no arcing in the short circuit. About the only time that this can happen in practice is when maintenance men have forgotten to remove protective grounding devices before the line breaker is closed. The voltage across an arcing short circuit is seldom less than about 4% of normal voltage, and this is sufficient to assure correct distance-relay operation even without the help of memory action.

Memory action does not adversely affect the distance-measuring ability of a distance relay. Such ability is important only for impedance values near the point for which the operating time steps from T_1 to T_2 or from T_2 to T_3. For such impedances, the primary voltage at the relay location does not go to zero, and the effect of the transient is "swamped."

THE VERSATILITY OF DISTANCE RELAYS

It is probably evident from the foregoing that on the R-X diagram we can construct any desired distance-relay operating characteristic composed of straight lines or circles. The characteristics shown here have been those of distance relays for transmission-line protection. But, by using these same characteristics or modifications of them, we can encompass any desired area on the R-X diagram, or we can divide the diagram into various areas, such that relay operation can be obtained only for certain relations between V, I, and θ. That this is a most powerful tool will be seen later when we learn what various types of abnormal system conditions "look" like on the R-X diagram.

THE SIGNIFICANCE OF Z

Since we are accustomed to associating impedance with some element such as a coil or a circuit of some sort, one might well ask what the significance is of the impedance expressed by the ratio of the voltage to the current supplied to a distance relay. To answer this question completely at this time would involve getting too far ahead of the story. It depends, among other things, on how the voltage and current supplied to the relay are obtained. For the protection of transmission lines against short circuits, which is the largest field of application of distance relays, this impedance is proportional, within certain limits, to the physical distance from the relay to the short circuit. However, the relay will still be energized by voltage and current under other than short-circuit conditions, such as when a system is carrying normal load, or when one part of a system loses synchronism with another, etc. Under any such condition, the impedance has a different significance from that during a short circuit. This is a most fascinating part of the story, but it must wait until we consider the application of distance relays.

At this point, one may wonder why there are different types of distance relays for transmission-line protection such as those described. The answer to this question is largely that each type has its particular field of application wherein it is generally more suitable than any other type. This will be discussed when we examine the application of these relays. These fields of application overlap more or less, and, in the overlap areas, which relay is chosen is a matter of personal preference for certain features of one particular type over another.

Problems

1. On an R-X diagram, show the impedance radius vector of a line section having an impedance of $2.8 + j5.0$ ohms. On the same diagram, show the operating characteristics of an impedance relay, a reactance relay, and a mho relay, each of which is adjusted to just operate for a zero-impedance short circuit at the end of the line section. Assume that the center of the mho relay's operating characteristic lies on the line-impedance vector.

Assuming that an arcing short circuit having an impedance of $1.5 + j0$ ohms can occur anywhere along the line section, show and state numerically for each type of relay the maximum portion of the line section that can be protected.

2. Derive and show the operating characteristic of an overcurrent relay on an R-X diagram.

3. A current-voltage directional relay has maximum torque when the current leads the voltage by 90°. The voltage coil is energized through a voltage regulator that maintains at the relay terminals a voltage that is always in phase with—and of the same frequency as—the system voltage, and that is constant in magnitude regardless of changes in the system voltage.

Derive the equation for the relay's operating characteristic in terms of the system voltage and current, and show this characteristic on an R-X diagram.

4. Write the torque equation, and derive the operating characteristic of a resistance relay.

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5 WIRE-PILOT RELAYS

Pilot relaying is an adaptation of the principles of differential relaying for the protection of transmission-line sections. Differential relaying of the type described in Chapter 3 is not used for transmission-line protection because the terminals of a line are separated by too great a distance to interconnect the CT secondaries in the manner described. Pilot relaying provides primary protection only; back-up protection must be provided by supplementary relaying.

The term "pilot" means that between the ends of the transmission line there is an interconnecting channel of some sort over which information can be conveyed. Three different types of such a channel are presently in use, and they are called "wire pilot," "carrier-current pilot," and "microwave pilot." A wire pilot consists generally of a two-wire circuit of the telephone-line type, either open wire or cable; frequently, such circuits are rented from the local telephone company. A carrier-current pilot for protective-relaying purposes is one in which low-voltage, high-frequency (30 kc to 200 kc) currents are transmitted along a conductor of a power line to a receiver at the other end, the earth and ground wire generally acting as the return conductor. A microwave pilot is an ultra-high-frequency radio system operating above 900 megacycles. A wire pilot is generally economical for distances up to 5 or 10 miles, beyond which a carrier-current pilot usually becomes more economical. Microwave pilots are used when the number of services requiring pilot channels exceeds the technical or economic capabilities of carrier current.

In the following, we shall first examine the fundamental principles of pilot relaying, and then see how these apply to some actual wire-pilot relaying equipments.

Why Current-Differential Relaying Is Not Used

Because the current-differential relays described in Chapter 3 for the protection of generators, transformers, busses, etc., are so selective

one might wonder why they are not used also for transmission-line relaying. The principal reason is that there would have to be too many interconnections between current transformers (CT's) to make current-differential relaying economically feasible over the usual distances involved in transmission-line relaying. For a three-phase line, six pilot conductors would be required, one for each phase CT and one for the neutral connection, and two for the trip circuit. Because even a two-wire pilot much more than 5 to 10 miles long becomes more costly than a carrier-current pilot, we could conclude that, on this basis alone, current-differential relaying with six pilot wires would be limited to very short lines.

Other reasons for not using current-differential relaying like that described in Chapter 3 are: (1) the likelihood of improper operation owing to CT inaccuracies under the heavy loadings that would be involved, (2) the effect of charging current between the pilot wires, (3) the large voltage drops in the pilot wires requiring better insulation, and (4) the pilot currents and voltages would be excessive for pilot circuits rented from a telephone company. Consequently, although the fundamental principles of current-differential relaying will still apply, we must take a different approach to the problem.

Purpose of a Pilot

Figure 1 is a one-line diagram of a transmission-line section connecting stations A and B, and showing a portion of an adjoining line section beyond B. Assume that you were at station A, where very accurate meters were available for reading voltage, current, and the

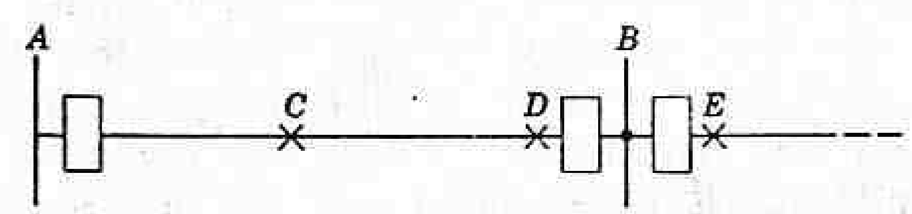


Fig. 1. Transmission-line sections for illustrating the purpose of a pilot.

phase angle between them for the line section AB. Knowing the impedance characteristics per unit length of the line, and the distance from A to B, you could, like a distance relay, tell the difference between a short circuit at C in the middle of the line and at D, the far end of the line. But you could not possibly distinguish between a fault at D and a fault at E just beyond the breaker of the adjoining line section, because the impedance between D and E would be so small as to produce a negligible difference in the quantities that you were measuring. Even though you might detect a slight difference, you could not be sure how much of it was owing to inaccuracies, though slight, in your meters or in the current and voltage transformers supplying your meters. And certainly, you would have difficulties if offset current waves were involved. Under such circumstances, you would hardly wish to accept the responsibility of tripping your circuit breaker for the fault at D and not tripping it for the fault at E.

But, if you were at station B, in spite of errors in your meters or source of supply, or whether there were offset waves, you could determine positively whether the fault was at D or E. There would be practically a complete reversal in the currents, or, in other words, approximately a 180° phase-angle difference.

What is needed at station A, therefore, is some sort of indication when the phase angle of the current at station B (with respect to the current at A) is different by approximately 180° from its value for faults in the line section AB. The same need exists at station B for faults on either side of station A. This information can be provided either by providing each station with an appropriate sample of the actual currents at the other station, or by a signal from the other station when its current phase angle is approximately 180° different from that for a fault in the line section being protected.

Tripping and Blocking Pilots

Having established that the purpose of a pilot is to convey certain information from one end of a line section to another in order to make selective tripping possible, the next consideration is the use to be made of the information. If the relaying equipment at one end of the line must receive a certain signal or current sample from the other end in order to prevent tripping at the one end, the pilot is said to be a "blocking" pilot. However, if one end cannot trip without receiving a certain signal or current sample from the other end, the pilot is said to be a "tripping" pilot. In general, if a pilot-relaying equipment at one end of a line can trip for a fault in the line with the breaker at the other end closed, but with no current flowing at that other end, it is a blocking pilot—otherwise it is like a tripping pilot.

It is probably evident from the foregoing that a blocking pilot is the preferred—if not the required—type. Other advantages of the blocking pilot will be given later.

D-C Wire-Pilot Relaying

Scores of different wire-pilot-relaying equipments have been devised, and many are in use today, where d-c signals in one form or another have been transmitted over pilot wires, or where pilot wires have constituted an extended contact-circuit interconnection between relaying equipments at terminal stations. For certain applications, some such arrangement has advantages—particularly where the distances are short and where a line may be tapped to other stations

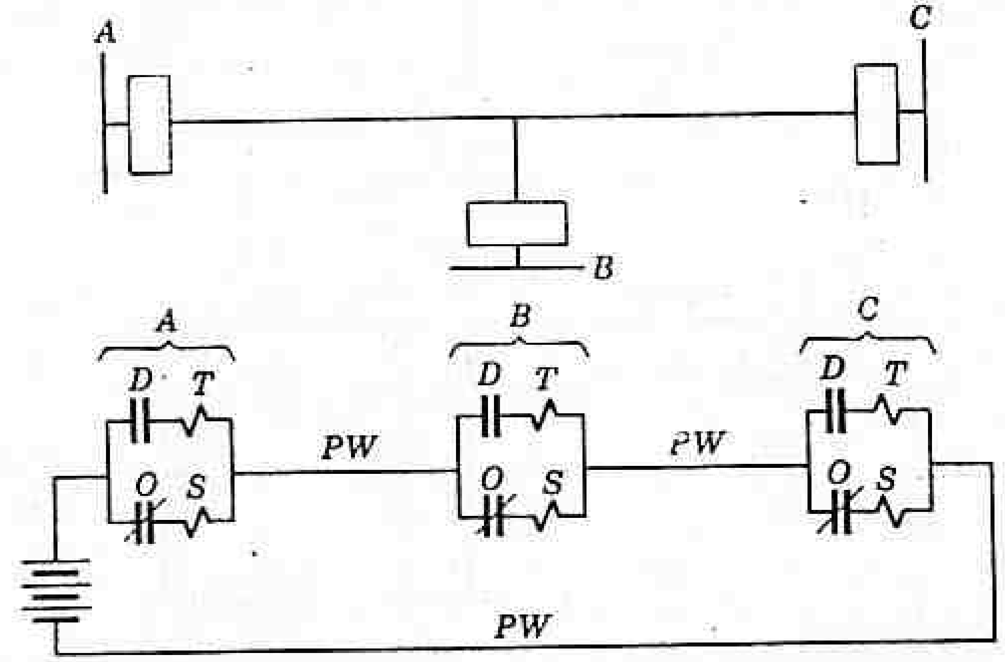


Fig. 2. Schematic illustration of a d-c wire-pilot relaying equipment. D = voltage-restrained directional (mho) relay; O = overcurrent relay; T = auxiliary tripping relay; S = auxiliary supervising relay; PW = pilot wire.

at one or more points. However, d-c wire-pilot relaying is nearly obsolete for other than very special applications. Nevertheless, a study of this type will reveal certain fundamental requirements that apply to modern pilot-relaying equipments, and will serve to prepare us better for understanding still other fundamentals.

An example of d-c wire-pilot relaying is shown very schematically in Fig. 2. The relaying equipments at the three stations are connected in a series circuit, including the pilot wires and a battery at station A. Normally, the battery causes current to flow through the "b" contacts of the overcurrent relay and the coil of the supervising relay at each station. Should a short circuit occur in the transmission-line section, the overcurrent relay will open its "b" contact at any station where there is a flow of short-circuit current. If the short-circuit-current flow at a given station is into the line, the directional relay at that station will close its "a" contact. The circuit at this station is thereby shifted to include the auxiliary tripping relay instead of the supervising relay. If this occurs at the other stations, current will flow through the tripping auxiliaries at all stations, and the breakers at all the line terminals will trip. But should a fault occur external to the protected-line section, the overcurrent relay at the station nearest the fault will pick up, but the directional relay will not close its contact because of the direction of current flow, and the circuit will be open

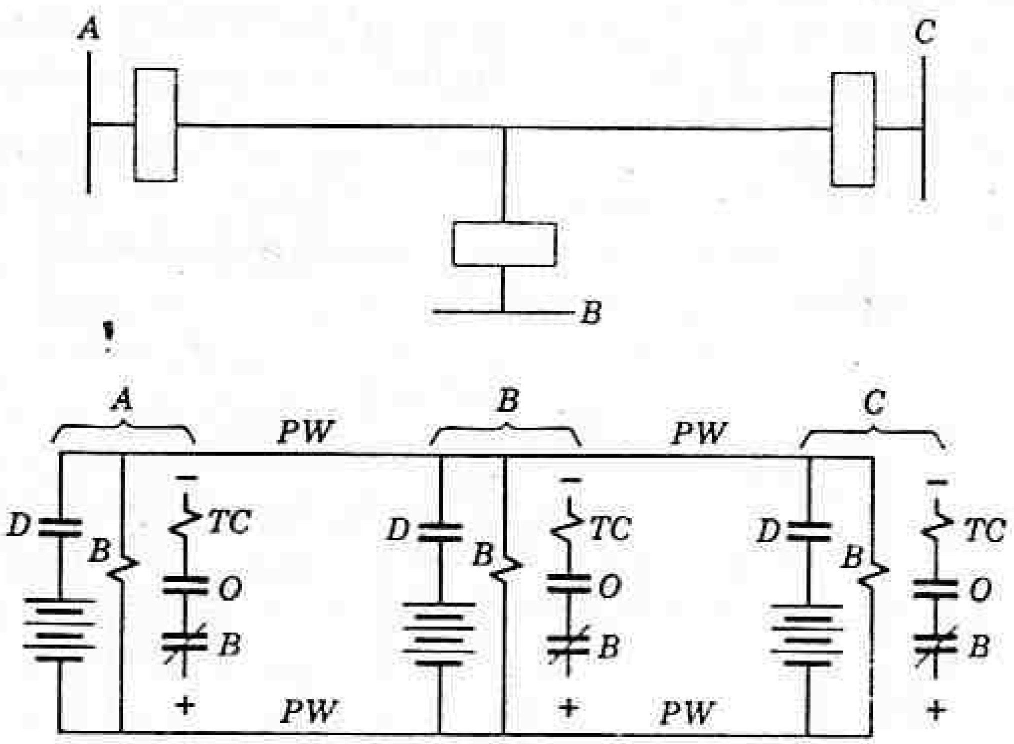


Fig. 3. Schematic illustration of a d-c wire-pilot scheme where information is transmitted over the pilot. D = voltage-restrained directional (mho) relay; B = auxiliary blocking relay; O = overcurrent relay; TC = trip coil; PW = pilot wire.

at that point, thereby preventing tripping at the other stations. If an internal fault occurs for which there may be no short-circuit-current flow at one of the stations, the overcurrent relay at that station will not pick up; but pilot-wire current will flow through the supervising auxiliary relay (whose resistance is equal to that of the tripping auxiliary relay), and tripping will still occur at the other two stations. (The supervising relays not only provide a path for current to flow so that tripping will occur as just described but also can be used to actuate an alarm should the pilot wires become open circuited or short circuited.) Therefore, this arrangement has the characteristics of a blocking pilot where the blocking signal is an interruption of current flow in the pilot. However, if the overcurrent and the supervising relays were removed from the circuit, it would be a tripping pilot, because tripping could not occur at any station unless all the directional relays operated to close their con-

tacts, and tripping would be impossible if there was no flow of short-circuit current into one end.

An example of a blocking pilot, where positive blocking information is transmitted by the pilot, is shown in Fig. 3. Here, the directional relay at each station is arranged to close its contact when short-circuit current flows out of the line as to an external fault. It can be seen that, for an external fault beyond any station, the closing of the directional-relay contact at that station will cause a d-c voltage to be impressed on the pilot that will pick up the blocking relay at each station. The opening of the blocking relay "b" contact in series with the trip circuit will prevent tripping at each station. For an internal fault, no directional relay will operate, and hence no blocking relay will pick up, and tripping will occur at all stations where there is sufficient short-circuit current flowing to pick up the overcurrent relay.

Additional Fundamental Considerations

Now that we are a little better acquainted with pilot relaying, we are prepared to consider some other fundamentals that apply to certain modern types.

Whenever tripping by a relay at one station has to be blocked by the operation of a relay at another station, the blocking relay should be more sensitive than the tripping relay. The reason for this is to be certain that any time the tripping relay can pick up for an external fault the blocking relay will be sure to pick up also, or else undesired tripping will occur.

The matter of contact "races" must also be considered. For example, refer to Fig. 3 where the "b" contact of the blocking relay must open before the overcurrent contact closes, when tripping must be blocked. With the scheme as shown, the overcurrent relay must be given sufficient time delay to make this a safe race. An ingenious scheme can be used to avoid the necessity for adding time delay, but this will be described later in connection with carrier-current-pilot relaying.

A further complication arises because of the necessity for using separate phase and ground relays in order to obtain sufficient sensitivity under all short-circuit conditions. This makes it necessary to be sure that any tendency of a phase relay to operate improperly for a ground fault will not interfere with the proper operation of the equipment. To overcome this possibility, the principle of "ground preference" is employed where necessary. "Ground preference" means that operation of a ground relay takes blocking and tripping cont away from the phase relays. This principle will be illustrated connection with carrier-current-pilot relaying.

Some pilot-relaying equipments utilizing the blocking-and-trippin relay principle must have additional provision against improper tri ping during severe power swings or loss of synchronism. Such pr vision will be described later.

A-C Wire-Pilot Relaying

A-c wire-pilot relaying is the most closely akin to current-diffe ential relaying. However, in modern a-c wire-pilot relaying, t magnitude of the current that flows in the pilot circuit is limite and only a two-wire pilot is required. These two features ma a-c wire-pilot relaying economically feasible over greater distanc than current-differential relaying. They also introduce certain limit tions in application that will be discussed later.

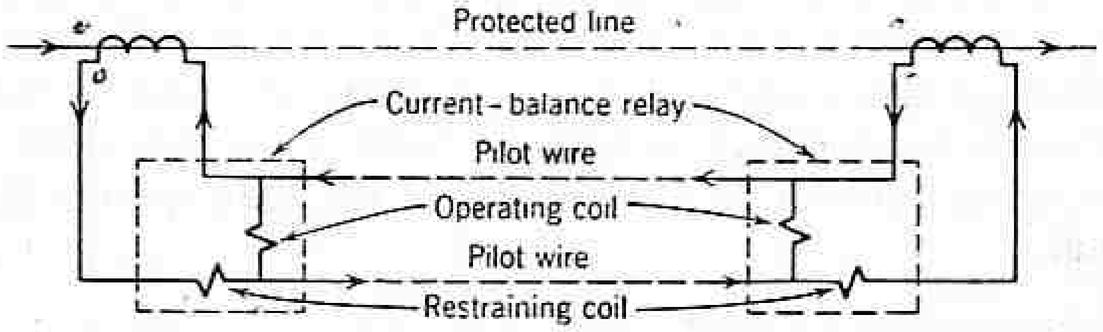


Fig. 4. Schematic illustration of the circulating-current principle of a-c wire-pi relaying.

First, we should become acquainted with two new terms to descri the principle of operation: "circulating current" and "opposed voltag Briefly, "circulating current" means that current circulates normal through the terminal CT's and the pilot, and "opposed voltage" mea that current does not normally circulate through the pilot.

An adaptation of the current-differential type of relaying describ in Chapter 3, employing the circulating-current principle, is sho schematically in Fig. 4. Except that a current-balance relay is us at each end of the pilot, this is essentially the same as the percenta differential type described in Chapter 3. The only reason for havi a relay at each end is to avoid having to run a tripping circuit t full length of the pilot.

A schematic illustration of the opposed-voltage principle is sho in Fig. 5. A current-balance type of relay is employed at each e and the CT's are connected in such a way that the voltages acro

the restraining coils at the two ends of the pilot are in opposition for current flowing through the line section as to a load or an external fault. Consequently, no current flows in the pilot except charging current, if we assume that there is no unbalance between the CT outputs. The restraining coils serve to prevent relay operation owing to such unbalance currents. But should a short circuit occur on the protected line section, current will circulate in the pilot and operate the relays at both ends. Current will also flow through the restraining coils, but, in a proper application, this current will not be sufficient to prevent relay operation; the impedance of the pilot circuit will be the governing factor in this respect.

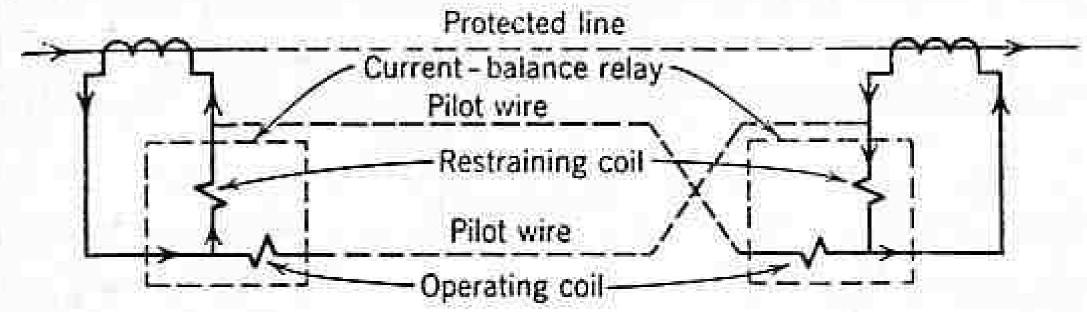


Fig. 5. Schematic illustration of the opposed-voltage principle of a-c wire-pilot relaying.

Short circuits or open circuits in the pilot wires have opposite effects on the two types of relaying equipment, as the accompanying table shows. Where it is indicated that tripping will be caused, tripping is contingent, of course, on the magnitude of the power-line current being high enough to pick up the relays.

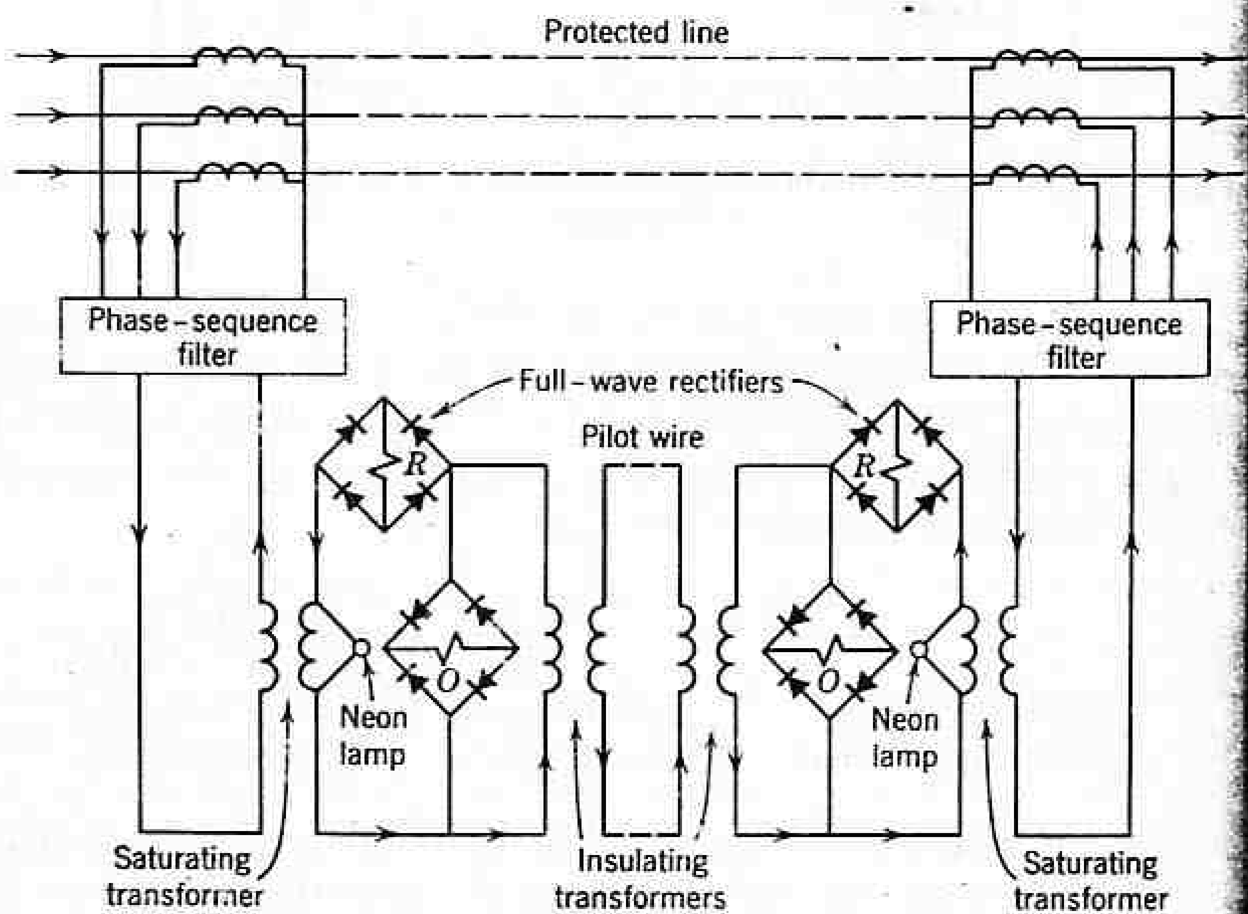
	Effect of Shorts	Effect of Open Circuits
Opposed voltage	Cause tripping	Block tripping
Circulating current	Block tripping	Cause tripping

Both the opposed-voltage and the circulating-current principles permit tripping at both ends of a line for short-circuit current flow into one end only. However, the application of either principle may involve certain features that provide tripping only at the end having short-circuit-current flow, as will be seen when actual equipments are considered.

As has been said before, the feature that makes a-c wire-pilot relaying economically feasible, for the distances over which it is applied, is that only two pilot wires are used. In order to use only two wires, some means are required to derive a representative single-phase sample from the three phase and ground currents at the ends of a transmission line, so that these samples can be compared ov the pilot. It would be a relatively simple matter to derive sampl such that tripping would not occur for external faults for which th same currents that enter one end of a line go out the other en substantially unchanged. The real problem is to derive such sampl that tripping will be assured for internal faults when the curren entering the line at the ends may be widely different. What mu be avoided is a so-called "blind spot," as described in Referen 1 of the Bibliography. However, we are not yet ready to analy such a possibility.

CIRCULATING-CURRENT TYPE

Figure 6 shows schematically a practical example of a circulatin current type of equipment.[2] The relay at each end of the pilot a d-c permanent-magnet-polarized directional type. The coil mark



R = Restraining coil
O = Operating coil

Fig. 6. Schematic connections of a circulating-current a-c wire-pilot rela equipment.

"O" is an operating coil, and "R" is a restraining coil, the two co acting in opposition on the armature of the polarized relay. Th coils are energized from full-wave rectifiers. Here, a d-c directio relay is being used with rectified a-c quantities to get high sensitivi

Although this relay is fundamentally a directional type, it is in effect very sensitive current-balance relay. Phase-sequence filters convert the three phase and ground currents to a single-phase quantity. Saturating transformers limit the magnitude of the rms voltage impressed on the pilot circuit, and the neon lamps limit the peak voltages. Insulating transformers at the ends of the pilot insulate the terminal equipment from the pilot circuit for reasons that will be given later.

This equipment is capable of tripping the breakers at both ends of a line for an internal fault with current flowing at only one end. Whether tripping at both ends will actually occur will depend on the magnitude of the short-circuit current and on the impedance of the pilot circuit. This will be evident from an examination of Fig. 6 where, at the end where no short-circuit current flows, the operating coil and the pilot are in series, and this series circuit is in parallel with the operating coil at the other end. In other words, at the end where fault current flows, the current from the phase-sequence filter divides between the two operating coils, the larger portion going through the local coil. If the pilot impedance is too high, insufficient current will flow through the coil at the other end to cause tripping there.

Charging current between the pilot wires will tend to make the equipment less sensitive to internal faults, acting somewhat like a short circuit between the pilot wires, but with impedance in the short circuit.

OPPOSED-VOLTAGE TYPE

An example of an opposed-voltage type of equipment is shown schematically in Fig. 7.[1] The relay at each end of the pilot is an a-c directional-type relay having in effect two directional elements with a common polarizing source, the two directional elements acting in opposition. Except for the effect of phase angle, this is equivalent to a very sensitive balance-type relay. The "mixing" transformer at each end provides a single-phase quantity for all types of faults. Saturation in the mixing transformer limits the rms magnitude of the voltage that is impressed on the pilot circuit. The impedance of the circuit connected across the mixing transformer is low enough to limit the magnitude of peak voltages to acceptable values.

The equipment illustrated in Fig. 7 requires enough restraint to overcome a tendency to trip for charging current between the pilot wires, although the angle of maximum torque of the operating directional element is such that it minimizes this tripping tendency.

The equipment will not trip the breakers at both ends of a line for an internal fault if current flows into the line at only one end; will trip only the end where there is fault current flowing. Curr will circulate through the operating and restraining coils at the oth

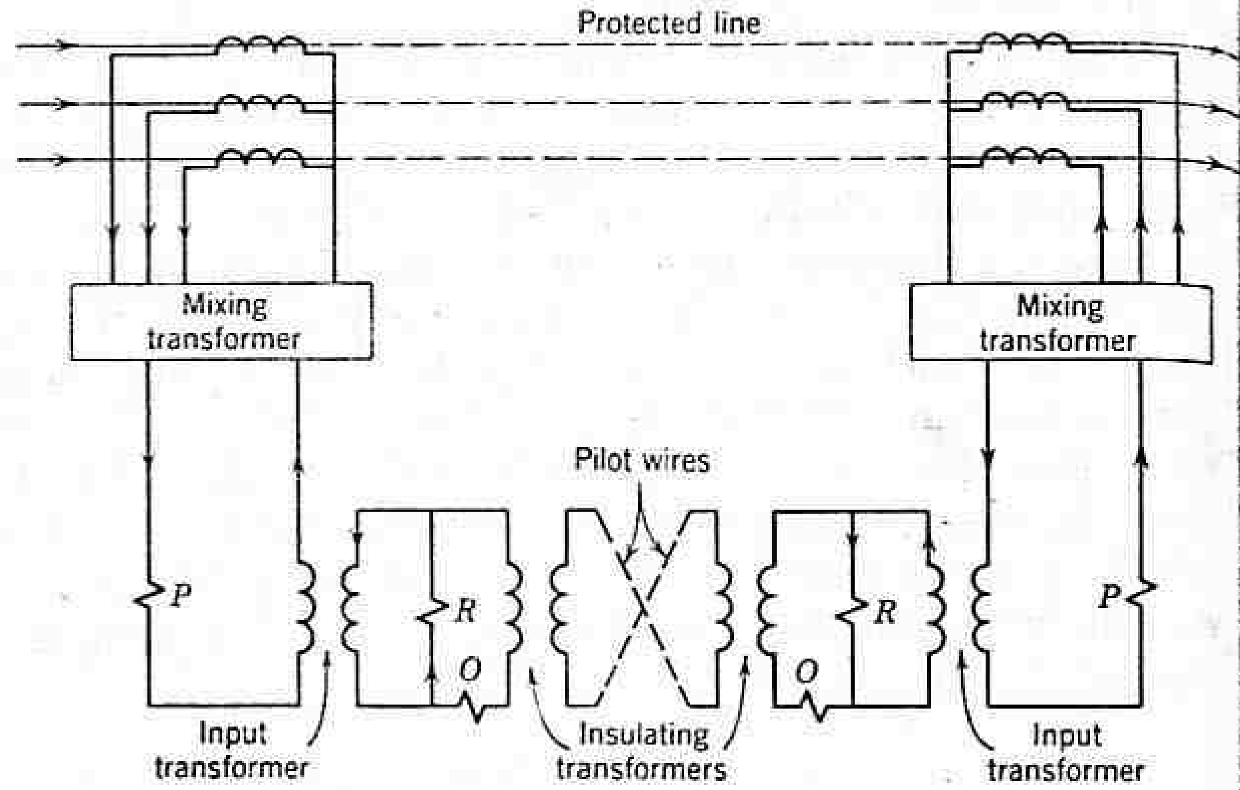


Fig. 7. Schematic connections of an opposed-voltage a-c wire-pilot relay equipment. P = current polarizing coil; R = voltage restraining coil; O = c rent operating coil.

end, but there will be insufficient current in the polarizing coil at th end to cause operation there. This characteristic is seldom objectio able, and it has the compensating advantage of preventing undesir tripping because of induced pilot currents.

ADVANTAGES OF A-C OVER D-C WIRE-PILOT EQUIPMENTS

Certain problems described in connection with d-c wire-pilot r laying are not associated with the a-c type. Since separate blocki and tripping relays are not used, the problem of different levels blocking and tripping sensitivity are avoided. Also, the proble associated with contact racing and ground preference do not ex Moreover, a-c wire-pilot relaying is inherently immune to pow swings or loss of synchronism. In view of the simplifications pe mitted by the elimination of these problems, one can understand w a-c wire-pilot relaying has largely superseded the d-c type.

LIMITATIONS OF A-C WIRE-PILOT EQUIPMENTS

Both the circulating-current and the opposed-voltage types that ha been described are not always applicable to tapped or multitermin lines, because both types use saturating transformers to limit the magnitudes of the pilot-wire current and voltage. The non-linear relation between the magnitudes of the power-system current and the output of the saturating transformer prevents connecting more than two equipments in series in a pilot-wire circuit except under certain restricted conditions. Since this subject involves so many details of different possible system conditions and ranges of adjustment of specific relaying equipments, it is impractical to discuss it further here. In general, the manufacturer's advice should be obtained before attempting to apply such a-c wire-pilot-relaying equipments to tapped or multiterminal lines.

SUPERVISION OF PILOT-WIRE CIRCUITS

Manual equipment is available for periodically testing the pilot circuit, and automatic equipment is available for continuously supervising the pilot circuit. The manual equipment provides means for measuring the pilot-wire quantities and the contribution from the ends. The automatic equipment superimposes direct current on the pilot circuit; trouble in the pilot circuit causes either an increase or a decrease in the d-c supervising current, which is detected by sensitive auxiliary relays.[6] The automatic equipment can be arranged not only to sound an alarm when the pilot wires become open circuited or short circuited but also to open the trip circuit so as to avoid undesired tripping; in such cases, it may be necessary to delay tripping slightly.

REMOTE TRIPPING OVER THE PILOT WIRES

Should it be desired to trip the remote breaker under any circumstance, it can be done by superimposing direct current on the pilot circuit. If automatic supervising equipment is in use, the magnitude of the d-c voltage imposed momentarily on the circuit for remote tripping is higher than that of the continuous voltage used for supervising purposes.[7] Parts of the automatic supervising equipment may be used in common for both purposes. A disadvantage of this method of remote tripping is the possibility of undesired tripping if, during testing, one inadvertently applies a d-c test voltage to the pilot wires. To avoid this, "tones" have been used over a separate pilot.

PILOT-WIRE REQUIREMENTS

Because pilot-wire circuits are often rented from the local telephone company, and because the telephone company imposes certain restrictions on the current and voltage applied to their circuits, these restrictions effectively govern wire-pilot-relaying-equipment design. The a-c equipments that have been described are suitable for telephone circuits since they impose no more than the permissible current and voltage on the pilot, and the wave forms are acceptable to the telephone companies.[8]

The equipments that have been described operate without special adjustment over pilot wires having as much as approximately 2000 ohms d-c loop resistance and 1.5 microfarads distributed shunt capacitance. However, one should determine these limitations in any application.

PILOT WIRES AND THEIR PROTECTION AGAINST OVERVOLTAGES

The satisfactory operation of wire-pilot relaying equipment depends primarily on the reliability of the pilot-wire circuit.[3] Protective-relaying requirements are generally more exacting than the requirements of any other service using pilot circuits. The ideal pilot circuit is one that is owned by the user and is constructed so as not to be exposed to lightning, mutual induction with other pilot or power circuits, differences in station ground potential, or direct contact with any power conductor. However, satisfactory operation can generally be obtained where these ideals are not entirely realized, if proper countermeasures are used.

The conventional a-c wire-pilot relaying equipments that have been described tolerate only about 5 to 15 volts induced between the two wires in the pilot loop. For this reason, the pilot wires should be a twisted pair if the mutual induction is high. For moderate induction, wires in spiraled quads will often suffice if the other pair in the quad will not carry high currents. In addition to other useful information, Reference 4 of the Bibliography contains a method for calculating voltages caused by mutual induction.

If supervising or remote-tripping equipment is not used, or, in other words, if there are no terminal-equipment connections to the pilot wires on the pilot-wire side of the insulating transformer, it is only a question of whether the insulating transformer and the pilot wires can withstand the voltage to ground that they will get from mutual induction and from differences in station ground potentials. The insulating transformers can generally be expected to have sufficient insulation, and only the pilot wires need to be critically examined. But if supervising equipment is involved, or if the pilot wires may otherwise be grounded at one end and do not have sufficient insulation,

additional means, including neutralizing transformers, may be required to protect personnel or equipment.[3,4,5,8]

Pilot wires exposed to lightning overvoltages must be protected with lightning arresters. Similarly, pilot wires exposed to contact with a power circuit must be protected.

The subject of pilot-wire protection has too many ramifications to do justice to it here. The Bibliography gives references to much useful information on the subject. In general, the manufacturer of the relaying equipment should be consulted, and also the local telephone company, if a telephone circuit is to be used. The subject is complicated by the fact that it is necessary not only to protect the equipment or personnel from harm but also, in so doing, to do nothing that will interfere with the proper functioning of the relaying equipment. Such things as mutual induction, difference in station ground potentials, and lightning overvoltages generally occur when there is a fault on the protected line or in the immediate vicinity, at just the time when the proper operation of the relaying equipment is required.

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6 CARRIER-CURRENT-PILOT AND MICROWAVE-PILOT RELAYS

Chapter 5 introduced the subject of pilot relaying, gave the funda- mental principles involved, and described some typical wire-pilo relaying equipments. In this chapter, we shall deal with carrie current-pilot and microwave-pilot relaying; for either type of pilo the relay equipment is the same. Two types of relay equipment wi be described, the "phase-comparison" type, which is much like the a- wire-pilot types, and the "directional-comparison" type, which similar to the d-c wire-pilot types.

The Carrier-Current Pilot

It is not necessary for one to understand the details of carrie current transmitters or receivers in order to understand the funda mental relaying principles. All one needs to know is that when voltage of positive polarity is impressed on the control circuit of th transmitter, it generates a high-frequency output voltage. In th United States, the frequency range allotted for this purpose is 30 t 200 kc. This output voltage is impressed between one phase con ductor of the transmission line and the earth, as shown schematicall in Fig. 1.

Each carrier-current receiver receives carrier current from its loca transmitter as well as from the transmitter at the other end of the line In effect, the receiver converts the received carrier current into a d- voltage that can be used in a relay or other circuit to perform an desired function. This voltage is zero when carrier current is no being received.

"Line traps" shown in Fig. 1 are parallel resonant circuits havin negligible impedance to power-frequency currents, but having ver high impedance to carrier-frequency currents. Traps are used to kee the carrier currents in the desired channel so as to avoid interferenc with or from other adjacent carrier-current channels, and also to avo

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loss of the carrier-current signal in adjoining power circuits for any reason whatsoever, external short circuits being a principal reason. Consequently, carrier current can flow only along the line section between the traps.

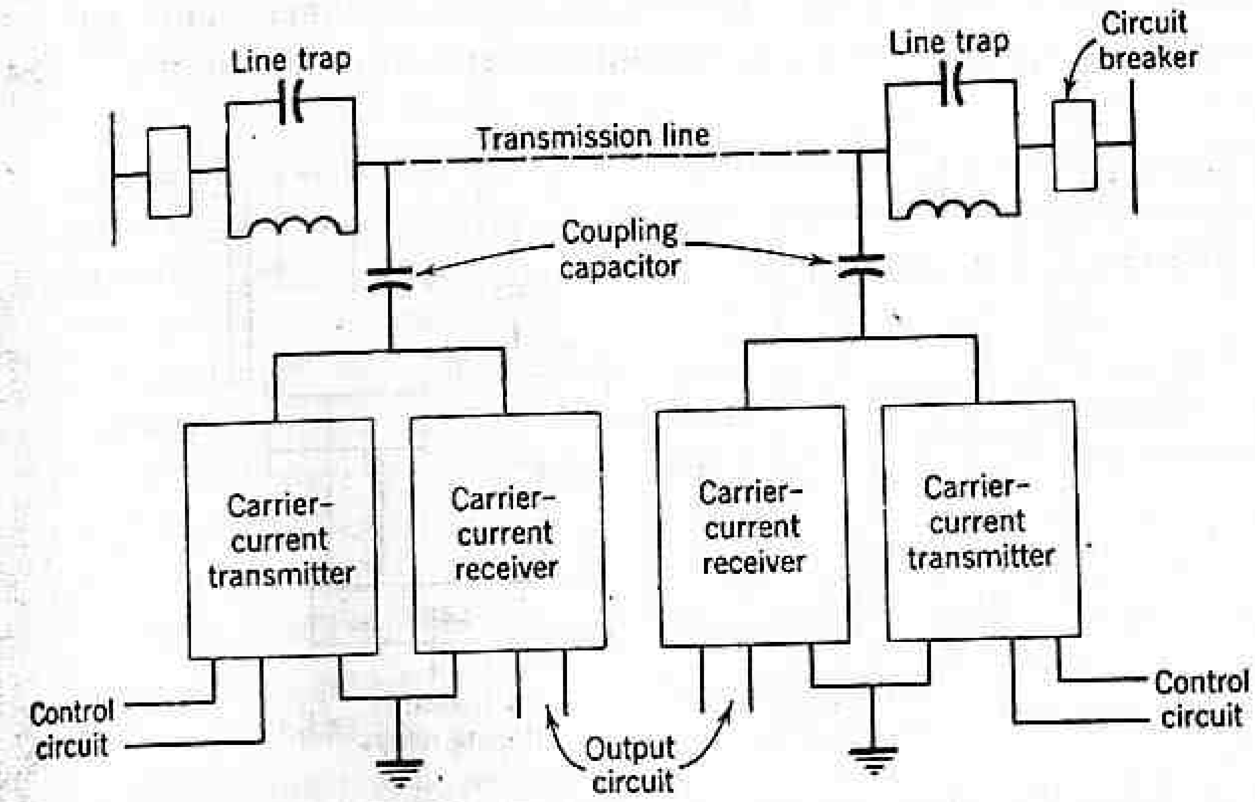

Fig. 1. Schematic illustration of the carrier-current-pilot channel.

The Microwave Pilot

The microwave pilot is an ultra-high-frequency radio system operating in allotted bands above 900 megacycles in the United States. The transmitters are controlled in the same manner as carrier-current transmitters, and the receivers convert the received signals into d-c voltage as carrier-current receivers do. With the microwave pilot, line coupling and trapping are eliminated, and, instead, line-of-sight antenna equipment is required.

The following descriptions of the relaying equipments assume a carrier-current pilot, but the relay equipment and its operation would be the same if a microwave pilot were used.

Phase-Comparison Relaying

Phase-comparison relaying equipment uses its pilot to compare the phase relation between current entering one terminal of a transmission-line section and leaving another. The current magni- tudes are not compared. Phase-comparison relaying provides

primary protection; back-up protection must be provided by suppl
mentary relaying equipment.

Figure 2 shows schematically the principal elements of the equip
ment at both ends of a two-terminal transmission line, using a carrie
current pilot. As in a-c wire-pilot relaying, the transmission-li
current transformers feed a network that transforms the CT outp
currents into a single-phase sinusoidal output voltage. This volta
is applied to a carrier-current transmitter and to a "comparer." Th

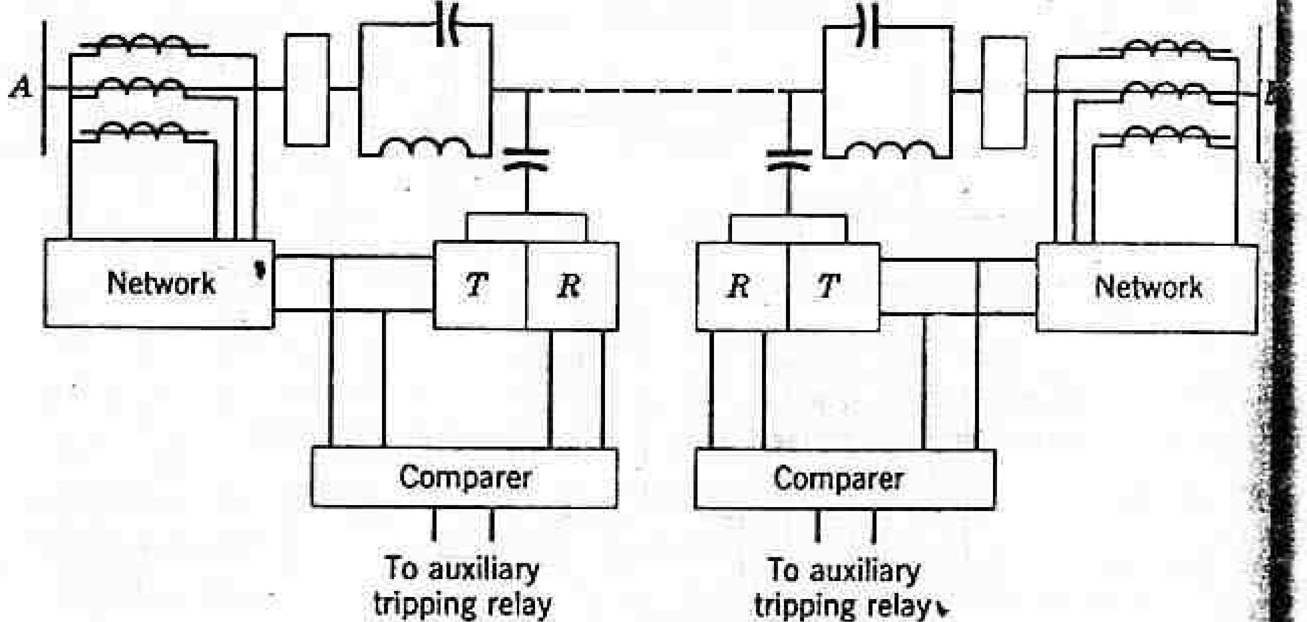

Fig. 2. Schematic representation of phase-comparison carrier-current-pil
relaying equipment. T = carrier-current transmitter; R = carrier-current receiv

output of a carrier-current receiver is also applied to the compar
The comparer controls the operation of an auxiliary relay for trippi
the transmission-line circuit breaker. These elements provide me
for transmitting and receiving carrier-current signals for compari
at each end the relative phase relations of the transmission-li
currents at both ends of the line.

Let us examine the relations between the network output volta
at both ends of the line and also the carrier-current signals that a
transmitted during external and internal fault conditions. These rel
tions are shown in Fig. 3. It will be observed that for an exter
fault at D, the network output voltages at stations A and B (wa
a and c) are 180° out of phase; this is because the current-transfor
connections at the two stations are reversed. Since an a-c voltage
used to control the transmitter, carrier current is transmitted o
during the half cycles of the voltage wave when the polarity is po
tive. The carrier-current signals transmitted from A and B (wa
b and d) are displaced in time, so that there is always a carri
current signal being sent from one end or the other. However, for t

internal fault at C, owing to the reversal of the network output voltage at station B caused by the reversal of the power-line currents there, the carrier-current signals (waves b and f) are concurrent, and there is no signal from either station every other half cycle.

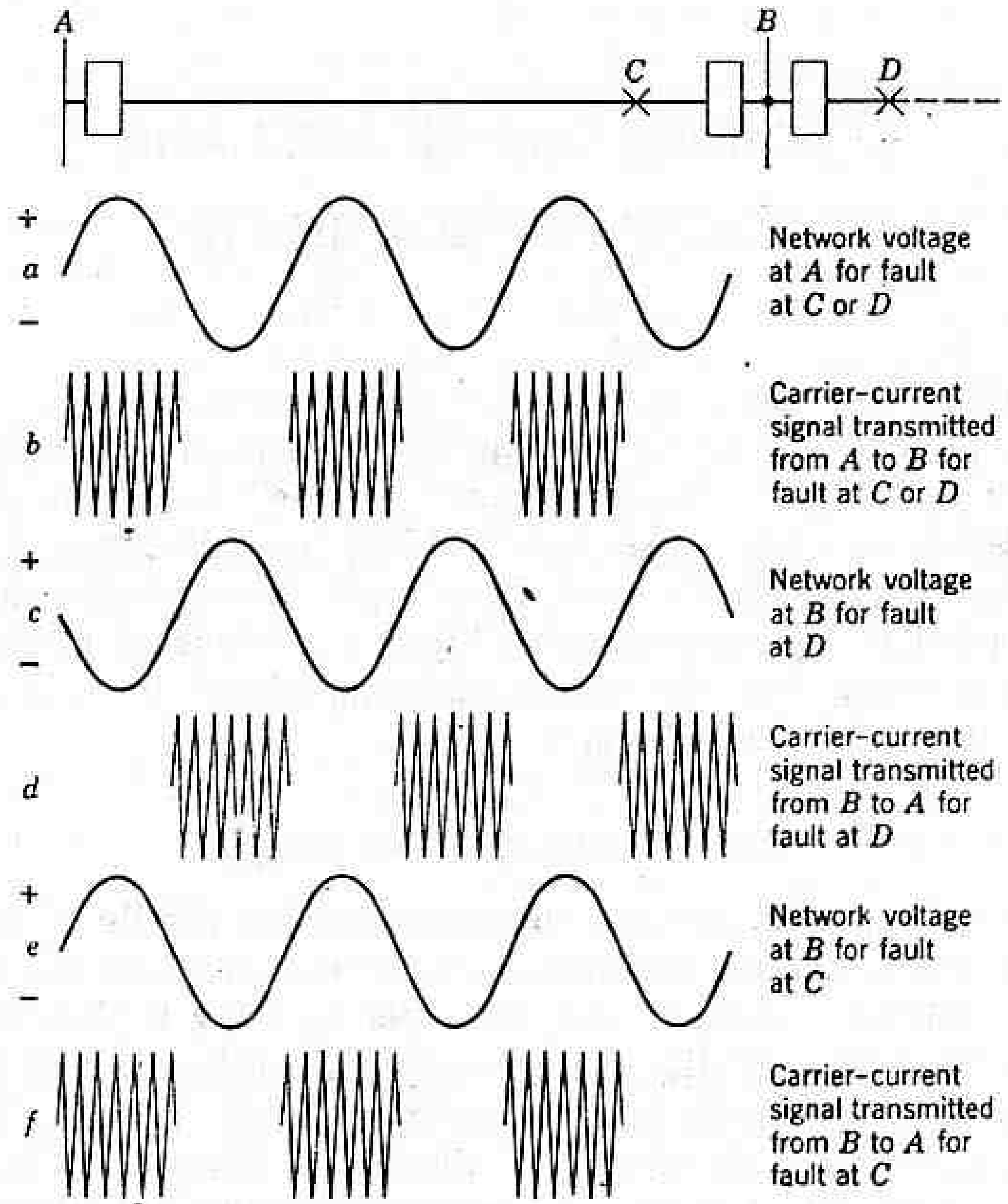

Fig. 3. Relations between network output voltages and carrier-current signals.

Phase-comparison relaying acts to block tripping at both terminals whenever the carrier-current signals are displaced in time so that there is little or no time interval when a signal is not being transmitted from one end or the other. When the carrier-current signals are approximately concurrent, tripping will occur wherever there is sufficient short-circuit current flowing. This is illustrated in Fig. 4 where the network output voltages are superimposed, and the related tripping and blocking tendencies are shown. As indicated in Figs. 3 and 4, the equipment at one station transmits a blocking carrier-current signal during one half cycle, and then stops transmitting and tries to trip during the next half cycle; if carrier current is not received from th other end of the line during this half cycle, the equipment operat to trip its breaker. But, if carrier current is received from the oth

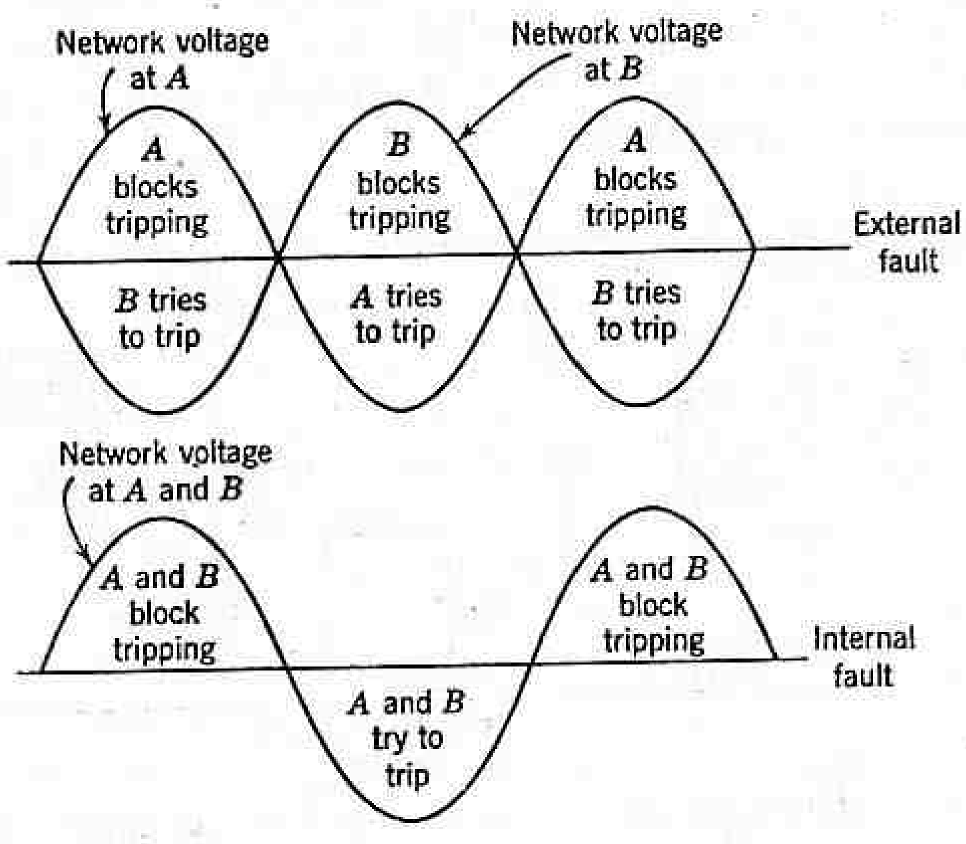

Fig. 4. Relation of tripping and blocking tendencies to network output voltag

end of the line during the interval when the local carrier-curre transmitter is idle, tripping does not occur.)

The heart of the phase-comparison system lies in what is sometim called the "comparer." The comparer of one type of relaying equi

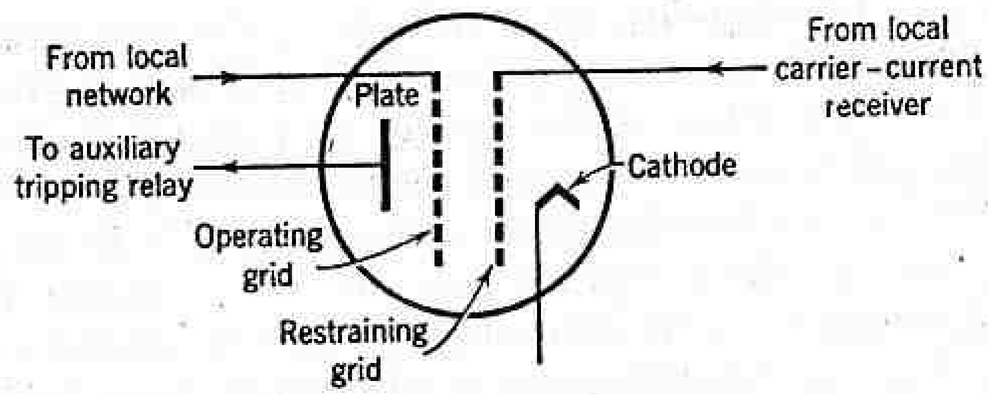

Fig. 5. Schematic representation of the comparer.

ment, shown schematically in Fig. 5, is a vacuum-tube equipment each end of the line, which is here represented as a single tube. (Wh voltage of positive polarity is impressed on the "operating" grid the local network, the tube conducts if voltage of negative polari is not concurrently impressed on the "restraining" grid by the loc

carrier-current receiver by virtue of carrier current received from the other end of the line. When the tube conducts, an auxiliary tripping relay picks up and trips the local breaker. Positive polarity is impressed on the operating grid of the local comparer during the negative half cycle of the network output of Fig. 3 when the local transmitter is idle. Therefore, the local transmitter cannot block local tripping. The voltage from the carrier-current receiver impressed on the restraining grid makes the tube non-conducting, whether the operating grid is energized or not, whenever carrier current is being received.)

It is not necessary that the carrier-current signals be exactly interspersed to block tripping, nor must they be exactly concurrent to permit tripping. For blocking purposes, a phase shift of the order of 35° either way from the exactly interspersed relation can be tolerated. Considerably more phase shift can be tolerated for tripping purposes. It is necessary that more phase shift be permissible for tripping purposes because more phase shift is possible under tripping conditions than under blocking conditions. Phase shift under blocking conditions (i.e., when an external fault occurs) is caused by the small angular difference between the currents at the ends of the line, owing to the line-charging component of current, and also by the length of time it takes for the carrier-current signal to travel from one end of the line to the other, which is approximately at the speed of light. In a 60-cycle system, this travel time accounts for about 12° phase shift per 100 miles of line; it can be compensated for by shifting the phase of the voltage supplied by the network to the comparer by the same amount. No compensation can be provided for the charging-current effect, but this phase shift is negligible except with very long lines. The major part of the phase shift under tripping conditions (i.e., when an internal fault occurs) is caused by the generated voltages beyond the ends of the line being out of phase, and also by a different distribution of ground-fault currents between the two ends as compared with the distribution of phase-fault currents (as, for example, if the main source of generation is at one end of the line and the main ground-current source is at the other end); in addition, the travel time of the carrier-current signal is also a factor.

The principle of different levels of blocking and tripping sensitivity, described in connection with d-c wire-pilot relaying, applies also to phase-comparison pilot relaying. So-called "fault detectors," which may be overcurrent or distance relays, are employed to establish these two sensitivity levels. It is desirable that carrier current not be transmitted under normal conditions, to conserve the life of the vacuum tubes, and also to make the pilot available for other uses when required by the relaying equipment. Consequently, one set of fa detectors is adjusted to pick up somewhat above maximum load cu rent, to permit the transmission of carrier current. The other set fault detectors picks up at still higher current, to permit tripping called for by the comparer. The required pickup adjustment of the tripping fault detectors might be considerably higher for tapped-li applications; this will be treated in more detail when we consider t application of relays for transmission-line protection. Tripping f an internal fault will occur only at the ends of a line where sufficie short-circuit current flows to pick up the tripping fault detectors.

It will be evident from the foregoing that the phase-comparis pilot is a blocking pilot, since a pilot signal is not required to perm tripping. Without the agency of the pilot, phase-comparison relayi reverts to high-speed non-directional overcurrent relaying. Failu of the pilot will not prevent tripping, but tripping will not be selecti under such circumstances; that is, undesired tripping may occur. short circuit on the protected line between ground and the conduct to which the carrier-current equipment is coupled will not interf with desired tripping, because carrier-current transmission is n required to permit tripping; external faults, being on the other si of a line trap, will not affect the proper transmission of carrier curre when it is required.

Phase-comparison relaying is inherently immune to the effects power surges or loss of synchronism between sources of generati beyond the ends of a protected line. Similarly, currents flowing in line because of mutual induction from another nearby circuit will n affect the operation of the equipment. In both of these situations, t currents merely flow through the line as to an external load or to external short circuit.

Directional-Comparison Relaying

Modern relaying equipment of the directional-comparison type op ates in conjunction with distance relays because the distance rel will provide back-up protection, and because certain elements of t distance relays can be used in common with the directional-compari equipment. However, for our immediate purposes, we shall consid only those elements that are essential to directional-compari relaying.

With directional-comparison relaying, the pilot informs the equ ment at one end of the line how a directional relay at the other e responds to a short-circuit. Normally, no pilot signal is transmitt

from any terminal. Should a short circuit occur in an immediately adjacent line section, a pilot signal is transmitted from any terminal where short-circuit current flows out of the line (i.e., in the non-tripping direction). While any station is transmitting a pilot signal, tripping is blocked at all other stations. But should a short circuit occur on the protected line, no pilot signal is transmitted and tripping occurs at any terminal where short-circuit current flows. Therefore, the pilot is a blocking pilot, since the reception of a pilot signal is not required to permit tripping.

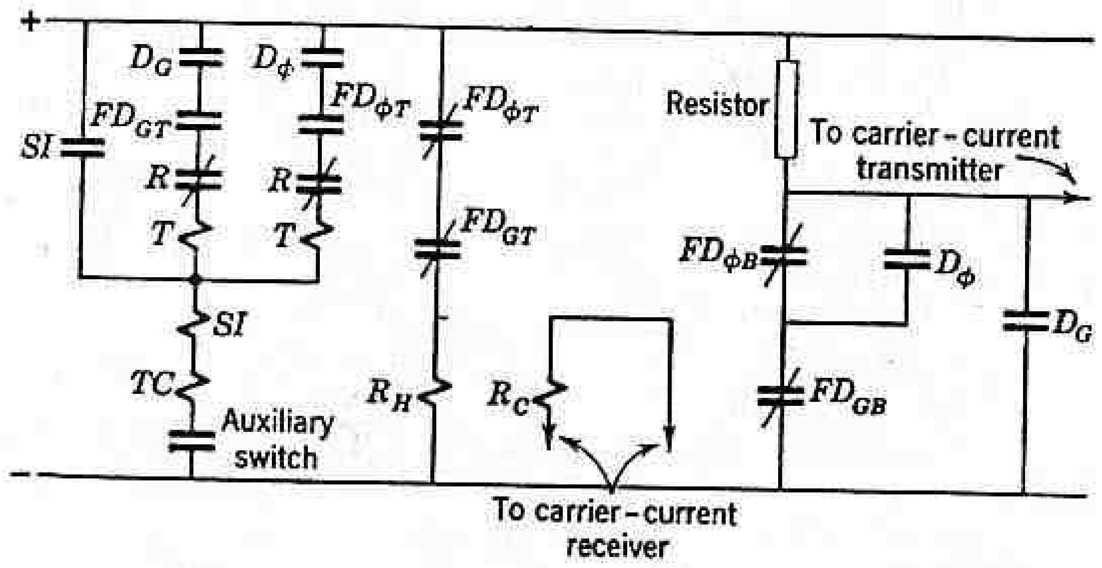

Fig. 6. Schematic diagram of essential contact circuits of directional-comparison relaying equipment. SI = seal-in relay; D_G = directional ground relay; $D\phi$ = directional phase relay; FD_{GT} = ground tripping fault-detector relay; $FD\phi_T$ = phase tripping fault-detector relay; R = receiver relay; R_H = d-c holding coil; R_c = carrier-current coil; T = target; TC = trip coil; FD_{GB} = ground blocking fault-detector relay; $FD\phi_B$ = phase blocking fault-detector relay.

The pilot signal is steady once it is started, and not every other half cycle as in phase-comparison relaying.

The essential relay elements at each end of a line are shown schematically in Fig. 6 for one type of equipment. With two exceptions, all the contacts are shown in the position that they take under normal conditions; the exceptions are that the receiver-relay contacts (R) are open because the receiver-relay holding coil (R_H) is energized normally, and the circuit-breaker auxiliary switch is closed when the breaker is closed. The phase directional-relay contacts (D_ϕ) may be closed or not, depending on the direction in which load current is flowing.

Now, let us assume that a short circuit occurs in an adjoining line back of the end where the equipment of Fig. 6 is located. If the magnitude of the short-circuit current is high enough to operate a blocking fault detector ($FD_{\phi B}$ for a phase fault or FD_{GB} for a ground fault), the operation of this fault detector opens the connection from th negative side of the d-c bus to the control circuit of the carrier-curre transmitter. The polarity of this connection then becomes positiv owing to the connection through the resistor to the positive side of th d-c bus, and the carrier-current transmitter transmits a signal to blo tripping at the other terminals of the line. There is no tendency trip at this terminal because the current is flowing in the direction open the directional-relay contacts (D_G or D_ϕ) in the tripping circu even though a tripping fault detector (FD_{GT} or $FD_{\phi T}$) may ha operated. Moreover, the receiver relay contacts (R) will have staye open because the coil R_C was energized by the carrier-current receiv at about the same instant that the coil R_H was de-energized by th opening of the "b" contact of FD_{GT} or $FD_{\phi T}$. At each of the oth terminals of the line where the current is flowing into the line, th operation will have been similar, except that, depending on the typ of fault, a directional relay will have closed its contacts. Howeve tripping will have been blocked by receipt of the carrier-curre signal, the contacts (R) of the receiver relay having been held op as described for the first terminal. The tripping fault detectors ma or may not have picked up since they are less sensitive than the block ing fault detectors, but tripping would have been blocked in any even The operation of a blocking fault detector at one of these oth terminals may have started carrier transmission from that termin but it would have been immediately stopped by the operation of directional relay.

For a short circuit on the protected line, the directional relays a all terminals where short-circuit current flows will close their contact thereby stopping carrier transmission as soon as it is started by th blocking fault detectors. With no carrier signal to block tripping, a terminals will trip where there is sufficient fault current to pick up tripping fault detector.

The directional-ground relay can stop carrier-current transmissio whether it was started by either the phase blocking fault detector the ground blocking fault detector, but the directional phase relay ca stop transmission only if it was started by the phase blocking fau detector. This illustrates how "ground preference" is obtained desired. The principle of ground preference is used when a dire tional phase relay is apt to operate incorrectly for a ground faul Ground preference is not required if distance-type phase-fault dete tors are used.

Figure 6 shows only the contacts of the phase relays of one phase. I the tripping and carrier-stopping circuits, the contact circuits for th

other two phases would be in parallel with those shown. In the receiver-relay d-c holding-coil circuit and in the carrier-starting circuit, the contacts would be in series.

A feature that contributes to high-speed operation is the "normally blocked trip circuit." As shown in Fig. 6, this feature consists of providing the carrier-current receiver relay with a second coil (R_H), which, when energized, holds the receiver-relay contact open as when carrier current is being received. This auxiliary coil is normally energized through a series circuit consisting of a "b" contact on each tripping fault-detector relay. In earlier equipments without the normally blocked trip circuit, the reception of carrier current had to open the receiver-relay "b" contact before a tripping fault detector could close its "a" contact, and this race required a certain time delay in the tripping-fault-detector operation to avoid undesired tripping. With the normally blocked trip circuit, the receiver-relay contact is held open normally by the R_H coil; and, when a fault occurs, carrier-current transmission is started and the R_C coil is energized at approximately the same time that the R_H coil is de-energized. Thus, the flux keeping the relay picked up does not have time to change. Therefore, the tripping fault detector can be as fast as possible, and there is no objectionable contact race.

The term "intermittent," as contrasted with "continuous," identifies a type of pilot in which the transmission of a pilot signal occurs only when short circuits occur. A continuous-type pilot would not require the normally blocked trip circuit, but it would have the same disadvantage as a tripping pilot because there would be no way to stop the transmission of the pilot signal at a station where the breaker was closed and where there was no flow of short-circuit current for an internal fault. Therefore, it is evident that the directional-comparison pilot is of the intermittent type. As such, it has the same desirable features, described for the phase-comparison pilot, of conserving the life of vacuum tubes and of permitting other uses to be made of the pilot when not required by the relaying equipment.

The blocking-fault-detector function may be directional or not, but the tripping-fault-detector function must be directional. In other words, a carrier signal may be started at a given station whenever a short circuit occurs either in the protected line or beyond its ends, and may then be stopped immediately if the current at that station is in the tripping direction; or the carrier signal may be started only if the current is in the non-tripping direction. The phase-fault detectors are distance-type relays. When mho-type distance relays are us the directional function is inherently provided, and the separate di tional relays of Fig. 6 are not required. Overcurrent and directional relays are used for ground-fault detectors.

Directional-comparison relaying requires supplementary equipment to prevent tripping during severe power surges or when loss of synchronism occurs. In a later chapter we shall see what loss of synchronism "looks" like to protective relays, and how it is possible to differentiate between such a condition and a short circuit.

The ground-relaying portion of directional-comparison equipment is apt to cause undesired tripping because of mutual induction during ground faults on certain arrangements of closely paralleled power lines. The remedy for this tendency is described in a later chapter where the effects of mutual induction are described.

Looking Ahead

We have now completed our examination of the operating principles and characteristics of several types of commonly used protective relaying equipments. Much more could have been said of present-day relays that might be helpful to one who intends to pursue this subject further. However, an attempt has been made to present the essential information as briefly as possible so as not to interfere with the continuity of the material. There are many more types of protective relays, some of which will be described later in connection with specific applications. However, these are merely those basic types that we have considered, but arranged in a slightly different way.

We are not yet ready to study the application of the various relays. We have learned how various relay types react to the quantities that actuate them. We must still know how to derive these actuating quantities and how they vary under different system-operating conditions. If one is able to ascertain the difference in these quantities between a condition for which relay operation is required and all other possible conditions for which a relay must not operate, he can then employ a particular relay, or a combination of relays with certain connections, that also can recognize the difference and operate accordingly.

Because protective relays receive their actuating quantities through the medium of current and voltage transformers, and because the connections and characteristics of these transformers have an important bearing on the response of protective relays, these transformers will be our next consideration.

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7 CURRENT TRANSFORMERS

Protective relays of the a-c type are actuated by current and voltag supplied by current and voltage transformers. These transforme provide insulation against the high voltage of the power circuit, an also supply the relays with quantities proportional to those of th power circuit, but sufficiently reduced in magnitude so that the rela can be made relatively small and inexpensive.

The proper application of current and voltage transformers involve the consideration of several requirements, as follows: mechanical co struction, type of insulation (dry or liquid), ratio in terms of primar and secondary currents or voltages, continuous thermal rating, short time thermal and mechanical ratings, insulation class, impulse leve service conditions, accuracy, and connections. Application standar for most of these items are available.[1] Most of them are self-evide and do not require further explanation. Our purpose here and i Chapter 8 will be to concentrate on *accuracy* and *connections* becau these directly affect the performance of protective relaying, and w shall assume that the other general requirements are fulfilled.

The accuracy requirements of different types of relaying equipme differ. Also, one application of a certain relaying equipment ma have more rigid requirements than another application involving th same type of relaying equipment. Therefore, no general rules can b given for all applications. Technically, an entirely safe rule would b to use the most accurate transformers available, but few would follo the rule because it would not always be economically justifiable.

Therefore, it is necessary to be able to predict, with sufficient accu racy, how any particular relaying equipment will operate from any give type of current or voltage source. This requires that one know ho to determine the inaccuracies of current and voltage transforme under different conditions, in order to determine what effect these in accuracies will have on the performance of the relaying equipment.

Methods of calculation will be described using the data that are published by the manufacturers; these data are generally sufficient. A problem that cannot be solved by calculation using these data should be solved by actual test or should be referred to the manufacturer. This chapter is not intended as a text for a CT designer, but as a generally helpful reference for usual relay-application purposes.

The methods of connecting current and voltage transformers also are of interest in view of the different quantities that can be obtained from different combinations. Knowledge of the polarity of a current or voltage transformer and how to make use of this knowledge for making connections and predicting the results are required.

Types of Current Transformers

All types of current transformers[1] are used for protective-relaying purposes. The bushing CT is almost invariably chosen for relaying in the higher-voltage circuits because it is less expensive than other types. It is not used in circuits below about 5 kv or in metal-clad equipment. The bushing type consists only of an annular-shaped core with a secondary winding; this transformer is built into equipment such as circuit breakers, power transformers, generators, or switchgear, the core being arranged to encircle an insulating bushing through which a power conductor passes.

Because the internal diameter of a bushing-CT core has to be large to accommodate the bushing, the mean length of the magnetic path is greater than in other CT's. To compensate for this, and also for the fact that there is only one primary turn, the cross section of the core is made larger. Because there is less saturation in a core of greater cross section, a bushing CT tends to be more accurate than other CT's at high multiples of the primary-current rating. At low currents, a bushing CT is generally less accurate because of its larger exciting current.

Calculation of CT Accuracy

Rarely, if ever, is it necessary to determine the phase-angle error of a CT used for relaying purposes. One reason for this is that the load on the secondary of a CT is generally of such highly lagging power factor that the secondary current is practically in phase with the exciting current, and hence the effect of the exciting current on phase-angle accuracy is negligible. Furthermore, most relaying

if we assume that the negative-phase-sequence impedances equal t
positive-phase-sequence impedances), $I_{a2} = -I_{a1}$, and the out
currents of connection A become:

$$I_a - I_b = j\sqrt{3}\, I_{a1}$$

$$I_b - I_c = -j2\sqrt{3}\, I_{a1}$$

$$I_c - I_a = j\sqrt{3}\, I_{a1}$$

For a phase-a-to-ground fault, if we again assume the same distri tion of positive- and negative-phase-sequence currents, $I_{a2} = I_{a1}$, a the output currents of connection A become:

$$I_a - I_b = 3I_{a1}$$

$$I_b - I_c = 0$$

$$I_c - I_a = -3I_{a1}$$

The currents for a two-phase-to-ground fault between phases b an can be obtained in a similar manner if one knows the relation betw the impedances in the negative- and zero-phase-sequence netwo It is felt, however, that the foregoing examples are sufficient illustrate the technique involved. The assumptions that were ma as to the distribution of the currents are generally sufficiently accura but they are not a necessary part of the technique; in any act case, one would know the true distribution and also any angular d ferences that might exist, and these could be entered in the fundamen equations.

The output currents from wye-connected CT's can be handled in similar manner.

THE ZERO-PHASE-SEQUENCE-CURRENT SHUNT

Figure 8 shows how three auxiliary CT's can be connected to sh zero-phase-sequence currents away from relays in the secondary wye-connected CT's. Other forms of such a shunt exist, but the shown has the advantage that the ratio of the auxiliary CT's is important so long as all three are alike. Such a shunt is useful a differential circuit where the main CT's must be wye-conne but where zero-phase-sequence currents must be kept from the ph relays. Another use is to prevent misoperation of single-phase dir tional relays during ground faults under certain conditions. Th will be discussed more fully later.

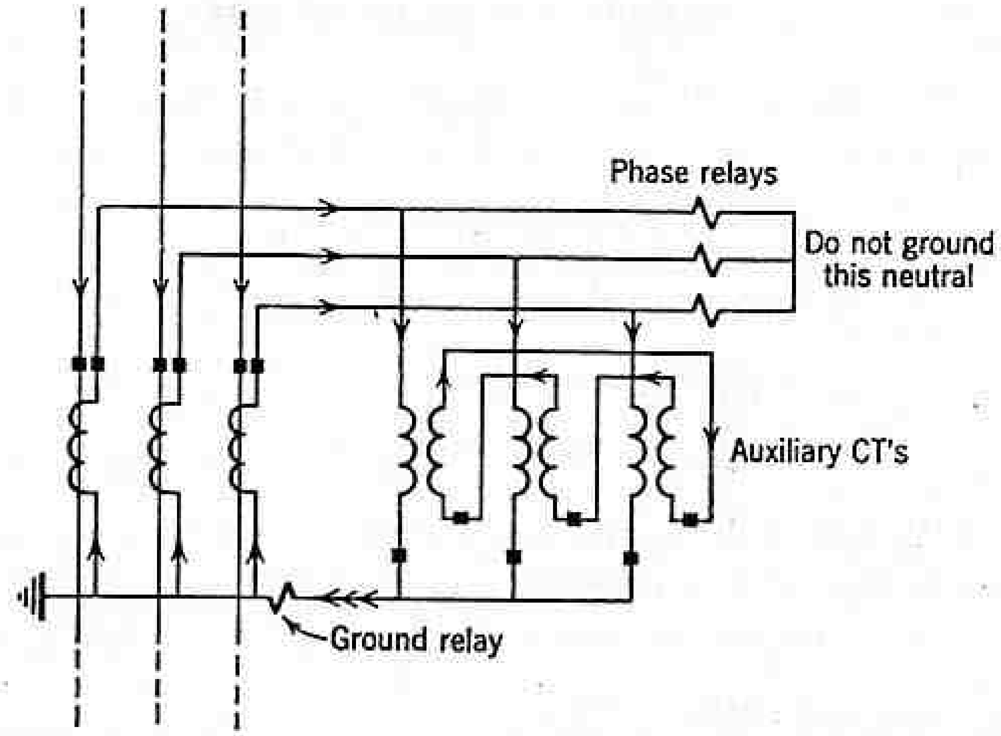

Fig. 8. A zero-phase-sequence-current shunt. Arrows show flow of zero-phase-sequence current.

Problems

1. What is the ASA accuracy classification for the full winding of the bushing CT whose secondary-excitation characteristic and secondary resistance are given in Fig. 3?

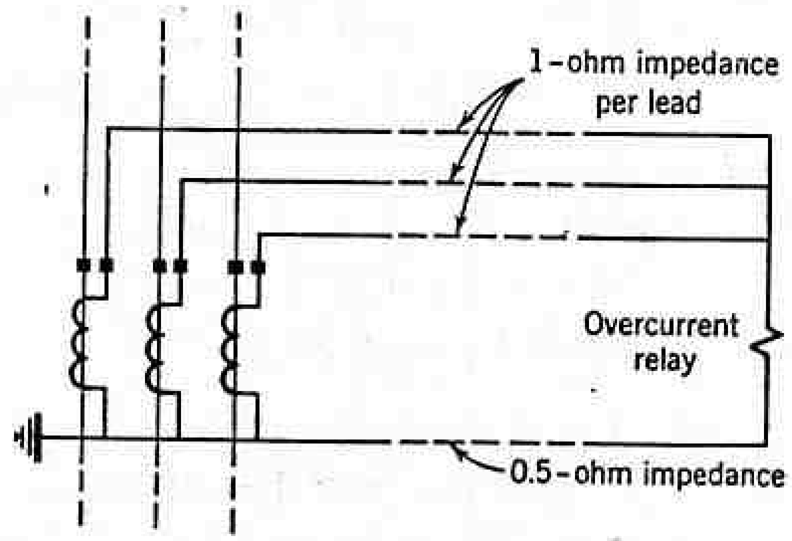

Fig. 9. Illustration for Problem 2.

2. For the overcurrent relay connected as shown in Fig. 9, determine the value pickup current that will provide relay operation at the lowest possible value of primary current in one phase.

If the overcurrent relay has a pickup of 1.5 amperes, its coil impedance at 1.5 amperes is 2.4 ohms. Assume that the impedance at pickup current varies inversely as the square of pickup current, and that relays of any desired pickup are available to you.

The CT's are the same as the 20-turn tap of the CT whose secondary-excitation characteristic is shown in Fig. 3.

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plications can tolerate what for metering purposes would be an intolerable phase-angle error. If the ratio error can be tolerated, the phase-angle error can be neglected. Consequently, phase-angle errors will not be discussed further. The technique for calculating the phase-angle error will be evident, once one learns how to calculate the ratio error.

Accuracy calculations need to be made only for three-phase- and single-phase-to-ground-fault currents. If satisfactory results are thereby obtained, the accuracy will be satisfactory for phase-to-phase and two-phase-to-ground faults.

CURRENT-TRANSFORMER BURDEN

All CT accuracy considerations require knowledge of the CT burden. The *external* load applied to the secondary of a current transformer is called the "burden." The burden is expressed preferably in terms of the impedance of the load and its resistance and reactance components. Formerly, the practice was to express the burden in terms of volt-amperes and power factor, the volt-amperes being what would be consumed in the burden impedance at rated secondary current (in other words, rated secondary current squared times the burden impedance). Thus, a burden of 0.5-ohm impedance may be expressed also as "12.5 volt-amperes at 5 amperes," if we assume the usual 5-ampere secondary rating. The volt-ampere terminology is no longer standard, but it needs defining because it will be found in the literature and in old data.

The term "burden" is applied not only to the total external load connected to the terminals of a current transformer but also to elements of that load. Manufacturers' publications give the burdens of individual relays, meters, etc., from which, together with the resistance of interconnecting leads, the total CT burden can be calculated.

The CT burden impedance decreases as the secondary current increases, because of saturation in the magnetic circuits of relays and other devices. Hence, *a given burden may apply only for a particular value of secondary current.* The old terminology of "volt-amperes at 5 amperes" is most confusing in this respect since it is not necessarily the actual volt-amperes with 5 amperes flowing, but is what the volt-amperes would be at 5 amperes if there were no saturation. Manufacturers' publications give impedance data for several values of overcurrent for some relays for which such data are sometimes required. Otherwise, data are provided only for one value of CT secondary current. If a publication does not clearly state for what value of

current the burden applies, this information should be requested. Lacking such saturation data, one can obtain it easily by test. At high saturation, the impedance approaches the d-c resistance. Neglecting the reduction in impedance with saturation makes it appear that a CT will have more inaccuracy than it actually will have. Of course, if such apparently greater inaccuracy can be tolerated, further refinements in calculation are unnecessary. However, in some applications neglecting the effect of saturation will provide overly optimistic results; consequently, it is safer always to take this effect into account.

It is usually sufficiently accurate to add series burden impedances arithmetically. The results will be slightly pessimistic, indicating slightly greater than actual CT ratio inaccuracy. But, if a given application is so borderline that vector addition of impedances is necessary to prove that the CT's will be suitable, such an application should be avoided.

If the impedance at pickup of a tapped overcurrent-relay coil is known for a given pickup tap, it can be estimated for pickup current for any other tap. The reactance of a tapped coil varies as the square of the coil turns, and the resistance varies approximately as the turns. At pickup, there is negligible saturation, and the resistance is small compared with the reactance. Therefore, it is usually sufficiently accurate to assume that the impedance varies as the square of the turns. The number of coil turns is inversely proportional to the pickup current, and therefore the impedance varies inversely approximately as the square of the pickup current.

Whether CT's are connected in wye or in delta, the burden impedances are always connected in wye. With wye-connected CT's the neutrals of the CT's and of the burdens are connected together, either directly or through a relay coil, except when a so-called "zero-phase-sequence-current shunt" (to be described later) is used.

It is seldom correct simply to add the impedances of series burdens to get the total, whenever two or more CT's are connected in such a way that their currents may add or subtract in some common portion of the secondary circuit. Instead, one must calculate the sum of the voltage drops and rises in the external circuit from one CT secondary terminal to the other for assumed values of secondary currents flowing in the various branches of the external circuit. The effective CT burden impedance for each combination of assumed currents is the calculated CT terminal voltage divided by the assumed CT secondary current. This effective impedance is the one to use, and it may be larger or smaller than the actual impedance which would apply if no other CT's were supplying current to the circuit.

If the primary of an auxiliary CT is to be connected into the secondary of a CT whose accuracy is being studied, one must know the impedance of the auxiliary CT viewed from its primary with its secondary short-circuited. To this value of impedance must be added the impedance of the auxiliary CT burden as viewed from the primary side of the auxiliary CT; to obtain this impedance, multiply the actual burden impedance by the square of the ratio of primary to secondary turns of the auxiliary CT. It will become evident that with an auxiliary CT that steps up the magnitude of its current from primary to secondary, very high burden impedances, when viewed from the primary, may result.

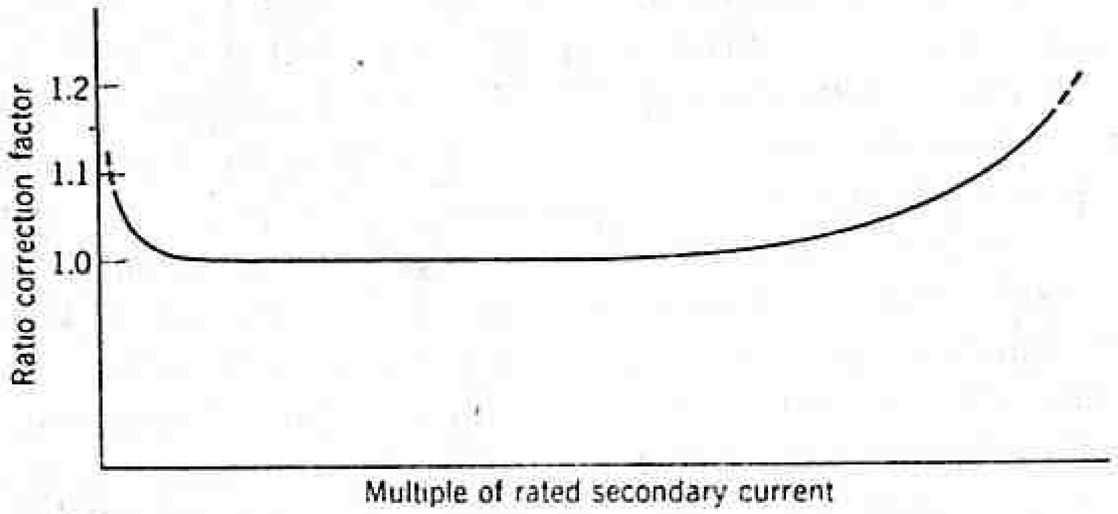

Fig. 1. Ratio-correction-factor curve of a current transformer.

RATIO-CORRECTION-FACTOR CURVES

The term "ratio-correction factor" is defined as "that factor by which the marked (or nameplate) ratio of a current transformer must be multiplied to obtain the true ratio."[1] The ratio errors of current transformers used for relaying are such that, for a given magnitude of primary current, the secondary current is less than the marked ratio would indicate; hence, the ratio-correction factor is greater than 1.0. A ratio-correction-factor curve is a curve of the ratio-correction factor plotted against multiples of rated primary or secondary current for a given constant burden, as in Fig. 1. Such curves give the most accurate results because the only errors involved in their use are the slight differences in accuracy between CT's having the same nameplate ratings, owing to manufacturers' tolerances. Usually, a family of such curves is provided for different typical values of burden.

To use ratio-correction-factor curves, one must calculate the CT burden for each value of secondary current for which he wants to know the CT accuracy. Owing to variation in burden with secondary current because of saturation, no single RCF curve will apply for all currents because these curves are plotted for constant burdens; instead, one must use the applicable curve, or interpolate between curves, for each different value of secondary current. In this way, one can calculate the primary currents for various assumed values of secondary current; or, for a given primary current, he can determine, by trial and error, what the secondary current will be.

The difference between the actual burden power factor and the power factor for which the RCF curves are drawn may be neglected because the difference in CT error will be negligible. Ratio-correction-factor curves are drawn for burden power factors approximately like those usually encountered in relay applications, and hence there is usually not much discrepancy. Any application should be avoided where successful relay operation depends on such small margins in CT accuracy that differences in burden power factor would be of any consequence.

Extrapolations should not be made beyond the secondary current or burden values for which the RCF curves are drawn, or else unreliable results will be obtained.

Ratio-correction-factor curves are considered standard application data and are furnished by the manufacturers for all types of current transformers.

CALCULATION OF CT ACCURACY USING A SECONDARY-EXCITATION CURVE[2]

Figure 2 shows the equivalent circuit of a CT. The primary current is assumed to be transformed perfectly, with no ratio or phase-angle error, to a current I_P/N, which is often called "the primary current referred to the secondary." Part of the current may be considered consumed in exciting the core, and this current (I_e) is called "the secondary-excitation current." The remainder (I_s) is the true secondary current. It will be evident that the secondary-excitation current is a function of the secondary-excitation voltage (E_s) and the secondary-excitation impedance (Z_e). The curve that relates E_s and I_e is called "the secondary-excitation curve," an example of which is shown in Fig. 3. It will also be evident that the secondary current is a function of E_s and the total impedance in the secondary circuit. This total impedance is composed of the effective resistance and the leakage reactance of the secondary winding and the impedance of the burden.

Figure 2 shows also the primary-winding impedance, but this impedance does not affect the ratio error. It affects only the magnitude of current that the power system can pass through the CT primary

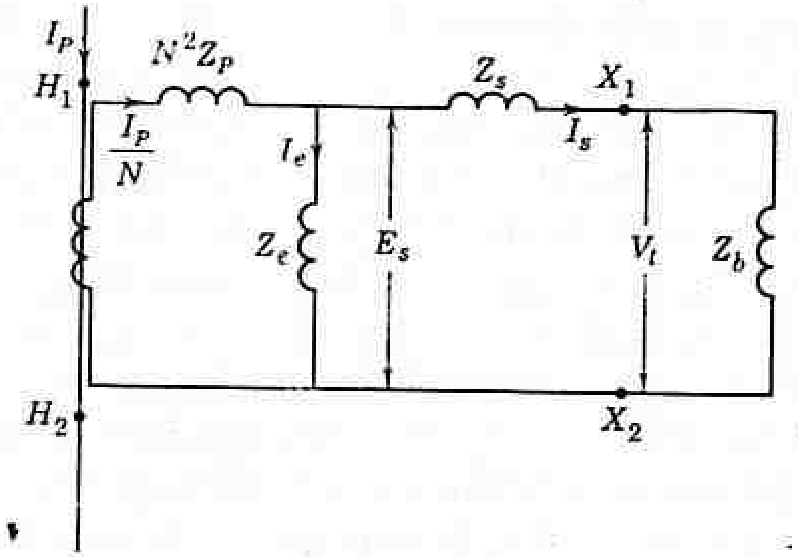

Fig. 2. Equivalent circuit of a current transformer. I_P = primary current in rms amperes; N = ratio of secondary to primary turns; Z_p = primary-winding impedance in ohms; I_e = secondary-excitation current in rms amperes; Z_e = secondary-excitation impedance in ohms; E_s = secondary-excitation voltage in rms volts; Z_s = secondary-winding impedance in ohms; I_s = secondary current in rms amperes; V_t = secondary terminal voltage in rms volts; Z_b = burden impedance in ohms.

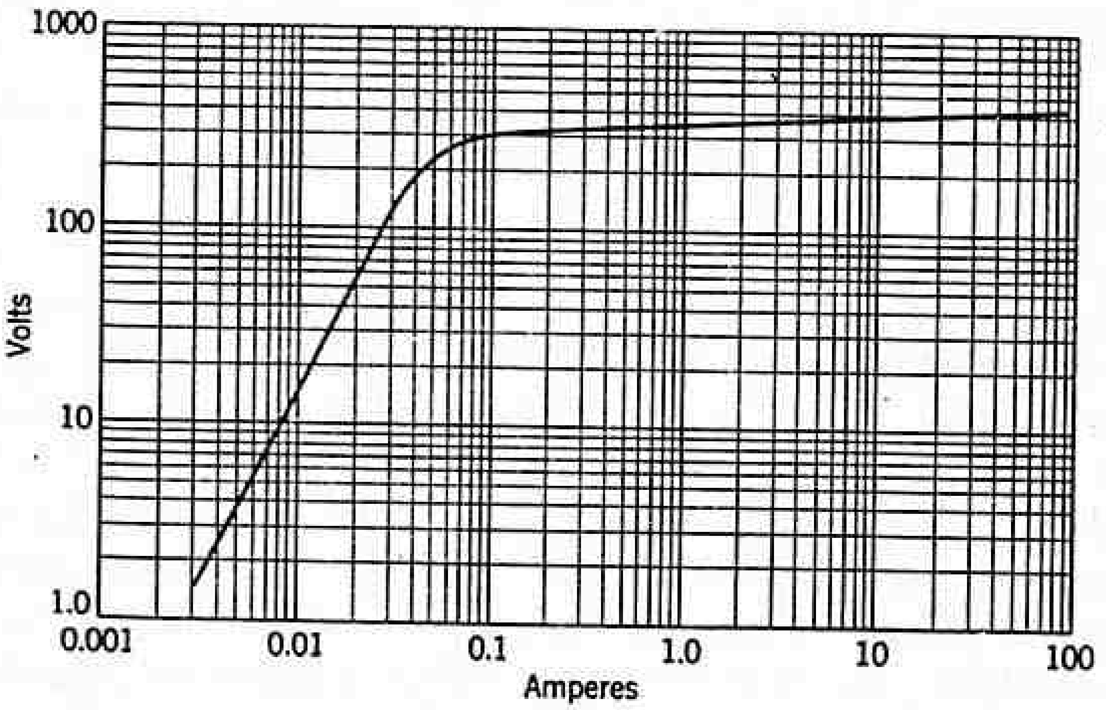

Fig. 3. Secondary-excitation characteristic. Frequency, 60; internal resistance 1.08 ohms; secondary turns, 240.

and is of importance only in low-voltage circuits or when a CT is connected in the secondary of another CT.

If the secondary-excitation curve and the impedance of the secondary winding are known, the ratio accuracy can be determined for any

burden. It is only necessary to assume a magnitude of secondary current and to calculate the total voltage drop in the secondary winding and burden for this magnitude of current. This total voltage drop is equal numerically to E_s. For this value of E_s, the secondary-excitation curve will give I_e. Adding I_e to I_s gives I_P/N, and multiplying I_P/N by N gives the value of primary current that will produce the assumed value of I_s. The ratio-correction factor will be I_P/NI_s. By assuming several values of I_s and obtaining the ratio-correction factor for each, one can plot a ratio-correction-factor curve. It will be noted that adding I_s arithmetically to I_e may give a ratio-correction factor that is slightly higher than the actual value, but the refinement of vector addition is considered to be unnecessary.

The secondary resistance of a CT may be assumed to be the d-c resistance if the effective value is not known. The secondary leakage reactance is not generally known except to CT designers; it is a variable quantity depending on the construction of the CT and on the degree of saturation of the CT core. Therefore, the secondary-excitation-curve method of accuracy determination does not lend itself to general use except for bushing-type, or other, CT's with completely distributed secondary windings, for which the secondary leakage reactance is so small that it may be assumed to be zero. In this respect, one should realize that, even though the total secondary winding is completely distributed, tapped portions of this winding may not be completely distributed; to ignore the secondary leakage reactance may introduce significant errors if an undistributed tapped portion is used.

The secondary-excitation-curve method is intended only for current magnitudes or burdens for which the calculated ratio error is approximately 10% or less. When the ratio error appreciably exceeds this value, the wave form of the secondary-excitation current—and hence of the secondary current—begins to be distorted, owing to saturation of the CT core. This will produce unreliable results if the calculations are made assuming sinusoidal waves, the degree of unreliability increasing as the current magnitude increases. Even though one could calculate accurately the magnitude and wave shape of the secondary current, he would still have the problem of deciding how a particular relay would respond to such a current. Under such circumstances, the safest procedure is to resort to a test.

Secondary-excitation data for bushing CT's are provided by manufacturers. Occasionally, however, it is desirable to be able to obtain such data by test. This can be done accurately enough for all practical purposes merely by open-circuiting the primary circuit, applying a-c voltage of the proper frequency to the secondary, and measuring the current that flows into the secondary. The voltage should preferably be measured by a rectifier-type voltmeter. The curve of rms terminal voltage versus rms secondary current is approximately the secondary-excitation curve for the test frequency. The actual excitation voltage for such a test is the terminal voltage minus the voltage drop in the secondary resistance and leakage reactance, but this voltage drop is negligible compared with the terminal voltage until the excitation current becomes large, when the CT core begins to saturate. If a bushing CT with a completely distributed secondary winding is involved, the secondary-winding voltage drop will be due practically only to resistance, and corrections in excitation voltage for this drop can be made easily. In this way, sufficiently accurate data can be obtained up to a point somewhat beyond the knee of the secondary-excitation curve, which is usually all that is required. This method has the advantage of providing the data with the CT mounted in its accustomed place.

Secondary-excitation data for a given number of secondary turns can be made to apply to a different number of turns on the same CT by expressing the secondary-excitation voltages in "volts-per-turn" and the corresponding secondary-excitation currents in "ampere-turns." When secondary-excitation data are plotted in terms of volts-per-turn and ampere-turns, a single curve will apply to any number of turns.

The secondary-winding impedance can be found by test, but it is usually impractical to do so except in the laboratory. Briefly, it involves energizing the primary and secondary windings with equal and opposite ampere-turns, approximately equal to rated values, and measuring the voltage drop across the secondary winding.[3] The voltage divided by the secondary current is called the "unsaturated secondary-winding impedance." If we know the secondary-winding resistance, the unsaturated secondary leakage reactance can be calculated. If a bushing CT has secondary leakage flux because of an undistributed secondary winding, the CT should be tested in an enclosure of magnetic material that is the same as its pocket in the circuit breaker or transformer, or else most unreliable results will be obtained.

The most practical way to obtain the secondary leakage reactance may sometimes be to make an overcurrent ratio test, power-system current being used to get good wave form, with the CT in place, and with its secondary short-circuited through a moderate burden. The only difficulty of this method is that some means is necessary to measure the primary current accurately. Then, from the data ob-

tained, and by using the secondary-excitation curve obtained as previously described, the secondary leakage reactance can be calculated. Such a calculation should be accurately made, taking into account the vector relations of the exciting and secondary currents and adding the secondary and burden resistance and reactance vectorially.

ASA ACCURACY CLASSIFICATION

The ASA accuracy classification[4] for current transformers used for relaying purposes provides a measure of a CT's accuracy. This method of classification assumes that the CT is supplying 20 times its rated secondary current to its burden, and the CT is classified on the basis of the maximum rms value of voltage that it can maintain at its secondary terminals without its ratio error exceeding a specified amount. Standard ASA accuracy classifications are as shown. The letter "H" stands for "high internal secondary impedance," which is a

10H10	10L10
10H20	10L20
10H50	10L50
10H100	10L100
10H200	10L200
10H400	10L400
10H800	10L800
2.5H10	2.5L10
2.5H20	2.5L20
2.5H50	2.5L50
2.5H100	2.5L100
2.5H200	2.5L200
2.5H400	2.5L400
2.5H800	2.5L800

characteristic of CT's having concentrated secondary windings. The letter "L" stands for "low internal secondary impedance," which is a characteristic of bushing-type CT's having completely distributed secondary windings or of window type having two to four secondary coils with low secondary leakage reactance. The number before the letter is the maximum specified ratio error in percent ($= 100|RCF - 1|$), and the number after the letter is the maximum specified secondary terminal voltage at which the specified ratio error may exist, for a secondary current of 20 times rated. For a 5-ampere secondary, which is the usual rating, dividing the maximum specified voltage by 100 amperes (20×5 amperes) gives the maximum specified burden impedance through which the CT will pass 100 amperes with no more than the specified ratio error.

At secondary currents from 20 to 5 times rated, the H class of transformer will accommodate increasingly higher burden impedance than at 20 times rated without exceeding the specified maximum ratio error, so long as the product of the secondary current times the burden impedance does not exceed the specified maximum voltage at 20 times rated. This characteristic is the deciding factor when there is a question whether a given CT should be classified as "H" or as "L." At secondary currents from rated to 5 times rated, the maximum permissible burden impedance at 5 times rated (calculated as before) must not be exceeded if the maximum specified ratio error is not to be exceeded.

At secondary currents from rated to 20 times rated, the L class of transformer may accommodate no more than the maximum specified burden impedance at 20 times rated without exceeding the maximum specified ratio error. This assumes that the secondary leakage reactance is negligible.

The reason for the foregoing differences in the permissible burden impedances at currents below 20 times rated is that in the H class of transformer, having the higher secondary-winding impedance, the voltage drop in the secondary winding decreases with reduction in secondary current more rapidly than the secondary-excitation voltage decreases with the reduction in the allowable amount of exciting current for the specified ratio error. This fact will be better understood if one will calculate permissible burden impedances at reduced currents, using the secondary-excitation method.

For the same voltage and error classifications, the H transformer is better than the L for currents up to 20 times rated.

In some cases, the ASA accuracy classification will give very conservative results in that the actual accuracy of a CT may be nearly twice as good as the classification would indicate. This is particularly true in older CT's where no design changes were made to make them conform strictly to standard ASA classifications. In such cases, a CT that can actually maintain a terminal voltage well above a certain standard classification value, but not quite as high as the next higher standard value, has to be classified at the lower value. Also, some CT's can maintain terminal voltages in excess of 800 volts, but because there is no higher standard voltage rating, they must be classified "800."

The principal utility of the ASA accuracy classification is for specification purposes, to provide an indication of CT quality. The higher the number after the letter H or L, the better is the CT. However, a published ASA accuracy classification applies only if the

full secondary winding is used; it does not apply to any portion of a secondary winding, as in tapped bushing-CT windings. It is perhaps obvious that with fewer secondary turns, the output voltage will be less. A bushing CT that is superior when its full secondary winding is used may be inferior when a tapped portion of its winding is used if the partial winding has higher leakage reactance because the turns are not well distributed around the full periphery of the core. In other words, the ASA accuracy classification for the full winding is not necessarily a measure of relative accuracy if the full secondary winding is not used.

If a bushing CT has completely distributed tap windings, the ASA accuracy classification for any tapped portion can be derived from the classification for the total winding by multiplying the maximum specified voltage by the ratio of the turns. For example, assume that a given 1200/5 bushing CT with 240 secondary turns is classified as 10L400; if a 120-turn completely distributed tap is used, the applicable classification is 10L200, etc. This assumes that the CT is not actually better than its classification.

Strictly speaking, the ASA accuracy classification is for a burden having a specified power factor. However, for practical purposes, the burden power factor may be ignored.

If the information obtainable from the ASA accuracy classification indicates that the CT is suitable for the application involved, no further calculations are necessary. However, if the CT appears to be unsuitable, a more accurate study should be made before the CT is rejected.

SERIES CONNECTION OF LOW-RATIO BUSHING CT'S

It will probably be evident from the foregoing that a low-ratio bushing CT, having 10 to 20 secondary turns, has rather poor accuracy at high currents. And yet, occasionally, such CT's cannot be avoided, as for example, where a high-voltage, low-current circuit or power-transformer winding is involved where rated full-load current is only, say, 50 amperes. Then, two bushing CT's per phase are sometimes used with their secondaries connected in series. This halves the burden on each CT, as compared with the use of one CT alone, without changing the over-all ratio. And, consequently, the secondary-excitation voltage is halved, and the secondary-excitation current is considerably reduced with a resulting large improvement in accuracy. Such an arrangement may require voltage protectors to hold down the secondary voltage should a fault occur between the primaries of the two CT's.

THE TRANSIENT OR STEADY-STATE ERRORS OF SATURATED CT'S

To calculate first the transient or steady-state output of saturated CT's, and then to calculate at all accurately the response of protective relays to the distorted wave form of the CT output, are a more formidable problem. With perhaps one exception,[5] there is little in the literature that is very helpful in this respect.

Fortunately, one can get along quite well without being able to make such calculations. With the help of calculating devices, comprehensive studies[6] have been made that provide general guiding principles for applying relays so that they will perform properly even though the CT output is affected by saturation. And relaying equipments have been devised that can be properly adjusted on the basis of very simple calculations. Examples of such equipments will be described later.

We are occasionally concerned lest a CT be too accurate when extremely high primary short-circuit currents flow! Even though the CT itself may be properly applied, the secondary current may be high enough to cause thermal or mechanical damage to some element in the secondary circuit before the short-circuit current can be interrupted. One should not assume that saturation of a CT core will limit the magnitude of the secondary current to a safe value. At very high primary currents, the air-core coupling between primary and secondary of wound-type CT's will cause much more secondary current to flow than one might suspect. It is recommended that, if the short-time thermal or mechanical limit of some element of the secondary circuit would be exceeded should the CT maintain its nameplate ratio, the CT manufacturer should be consulted. Where there is such possibility, damage can be prevented by the addition of a small amount of series resistance to the existing CT burden.

OVERVOLTAGE IN SATURATED CT SECONDARIES

Although the *rms* magnitude of voltage induced in a CT secondary is limited by core saturation, very high voltage *peaks* can occur. Such high voltages are possible if the CT burden impedance is high and if the primary current is many times the CT's continuous rating. The peak voltage occurs when the rate-of-change of core flux is highest, which is approximately when the flux is passing through zero. The maximum flux density that may be reached does not affect the magnitude of the peak voltage. Therefore, the magnitude of the peak voltage is practically independent of the CT characteristics other than the nameplate ratio.

One series of tests on bushing CT's produced peak voltages whose magnitudes could be expressed empirically as follows:

$$e = 3.5ZI^{0.53}$$

where e = peak voltage in volts.
Z = unsaturated magnitude of CT burden impedance in ohms.
I = primary current divided by the CT's nameplate ratio. (Or, in other words, the rms magnitude of the secondary current if the ratio-correction factor were 1.0.)

The value of Z should include the unsaturated magnetizing impedance of any idle CT's that may be in parallel with the useful burden. If a tap on the secondary winding is being used, as with a bushing CT, the peak voltage across the full winding will be the calculated value for the tap multiplied by the ratio of the turns on the full winding to the turns on the tapped portion being used, in other words, the CT will step up the voltage as an autotransformer. Because it is the practice to ground one side of the secondary winding, the voltage that is induced in the secondary will be impressed on the insulation to ground. The standard switchgear high potential test to ground is 1500 volts rms, or 2121 volts peak; and the standard CT test voltage is 2475 volts rms or 3500 volts peak.[1] The lower of these two should not be exceeded.

Harmfully high secondary voltages may occur in the CT secondary circuit of generator differential-relaying equipment when the generator kva rating is low but when very high short-circuit kva can be supplied by the system to a short circuit at the generator's terminals. Here, the magnitude of the primary current on the system side of the generator windings may be many times the CT rating.[4] These CT's will try to supply very high secondary currents to the operating coils of the generator differential relay, the unsaturated impedance of which may be quite high. The resulting high peak voltages could break down the insulation of the CT's, the secondary wiring, or the differential relays, and thereby prevent the differential relays from operating to trip the generator breakers.

Such harmfully high peak voltages are not apt to occur for this reason with other than motor or generator differential-relaying equipments because the CT burdens of other equipments are not usually so high. But, wherever high voltage is possible, it can be limited to safe values by overvoltage protectors.

Another possible cause of overvoltage is the switching of a capacitor bank when it is very close to another energized capacitor bank.[8]

The primary current of a CT in the circuit of a capacitor bank bei energized or de-energized will contain transient high-frequency cu rents. With high-frequency primary and secondary currents, a C burden reactance, which at normal frequency is moderately lo becomes very high, thereby contributing to CT saturation and hi peak voltages across the secondary. Overvoltage protectors may required to limit such voltages to safe values.

It is recommended that the CT manufacturer be consulted whene there appears to be a need for overvoltage protectors. The protect characteristics must be coordinated with the requirements of a pa ticular application to (1) limit the peak voltage to safe values, (not interfere with the proper functioning of the protective-relayi equipment energized from the CT's, and (3) withstand the total amou of energy that the protector will have to absorb.

PROXIMITY EFFECTS

Large currents flowing in a conductor close to a current transform may greatly affect its accuracy. A designer of compact equipme such as metal-enclosed switchgear, should guard against this effe If one has all the necessary data, it is a reasonably simple matter calculate the necessary spacings to avoid excessive error.[9]

Polarity and Connections

The relative polarities of CT primary and secondary terminals a identified either by painted polarity marks or by the symbo "H_1" and "H_2" for the primary terminals and "X_1" and "X_2" f the secondary terminals. The convention is that, when primary cu rent enters the H_1 terminal, secondary current leaves the X_1 termi as shown by the arrows in Fig. Or, when current enters the H terminal, it leaves the X_2 ter nal. When paint is used, t terminals corresponding to H and X_1 are identified.

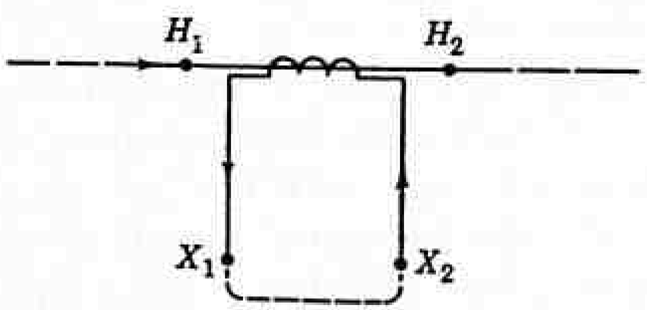

Fig. 4. The polarity of current transformers.

Standard practice is to sh the corresponding terminals connection diagrams merely b squares, as in Fig. 5.

Since a-c current is continually reversing its direction, one mig well ask what the significance is of polarity marking. Its significa is in showing the direction of current flow relative to another curr

to a voltage, as well as to aid in making the proper connections. If CT's were not interconnected, or if the current from one CT did

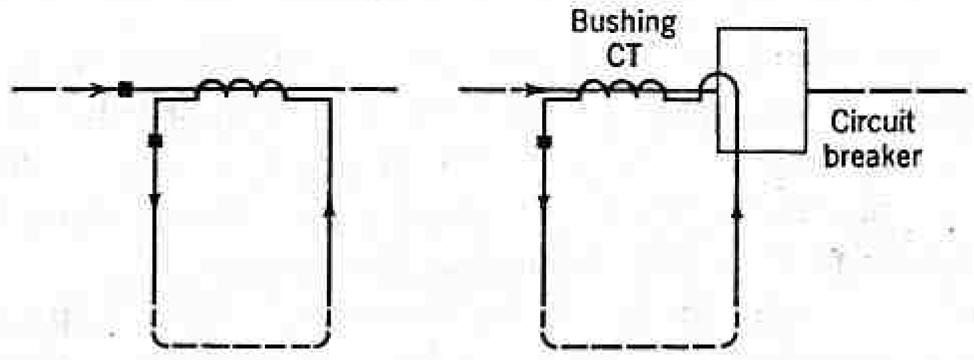

Fig. 5. Convention for showing polarity on diagrams.

not have to cooperate with a current from another CT, or with a voltage from a voltage source, to produce some desired result such as torque in a relay, there would be no need for polarity marks.

WYE CONNECTION

CT's are connected in wye or in delta, as the occasion requires. Figure 6 shows a wye connection with phase and ground relays. The currents I_a, I_b, and I_c are the vector currents, and the CT ratio is assumed to be 1/1 to simplify the mathematics. Vectorially, the

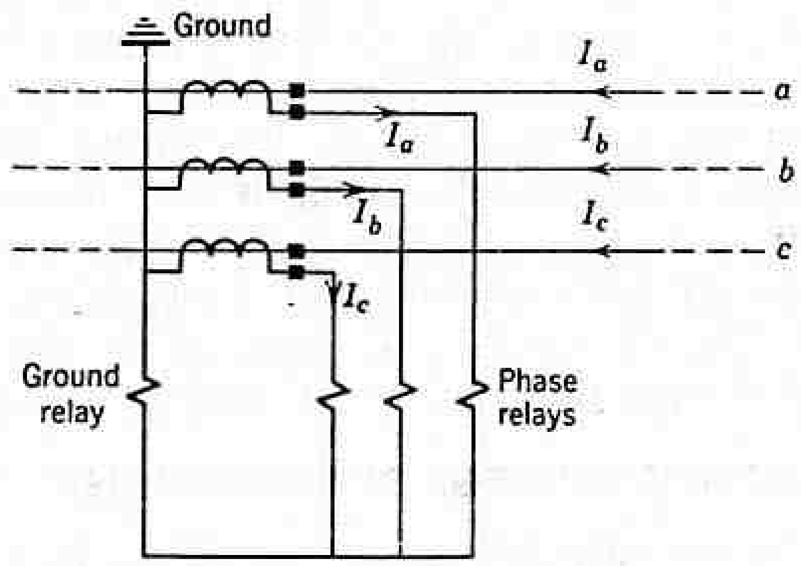

Fig. 6. Wye connection of current transformers.

primary and secondary currents are in phase, neglecting phase-angle errors in the CT's.

The symmetrical-component method of analysis is a powerful tool, not only for use in calculating the power-system currents and voltages for unbalanced faults but also for analyzing the response of protective relays. In terms of phase-sequence components of the power-syst currents, the output of wye-connected CT's is as follows:

$$I_a = I_{a1} + I_{a2} + I_{a0}$$

$$I_b = I_{b1} + I_{b2} + I_{b0} = a^2 I_{a1} + a I_{a2} + I_{a0}$$

$$I_c = I_{c1} + I_{c2} + I_{c0} = a I_{a1} + a^2 I_{a2} + I_{a0}$$

$$I_a + I_b + I_c = I_{a0} + I_{b0} + I_{c0} = 3I_{a0} = 3I_{b0} = 3I_{c0}$$

where 1, 2, and 0 designate the positive-, negative-, and zero-pha sequence components, respectively, and where "a" and "a^2" are ope tors that rotate a quantity counterclockwise 120° and 240°, respectiv

DELTA CONNECTION

With delta-connected CT's, two connections are possible, as show Fig. 7. In terms of the phase-sequence components, I_a, I_b, and I_c the same as for the wye-connected CT's. The output currents of delta connections of Fig. 7 are, therefore:

Connection A.

$$\begin{aligned}
I_a - I_b &= (I_{a1} - I_{b1}) + (I_{a2} - I_{b2}) \\
&= (1 - a^2)I_{a1} + (1 - a)I_{a2} \\
&= (\tfrac{3}{2} + j\sqrt{3}/2)I_{a1} + (\tfrac{3}{2} - j\sqrt{3}/2)I_{a2}
\end{aligned}$$

$$\begin{aligned}
I_b - I_c &= (1 - a^2)I_{b1} + (1 - a)I_{b2} \\
&= a^2(1 - a^2)I_{a1} + a(1 - a)I_{a2} \\
&= (a^2 - a)I_{a1} + (a - a^2)I_{a2} \\
&= -j\sqrt{3}\, I_{a1} + j\sqrt{3}\, I_{a2}
\end{aligned}$$

$$\begin{aligned}
I_c - I_a &= (1 - a^2)I_{c1} + (1 - a)I_{c2} \\
&= a(1 - a^2)I_{a1} + a^2(1 - a)I_{a2} \\
&= (a - 1)I_{a1} + (a^2 - 1)I_{a2} \\
&= (-\tfrac{3}{2} + j\sqrt{3}/2)I_{a1} + (-\tfrac{3}{2} - j\sqrt{3}/2)I_{a2}
\end{aligned}$$

Connection B.

$$\begin{aligned}
I_a - I_c &= -(I_c - I_a) \\
&= (\tfrac{3}{2} - j\sqrt{3}/2)I_{a1} + (\tfrac{3}{2} + j\sqrt{3}/2)I_{a2}
\end{aligned}$$

$$\begin{aligned}
I_b - I_a &= -(I_a - I_b) \\
&= (-\tfrac{3}{2} - j\sqrt{3}/2)I_{a1} + (-\tfrac{3}{2} + j\sqrt{3}/2)I_{a2}
\end{aligned}$$

$$\begin{aligned}
I_c - I_b &= -(I_b - I_c) \\
&= j\sqrt{3}\, I_{a1} - j\sqrt{3}\, I_{a2}
\end{aligned}$$

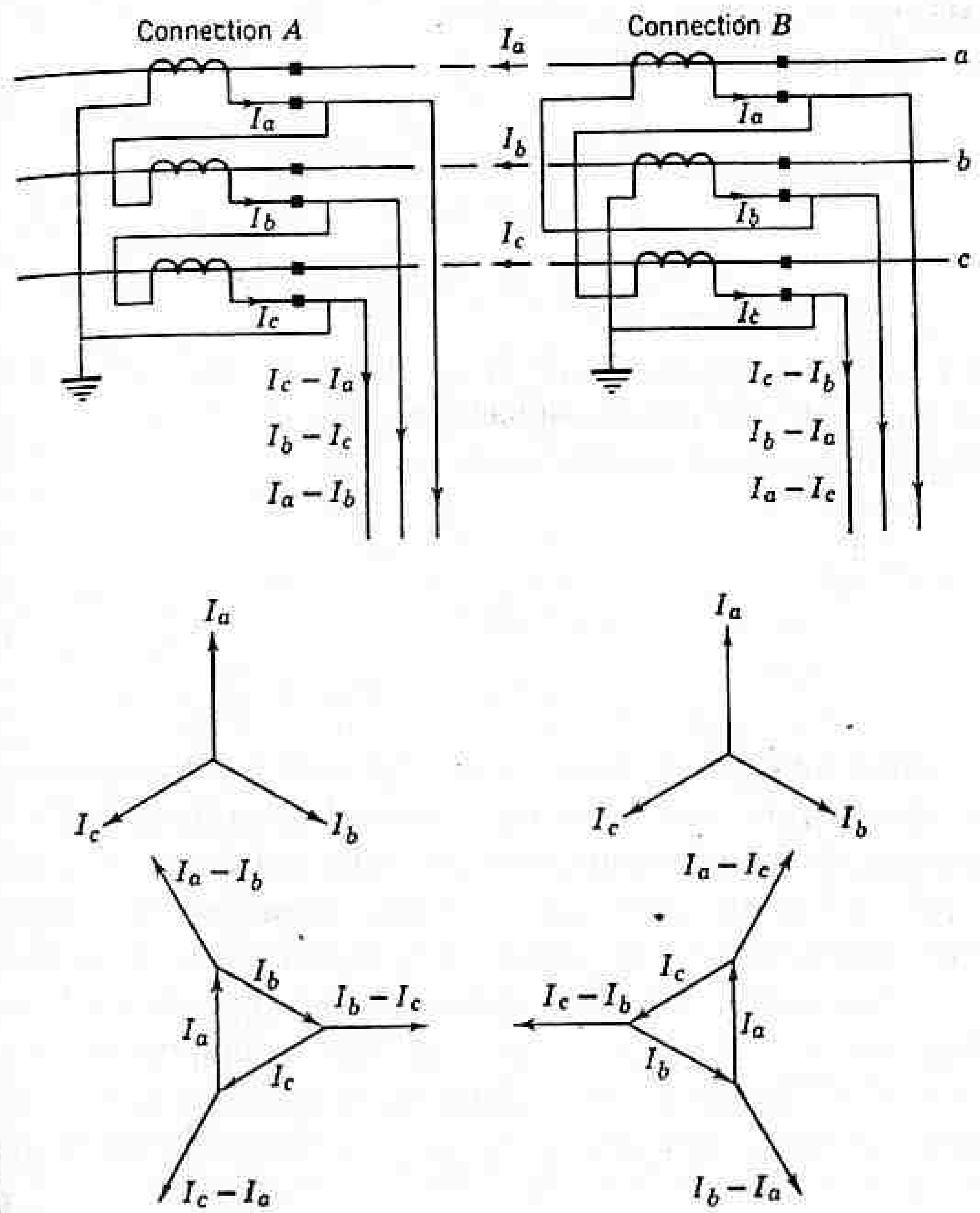

Fig. 7. Delta connections of current transformers and vector diagrams for balanced three-phase currents.

It will be noted that the zero-phase-sequence components are not present in the output circuits; they merely circulate in the delta connection. It will also be noted that connection B is merely the reverse of connection A.

For three-phase faults, only positive-phase-sequence components are present. The output currents of connection A become:

$$I_a - I_b = (\tfrac{3}{2} + j\sqrt{3}/2)I_{a1}$$

$$I_b - I_c = -j\sqrt{3}\, I_{a1}$$

$$I_c - I_a = (-\tfrac{3}{2} + j\sqrt{3}/2)I_{a1}$$

For a phase-b-to-phase-c fault, if we assume the same distribution of positive- and negative-phase-sequence currents (which is permissible

8 VOLTAGE TRANSFORMERS

Two types of voltage transformer are used for protective-relaying purposes, as follows: (1) the "instrument potential transformer," hereafter to be called simply "potential transformer," and (2) the "capacitance potential device." A potential transformer is a conventional transformer having primary and secondary windings. The primary winding is connected directly to the power circuit either between two phases or between one phase and ground, depending on the rating of the transformer and on the requirements of the application. A capacitance potential device is a voltage-transforming equipment using a capacitance voltage divider connected between phase and ground of a power circuit.

Accuracy of Potential Transformers

The ratio and phase-angle inaccuracies of any standard ASA accuracy class[1] of potential transformer are so small that they may be neglected for protective-relaying purposes if the burden is within the "thermal" volt-ampere rating of the transformer. This thermal volt-ampere rating corresponds to the full-load rating of a power transformer. It is higher than the volt-ampere rating used to classify potential transformers as to accuracy for metering purposes. Based on the thermal volt-ampere rating, the equivalent-circuit impedances of potential transformers are comparable to those of distribution transformers.

The "burden" is the total external volt-ampere load on the secondary at rated secondary voltage. Where several loads are connected in parallel, it is usually sufficiently accurate to add their individual volt-amperes arithmetically to determine the total volt-ampere burden.

If a potential transformer has acceptable accuracy at its rated voltage, it is suitable over the range from zero to 110% of rated transformers on the low-voltage side that are used for the purpose of supplying voltage to distance relays. Figure 11 shows the connections if the power transformers are connected wye-delta. Figure 12 shows the connections if the power transformers are connected delta-wye.

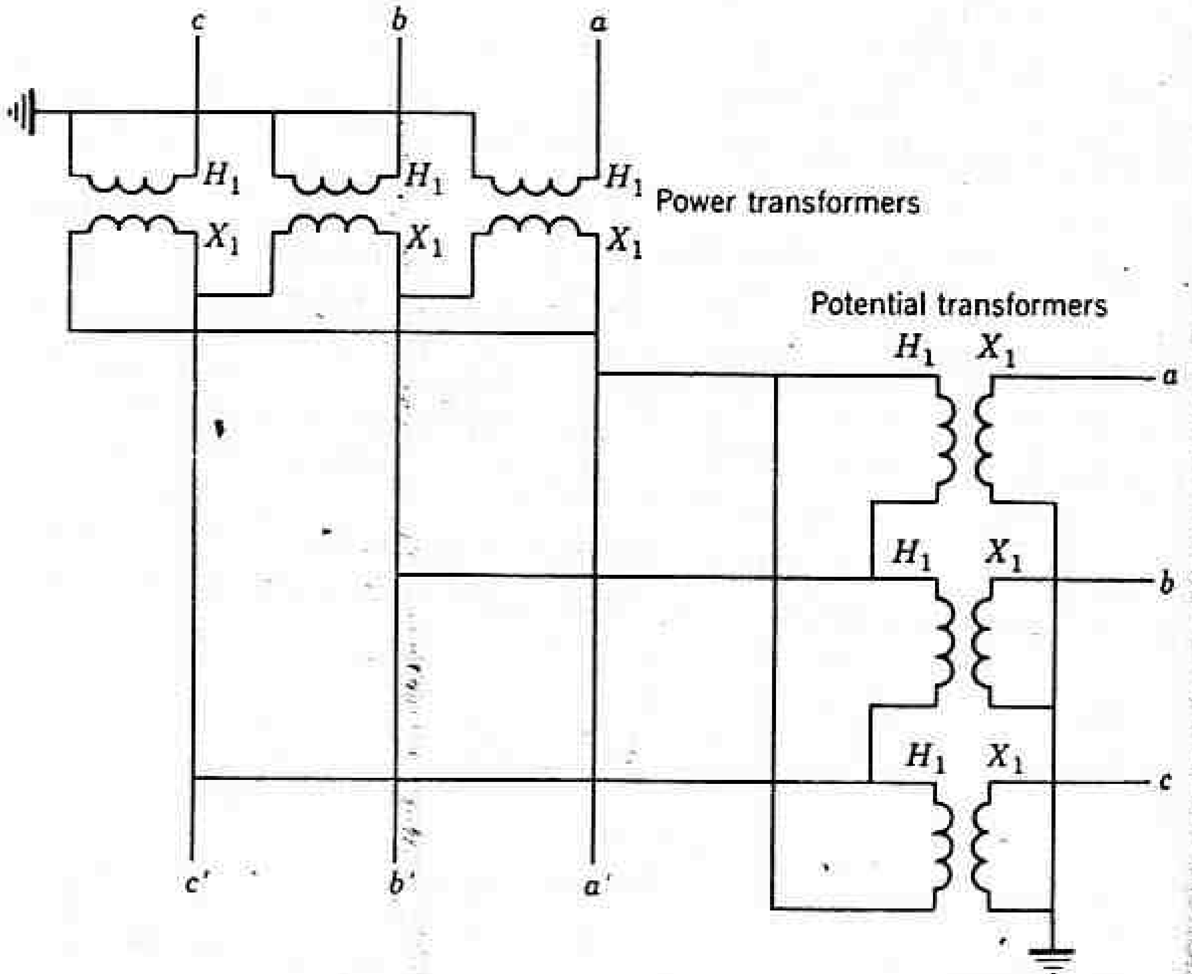

Fig. 11. Connections of potential transformers on low-voltage side of wye-delta power transformer for use with distance relays.

For either power-transformer connection, the phase-to-phase voltages on the secondary side of the potential transformers will contain the same phase-sequence components as those derived for the connections of Fig. 7, if we neglect the voltage drop or rise owing to load or fault currents that may flow through the power transformer. If, for one reason or another, the potential transformers must be connected delta-delta or wye-wye, or if the voltage magnitude is incorrect, auxiliary potential transformers must be used to obtain the required voltages for the distance relays.

The information given for making the required connections for distance relays should be sufficient instruction for making any other desired connections for phase relays. Other application considerations involved in the use of low-voltage sources for distance and other relays will be discussed later.

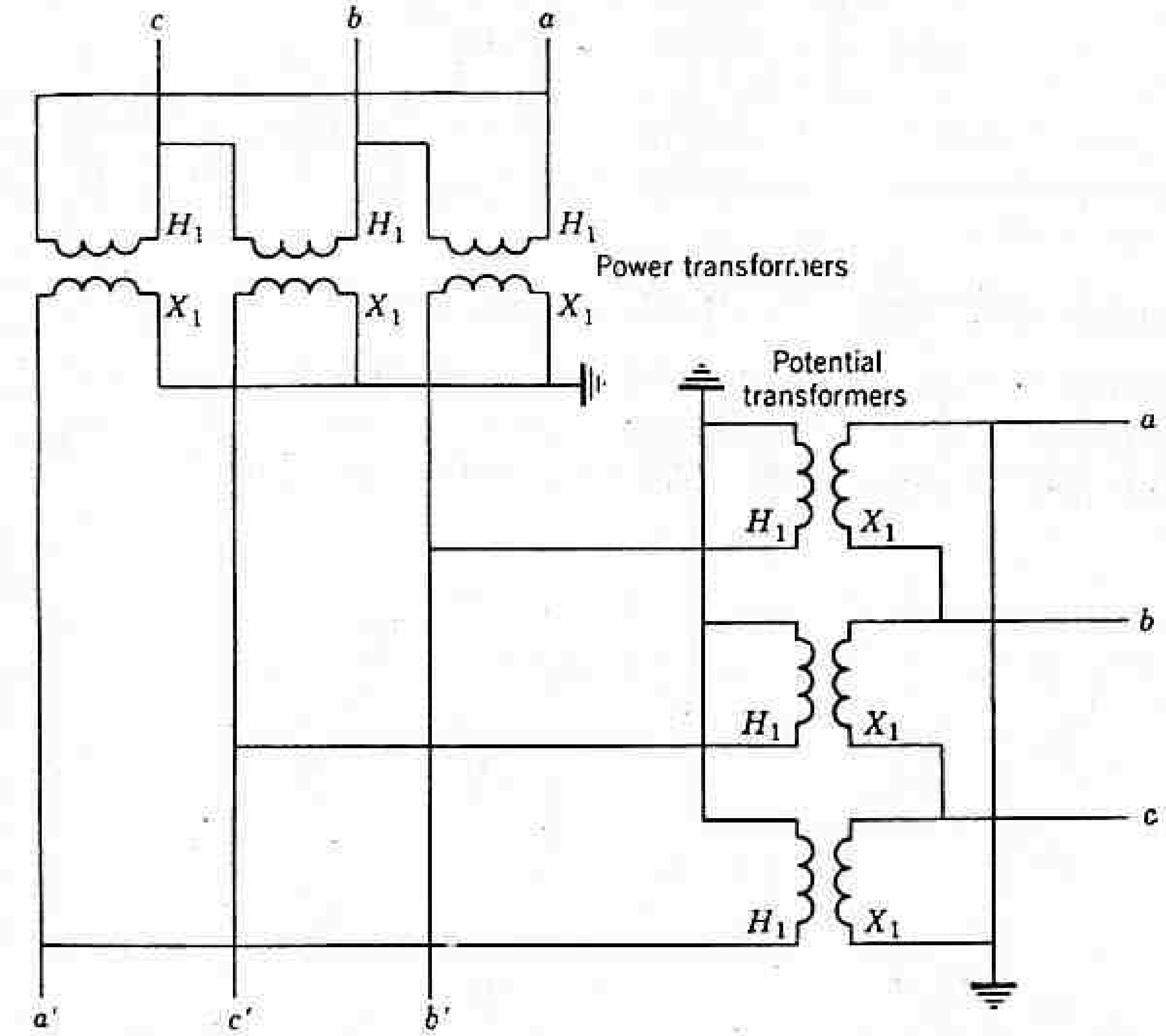

Fig. 12. Connections of potential transformers on low-voltage side of delta-wye power transformer for use with distance relays.

CONNECTIONS FOR OBTAINING POLARIZING VOLTAGE FOR DIRECTIONAL-GROUND RELAYS

The connections for obtaining the required polarizing voltage are shown in Fig. 13. This is called the "broken-delta" connection. The voltage that will appear across the terminals nm is as follows:

$$\begin{aligned} V_{nm} &= V_a + V_b + V_c \\ &= (V_{a1} + V_{a2} + V_{a0}) + (V_{b1} + V_{b2} + V_{b0}) + (V_{c1} + V_{c2} + V_{c0}) \\ &= V_{a0} + V_{b0} + V_{c0} = 3V_{a0} = 3V_{b0} = 3V_{c0} \end{aligned}$$

In other words, the polarizing voltage is 3 times the zero-phase-sequence component of the voltage of any phase.

The actual connections in a specific case will depend on the type of voltage transformer involved and on the secondary voltage required for other than ground relays. If voltage for distance relays must also be supplied, the connections of Fig. 14 would be used.

If voltage is required only for polarizing directional-ground relays, three coupling capacitors and one potential device, connected as in

Fig. 15 would suffice. The voltage obtained from this connection is 3 times the zero-phase-sequence component.

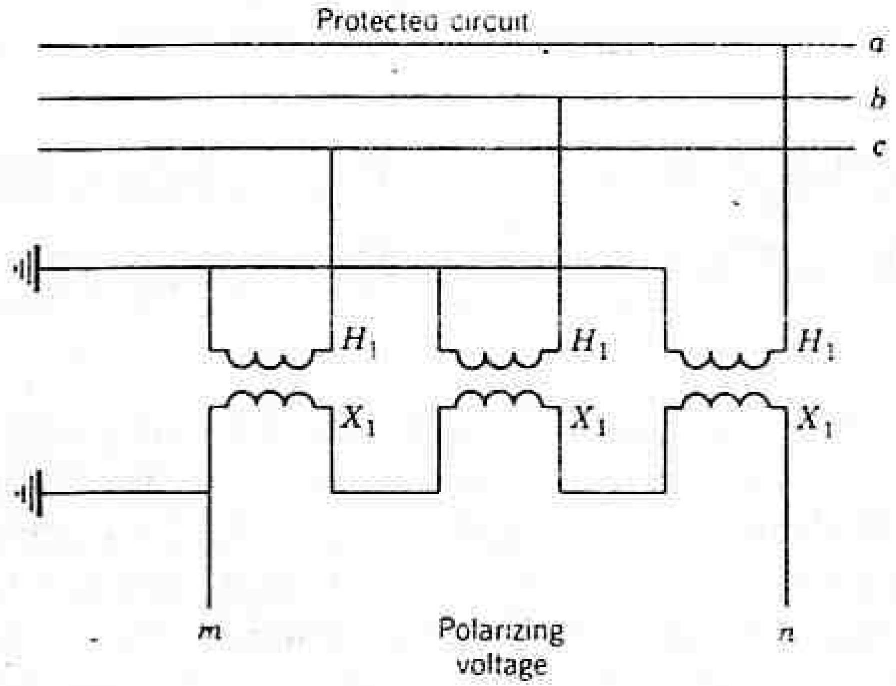

Fig. 13. The broken-delta connection.

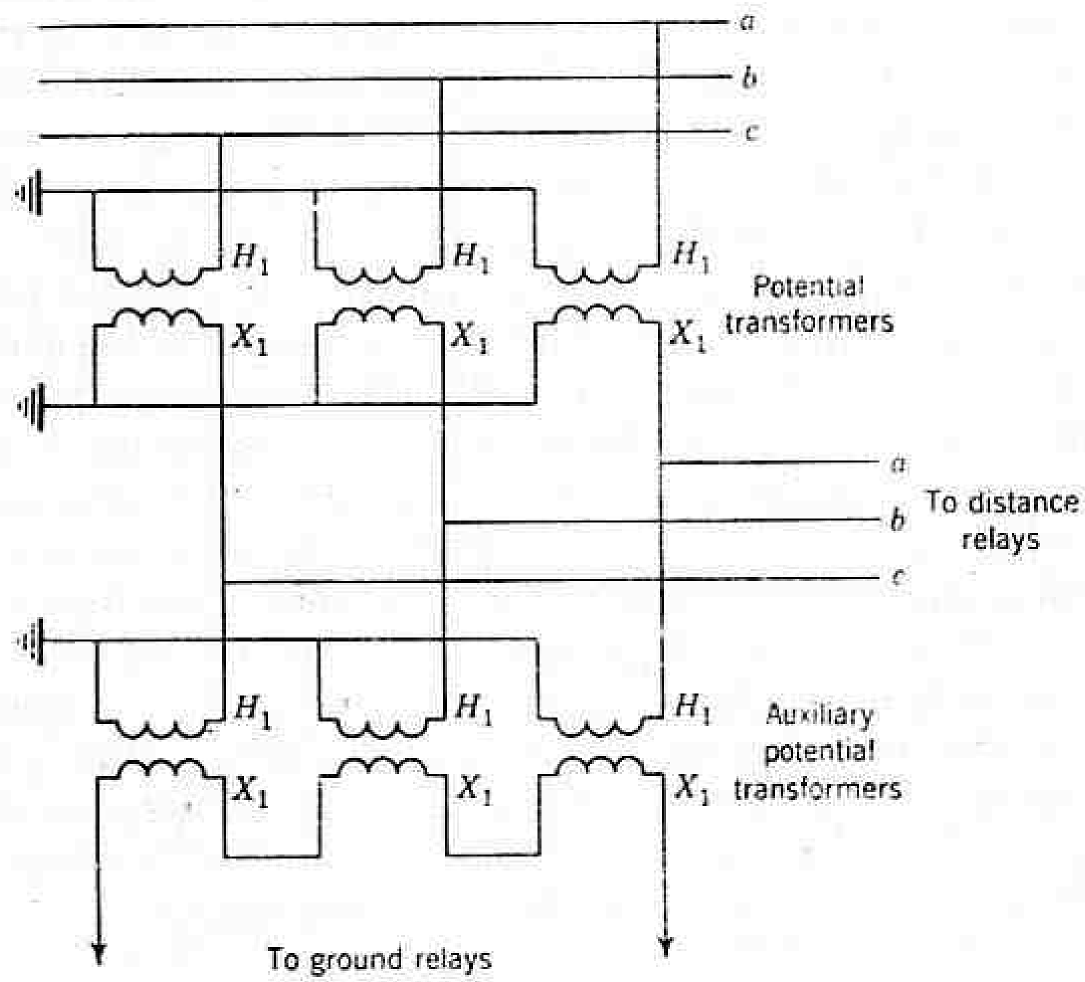

Fig. 14. Potential-transformer connections for distance and ground relays.

The connection of Fig. 15 cannot always be duplicated with bushing potential devices because at least some of the capacitance correspond-

ing to the auxiliary capacitor C_2 might be an integral part of the bushing and could not be separated from it. The capacitance to ground of interconnecting cable may also have a significant effect.

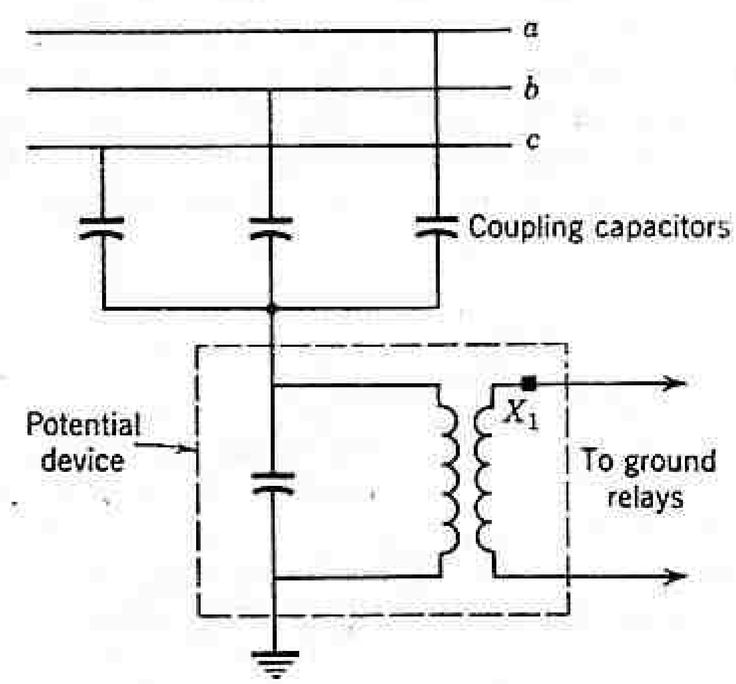

Fig. 15. Connection of three coupling capacitors and one potential device for providing polarizing voltage for directional-ground relays.

The three capacitance taps may be connected together, and a special potential device may be connected across the tap voltage as shown in Fig. 16, but the rated burden may be less than that of Table 1.

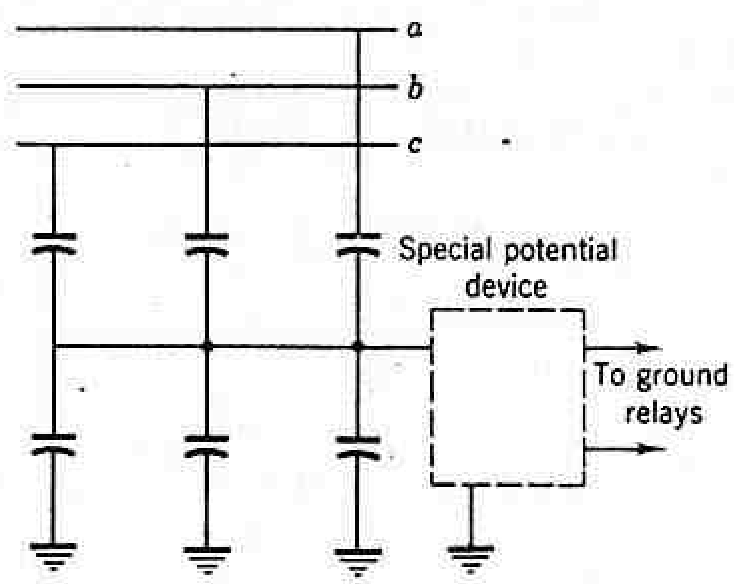

Fig. 16. Use of one potential device with three capacitance bushings.

Incidentally, a capacitance bushing cannot be used to couple carrier current to a line because there is no way to insert the required carrier-current choke coil in series with the bushing capacitance between the tap and ground, to prevent short-circuiting the output of the carrier-current transmitter.

Problem

1. Given a wye-delta power transformer with standard connections. According to the definitions of this chapter, draw the connection diagram and the three-phase voltage vector diagram for the HV and the LV sides, labeling the HV phases a, b, and c and the corresponding LV phases a', b', and c', (1) for positive-phase-sequence voltage applied to the HV side, and (2) for negative-phase-sequence voltage applied to the HV side. When positive-phase-sequence voltage is applied to the HV side, the phase sequence is a-b-c. When negative-phase-sequence voltage is applied, there is no change in connections, but the phase sequence is a-c-b.

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voltage. Operation in excess of 10% overvoltage may cause increas errors and excessive heating.

Where precise accuracy data are required, they can be obtain from ratio-correction-factor curves and phase-angle-correction curv supplied by the manufacturer.

Capacitance Potential Devices

Two types of capacitance potential device are used for protecti relaying: (1) the "coupling-capacitor potential device," and (2) th "bushing potential device." The two devices are basically alike, th principal difference being in the type of capacitance voltage divid

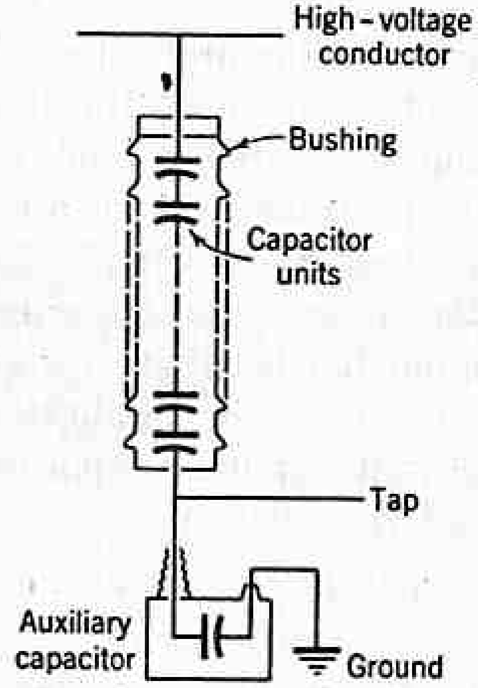

Fig. 1. Coupling-capacitor voltage divider.

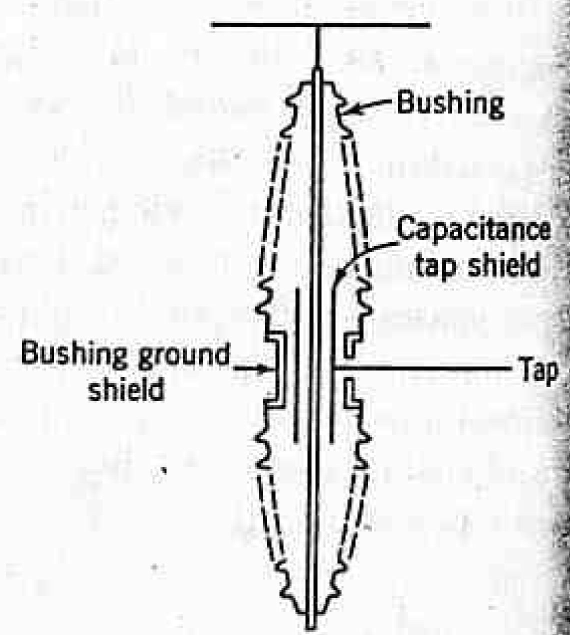

Fig. 2. Capacitance-bushing volt- age divider.

used, which in turn affects their rated burden. The coupling-capaci device uses as a voltage divider a "coupling capacitor" consisting of stack of series-connected capacitor units, and an "auxiliary capacito as shown schematically in Fig. 1. The bushing device uses the cap tance coupling of a specially constructed bushing of a circuit break or power transformer, as shown schematically in Fig. 2.

Both of these relaying potential devices are called "Class A devices.[2] They are also sometimes called "In-phase" or "Resona devices[3] for reasons that will be evident later. Other types potential devices, called "Class C" or "Out-of-phase" or "Non-re nant," are also described in References 2 and 3, but they are not ge erally suitable for protective relaying, and therefore they will n be considered further here.

A schematic diagram of a Class A potential device including the capacitance voltage divider is shown in Fig. 3. Not shown are the

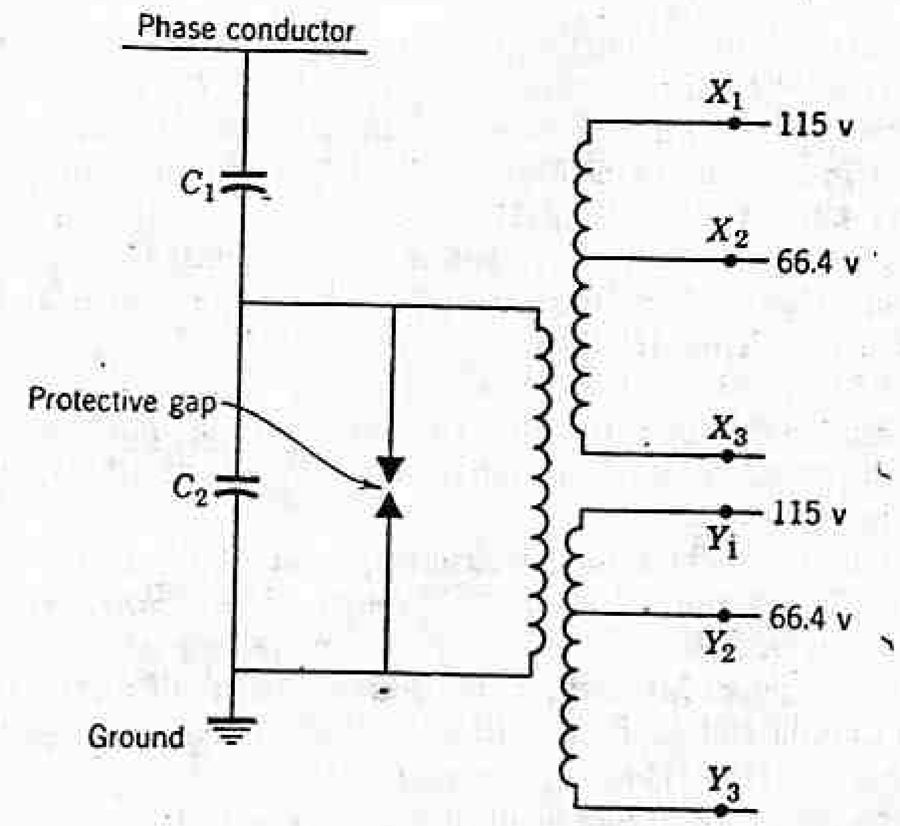

Fig. 3. Schematic diagram of a Class A potential device.

means for adjusting the magnitude and phase angle of the secondary voltage; the means for making these adjustments vary with different manufacturers, and a knowledge of them is not essential to our present purposes. The Class A device has two secondary windings as shown. Both windings are rated 115 volts, and one must have a 66.4-volt tap. These windings are connected in combination with the windings of the devices of the other two phases of a three-phase power circuit. The connection is "wye" for phase relays and "broken delta" for ground relays. These connections will be illustrated later.

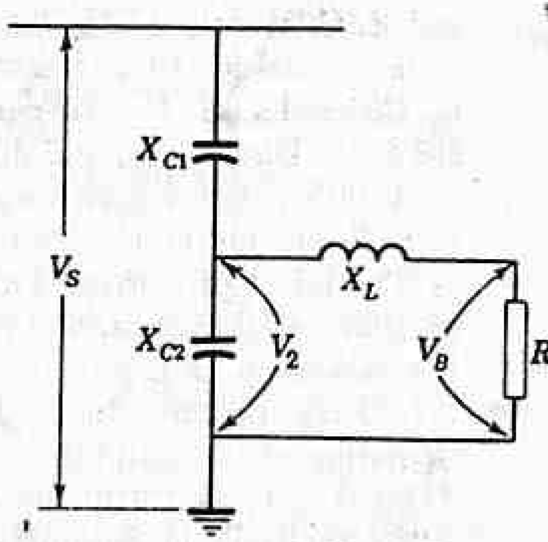

Fig. 4. Equivalent circuit of a Class A potential device.

The equivalent circuit of a Class A device is shown in Fig. 4. The equivalent reactance X_L is adjustable to make the burden voltage V_B be in phase with the phase-to-ground voltage of the system V_S. The burden is shown as a resistor because, so far as it is possible, it is the practice to correct the power factor of the burden approximately to unity by the use of auxiliary capacitance burden. When the device is properly adjusted,

$$X_L = \frac{X_{C1}X_{C2}}{X_{C1} + X_{C2}}$$

which explains why the term "Resonant" is applied to this devi
Actually, X_{C2} is so small compared with X_{C1} that X_L is practically eq
to X_{C2}. Therefore, X_L and X_{C2} would be practically in parallel resona
were it not for the presence of the burden impedance.

The gross input in watts from a power circuit to a capacitance pot
tial-device network is:[3]

$$W = 2\pi f C_1 V_S V_2 \sin \alpha \quad \text{watts}$$

where f = power-system frequency.
α = phase angle between V_S and V_2.
C_1 = capacitance of main capacitor (see Fig. 3) in farads.

V_S and V_2 are volts defined as in Fig. 4. If the losses in the netw
are neglected, equation 2 will give the output of the device. F
special applications, this relation is useful for estimating the ra
burden from the known rated burden under standard conditions;
is only necessary to compare the proportions in the two cases, reme
bering that, for a given rating of equipment, the tap voltage V_2 var
directly as the applied voltage V_S.

For a given group of coupling-capacitor potential devices, t
product of the capacitance of the main capacitor C_1 and the ra
circuit-voltage value of V_S is practically constant; in other wor
the number of series capacitor units that comprise C_1 is approximate
directly proportional to the rated circuit voltage. The capacitan
of the auxiliary capacitor C_2 is the same for all rated circuit voltag
so as to maintain an approximately constant value of the tap volta
V_2 for all values of rated circuit voltage.

For bushing potential devices, the value of C_1 is approximately co
stant over a range of rated voltages, and the value of C_2 is vari
by the use of auxiliary capacitance to maintain an approximate
constant value of the tap voltage V_2 for all values of rated circ
voltage.

STANDARD RATED BURDENS OF CLASS A POTENTIAL DEVICES

The rated burden of a secondary winding of a capacitance potent
device is specified in watts at rated secondary voltage when rat
phase-to-ground voltage is impressed across the capacitance volta
divider. The rated burden of the device is the sum of the watt burde
that may be impressed on both secondary windings simultaneous

Adjustment capacitors are provided in the device for connecting in parallel with the burden on one secondary winding to correct the total-burden power factor to unity or slightly leading.

The standard[2] rated burdens of bushing potential devices are given in Table 1.

Table 1. Rated Burdens of Bushing Potential Devices

Rated Circuit Voltage, kv		Rated Burden, watts
Phase-to-Phase	Phase-to-Ground	
115	66.4	25
138	79.7	35
161	93.0	45
230	133.0	80
287	166.0	100

The rated burden of coupling-capacitor potential devices is 150 watts for any of the rated circuit voltages, including those of Table 1.

STANDARD ACCURACY OF CLASS A POTENTIAL DEVICES

Table 2 gives the standard maximum deviation in voltage ratio and phase angle for rated burden and for various values of primary voltage, with the device adjusted for the specified accuracy at rated primary voltage.

Table 2. Ratio and Phase-Angle Error versus Voltage

Primary Voltage, percent of rated	Maximum Deviation	
	Ratio, percent	Phase Angle, degrees
100	± 1.0	± 1.0
25	± 3.0	± 3.0
5	± 5.0	± 5.0

Table 3 gives the standard maximum deviation in voltage ratio and phase angle for rated voltage and for various values of burden with the device adjusted for the specified accuracy at rated burden.

Table 3. Ratio and Phase-Angle Error versus Burden

Burden, percent of rated	Maximum Deviation	
	Ratio, percent	Phase Angle, degrees
100	± 1.0	± 1
50	± 6.0	± 4
0	± 12.0	± 8

Table 3 shows that for greatest accuracy, the burden should not be changed without readjusting the device.

EFFECT OF OVERLOADING

As the burden is increased beyond the rated value, the errors will increase at about the rate shown by extrapolating the data of Table 3, which is not very serious for protective relaying. Apart from the possibility of overheating, the serious effect is the accompanying increase of the tap voltage (V_2 of Fig. 4). An examination of the equivalent circuit, Fig. 4, will show why the tap voltage increases with increasing burden. It has been said that X_L is nearly equal to X_C, and therefore these two branches of the circuit will approach parallel resonance as R is decreased (or, in other words, as the burden is increased). Hence, the tap voltage will tend to approach V_S. As the burden is increased above the rated value, the tap voltage will increase approximately proportionally.

The objection to increasing the tap voltage is that the protective gap must then be adjusted for higher-than-normal arc-over voltage. This lessens the protection afforded the equipment. The circuit elements protected by the gap are specified[2] to withstand 4 times the normal tap voltage for 1 minute. Ordinarily, the gap is adjusted to arc over at about twice normal voltage. This is about as low an arc-over as the gap may be adjusted to have in view of the fact that for some ground faults the applied voltage (and hence the tap voltage) may rise to $\sqrt{3}$ times normal. Obviously, the gap must not be permitted to arc over for any voltage for which the protective-relaying equipment must function. Since the ground-relay burden loads the devices only when a ground fault occurs, gap flashover may be a problem when thermal overloading is not a problem. Before purposely overloading a capacitance potential device, one should consult the manufacturer.

As might be suspected, short-circuiting the secondary terminals of the device (which is extreme overloading) will arc over the gap continuously while the short circuit exists. This may not cause any damage to the device, and hence it may not call for fusing, but the gap will eventually be damaged to such an extent that it may no longer protect the equipment.

Even when properly adjusted, the protective gap might arc over during transient overvoltages caused by switching or by lightning. The duration of such arc-over is so short that it will not interfere with the proper operation of protective relays. The moment the overvoltage ceases, the gap will stop arcing over because the impedance of the main capacitor C_1 is so high that normal system voltage cannot maintain the arc.

It is emphasized that the standard rated burdens are specified as though a device were connected and loaded as a single-phase device. In practice, however, the secondary windings of three devices are interconnected and loaded jointly. Therefore, to determine the actual loading on a particular device under unbalanced voltage conditions, as when short circuits occur, certain conversions must be made. This is described later in more detail for the broken-delta burden. Also, the effective burden on each device resulting from the phase-to-phase and phase-to-neutral burdens should be determined if the loading is critical; this is merely a circuit problem that is applicable to any kind of voltage transformer.

NON-LINEAR BURDENS

A "non-linear" burden is a burden whose impedance decreases because of magnetic saturation when the impressed voltage is increased. Too much non-linearity in its burden will let a capacitance potential device get into a state of ferroresonance,[4] during which steady overvoltages of highly distorted wave form will exist across the burden. Since these voltages bear no resemblance to the primary voltages, such a condition must be avoided.

If one must know the maximum tolerable degree of non-linearity, he should consult the manufacturer. Otherwise, the ferroresonance condition can be avoided if all magnetic circuits constituting the burden operate at rated voltage at such low flux density that any possible momentary overvoltage will not cause the flux density of any magnetic circuit to go beyond the knee of its magnetization curve (or, in other words, will not cause the flux density to exceed about 100,000 lines per square inch). Since the potential-device secondary-winding voltage may rise to $\sqrt{3}$ times rated, and the broken-delta voltage may rise to 3 times rated, the corresponding phase-to-neutral and broken-delta burdens may be required to have no more than $1/\sqrt{3}$ and $1/3$, respectively, of the maximum allowable flux density at rated voltage.

If burdens with closed magnetic circuits, such as auxiliary potential transformers, are not used, there is no likelihood of ferroresonance. Class A potential devices are provided with two secondary windings purposely to avoid the need of an auxiliary potential transformer. The relays, meters, and instruments generally used have air gaps in their magnetic circuits, or operate at low enough flux density to make their burdens sufficiently linear.

THE BROKEN-DELTA BURDEN AND THE WINDING BURDEN

The broken-delta burden is usually composed of the voltage-pola ing coils of ground directional relays. Each relay's voltage-c circuit contains a series capacitor to make the relay have a lagg angle of maximum torque. Consequently, the voltage-coil circuit a leading power factor. The volt-ampere burden of each relay expressed by the manufacturer in terms of the rated voltage of relay. The broken-delta burden must be expressed in terms of rated voltage of the potential-device winding or the tapped porti of the winding—whichever is used for making up the broken-de connection. If the relay- and winding-voltage ratings are the sa the broken-delta burden is the sum of the relay burdens. If voltage ratings are different, we must re-express the relay burd in terms of the voltage rating of the broken-delta winding bef adding them, remembering that the volt-ampere burden will vary the square of the voltage, assuming no saturation.

The actual volt-ampere burdens imposed on the individual windi comprising the broken-delta connection are highly variable and only indirectly related to the broken-delta burden. Normally, three winding voltages add vectorially to zero. Therefore, no curr flows in the circuit, and the burden on any of the windings is ze When ground faults occur, the voltage that appears across the brok delta burden corresponds to 3 times the zero-phase-sequence co ponent of any one of the three phase-to-ground voltages at potential-device location. We shall call this voltage "$3V_0$." Wh the actual magnitude of this voltage is depends on how solidly system neutrals are grounded, on the location of the fault with resp to the potential device in question, and on the configuration of transmission circuits so far as it affects the magnitude of the ze phase-sequence reactance. For faults at the potential-device locati for which the voltage is highest, $3V_0$ can vary approximately fr 1 to 3 times the rated voltage of each of the broken-delta windin (This voltage can go even higher in an ungrounded-neutral syst should a state of ferroresonance exist, but this possibility is not co sidered here because it must not be permitted to exist.) If we assu no magnetic saturation in the burden, its maximum current magnitu will vary with the voltage over a 1 to 3 range.

The burden current flows through the three broken-delta windi in series. As shown in Fig. 5, the current is at a different phase an with respect to each of the winding voltages. Since a ground fa can occur on any phase, the positions of any of the voltages of Fig

relative to the burden current can be interchanged. Consequently, the burden on each winding may have a wide variety of characteristics under different circumstances.

Another peculiarity of the broken-delta burden is that the load is really carried by the windings of the unfaulted phases, and that the

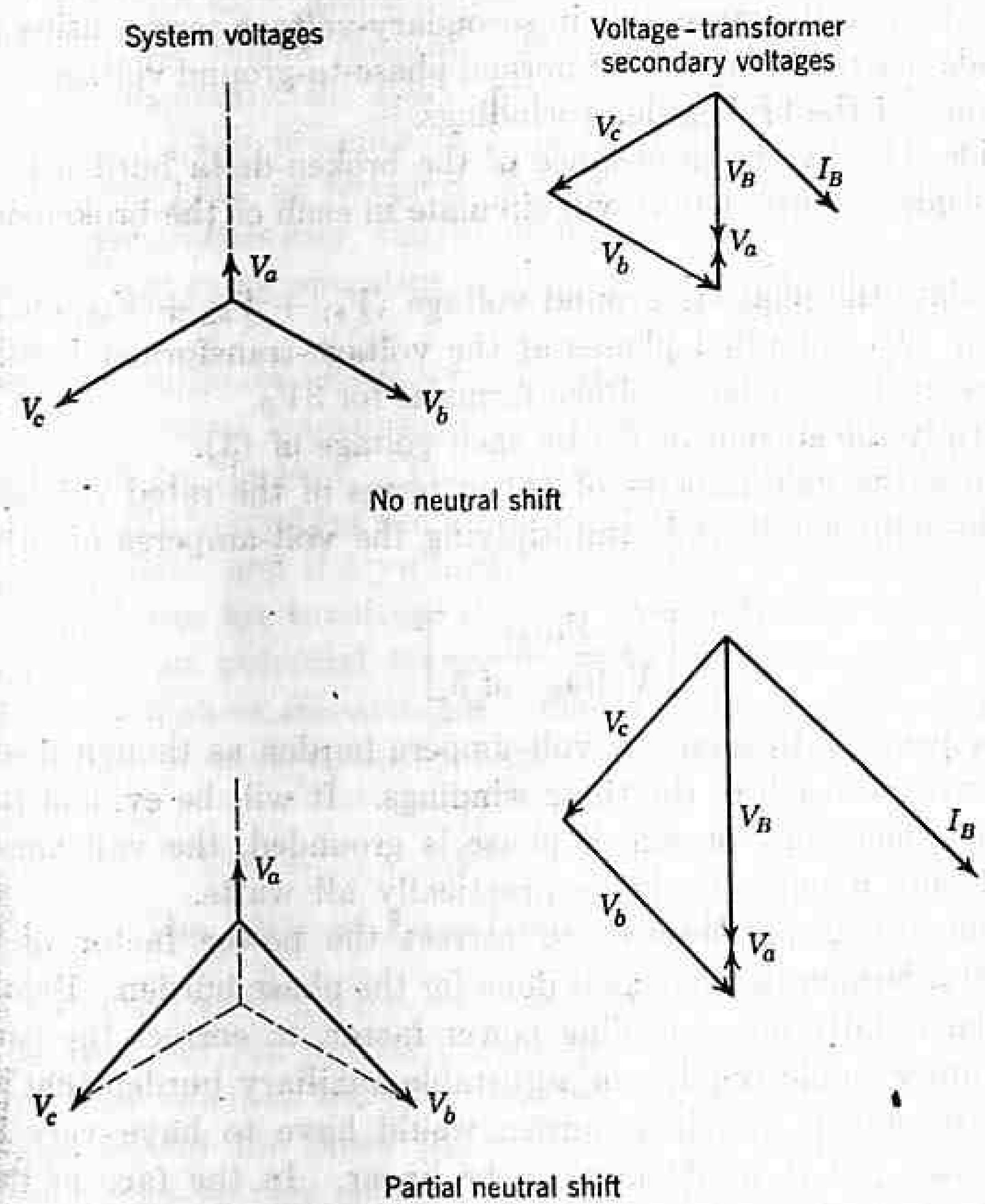

Fig. 5. Broken-delta voltages and current for a single-phase-to-ground fault on phase a some distance from the voltage transformer.

voltages of these windings do not vary in direct proportion to the voltage across the broken-delta burden. The voltages of the unfaulted-phase windings are not nearly as variable as the broken-delta-burden voltage. The winding voltages of the unfaulted phases vary from approximately rated voltage to $\sqrt{3}$ times rated, while the broken-delta-burden voltage, and hence the current, is varying from less than rated to approximately 3 times rated.

As a consequence of the foregoing, on the basis of rated voltage, the burden on any winding can vary from less than the broken-delta burden to $\sqrt{3}$ times it. For estimating purposes, the $\sqrt{3}$ multiplier would be used, but, if the total burden appeared to be excessive, one would want to calculate the actual burden. To do this, the following steps are involved:

1. Calculate $3V_0$ for a single-phase-to-ground fault at the potential-device location, and express this in secondary-voltage terms, using as potential-device ratio the ratio of normal phase-to-ground voltage to the rated voltage of the broken-delta windings.
2. Divide $3V_0$ by the impedance of the broken-delta burden to get the magnitude of current that will circulate in each of the broken-delta windings.
3. Calculate the phase-to-ground voltage ($V_{b1} + V_{b2} + V_{b0}$, etc.) of each of the two unfaulted phases at the voltage-transformer location, and express it in secondary-voltage terms as for $3V_0$.
4. Multiply the current of (2) by each voltage of (3).
5. Express the volt-amperes of (4) in terms of the rated voltage of the broken-delta windings by multiplying the volt-amperes of (4) by the ratio:

$$\left[\frac{V_{\text{rated}}}{\text{Voltage of 3}}\right]^2$$

It is the practice to treat the volt-ampere burden as though it were a watt burden on each of the three windings. It will be evident from Fig. 5 that, depending on which phase is grounded, the volt-ampere burden on any winding could be practically all watts.

It is not the usual practice to correct the power factor of the broken-delta burden to unity as is done for the phase burden. Because this burden usually has a leading power factor, to correct the power factor to unity would require an adjustable auxiliary burden that has inductive reactance. Such a burden would have to have very low resistance and yet it would have to be linear. In the face of these severe requirements, and in view of the fact that the broken-delta burden is usually a small part of the total potential-device burden, such corrective burden is not provided in standard potential devices.

COUPLING-CAPACITOR INSULATION COORDINATION AND ITS EFFECT ON THE RATED BURDEN

The voltage rating of a coupling capacitor that is used with protective relaying should be such that its insulation will withstand the flashover voltage of the circuit at the point where the capacitor [illegible] connected. Table 4 lists the standard[2] capacitor withstand test

Table 4. Standard Withstand Test Voltages for Coupling Capacitors

Rated Circuit Voltage, kv		Withstand Test Voltages		
			Low Frequency	
Phase-to-Phase	Phase-to-Ground	Impulse, kv	Dry 1-Min, kv	Wet 10-Sec, kv
115	66.4	550	265	230
138	79.7	650	320	275
161	93.0	750	370	315
230	133.0	1050	525	445
287	166.0	1300	655	555

voltages for some circuit-voltage ratings for altitudes below 3300 feet.

The flashover voltage of the circuit at the capacitor location will depend not only on the line insulation but also on the insulation of other terminal equipment such as circuit breakers, transformers, and lightning arresters. However, there may be occasions when these other terminal equipments may be disconnected from the line, and the capacitor will then be left alone at the end of the line without benefit of the protection that any other equipment might provide. For example, a disconnect may be opened between a breaker and the capacitor, or a breaker may be opened between a transformer or an arrester and the capacitor. If such can happen, the capacitor must be able to withstand the voltage that will flash over the line at the point where the capacitor is connected.

Some lines are overinsulated, either because they are subjected to unusual insulator contamination or because they are insulated for a future higher voltage than the present operating value. In any event, the capacitor should withstand the actual line flashover voltage unless there is other equipment permanently connected to the line that will hold the voltage down to a lower value.

At altitudes above 3300 feet, the flashover value of air-insulated equipment has decreased appreciably. To compensate for this decrease, additional insulation may be provided for the line and for the other terminal equipment. This may require the next higher standard voltage rating for the coupling capacitor, and it is the practice to specify the next higher rating if the altitude is known to be over 3300 feet.

When a coupling-capacitor potential device is to be purchased for operation at the next standard rated circuit voltage below the coupling-capacitor rating, the manufacturer should be so informed. In such a case, a special auxiliary capacitor will be furnished that will provide normal tap voltage even though the applied voltage is one step less

than rated. This will give the device a rated burden of 120 wat
If a special auxiliary capacitor were not furnished, the rated burd
would be about 64% of 150 watts instead of 80%. The forego
will become evident on examination of equation 2 and on considerati
of the fact that each rated insulation class is roughly 80% of t
next higher rating.

The foregoing applies also to bushing potential devices, except th
sometimes a non-standard transformer unit may be required to g
80% of rated output when the device is operating at the next stand
rated circuit voltage below the bushing rating.

COMPARISON OF INSTRUMENT POTENTIAL TRANSFORMERS AND CAPACITANCE POTENTIAL DEVICES

Capacitance potential devices are used for protective relaying on
when they are sufficiently less expensive than potential transforme
Potential devices are not as accurate as potential transformers, a
also they may have undesirable transient inaccuracies unless th
are properly loaded.[5] When a voltage source for the protective rela
of a single circuit is required, and when the circuit voltage is approx
mately 69 kv and higher, coupling-capacitor potential devices are le
costly than potential transformers. Savings may be realized somewh
below 69 kv if carrier current is involved, because a potential-dev
coupling capacitor can be used also, with small additional expen
for coupling the carrier-current equipment to the circuit. Bushi
potential devices, being still less costly, may be even more economica
provided that the devices have sufficiently high rated-burden capacit
However, the main capacitor of a bushing potential device cannot
used to couple carrier-current equipment to a power circuit. Wh
compared on a dollars-per-volt-ampere basis, potential transforme
are much cheaper than capacitance potential devices.

When two or more transmission-line sections are connected to
common bus, a single set of potential transformers connected to t
bus will generally have sufficient capacity to supply the protecti
relaying equipments of all the lines, whereas one set of capacitan
potential devices may not. The provision of additional potent
devices will quickly nullify the difference in cost. In view of t
foregoing, one should at least consider bus potential transformers, ev
for a single circuit, if there is a likelihood that future requireme
might involve additional circuits.

Potential transformers energized from a bus provide a furt
slight advantage where protective-relaying equipment is involved
which dependence is placed on "memory action" for reliable operati

When a line section protected by such relaying equipment is closed in on a nearby fault, and if potential transformers connected to the bus are involved, the relays will have had voltage on them before the line breaker was closed, and hence the memory action can be effective. If the voltage source is on the line side of the breaker, as is usually true with capacitance potential devices, there will have been no voltage on the relays initially, and memory action will be ineffective. Consequently, the relays may not operate if the voltage is too low owing to the presence of a metallic fault with no arcing, thereby requiring back-up relaying at other locations to clear the fault from the system. However, the likelihood of the voltage being low enough to prevent relay operation is quite remote, but the relays may be slow.

Some people object to bus potential transformers on the basis that trouble in a potential transformer will affect the relaying of all the lines connected to the bus. This is not too serious an objection, particularly if the line relays are not allowed to trip on loss of voltage during normal load, and if a voltage-failure alarm is provided.

Where ring buses are involved, there is no satisfactory location for a single set of bus potential transformers to serve the relays of all circuits. In such cases, capacitance potential devices on the line side of the breakers of each circuit are the best solution when they are cheaper.

The Use of Low-Tension Voltage

When there are step-down power transformers at a location where voltage is required for protective-relaying equipment, the question naturally arises whether the relay voltage can be obtained from the low-voltage side of the power transformers, and thereby avoid the expense of a high-voltage source. Such a low-voltage source can be used under certain circumstances.

The first consideration is the reliability of the source. If there is only one power transformer, the source will be lost if this power transformer is removed from service for any reason. If there are two or more power transformers in parallel, the source is probably sufficiently reliable if the power transformers are provided with separate breakers.

The second consideration is whether there will be a suitable source for polarizing directional-ground relays if such relays are required. If the power transformers are wye-delta, with the high-voltage side connected in wye and the neutral gounded, the neutral current can be used for polarizing. Of course, the question of whether a single power transformer can be relied on must be considered as in the preceding paragraph. If the high-voltage side is not a grounded wye, then a high-voltage source must be provided for directional-ground relays, and it may as well be used also by the phase relays.

Finally, if distance relays are involved, the desirability of "transformer-drop compensation" must be investigated. This subject will be treated in more detail when we consider the subject of transmission-line protection.

The necessary connections of potential transformers for obtaining the proper voltages for distance relays will be discussed later in this chapter. Directional-overcurrent relays can use any conventional potential-transformer connection.

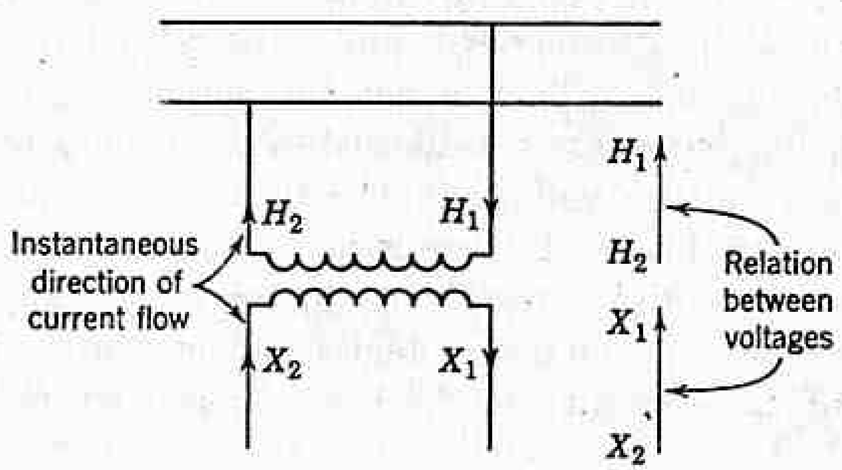

Fig. 6. Significance of potential-transformer polarity marks.

Polarity and Connections

The terminals of potential transformers are marked to indicate the relative polarities of the primary and secondary windings. Usually the corresponding high-voltage and low-voltage terminals are marked "H_1" and "X_1," respectively (and "Y_1" for a tertiary). In capacitance potential devices, only the X_1 and Y_1 terminals are marked, the H_1 terminal being obvious from the configuration of the equipment.

The polarity marks have the same significance as for current transformers, namely, that, when current enters the H_1 terminal, it leaves the X_1 (or Y_1) terminal. The relation between the high and low voltages is such that X_1 (or Y_1) has the same instantaneous polarity as H_1, as shown in Fig. 6. Whether a transformer has additive or subtractive polarity may be ignored because it has absolutely no effect on the connections.

Distance relays for interphase faults must be supplied with voltage corresponding to primary phase-to-phase voltage, and any one of the

three connections shown in Fig. 7 may be used. Connection A is chosen when polarizing voltage is required also for directional-ground relays; this will be discussed later in this chapter. The equivalent of connection A is the only one used if capacitance potential devices are involved. Connections B and C do not provide means for polariz-

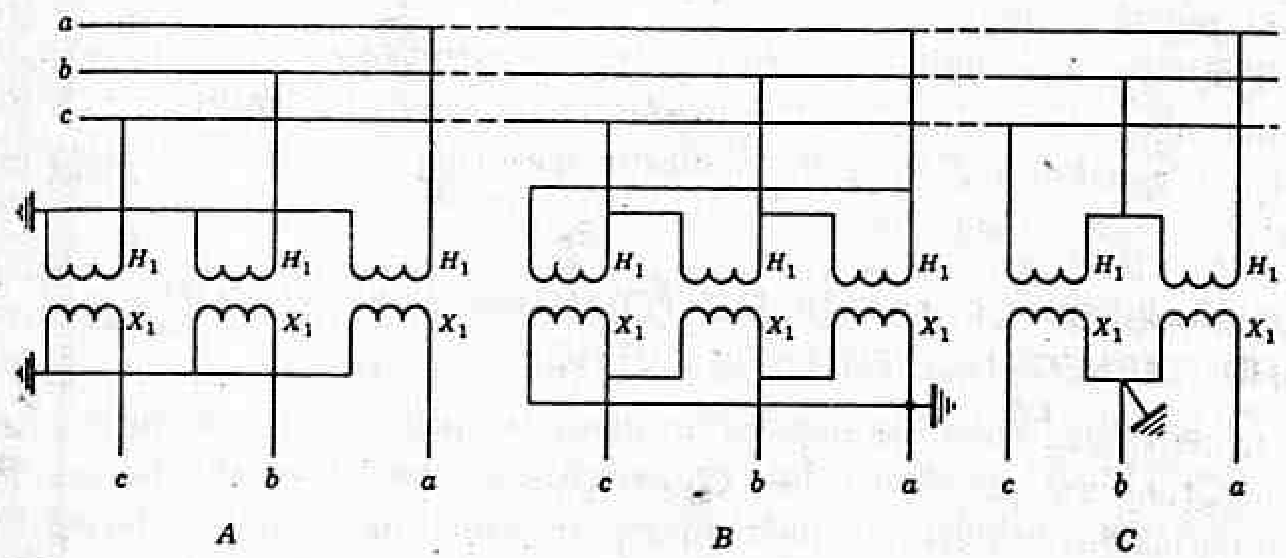

Fig. 7. Connections of potential transformers for distance relays.

ing directional-ground relays; of these two, connection C is the one generally used because it is less expensive since it employs only two potential transformers. The burden on each potential transformer is less in connection B, which is the only reason it would ever be chosen.

The voltages between the secondary leads for all three connections of Fig. 7 are the same, and in terms of symmetrical components are:

$$
\begin{aligned}
V_{ab} &= V_a - V_b \\
&= V_{a1} + V_{a2} + V_{a0} - V_{b1} - V_{b2} - V_{b0} \\
&= (1 - a^2)V_{a1} + (1 - a)V_{a2} \\
&= (\tfrac{3}{2} + j\sqrt{3}/2)V_{a1} + (\tfrac{3}{2} - j\sqrt{3}/2)V_{a2}
\end{aligned}
$$

Similarly,

$$
\begin{aligned}
V_{bc} &= (1 - a^2)V_{b1} + (1 - a)V_{b2} \\
&= a^2(1 - a^2)V_{a1} + a(1 - a)V_{a2} \\
&= (a^2 - a)V_{a1} + (a - a^2)V_{a2} \\
&= -j\sqrt{3}\,V_{a1} + j\sqrt{3}\,V_{a2} \\
V_{ca} &= (1 - a^2)V_{c1} + (1 - a)V_{c2} \\
&= a(1 - a^2)V_{a1} + a^2(1 - a)V_{a2} \\
&= (a - 1)V_{a1} + (a^2 - 1)V_{a2} \\
&= (-\tfrac{3}{2} + j\sqrt{3}/2)V_{a1} + (-\tfrac{3}{2} - j\sqrt{3}/2)V_{a2}
\end{aligned}
$$

It will be observed that these relations are similar to those obtained for the output currents of the delta-connected CT's of Chapter 7, Fig. 7.

LOW-TENSION VOLTAGE FOR DISTANCE RELAYS

The potential transformers must be connected to the low-voltage source in such a way that the phase-to-phase voltages on the high-voltage side will be reproduced. The connection that must be used

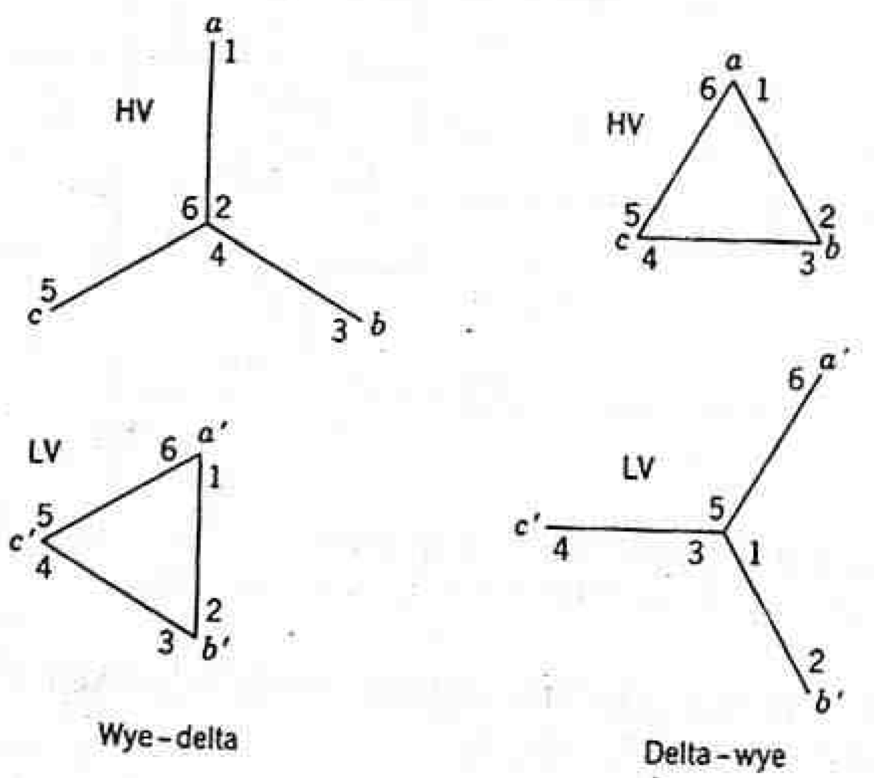

Fig. 8. Three-phase voltages for standard connection of power transformers.

will depend on the power-transformer connections. If, as is not usually the case, the power-transformer bank is connected wye-wye or delta-delta, the potential-transformer connections would be the same as though the potential transformers were on the high-voltage side. Usually, however, the power transformers are connected wye-delta or delta-wye.

First, let us become acquainted with the standard method of connecting wye-delta or delta-wye power transformers. Incidentally, in stating the connections of a power-transformer bank, the high-voltage connection is stated first; thus a wye-delta transformer bank has its high-voltage side connected in wye, etc. The standard method of connecting power transformers does not apply to potential transformers (which are connected as required), but the technique involved in making the desired connections will apply also to potential transformers. The standard connection for power transformers is that, with balanced three-phase load on the transformer bank, the current

in each phase on the high-voltage side will lead by 30° the current in each corresponding phase on the low-voltage side. Also, the no-load phase-to-phase voltages on the high-voltage side will lead the corresponding low-voltage phase-to-phase voltages by 30°. For this to be true, the three-phase voltages must be as in Fig. 8, where a' corresponds to a, b' to b, and c' to c. The numbers on the voltage vectors of Fig. 8 designate the corresponding ends of the transformer windings, 1–2 designating the primary and secondary windings of one transformer, etc. Now, consider three single-phase transformers as in Fig. 9 with their primary and secondary windings designated 1–2, etc. If we assume that the transformers are rated for either phase-to-phase or phase-to-

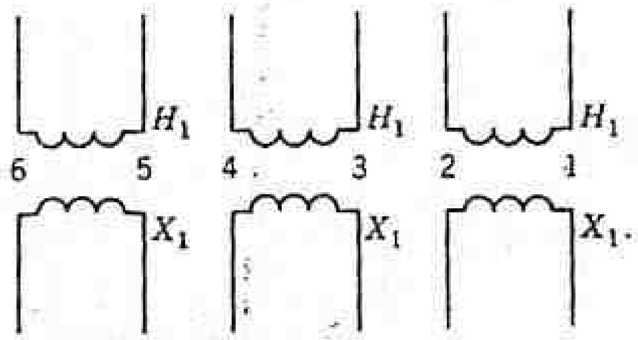

Fig. 9. Numbering the ends of the transformer windings preparatory to making three-phase connections.

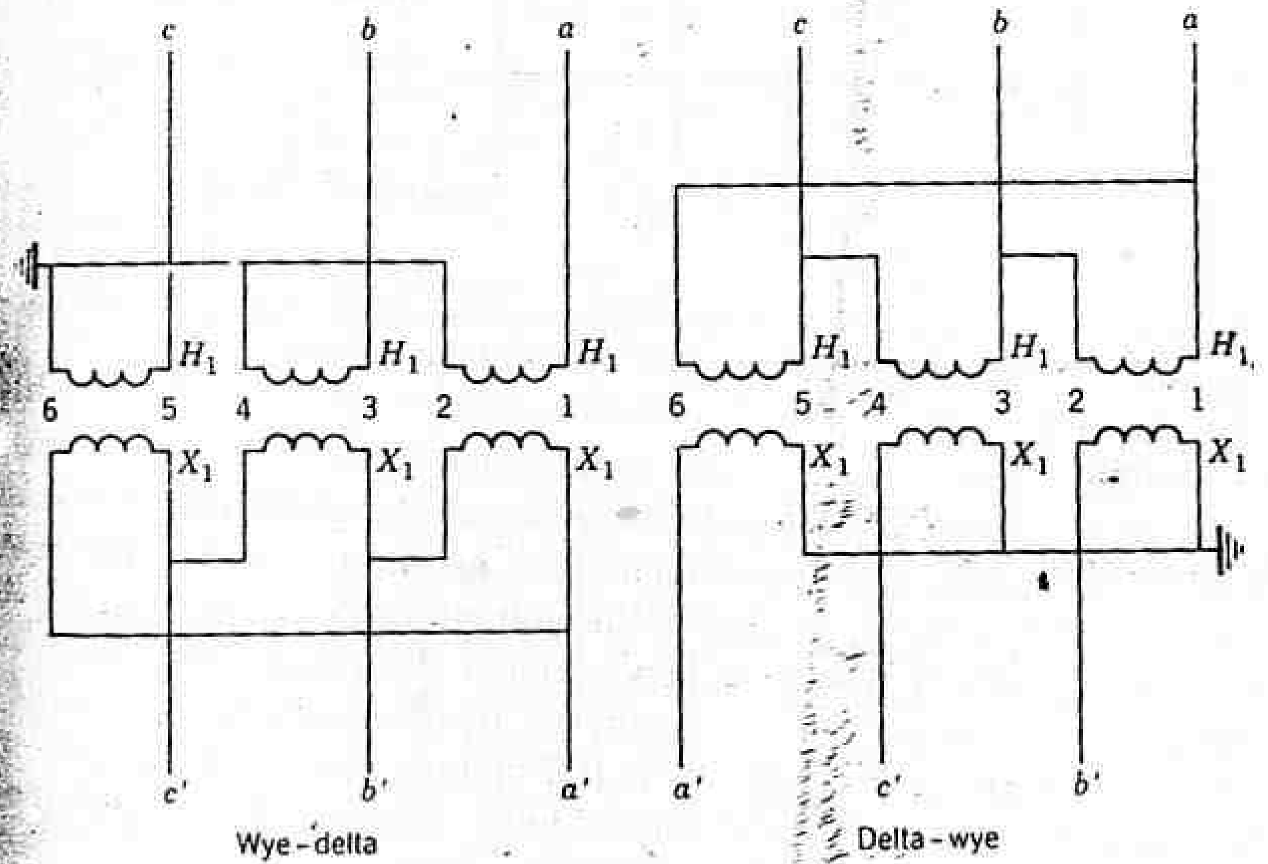

Fig. 10. Interconnecting the transformers of Fig. 9 according to Fig. 8 to get standard connections.

ground connection, it is only necessary to connect together the numbered ends that are shown connected in Fig. 8, and the connections of Fig. 10 will result.

We can now proceed to examine the connections of potential

9 METHODS FOR ANALYZING, GENERALIZING, AND VISUALIZING RELAY RESPONSE

The material that has been presented thus far will enable one to translate power-system currents and voltages into protective-relay response in any given case. From that standpoint, the material of this chapter is unnecessary. Nor is this chapter intended to teach one how to determine these currents and voltages by the methods of symmetrical components,[1,2] since it is assumed that this is known. The purpose of this chapter is best explained by a simple example.

In Chapter 7, we learned that a relay coil connected in the neutral lead of three wye-connected current transformers would have a current in it equal to $3I_{a0}$. Assuming that this is an overcurrent relay, we can immediately say that this relay will respond only to zero-phase-sequence current. This is important and useful knowledge, because we then know that the relay will respond only to faults involving ground. Furthermore, we do not have to calculate the positive- and negative-phase-sequence components of current in the circuit protected by the relay; all we need to know is the zero-phase-sequence component. Moreover, merely by looking at the phase-sequence diagram for any fault, we can tell whether this relay will receive zero-phase-sequence current, and how the magnitude and direction of this current will change with a change in fault location. Therefore, it is evident that we have at our disposal a much broader conception of the response of this relay than merely knowing that it will operate whenever it receives more than a certain magnitude of current. The value of being able to visualize and generalize relay response will become even more evident in the case of any relay that responds to certain combinations of voltage, current, and phase angle.

The *R-X* Diagram

The *R-X* diagram was introduced in Chapter 4 to show the operating characteristics of distance relays. Now, we are about to use it to tendency of certain ground relays to "overreach" for phase faults; because of this tendency it is customary to provide means for blocking tripping by ground distance relays when a fault involves two or more phases, or at least to block tripping by the ground relays that can overreach.

The principal use of the foregoing type of construction for practical application purposes is when one must know how distance relays will respond to faults on the other side of a power transformer. This will now be considered.

EFFECT OF A WYE-DELTA OR A DELTA-WYE POWER TRANSFORMER BETWEEN DISTANCE RELAYS AND A FAULT

For other than three-phase faults, the presence of a wye-delta or delta-wye transformer between a distance relay and a fault changes the complexion of the fault as viewed from the distance-relay location,[6] because of the phase shift and the recombination of the currents and voltages from one side to the other of the power transformer. In passing through the transformer from the fault to the relay location, the positive-phase-sequence currents and voltages of the corresponding phases are shifted 30° in one direction, and the negative-phase-sequence quantities are shifted 30° in the other direction. The zero-phase-sequence quantities are not transmitted through such a power transformer. The 30° shift described here is not at variance with the 90° shift described in some textbooks on symmetrical components. The 90° shift is a simpler mathematical manipulation, but it does not apply to what is usually considered the *corresponding* phase quantities.

In terms of only the magnitude of per unit quantities in an equivalent system diagram, the only effect of the presence of a power transformer is its impedance in the phase-sequence circuits. But to combine the per unit phase-sequence quantities and convert them to volts and amperes at the relay location, one must first shift the per unit quantities by the proper phase angle from their positions on the fault side of the power transformer. If the power transformer has the standard connections described in Chapter 8 whereby the high-voltage phase currents lead the corresponding low-voltage phase currents by 30° under balanced three-phase conditions, the positive-phase-sequence currents and voltages on the HV side lead the corresponding positive-phase-sequence components on the LV side by 30°. (Under balanced three-phase conditions, only positive-phase-sequence quantities exist, and the vector diagram for this condition is a positive-phase-sequence diagram; this is a good way to determine the direction

and amount of shift for any connection.) The negative-phase-sequence quantities on the HV side lag the corresponding LV quantities by 30°, or, in other words, they are shifted by the same amount as the positive-phase-sequence quantities, but in the opposite direction.

For three-phase faults where there are only positive-phase-sequence currents and voltages, the fact that these quantities are shifted 30° in going through the transformer may be ignored because all of them are shifted in the same direction. On the R-X diagram, a three-phase fault on the other side of a power transformer is represented merely by adding to the positive-phase-sequence impedance between the relay and the transformer the positive-phase-sequence impedance of the transformer and of the line between the transformer and the fault. If the impedances are in ohms, it is only necessary to be sure that the impedances of the transformer and the line between it and the fault are expressed in terms of the rated voltage of the transformer on the relay side; if the impedances are in percent or per unit, each impedance should be based on the base voltage of the portion of the circuit in which it exists, exactly the same as for any short-circuit study. It is probably evident that all three relays will operate alike for a three-phase fault.

The net effect of the shift in the positive- and negative-phase-sequence components on the impedance appearing to a distance relay on the HV side for a fault on the LV side is compared in Table 5 with data from Table 4 for a phase-b-to-phase-c fault. For the purposes of comparison, the same impedance values between the relay and the fault are assumed for both fault locations, and the effect of fault resistance is neglected.

Table 5. Comparison of Appearance of Phase-*b*-to-Phase-*c* Faults on Either Side of a Wye-Delta or Delta-Wye Power Transformer to Distance Relays on the HV Side

	HV Fault (From Table 4)	LV Fault
Z_{ab}	$Z_1' - j\sqrt{3}\,Z_{X1}$	$Z_1' - j\dfrac{\sqrt{3}}{3}Z_{X1}$
Z_{bc}	Z_1'	$Z_1' + j\dfrac{\sqrt{3}}{3}Z_{X1}$
Z_{ca}	$Z_1' + j\sqrt{3}\,Z_{X1}$	∞

The effect of the LV fault on the graphical construction for showing these impedances on an R-X diagram is to shift the construction lines

AM, AN, and AF by 30° in the counterclockwise direction from the positions in Fig. 8 to the new positions AM', AN', and AF' as illustrated in Fig. 10. In other words, $Z_{ab} = OM'$, $Z_{bc} = OF'$, and Z_{ca} = infinity

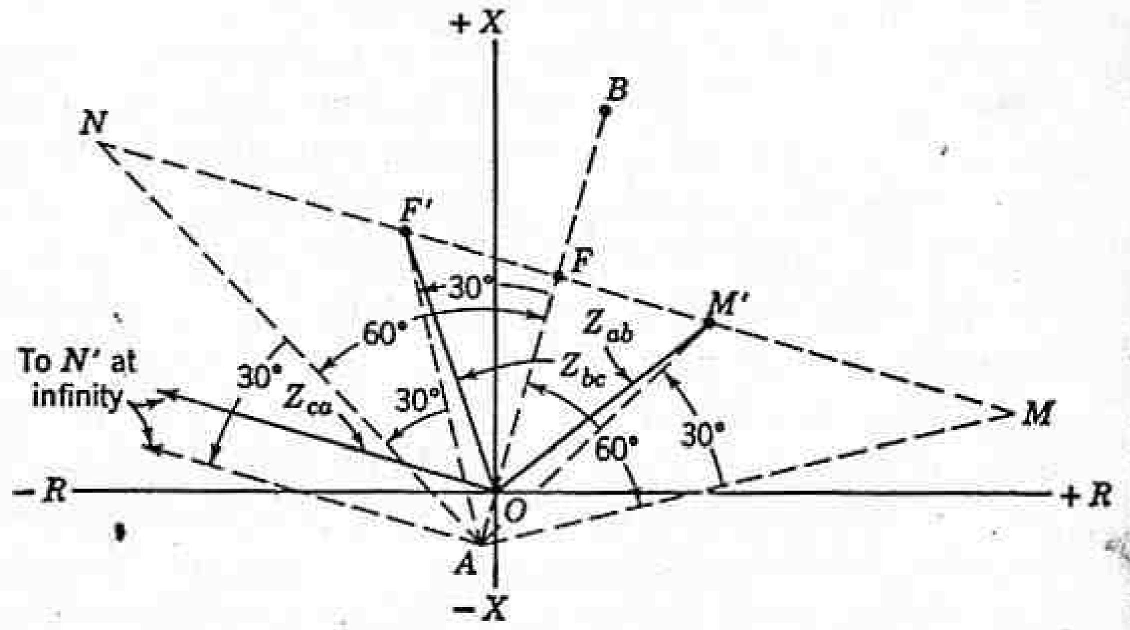

Fig. 10. Appearance to phase distance relays of a phase-*b*-to-phase-*c* fault on the low-voltage side of a wye-delta or delta-wye power transformer.

because the construction line is parallel to the line MN. Table 5 and Fig. 10 apply whether the power transformer is connected wye-delta or delta-wye, so long as it has the standard connections described in

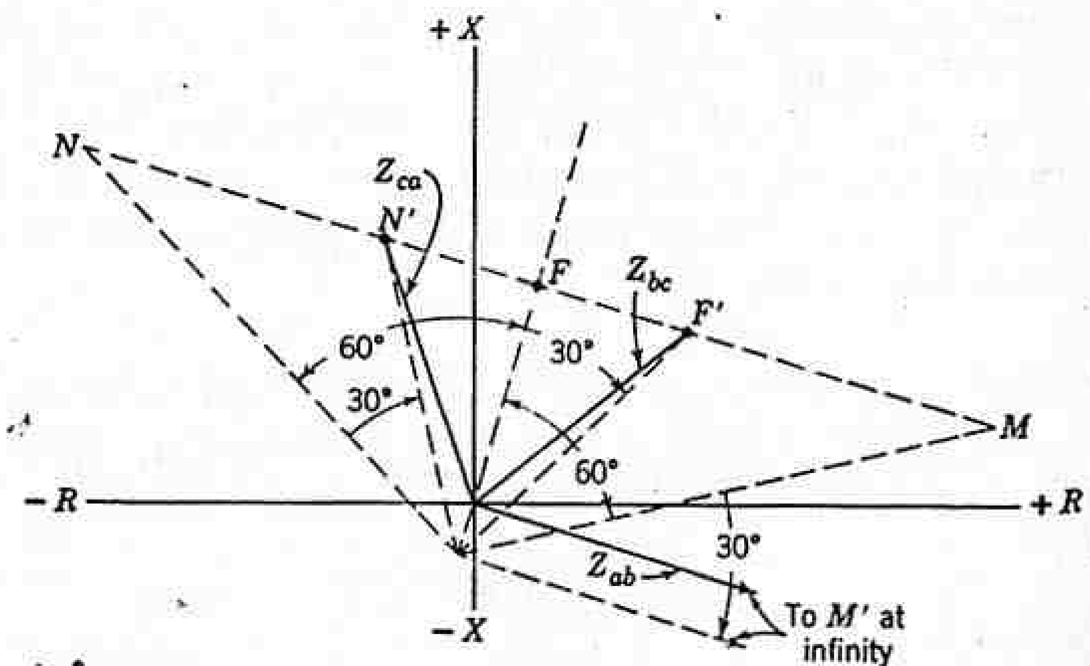

Fig. 11. Appearance, to phase distance relays on the LV side, of a phase-*b*-to-phase-*c* fault on the HV side of a wye-delta or delta-wye power transformer.

Chapter 8. It will be noted that the construction of Fig. 10 also uses as a starting point the line OF which represents the positive-phase-sequence impedance for a three-phase fault at the fault location, including the transformer impedance.

If the relay is on the LV side of the power transformer, and the phase-*b*-to-phase-*c* fault is on the HV side, the construction of Fig. 11 applies. It will be noted that here the construction lines are shifted 30° clockwise from their positions for the fault on the same side as the relay.

Comparing the foregoing R-X diagrams, we note that as we move the fault from the relay side of the power transformer to the other side, the construction lines shift 30° in the same direction that the negative-phase-sequence components shift in going through the transformer from the relay to the other side. This assumes that the transformer has the standard connections.

Space does not permit the consideration of the appearance to phase distance relays of single-phase-to-ground faults on the other side of a transformer, or of the appearance to ground distance relays of various types of faults on the other side of a transformer. Suffice it to say, a single-phase-to-ground fault on one side looks like a phase-to-phase fault on the other side, and vice versa, when wye-delta or delta-wye power transformers are involved.

The significant information that we get from studies of this kind may be summarized as follows:

1. If we want to be sure that any kind of distance relay on one side will not operate for any kind of fault on the other side, we must be sure that it will not operate for a three-phase fault.
2. If we want to be sure that a phase distance relay on one side will operate for any kind of fault on the other side, we must be sure that it will operate for a phase-to-phase fault.
3. If we want to be sure that a ground distance relay on one side will operate for any kind of fault on the other side, we must be sure that it will operate for a single-phase-to-ground fault. This assumes that the system neutral is grounded in such a way that a single-phase-to-ground fault at the location under consideration will cause short-circuit current to flow at the relay location.

After one has tried to adjust distance relays to provide back-up protection for certain faults on the other side of a transformer bank, it will become evident that it would be more practical either to use back-up units connected to measure distance correctly for such faults or to use the "reversed-third-zone" principle which will be described in Chapter 14. The connection of back-up units to measure distance correctly is the same principle as that when low-tension current and voltage are used, except that the high-tension quantities must be so combined as to duplicate the low-tension quantities.

Power Swings and Loss of Synchronism

Power swings are surges of power such as those after the removal of a short circuit, or those resulting from connecting a generator to its system at an instant when the two are out of phase. The characteristic of a power swing is the same as the early stages of loss of synchronism, and hence the loss-of-synchronism characteristic can describe both phenomena.

Fig. 12. One-line diagram of a system, illustrating loss-of-synchronism characteristics.

Consider the one-line diagram of Fig. 12 where a section of transmission line is shown with generating sources beyond either end of the line section. As for short-circuit studies, it is the practice, when possible, to represent the system by its two-generator equivalent.

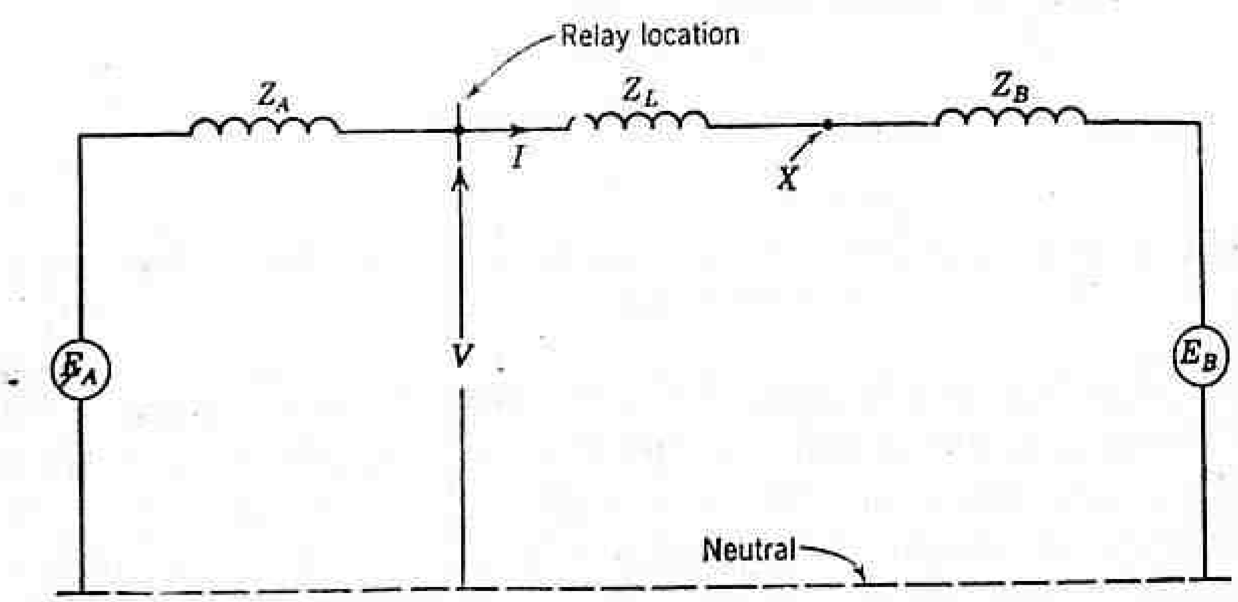

Fig. 13. System constants and relay current and voltage for Fig. 12.

The location of a relay is shown whose response to loss of synchronism between the two generating sources is to be studied. Each generating source may be either an actual generator or an equivalent generator representing a group of generators that remain in synchronism. (If generators within the same group lose synchronism with each other, this simple approach to the problem cannot be used, and a network-analyzer study may be required to provide the desired data.) The effects of shunt capacitance and of shunt loads are neglected.

Figure 13 indicates the pertinent phase-to-neutral (positive-phase-sequence) impedances and the generated voltages of the system of Fig. 12, and also the phase current and phase-to-neutral voltage at the relay location. An equivalent generator reactance of 90% of the direct-axis rated-current transient reactance most nearly represents a generator during the early stages of a power swing, and should be used for calculating the impedances in such an equivalent circuit.[7] In practice the generator reactance and the generated voltage are assumed to remain constant.

We can derive the relay quantities as follows:

$$I = \frac{E_A - E_B}{Z_A + Z_L + Z_B}$$

$$V = E_A - IZ_A = E_A - \frac{(E_A - E_B)Z_A}{Z_A + Z_L + Z_B}$$

$$\frac{V}{I} = Z = \frac{E_A}{E_A - E_B}(Z_A + Z_L + Z_B) - Z_A$$

If we let E_B be the reference, and let E_A advance in phase ahead of E_B by the angle θ, and if we let the magnitude of E_A be equal to nE_B, where n is a scalar, then

$$\frac{E_A}{E_A - E_B} = \frac{n(\cos\theta + j\sin\theta)}{n(\cos\theta + j\sin\theta) - 1}$$

This equation will resolve into the form:

$$\frac{E_A}{E_A - E_B} = \frac{n[(n - \cos\theta) - j\sin\theta]}{(n - \cos\theta)^2 + \sin^2\theta}$$

If we take the special case where $n = 1$, the equation becomes:

$$\frac{E_A}{E_A - E_B} = \frac{1}{2}\left(1 - j\cot\frac{\theta}{2}\right)$$

Therefore, Z becomes:

$$Z = \frac{Z_A + Z_L + Z_B}{2}\left(1 - j\cot\frac{\theta}{2}\right) - Z_A$$

This value of Z is shown on the R-X diagram of Fig. 14 for a particular value of θ less than 180°. Point P is thereby seen to be a point on the loss-of-synchronism characteristic. Further thought will reveal that all other points on the loss-of-synchronism characteristic will lie on the dashed line through P. This line is the perpendicular bisector of the straight line connecting A and B.

The loss-of-synchronism characteristic has been expressed in terms of the ratio of a phase-to-neutral voltage to the corresponding phase current. Under balanced three-phase conditions that exist during loss of synchronism, this ratio is exactly the same as the ratio of

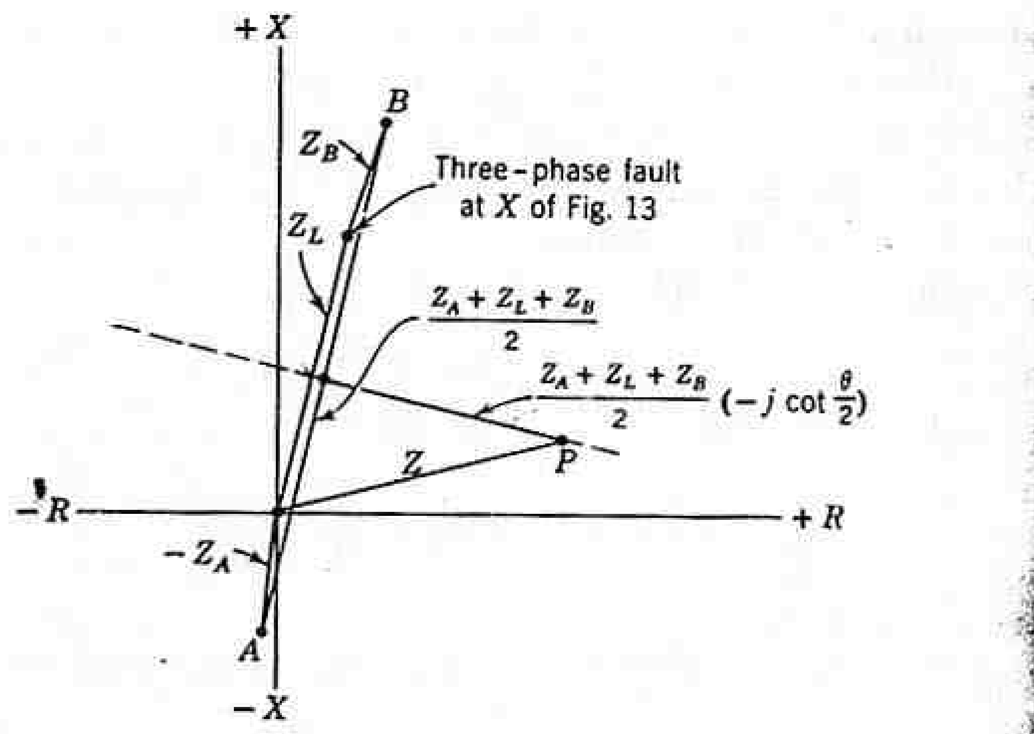

Fig. 14. Construction for locating a point on the loss-of-synchronism characteristic.

delta voltage to delta current that was used earlier in this chapter for describing the appearance of short circuits to phase distance relays. Therefore, it is permissible to superimpose such loss-of-synchronism characteristics, short-circuit characteristics, and distance-relay characteristics on the same R-X diagram. For example, a three-phase fault (X of Fig. 13) at the far end of the line section from the relay location appears to distance relays as a point at the end of Z_L, as shown in Fig. 14.

The foregoing observation will lead to the further observation that the point where the loss-of-synchronism characteristic intersects the impedance Z_L would also represent a three-phase fault at that point. In other words, at one instant during loss of synchronism, the conditions are exactly the same as for a three-phase fault at a point approximately midway electrically between the ends of the system. This point is called the "electrical center" or the "impedance center" of the system. This point would be exactly midway if the various impedances had the same X/R ratio, or, in other words, if all of them were in line on the diagram. The point where the loss-of-synchronism characteristic intersects the total-impedance line AB is reached when generator A has advanced to 180° leading generator B.

As shown in Fig. 15, the location of P for any angle θ between the generators can be found graphically by drawing a straight line from either end of the total-impedance line AB at the angle $\left(90 - \frac{\theta}{2}\right)$ to AB. The point P is the intersection of this straight line with the loss-of-synchronism characteristic, which is the perpendicular bisector of the line AB. When θ is 90°, P lies on the circle whose diameter is the total-impedance line AB. This fact is useful to remember because it provides a simple method to locate a point corresponding to about the maximum load transfer.

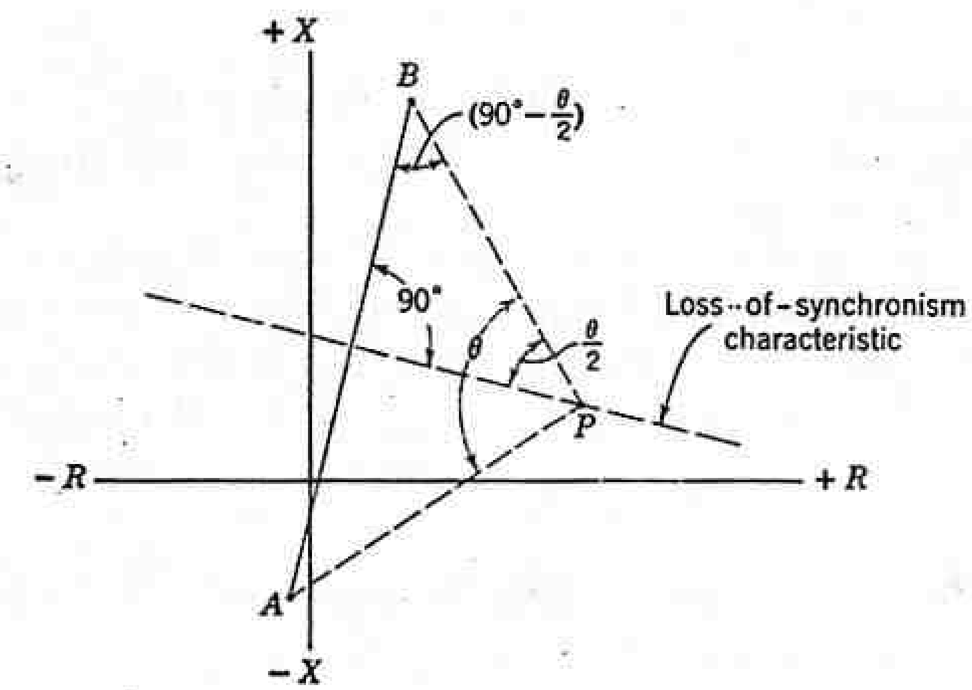

Fig. 15. Locating any point on the loss-of-synchronism characteristic corresponding to any value of θ.

The preceding development of the loss-of-synchronism characteristic was for the special case of $n = 1$. For most purposes, the characteristic resulting from this assumption is all that one needs to know in order to understand distance-type-relay response to loss of synchronism. However, without going into too much detail, let us at least obtain a qualitative picture of the general case where n is greater or less than unity.

All loss-of-synchronism characteristics are circles with their centers on extensions of the total-impedance line AB of Fig. 15. The characteristic when $n = 1$ is a circle of infinite radius. Any of these characteristics could be derived by successive calculations, if we assumed a value for n and then let θ vary from 0 to 360° in the general formula:

$$Z = (Z_A + Z_L + Z_B)n \frac{(n - \cos\theta) - j\sin\theta}{(n - \cos\theta)^2 + \sin^2\theta} - Z_A$$

Or one might manipulate the formula mathematically so as to get expressions for the diameter and the location of the center of the circle for any value of n. Figure 16 shows three loss-of-synchronism characteristics for $n > 1$, $n = 1$, and $n < 1$. The total-system-impedance line is again shown as AB.

The dashed circle through A, B, P', P, and P'' is an interesting aspect because all points on this circle to the right of the line AB, such as P', P, and P'' are for the same angle θ by which generator A has advanced ahead of generator B. This might be expected in view of the fact that the angle between a pair of lines drawn from any

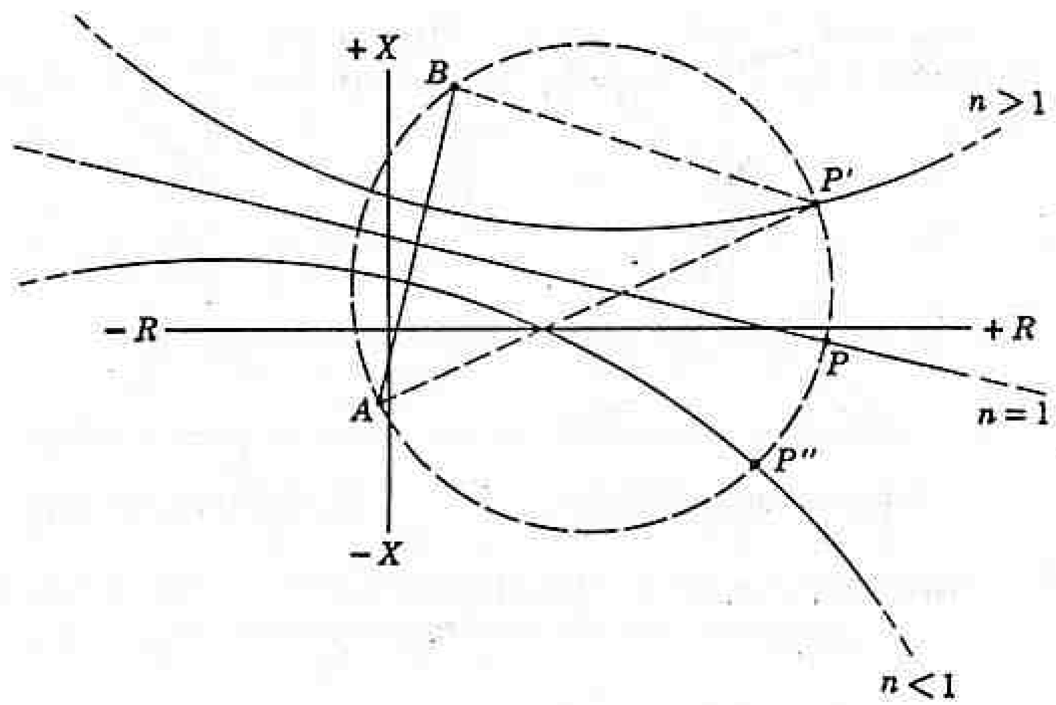

Fig. 16. General loss-of-synchronism characteristics.

point on this part of the circle to A and B is equal to the angle between another pair of lines drawn from any other point on this part of the circle to A and B.

Another interesting aspect of the diagram of Fig. 16 is that the ratio of the lengths of a pair of straight lines drawn from any point on the right-hand part of the circle to A and B will be equal to n. In other words, $P'A/P'B = n$. This suggests a simple method by which the loss-of-synchronism characteristic can be constructed graphically for any value of n. With a compass, one can easily locate three such points, all of which satisfy this same relation; having three points, one can then draw the circle.

This also suggests how to derive mathematical expressions for the radius of the circle and the location of its center. It is only necessary to assume the two possible locations of P' on the line AB and its extension, as shown on Fig. 17, and to obtain the characteristics of the circle that satisfy the relation $P'A/P'B = n$ for both locations.

According to this suggestion, it can be shown that, if we let Z_T be the total system impedance, then, for $n > 1$:

$$\text{Distance from } B \text{ to center of circle} = \frac{Z_T}{n^2 - 1}$$

$$\text{Radius of the circle} = \frac{nZ_T}{n^2 - 1}$$

These are illustrated in Fig. 17.

The circles for $n < 1$ are symmetrical to those for $n > 1$, but with their centers beyond A; the same formulae can be used if $1/n$ is inserted in place of n.

The construction of the loss-of-synchronism characteristic is more complicated if the effects of shunt capacitance and loads are taken

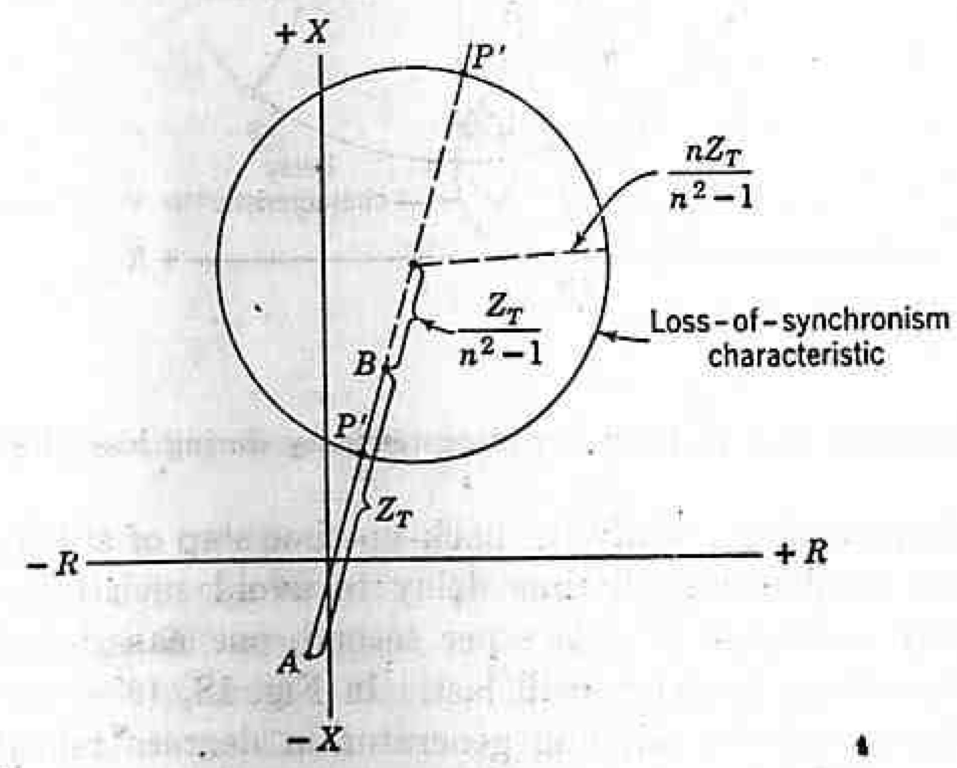

Fig. 17. Graphical construction of loss-of-synchronism characteristic.

into account. Also, the presence of a fault during a power swing or loss of synchronism further complicates the problem. However, seldom if ever will one need any more information than has been given here. The entire subject is treated most comprehensively in references 5 and 8 of the Bibliography.

EFFECT ON DISTANCE RELAYS OF POWER SWINGS OR LOSS OF SYNCHRONISM

To determine the response of any distance relay, it is only necessary to superimpose its operating characteristic on the R-X diagram of the loss-of-synchronism characteristic. This will show immediately whether any portion of the loss-of-synchronism characteristic enters the relay's operating region.

The fact that the loss-of-synchronism characteristic passes through or near the point representing a three-phase short circuit at the electrical center of the system indicates that any distance relay whose range of operation includes this point will have an operating tendency. Whether the relay will actually complete its operation and trip its breaker depends on the operating speed of the relay and the length of time during which the loss-of-synchronism conditions will produce

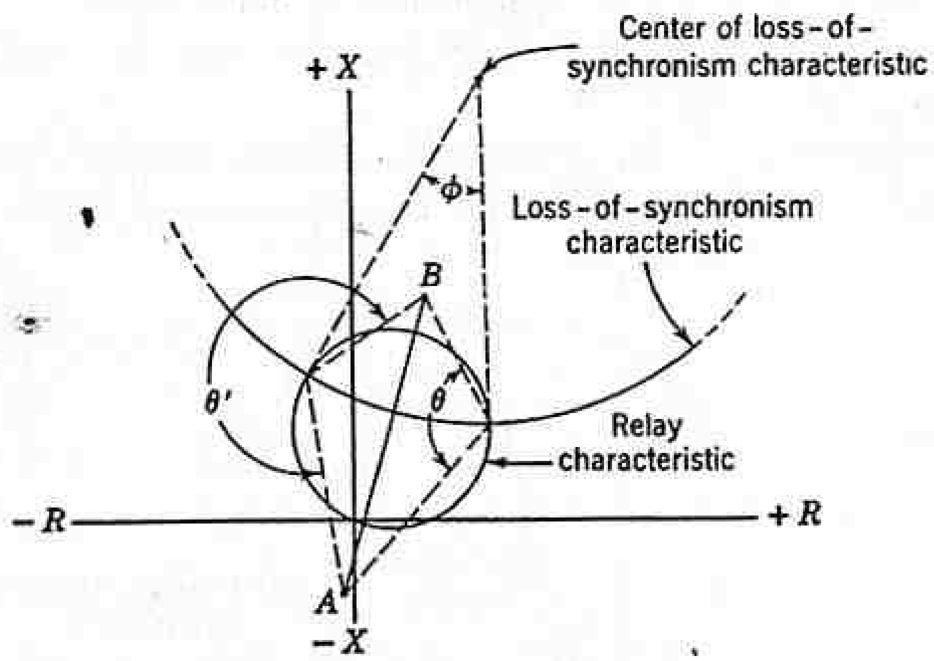

Fig. 18. Determination of relay operating tendency during loss of synchronism.

an operating tendency. Only the back-up-time step of a distance relay is likely to involve enough time delay to avoid such tripping. For a given rate of slip S in cycles per second, one can determine how long the operating tendency will last. In Fig. 18, $(\theta' - \theta)$ gives the angular change of the slipping generator in degrees relative to the other generator. If we assume a constant rate of slip, the time during which an operating tendency will last is $t = (\theta' - \theta)/360S$ seconds. Note that the angular change is not given by the angle ϕ of Fig. 18; once around the loss-of-synchronism circle is one slip cycle, but the rate of movement around the circle is not constant for a constant rate of slip.

The effect of changes in system configuration or generating capacity on the location of the loss-of-synchronism characteristic should be taken into account in determining the operating tendencies of distance relays. Such changes will shift the position of the electrical center with respect to adjoining line sections, and hence may at one time put the electrical center within reach of relays at one location, and at another time put it within reach of relays at another location.

This subject will be treated in more detail when we consider the application of distance relays to transmission-line protection.

Response of Polyphase Directional Relays to Positive- and Negative-Phase-Sequence Volt-Amperes

It has been shown[9] that the torque of polyphase directional relays can be expressed in terms of positive- and negative-phase-sequence volt-amperes. The proof of this fact involves the demonstration that only currents and voltages of the same phase sequence produce net

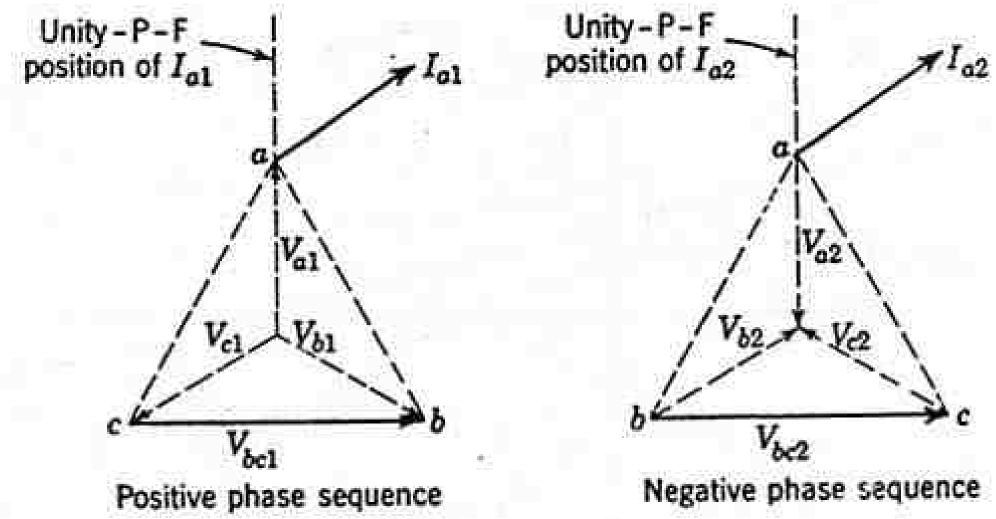

Fig. 19. Corresponding positive- and negative-phase-sequence torque-producing quantities for the quadrature connection.

torque in a polyphase directional relay. Moreover, when delta voltages or delta currents energize a polyphase directional relay, zero-phase-sequence currents produce no net torque because there are no zero-phase-sequence components in the delta quantities.

Making use of the foregoing facts, let us examine briefly the information that can be derived regarding the torques produced by the various conventional connections described in Chapter 3. Consider first the quadrature connection.

Figure 19 shows the corresponding positive- and negative-phase-sequence currents and voltages that produce net torque in one element of a polyphase directional relay; each of the other two elements will produce the same net torque since the positive- and negative-phase-sequence currents and voltages are balanced three phase. Additional torques are produced in each of the three elements by currents and voltages of opposite phase sequence, and these torques are not necessarily equal in each element, but they add to zero in the three elements, and hence can be neglected. (If single-phase directional relays were involved, these additional torques would have to be considered.)

Before proceeding to develop the torque relations, let us note that in Fig. 19 the arrows are on opposite ends of the phase-to-neutral voltages for the two phase sequences. The reason for this is that negative-phase-sequence voltages are voltage drops, whereas positive-phase-sequence voltages are voltage rises minus voltage drops; therefore, if corresponding positive- and negative-phase-sequence currents are in phase, their voltages are 180° out of phase, if we assume positive-, negative-, and zero-phase-sequence impedances to have the same X/R ratio. Another observation is that I_{a2} being shown in phase with I_{a1} has no significance; the important fact is that I_{a2} is assumed to lag the indicated unity-power-factor position by the same angle as I_{a1}. (The justification for this assumption is given later.)

If I_{a1} is β degrees from its maximum-torque position, the total torque is:

$$T \propto (V_{bc1}I_{a1} + V_{bc2}I_{a2}) \cos \beta$$

(Note that the voltage and current values in this and in the following torque equations are positive rms magnitudes, and should not be expressed as complex quantities. Note also that β may be positive or negative because the current may be either leading or lagging its maximum-torque position.) We can simplify the foregoing relation to:

$$T \propto (V_1I_1 + V_2I_2) \cos \beta$$

where the subscripts 1 and 2 denote positive- and negative-phase-sequence components, respectively, of the quantities supplied to the relay.

The vector diagrams for the 60° connection are shown in Fig. 20. The torque relations for Fig. 20 are:

$$T \propto V_1I_1 \cos \beta + V_2I_2 \cos (60° + \beta)$$

Likewise, the torque for the 30° connection is:

$$T \propto V_1I_1 \cos \beta + V_2I_2 \cos (120° + \beta)$$

From the foregoing relations, the difference in response for the various connections depends on the relative magnitude of the negative-phase-sequence voltage-current product to the positive-phase-sequence product. If there are no negative-phase-sequence quantities, the response is the same for any connection. The negative-phase-sequence product can vary from zero to a value equal to the positive-phase-sequence product. Equality of the products occurs for a phase-to-

phase fault at the relay location with no fault resistance. For such a fault, our assumption of the same X/R ratio is most legitimate since we are dealing only with the positive- and negative-phase-sequence networks where this ratio is practically the same. Figure 21 shows the torque components and total torques versus β for this extreme condition where both products are equal. The so-called "zero-degree" connection will be discussed later.

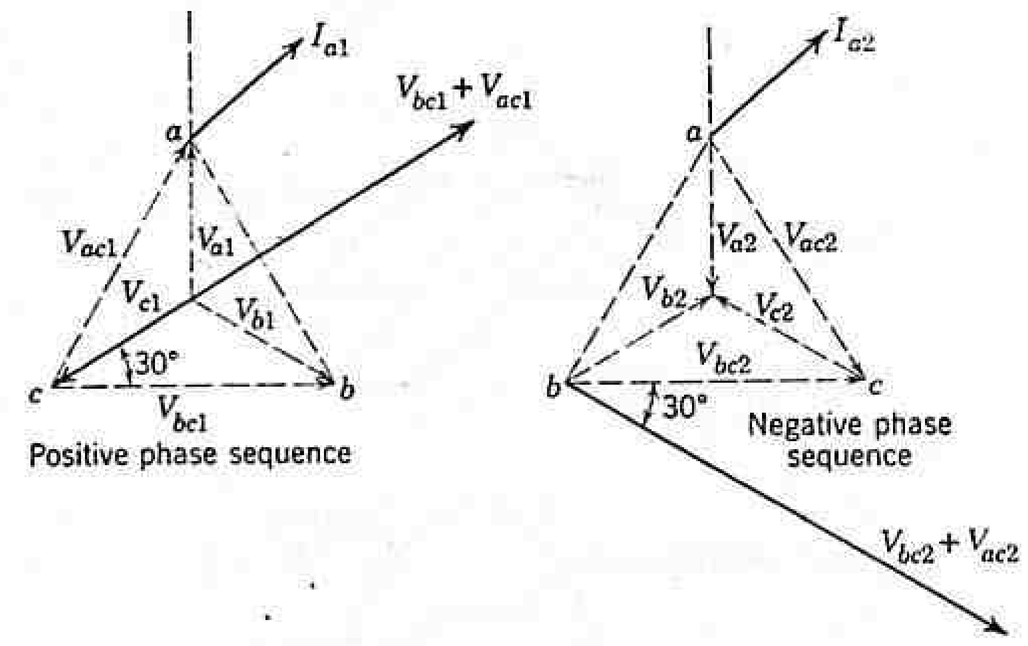

Fig. 20. Corresponding torque-producing quantities for the 60° connection.

For the limiting conditions of Fig. 21, if we assume that we want to develop positive net torque over the largest possible range of β within ±90°, the 90° connection is seen to be the best, and the 30° connection is the poorest. Remember that we may have balanced three-phase conditions alone, for which the torque is simply $V_1I_1 \cos \beta$, or we may have unbalanced conditions for which the total torque will be produced. Therefore, under the limiting conditions of a phase-to-phase fault at the relay location, and with no fault resistance, the three connections will produce positive torque over the total range of β shown in the accompanying table.

Connection	Range of β
Quadrature	180°
60°	150°
30°	120°

The ranges for the 60° and 30° connections will increase and approach 180° as the negative-phase-sequence product becomes smaller and smaller relative to the positive-phase-sequence product, or, in other words, as the fault is farther and farther away from the relay location. The fact that under short-circuit conditions the current does not range over the maximum theoretical angular limits (current limited only by resistance or only by inductive reactance) makes all

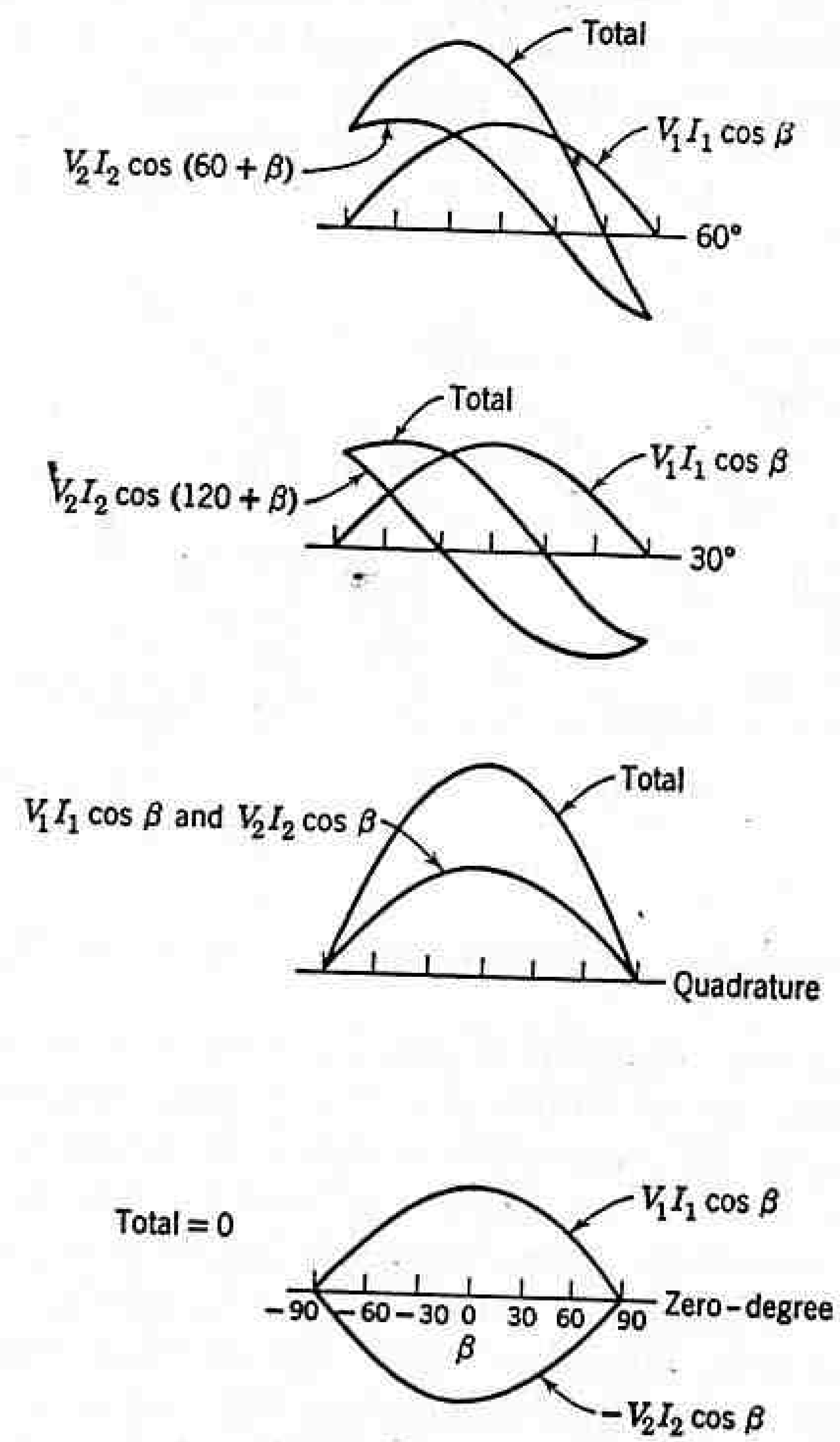

Fig. 21. Component and total torques of polyphase directional relays for conventional connections.

three connections usable, but the quadrature connection provides the largest margin of safety for correct operation. (The possibility that capacity reactance may limit the current is not considered here, but it is an important factor when series capacitors are used in lines.)

The zero-degree connection is that for which the current and voltage supplied to each relay element are in phase under balanced three-phase

unity-power-factor conditions, as, for example, $I_a - I_b$ and V_{ab}. If there are no zero-phase-sequence components present, I_a and V_a could also be used. The equation for the torque produced with this connection is:

$$T \propto V_1 I_1 \cos \beta + V_2 I_2 \cos (180^\circ + \beta)$$

$$\propto (V_1 I_1 - V_2 I_2) \cos \beta$$

The zero-degree connection will produce positive net torque over the same range of β as the quadrature connection, but the magnitude of the net torque over most of the range is less than for the other connections. For the limiting condition assumed for Fig. 21, the net torque is zero. The zero-degree connection is mentioned here to show that, by adding or subtracting the torques of a 90° polyphase relay and a zero-degree polyphase relay, operation can be obtained from either positive- or negative-phase-sequence volt-amperes. However, a most precise balance of the quantities must be effected if the net torque is to be truly representative of the desired quantity.

It follows from the foregoing that the response of a polyphase directional relay will be the same for a given type of fault whether or not there is a wye-delta or delta-wye power transformer between the relay and the fault. Although such a power transformer causes an angular shift in the phase-sequence quantities, the positive-phase-sequence quantities being shifted in one direction and the negative-phase-sequence quantities in the other, the interacting currents and voltages of the same phase sequence are shifted in the same direction and by the same amount. Hence, there is no net effect aside from the current-limiting-impedance effect of the power transformer itself.

Response of Single-Phase Directional Relays to Short Circuits

The impedances seen by single-phase directional relays for different kinds of faults can be constructed by the methods used for distance relays. Reference 10 is an excellent contribution in this respect. Unfortunately the torques of single-phase relays cannot be expressed as simply as for polyphase relays, in terms of positive- and negative-phase-sequence volt-amperes. In other words, simple generalizations cannot be made for single-phase directional relays. It is more fruitful to examine the types of application where misoperation is known to be most likely. This will be done later when we consider the application of directional relays for transmission-line protection.

Phase-Sequence Filters

It is sometimes desirable to operate protective-relaying equipm from a particular phase-sequence component of the three-phase sys currents or voltages. Although the existence of phase-sequence co ponents may be considered a mathematical concept, it is possil nevertheless, to separate out of the three-phase currents or volta actual quantities that are directly proportional to any of the pha sequence components. The clue to the method by which this can done is given by the three following equations from symmetric component theory:

$$I_{a1} = \tfrac{1}{3}(I_a + aI_b + a^2 I_c)$$

$$I_{a2} = \tfrac{1}{3}(I_a + a^2 I_b + aI_c)$$

$$I_{a0} = \tfrac{1}{3}(I_a + I_b + I_c)$$

These equations give the phase-sequence components of the curre in phase a in terms of the actual three-phase currents. Knowi the phase-sequence components for phase a, we can immediately wri down the components for the other two phases. The components voltage are similarly expressed.

A phase-sequence filter does electrically what these three equatio describe graphically. We can quickly dismiss the problem of obtai ing the zero-phase-sequence component because we have already se in Chapter 7 that the current in the neutral of wye-connected CT's 3 times the zero-phase-sequence component. To obtain a quanti proportional to the positive-phase-sequence component of the curre in phase a, we must devise a network that (1) shifts I_b 120° counte clockwise, (2) shifts I_c 240° counterclockwise, and (3) adds I_a ve torially to the vector sum of the other two shifted quantities. I can be similarly obtained except for the amount of shift in I_b and Since we are seeking quantities that are only *proportional* to t actual phase-sequence quantities, we shall not be concerned by chang in magnitude of the shifted quantities so long as all three are co pensated alike for magnitude changes in any of them. We shou remember also that a 120° shift of a quantity in the counterclockwi direction is the same as reversing the quantity and shifting it 6 in the clockwise direction, etc.

Before considering actual networks that have been used for obtaini the various phase-sequence quantities, let us first see some oth relations, derived from those already given, that show some oth manipulations of the actual currents for getting the desired co

nents. The manipulations indicated by these relations are used some filters where a zero-phase-sequence quantity does not exist where it has first been subtracted from the actual quantities (in other words, where $I_a + I_b + I_c = 0$). One combination is:

$$I_{a1} = \frac{1 - a^2}{3}(I_b - I_c) - I_b$$

$$I_{a2} = \frac{1 - a}{3}(I_b - I_c) - I_b$$

Another combination is:

$$I_{a1} = \frac{1 - a^2}{3}(I_a - a^2 I_b)$$

$$I_{a2} = \frac{1 - a}{3}(I_a - aI_b)$$

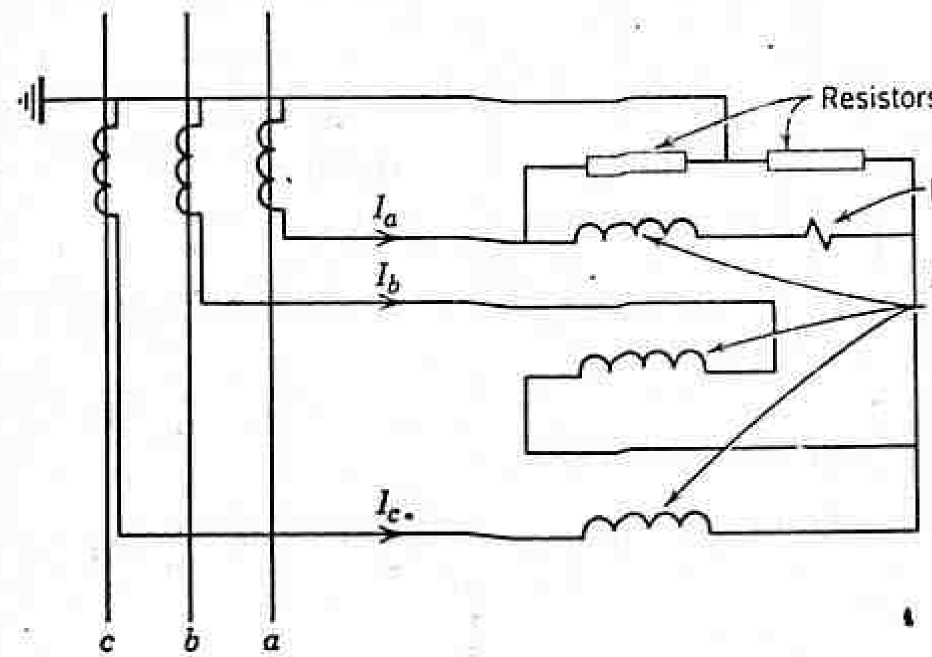

Fig. 22. A positive-phase-sequence-current filter and relay.

Still another combination is:

$$I_{a1} = \frac{a - a^2}{3}(I_b - aI_a)$$

$$I_{a2} = \frac{a^2 - a}{3}(I_b - a^2 I_a)$$

Figure 22 shows a positive-phase-sequence-current filter that has been used;[11] by interchanging the leads in which I_b and I_c flow, the filter becomes a negative-phase-sequence-current filter. A filter that provides a quantity proportional to the negative-phase-sequence component alone, or the negative plus an adjustable proportion of t zero, is shown in Fig. 23;[12] by interchanging the leads in which I_b a I_c flow, the filter becomes a positive-plus-zero-phase-sequence-curre filter.

The references given for the filters of Figs. 22 and 23 contain pro of the capabilities of the filters. The purpose here is not to co sider details of filter design but merely to indicate the techniq involved. Variations on the filters shown are possible. Excellent de scriptions of the many possible types of filters are given in Referenc

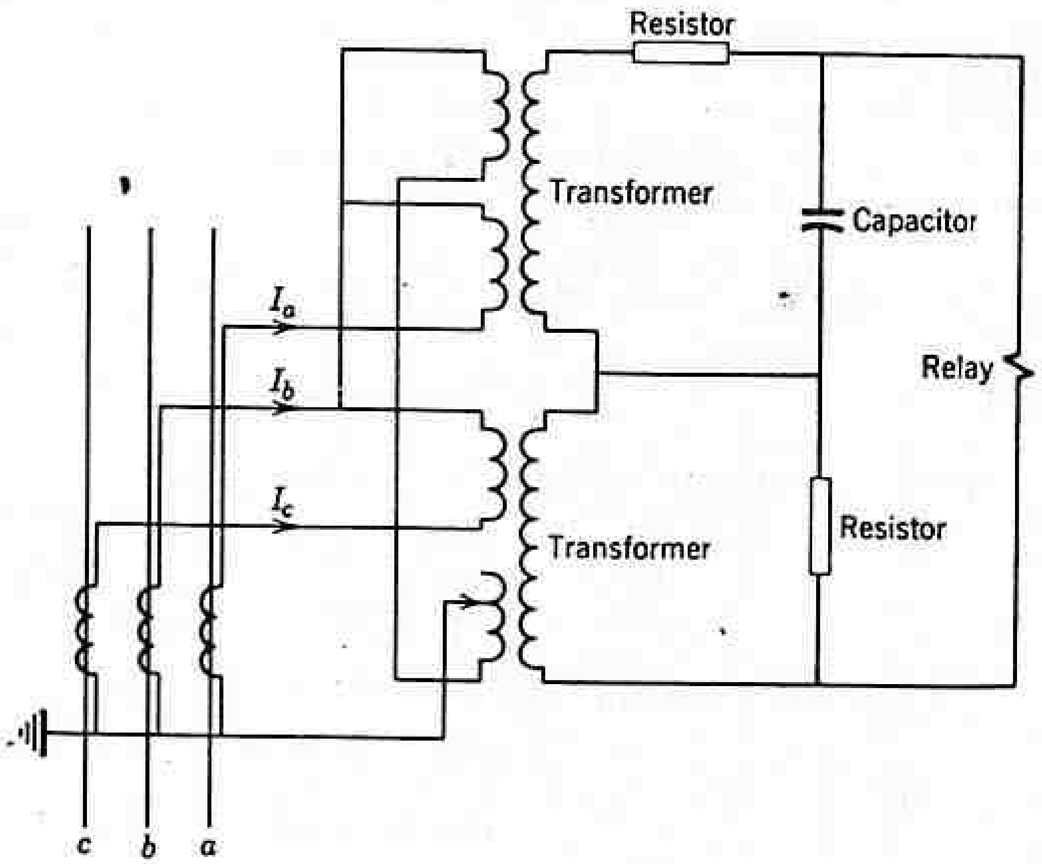

Fig. 23. A combination negative- and zero-phase-sequence-current filter a relay.

1 and 13 of the Bibliography. These books show voltage as well current filters.

A consideration that should be observed in the use of phase-seque filters is the effect of saturation in any of the filter coil elements the segregating ability of the filter. Also, frequency variations a harmonics of the input currents will affect the output.[14] It will appreciated that the actual process of shifting quantities and comb ing them, as indicated by symmetrical-component theory, require high degree of precision if the derived quantity is to be tru representative of the desired quantity.

Problems

1. Given the system shown in Fig. 24, including the transmission-line sections AB and BC, and mho-type phase distance relays for protecting these lines. On an R-X diagram, show quantitatively the characteristics of the three mho units

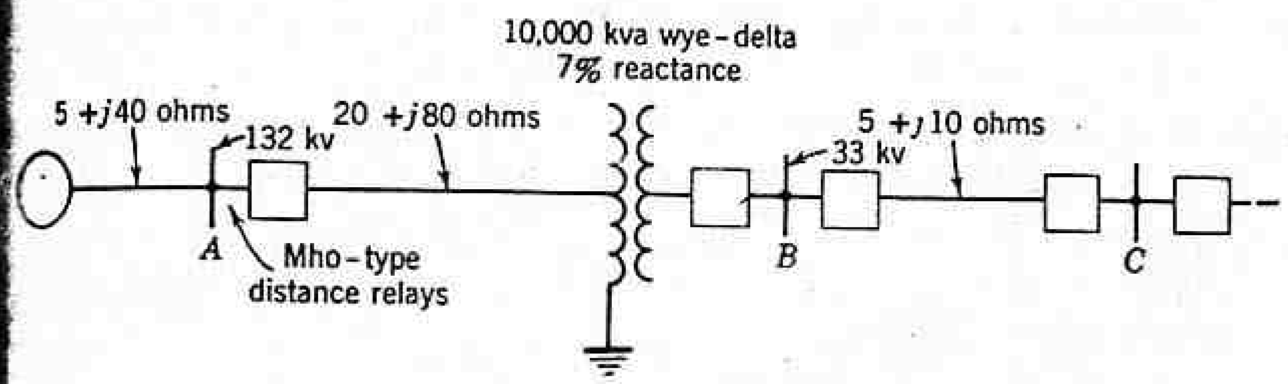

Fig. 24. Illustration for Problem 1.

of each relay for providing primary protection for the line AB and back-up protection for the line BC. Assume that the centers of the mho characteristics are at 60° lag on the R-X diagram.

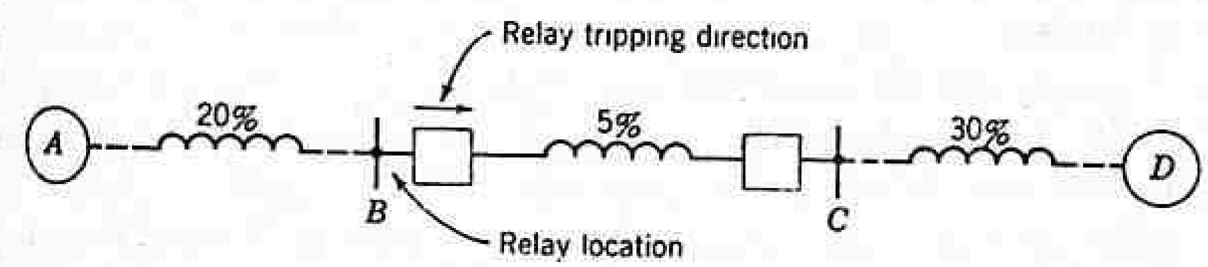

Fig. 25. Illustration for Problem 2.

2. Given a system and a distance relay located as shown in Fig. 25. Assume that the relay is a mho type having distance and time settings as follows:

Zone	Distance Setting	Time Setting
1st	90% of line BC	High speed
2nd	120% of line BC	0.3 sec
3rd	300% of line BC	0.5 sec

Assume also that the centers of the mho circles lie at 60° lag on the R-X diagram. The values on the system diagram are percent impedance on a given kva base. Assume that the X/R ratio of each impedance is tan 60°. As viewed from the relay location, the system is transmitting synchronizing power equal to base kva at base voltage over the line BC toward D at 95% lagging PF, when generator A starts to lose synchronism with generator D by speeding up with respect to D. Assume that the rate of slip is constant at 0.2 slip-cycle per second. Will the relay operate to trip its breaker? Illustrate by showing the relay and the loss-of-synchronism characteristics on an R-X diagram.

3. Given a polyphase directional relay, the three elements of which use the combinations of current and voltage shown on p. 192.

study the response of distance-type relays to various abnormal system conditions. With this diagram, the operating characteristic of any distance relay can be superimposed on the same graph with any system characteristic, making the response of the relay immediately apparent.

A distance relay operates for certain relations between the magnitudes of voltage, current, and the phase angle between them. For any type of system-operating condition, there are certain characteristic relations between the voltage, current, and phase angle at a given distance-relay location in the system. Thus, the procedure is to construct a graph showing the relations between these three quantities (1) as supplied from the system, and (2) as required for relay operation.

PRINCIPLE OF THE R-X DIAGRAM

As described in Chapter 4, the basis of the R-X diagram is the resolution of the three variables—voltage, current, and phase angle—into two variables. This is done by dividing the rms magnitude of voltage by the rms magnitude of current and calling this an im-

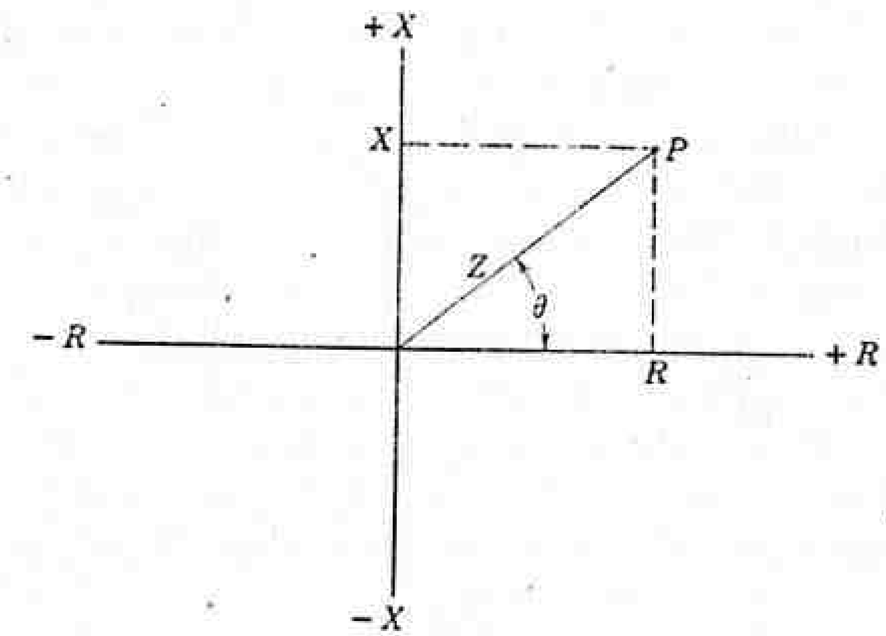

Fig. 1. The R-X diagram.

pedance "Z." (For the moment, let us not be concerned with the significance of this impedance.) Then, the resistance and reactance components of Z are derived, by means of the familiar relations $R = Z\cos\theta$ and $X = Z\sin\theta$. We shall call θ positive when I lags V, assuming certain relay connections and references. These values of R and X are the coordinates of a point on the R-X diagram representing a given combination of V, I, and θ. R and X may be positive or negative, but Z must always be positive; any negative values of Z obtained by substituting certain values of θ in an equation should be ignored since they have no significance.

Figure 1 shows the R-X diagram and a point P representing fixed values of V, I, and θ, when I is assumed to lag V by an angle less than 90°. A straight line drawn from the origin to P represents Z, and θ is the angle measured counterclockwise from the $+R$ axis to Z.

It is probably obvious that P can be located from a knowledge of Z and θ without deriving the R and X components. Or, by calculating the complex ratio of V to I, the values of R and X can be obtained immediately without consideration of θ. If V, I, and θ vary, several points can be plotted, and a curve can be drawn through these points to represent the characteristic.

CONVENTIONS FOR SUPERIMPOSING RELAY AND SYSTEM CHARACTERISTICS

In order to superimpose the plot of a relay characteristic on the plot of a system characteristic to determine relay operation, both plots must be on the same basis. A given relay operates in response to voltage and current obtained from certain phases.[3] Therefore, the system characteristic must be plotted in terms of these same phase quantities as they exist at the relay location. Also, the coordinates must be in the same units. The per unit or percent system is generally employed for this purpose. If actual ohms are used, both the power-system and the relay characteristics must be on either a primary or a secondary basis, taking into account the current- and voltage-transformation ratios, as follows:

$$\text{Secondary ohms} = \text{Primary ohms} \times \frac{\text{CT ratio}}{\text{VT ratio}}$$

Finally, both coordinates must have the same scale, because certain characteristics are circular if the scales are the same.

It is necessary to establish a convention for relating a relay characteristic to a system characteristic on the R-X diagram. The convention must satisfy the requirement that, for a system condition requiring relay operation, the system characteristic must lie in the operating region of the relay characteristic. The convention is to make the signs of R and X positive when power and lagging reactive power flow in the tripping direction of the distance relays under balanced three-phase conditions. Lagging reactive power is here considered to flow in a certain direction when current flows in that direction as though into a load whose reactance is predominantly inductive. It is the practice to assume "delta" (defined later) currents and voltages as the basis for plotting both system and relay characteristics when phase distance relays are involved, or phase current and the corresponding phase-to-ground voltage (called "wye" quanti-

Element No.	I	V
1	$I_a - I_b$	$V_{bc} - V_{ac}$
2	$I_b - I_c$	$V_{ca} - V_{ba}$
3	$I_c - I_a$	$V_{ab} - V_{cb}$

Write the torque equations in terms of the positive- and negative-phase-sequ volt-amperes. What do you think of this as a possible connection for such rela

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ties) when ground distance relays are involved. In either case, three relays are involved, each receiving current and voltage from different phases. Either the delta or the wye voltage-and-current combination will give the same point on the R-X diagram under balanced three-phase conditions.

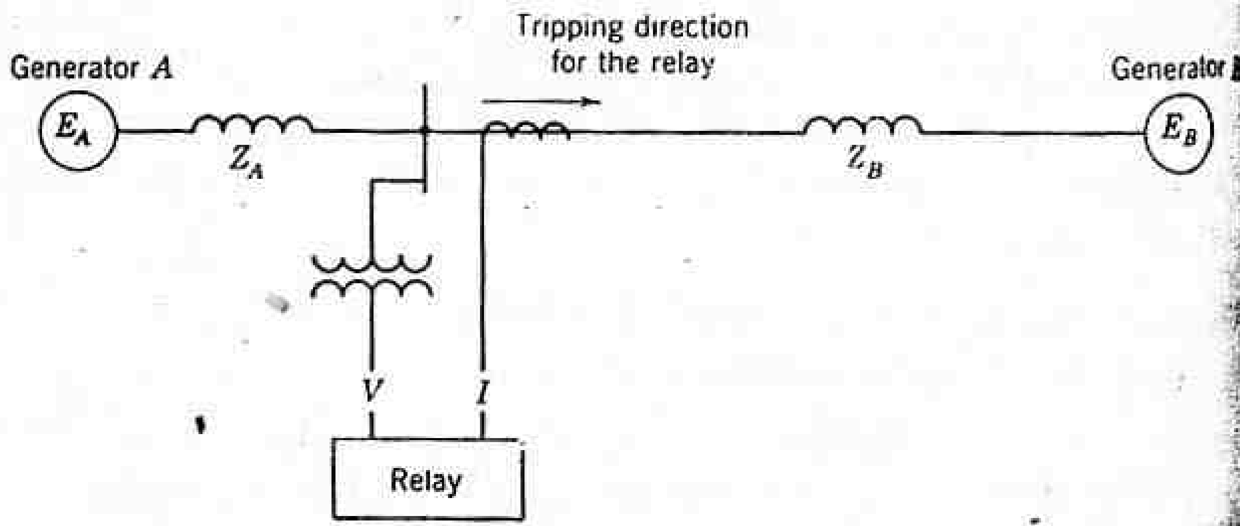

Fig. 2. Illustration for the convention for relating relay and system characteristics on the R-X diagram.

To illustrate this convention, refer to Fig. 2 where a distance relay is shown to be energized by voltage and current at a given location in a system. The coordinates of the impedance point on the R-X diagram representing a balanced three-phase system condition as viewed in the tripping direction of the relay will have the signs shown in Table 1. Leading reactive power is here considered to flow in a certain direction when current flows in that direction as though into a load whose reactance is predominantly capacitive.

Table 1. Conventional Signs of R and X

Condition	Sign of R	Sign of X
Power from A toward B	+	
Power from B toward A	−	
Lagging reactive power from A toward B		+
Lagging reactive power from B toward A		−
Leading reactive power from A toward B		−
Leading reactive power from B toward A		+

The following relations give the numerical values of R and X for any balanced three-phase condition:

$$R = \frac{V^2W}{W^2 + RVA^2}$$

$$X = \frac{V^2RVA}{W^2 + RVA^2}$$

where V is the phase-to-phase voltage, W is the three-phase power, and RVA is the three-phase reactive power. R and X are components of the positive-phase-sequence impedance which could be obtained under balanced three-phase conditions by dividing any phase-to-neutral voltage by the corresponding phase current. All the quantities in the formulae must be expressed in actual values (i.e., ohms, volts, watts, and reactive volt-amperes), or all in percent or per unit.

By applying the proper signs to R and X, one can locate the point on the R-X diagram representing the impedance for any balanced three-phase system condition. For example, the point P of Fig. 1 would represent a condition where power and lagging reactive power were being supplied from A toward B in the tripping direction of the relay. For a relay in the system of Fig. 2 whose tripping direction is opposite to that shown, interchange A and B in the designation of the generators of Fig. 2 and in Table 1; in other words, follow the rule already given that the signs of R and X are positive when power and lagging reactive power flow in the tripping direction of the relay. For example, if the point P of Fig. 1 represents a given condition of power and reactive power flow as it appears to the relay of Fig. 2, then to a relay with opposite tripping direction the same condition appears as a point diametrically opposite to P on Fig. 1. Occasionally, it may be desired to show on the same diagram the characteristics of relays facing in opposite directions. Then the rule cannot be followed, and care must be taken to avoid confusion.

Because it is customary to think of impedance in terms of combinations of resistance and reactance of circuit elements, one may wonder what significance the Z of an R-X diagram has. By referring to Fig. 2, it can easily be shown that the ratio of V to I is as follows:

$$\frac{V}{I} = Z = \frac{E_AZ_B + E_BZ_A}{E_A - E_B}$$

where all quantities are complex numbers, and where E_A and E_B are the generated voltages of generators A and B, respectively. Therefore, in general, Z is not directly related to any actual impedance of the system. From this general equation, system characteristics can be developed for loss of synchronism between the generators or for loss of excitation in either generator.

For normal load, loss of synchronism, loss of excitation, and three-phase faults—all balanced three-phase conditions—a system characteristic has the same appearance to each of the three dista relays that are energized from different phases. For unbalan short circuits, the characteristic has a different appearance to ea of the three relays, as we shall see shortly.

Other conventions involved in the use of the R-X diagram will described as it becomes necessary.

By using distance-type relay units individually or in combinati any region of the R-X diagram can be encompassed or set apart fr another region by one or more relay characteristics. With the kno edge of the region in which any system characteristic will lie through which it will progress, one can place distance-relay cha acteristics in such a way that a desired kind of relay operation w be obtained only for a particular system characteristic.

Short Circuits

For general studies, it is the practice to think of a power syst in terms of a two-generator equivalent, as in Fig. 3. The generat voltages of the two generators are assumed to be equal and in pha The equivalent impedances to the left of the relay location and

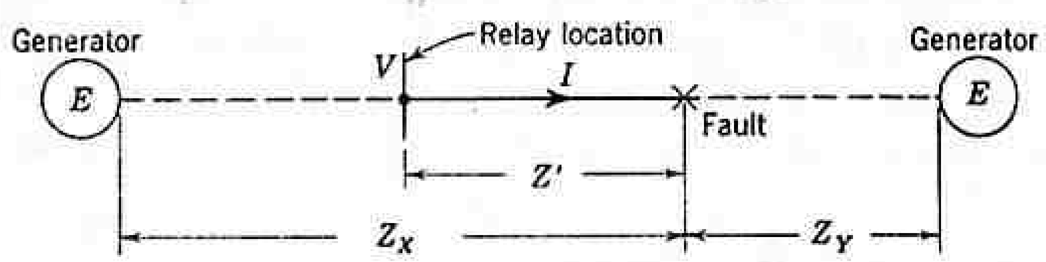

Fig. 3. Equivalent-system diagram for defining relay quantities during fau

the right of the short circuit are those that will limit the magnitud of the short-circuit currents to the actual known values. The sho circuit is assumed to lie in the tripping direction of the relay.

The possible effect of mutual induction from a circuit paralleli the portion of the system between the relay and the fault will neglected. Also, load and charging current will be neglected; ho ever, they may not be negligible if the fault current is very low.

Nomenclature to identify specific values or combinations of t quantities indicated on Fig. 3 will be as follows:

Z = System impedance viewed both ways from the fault = $\dfrac{Z_X Z_Y}{Z_X + Z_Y}$

C = Ratio of the relay current I to the total current in the fault $\dfrac{Z_Y}{Z_X + Z_Y}$

Subscripts a, b, and c denote phases a, b, and c, respectively. Throughout this book, positive phase sequence is assumed to be a-b-c. Subscripts 1, 2, and 0 denote positive, negative, and zero phase sequence, respectively.

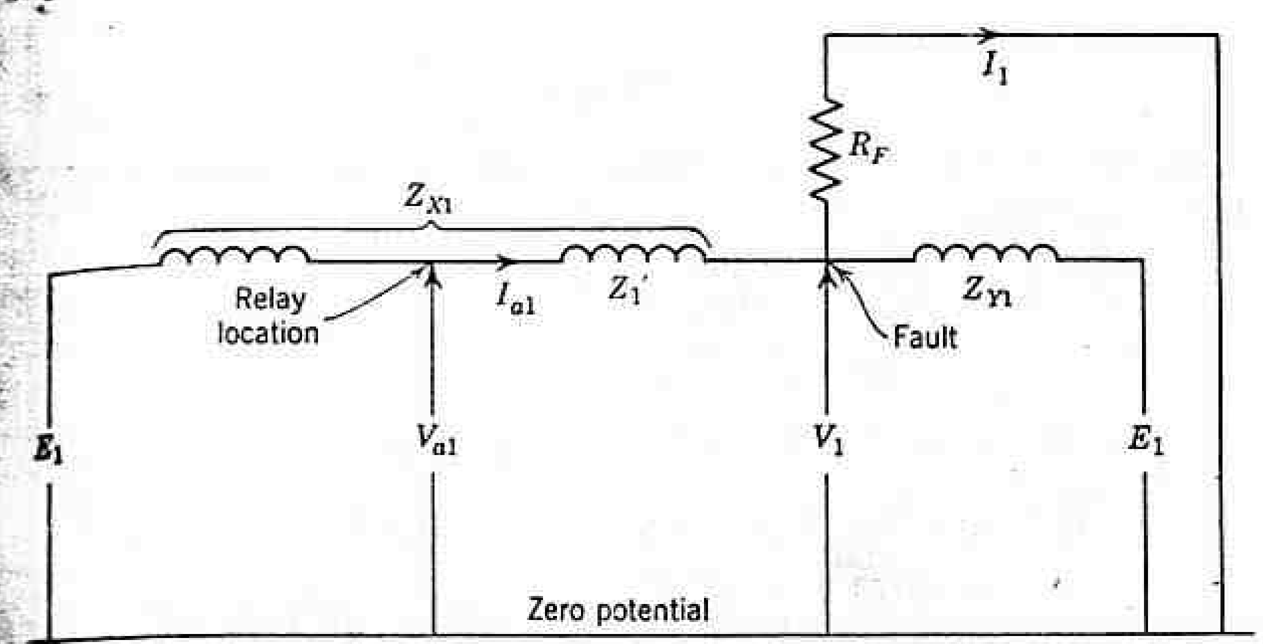

Fig. 4. Positive-phase-sequence network for a three-phase fault.

THREE-PHASE SHORT CIRCUITS

For a three-phase fault, the positive-phase-sequence network is as shown in Fig. 4 for the quantities of phase a. Whenever the term "three-phase" fault is used, it will be assumed that the fault is balanced, i.e., that only positive-phase-sequence quantities are involved. The quantity R_F is the resistance in the short circuit, assumed to be from phase to neutral of each phase.

By inspection, we can write:

$$I_1 = \frac{E_1}{Z_1 + R_F}$$

$$I_{a1} = \frac{Z_{Y1} I_1}{Z_{Y1} + Z_{X1}} = C_1 I_1 = \frac{C_1 E_1}{Z_1 + R_F}$$

$$V_1 = I_1 R_F = \frac{E_1 R_F}{Z_1 + R_F}$$

$$V_{a1} = V_1 + I_{a1} Z_1' = \frac{E_1 R_F}{Z_1 + R_F} + \frac{C_1 E_1 Z_1'}{Z_1 + R_F}$$

Let

$$\frac{E_1}{Z_1 + R_F} = \frac{1}{K}$$

Then

$$K I_{a1} = C_1$$

$$K V_{a1} = R_F + C_1 Z_1'$$

Since there are no negative- or zero-phase-sequence quantities for three-phase fault, we can write:

$$KI_{a2} = 0$$
$$KI_{a0} = 0$$
$$KV_{a2} = 0$$
$$KV_{a0} = 0$$

Therefore, the actual phase currents and phase-to-neutral voltages at the relay location are:

$$KI_a = KI_{a1} + KI_{a2} + KI_{a0} = C_1$$
$$KI_b = a^2KI_{a1} + aKI_{a2} + KI_{a0} = a^2C_1$$
$$KI_c = aKI_{a1} + a^2KI_{a2} + KI_{a0} = aC_1$$
$$KV_a = KV_{a1} + KV_{a2} + KV_{a0} = R_F + C_1Z_1'$$
$$KV_b = a^2KV_{a1} + aKV_{a2} + KV_{a0} = a^2(R_F + C_1Z_1')$$
$$KV_c = aKV_{a1} + a^2KV_{a2} + KV_{a0} = a(R_F + C_1Z_1')$$

If delta-connected CT's are involved,

$$K(I_a - I_b) = (1 - a^2)C_1$$
$$K(I_b - I_c) = (a^2 - a)C_1$$
$$K(I_c - I_a) = (a - 1)C_1$$

The phase-to-phase voltages are:

$$KV_{ab} = K(V_a - V_b) = (1 - a^2)(R_F + C_1Z_1')$$
$$KV_{bc} = K(V_b - V_c) = (a^2 - a)(R_F + C_1Z_1')$$
$$KV_{ca} = K(V_c - V_a) = (a - 1)(R_F + C_1Z_1')$$

PHASE-TO-PHASE SHORT CIRCUITS

Figure 5 shows the phase a phase-sequence networks for a phase-b-to-phase-c fault. By inspection, we can write:

$$I_1 = \frac{E_1}{Z_1 + Z_2 + R_F} = \frac{E_1}{2Z_1 + R_F}$$

(assuming $Z_2 = Z_1$). We shall let $E_1/(2Z_1 + R_F) = 1/K$ for the same reason as for the three-phase short-circuit calculations, realizing that the values of K are not the same in both cases. It should also be realized that the values of R_F will probably be different in both cases.

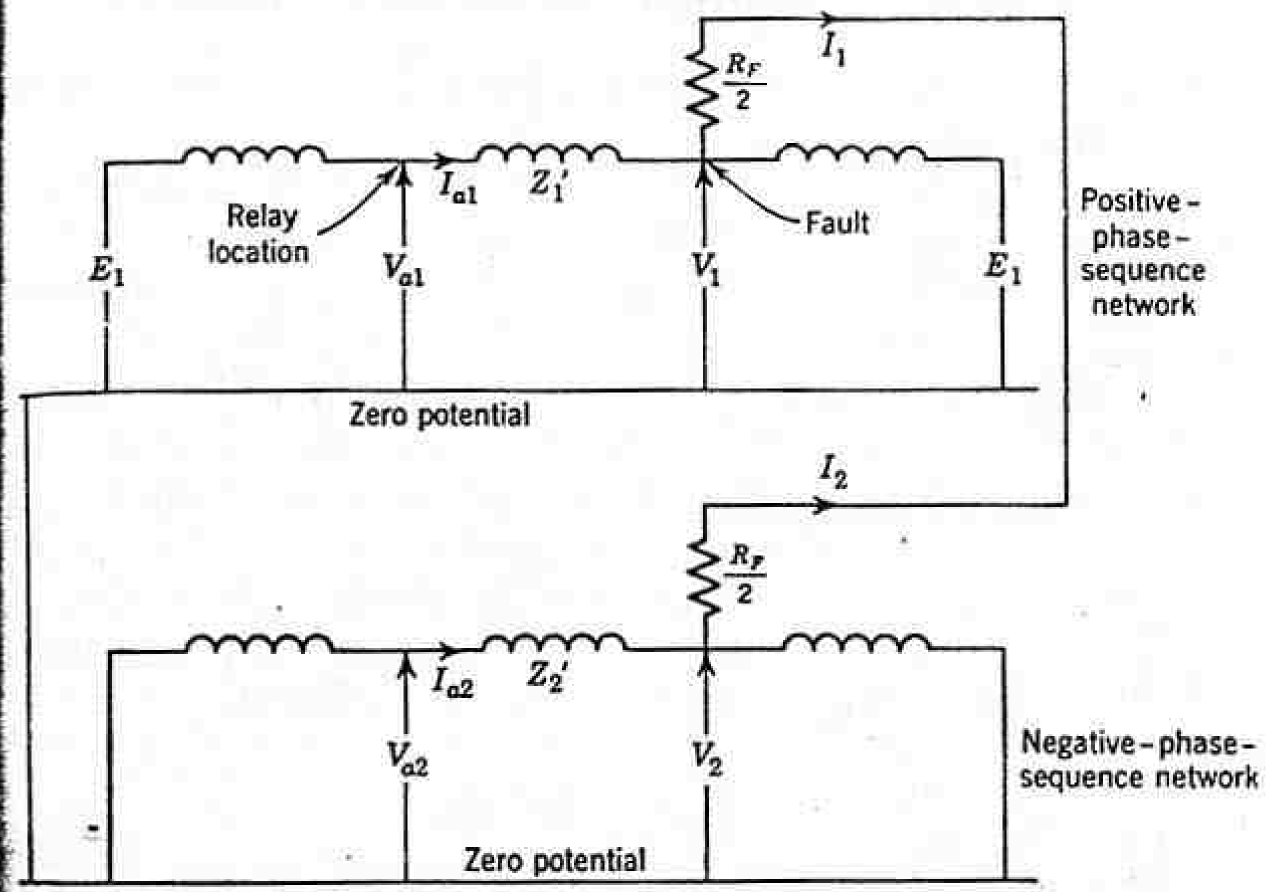

Fig. 5. Phase a phase-sequence networks for a phase-b-to-phase-c fault.

Here, R_F is the resistance between the faulted phases. Figure 5 shows $R_F/2$ in series with each network, in order to be consistent with certain references for this chapter (1,2,5). This is simply a caution not to attach too much significance to apparent differences in the R_F term. Continuing, we can write:

$$V_1 = (I_1 - I_2)\frac{R_F}{2} - I_2Z_2$$
$$= I_1R_F + I_1Z_1 \quad \text{since} \quad I_2 = -I_1 \text{ and } Z_2 = Z_1 \text{ (assumed)}$$
$$V_{a1} = V_1 + I_{a1}Z_1'$$
$$= I_1(R_F + Z_1 + C_1Z_1') \quad \text{since} \quad I_{a1} = C_1I_1 \text{ by definition}$$
$$= \frac{1}{K}(R_F + Z_1 + C_1Z_1')$$
$$KV_{a1} = R_F + Z_1 + C_1Z_1'$$
$$V_2 = -I_2Z_2 = I_1Z_1$$
$$V_{a2} = V_2 + I_{a2}Z_2'$$

But $Z_2' = Z_1'$ for transmission lines, and $I_{a2} = C_2I_2$ by definition, and hence:

$$V_{a2} = I_1Z_1 + C_2I_2Z_1'$$

We shall further assume that $C_2I_2 = -C_1I_1$, and hence:

$$V_{a2} = I_1Z_1 - C_1I_1Z_1'$$
$$= I_1(Z_1 - C_1Z_1')$$
$$KV_{a2} = Z_1 - C_1Z_1'$$

By definition, $I_{a1} = C_1I_1$,

$$KI_{a1} = C_1$$

Since $I_{a2} = -I_{a1}$,

$$KI_{a2} = -KI_{a1} = -C_1$$

Since there are no zero-phase-sequence quantities,

$$KV_{a0} = 0$$
$$KI_{a0} = 0$$

We could continue, as for the three-phase fault, and write the actu currents and voltages at the relay location, but the technique is th same as before. The final values are given in Tables 2 and 3. Als

Table 2. Currents during Faults

Quantity at Relay Location	Value of Quantity for Various Types of Fault: Three-Phase	Phase b to Phase c	Phase a to Grou
KI_{a1}	C_1	C_1	C_1
KI_{a2}	0	$-C_1$	C_1
KI_{a0}	0	0	C_0
KI_a	C_1	0	$C_0 + 2C_1$
KI_b	a^2C_1	$(a^2 - a)C_1$	$C_0 - C_1$
KI_c	aC_1	$-(a^2 - a)C_1$	$C_0 - C_1$
$K(I_a - I_b)$	$(1 - a^2)C_1$	$-(a^2 - a)C_1$	$3C_1$
$K(I_b - I_c)$	$(a^2 - a)C_1$	$2(a^2 - a)C_1$	0
$K(I_c - I_a)$	$(a - 1)C_1$	$-(a^2 - a)C_1$	$-3C_1$
$K(I_a + I_b + I_c)$	0	0	$3C_0$
K	$\frac{Z_1 + R_F}{E_1}$	$\frac{2Z_1 + R_F}{E_1}$	$\frac{2Z_1 + Z_0 + 3R_F}{E_1}$

the calculations for a phase-a-to-ground fault will be omitted, but th values are given in the tables. The tables do not include the valu for a phase-b-to-phase-c-to-ground fault because they are too com plicated, and are not very significant. The purpose here is n to present all the data, but to show the technique involved in de termining it, and it is felt that in this respect enough data will hav been given. Complete data will be found in two different AIE papers.[4,5]

Table 3. Voltages during Faults

Quantity at Relay Location	Value of Quantity for Various Types of Fault: Three-Phase	Phase b to Phase c	Phase a to Ground
KV_{a1}	$C_1Z_1'+R_F$	$C_1Z_1'+Z_1+R_F$	$C_1Z_1'+Z_1+Z_0+3R_F$
KV_{a2}	0	$Z_1-C_1Z_1'$	$C_1Z_1'-Z_1$
KV_{a0}	0	0	$C_0Z_0'-Z_0$
KV_a	$C_1Z_1'+R_F$	$2Z_1+R_F$	$2C_1Z_1'+C_0Z_0'+3R_F$
KV_b	$a^2(C_1Z_1'+R_F)$	$(a^2-a)C_1Z_1'-Z_1+a^2R_F$	$-C_1Z_1'+(a^2-a)Z_1+(a^2-1)Z_0+C_0Z_0'+3a^2R_F$
KV_c	$a(C_1Z_1'+R_F)$	$(a-a^2)C_1Z_1'-Z_1+aR_F$	$-C_1Z_1'+(a-a^2)Z_1+(a-1)Z_0+C_0Z_0'+3aR_F$
$K(V_a-V_b)$	$(1-a^2)(C_1Z_1'+R_F)$	$(a-a^2)C_1Z_1'+3Z_1+(1-a^2)R_F$	$3C_1Z_1'-(a^2-a)Z_1-(a^2-1)(Z_0+3R_F)$
$K(V_b-V_c)$	$(a^2-a)(C_1Z_1'+R_F)$	$2(a^2-a)C_1Z_1'+(a^2-a)R_F$	$2(a^2-a)Z_1+(a^2-a)(Z_0+3R_F)$
$K(V_c-V_a)$	$(a-1)(C_1Z_1'+R_F)$	$(a-a^2)C_1Z_1'-3Z_1+(a-1)R_F$	$-3C_1Z_1'+(a-a^2)Z_1+(a-1)(Z_0+3R_F)$
$K(V_a+V_b+V_c)$	0	0	$3(C_0Z_0'-Z_0)$
K	$\frac{Z_1+R_F}{E_1}$	$\frac{2Z_1+R_F}{E_1}$	$\frac{2Z_1+Z_0+3R_F}{E_1}$

DISCUSSION OF ASSUMPTIONS

The error in assuming the positive- and negative-phase-seque impedances to be equal depends on the operating speed of the re involved and on the location of the fault and relay relative t generator. All the error is in the assumed generator impedan Whereas the negative-phase-sequence reactance of a generator is c stant, the positive-phase-sequence reactance will grow larger f subtransient to synchronous within a very short time after a fa occurs. However, unless the fault is at the terminals of a generat the constant impedance of transformers and lines between a genera and the fault will tend to lessen the effect of changes in the generat positive-phase-sequence reactance.

The assumption that positive- and negative-phase-sequence i pedances are equal is sufficiently accurate for analyzing the respo of high-speed distance-type relay units. For the short time tha takes a high-speed relay to operate after a fault has occurred, equivalent positive-phase-sequence reactance of a generator is ne enough equal to the negative-phase-sequence reactance so that th is negligible over-all error in assuming them to be equal. Actua it is usually the practice to use the rated-voltage direct-axis transi reactance for both.

When time-delay distance-type units are involved, such as back-up relaying, the assumption of equal positive- and negati phase-sequence impedances could produce significant errors. T is especially true for a fault near a generator and with the re located between the generator and the fault, in which event relay's operation would be largely dependent on the generator ch acteristics alone. On the other hand, the "reach" of a back-up re does not have to be as precise as that of high-speed primary relay which permits more error in its adjustment. Suffice it to say t this possibility of error, even with time-delay relays, is gener ignored for distance relaying except in very special cases.

Actually, this consideration of the possible error resulting f assuming equal positive- and negative-phase-sequence impeda is somewhat academic where distance relays are involved. Whate error there may be will generally affect the response of only th relays on whose operation we do not ordinarily rely anyway. exception to this is for faults on the other side of a wye-delta delta-wye transformer, which we shall consider later.

Neglecting the effect of mutual induction, where mutual induc exists, would noticeably affect the response of only ground rel

t is the practice to ignore mutual induction when dealing with phase elays. The effect of mutual induction on the response of ground istance relays may have to be considered; this is treated in detail Reference 3.

ETERMINATION OF DISTANCE-RELAY OPERATION FROM HE DATA OF TABLES 2 AND 3

Modern distance relays are single-phase types. The three relays sed for phase-fault protection are supplied with the following ombinations of current and voltage:

Current	Voltage
$I_a - I_b$	$V_{ab} = V_a - V_b$
$I_b - I_c$	$V_{bc} = V_b - V_c$
$I_c - I_a$	$V_{ca} = V_c - V_a$

hese quantities are often called "delta currents" and "delta voltages." ach relay is intended to provide protection for faults involving the hases between which its voltage is obtained.

It was shown in Chapter 4 that all distance relays operate according o some function of the ratio of the voltage to the current supplied o the relay. We are now able to determine what the ratio of these uantities is for each phase relay for any type of fault, by using the ata of Tables 2 and 3. These ratios are given in Table 4.

Table 4. Impedances "Seen" by Phase Distance Relays for Various Kinds of Short Circuits

	Value of Ratio for Various Types of Fault		
Ratio	3-Phase	Phase b to Phase c	Phase a to Ground
$\frac{K(V_a - V_b)}{K(I_a - I_b)}$	$Z_1' + \frac{R_F}{C_1}$	$Z_1' - j\sqrt{3}\,Z_{X1} - \frac{a}{C_1} R_F$	$Z_1' + j\frac{\sqrt{3}}{3} Z_{X1} + \frac{(1 - a^2)(Z_0 + 3R_F)}{3C_1}$
$\frac{K(V_b - V_c)}{K(I_b - I_c)}$	$Z_1' + \frac{R_F}{C_1}$	$Z_1' + \frac{R_F}{2C_1}$	∞
$\frac{K(V_c - V_a)}{K(I_c - I_a)}$	$Z_1' + \frac{R_F}{C_1}$	$Z_1' + j\sqrt{3}\,Z_{X1} - \frac{a^2}{C_1} R_F$	$Z_1' - j\frac{\sqrt{3}}{3} Z_{X1} - \frac{(a - 1)(Z_0 + 3R_F)}{3C_1}$

For a three-phase fault, all three relays "see" the positive-phase-equence impedance of the circuit between the relays and the fault, lus a multiple of the arc resistance. This multiple depends on the fraction of the total fault current that flows at the relay location and is larger for smaller fractions.

For a phase-to-phase fault at a given location, the relay energized by the voltage between the faulted phases sees the same impedance as for three-phase faults at that location, except, possibly, for differences in the R_F term. As already noted, the value of R_F may be different for the two types of fault. The subject of fault resistance will be treated later in more detail when we consider the application of distance relays. The other two relays see other impedances.

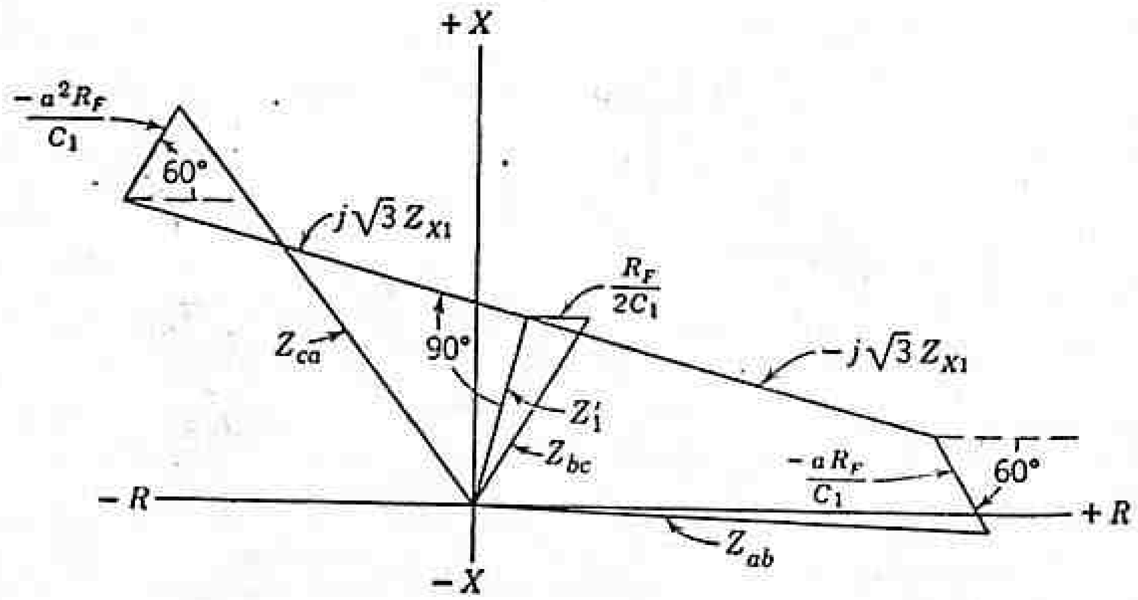

Fig. 6. Impedances seen by each of the three phase distance relays for a phase-b-to-phase-c fault.

These values of impedance seen by the three relays can be shown on an R-X diagram, as in Fig. 6. The terms Z_{bc}, Z_{ab}, and Z_{ca} identify the impedances seen by the relays obtaining voltage between phases bc, ab, and ca, respectively. If we were to follow rigorously the conventions already described for the R-X diagram, we should draw three separate diagrams, one each for the constructions for obtaining Z_{bc}, Z_{ab}, and Z_{ca}. This is because each one involves the ratio of different quantities. However, since the relay characteristics would be the same on all three diagrams, it is more convenient to put all impedance characteristics on the same diagram, and also it reveals certain interesting interrelations, as we shall see shortly.

For phase-b-to-phase-c faults, with or without arcs, and located anywhere on a line section from the relay location out to a certain distance, the heads of the three impedance radius vectors will lie on or within the boundaries of the shaded areas of Fig. 7. These areas would be generated if we were to let Z_1' and R_F of Fig. 6 increase from zero to the value shown.

To use the data shown by Fig. 7, it is only necessary to superimpose the characteristic of any distance relay using one of the combinations of delta current and voltage in order to determine its operating tendencies. This has been done on Fig. 7 for an impedance-type distance relay adjusted to operate for all faults having any impedance within the shaded area Z_{bc}. Had we shown the three fault areas Z_{ab}, Z_{bc}, and Z_{ca} on three different R-X diagrams, the relay characteristic would still have looked the same on all three

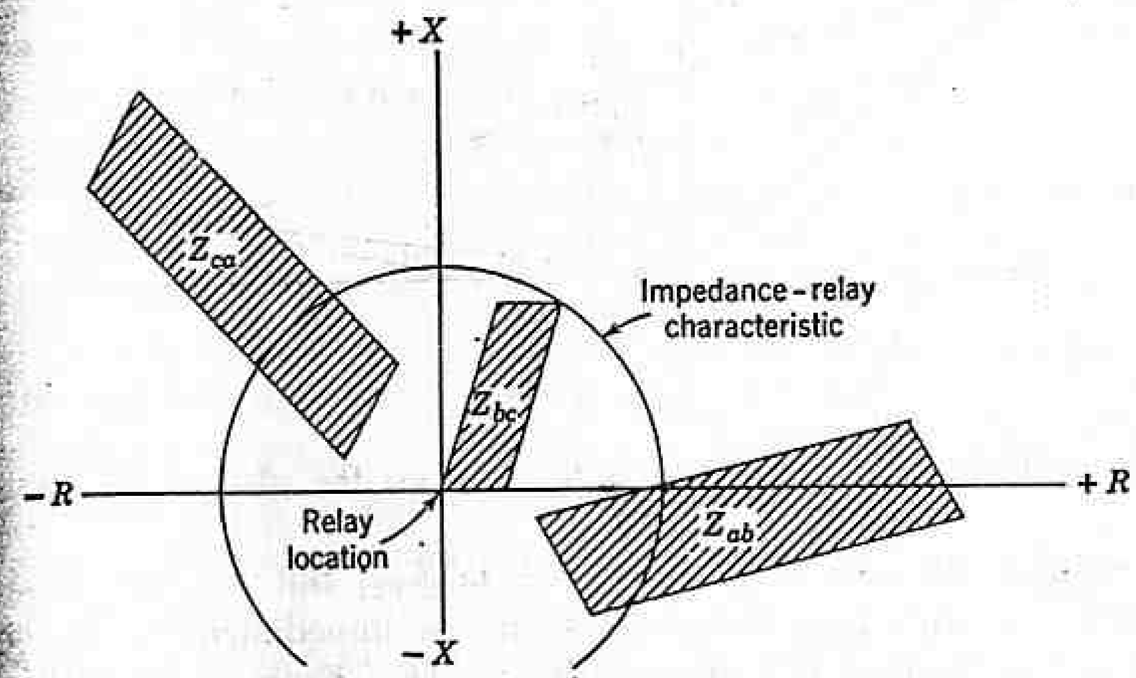

Fig. 7. Impedance areas seen by the three phase distance relays for various locations of a phase-b-to-phase-c fault with and without an arc.

diagrams since the practice is to adjust all three relays alike. Therefore, the relay characteristic of Fig. 7 may be thought of as that of any one of the three relays. For any portion of shaded area lying inside the relay characteristic, it is thereby indicated that for certain locations of the phase-b-to-phase-c fault, the relay represented by that area will operate.

For the adjustment of Fig. 7, all three relays will operate for nearby faults, represented by certain values of Z_{ca} and Z_{ab}, where the shaded areas fall within the operating characteristic of the impedance relay. Such operation is not objectionable, but the target indications might lead one to conclude that the fault was three-phase instead of phase-to-phase.

We may generalize the picture of Fig. 7, and think of the Z_{bc} area as representing the appearance of a phase-to-phase fault to the distance relay that is supposed to operate for that fault. Then, the Z_{ca} area shows the appearance of the fault to the relay using the voltage lagging the faulted phase voltage (sometimes called the "lagging" relay); and the Z_{ab} area shows the appearance of the fault to th relay using the voltage leading the faulted phase voltage (sometim called the "leading" relay).

We can construct the diagram of Fig. 6 graphically, as in Fig. neglecting the effect of arc resistance. Draw the line OF equal to Z of Fig. 6. Extend OF to A, making FA equal to Z_{X1}, the positiv phase-sequence impedance from the fault to the end of the system ba

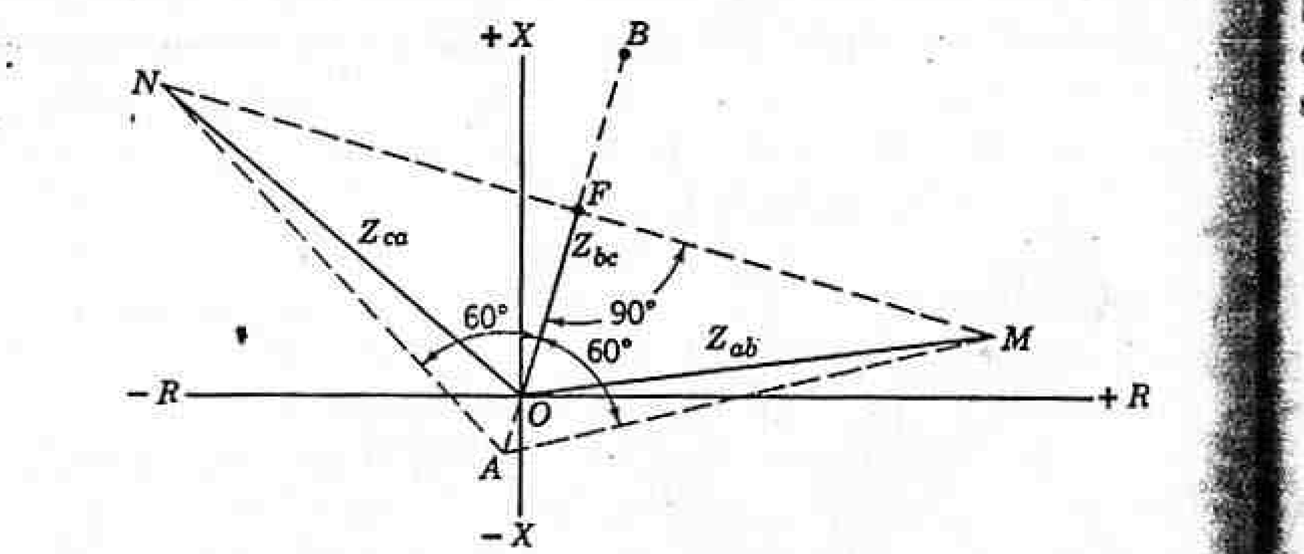

Fig. 8. Graphical construction of Fig. 6, neglecting the effect of arc resista

of the relay location. Actually, FA is Z_{X2}, but we are assumi the positive- and negative-phase-sequence impedances to be equ Draw a line through F perpendicular to AF. From A, draw lines 60° to AF until they intersect the perpendicular to AF at M and Then:

$$OF = Z_{bc}$$

$$OM = Z_{ab}$$

$$ON = Z_{ca}$$

The proof that this construction is valid is that the tangent of the an FAM is equal to:

$$\frac{\sqrt{3}\,Z_{X1}}{Z_{X1}} = \sqrt{3}$$

which is the tangent of 60°. The construction for showing the eff of fault resistance can be added to Fig. 8 by the method used Fig. 6.

It should be noted that the line segments FO and OA would lie on the same straight line as in Fig. 8 if their X/R ratios w different. Then a straight line FA that did not go through the ori would be drawn, and the rest of the construction would be based

it, the perpendicular to it being drawn through F, and the lines AM and AN being drawn at 60° to it.

The appearance of a phase-a-to-ground fault to phase distance relays is shown in Fig. 9. Except for the last term in Table 4, this diagram can be constructed graphically by drawing the two construction lines at 30° to FA.

Similar constructions can be made for distance relays used for ground-fault protection. However, these constructions will not be described here. A paper containing a complete treatment of this subject is listed in the Bibliography.[5]

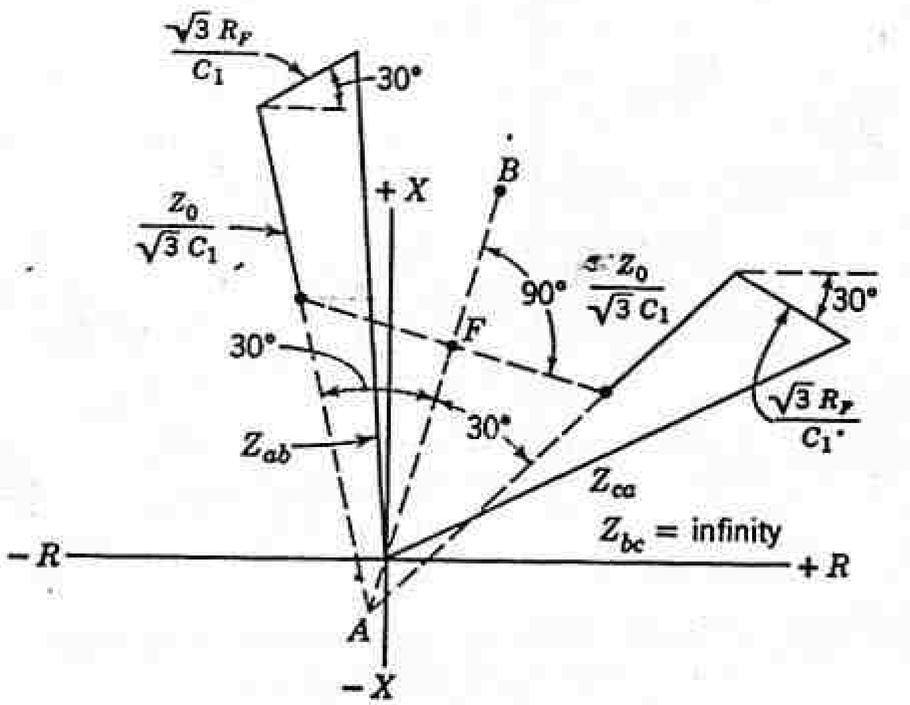

Fig. 9. Appearance of a phase-a-to-ground fault to phase distance relays.

The foregoing constructions, showing what different kinds of faults look like to distance relays, are of more academic than practical value. In other words, although these constructions are extremely helpful for understanding how distance relays respond to different kinds of faults, one seldom has to make such constructions to apply distance relays. It is usually only necessary to locate the point representing the appearance of a fault to the one relay that should operate for the fault. In other words, only the positive-phase-sequence impedance between the relay and the fault is located. The information gained from such constructions explains why relay target indications cannot always be relied on for determining what kind of fault occurred; in other words, three targets (apparently indicating a three-phase fault) might show for a nearby phase-to-phase fault. Or a phase relay might show a target for a nearby single-phase-to-ground fault, etc. The construction has also been useful for explaining a

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PREFACE

"Science is systematized knowledge. Art is knowledge made efficient by skill."

Webster's Collegiate Dictionary, Fifth Edition, G. and C. Merriam Co., Springfield, Mass., 1942

This is a textbook on protective relaying. Much of the material has been used for several years as notes for teaching the subject in the Power Systems Engineering Course given by the General Electric Company. These notes were written because there was no suitable reference book available that properly presented the subject to the novice.

From the experience gained, the notes were revised to improve their clarity and to add necessary explanatory material. Therefore, the material has been tested in the classroom and it should prove useful both as a reference for teaching the subject and for the purpose of self-education.

As already intimated, the book assumes no prior knowledge of protective relaying. In fact, as the student will quickly discover, one needs to know only the fundamental principles of electrical engineering to become well acquainted with protective relaying. He will not be able to master the subject without practical experience in the field, but the subject will lose most of the mystery generally associated with it.

In spite of the elementary nature of the book, it should also be useful to the practicing relay engineer. The book contains new material, it treats many subjects in a different manner from that found elsewhere, and it may help many to understand better what they already know. At least, that has been my experience in writing the material and presenting it to the student. Also, the book contains references to basic source material that has been found to be most authoritative and useful.

Theoretical considerations that have no practical utility have been studiously avoided. Only material is included that I know is useful on the basis of over 25 years of experience. This is not to say that the book will answer every question that may arise, but it will at least help one to find the answer. Neither is the book an historical reference or a reference to foreign practices.

So far as it is possible to make it so, the book is timeless. It contains fundamental information that is applicable to present-day North American practice, but the nature of the material is such that it will be applicable whenever or wherever protective relays are involved. It follows that the book tries to be impartial to all manufacturers of protective relays. Naturally, I have had the most ready access to data, etc., pertaining to relays manufactured by the company with which I am associated, but I have conscientiously tried to avoid any taint of commercialism.

In general, proofs are avoided. References are given to source material containing proofs where such is considered necessary. There are too many worth-while things to be covered to burden the book with proofs unless they are an actual aid to a better understanding of the subject.

The references are not always to prove or confirm a point in the text, but are sometimes other opinions on the subject. With few exceptions, the references are not intended to give credit for original work or contributions, but to present the most up-to-date treatments of the subjects. In general, references are made only to publications that are easily available to the student; many other valuable contributions to the literature have been made, but they consist of conference papers and publications of individual companies or associations that are not readily available in most libraries; in this respect, it is strongly recommended that authors of such material seek eventual publication in the technical press.

This book studiously avoids photographs and nomenclature of actual relays. Such things would "date" the book, take up valuable space, and would add but little to its value. One does not need to know what a relay looks like to learn how it operates and how to apply it. A relay photograph, especially as reproducible in a book, shows practically nothing of real value. The student does not have to go far to see actual relays. Also, the manufacturers will provide well-illustrated publications.

Schenectady, N. Y
January, 1956

C. Russell Mason

ACKNOWLEDGMENTS

The experiences and knowledge of many people are contained in this book; most of these contributions I can only humbly acknowledge in a general way. Specifically, I am greatly indebted to my immediate associates for their contributions to this book, both directly and indirectly, and particularly to Messrs. R. E. Cordray, H. T. Seeley, W. C. New, C. G. Dewey, R. H. Macpherson, J. R. McGlynn, W. C. Morris, H. Bany, L. F. Kennedy, A. J. McConnell, and D. B. Brandt. The sharing of their knowledge and philosophies, and their criticisms and suggestions for improving the book, have been most valuable.

For their painstaking stenographic help in the various stages of preparing the manuscript, I am indebted to the Misses Alicia Corrado, Charlotte Carpenter, and Rose Cuda.

CONTENTS

1 THE PHILOSOPHY OF PROTECTIVE RELAYING

What is Protective Relaying?

We usually think of an electric power system in terms of its more impressive parts—the big generating stations, transformers, high-voltage lines, etc. While these are some of the basic elements, there are many other necessary and fascinating components. Protective relaying is one of these.

The role of protective relaying in electric-power-system design and operation is explained by a brief examination of the over-all background. There are three aspects of a power system that will serve the purposes of this examination. These aspects are as follows:

A. Normal operation.
B. Prevention of electrical failure.
C. Mitigation of the effects of electrical failure.

The term "normal operation" assumes no failures of equipment, no mistakes of personnel, nor "acts of God." It involves the minimum requirements for supplying the existing load and a certain amount of anticipated future load. Some of the considerations are:

A. Choice between hydro, steam, or other sources of power.
B. Location of generating stations.
C. Transmission of power to the load.
D. Study of the load characteristics and planning for its future growth.
E. Metering.
F. Voltage and frequency regulation.
G. System operation.
H. Normal maintenance.

The provisions for normal operation involve the major expense for equipment and operation, but a system designed according to this aspect alone could not possibly meet present-day requirements. Electrical equipment failures would cause intolerable outages. There must

RAVINDRANATH
CHANDER

POWER SYSTEM PROTECTION AND SWITCHGEAR

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This book
is dedicated
with **love** and **affection** to

RAMANA

Ashma

PADMINI

Punit

PARVATI

Niteesh

Foreword

Power system protection is one of the swiftly developing fields in electrical engineering. The last two decades have seen the development and large scale application of static relays, vacuum, sulphur hexafluoride (SF_6) and direct current circuit breakers. These new devices have considerably improved the reliability and safety of integrated power systems.

The present volume is intended to meet the growing demand of students and professional engineers for an uptodate treatise in the area of circuit breaking and protective relaying. The authors have taken great pains in collecting material from all available literature, and have drawn upon their long experience of teaching the subject to arrange the material in a manner which would appeal to both undergraduate and postgraduate students.

The book is divided into two parts—the first twelve chapters are devoted to protective relays while the last six to circuit breakers. The chapters are logically arranged and the presentation is easy to follow for even those who are unfamiliar with the subject. Some aspects of design, testing and commissioning have also been included and these should be invaluable to practising engineers engaged in the power utility services.

I am certain that the book will prove to be a valuable addition to the growing literature in the field of power system engineering.

July 1976
Kharagpur

C.S. Jha

Preface

Protective relays and switchgear are items of equipment with which every power engineer has to deal in the course of his professional career. In recognition of this fact, study of these topics is included at the first degree level as well as the advanced courses in electrical engineering. However, suitable books treating these topics in an integrated manner are not many. Further, most of the books that are available are somewhat outdated. A wealth of information on these topics is, no doubt, available in several journals on power engineering, though this has not been brought together in a form suitable for classroom use. In order to meet the growing demand from the students and the practising engineers for a reliable source of information on this subject, we undertook the task of writing this book.

Although this book is largely intended for the students of electrical engineering, we have not lost sight of the needs of the practising engineers. The engineer engaged in the system protection work will find that this book gives him not only sound understanding of the theoretical background but also provides information on relevant aspects of his work like testing, maintenance and design of protective gear.

Much of the material contained in this book has been used as notes while teaching the subject to the students of Indian Institute of Technology, Bombay, and Malaviya Regional Engineering College, Jaipur. The notes were also used for extension lectures which we delivered to the practising engineers of Rajasthan State Electricity Board. We have greatly benefitted from the criticism of those who attended our courses. We are therefore hopeful that the book will successfully meet the requirements of those for whom it is intended.

A textbook by its very nature cannot be an original work. We have drawn upon the wealth of published literature on the subject available in various journals not only in English but also in Russian. An extensive bibliography has been provided to indicate our source material. This will also help the more serious student locate detailed information on various topics of his interest.

October 1976
Jaipur 302004

B. Ravindranath
M. Chander

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This book has been prepared under the University Grants Commission's scheme for writing university level textbooks. We wish to acknowledge our gratefulness for the Commission's financial assistance in the form of a fellowship granted to one of the authors and grants for contingency expenditure.

It is not possible to complete a book like this without drawing upon the help of a large number of sources. We would like to place on record here our indebtedness to the various organizations and individuals whose cooperation has made it possible for us to complete the present work.

To Dr C.S. Jha, Director, Indian Insititute of Technology, Kharagpur, we are indebted not only for writing the foreword to the book but also for giving us his valuable comments. We are thankful to Dr Dharmendra Kumar, Principal, Malaviya Regional Engineering College, Jaipur, for his sustained interest in the project and guidance.

Dr B.N. Sharma, Principal, Madan Mohan Malaviya Engineering College, Gorakhpur, Dr Ram Saran, Professor of Electrical Engineering at the Institute of Technology, Banaras Hindu University, and Dr M.P. Chaurasia, Professor and Head, Department of Electrical Engineering, Government Engineering College, Jabalpur, have carefully gone through the entire manuscript and given number of comments which we found extremely useful in improving the presentation of the subject matter of the book. We thank them for their advice. Mr Prithvi Singh, Member (Technical), Rajasthan State Electricity Board, assessed the manuscript from the point of view of the practising engineers and we gratefully acknowledge his comments.

The material provided at the advanced course in relaying and switchgear conducted by the University of Roorkee and at the advanced course in power system analysis and dynamics held at the Indian Institute of Technology, Kanpur, were useful in clarifying certain concepts. We are thankful to the conveners and participants of these courses. To our colleagues, friends and former students who have helped us at one time or another while the book was in preparation we offer our sincere thanks.

Tata-Merlin & Gerin Limited, Bombay and Jyoti Limited, Baroda, readily responded to our requests and provided photographs for inclusion in the book. We thank them for permitting the use of these photographs.

The National Book Trust, India, have granted subsidy for the publication of the book. But for this grant, it would not have been possible to produce the book at a price within the reach of the student community. We are grateful to the Trust for this assistance.

A Note for the Reader

This book contains two parts. Part I comprising twelve chapters is devoted to protective relays and power system protection. The approach adopted in these chapters is to treat the relays in a very generalized form mathematically and then to develop the characteristics of different relays in the form of a logical extension. After considering the principles of protection and protective relays, their application to the main elements of a power system are described. Static relays which are fast coming up and replacing the conventional electromechanical relays are described in Chapters 9 to 12.

The second part, i.e. Chapters 13 to 18, is devoted to the theory of circuit interruption and circuit breakers. Development of the most modern circuit breaker has been dealt with in different stages, right from the primitive knife switch through conventional circuit breakers to the latest sulphur hexafluoride circuit breaker. The ability of a circuit breaker has been defined in terms of circuit severity. For determining the successful operation of the breaker the circuit severity and the circuit breaker effort are compared. This is a very useful concept in circuit breaking.

The undergraduate students who take up the study of power system protection for the first time may omit the following chapters and sections: Chapters 7, 8, 10, 11 and 12; Sections 15.6, 15.7, 15.8 and 18.9. These chapters can be studied with profit by the advanced students who have already acquired a reasonable understanding of the subject.

Contents

PART I: PROTECTIVE RELAYS

PART II Circuit Breakers

CHAPTER **13**

Theory of Circuit Interruption

13.1 Introduction

The duty of a circuit breaker is to switch on and switch off, once or repeatedly several times different electrical circuits during normal as well as abnormal operating conditions. While making or breaking the switching contacts there is a transitionary stage of arcing between the contacts which is governed by electric discharges between the contacts. If current is flowing in a circuit before the switch opens, an arc is created between the contacts at the instant of separation, and the current is thus able to continue in the circuit until the discharge ceases. The study of this phenomena though very complex is of immense importance for the design and the operational characteristics of the circuit breaker.

13.2 Physics of Arc Phenomena

Discharge in a.c. circuit breakers, generally in the form of an arc, occurs in two ways. When the contacts are being separated arcing is possible even when the circuit emf is considerably below the minimum cold electrode breakdown voltage, because of the large local increase in voltage due to the circuit self-inductance. This way of drawing an arc is common to both d.c. and a.c. circuit breakers. The second method occurs only in a.c. circuit breakers. In this case the arc is extinguished every time the current passes through zero and can restrike only if the transient recovery voltage across the electrodes already separated and continuing to separate reaches a sufficiently high value known as breakdown voltage. It is known that the arc phenomenon depends upon:

1. The nature and pressure P of the medium.
2. The external ionizing and deionizing agents present.

3. The voltage V across the electrodes and its variation with time.
4. The nature, shape and separation of electrodes.
5. The nature and shape of vessel and its position in relation to the electrodes.

An ideal gas is a pure dielectric because it consists of molecules which are electrically neutral. It can be made to conduct only when some means are employed to create free electrons and ions in the gas, although some free electrons and positive ions are present in the gas which are created by ultraviolet radiation, cosmic rays, radioactivity of earth, etc. But this as such is insufficient to sustain conduction through the gas. In order to understand how the gas becomes conducting, it must be remembered that a gas consists of molecules moving about with considerable velocities and colliding with one another. Their velocities are not all the same but are grouped about a *mean value* in a Maxwellian distribution. The mean KE of the molecules $\frac{1}{2}mv^2$ is equal to (3/2) KT where T is the absolute temperature and K is the Boltzmann's constant. It is common knowledge that air molecules at room temperature (300°K) move randomly with approximately 500 m/s and collide very frequently at 10^{10} times per sec. Nevertheless the KE of these molecules (the average of which is proportional to the absolute temperature) is too low to enable even the fastest particles to damage those with which they collide.

At higher temperatures, however, it happens that the molecules break down at the most severe collisions and dissociate into their atoms. Energies of 9.7 eV and 5.1 eV respectively are needed to dissociate an N_2 or O_2 molecule. The degree of dissociation x_d is described by the formula

$$P\left(\frac{x_d^2}{1-x_d^2}\right)=AT^{3/2}\exp\left(-\frac{W_d}{KT}\right) \qquad (13.1)$$

where

A=a constant, W_d=energy of dissociation

P=gas pressure, K=Boltzmann's constant, and

T=absolute temperature.

At still higher temperatures some molecules and atoms are deprived of an electron and the hot gas called plasma becomes a conductor. The degree of ionization x_i due to thermal collision is described analogously to Eq. (13.1) by

$$P\left(\frac{x_i^2}{1-x_i^2}\right)=AT^{5/2}\exp\left(-\frac{W_i}{KT}\right) \qquad (13.2)$$

W_i being the energy of ionization.

This thermal ionization resulting from random collisions in a hot gas must be distinguished from impact ionization, which is caused by electrons accelerated in an electric field between two collisions. The latter cause dielectric breakdown, even in a cold gas. Figures (13.1) and (13.2) show variation of x_d, x_i, thermal conductivity K and electrical conductivity σ with temperature.

The temperature at which an appreciable number of electrons and positive ions begin to form, thus depends on the degree of ionization of the gas. In normal arc plasma only a very small fraction of the atoms are ionized (about 0.01%), and the arc temperatures lie in the range 5000°K for H_2, 6000°K for N_2 and 6000°K for air. In concentrated arc columns such as those in gas blast breakers this figure becomes about 1% and th temperature is then correspondingly 10 to 12×10^3 °K for N_2. The free electrons can carry an electric current under an electric field in rougl the same way as do the free electrons in a metal.

In the arc however the gas is not heated from outside but by electrica energy released in it. The electrons are accelerated in the field of arc and they give up the energy they acquire in this way to the gas when they collide with its atoms or molecules. Now so long as the rate at which energy is imparted by the electrons from the field to the plasma in this way is small compared with the rate of interchange of energy amongst the particles themselves, the whole plasma will be very nearly in thermal equilibrium and the molecules, ions and electrons will all have the same temperature. This is not always the case; when the arc starts up, or is about to be extinguished or is in glow or diffused form (low pressure), the rate of exchange of energy between the arc and its surroundings becomes comparable to the internal rate of energy exchange and thermal equilibrium breaks down. In the low pressure discharges the atoms and positive ions can be nearly at room temperature, while the electrons may have energies corresponding to 10 to 15 thousand °K. As long as the velocity distribution amongst the electrons themselves is Maxwellian it is usual to refer to them as having a corresponding temperature.

The electrical conductivity of a metal in its normal state, however, is due to the existence within it of *free* conductivity electrons, of which there are approximately as many as there are atoms in the metal. Normally these free electrons are prevented from escaping from the boundary of a metal conductor.

A number of processes can cause emission of free electrons from a metal and in the initiation of an arc in a CB. Two of these processes are believed to be important: (1) increase of temperature, giving thermionic emission of electrons, and (2) high voltage gradient at the cathode, causing *field emission* of electrons. Conditions at the instant of contact separation lead to either or both of these processes. At the time of separation of the contacts, the area and the pressure between the separating contacts decrease

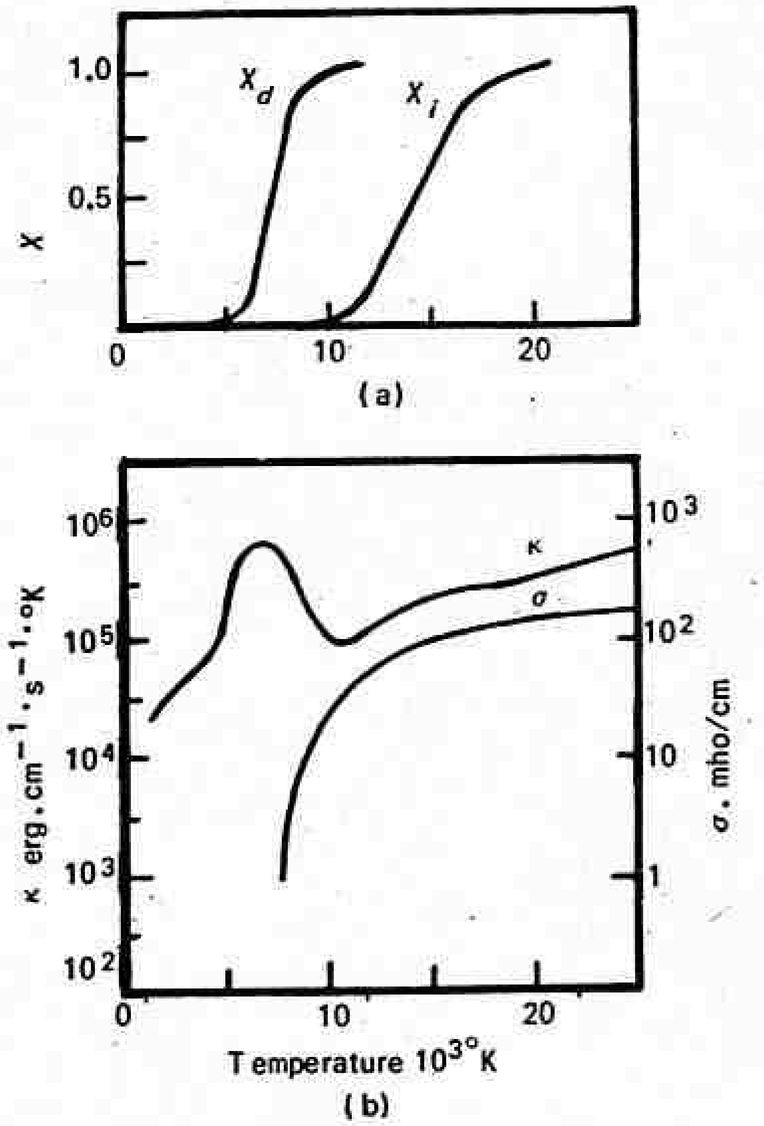


FIGURE 13.1 (a) Degrees of dissociation x_d and ionization x_i as functions of temperature; (b) Thermal conductivity K and electrical conductivity σ as functions of temperature.

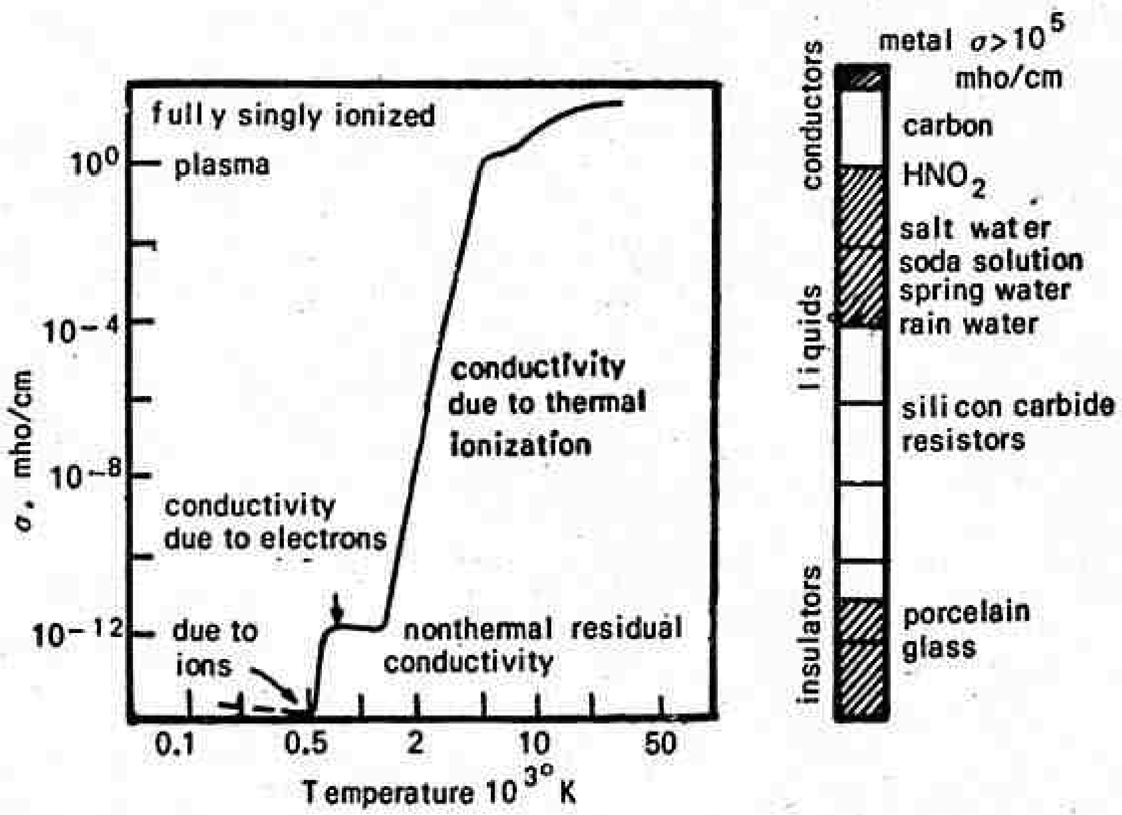


FIGURE 13.2 Electrical conductivity σ vs. temperature of air at atmospheric pressure.

rapidly, resulting in an increase of electrical resistance and intense local heating, which may be sufficient for thermionic emission. Although this momentary resistance may only be a fraction of an ohm, the current may be extremely high, many hundreds or thousands of amperes giving a voltage drop of a few volts across the extremely small distance of separation and thus resulting in a high voltage gradient. The voltage gradient may be sufficient to cause the emission of electrons from the cathode and the process is known as field emission. Both types of emission are affected appreciably by the nature, shape and separation of contacts.

However, it is known that with copper contacts normally used in circuit breakers, very little thermionic emission can occur at temperatures below the melting point. The voltage gradient for field emission must be of the order of 10^6 volts/cm, and hence it is seen that field emission is more responsible for initiating the arc at contact separation.

13.3 Maintenance of the Arc

From the foregoing discussion it can be said that with the initiation of the arc between the electrodes, sufficient number of electrons will be liberated from the cathode and in moving from cathode to anode will cause the medium to ionize. The ionization of the medium involves a rapid creation of electrons which serve to maintain the arc, after field emission has largely ceased. Thus each emitted electron multiplies in numbers by deriving energy from the field. The diffusion and recombination process keeps on replacing the electrons lost to the anode. Finally if the current is high the discharge attains the form of an arc having a temperature high enough for thermal ionization to become the main source of electrical conductivity, and runs with low voltage gradient.

13.4 Losses from Plasma

There are three forms of heat loss from an arc column: (1) conduction, (2) convection and (3) radiation. The losses from switchgear are by (1) and (2) only, as (3) is negligibly small. In breakers having plainbreak in oil, arcs in chutes or tubes or narrow slots, the loss is nearly all due to conduction. Whenever there is anything in the nature of a blast present, even in plainbreak the loss is a conduction-convection problem. The ordinary arc in air is also a conduction-convection problem. Steenbeck showed experimentally that if the effect of convection is reduced to zero by placing the arc in a gravity-free field then the loss is reduced to half.

13.5 Essential Properties of Arc

The manner in which the arc medium is made to conduct has already been studied. A plot of instantaneous values of voltage e_B between the electrodes of a burning arc against the corresponding values of current gives the arc characteristics. With the increase of arc current the temperature rises and the process of ionization becomes more active thereby increasing the conductivity of the medium and thus the arc voltage decreases. The increase of current in the higher range does increase the conductivity but has much less marked effect upon the voltage. The initial breakdown of the gap between the electrodes requires a high ignition voltage e_Z at zero current (Fig. (13.3)). It is also seen that by changing the rate of change of current the characteristics shift. If the current changes rapidly with time the characteristics are known as *dynamic* and if the rate of change of current is small the characteristics are known as *static*. However, during most of the half cycle the quantity $(di/dt)/i$ is small and a plot of voltage against current gives static characteristics. Near current zero when $(di/dt)/i$ becomes large this will no longer be true.

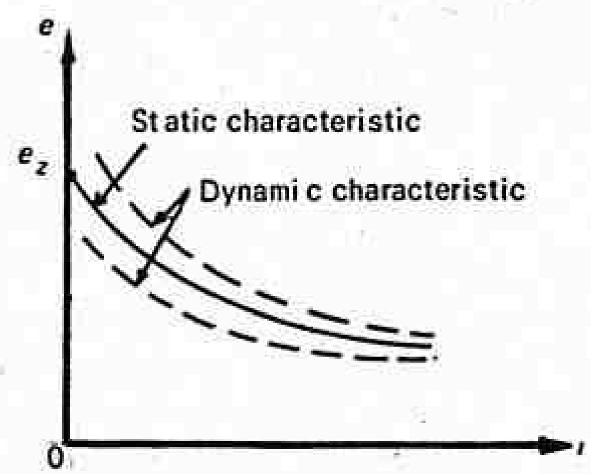


FIGURE 13.3 Static and dynamic characteristics.

If the current through the arc is suddenly changed it is found that the voltage across it does not assume the value corresponding to the new value of the current on the static characteristics. Thus if the current is suddenly increased the instantaneous voltage across it is found to be higher than that given by the static characteristics. The reason is that at any given current the arc and its surroundings have a heat content represented by the heated, dissociated, ionized gas which makes up the arc regime.

The total heat content in the steady state as well as the heat loss obviously depend on the current, but it takes time for this heat content to change and things depart therefore from the static characteristic until the new heat content is established. This is sometimes expressed by saying that there is *thermal hysterisis* in the changing arc.

When the current falls from a sufficiently high value, the transition is entirely an effect of temperature. This means that the transition with falling temperature may take place at various instantaneous current values depending upon the rate of current fall that is, the thermal hysterisis effect must be considered. Thus, with rapidly-falling current the value at which the transition occurs may be much smaller than with slowly-falling current. This is one reason why such transitions are not generally observed in high current a.c. circuit breakers. Also in air-blast breakers the core temperature of the arc tends to be maintained at a high value right up to the current zero instant, and the possibility of transition becomes remote. Only in some oil circuit breakers, the efficient cooling of the arc because of the high thermal conductivity of the gas formed, enables the arc temperature to fall relatively quickly as the current decreases, and a transition to the high voltage takes place before current zero. The distribution of voltage along the arc is not linear. It is known that very close to the cathode there is a positive space charge and near the anode a negative space charge. Both produce high voltage gradients as compared with that in the main arc stream, the corresponding steep voltage drops occurring are e_K and e_a respectively (Fig. (13.4)). The voltage drop along the main arc stream e_1 is proportional to its length l and depends on the property of gas and the conditions under which gas exists. Gases with higher voltage gradients along the main arc stream have better arc extinguishing properties.

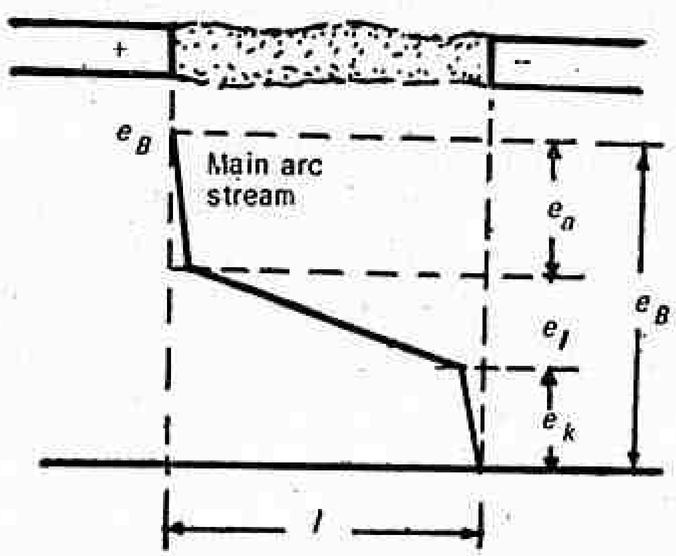


FIGURE 13.4 Voltage distribution along the arc.

The temperature of metallic arc spots is about 2000 to 3000°C, whereas with carbon electrodes the temperature rises up to 3000 to 4000°C.

The gas temperature in the arc has been measured as being 5000 to 8000°C, the lower values refer to smaller currents and higher values to larger currents. True arcs with white-hot cathode, in general, are developed with currents above 0.5 A. Below this limit application of high voltage forms a glow current which does not need a hot cathode.

For moderate values of current and voltage, the arc characteristic can be expressed by Ayrton's equation:

$$e_B=a+\frac{b}{i} \tag{13.3}$$

Thus with rising current, the voltage decreases as a hyperbola. The constants a and b vary linearly with the length l of the arc

$$a=\alpha+\gamma l \tag{13.4}$$
$$b=\beta+\delta l$$

Average values of α, γ, β and δ for arcs in air between copper electrodes are

$$\alpha=30V\,; \quad \gamma=10V/cm$$
$$\beta=10Va; \quad \delta=30Va/cm$$

The a.c. current varies periodically going through zero twice during a cycle. According to change of current the discharge alternates. If voltage and current are measured at an a.c. arc, distorted curve shapes are found depending on the type of the arc gas, the material of the electrodes and the frequency of the current.

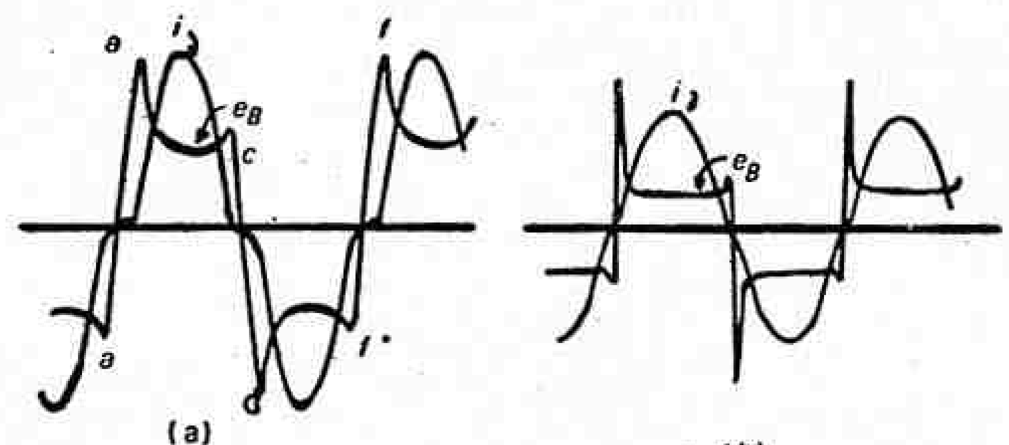


FIGURE 13.5 Voltage and current waves of an a.c. arc: (a) for carbon electrodes in air; (b) for copper electrodes in air.

Figure (13.5a) shows such curves for a carbon arc and Fig. (13.5b) for a copper arc both burning in air at normal frequency. From such changes with time the voltage-current characteristics can be directly derived as represented in Fig. (13.6a) for carbon and Fig. (13.6b) for copper electrodes.

These characteristics are no longer unique but consist of two different branches, one for increasing and the other for decreasing current. This difference as pointed out earlier is due to heat capacity of the electrodes and the arc gas, which are not able to follow the instantaneous condition with rapid variation of the state. Because of the great heat conduction of metal electrodes the two branches of the characteristic of Fig. (13.6b) are not so widely different as those of Fig. (13.6a) for carbon electrodes.

At points a and d arc discharges occur, at points c and f the arc is extinguished. During the intervals between points "a-a", "c-d", "f-f" unstable discharge takes place. Interruption of the loaded circuit is always accompanied by arc discharge between the contacts of the opening

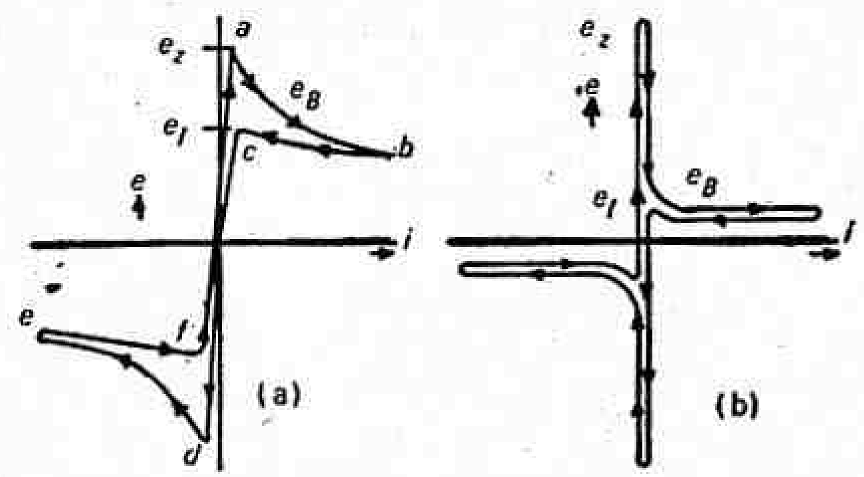


FIGURE 13.6 Voltage-current characteristics of a.c. arcs at normal frequency: (a) for carbon electrodes; (b) for copper electrodes.

apparatus. During this process a large quantity of energy (mostly in heat form) is released in the arc space. This energy can be calculated according to the following expression:

$$W_e=\int_0^{t_{arc}} i e_B dt \tag{13.5}$$

where i=instantaneous value of current
e_B=voltage drop across the arc
t_{arc}=time during which arc exists

This energy can cause damage to circuit breaker contacts, vaporization of oil, increasing of pressure inside tank, etc. Obviously by reducing the arcing time the possible damage to the circuit breaker can be avoided. In a.c. circuit breakers therefore the deionization of the arc path is easily achieved at current zero position.

It can be seen that the a.c. arc is useful in the sense that if the circuit was interrupted abruptly there would occur dangerous overvoltages between the contacts due to the inductance of the circuit. Interruption of the circuit occurs only at the instant when current reaches normal zero when the arc disappears. In other words, a.c. arc synchronizes the instant of opening of the circuit with the normal current zero irrespective of the instant of contacts parting.

13.6 Arc Interruption Theories

In circuit breakers two modes of arc interruption can be identified: (a) high resistance interruption, and (b) low resistance or current zero interruption.

13.6.1 High Resistance Interruption

In this case the arc is controlled in such a way that its effective resistance increases with time so that the current is reduced to a value insufficient to maintain it. The arc resistance may be increased with lengthening, cooling and splitting the arc. The main drawback with this type of interruption is that the energy dissipated is high and so it is only used in low and medium power a.c. circuit breakers and in d.c. circuit breakers.

13.6.2 Low Resistance or Current Zero Interruption

This method is employed in a.c. arc interruption. A 50 Hz alternating current passes through zero 100 times per second. At every current zero the arc extincts for a brief moment and again the arc restrikes with the rising current. The phenomenon of arc extinction is very complicated and can be explained by number of theories. The two important theories giving some basic concepts are described below.

Slepian's Theory. The arc which is in the plasma form has voltage stress sufficient to detach electrons from their atomic orbits, the process as a whole being accompanied by the release of great heat. To stop this process, it is necessary to remove the ionized gas, or to produce a state of instability by causing the electrons to recombine at a rate greater than that at which they are being released. By either method the resistance of the arc-path rapidly increases until the path again becomes an insulator. Zero current position offers the most favourable situation for this where residual ionization is small. In other words, the basic problem is to build up the dielectric strength between the circuit breaker contacts. If the rate at which the dielectric strength increases is faster than the rate at which voltage stress rises, the arc will be extinguished; if otherwise the arc may be interrupted for a brief period but it again restrikes. This is illustrated in Fig. (13.7).

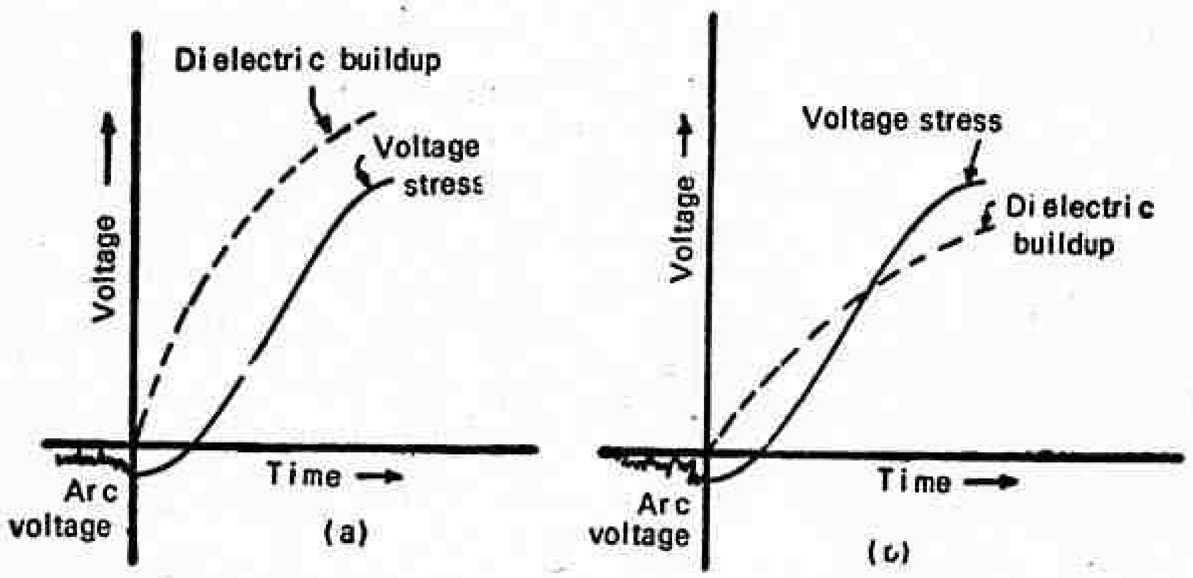


FIGURE 13.7 Build up of dielectric strength and voltage stress between circuit breaker contacts from the instant of zero current: (a) arc extinguishes; (b) interruption followed by dielectric failure.

The theory assumes that the restriking voltage and build-up of dielectric strength are independent quantities. This assumption is not quite correct, because the dielectric strength calculations do not agree with the observed values. However the theory explains the arc extinction process in a simple and convincing manner. Slepian was the first to point out that the restriking voltage plays an important role in arc extinction.

Energy Balance Theory. With the development of gas blast breakers where very large amounts of post-arc conductivity could exist and still the circuit could be interrupted. Also the very high rates of rise of restriking voltage did not have such a marked effect on the breaker as one would expect. This led to a consideration as to whether the post zero period could not better be explained in terms of an energy balance rather than as a race for electrical strength. Cassie suggested that, fundamentally, the reestablishment or interruption of the arc is an energy balance process. If the energy input to the arc, subsequent to the current zero continues to increase the arc restrikes, if not, the circuit is interrupted. This suggestion is sounder than the Selpian's theory. Successful interruption of the arc subsequent to a current zero entails increasing the reignition voltage to a value in excess of any voltage the circuit can produce across the arc.

A post-current-zero energy balance is not the only way that breakers can operate. In dealing with the post-arc conductivity problem it is necessary to go into the aerodynamics of the gas blast breakers more fully. The mechanism of heat loss leads to greater diffusion losses than was originally supposed by Cassie while propounding the theory.

QUESTIONS

1. Explain the physics of arc phenomena. On what factors does the arc phenomenon depend?
2. What causes the initiation of electric arc at the instant of contact separation? Which of these is chiefly responsible for the creation of arc in circuit breakers and why?
3. What are the essential properties of arc? Distinguish between the static and dynamic characteristics.
4. Which of the following principles is employed in high voltage a.c. circuit breakers? Give reasons.
   (i) High resistance interruption.
   (ii) Low resistance interruption.
5. Explain Slepian's theory of arc interruption and discuss its limitations. How does energy balance theory explain the process of arc interruption?

CHAPTER 14

Circuit Constants in Relation to Circuit Breaking

14.1 Introduction

The circuit breaker is called upon to perform very arduous duties under different circumstances. The performance of the circuit breaker is to a large extent dependent on the nature of the circuit in which it is connected. It is the purpose of this chapter to present the salient features of the interaction between the circuit breaker and the circuit to which it is connected.

14.2 Circuit Breaker Rating

The ratings of a circuit breaker refer to the characteristic values that define the working conditions for which the circuit breaker is designed and built. Circuit breakers must be capable of carrying continuously the full load current, without excessive temperature rise, and should be capable of withstanding the electrodynamic forces. The circuit breaker should also be in a position to interrupt fault currents safely. The standard ratings of different classes of circuit breakers are given in various national and international standards. According to I.E.C. Specifications 56-1 (1954) and American Standards, an a.c. circuit breaker has the following ratings:

1. Rated voltage, rated current.
2. Rated frequency.
3. Rated breaking capacities, symmetrical and asymmetrical.
4. Rated making capacities.
5. Rated short-time current or rated maximum duration of short circuit.
6. Rated operating duty.

(1) *Rated Voltage.* During normal operating conditions the voltage at any point of the power system is not constant. Due to this the manufacturer guarantees perfect operation of the circuit breaker at rated maximum voltage, which as a rule is higher than rated nominal voltage.

The rated maximum voltage of a circuit breaker is the highest rms voltage, above nominal system voltage, for which the circuit breaker is designed and is the upper limit for operation.

Rated current. The rated current of a circuit breaker is the designated limit of current in rms amperes which it shall be capable of carrying continuously without exceeding the limit of observable temperature rise.

The temperature rise of each of the various parts of the circuit breaker when tested to demonstrate rated continuous current, shall not exceed the limit given for that part as indicated in Table 14.1.

Table 14.1 *Temperature rise limits for various parts of a circuit breaker*

	Limit of temperature rise °C	
	Oil CB	*Oilless CB*
(a) Contact in air when clean and bright	30	35
(b) Contacts in oil	30	
(c) Oil	30	
(d) Potential coils, class *O* insulation	35	35
(e) Series coils, class *O* insulation	50	50
(f) Series and potential coils class A insulation	50	50
(g) Series and potential coils, bare or class B insulation	70	70
(h) All other parts	70	70

For circuit breakers installed in enclosures, these temperature rise limits are based on the ambient temperature inside the enclosure, which should not exceed 40°C if the circuit breakers have copper to copper contacts, or 55°C if the circuit breakers have silver or other contacts.

Care should be taken to consider the possible increase of temperature rise of contacts in air due to oxidation of the contact surfaces. The breaker can retain its rating provided there is sufficient maintenance to keep the temperature rise within the specified limits.

For applications at altitudes higher than 1000 m the basic impulse insulation level (BIL) rated maximum voltage, and rated current shall be starts discharging giving negative i_c, whereas i and i_a are still positive, so that the arc is supplied from both the source and the capacitance, obviously during this period i_a is greater than i. At instant b when i reaches zero, Fig. (14.14b), the arc is supplied only by the capacitance $i_a=i_c$ and $i=0$. After this instant the current i reverses, and the difference constitutes i_a. In the negative direction i rises at a faster rate than i_c until at instant c, $i=i_c$ and the arc is extinguished, i.e. $i_a=0$ (Fig. (14.14c)).

The interaction between arc and circuit can be calculated around current zero, if the time constant τ and rate of power dissipation of the arc, as well as the initial conditions of the interaction interval are known. These values can be measured and put into a mathematical arc model, which has to be combined with the differential equation of the circuit. The voltage required to maintain an arc at a given current may be much less when the current has been decreasing rapidly than in the static case.

The heat balance of the arc, and hence its temperature and conductivity, is determined by $P=e_a i_a$ (the electrical power input) and P_0 (the rate of heat removal by the blast). If R is taken as the instantaneous value of the arc resistance and τ the thermal time constant, we obtain

$$\left(\frac{1}{R}\right)\frac{dR}{dt}=\frac{1}{\tau}\left[\frac{P}{P_0}-1\right] \tag{14.6}$$

For successful clearance R continues to increase after current zero. With the aid of computer it is possible to calculate the curves of current and voltage around current zero and to decide whether or not residual conductance and thermal reignition of the arc path occurs.

14.7 Current Chopping

When interrupting small inductive currents such as transformer excitation currents, circuit breakers tend to clear before the natural current zero is reached. This is because the low-current ionized conducting path may become prematurely unstable, forcing the low arc current to zero along a very steep wave front. This phenomenon is known as current chopping and this in turn is responsible for inducing a high voltage transient across the breaker gap. If the chop occurs at a current i the stored energy in the inductance is $\frac{1}{2}Li^2$ which will discharge into the stray capacitance; equating these energies gives a voltage across the breaker of $e=i\sqrt{L/C}$ which may reach dangerous values. Figure (14.15) illustrates the current chopping phenomena, it is quite possible that the prospective value of voltage given by $e=i\sqrt{L/C}$ is quite high as compared to the dielectric strength gained by the gap so that the breaker restrikes and again the current is chopped and restriking occurs till finally the current is suppressed without a restrike.

This phenomenon can be analyzed from the circuit point of view by

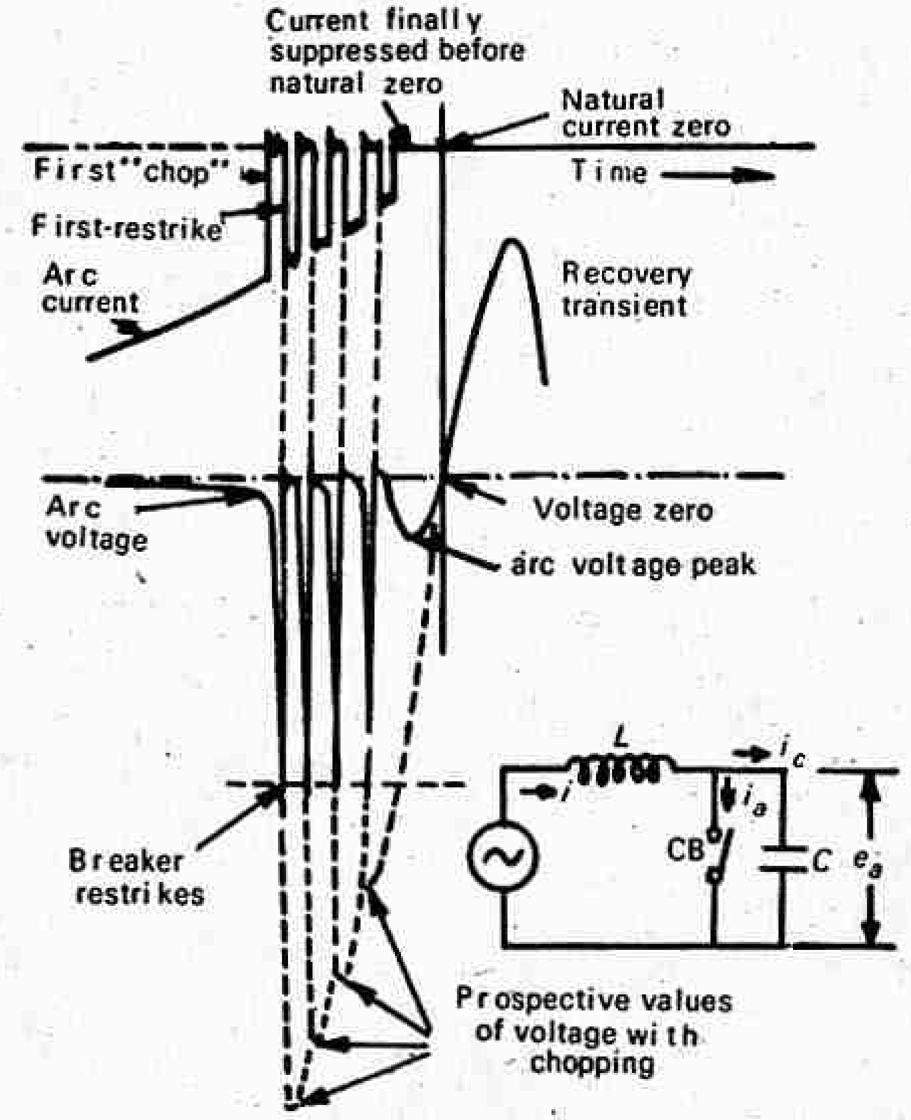


FIGURE 14.15 Effects of current chopping.

considering that the circuit breaker is represented by a variable resistance being infinity when the circuit breaker is open and zero when closed. The transition from one position to the other can also be represented by a variable resistance. The extinguishing of the arc is brought about by a thermal mechanism. The thermal clearance and the increase in voltage across the contact gap may occur more or less at the same time, but with a high voltage air-blast circuit breaker operating under normal conditions thermal clearance may take place before the arc voltage zero, and therefore before the onset of the restriking voltage transient. This is illustrated in Fig. (14.16).

Although the arc voltage e_a may increase only slightly near current zero, the rate of increase is very large and may cause current to be diverted into the system capacitance shunting the circuit breaker, thereby bringing the current through the circuit breaker to zero prematurely. Owing to this premature reduction of the current, and to the fact that only a small voltage exists across the contacts, near current zero, the power input to the arc is relatively small and thermal clearance is facilitated. It is therefore only after some further period following arc extinction that the full value of the restriking voltage appears across the contacts.

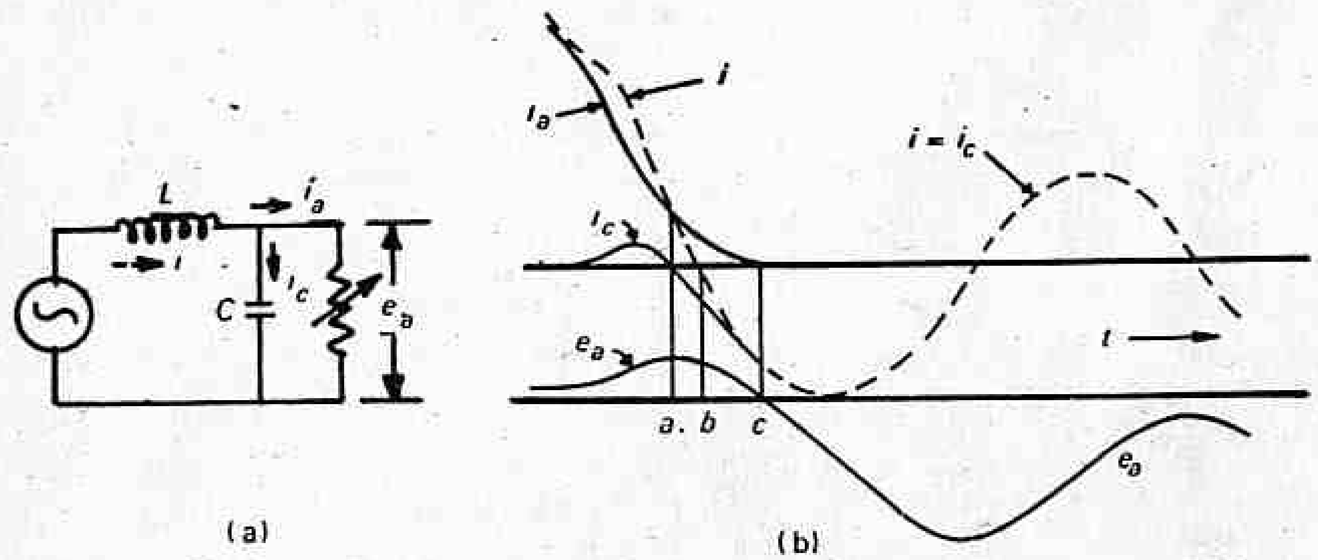


FIGURE 14.16 (a) Basic circuit; (b) current deformation resulting from the interaction of arc voltage with inductance and capacitance of the circuit.

An air-blast circuit breaker not shunted by capacitance would probably extinguish the arc by the same basic mechanism, but the time during which post-zero conductivity appears would be reduced. In practice some capacitance in parallel with the circuit breaker always exists and it is possible for extinction to take place before voltage zero. This premature supression of the arc current by diversion into shunt capacitance is a basic form of current chopping.

Figure (14.17) shows values of typical EHV air-blast breakers rated at about 20-25 KV rms per interrupter.

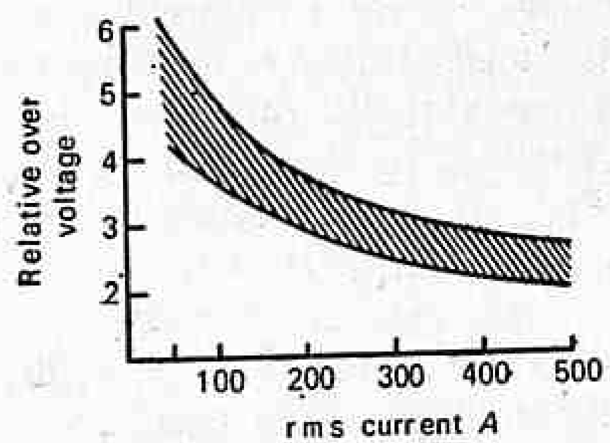


FIGURE 14.17 Overvoltages produced by circuit breakers without switching resistors.

As the rms current is reduced, the per unit overvoltage rises to a maximum when the peak value of the current is chopped. Over voltages are reduced by the voltage-grading resistors shunting the interrupters; the amount of the reduction however depends strongly on the inductance and inversely on the capacitance of the circuit. A resistance of 5-10 $K\Omega$ per interrupter is usually sufficiently low to give adequate voltage grading, but at transmission voltages, values as low as 1-2 $K\Omega$ are necessary if over-

voltages are to be limited to 2.0—2.5 pu at the lower values of interrupted current.

14.8 The Duties of Switchgear

Under different circumstances circuit breakers may be subjected to widely varying stresses. First of all the current varies from a few amperes due to no-load current of a transformer up to the heaviest short-circuit currents, which may amount to a hundred kiloamperes. Moreover the circuit impedance itself may change within the first 10^{-4} to 10^{-3} second because open lines or cables connected to the bus bars at the breaker behave initially like resistances (having the values of their surge impedances), but later like capacitances. Whereas load currents are more or less ohmic, short-circuit currents are purely inductive and the currents of unloaded lines are mainly capacitive.

Circuit breakers not only must interrupt but also must close the circuit. This may cause some trouble, especially if the breaker closes on a short circuit, because then the voltage breakdown that bridges the contact gap before the contacts touch produces a high-current arc, which melts the contacts before closure. Such a situation is not desirable since the breaker must be able to open the contacts again. Often automatic reclosing is required, because usually the faults are of temporary nature. About 20% of the short circuits persist, however, and immediately after reclosing, the breaker again has to interrupt the short-circuit-current just made. This is a very severe duty, especially if there are extremely high currents requiring heavy contacts to be accelerated and decelerated in both directions within hundredths of a second without bouncing, which would result in contact welding and wear.

The main duties which a circuit breaker has to perform in addition to satisfying the rated breaking capacities and rated making and breaking times are:

(a) Short-circuit interruption.
(b) Interruption of small inductive currents.
(c) Capacitor switching.
(d) Asynchronous switching.
(e) Interruption of short-line fault.

14.8.1 Short-Circuit Interruption

The short-circuit current depends upon the voltage E and the series reactance X. After the arc extinguishes at natural zero of the 50 Hz waveform, the circuit recovers and a restriking transient voltage or transient recovery voltage (TRV) is impressed across the switch. The magnitude and shape of the TRV waveform is very important to the circuit breaker and has already been discussed in detail in section 14.3.

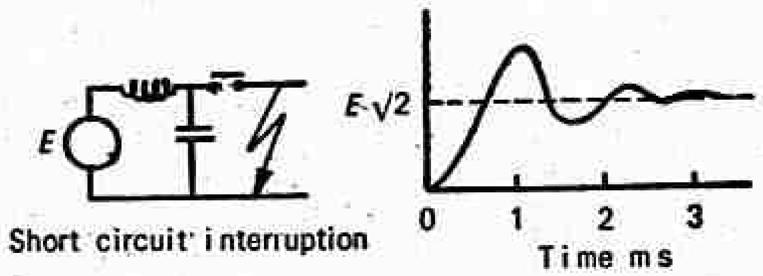


FIGURE 14.18 Short-circuit interruption.

14.8.2 Interruption of Small Inductive Currents

The magnetizing current of transformer is quite small, its interruption constitutes in itself no problem for a circuit breaker. The supression of these low currents before natural zero gives rise to dangerous overvoltages up to about 3.0 pu across the inductance. Some protective devices such as resistors parallel to the circuit breaker, through which the transformer energy can be discharged without causing excessive overvoltages, or lightning arrestors have to be provided. Certain types of circuit breakers may reignite, i.e. reestablish electrical contact, the voltage across the switch collapsing to zero. The voltage on the inductance subsequently reappears and is often smaller than voltage if no reignition had occurred (dotted curve in Fig. (14.19)).

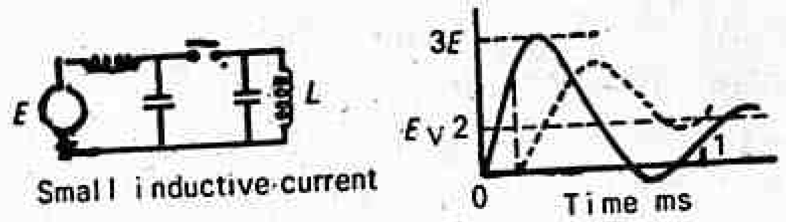


FIGURE 14.19 Small inductive currents.

14.8.3 Capacitor Switching

Switching of unloaded transmission lines or switching of capacitor banks imposes on circuit breakers the duty of interrupting capacitive current at zero leading power factor. This can result in an abnormally high voltages across the circuit breaker gap if the breaker restrikes. It can be seen from Fig. (14.20) that at A when capacitive current zero is reached the transmission line is at maximum voltage so that when interruption occurs the line is left in a fully charged condition to this maximum value of the generated voltage. After instant A the breaker gap is subjected to the difference of voltages V_g and V_c. After a time interval of half cycle from A, i.e. at instant B the voltage across the breaker is two times maximum

value of V_g. Within such a short interval of half-cycle the breaker has been subjected to a severe condition, with the result that the breaker might restrike. If such a condition occurs the voltage across the breaker falls almost instantaneously from two times maximum value of V_g to zero.

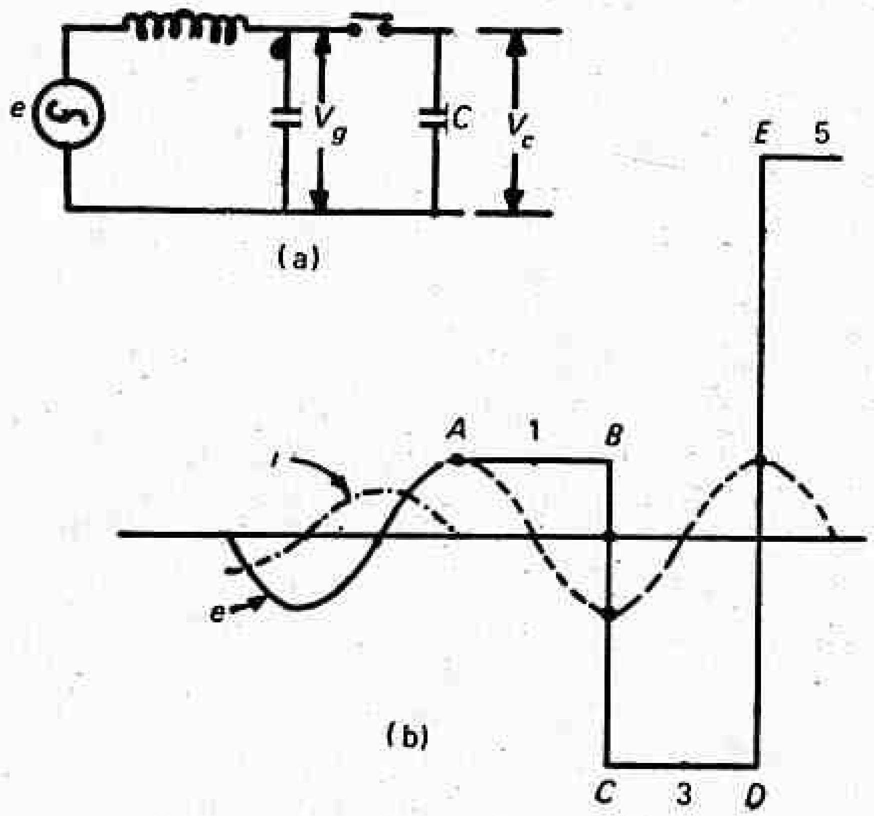


FIGURE 14.20 Interruption of capacitance current.

In doing so high frequency oscillations are set up which build up the voltage to −3 times maximum value of V_g. The restrike current reaches zero value which provides an opportunity to interrupt. The line is charged to a voltage of−3 times maximum value of V_g to earth after interruption of restrike current. At this stage immediately after C the voltage across the breaker is only two times maximum value of V_g since the generated voltage itself is negative maximum. The voltage across the gap now continues to increase and at D this reaches a value 4 times maximum value of V_g. If the breaker restrikes again at this point the events of B will be repeated on an even more formidable scale as the voltage swing will now be 8 times maximum V_g and the line may then be left isolated at a potential of 5 times maximum V_g to earth. Theoretically this phenomena may proceed indefinitely increasing the voltage by successive increments of 2 times maximum V_g. This is limited only by leakage and corona losses or by a breakdown of system insulation. Although these extreme conditions are improbable and rare they do sometimes occur causing serious damage. The sole cause of this type of overvoltage is the inability of the circuit breaker to provide adequate dielectric strength in the gap after interruption. Only forced-blast or multibreak HV circuit breakers can withstand this stress within such a short time.

14.8.4 Asynchronous Switching

Phase opposition may occur if the breaker recloses after a fairly long pause, during which the generators E_1 and E_2 fall out of synchronism (Fig. (14.21)). When the switch opens the peak value of the transient recovery voltage is determined by the sum of E_1 and E_2 and approaches two times that of the short-circuit interruption.

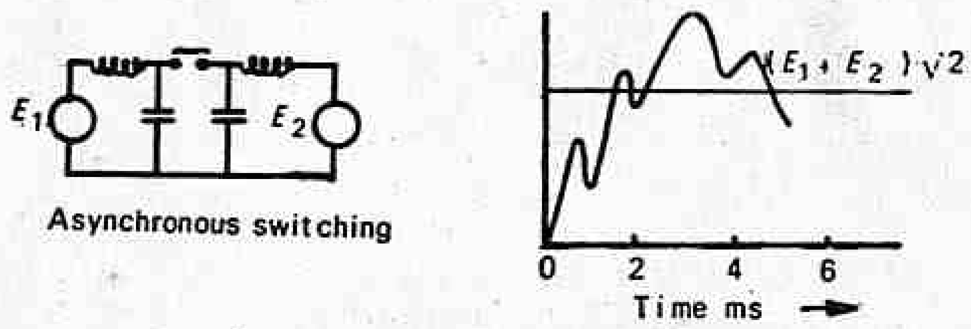


FIGURE 14.21 Asynchronous switching.

14.8.5 Interruption of Short Line Fault

The interruption of short-circuit current due to faults on the first few km of overhead lines imposes a serious duty on the circuit breaker. This is because the transient recovery voltage across the breaker terminals is accompanied by a high-frequency line-side component, whereas the reduction of short-circuit current due to the inductance of the short-circuited line is only slightly less than that of a terminal fault.

The transient voltage of the short-circuited line is proportional to the magnitude of the short-circuit current, and the frequency is inversely proportional to the length of the short-circuited line. After the interruption of the short-circuit current the voltage drop along the line is left behind in the form of a line charge. This charge decays in the form of a travelling wave oscillating at its natural frequency. The rate of rise of these oscillations is quite high owing to the effective surge impedance of the short-circuited line. The RRRV is given by the following relation

$$\text{RRRV} = \sqrt{2} I \omega Z$$

where

I=short-circuit current
ω=service angular frequency

and

Z=the effective surge impedance of the short-circuited line

The RRRV after interruption of a terminal short circuit is of the order of 1.5 KV/μs, whereas the interruption of a short line fault (short circuit about one km away from a line circuit breaker) can cause an RRRV of the order of 6 to 8 KV/μs, depending upon the surge impedance of the line.

EXAMPLE 14.1

A three-phase circuit breaker is rated at 1250 A, 2000 MVA, 33 KV, 4s. Find the rated symmetrical breaking current, making current and short time rating.

Solution. Rated symmetrical breaking current (rms) $= \dfrac{2000}{\sqrt{3} \times 33}$

$= 35$ KA

Rated making current $= 2.55 \times 35$

$= 89$ KA

Short time rating $= 35$ KA for 4s

EXAMPLE 14.2

The test oscillogram shown in Fig. (14.22) was obtained during a make-break test on a circuit breaker. The values marked in the figure are:

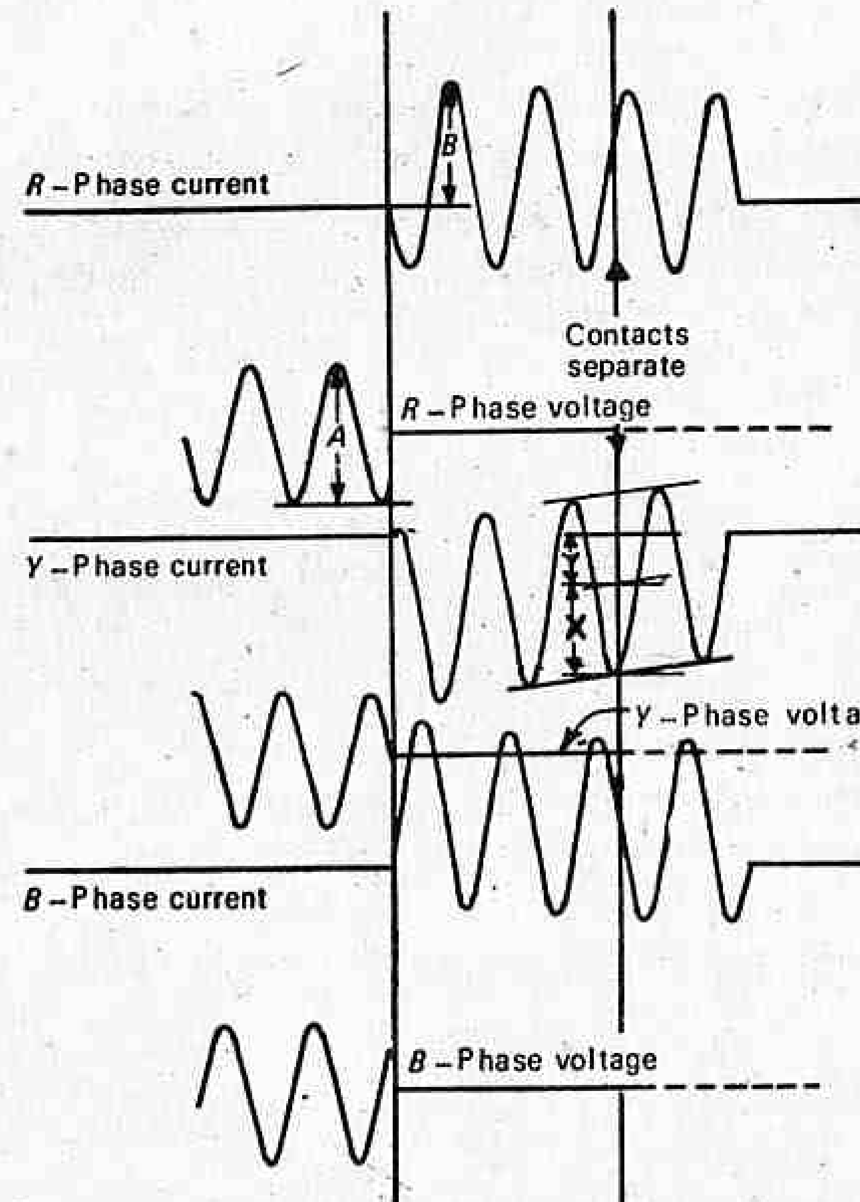


FIGURE 14.22 Oscillogram of a make-break test on a circuit breaker.

$$A=20 \text{ KV}$$
$$B=30 \text{ KA}$$
$$X=21 \text{ KA}$$
$$Y=12 \text{ KA}$$

Find:

(a) Line voltage rating of the breaker.
(b) Peak making current for the red phase only.
(c) A.C. and d.c. components of the breaking current at the instant of contact separation for the yellow phase only. Hence determine whether the test is symmetrical or asymmetrical and estimate the breaking current.

Solution. (a) Peak to peak phase system voltage $=A=20$ KV

Phase system voltage (rms) $=\dfrac{20}{2\sqrt{2}}$
$=7.07$ KV

Rated line voltage $=\sqrt{3}\times 7.07$
$=12.26$ KV

(b) Peak making current $=B=30$ KA

(c) A.C. component of breaking current $=X=21$ KA

D.C. component of breaking current $=Y=12$ KA

Obviously the test is asymmetrical as the d.c. component is not zero at the instant of contact separation.

Hence Asymmetrical breaking current $=\sqrt{\left(\dfrac{X}{\sqrt{2}}\right)^2+Y^2}$

$$=\sqrt{\left(\frac{21}{\sqrt{2}}\right)^2+12^2}$$
$$=19.1 \text{ KA}$$

EXAMPLE 14.3

A 50 Hz, 11 KV, three-phase alternator with earthed neutral has a reactance of 5 ohms per phase, and is connected to busbar through a circuit breaker. The capacitance to earth between the alternator and the circuit breaker is $0.02\ \mu F$ per phase. Assuming the resistance of the generator to be negligible calculate the following:

(a) Maximum voltage across the contacts of the circuit breaker.
(b) Frequency of oscillations.
(c) The average rate of rise of restriking voltage up to the first peak.

Solution. The maximum value of recovery voltage $E_{max}=\sqrt{2}\times\dfrac{11}{\sqrt{3}}$ (phase to neutral)

$=8.96$ KV

Now $v_c=E_{max}(1-\cos\omega t)$

$\because$ Maximum restriking voltage (phase to neutral) $=2E_{max}$

$=2\times 8.96$
$=17.92$ KV

The frequency of oscillations is given by

$$f_n=\frac{1}{2\pi\sqrt{LC}}\ Hz$$

Now $X_L=5$ ohms

$$L=\frac{5}{2\pi\times 50}\ H$$

Hence

$$f_n=\frac{1}{2\pi\sqrt{\dfrac{5}{2\pi\times 50}\times 0.02\times 10^{-6}}}\ Hz$$
$$=8.9 \text{ KHz}$$

The average rate of rise of restriking voltage up to the first peak is given by

$$\frac{\text{Maximum restriking voltage}}{\text{Time up to first peak}}$$
$$v_c=E_{max}(1-\cos\omega t)$$

The first peak of restriking voltage will occur at

$$t=\frac{\pi}{\omega}=\pi\sqrt{LC}$$

Hence average RRRV $=\dfrac{17.92}{t}$

$=17.92\times 2f_n$
$=17.92\times 2\times 8.9\times 10^3$ KV/sec
$=319\times 10^3$ KV/sec

EXAMPLE 14.4

Calculate the RRRV of a 220 KV circuit breaker with earthed neutral. The short-circuit test data obtained is as follows:

The current broken is symmetrical and the restriking voltage has an oscillatory frequency of 15 KHz. The power factor of the fault is 0.2.

Assume the short circuit to be an earthed fault.

Solution. Maximum value of the system voltage $E_{max}=\sqrt{2}\times\frac{220}{\sqrt{3}}$ (line to neutral)

$$=179.5\text{ KV}$$

Instantaneous value of recovery voltage $=E_{max}\times\sin\phi$ (line to neutral)

$$=179.5\times\sin(\cos^{-1}0.2)$$

$$=179.5\times0.9799$$

$$=176\text{ KV}$$

$\therefore$ Maximum value of restriking voltage $=2\times$recovery voltage

$$=2\times176$$

$$=352\text{ KV}$$

Maximum restriking voltage occurs when

$$t=\pi\sqrt{LC}=\frac{1}{2f_n}$$

$$\text{Hence RRRV}=\frac{\text{Maximum restriking voltage}}{t}$$

$$=352\times2\times15\times10^3\text{ KV/sec}$$

$$=1056\times10^4\text{ KV/sec}$$

EXAMPLE 14.5

An air-blast circuit breaker designed to interrupt a transformer magnetizing current of 15A (rms) chops the current at an instantaneous value of 12A. The value of L and C in the circuit are $8H$ and $0.009\ \mu F$. Find the voltage that appears across the circuit breaker. Assume that the inductive energy is transformed to capacitance.

Solution.

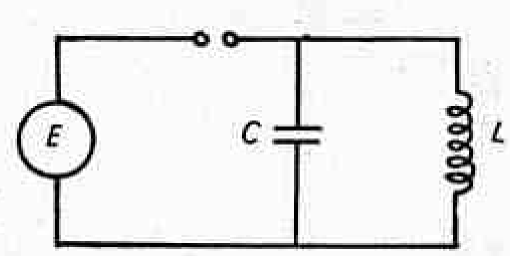


FIGURE 14.23

$$\tfrac{1}{2}Li^2=\tfrac{1}{2}Ce^2$$

$\therefore$ Voltage across the capacitor $e=i\sqrt{\frac{L}{C}}$

Substituting the values

$$e=12\sqrt{\frac{8\times10^6}{0.009}}$$

$$=358\text{ KV}$$

QUESTIONS

1. Explain the terms symmetrical breaking current, asymmetrical breaking current and making current as applied to circuit breakers and show how these currents can be determined from oscillograms taken during short-circuit tests on a three-phase circuit breaker. What is meant by the rated MVA breaking capacity of such a breaker?
2. Explain the terms recovery voltage, restriking voltage and RRRV. Derive an expression for the restriking voltage in terms of system capacitance and inductance.

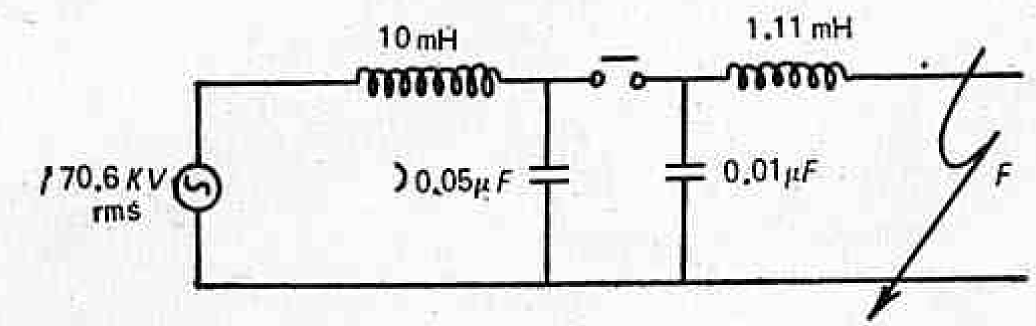


FIGURE 14.24

3. Figure 14.24 shows one phase of a three-phase 132 KV, 50 Hz circuit breaker situated in a power system. A fault occurs at point F, which is a short distance along the line. Obtain an expression for the undamped restriking voltage immediately following the first current zero at which extinction occurs. The breaker may be assumed to be sufficiently slow in operation for transient components of fault current to be negligible.
   [$(v_c=90\,(1-\cos 7150\,t)+10\,(1-\cos 47800\,t)$]
4. In connection with switchgear clearly explain the significance of the term RRRV.
   In a short-circuit test on a circuit breaker, the following readings were obtained on a single frequency transient;
   (i) Time to reach the peak restriking voltage, 50 μs.
   (ii) The peak restriking voltage, 110 KV.

Calculate the average RRRV and the frequency of oscillations.

(2.2 KV/μs; 10KHz)

5. Write technical notes on the following:
   (i) Capacitive current breaking.
   (ii) Current chopping phenomena.
   (iii) Interruption of kilometric fault.

multiplied individually by the following correction factors given in Table 14.2.

Table 14.2 *Correction factors for various altitudes*

Altitude (metres)	*Rated max. voltage and insulation level*	*Rated current*
1000	1.00	1.00
1500	0.95	0.99
3000	0.80	0.96

Interpolated correction factors shall be used in determining correction factors for intermediate altitudes.

(2) *Rated Frequency.* The rated frequency of the circuit breaker is the frequency at which it is designed to operate. Standard frequency is 50 Hz. Applications at other frequencies should receive special consideration.

(3) *Rated Breaking Capacities, Symmetrical and Asymmetrical.* It can be seen from the shape of the short-circuit current Fig. (14.1) that the rms value of the current varies with time on account of the presence of d.c component of the current which decreases with time.

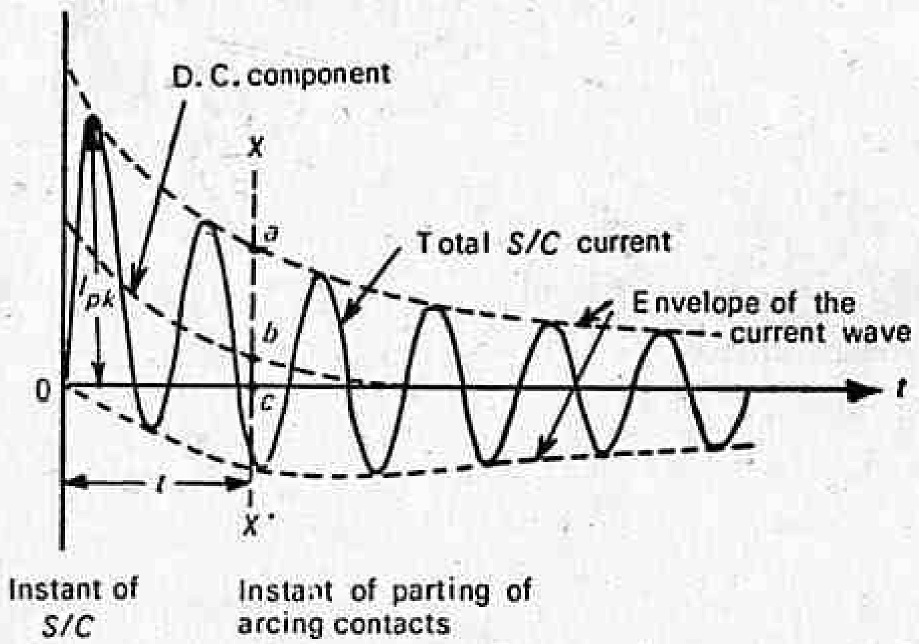


FIGURE 14.1 Short-circuit current wave.

After the instant of fault, the short circuit current starts decaying from a high initial value to a sustained value. In addition, owing to *relaying time* the circuit breaker starts to open its arcing contacts only some time later, after the initiation of short circuit. Therefore, the actual current interrupted by the circuit breaker is less than the initial value of short-circuit current.

The IEC definition of breaking current is as follows:

Breaking Current. The breaking current of a pole of a circuit breaker is the current in that pole at the instant of contact-separation. It is expressed by two values.

(a) *The symmetrical breaking current.* This is the rms value of a.c. component of the current in the pole at the instant of contact separation.

$$I_{sym}=\frac{ab}{\sqrt{2}} \qquad \text{[refer Fig. (14.1)]}$$

(b) *The asymmetrical breaking current.* This is the rms value of the total current comprising the a.c. and d.c. components of the current in that pole at the instant of contact separation.

$$I_{asym}=\sqrt{\left[\left(\frac{ab}{\sqrt{2}}\right)^2+(bc)^2\right]} \qquad \text{[refer Fig. (14.1)]}$$

Now according to these two values of breaking currents there are two corresponding values of breaking capacities. Conventionally the breaking capacity in MVA is equal to $\sqrt{3}$ times the rated voltage in KV times the rated breaking current in KA. However, the breaking capacities can now be defined as follows:

(i) The symmetrical breaking capacity, is the value of symmetrical breaking current which the circuit breaker is capable of breaking at a stated recovery voltage and a stated reference restriking voltage under prescribed conditions.

(ii) The asymmetrical breaking capacity is the value of the asymmetrical breaking current which the circuit breaker is capable of breaking at a stated recovery voltage and a stated reference restriking voltage under prescribed conditions.

(4) *Rated Making Current Capacities.* This value characterizes the capability of breakers to close its contacts against short-circuit currents.

Making currents. The making current of a circuit breaker, when closed on a short circuit, is the rms value of the total current (including both a.c. and d.c. components) which is measured from the envelope of the current wave at the time of its first major peak.

The making current may also be expressed in terms of instantaneous value of current in which case it is measured at the first major peak of the current wave. This value is known as designed peak making current.

Figure (14.1) shows the short-circuit current wave, where I_{pk} represents the peak making current.

The making capacity of a circuit breaker is the current that the circuit breaker is capable of making at stated voltage under prescribed conditions of use and behaviour.

The rated making capacities of a circuit breaker are those which correspond to rated voltage. The absence of any indication to the contrary

Table 14.3 *Standard ratings of circuit breakers as per IEC specifications 56-3-1959*

Voltage (KV) (rms) *Nominal*	*Maximum design*	*Breaking capacity* (MVA)	*Normal current* (amperes)					
3	3.6	50	400	—	—	—	—	—
		150	—	630	(800)	1250	—	—
		250	—	—	—	1250	1600	2500
6	7.2	100	400	—	—	—	—	—
		150	400	630	(800)	1250	—	—
		250	—	630	(800)	1250	—	—
		350	—	630	(800)	1250	1600	—
		500	—	—	—	1250	1600	2500
10	12	150	400	—	—	—	—	—
		250	400	630	(800)	1250	—	—
		350	—	630	(800)	1250	1600	2500
		500	—	630	(800)	1250	1600	2500
		750	—	—	—	1250	1600	2500
		1000	—	—	—	1250	1600	2500
15	17.5	150	400	630	(800)	—	—	—
		250	400	630	(800)	1250	—	—
		350	—	630	(800)	1250	—	—
		500	—	630	(800)	1250	—	—
		750	—	630	(800)	1250	—	—
		1000	—	—	—	1250	1600	—
20	24	250	400	630	(800)	—	—	—
		350	(400)	630	(800)	1250	—	—
		500	(400)	630	(800)	1250	—	—
		750	—	630	(800)	1250	—	—
		1000	—	—	—	1250	1600	—
		1500	—	—	—	—	1600	2500
30	36	350	400	60	(800)	—	—	—
		500	[400]	630	[800]	—	—	—
		(750)	400	—	(800)	1250	—	—
		1000	—	630	(800)	1250	1600	—
		1500	—	—	—	1250	1600	—
		2500	—	—	—	1250	1600	2500
45	52	500	—	630	(800)	—	—	—
		1000	—	630	(800)	1250	—	—
		1500	—	—	—	1250	1600	—
60	72.5	750	—	630	(800)	—	—	—
		1000	—	630	(800)	—	—	—
		1500	—	630	(800)	1250	—	—
		2500	—	—	—	1250	1600	—
80	100	1000	—	630	—	—	—	—
		1500	—	630	—	—	—	—
		2500	—	630	—	1250	—	—
100	123	1500	—	630	—	—	—	—
		2500	—	630	800	—	—	—
		3500	—	—	800	1250	—	—
		5000	—	—	—	1250	—	—
120	145	1500	—	630	—	—	—	—
		2500	—	630	—	—	—	—
		3500	—	—	800	1250	—	—
		5000	—	—	800	1250	—	—
		7500	—	—	—	1250	1600	—
		10000	—	—	—	—	1600	—
150	170	2500	—	630	—	—	—	—
		3500	—	—	800	1250	—	—
		5000	—	—	800	1250	—	—
		7500	—	—	—	1250	1600	—
		10000	—	—	—	—	1600	—
220	245	3500	—	—	800	—	—	—
		5000	—	—	800	1250	—	—
		7500	—	—	—	1250	1600	—
		10000	—	—	—	1250	1600	—
275	300	15000	—	—	—	—	1600	—
		7500	—	—	—	1250	—	—
		10000	—	—	—	1250	1600	—
		15000	—	—	—	—	1600	—
380	420	10000	—	—	—	—	—	2000
		15000	—	—	—	1250	—	2000
		25000	—	—	—	1250	—	2000

NOTE : (i) The rated vaules of (800) A and (400) A shown in round brackets are only alternative values to 630 A.
(ii) The values 400 A and 800 A in square brackets are alternatives to the single value 630 A.
(iii) The value (750) A in round brackets is alternative to 1000 A.

on the name plate implies that each rated making capacity is of the value given by:

$$\text{Rated making capacity} = 1.8 \times \sqrt{2} \times \text{symmetrical breaking capacity}$$
$$= 2.55 \times \text{symmetrical breaking capacity}$$

Factor 1.8 is employed to account for the asymmetry present in the short-circuit current.

(5) *Rated Short Time Current.* The short time current of a circuit breaker is the rms value of current that a circuit breaker can carry in a fully closed position without damage, for the specified short time interval under prescribed conditions. It is normally expressed in terms of KA for a period of 1 sec or 4 sec, known as one-second rating and four-second rating, respectively. These ratings are based on thermal limitations.

No similar short time ratings are given for low-voltage breakers because such breakers are normally equipped with direct acting series overload trips.

(6) *Rated Operating Duty.* The operating duty of a circuit breaker consists of a prescribed number of unit operations at stated intervals.

According to IEC recommendations for rated operating duty for breakers which are not intended for auto-reclosure, there are two alternatives

(a) $O-t-CO-t'-CO$
(b) $O-t''-CO$

where O = opening operation

C = closing operation

CO = closing followed by opening

t, t', t'' = time intervals

t and t' are expressed in minutes

t'' in seconds

Circuit breakers with auto-reclosures have the operating duty as follows:

$$O-0-CO$$

0 is the dead time of the circuit breaker expressed in cycles.

The various components of operating time of circuit breaker are illustrated in Fig. (14.2).

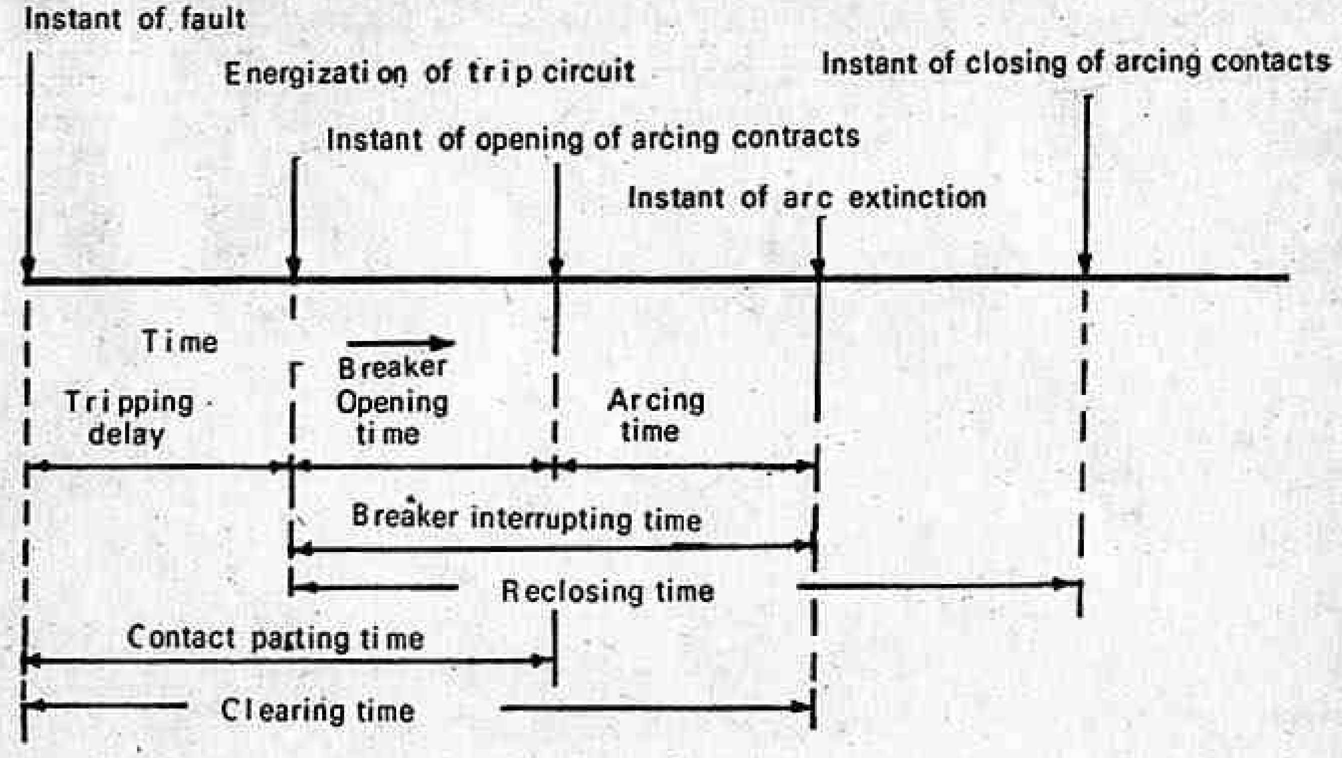


FIGURE 14.2 Various components of operating time of circuit breaker.

14.3 Circuit Constants and Circuit Conditions

While closing or opening the circuit breaker, the circuit constants play an important role. It was noticed in practice a circuit breaker that would operate satisfactorily at one point on a system may not do so at another, showing that the circuit conditions have some influence on the circuit breaker behaviour.

Figure (14.3) shows a power system and its equivalent circuit, where L is the inductance of the generator, transformer and the transmission line

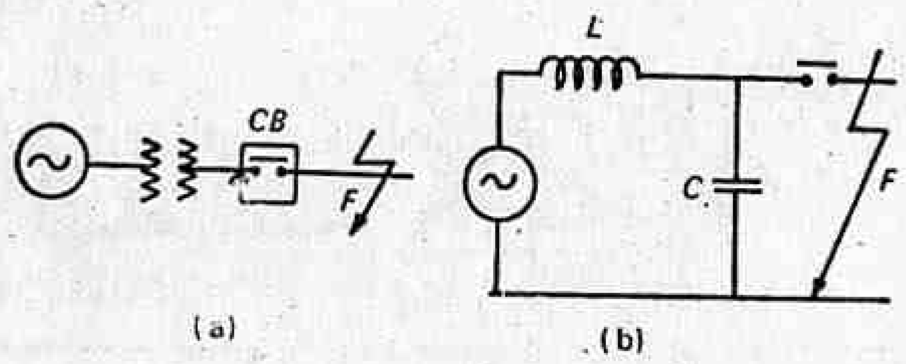


FIGURE 14.3 Power system and its equivalent circuit.

and C is the capacitance of the generator, transformer, transmission line and the bushings of the circuit breaker. The last item can be neglected at system frequency but it becomes effective at high frequencies. Overvoltages are caused by switching and also by certain faults. Figure (14.4) shows typical magnitudes of overvoltage due to switching and faults.

The transients resulting from switching are caused by residual energy (either electric or electromagnetic or both), i.e. energy stored in capacitance

C or inductance L or both, when it undergoes a change from one steady state to another owing to interruption of circuit.

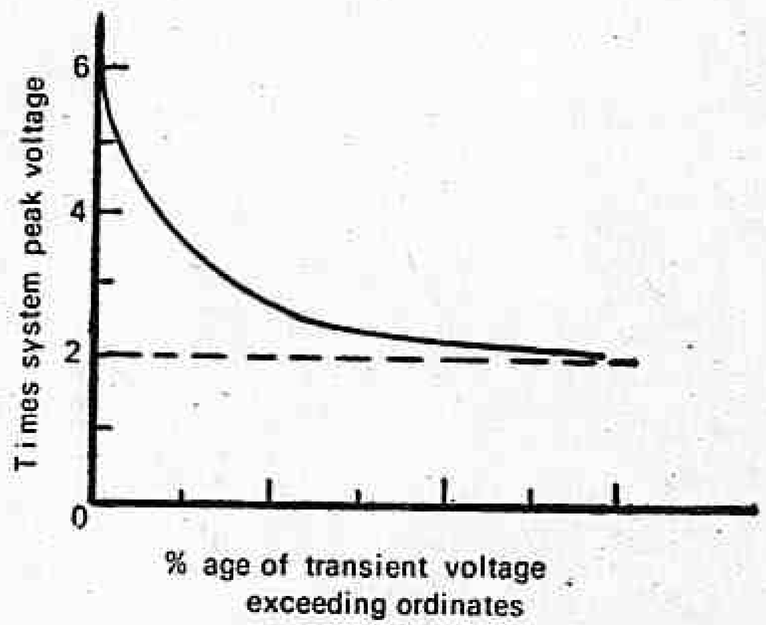


FIGURE 14.4 Magnitudes of overvoltages due to switching and faults (excluding voltages less than twice system peak voltage).

14.3.1 Voltage After Final Current Zero

Experience in service and at short-circuit testing stations has demonstrated that the behaviour of circuit breakers when breaking short-circuit currents depend on a number of factors which may be termed as conditions of severity.

The short-circuit current wave and the voltage wave (Fig. (14.5)) show that, as the current interruption takes place invariably at zero current of

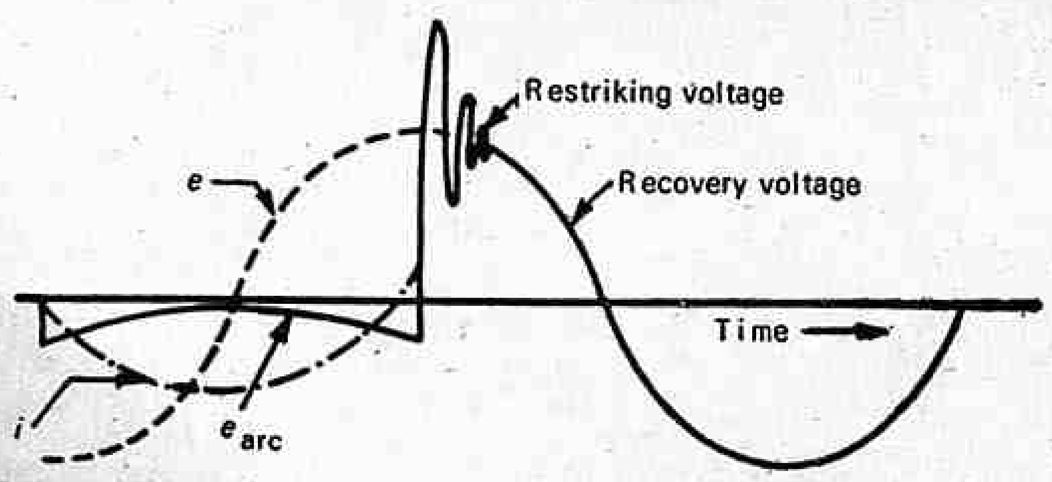


FIGURE 14.5 Restriking and recovery voltage wave shapes.

the current wave, the voltage that appears across the poles of the circuit breaker has an important bearing on the performance of the circuit breaker. As a matter of fact the successful interruption of the current itself is dependent on this voltage.

This voltage that appears across the poles after current interruption as seen in Fig. (14.5) has a transient part immediately after current interruption, which is known as *restriking voltage* and after the transient oscillations subside it attains the normal frequency voltage and then it is known as *recovery voltage*. These two terms are however defined as follows.

Recovery voltage. It is defined as the normal frequency rms voltage appearing between the poles of the circuit breaker after final arc extinction.

Restriking voltage. It is defined as the transient voltage that exists at or in close proximity to reach zero current pause during the arcing time.

14.3.2 Conditions of Severity

The instantaneous value of recovery voltage at the instant of final current zero depends on the following factors:

(a) *Effect of Power Factor of Circuit.* The instantaneous value of the recovery voltage depends on the p.f. as illustrated in Fig. (14.6). It is clear therefore that a reactive short circuit is much more difficult to interrupt than a resistive short circuit of the same current and voltage, as the instantaneous value of the recovery voltage in the former case is high (maximum voltage) as compared to the latter (zero voltage). Unfortunately all serious short circuits are almost purely reactive.

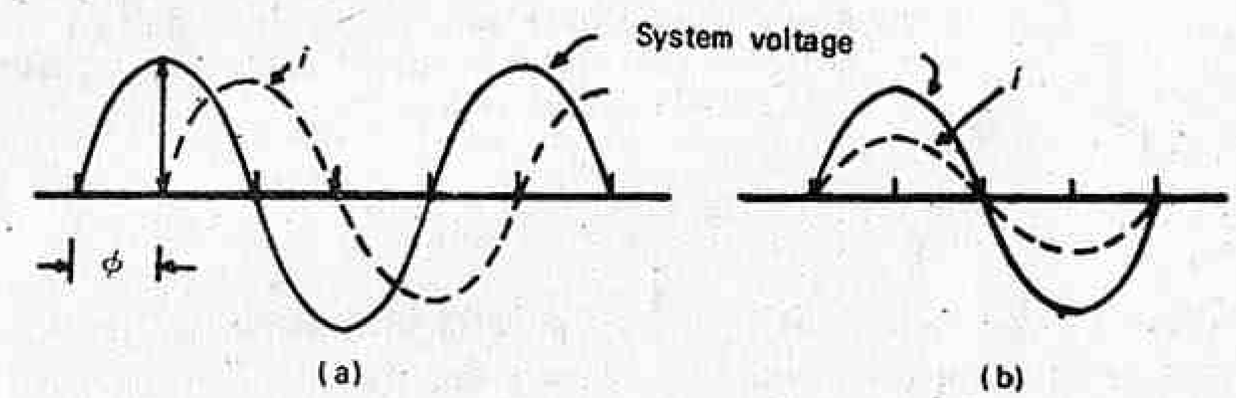


FIGURE 14.6 Effect of power factor on the instantaneous value of the recovery voltage.

(b) *Effect of Circuit Conditions.* The type of fault and the condition of the neutral point, i.e. whether earthed or insulated also affects the voltage across the poles of the circuit breaker in which the arc is first extinguished. This is illustrated in Fig. (14.7). If the neutral is insulated or the fault does not involve earth, a voltage of 1.5 times phase voltage appears across the pole of the circuit breaker in which the arc is first extinguished.

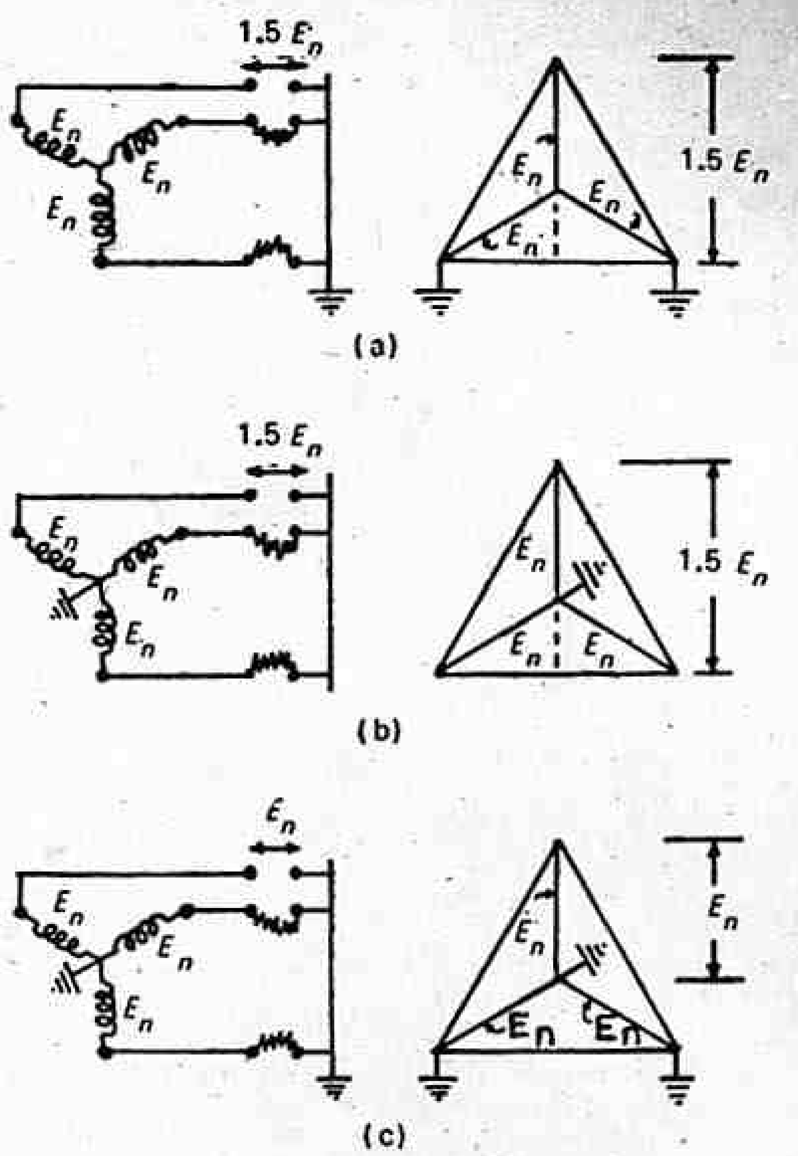


FIGURE 14.7 Recovery voltage of the first phase to clear in a circuit breaker interrupting a three-phase fault: (a) neutral insulated and fault earthed; (b) neutral earthed and fault insulated; (c) neutral earthed and fault earthed.

(c) *Current Asymmetry*. With the asymmetry introduced in the current wave to be interrupted it is possible to vary the instantaneous value of the recovery voltage at current zero. This is illustrated in Fig. (14.8).

The existence of a large d.c. component in a short-circuit current may cause the recovery voltage wave to start near the zero point instead of at its crest. The instantaneous value of recovery voltage is thus considerably reduced.

(d) *Effect of Armature Reaction*. The recovery voltage is less than the normal system voltage because of demagnetizing effect of armature reaction. The short-circuit currents are of lagging power factor and are flowing in the generator windings. They have a demagnetizing armature reaction. Hence they reduce the terminal voltage.

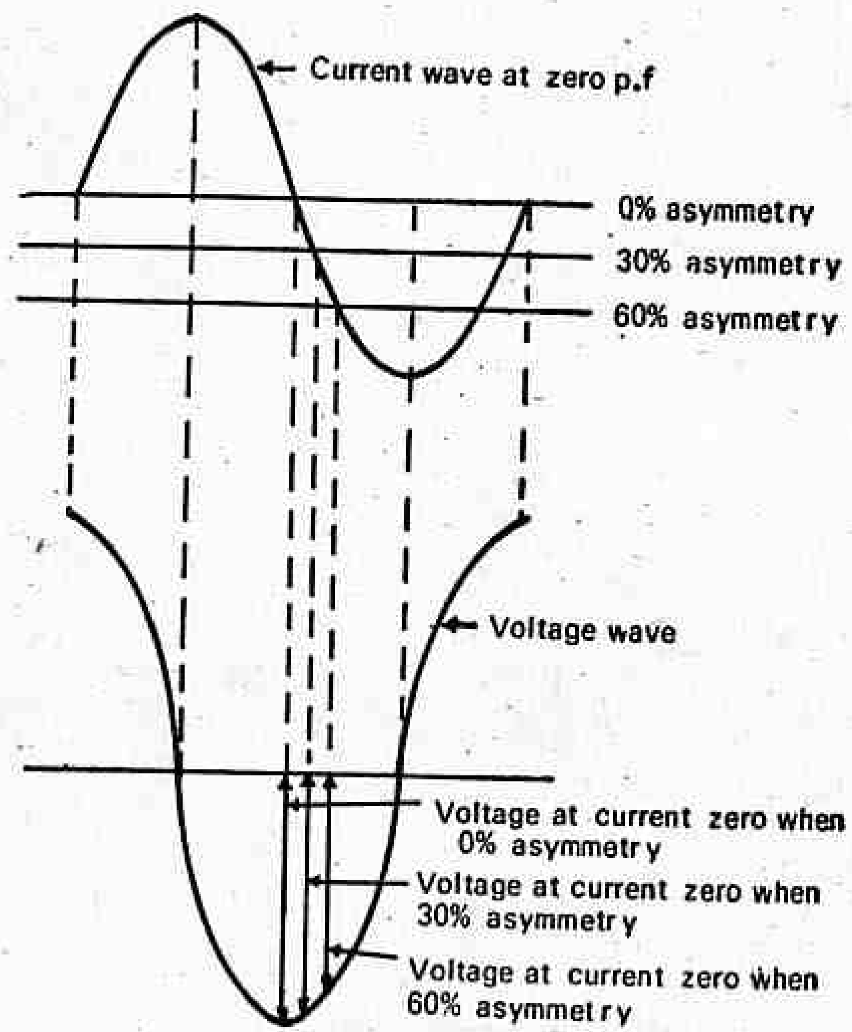


FIGURE 14.8 Effect of current asymmetry on the instantaneous value of the recovery voltage.

14.4 Restriking Voltage Transient

Electrically a power system is an oscillatory network so that it is logical to expect that the interruption of fault current will give rise to a transient, whose frequency depends on the constants of the circuit. It has been pointed out earlier that this transient voltage is referred to as restriking voltage, which occurs immediately following arc extinction. The arc voltage across the contacts at this instant is normally quite low, whereas the power frequency voltage in the circuit is at or near its peak value.

Considering again a simple circuit of Fig. (14.9) in which an inductive source is cleared of a fault condition by the opening of circuit breaker S, arc extinction occurring at an instant of zero current.

The restriking voltage v_c developed across the opened breaker contacts is given in Laplace form by

$$v_c = \frac{E_{max}/p}{pL + \frac{1}{pc}} \tag{14.1}$$

$$= \frac{E_{max}}{L}\left[\frac{1}{p\,(p^2+\omega^2)}\right]$$

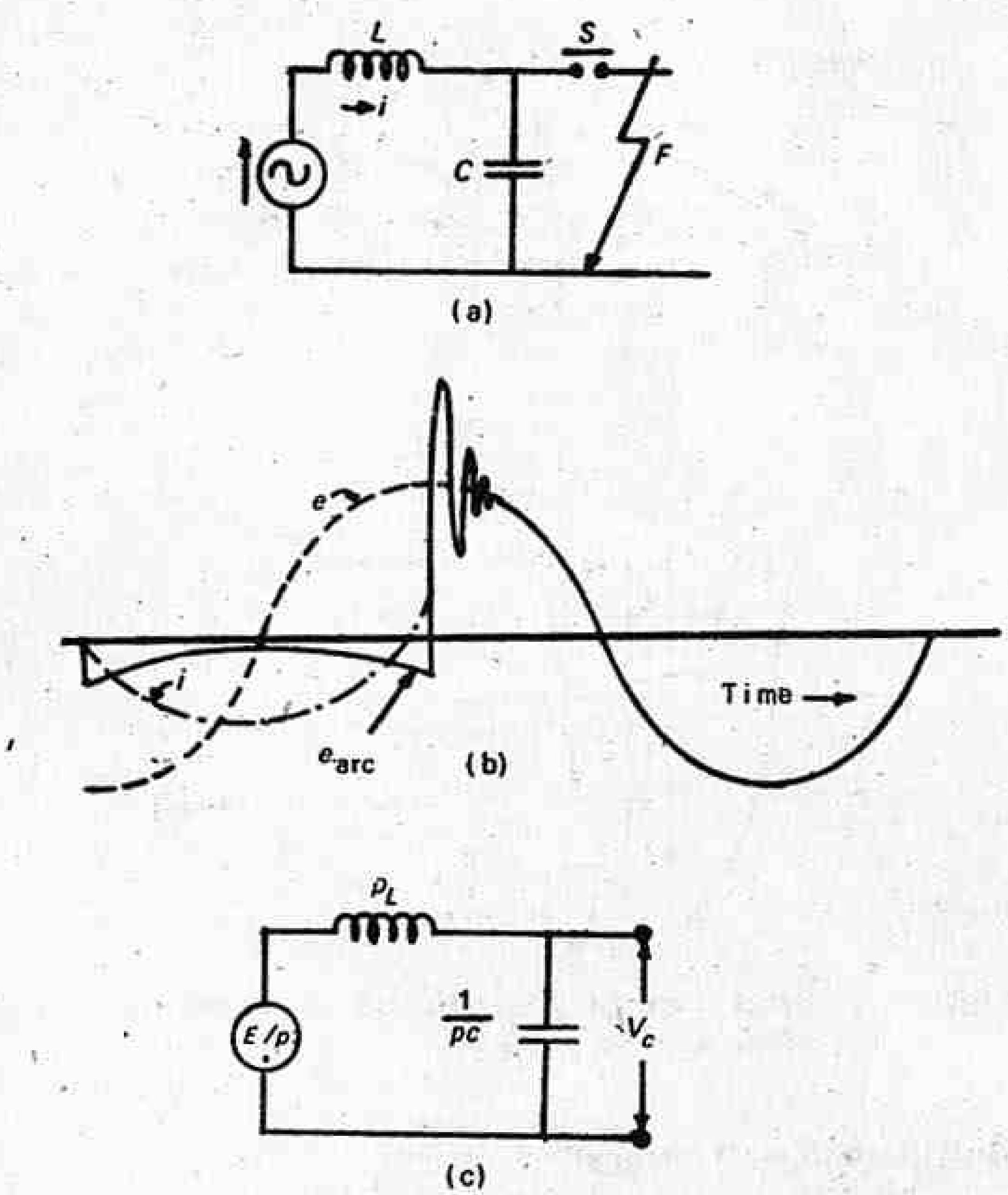


FIGURE 14.9 (a) Basic circuit. (b) Current and voltage waveforms. (c) Laplace equivalent circuit.

where $\omega = 1/\sqrt{LC}$ and E_{max}=peak value of recovery voltage. Transforming back into a time function

$$v_c = E_{max}\,(1-\cos\omega t) \tag{14.2}$$

The maximum value of restriking voltage v_c is $2\,E_{max}$ and occurs at $t=\pi/\omega$ or equal to $\pi\sqrt{LC}$. The oscillatory transient voltage has a frequency of $1/2\pi\sqrt{LC}$ Hertz.

14.4.1 Classification of Restriking Transients

Restriking voltage transients, and consequently their respective circuits can generally be placed under two main headings.

(1) *Single Frequency Oscillatory Transients.* Conditions are as shown in Fig. (14.9a). The voltage wave form is shown in Fig. (14.9b). When the switch contacts part an arc is formed which normally extinguishes at a

current zero, the circuit voltage then being at its peak. This voltage tries to appear across the circuit breaker but is delayed in doing so due to presence of capacitance *C*, which gets charged and then establishes the voltage across the circuit breaker. However a transient (restriking) voltage at the natural frequency of the simple *L-C* series circuit is superimposed on that already existing in the circuit (recovery voltage) as shown in Fig. (14.9b). The natural frequencies are of the order of 1000 to 10,000 Hz.

(2) *Double Frequency Transients.* It is quite possible that the circuit breaker *S* may have *L* and *C* parameters on its two sides, as shown in Fig. (14.10). Before clearance the points *a* and *b* are at the same potential. After the fault is cleared, i.e. the arc has been extinguished, both the circuits oscillate at their own natural frequencies a composite double frequency transient appears across the circuit breaker *S* (Fig. (14.10b)).

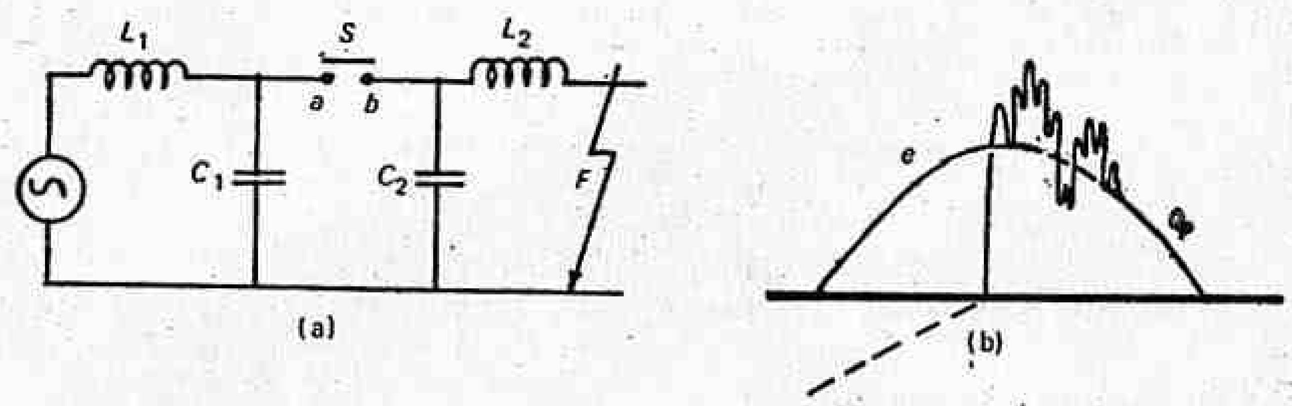


FIGURE 14.10 Double frequency restriking transient.

14.5 Characteristics of Restriking Voltage

The important characteristics of restriking voltage which affect the circuit breaker performance are: (a) amplitude factor, (b) rate of rise of restriking voltage (RRRV).

(a) *Amplitude Factor.* The amplitude factor is defined as the ratio of the peak of transient voltage to the peak system frequency voltage. BS 116 specify the standard for evaluating amplitude factor.

(b) *Rate of Rise of Restriking Voltage (RRRV).* The RRRV is defined as the slope of the steepest tangent to the restriking voltage curve. It is expressed in volts per microsecond. For a restriking voltage having a single frequency transient component the RRRV is obtained by dividing the maximum amplitude of the oscillation by the duration of the first half wave. Higher values of natural frequencies can be related with higher rates of rise of restriking voltage. It is clear that other things being equal, the duty of a circuit breaker is much more severe when used in a network of high natural frequency than on a network having low natural frequency because the average RRRV is very much greater in the first case. In the latter case the voltage across the contacts of the circuit breaker rises slowly thereby giving longer time for building up of the dielectric strength.

14.5.1 Expression for RRRV

The expression for the restriking voltage has already been derived in Eq. (14.2).

$$\text{RRRV} = \frac{dv_c}{dt}$$

$$\frac{dv_c}{dt} = E_m\omega \sin \omega t \tag{14.3}$$

Maximum value of RRRV occurs when

$$\omega t = \frac{\pi}{2}$$

or
$$t = \frac{\pi}{2\omega}$$

or
$$t = \sqrt{LC}\,\frac{\pi}{2} \tag{14.4}$$

Hence maximum value of RRRV

$$\text{RRRV}_{max} = E_m\omega$$

Further, the peak restriking voltage occurs when v_c is maximum, i.e. at

$$\frac{dv_c}{dt} = 0$$

or
$$\omega t = \pi$$

i.e.
$$t = \pi\sqrt{LC} \tag{14.5}$$

14.5.2 Factors Affecting the Restriking Voltage Characteristics

After current zero, the initial rate of rise and the peak value of the restriking voltage stressing the contact gap depend on the configuration of the network, its natural frequency and on the relative position of the resistances (in parallel or series with the main capacitance of the circuit) as shown in Fig. (14.11). It is quite logical to expect that the presence of resistance damps the rate of rise of restriking voltage. The true nature of attenuation is complicated since the losses depend on many things such as

conductor resistance, iron loss, dielectric loss, corona, etc. These factors vary with frequency and voltage in different ways.

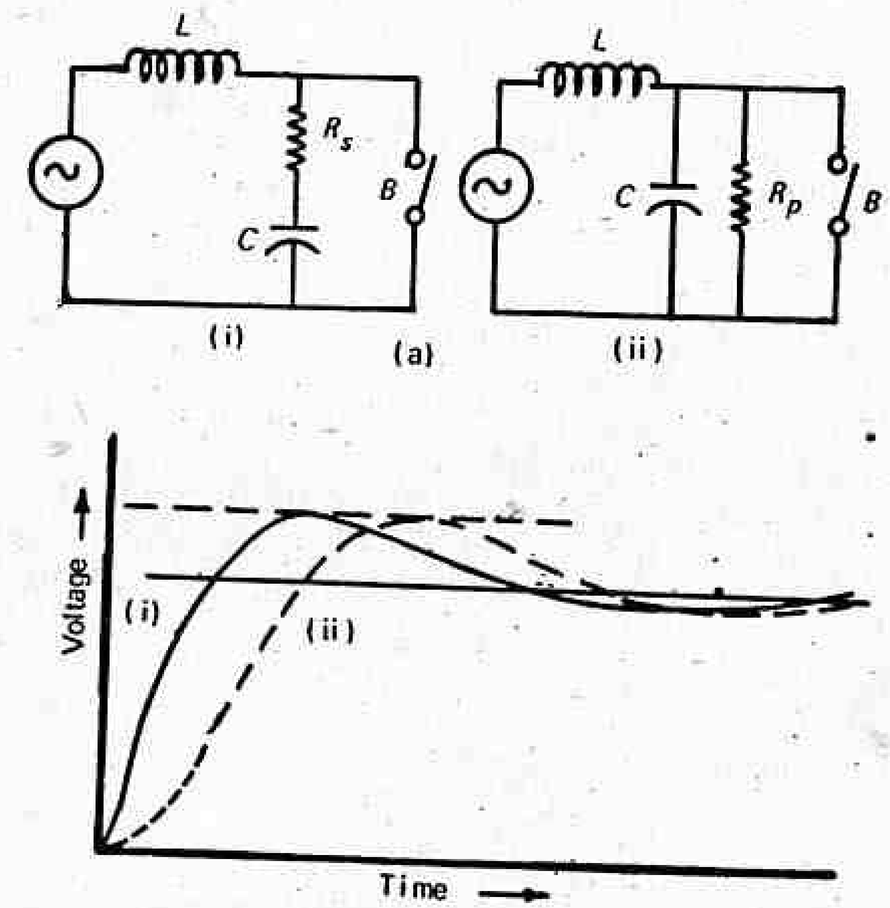


FIGURE 14.11 (a) Typical switching circuits, with resistances in series and in parallel with the circuit capacitance. (b) Restriking voltage curves.

In a network consisting of generators, transformers, reactors, and transmission line, each of them exerts its own damping. Usually the attenuation due to them is too small to be relied upon for improvement in the performance of a breaker. Where high RRRV are expected circuit breakers with shunt resistances (Fig. (14.11)) are used. Now to ensure that the voltage across the breaker builds up exponentially to the 50 Hz recovery voltage, without overshoot, instead of exhibiting the oscillatory doubling effect associated with an undamped circuit, the value of resistance R_p needed to achieve critical damping is $\frac{1}{2}\sqrt{L/C}$. Figure (14.12) shows the restriking voltage critically damped and other related wave shapes.

It can thus be inferred that the shunt resistance across the breaker modifies the oscillatory restriking voltage into an aperiodic wave (curve V). This entails the arc to be extinguished even though the dielectric strength of the gap increases only relatively slowly (curve V_2) as a result of severe short circuit. Inclusion of the shunt resistor thus increases the rupturing capacity of the breaker.

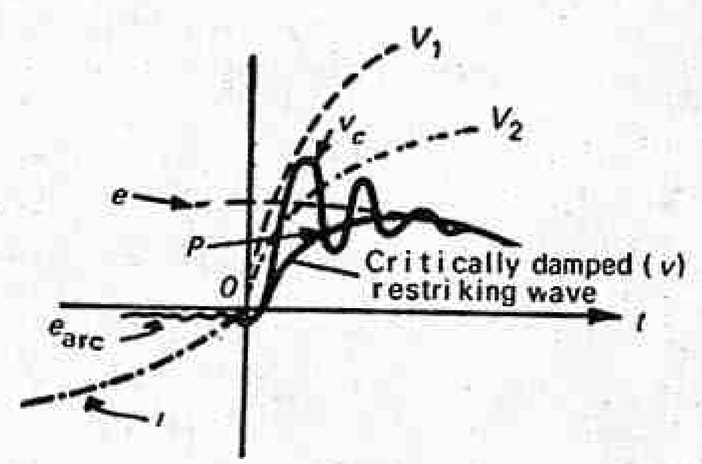


FIGURE 14.12 Critically damped restriking voltage and other related wave shapes. e—alternator voltage; v_c—restriking voltage following oscillatory law when no parallel resistor is connected; v—critically damped restriking voltage when shunt resistance of value $R_p=\frac{1}{2}\sqrt{L/C}$ connected; V_1—increasing dielectric strength of the contact gap after interruption of a relatively small fault current; V_2—increasing dielectric strength of the contact gap after interruption of a relatively large fault current; i—fault current; e_{arc}—arc voltage; 0—instant of arc extinction (fault current zero); P—intersection point of the curves of restriking voltage v_c and recovery dielectric strength. Intersection means that restrike of the arc can occur.

Figure (14.13) shows the relation of RRRV and rupturing capacity of an air-blast circuit breaker with and without shunt resistors as a function of *natural* frequency. It has already been pointed out earlier that without shunt resistance the RRRV is directly proportional to the natural frequency of the circuit, and the rupturing capacity of the breaker therefore falls rapidly with increasing frequencies. In the case of breaker with shunt resistance the RRRV cannot exceed a certain value determined by the resistor and hence the rupturing capacity does not fall to that extent. For

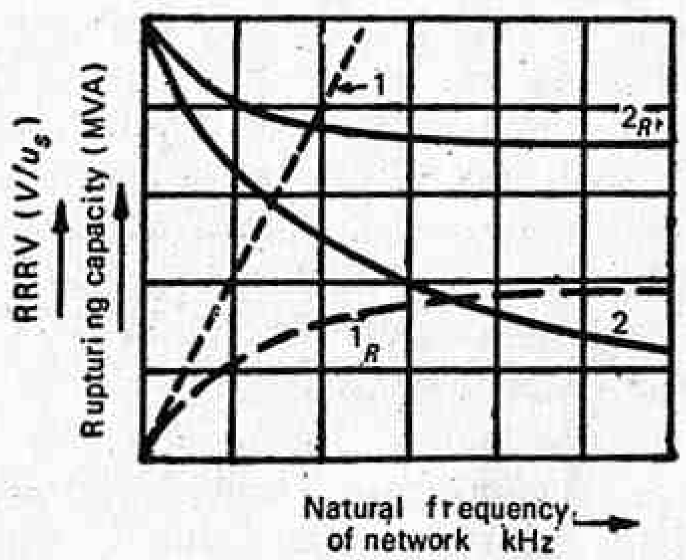


FIGURE 14.13 RRRV and rupturing capacity of an *ABCB* expressed as a function of natural frequency. 1—RRRV without resistor; 1_R—RRRV with shunt resistor; 2—rupturing capacity without resistor; 2_R—rupturing capacity with resistor.

higher values of natural frequencies the advantage gained in the rupturing capacity is more.

14.6 Interaction between the Breaker and Circuit

The circuit breaker performance can well be seen from the interaction between the breaker and the circuit. It is convenient to regard the short-circuit current i in the period around current zero as composed of two parts: the arc current i_a and the transient current i_c flowing in the capacitive part of the circuit which determines the restriking voltage. The voltage across the circuit breaker e_a is related to i_a by the dynamic characteristics of the arc and also to i_c by the inherent transient response of the external circuit, while at any instant before or after zero $i=i_c+i_a$. Figure (14.14) shows in schematic form how the current across the capacitance C aids interruption by lowering the current immediately before zero.

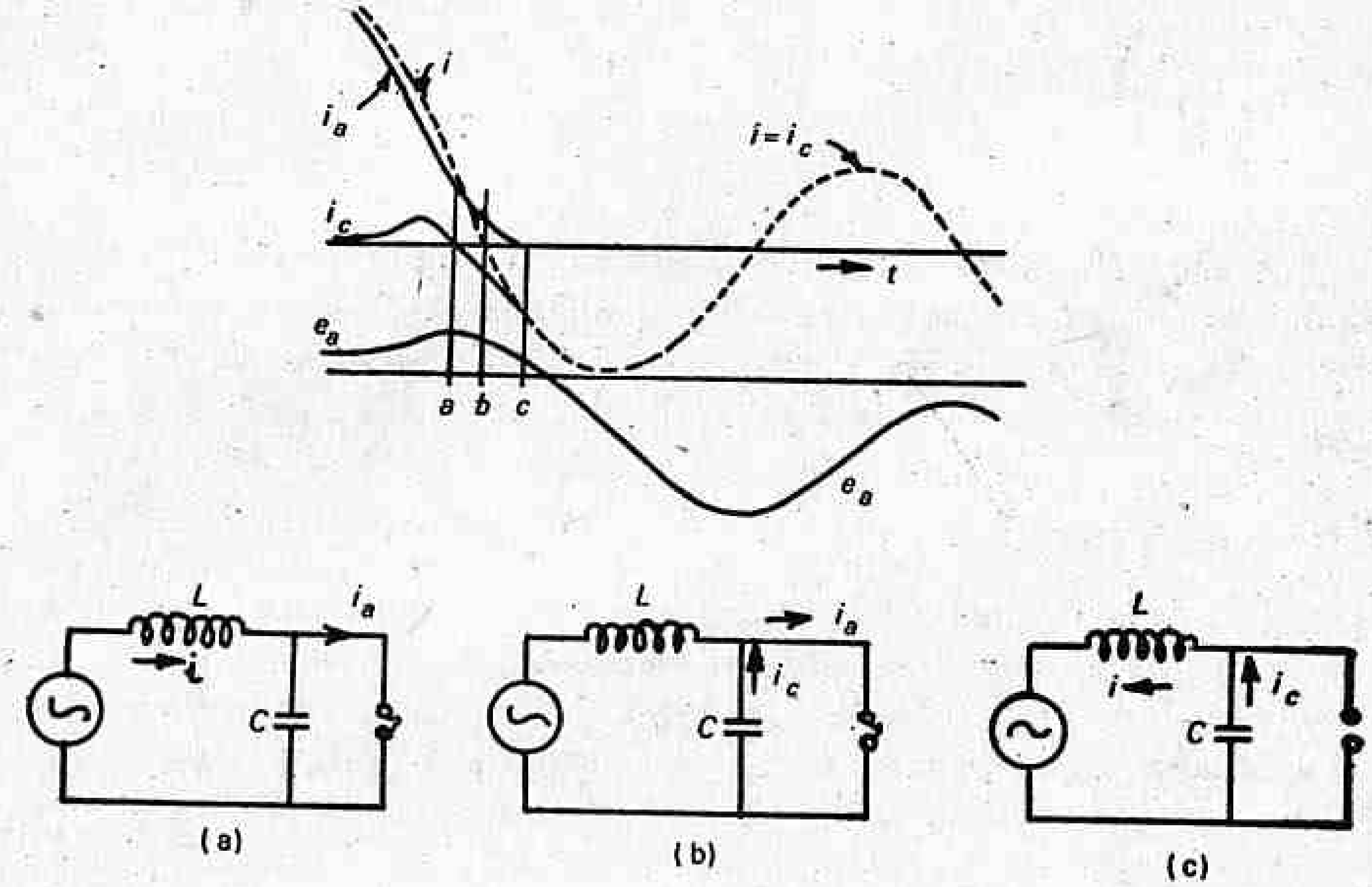


FIGURE 14.14 Effect of parallel capacitance on arc current near zero.

If e is the supply voltage in the circuit then the equation of the circuit can be written as $e=L\,di/dt+e_a$. Considering the events occurring from the time when e_a begins to rise, this causes a diversion of current into the shunt capacitance C given by $i_c=C\,de_a/dt$. This current is positive and since $i_a=i-i_c$, it is obtained at the expense of the arc current which therefore starts to fall more rapidly than i. Now as the instant a is approached, the rate of fall of i_a diminishes and at instant a, $de_a/dt=0$, $i_c=0$, and $i_a=i$ (Fig. (14.14a)). Immediately after this the capacitance C

CHAPTER **15**

Theory and Practice of Conventional Circuit Breakers

The type of circuit breaker is decided by the method by which the residual current is deionized at current zero, and the ability of the dielectric condition to withstand the restriking voltage transient, which appears after current ceases to flow. To control this deionization in the least possible time various techniques have been adopted such as air break, oil and air blast interruption.

15.1 Automatic Switch

The simplest circuit interruption device is the knife switch. By closing the switch against the action of a spring we have an automatic device in which the energy for opening the contacts is stored by the closing operation. Such a device is shown in Fig. (15.1). Here only a small force and a short time is needed to open the switch by means of a simple latch, which when it is tripped, releases the stored energy of the spring

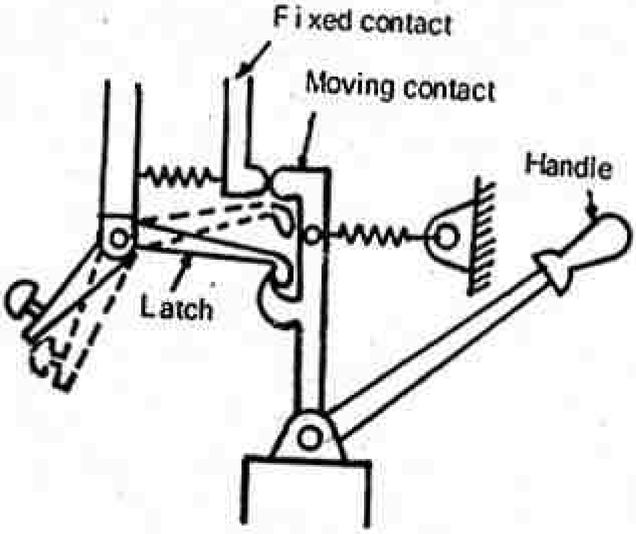


FIGURE 15.1 Automatic switch.

resulted in a growing use of pneumatic operation for oil immersed circuit breakers and this in turn has encouraged the investigation into the use of compressed gas as a circuit breaking medium. It is well known that it is the hydrogen released from the oil by the arc and not the oil itself that did most of the work. This has resulted in the investigation of a gas blast device.

Although a patent was taken out in 1927, due to the unchallenged supremacy of oil breakers it was not until 1940s that air blast was used commercially as a circuit breaking medium. The success in the development of air-blast breaker has been so rapid and significant that today it surpasses all other types. Majority of the circuit breakers for voltages over 110 KV today are of air-blast type. Table 15.2 shows the typical voltages and short-circuit ratings of air-blast circuit breakers. The world ratings have increased generally as shown in Table 15.2 and the first 1100/1300 KV uhv ratings are expected by the 1990s.

Table 15.2 *Typical voltages and short-circuit ratings of air-blast circuit breakers*

System voltage (KV)	66	110–132	220	275	300	400	500	735
Short-circuit rating (MVA)	2500 to 5,000	2500 to 10,000	5000 to 20,000	10,000 to 20,000	10,000 to 20,000	25,000 to 35,000	30,000 to 40,000	35,000 to 60,000
No. of breaks per phase	2	2 to 4	2 to 6	4 to 8	4 to 8	4 to 12	6 to 12	8 to 12

15.5.2 Interruption Methods

It is not possible to produce a low resistance arc without a considerable gas pressure so that the only type available employs a high-pressure gas blast sweeping across the contact space. The gases which can be used are compressed air, nitrogen, carbon dioxide, hydrogen and freon. Now nitrogen is equivalent in circuit breaking properties to compressed air and therefore there is no advantage in using nitrogen. Carbon dioxide has the drawback of its being difficult to control owing to freezing at valves and other restricted passages. Tests have shown an increased breaking capacity by the use of hydrogen, but its cost and that of the ancillary apparatus are a serious objection. Freon has high dielectric strength and good extinguishing properties, but it is expensive and it is decomposed by the arc into acid forming elements. It follows from the above that compressed air is the accepted circuit-breaking medium for gas-blast circuit breakers.

All air-blast circuit breakers follow the principle of separating their contacts in a flow of air established by the opening of a blast valve. The arc which is drawn is usually rapidly positioned centrally through a nozzle where it is kept to a fixed length and is subject to maximum scavenging by the air flow. Arrangements vary but can be grouped into three types as shown in Fig. (15.12): (a) axial blast, (b) radial blast and (c) cross blast. Axial or radial blast seems to be favoured for the higher voltages although cross blast breakers particularly for voltages of about 15 KV and heavy current (up to 100 KA) have proved satisfactory and require less air than would an axial-blast breaker at these high currents.

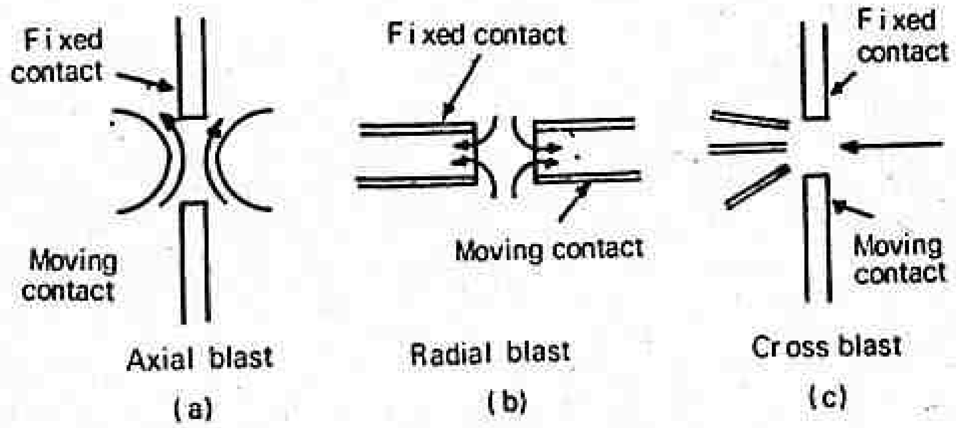


FIGURE 15.12 Air blast circuit breakers.

It is well recognized that the main structural advantage of the axial-blast circuit breaker over the cross blast is its easier adoptability to high voltage insulation particularly for outdoor applications. This is because the interrupting chambers can be fully enclosed in porcelain tubes. The axial blast type of circuit breaker thus is ideal for high and super voltage application and outdoors where dust and corrosive fumes are encountered. In the indoor high power medium voltage class of circuit breakers currents of 2000–4000 A are common, requiring special multifinger contacts in order to keep the temperature low enough to prevent damaging oxidation. A multiple interruption by air blast can be arranged for very high voltages and exerting a joint radial and axial cooling by direct air convections. In order to secure high air velocities in air-blast circuit breakers it is imperative to provide for relatively short wide passages for the air flow between pressure reservoir and arc. If the necessary volume of air is available near the arc, velocities exceeding that of sound may be attained at the critical instant of extinction.

15.5.3 Principle of Operation

Gas blast interruption is dependent on turbulent cooling, and is therefore influenced by aerodynamic configuration, including nozzles, gas flow passages and mass flow. Compressed air is an excellent insulant, and is forced on the arc at the instant of contact separation. The compressed air sweeps the arc through the nozzle, which helps exhaust the hot gas and the arcing products to the atmosphere. In this way the interrupter of an air-blast circuit breaker performs its operating cycle for its ideal characteristics. Extinction occurs at the first current zero when the flow of compressed air increases rapidly to establish the dielectric strength between the electrodes to withstand restriking voltage. The growth of dielectric strength is rapid and pressure of air is so high that the final gap caused by interposition of insulating layer of air between the contacts need only be small, thus reducing the size of the device. The energy supplied for arc extinction is obtained from high pressure air and is independent of the current to be interrupted.

15.5.4 Aerodynamic Effects During Arcing

A knowledge of the air flow characteristics is important to circuit breaker design, since the removal of hot plasma and particulate matter determines both the interrupting ability and also the dielectric strength. Initiation of the lateral arc in the air turbulator causes a pressure disturbance in the flow of compressed air. The source of the disturbance (i.e. hot gas channel) being initially free, moves downstream at the same velocity as the compressed air. The arc (i.e. hot gas channel) is thus transferred rapidly into such a position that it offers the maximum drag to the air flow, namely, into a central position along the axis of the nozzle. This rapid transfer is to be expected from a consideration of the velocity distribution in a typical air blast nozzle. In this central position, the arc must either stand or fall. The ensuing aerodynamic condition at the nozzle may be regarded as a series of momentary disturbances of the flowing air due to the release of arc energy from a fixed source; these disturbances are such that throughout the arcing period, the stream of air tends to yield to the pressure caused by the expansion and dissociation of air in the inner stream

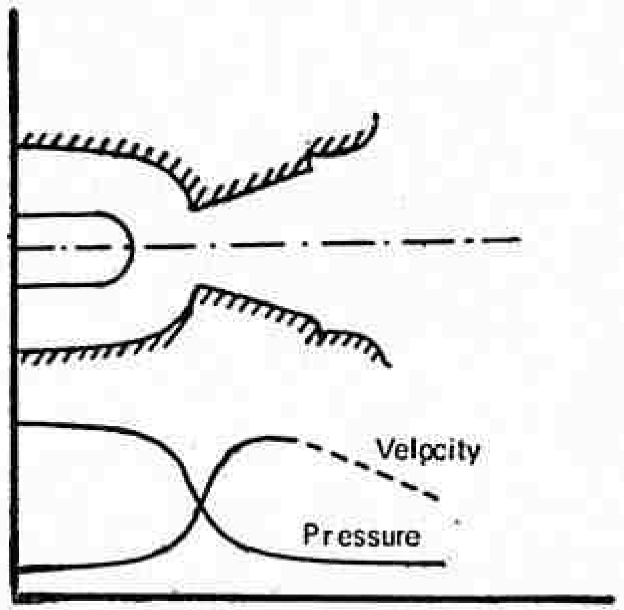


FIGURE 15.13 Pressure and velocity distribution in a typical contact structure.

zones as this air continuously enters the leading end of the arc zone. Conversely arc acts almost as an obstacle in nozzle, around which the bulk of air must flow. Figures (15.13) and (15.14) illustrate pressure and velocity distribution and the gas flow through nozzles. It is seen that the presence of arcing causes considerable reduction in the quantity of air passing through the nozzle because of dissociation and expansion of air in the inner stream zones.

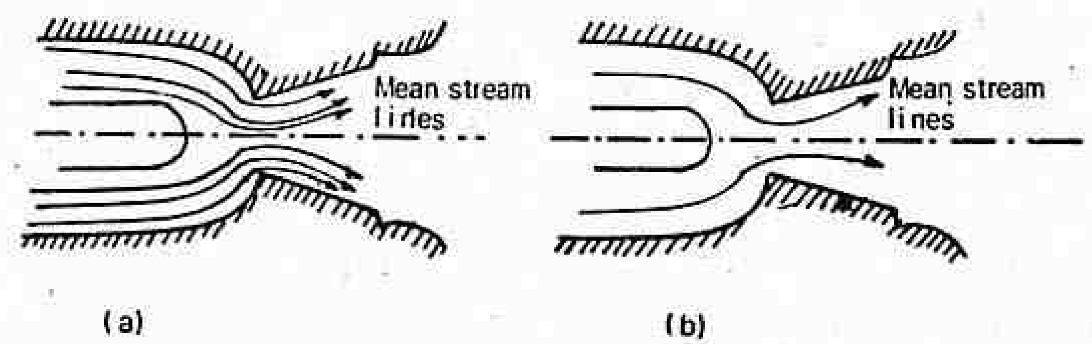


FIGURE 15.14 Gas flow through nozzles: (a) no arcing; (b) arc present.

This effect is dependent on the length of arc at high pressure side of nozzle and on current flowing, i.e. the amount of preheating which air stream undergoes before reaching the throat of nozzle. At small currents the ionized arc column is repeatedly disrupted, and the electron discharge is interrupted; this is known as current suppression. At very large currents the air column gets heated up rapidly and the interruption becomes difficult and takes a longer time.

The aerodynamic arrangement of air-blast breakers is devised to make the ratio of air pressure at interrupting nozzles to the pressure in the receiver as high as possible. To this end, valve gear and pipe system should be made large and free from unnecessary bends, so that the major component of pressure drop occurs across the nozzles themselves.

15.5.5 Factors Influencing Performance of Air-Blast Circuit Breakers

There are a number of limiting parameters affecting the performance of the breaker; some of them lead to contradictory requirements that make the development of switch gear so difficult yet uniquely fascinating. Some of the important factors are discussed below.

(a) *Air Pressure.* Air is readily compressible and the dielectric switching capabilities have been shown to increase up to at least 150 atmospheres. The performance may therefore be expected to vary as some function of pressure, for the same contact structure. The results indicate a linear increase in breaking capacity with pressure at the nozzle, the lower limit being reached when the contact-gap setting is unable to withstand the voltage. The use of high pressure gas permits high mechanism speeds and fast arc scavenging.

(b) *Circuit Severity.* It has long been known that air-blast breakers are sensitive to variations in the rate of rise of restriking voltage (RRRV) which is normally taken as a measure of circuit severity. Since the blast effect is constant for all currents the rate at which the gap recovers its dielectric strength, which varies approximately inversely as the amount of ionization present, i.e. inversely as the current, falls with increasing MVA. This indicates that at low MVA values the breaker can cope with higher RRRVs than at higher MVA. If the RRRV is increased above the value indicated for each MVA level then the additional stress will produce a sudden increase in arcing time. Figure (15.15) shows the normal variation of breaking capacity with RRRV. Furthermore the effect of RRRV upon current zero conditions is more likely to show up in a breaker where the chance of extinction decreases after the optimum gap has been reached, as compared with the oil circuit breaker where the chance of extinction increases from one current zero to the next.

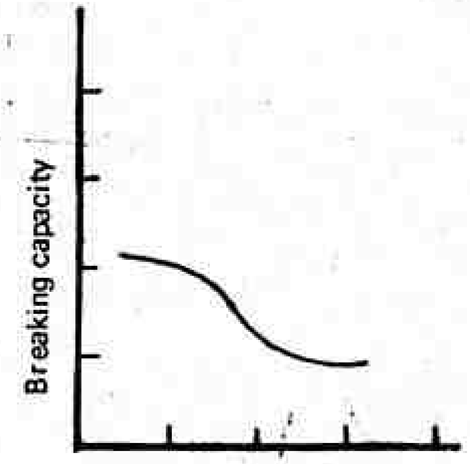


FIGURE 15.15 Variation of breaking capacity with RRRV of an air-blast circuit breaker.

(c) *Distance between Contacts.* It is seen that appreciable variations in performance can be obtained by varying size of the gap. The best condition for arc extinction is obtained for a specific optimum distance between contacts. If this distance is increased or decreased, the arc extinction becomes less effective and consequently breaking capacity of the breaker will be reduced. Figure (15.16) shows the relation of breaking capacity and contact gap, but optimum distance between the contacts for arc extinction condition does not necessarily ensure the required dielectric strength between the contacts, once the compressed air supply is stopped. This calls for the introduction of an isolating switch as part of this type of circuit breaker. High voltage breaker with a short gap and an isolator can give a total break time as small as 2 cycles. Sometimes the isolator is eliminated but the contact gap is made greater than the optimum value.

Such an alternative is an economic possibility when the service voltage is low enough to permit a convenient final gap length for insulation clearance at normal air pressure.

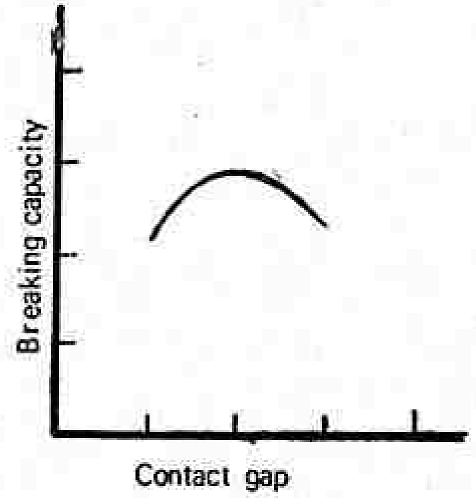


FIGURE 15.16 Variation of breaking capacity with contact gap of an air-blast circuit breaker.

It is possible to develop a relation connecting perfomance with the geometry of the contact structure. Consideration of the process of arc extinction leads to the assumption that if a number of circuit breakers are both aerodynamically and dielectrically similar, their circuit breaking performances will be equal. For aerodynamic similarity, Reynold's number (vl/u) and Mach's number (v/v_s) must be constant.
where

v=velocity between similarly situated points
l=length between the points
u=kinematic viscosity (which is inversely proportional to pressure)
v_s=velocity of sound in the gas

It can thus be deduced that for equal performance of a number of geometrically similar circuit breakers the product of air pressure and some selected linear dimension (e.g. the nozzle diameter of each) must be constant throughout.

For the dielectric similarity Townsend's laws are applicable which requires that the product of mass of gas per cubic centimetre and some selected linear dimension must be constant, and since this is precisely the same requirement as for aerodynamic similarity it follows therefore that both requirements are met simultaneously. This means that if the air pressure varies between two circuit breakers as l/p, the dimensions must vary as p/l.

It has already been mentioned that performance is proportional to pressure when linear dimensions are constant. Nevertheless, it should be noted that increasing the pressure also allows the contacts to be placed closer together, and so a further increase in performance is possible.

If the linear dimension is taken as the diameter of the nozzle, the performance at constant voltage can be expressed as follows:

Performance $(I\times U) \propto p\times d\times$factor depending upon nozzle geometry.

or $\dfrac{I\times U}{p\times d} \propto$ factor depending upon nozzle geometry

where

I=current broken, KA

$U=RRRV\,(V/\mu s)$

p=pressure at nozzle kg/m^2 absolute

d=diameter of nozzle, m

or $\dfrac{I\times U}{p\times d}$=function of G/d at constant voltage

where

d=diameter of nozzle, m

G=length of gap, m

(d) *Contact Material.* A definite improvement in performance is observed by the use of high-boiling point metals, such as the tungsten-copper compounds now available as a result of advancement in powder metallurgy. By the use of these metals the breaking capacity can be increased, burning and erosion considerably reduced and flame emission minimized. The development of such metals coupled with the short arcing time of the air-blast circuit breaker has made it possible to produce contacts that will not need replacing during the lifetime of a circuit breaker.

(e) *Area of Cross Section of the Exit Hole.* The breaking capacity is increased with the area of cross-section of the exit through which hot and decomposed gas can escape. This is explained by the fact that the arc liberates tremendous heat in very short duration of time and air within the chamber suddenly expands almost with explosion. The building up of pressure due to this will severely restrict the energy of main air pressure to the arc extinction chamber. There are cases when the exit is so small that fresh supply of air cannot enter fast enough and the arc left unquenched over a long period.

(f) *Resistance Switching.* It is well known that the resistance in parallel with the circuit breaker damps the voltage oscillations. When the voltage and MVA of a circuit are fixed, the transient can be influenced only by increasing C or reducing R. To increase C is uneconomical, but a reduction in R can be brought about by shunting the breaker with a resistor during switching period.

The shunt resistor may perform one or more of the following functions:

(i) To reduce the rate of rise and amplitude of restriking voltage transient and thus ease the duty.
(ii) To reduce transient voltage produced when switching inductive or capacitive loads.
(iii) To improve uniformity of voltage sharing in case of multibreak circuit breakers.
(iv) To suppress and to control the switching surge severity in an *EHV* system.

Values of resistances required to perform the aforesaid functions are quite different. It is often necessary to compromise and make one resistor do more than one of these jobs. Shunt resistors may be either linear resistors or nonlinear resistors.

(g) *Mass Flow.* The breaking capacity of air-blast circuit breakers depend upon the mass of air flowing per unit time through the nozzle in the arcing chamber. The presence of arc obstructs the flow of air and this depends on the temperature of arc column, since the mass flow is roughly inversely proportional to temperature. In this regard a factor referred to as mass flow number (M) defined as the ratio of mass flow of air per unit time with arc to the mass flow of air per unit time without arc, is taken into account to express the performance of circuit breaker.

Mass flow number (M) has been shown to be a function of $I/(d^{1.5}p^{0.5})$.
where

I=rms current
d=nozzle diameter
p=reservoir pressure

15.5.6 Basic Construction of Air-Blast Circuit Breakers

Figure 15.17 shows the essential elements of an air-blast interrupter. With the breaker closed, load current is carried by heavy copper main contacts. Following the instruction to trip, the air blast at about 2 MN/m^2 ($1MN/m^2$=145 psi=9.9 atmospheres) is turned on by the opening of a valve and the moving contacts set in rapid motion by the action of compressed

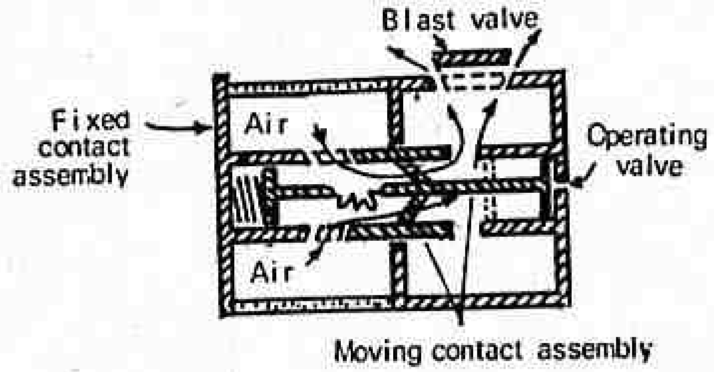


FIGURE 15.17 Air-blast interrupter.

air on a piston. As the contacts part, an arc is either drawn between special arcing contacts or transferred to them by the blast. The maximum separation of the contacts is in the region 10–20 mm and is commonly attained in 3 ms.

In actual air-blast circuit breakers local air storage may be at earth potential and air supplied to the interrupters through insulating pipes or it may be mounted at the level of the interrupters at line potential and the air fed through insulating pipes. The blast valve may also be in one of many positions as given below:

(i) Receiver on the ground and blast valve at low level. Here the blast pipe must be filled before the interrupters are supplied with air.
(ii) Receiver on the ground and blast valve at high level. This reduces the amount of air wasted but requires an insulated drive to the blast valve.
(iii) Live receiver and blast valve. Shorter opening times are possible as the air is stored near the interrupter units.

15.5.7 Use of Interrupters in Series

It has already been shown that multibreak systems have definite advantages. However the distribution of voltage is uneven across the different breaks. Two ways exist of ensuring that the voltage across the breaker is evenly shared by the series breaks. First a capacitance say 500 pF per break can be added. Second, a resistor divider arrangement using about 10,000 ohms across each break produces good grading although a series isolating switch in compressed or free air is required to break the small resistor current following clearance of the main circuit.

Lower resistances could cause sequential breakdowns; if one of the units fails and is supplied by a high current across the resistors in parallel to the other units, it would not be able to recover, but another unit would also reignite because of the higher voltage stress. The resistances may be either nonlinear or constant.

When switching a fault on a short transmission line, a high frequency transient voltage (up to 50 Khz, rising at up to 10,000 V/μs) appears at the breaker terminals. Under this stress at the limit of the circuit breaker performance, post-zero conductivity can be present following arc extinction and it is the conductivity of the individual arc column which determines the voltage grading across each break. The short line severity is not expected to increase at ultra high voltage (UHV) levels.

15.5.8 Requirements for UHV Circuit Breakers

The specific requirements demanded of a UHV circuit breaker by system

and operator considerations are at present considered to be the following.

(a) *Speed of Operation.* For UHV systems the speed of breaker operation is very important since a loss of stability would be most serious to the system. A total interrupting time of two cycles or 40 ms is possible. As far as the air-blast breaker is concerned, its main contribution is the high operating pressure available for fast mechanism operation and guaranteed arc extinction in one half cycle of arcing.

(b) *Limitation of Switching Surges.* UHV systems are not troubled so much by lightning surges as by internally produced voltage surges. Closing on to deenergized lines is the greatest problem and is of more importance than the case of opening lightly loaded long transmission lines. There are three common solutions or combinations of solutions to limit the production of switching over voltages.

(i) *Synchronization.* In this case a circuit breaker is closed only when, for an unenergized line, the source voltage is zero or for an energized line, the voltage across the breaker equals zero. The latter zero, however can be difficult to predict if shunt reactors are on the line. A closing accuracy of 1 ms is needed and so the physical problems are onerous.

(ii) *Closing with resistor insertions.* Closing with a series resistor 7 to 8 ms before the main contacts reduces the surge phenomenon both on resistor insertion and subsequent shorting. This insertion time has to allow the last reflected surge to return to the breaker, thus equalling the scatter between poles plus twice the transit time to the end of the line. The optimum resistance value is approximately equal to the surge impedance of the line, i.e. 300 to 400 ohms. If the value chosen is too high then the major

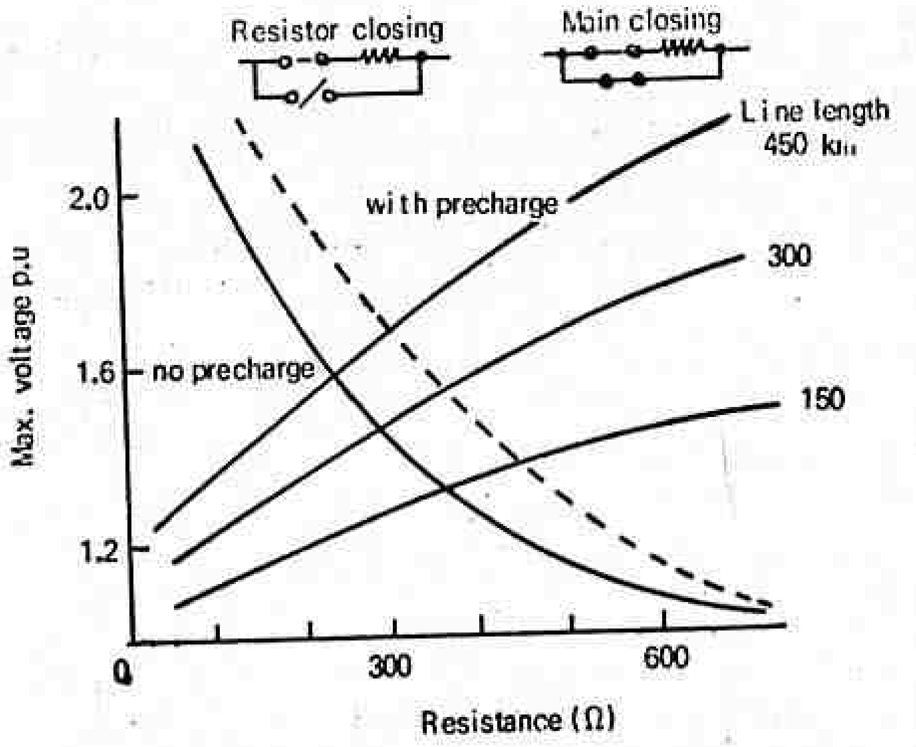


FIGURE 15.18 Typical overvoltage with resistor insertion.

overvoltage occurs on shorting the resistor and if too low then the overvoltage occurs on resistor insertion. Figure (15.18) shows likely overvoltages predicted from a typical transient network analyzer study. Obviously the correct choice of supply and line parameters is important for accurate forecasting.

(iii) *Closing with two or more resistors.* An extension of the idea above which further limits the overvoltage by sequential switching of higher than lower resistance values prior to the closure of the main contacts. A combination of (i) and (ii) can reduce overvoltages to less than 1.8 pu. It must be borne in mind that surges up to 1.5 pu can be obtained from straightforward three-phase switching transients.

(c) *Insulation Coordination.* Insulation coordination concerns the use of adequate dimensions for the various components of a transmission system such that any overvoltages occurring should be kept within specified limits and if flashover were to occur it would cause limited damage. In circuit breakers there are two main flash over paths: first to earth via external and internal surfaces and, secondly, across the contacts. For the latter, a uniform voltage distribution is desirable and the inter contact flashover path is made the stronger of the two by 15% or so. Surge arresters are used for UHV systems since it is difficult to coordinate solid and gaseous insulations for different geometries and wave shapes at the highest voltages to ensure that flashover occurs where it does the least damage.

(d) *Noise Level.* Air-blast circuit breakers avoid the risk of fire in or near circuit breakers containing large quantities of oil, but in turn are sometimes criticized because of noise. If the operating air is not permitted to blast into atmosphere but is contained within a closed vessel, then the noise level can be reduced to that corresponding to an oil breaker. This type of *enclosed blast* circuit breaker may comprise a number of blast heads enclosed within a metal tank, the latter forming the exhaust reservoir. Alternatively the blast heads may be mounted on porcelain support insulators with high and low pressure reservoirs suitably disposed.

The present British maximum for the allowable impulsive noise is approximately 95 dB at 25 m distance and the noise frequency spectrum is generally examined. Audible corona noise which also produces radio and TV interference must be reduced to an acceptable level especially in wet weather by suitable electrostatic stress relief of components.

15.5.9 Development of Air-Blast Switchgear

The development of air-blast circuit breakers has taken place in three stages shown schematically in Fig. (15.19):

(a) Momentarily pressurized air-blast breakers with isomaker in the atmosphere.
(b) Momentarily pressurized air-blast breakers with isomaker in separate pressurized chamber.
(c) Permanently pressurized air-blast breakers with isomaker in separate pressurized chambers.

In the first design air-blast valve is placed inside the storage tank at earth potential and the contacts are separated by the air pressure acting against a spring. The blast is removed after about 100 ms and the contacts reclose. An isomaker arm opens in free air about 40 ms after the main contacts breaking the current of a few amperes flowing through voltage grading resistors and serve both to isolate and to make the circuit.

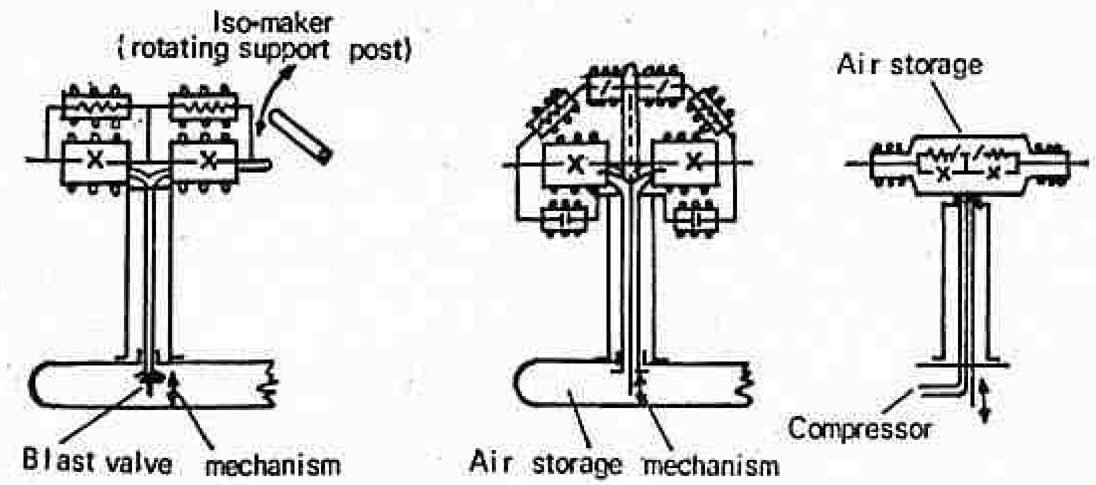


FIGURE 15.19 Electrical arrangement of main and auxiliary interrupters with grading capacitors and resistors.

The main drawbacks with this type of air-blast breakers are:

(i) For the highest voltage steps (420, 525, 765 KV) isolators of greater length and therefore of higher inertia must be used. It becomes difficult to give them the high speeds required on breaking and on closing under all atmospheric conditions with a sufficient reliability.
(ii) When the isolator is long it practically becomes impossible to achieve the high speed auto-reclosing feature.
(iii) Compressed air consumption is quite high.
(iv) Due to its weight and general architecture the circuit breaker cannot be suspended.
(v) The construction design does not lead to the lowest possible cost.

In the second series of air-blast breakers the tripping operation is secured by admitting compressed air into the interrupter when the main valve opens. Air activates the piston causing the contacts to open and then extinguish the arc. Exhaust gases are expanded to the atmosphere through the nozzles. A few hundredths of a second later, the valves are closed and the compressed air can now no longer be expelled to the atmosphere. The contacts are held open in compressed air. The circuit breaker can remain in this position indefinitely. For closing, the valve is reclosed and thus the receiver and the interrupter do not communicate with each other. Valves are open which in turn depressurize the interrupter. Drawn back by its springs, the moving contact closes.

The advantages of this arrangement over the first series of air-blast breakers are:

(i) The circuit breaker is generally light because of the elimination of heavy series isolator.
(ii) The isolator is no longer a hindrance to reach extra high voltages. By mounting 2, 3, 4 or 8 interrupters in series it is possible to build circuit breakers for 100, 170, 245, 420, 525, 735 KV.
(iii) Since closing and opening operations utilize only low inertia parts, high speed auto-reclosures with dead times of about 0.03s are possible.
(iv) The higher weight and smaller size makes it possible easily to build interrupting elements for either supported or suspended installation.

The disadvantages of this series are:

(i) Emptying the interrupters on every closing operation entails a high compressed air consumption, since for the subsequent tripping operation the corresponding dead volume must be filled again. Furthermore the closing time is too long.
(ii) When the circuit breaker comprises a number of interrupters per pole the existence of main valve imposes that these interrupters are arranged symmetrically with respect to the valve so that compressed air supply is perfectly balanced. Consequently there is an important restraint in the architecture of the circuit breaker. For instance, it is not easy to achieve a circuit breaker with 3 or 4 interrupters mounted vertically one over the other and to have the circuit breaker occupy the minimum space area.
(iii) On tripping, the pressure in the interrupter does not reach its maximum value forthwith and thus the blast is not fully utilized when the contacts begin to part.

In the third series of air-blast breakers the compressed air is always stored in interrupters at 100% of the rated value. The tripping operation is secured by an auxiliary relay which opens the exhaust valves first and then followed by the opening of the contacts. A few ms later the exhaust valves reclose whereas the contacts are held open. On closing, the contacts are closed by the depressurizing action whereas the valves remain still closed.

The main advantages of this series of air-blast breakers over the previous designs are:

(i) As the air pressure in the chamber is always at full rated value, full efficiency is realized thus ensuring large breaking capacities.
(ii) On account of the above reason the build up of dielectric strength across contacts immediately after their separation is greatly improved.
(iii) Air consumption is extremely low because only a small quantity of air is exhausted and the chambers are not to be recharged to the full volume. On account of this air consumption and acoustic energy due to the exhaust of air are extremely low.
(iv) Owing to better dielectric properties of compressed air and the rated pressure at the time of contact separation the breaking capacity of each chamber increases, thus reducing the number of breaks per phase and also reducing the maintenance and overall dimensions.
(v) Owing to the permanently pressurized design the erosion by the preliminary spark during closing operation is considerably reduced.
(vi) Since the contacts are surrounded by the high pressure medium that is a good conductor of heat the rated normal current rating can be raised up to 2000 A without any difficulty.
(vii) Low weight of complete breaker and absence of ground shocks permits installation any where and substantially reduces foundation costs.

The most recent *modular* designs extend the above principles, while higher pressures (about $6 MN/m^2$) and the use of low value damping resistors about 400 ohms per pole permits a halving of the required number of interrupters. The module, which contains two main and two auxiliary interrupters and two resistors, also serves for compressed air storage, and replaces four interrupters of the older design. Silencers are an integral part of the design. Fault clearance can be attained within 30-40 ms.

15.6 Performance of Circuit Breakers and System Requirements

Analysis of circuit interruption and the foregoing discussion of various circuit breakers apply to circuit breakers in practice if they had ideal switching characteristics. The ideal circuit breaker has a negligible arc voltage and has the ability to develop instantaneously infinite arc-gap resistance at natural current zero. In practice circuit breakers do not behave ideally and therefore it is necessary to consider the conditions that actually occur in three main types of circuit breakers.

1. Oil circuit breakers with plain break.
2. Oil breakers with arc-control device (self-blast).
3. Forced-blast breakers.

15.6.1 Voltage Distribution in Oil Circuit Breakers with Plain Break

In this type of circuit breaker because of the nature of the interruption process, the conditions following the final current zero tend to be unstable in character. Usually a long arc is drawn and the arc resistance does not reach infinite value at current-zero with the result that some leakage current flows. This leakage current can play a dual role, i.e. either it can make the performance of the breaker a success or it can vitiate the interruption process.

The leakage current damps the restriking voltage oscillations, thereby reducing circuit severity, and make interruption easier (Fig. (15.20)). At the same time, the leakage provides a form of resistance grading which

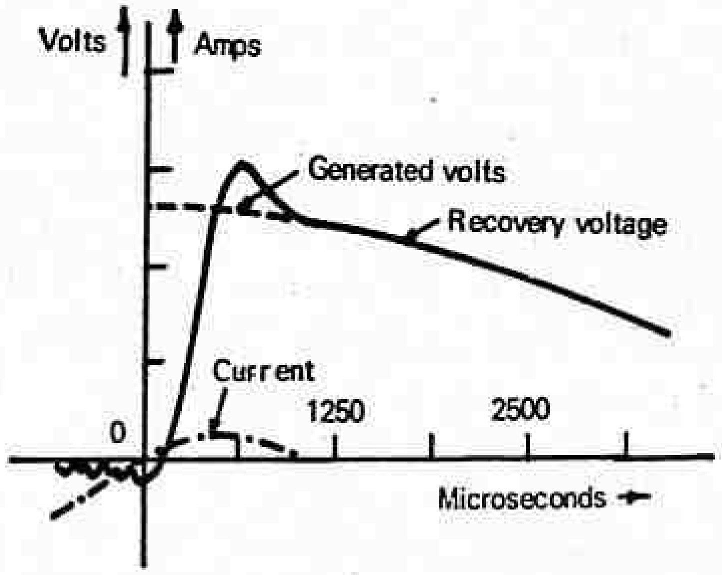


FIGURE 15.20 Interruption of inductive current by a plain-break oil CB showing successful interruption.

helps in equalizing the distribution of the restriking voltage across the multibreak system, overcoming the inherent voltage distortion caused by stray capacitance, which would otherwise have rendered most of the interrupting gaps virtually useless, because they carry but a small share of the overall voltage. This can be illustrated by taking a simple case of a bulk oil circuit breaker with two breaks per pole. Figure (15.21) shows the circuit breaker and various capacitances between the contacts and between the cross bar and the earthed tank, the equivalent circuit is also shown. In the event of a phase-to-ground fault, the voltage distribution between circuit breaker contacts can be easily found from the equivalent circuit. It can be seen that

$$\frac{V_1}{V_2} = \frac{C_2 + C_3}{C_1}$$

Now C_1 and C_2 are of the same order, but C_3 is much greater than C_1 or C_2, hence $V_1 \gg V_2$. Typical values of capacitances across contacts (C_1, C_2) are 10 to 40 $\mu\mu F$ and the stray capacitance to ground (C_3) 40 to

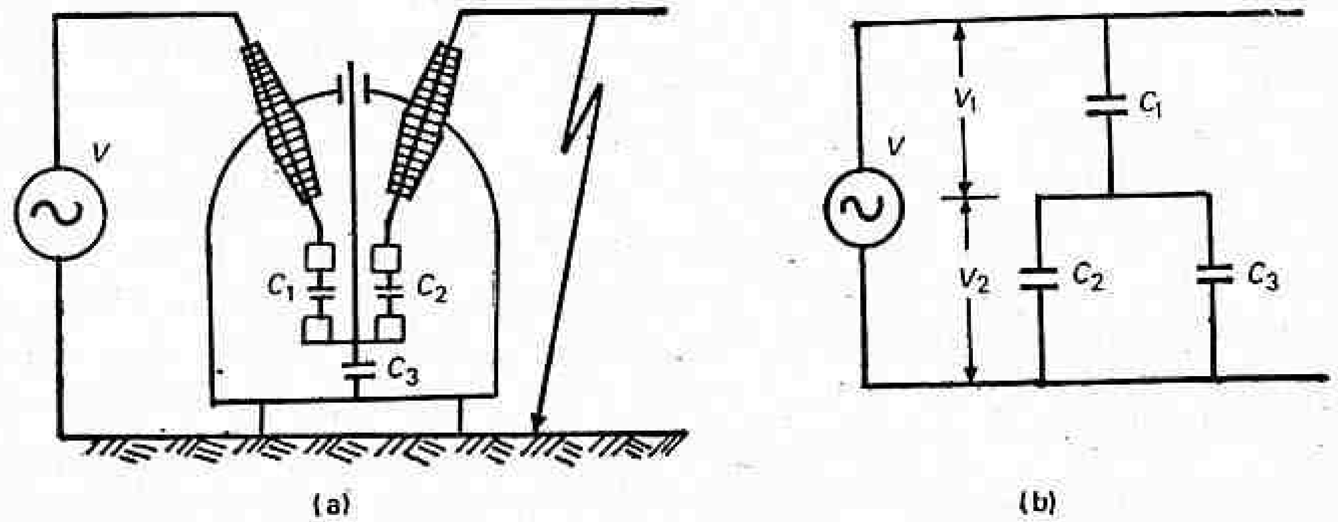


FIGURE 15.21 Distribution of recovery voltage in double break dead tank circuit breaker.

100 $\mu\mu F$. However, if there is an appreciable leakage current through the arc, the capacitance voltage control may be swamped. The leakage current may increase with rising voltage stress, in which case the arc restrikes (Fig. (15.22)). In extreme cases if this happened in the fully open position, the energy released is sufficient to damage circuit breaker.

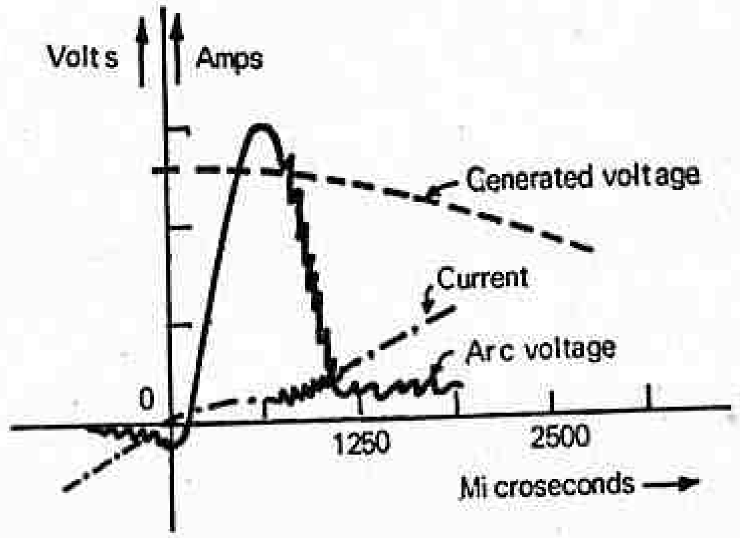


FIGURE 15.22 Interruption of inductive current by a plain-break oil CB showing interruption followed by restrike.

As the variable nature of leakage current cannot be predicted, plain-break oil circuit breakers are used for lower breaking capacities and up to 11 KV only.

15.6.2 Voltage Distribution in Oil Circuit Breakers with Arc Control Devices

The controlled nature of turbulence and resultant deionization in this type eliminates the erratic operation of the plain-break by virtually eliminating the leakage current, but it also eliminates the useful voltage damping and voltage distribution function which this current had performed in the plain-break type. Voltage distribution of such a type is shown in Fig. (15.23). Under these conditions, capacitance will control the voltage distribution and only a small part of the voltage duty is carried by the second break, it has been shown above that a major part of the voltage comes across the first break, i.e. capacitance C_1. In this respect the second break is of little value electrically. But if the advantages of the multibreaks are to be derived then it has to be fitted with positive voltage grading and damping devices in the form of shunt resistors. These additions though expensive, make the ehv oil circuit breaker reliable by performing consistently the function the leakage current had previously carried out in the plain-break oil circuit breaker. A desirable compromise would be for leakage current to be deliberately retained, but with effective control. No means of achieving this have as yet been suggested, and this problem may remain insoluble because of the difficulty of control problem it presents.

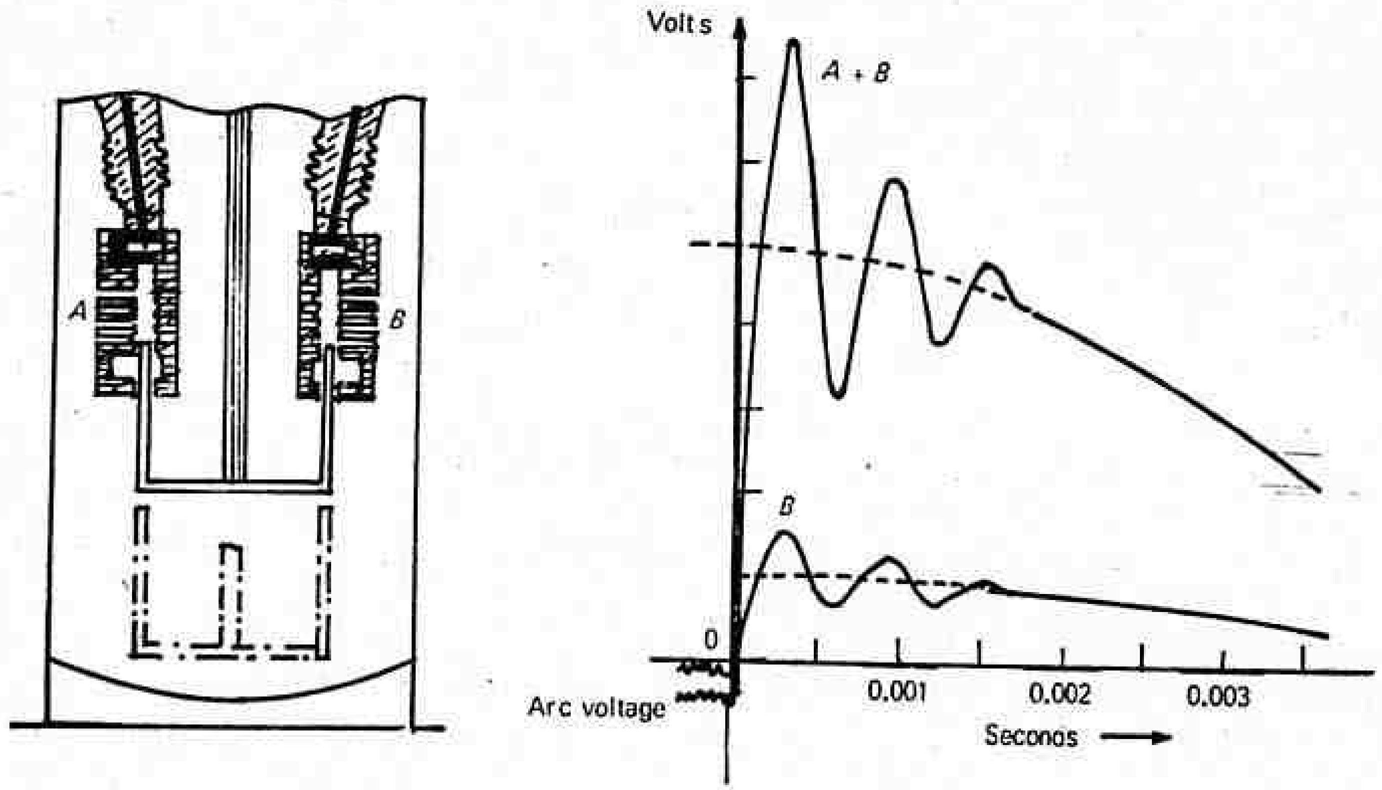


FIGURE 15.23 Voltage distribution in an oil CB with arc control devices.

A problem associated with the self-blast circuit breaker is the interruption of low currents when the pressure generated is also small and the system RRRV is high. These led to longer arc-duration when interrupting small currents than when interrupting large currents. This is overcome in the forced blast breakers.

15.6.3 Speed of Operation

Uptil now fault clearance times of 140 ms have been acceptable; this allows 60 ms for the relays and 80 ms for the breaker. Minimum oil circuit breakeıs meet this requirement very easily. These timings can still be

reduced by improved designs. Fault clearance timings of 3 cycles are being specified nowadays. This allows one cycle for the relay and two cycles for the breaker. Attempts are being made to reduce the operating times of circuit breakers to less than two cycles. A most promising development in this regard however appears to be the use of vacuum circuit breakers.

15.6.4 Terminal Short-Circuit and RRRV

These two factors are against each other during current interruption at current zero. Under short circuit, the stress on circuit breaker depends on the current and rate at which the voltage rises across the contacts of the circuit breaker. The rate of rise of the voltage across the circuit breaker contacts just after current zero is defined by the capacitance, inductance and resistance of the system. The amplitude and frequency of this voltage which is called transient restriking voltage result in an RRRV which conditions the restriking after current zero. In the forced blast breakers the rate of rise of dielectric strength is initially low. Due to this the air blast circuit breaker is inherently sensitive to RRRV. Forced-blast designs have special advantages in the high voltage field, where rapid interruption is important; they have been developed in multibreak form employing capacitance voltage-grading across the gaps (Fig. (15.24)).

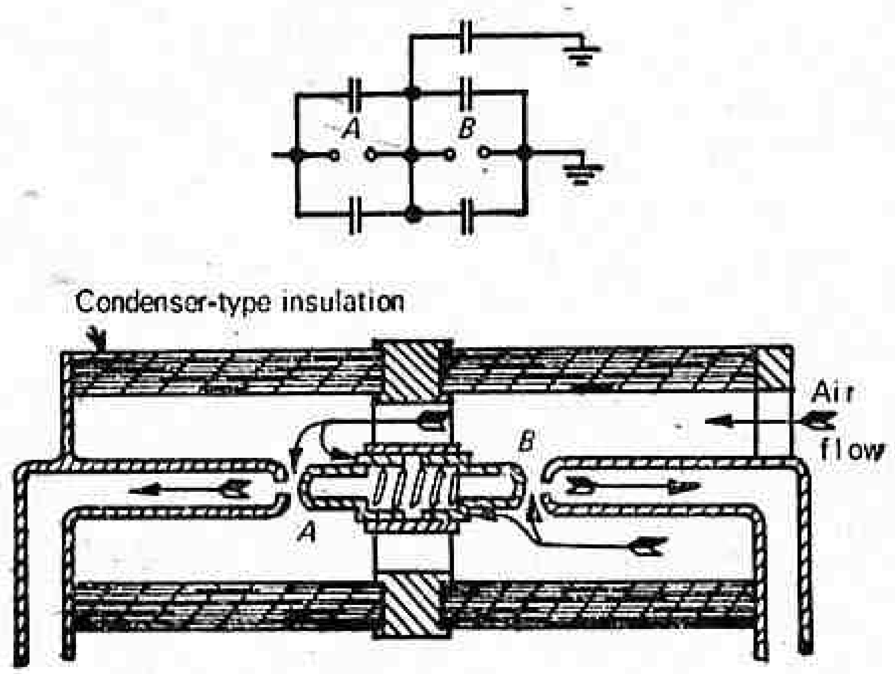


FIGURE 15.24 Air-blast circuit breaker with capacitance voltage grading.

With both oil blast and air blast, the velocity of dielectric is independent of fault current. It follows that these circuit breakers can interrupt low currents at very high RRRV with the same arc duration as at full rating; therefore the increase in arc duration that is a characteristic of the self-blast type under low-current conditions is avoided. On the other hand, no increase in velocity of the dielectric is obtained at heavy currents; in fact, it is usually reduced, so that the RRRV which forced-blast circuit breakers can then withstand is somewhat lower than at small currents. This matches with the characteristic of high voltage systems. Oil circuit breakers are practically insensitive to RRRV at the location of the circuit breaker. Due to this an exact idea of RRRV at the location of the circuit breaker is not necessary. Moreover there is no necessity of derating the circuit breakers even when installed in locations having very high RRRVs.

15.6.5 Interruption of Small Inductive Currents

When small inductive currents, such as those flowing through transformers on no load are interrupted before natural zero, i.e. *current chopping* voltage oscillations, which lead to transient overvoltages result. The voltage oscillations are caused both on the line as well as on the supply side. The magnitude of overvoltages will usually be high on the line side due to high impedance of the transformer. The overvoltages produced during interruption of small inductive currents can be limited by repetitive restrikes in the circuit breakers (Fig. (15.25)) or by fitting shunt resistors of suitable value across the circuit breaker.

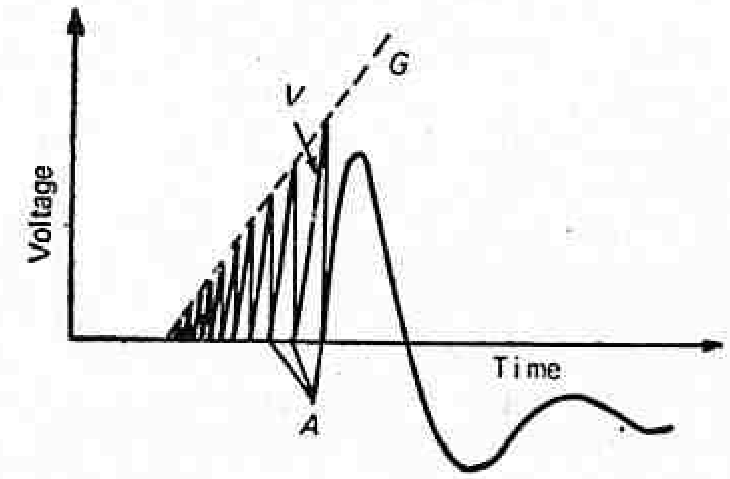


FIGURE 15.25 Voltage oscillograms during the interruption of a small inductive current by an ABCB. Overvoltages are prevented because of the sufficiently slow contact speed. V—recovery voltage across contact gap; A—spark voltage; G—increasing dielectric strength during contact separation.

Though an overvoltage factor of 3.5 can sometimes be tolerated, a fa... of 2.5 is now frequently specified. Oil breakers with arc control ...erate satisfactorily under these conditions while forced-blast ...roduce overvoltages and special means have to be provided ... Normally minimum oil circuit breakers do not give an ...eeding 2.5. However, if lower overvoltage factor is ...an be fitted with shunt resistors.

Upt... 60 ms for ... breakers meet this ...

15.6.6 Interruption of Capacitive Currents

Modern circuit breakers are required to interrupt long transmission lines on no load very frequently. Under certain circumstances these interruptions may produce overvoltages. With each restrike the voltage on the line side surges up, but in practice the overvoltages do not attain dangerous values due to damping of the oscillations. Thus for interruption of capactive currents the ideal is restrike free performance of the circuit breaker.

Minimum oil circuit breakers are not entirely restrike free unless specially designed for this duty. For most of the systems up to 132 KV one or two restrikes are permitted provided the maximum overvoltage is limited to 2.5 to 3 times the normal. For system voltages of 220 KV and above it is necessary to have restrike free circuit breaker. Minimum oil circuit breakers of multibreak design and having artificial oil injection are restrike free and do not produce overvoltages while interrupting capacitive currents or disconnecting unloaded lines. Air-blast circuit breakers are also restrike free and hence are preferred for system voltages of 220 KV and above.

15.6.7 High Speed Reclosing

Many faults in the power systems are transient in nature and cause disconnection of the circuit without damage to the lines or plant. The supply in such cases can be restored by momentary isolation of the faulted line followed by reenergizing after a predetermined time. For successful auto-reclosing the characteristics of circuit breakers and networks have to be taken into consideration. These can be broadly defined as:

(i) The fault current must be interrupted in the shortest possible time, to avoid transient fault establishing into a sustained fault.

(ii) The supply should be resumed as soon as possible to minimize inconvenience to consumer.

(iii) A minimum dead time must be allowed for dielectric strength at the fault point to recov... before line is reenergized.

(iv) The circuit breaker mechanism must be allowed time to establish before reclosure is attempted.

For performing auto-reclosing duty, the operating mechanism of the circuit breaker is arranged in such a way that if after first reclosing the fault is not cleared the breaker performs a second interruption after which the system is permanently isolated from the fault. The dead time is usually in the range of 0.2 to 0.6 second.

15.6.8 Short-Line Fault

If a fault occurs close to sub-station the initial rate of rise of restriking and opens the contacts. The switch now becomes a true circuit breaker which can interrupt the current under predetermined conditions, e.g. when a short circuit occurs or when excess current endangers the system. This is obviously a very crude method of control and is used only in simple low voltage circuits.

15.2 Air-Break Circuit Breakers

The arc interruption process of air-break circuit breakers is based on the natural deionization of gases by a cooling action. The arc is resilient and can be stretched, and has resistance which can be increased both by length and confinement. Hence the increase of arc resistance is so high that the short-circuit current drops and the current and voltage are brought into phase. Reducing the phase difference between the system voltage and the short-circuit current assures that when the arc current is interrupted at its zero value, the recovery voltage has a very low value at this instant. Restriking voltage is thus reduced to a much smaller value and is not allowed to reach two-times the value of the system peak voltage, a phenomenon that occurs in most cases, when arc current is interrupted at low power factor by means of other conventional circuit breakers. The energy dissipated in the arc is however high and this limits the application of high-resistance interruption to low and medium power a.c. circuit breakers; it is also used for low and medium power d.c. circuit breakers.

15.2.1 Methods for Increasing Arc Resistance

The following methods are employed for increasing arc resistance.

(i) *Arc lengthening*. Resistance is approximately proportional to length of the arc.

(ii) *Arc cooling*. The voltage required to maintain ionization increases with a decrease of temperature so that cooling effectively increases the resistance.

(iii) *Arc splitting*. An appreciable voltage is absorbed at the two contact surfaces so that if the arc can be split into a number of small arcs in series the voltage available for the actual arc column is reduced.

(iv) *Arc constraining*. If the arc can be constrained into a very narrow channel the voltage necessary to maintain it is increased.

The above-mentioned methods have been successfully carried out in the following types of air-break circuit breakers.

15.2.2 Plain Break Types

This is the simplest type of air-break circuit breaker where contacts are

made in the shape of two horns. The arc initially strikes across the shortest distance between the horns, but it is then driven steadily upwards by the convection currents set up due to heating of air during arcing and the interaction of magnetic and electric fields. The arc extends from one tip to the other when the horns are fully separated resulting in arc lengthening and cooling. The relative slowness of the process and the possibility of the arc spreading to adjacent metal work limits the application to about 500 V and to low power circuits. Figure (15.2) shows such a breaker.

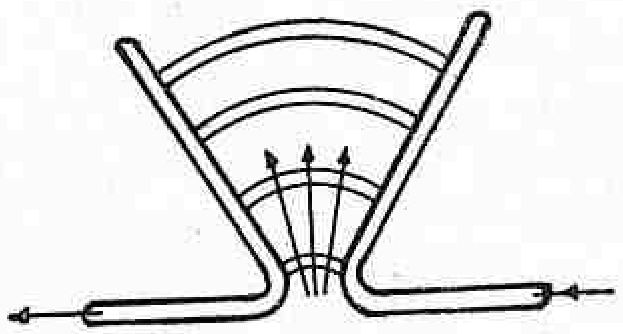


FIGURE 15.2 A simple air-break breaker.

15.2.3 Magnetic Blow-Out Type

In a number of air circuit breakers used in circuits up to 11 KV the extinction of the arc is carried out by means of a magnetic blast. To achieve this the arc is subjected to the action of magnetic field set up by coils connected in series with the circuit being interrupted. Such coils are called blow out coils, because they help in the arc being magnetically *blown out*. Figure (15.3) shows the principal scheme of a magnetic-blast circuit breaker. The arc is blown magnetically into arc chutes where the arc is lengthened, cooled and extinguished. The arc shields prevent spreading of the arc to adjacent metal work. As the breaking action becomes more effective with heavy currents, this principle has resulted in increasing the breaking capacities of these breakers to higher values.

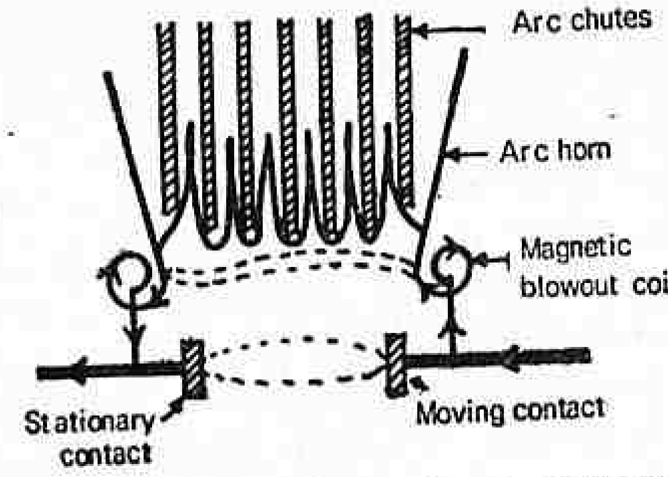


FIGURE 15.3 Principal scheme of a magnetic-blast breaker.

fact, it is usually reduced, so that the RRRV which forced-blast circuit breakers can then withstand is somewhat lower than at small currents. This matches with the characteristic of high voltage systems. Oil circuit breakers are practically insensitive to RRRV at the location of the circuit breaker. Due to this an exact idea of RRRV at the location of the circuit breaker is not necessary. Moreover there is no necessity of derating the circuit breakers even when installed in locations having very high RRRVs.

15.6.5 Interruption of Small Inductive Currents

When small inductive currents, such as those flowing through transformers on no load are interrupted before natural zero, i.e. *current chopping* voltage oscillations, which lead to transient overvoltages result. The voltage oscillations are caused both on the line as well as on the supply side. The magnitude of overvoltages will usually be high on the line side due to high impedance of the transformer. The overvoltages produced during interruption of small inductive currents can be limited by repetitive restrikes in the circuit breakers (Fig. (15.25)) or by fitting shunt resistors of suitable value across the circuit breaker.

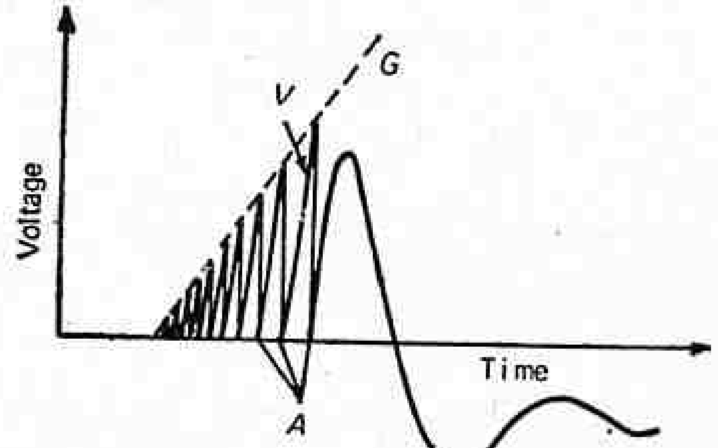


FIGURE 15.25 Voltage oscillograms during the interruption of a small inductive current by an ABCB. Overvoltages are prevented because of the sufficiently slow contact speed. V—recovery voltage across contact gap; A—spark voltage; G—increasing dielectric strength during contact separation.

Though an overvoltage factor of 3.5 can sometimes be tolerated, a factor of 2.5 is now frequently specified. Oil breakers with arc control devices operate satisfactorily under these conditions while forced-blast breakers may produce overvoltages and special means have to be provided to prevent them. Normally minimum oil circuit breakers do not give an overvoltage factor exceeding 2.5. However, if lower overvoltage factor is required, these breakers can be fitted with shunt resistors.

15.6.6 Interruption of Capacitive Currents

Modern circuit breakers are required to interrupt long transmission lines on no load very frequently. Under certain circumstances these interruptions may produce overvoltages. With each restrike the voltage on the line side surges up, but in practice the overvoltages do not attain dangerous values due to damping of the oscillations. Thus for interruption of capactive currents the ideal is restrike free performance of the circuit breaker.

Minimum oil circuit breakers are not entirely restrike free unless specially designed for this duty. For most of the systems up to 132 KV one or two restrikes are permitted provided the maximum overvoltage is limited to 2.5 to 3 times the normal. For system voltages of 220 KV and above it is necessary to have restrike free circuit breaker. Minimum oil circuit breakers of multibreak design and having artificial oil injection are restrike free and do not produce overvoltages while interrupting capacitive currents or disconnecting unloaded lines. Air-blast circuit breakers are also restrike free and hence are preferred for system voltages of 220 KV and above.

15.6.7 High Speed Reclosing

Many faults in the power systems are transient in nature and cause disconnection of the circuit without damage to the lines or plant. The supply in such cases can be restored by momentary isolation of the faulted line followed by reenergizing after a predetermined time. For successful auto-reclosing the characteristics of circuit breakers and networks have to be taken into consideration. These can be broadly defined as:

(i) The fault current must be interrupted in the shortest possible time, to avoid transient fault establishing into a sustained fault.

(ii) The supply should be resumed as soon as possible to minimize inconvenience to consumer.

(iii) A minimum dead time must be allowed for dielectric strength at the fault point to recover before line is reenergized.

(iv) The circuit breaker mechanism must be allowed time to establish before reclosure is attempted.

For performing auto-reclosing duty, the operating mechanism of the circuit breaker is arranged in such a way that if after first reclosing the fault is not cleared the breaker performs a second interruption after which the system is permanently isolated from the fault. The dead time is usually in the range of 0.2 to 0.6 second.

15.6.8 Short-Line Fault

If a fault occurs close to sub-station the initial rate of rise of restriking voltage is high but the amplitude is low. If a fault occurs away from the breaker the initial rate of rise is low but amplitude is high and the value of the short-circuit current is also small. The breaker will not be over-stressed in both the cases. Between the above two cases there are intermediate ranges (in most cases from 500 m to 6 km) where both the amplitudes as well as rate of rise of first loop may be of such value as to cause the restrike in the breaker.

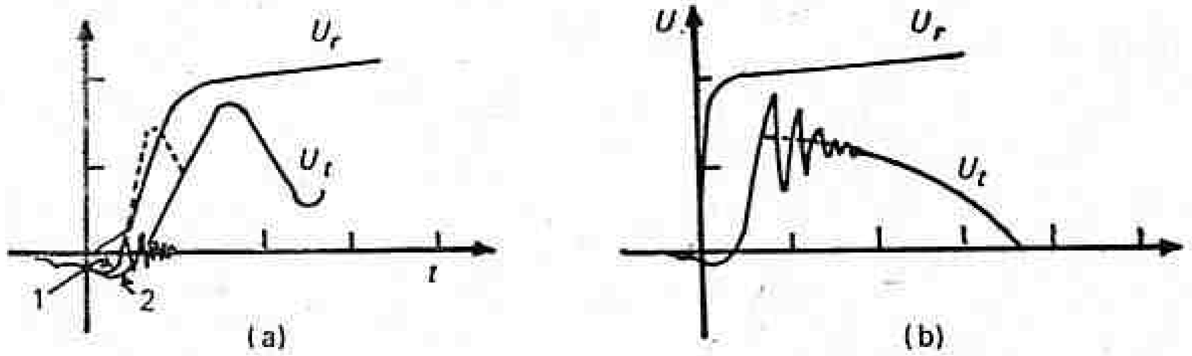


FIGURE 15.26 Dielectric restoration curves: (a) air-blast circuit breaker: u_r—restoration curve; u_t—restriking voltage; 1—high RRRV; 2—low RRRV. (b) oil circuit breaker: u_r—restoration curve; u_t—restriking voltage.

Minimum oil circuit breakers are not sensitive to short-line faults. This is due to the fact that dielectric restoration curve of oil circuit breaker shows a steep rise and then flattens (Fig. (15.26)), and in most cases the dielectric restoration curves are above restriking voltage curve.

15.7 Modification of Circuit Breaker Duty by Shunt Resistors

15.7.1 Linear Resistance Damping

By introducing a linear resistance across the circuit breaker during interruption, the restriking transients are damped. Provision has to be made for subsequent interruption of the resistance circuit. Two such ways are shown in Fig. (15.27). In Fig. (15.27a) the resistor R is switched into circuit by the breakdown of the ionized exhaust that are blown from gap No. 1 to gap No. 2. Immediately after gap No. 1 has ceased to carry current, gap No. 2 is still fed by hot ionized air which causes it to be broken down by the restriking transient in preference to gap No. 1. At the next current zero gap No. 2 is fed with cold unionized air and the resistor current is in turn broken. In Fig. (15.27b) the arc in the shunted gap No. 1 is extinguished first and the resistor then shunts L and C until the arc carrying the resistor current in gap No. 2 is extinguished. By this time the restriking voltage transient decays down.

It will thus be noted that the voltage transient encountered on finally

clearing the circuit is impressed on gaps 1 and 2 in parallel in case of Fig. (15.27a) and on gap No. 2 only in case of Fig. (15.27b).

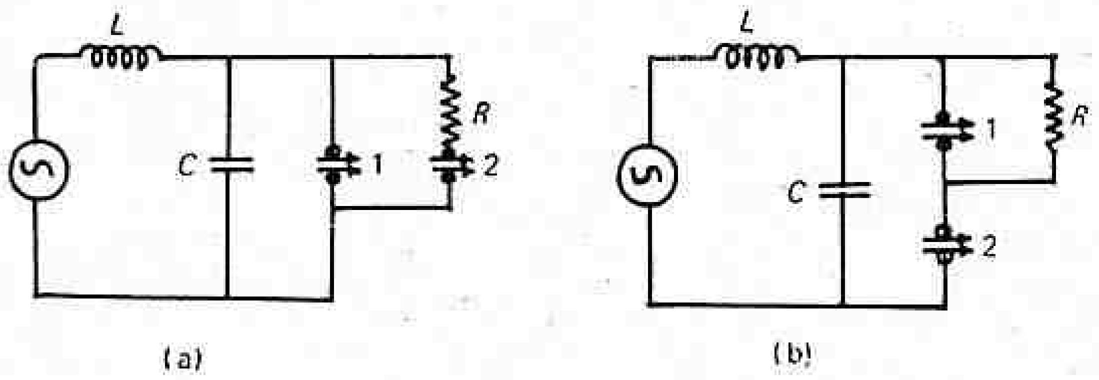


FIGURE 15.27 Methods of resistance switching.

For capacitive current breaking and current chopping gap No. 1 can be proportioned solely to clear the rated breaking capacity current and no thought need be given to the electric strength which the gap attains. In practice it is found that arrangement (a) is most suitable for breakers of 33 KV and below whilst arrangement (b) is most suitable for 66 KV and above. This is because for voltages up to 33 KV high restriking rates may be associated with the maximum fault MVA likely to be experienced. This differs from the conditions found on higher voltage networks where coupled lines tend to reduce the RRRV at large fault MVA.

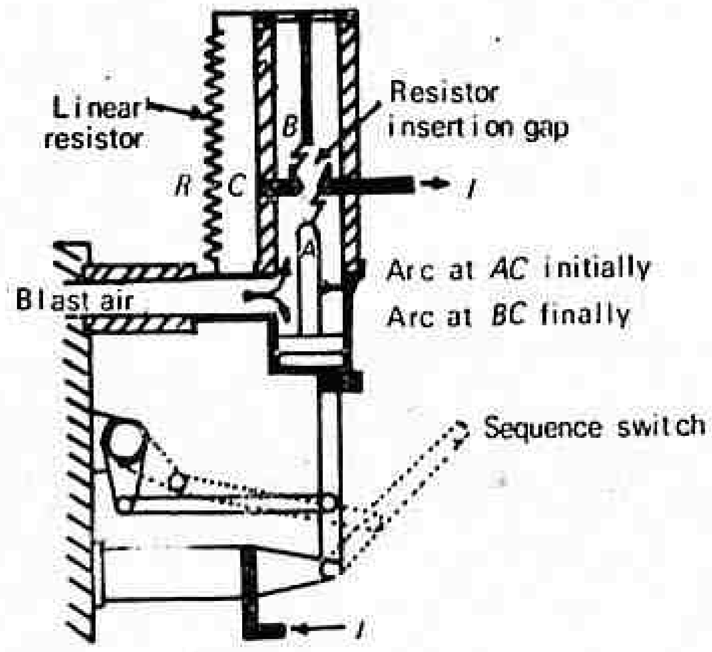


FIGURE 15.28 33 KV air-blast circuit breaker with linear resistance shunt damping.

Figure (15.28) shows diagrammatically, linear resistors applied to an air-blast circuit breaker incorporating arrangement (a) and Fig. (15.29) shows the current voltage curves for inductive current interruption. However, on high voltage systems such as 132/400 KV, the use of shunt resistors in case of forced blast oil or air-blast circuit breakers is of little importance. In this case the RRRV/MVA characteristic can be obtained with designs which can cope with ordinary conditions of service. Nevertheless shunt resistors are used at times because of other considerations as mentioned earlier. Though such a use of resistors results in reduced duty on the main interruptors, the additional apparatus required for the interruption of resistor current tends to increase the complication of the complete forced-blast circuit breaker. In all cases where shunting resistors are used auxiliary contacts to break the residual current must be provided. In case the current exceeds 200 A, the auxiliary contacts themselves must have some form of arc extinguishing blast.

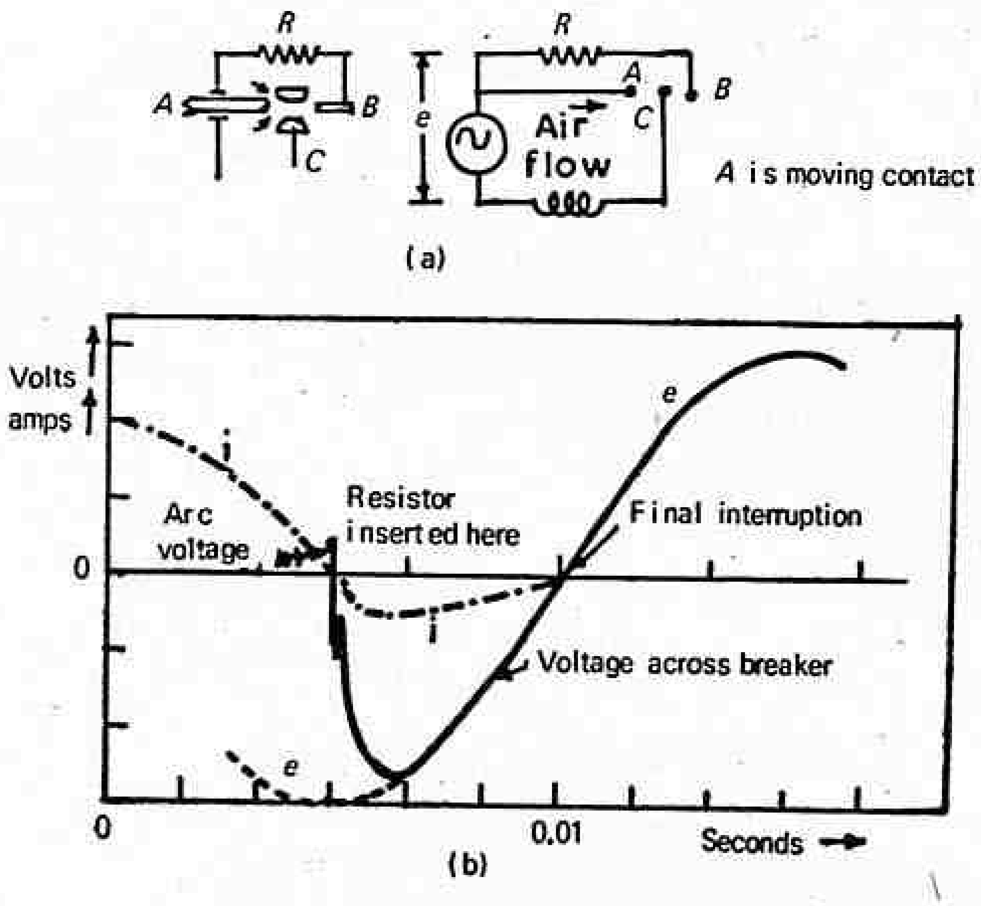


FIGURE 15.29 Interruption of inductive current by air-blast circuit breaker with linear resistance damping.

For self-blast oil circuit breakers, the most onerous duty with respect to RRRV and voltage peak tends to occur at relatively low fault values, of the order of 10 to 30% of the breaking capacity. Under these conditions, pressure in the arc-control device is low at the time when high system RRRV is associated with 100% recovery-voltage peak. This is overcome by connecting linear resistance in parallel which will pass sufficient current to limit the RRRV. However if the sensitivity of the design is attributable more to restriking voltage peak than to RRRV, account must be taken of the values of system constants when transmission lines of large capacitance are coupled. With such designs and when the capacitance is large, much larger shunt currents (increased in the ratio $\sqrt{C}$) are required to ensure critical damping. Figure (15.30) shows a two-break circuit breaker, shunted by linear resistors, interruption of the fault current occurs during the initial part of contact travel. Continuation of the contact travel interrupts the

shunt current in the isolation gap outside the pot throats, but in this case without additional complication.

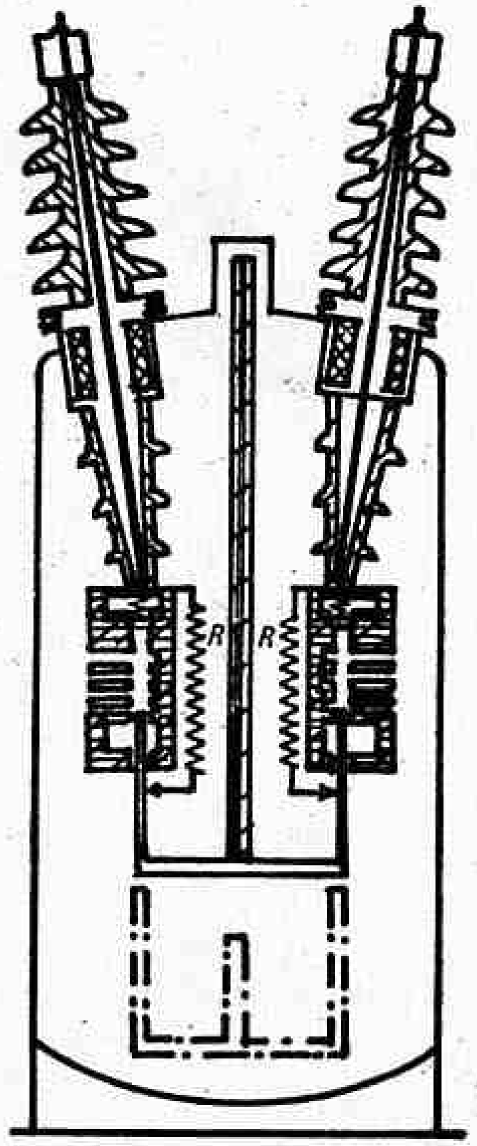


FIGURE 15.30 Double-break oil circuit breaker with linear resistance damping and voltage grading.

The shunt resistor absorbs electrical energy and converts into heat energy during small inductive current interruption when overvoltage oscillations are produced by current chopping.

The shunt resistor prevents restrikes or limits their number during capacitive current interruption, as illustrated in Fig. (15.31). The resistor current must however be so proportioned that overvoltage surges are not produced when the resistor current itself is interrupted, and this implies an upper limit to the current that can be permitted.

15.7.2 Nonlinear Resistance Shunts

Nonlinear resistors are especially suitable, both from space and reliability considerations for small shunt currents in conditions where wire-wound resistors tend to be less satisfactory on mechanical grounds. Where heavy currents are involved, there may be difficulty in accommodating the relatively large volume of resistor material that is required.

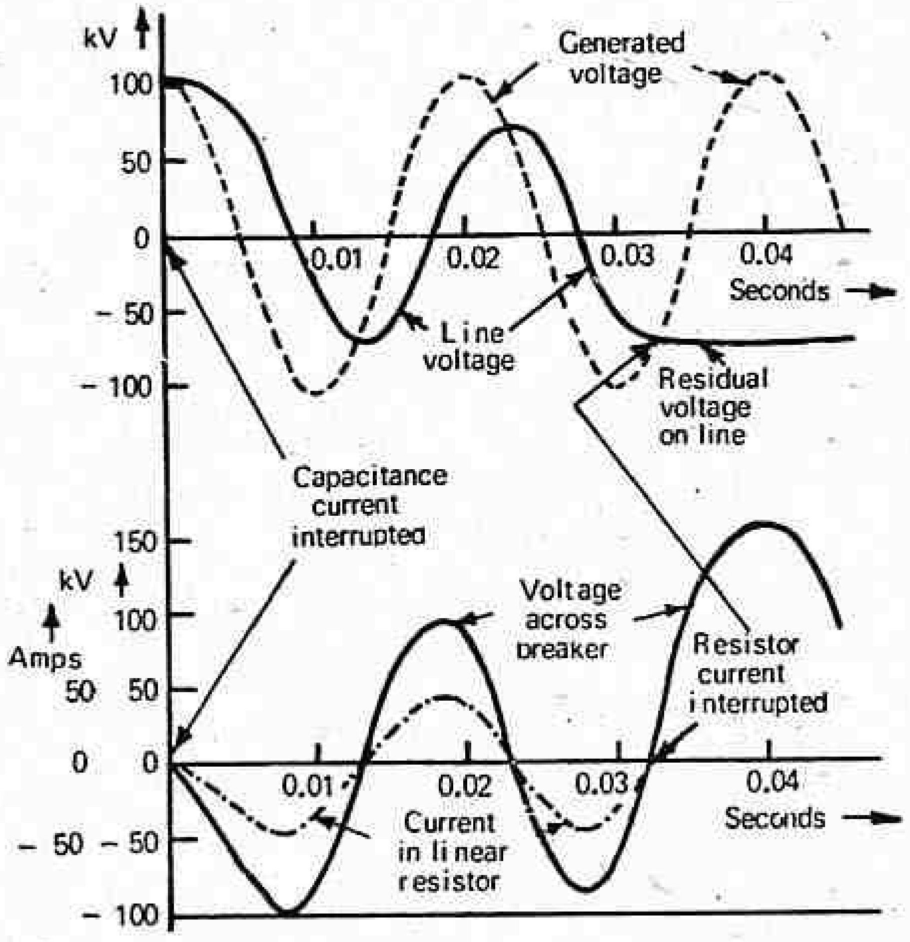


FIGURE 15.31 Interruption of capacitance current by circuit breaker with linear-resistance shunts.

Nonlinear resistors are particularly suited to voltage division and overvoltage suppression applications in which relatively small current of the order of 1–10 A at normal crest voltage are adequate. They are not suitable for modification of RRRV and of the voltage peak. Figure (15.32) and Fig. (15.33) show the schematic arrangement for voltage grading with the help of nonlinear resistors in oil circuit breakers and air-blast circuit breakers respectively.

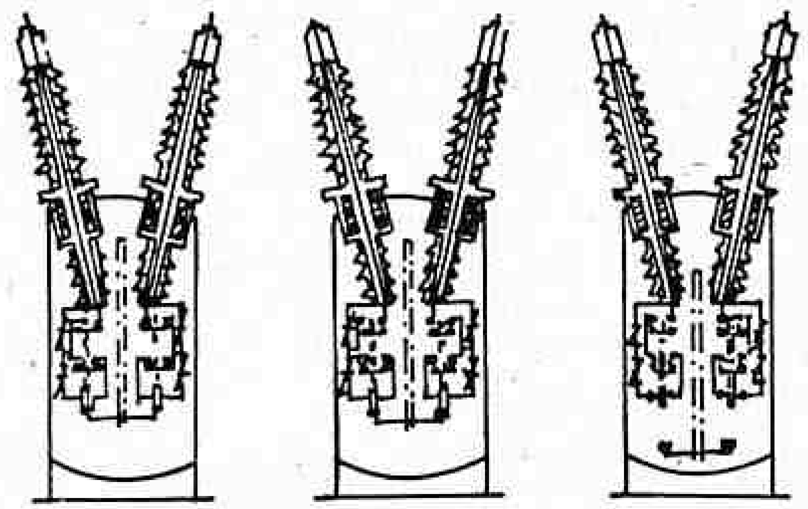


FIGURE 15.32 Schematic arrangement of an 8-break OCB voltage grading by nonlinear resistors: (a) breaker closed, fault or load current flowing; (b) arcing contacts open, resistor current flowing; (c) breaker fully open, no current flowing.

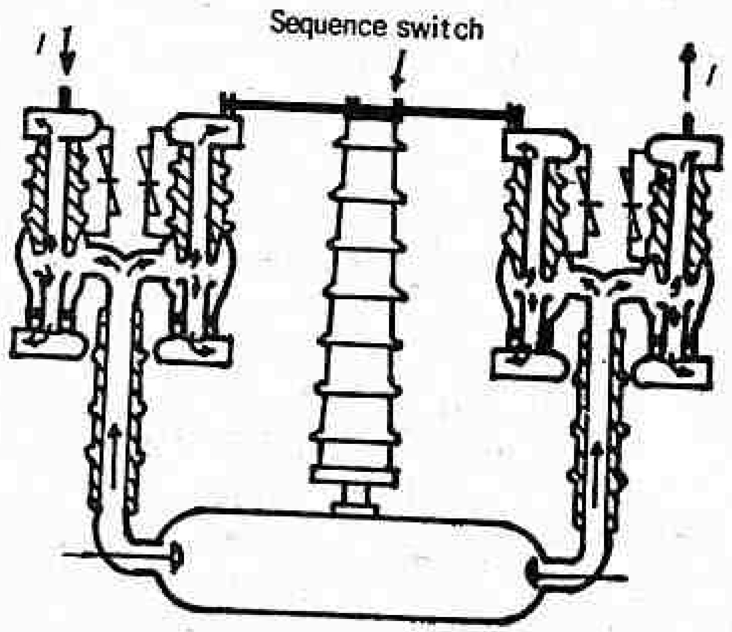


FIGURE 15.33 Schematic arrangement of a 4-break ABCB voltage grading by nonlinear resistors.

The nonlinear resistor ensures accurate voltage distribution across the breaks and, because of rapid increase in shunt current with rise in voltage, it suppresses overvoltages when switching small inductive currents (Fig. (15.34)). The shunt current is interrupted without difficulty by the sequence isolator in oil in case of oil circuit breaker. Although capacitance can also grade the voltage distribution across the multibreaks, it cannot damp the overvoltages. The nonlinear resistance current can be so proportioned that it assists in the interruption of capacitive currents in a

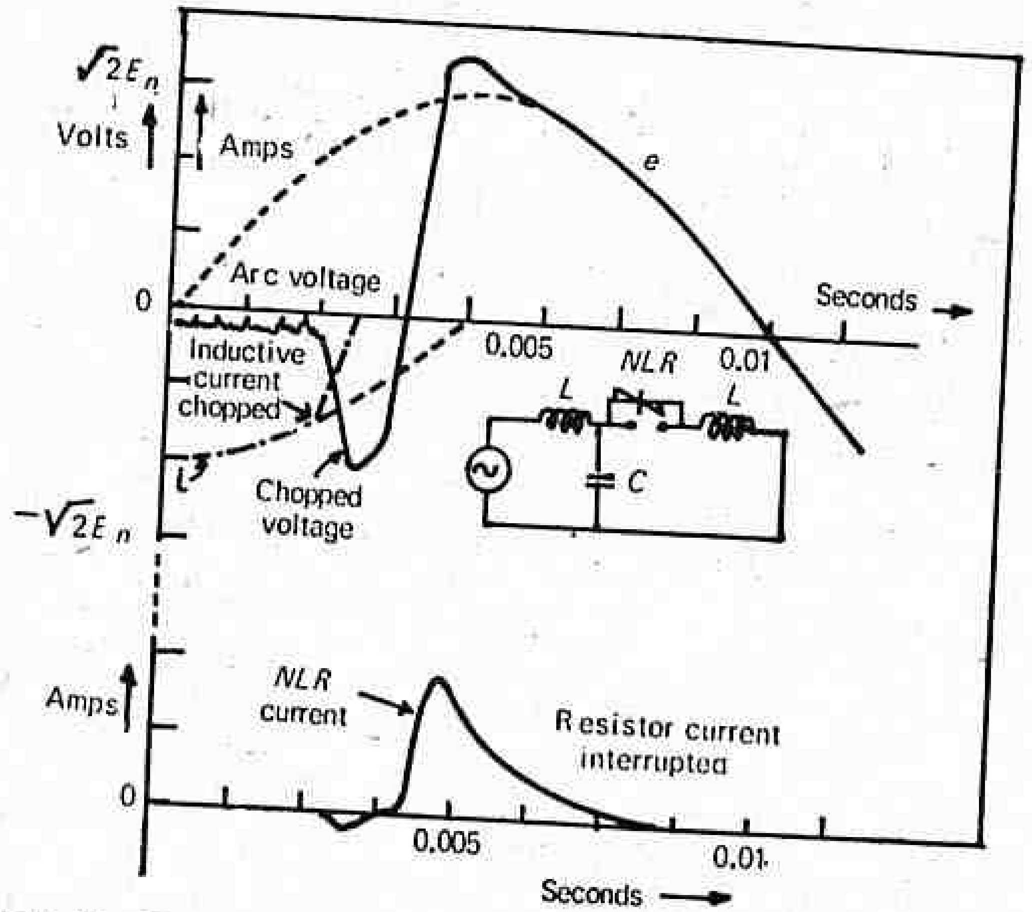


FIGURE 15.34 Damping of overvoltages by nonlinear resistor shunts interrupting a small inductive current.

manner similar to that obtained by the use of linear resistors.

An approximate idea of the value of shunt resistor to perform various duties can be given as follows:

(i) To equalize voltage distribution across two or more breaks. High values (10,000–100,000 ohms) are required. Capacitors may also be used for this purpose.

(ii) To suppress overvoltages due to current chopping. More important with air-blast breakers (10,000–20,000 ohms).

(iii) To avoid damage when switching capacitive currents (2000–5000 ohms).

(iv) To control RRRV values of 1000 to 2000 ohms required for oil circuit breakers where the resistors are most effective for low-current interruptions, and values of 50–100 ohms for medium voltage air-blast breakers.

The higher values, (i) and (ii), may well be nonlinear resistors. The low resistors of (iv) would require impracticably large nonlinear units and wire-wound linear resistors are used for this purpose.

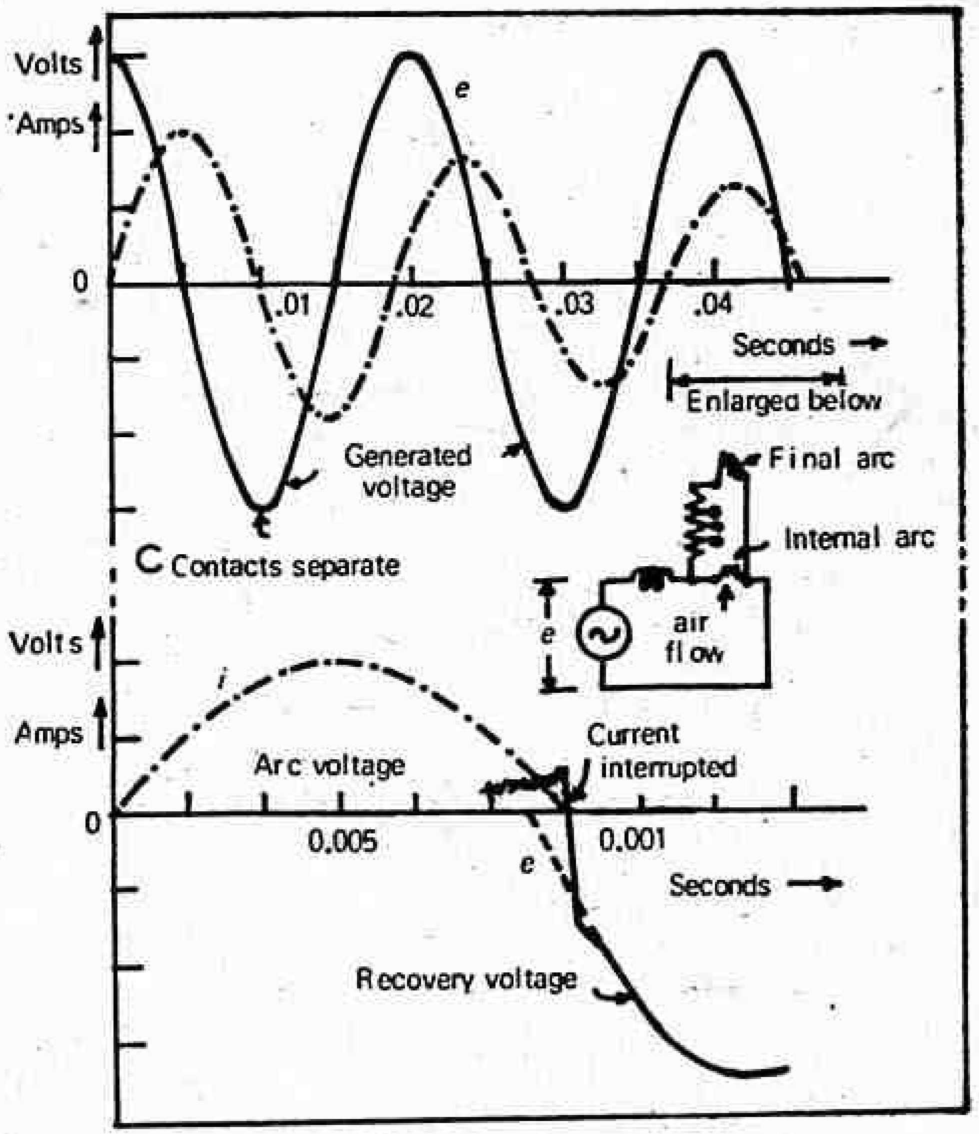


FIGURE 15.35 **Power factor modification using a series resistance in an air-blast circuit breaker.**

15.8 Power Factor Correction by Series Resistance

RRRV for inductive faults can also be reduced by artificial increase of power factor. The application of this method to air-blast circuit breakers is of principal interest for low voltage (up to 15 KV) designs. The arc itself acts as a series linear resistance as already explained in air-break circuit breakers. Figure (15.35) illustrates the modification of power factor by introduction of arc resistance which increases as the length of arc increases and thus facilitates current interruption and RRRV conditions are also improved.

15.9 Comparative Merits of Different Types of Conventional Circuit Breakers

Having studied the operational principles, the constructional features and fields of application of the bulk oil, minimum oil and air-blast circuit breakers, it would be worthwhile to consider their relative merits and disadvantages.

(a) *Bulk Oil Circuit Breakers.* The main advantages of this type of circuit breaker are:

(1) Simplicity of construction.
(2) High rupturing capacity.
(3) Suitability for automatic as well as manual operation.
(4) Possibility of locating current transformers in bushings.

The disadvantages are:

(1) Fire hazard.
(2) Explosion hazard.
(3) Necessity for periodic inspection of the quality and quantity of oil in the tank.
(4) Large volume of high grade mineral oil which is not only costly, but is scarcely available in our country.
(5) Necessity of storing large quantity of oil in the generating stations and substations.
(6) Unsuitability for indoor installation.
(7) Unsuitability for repeated cycles of operation in connection with automatic reclosing.
(8) Greater wear and tear of the contacts resulting in their frequent replacement.
(9) Comparatively large quantities of steel required for the construction of the tank.
(10) Larger size and greater weight.

(b) *Minimum Oil Circuit Breakers.* These circuit breakers have the following advantages:

(1) Comparatively smaller quantity of oil.
(2) Comparatively less weight and size.
(3) Lower cost.
(4) Suitable for both automatic and manual operation.
(5) Easier access to the contacts.

They, however, suffer from the following disadvantages:

(1) Fire and explosion hazards do exist in this type of circuit breaker, although to a lesser extent than in bulk oil circuit breakers.
(2) Totally unsuitable for repeated cycles of operation.
(3) Requires a more frequent inspection and replacement of oil.
(4) Greater contact damage.
(5) Difficulty in locating current transformers.
(6) Comparatively lower rupturing capacity.

(c) *Air Blast Circuit Breakers.* These circuit breakers are finding a much wider application in the high voltage power systems in our country because of the following advantages:

(1) No explosion or fire hazard.
(2) Very fast in operation.
(3) Suitable for rapid reclosing.
(4) Very high rupturing capacity.
(5) Opening unloaded transmission lines or highly capacitive systems do not present much difficulty.
(6) Less contact damage.
(7) Very easy access to the contacts.
(8) Comparatively less weight.

These breakers, however, do have a few disadvantages:

(1) They require the installation of a complete compressed air system consisting of electric motor, air compressor, air tight tubes, etc.
(2) Their construction is much more complicated.
(3) Their cost is higher.
(4) Requires highly trained personnel for their maintenance.
(5) They are more sensitive to RRRV (rate of rise of recovery voltage).

QUESTIONS

1. Discuss the principle of arc extinction in an oil circuit breaker with reference to restriking and recovery voltages.
2. Explain with a neat sketch the working of cross-jet explosion pot used for arc-quenching in bulk oil circuit breakers. What are its limitations?
3. In what respects is a minimum oil circuit breaker an improvement over the bulk oil breaker. What are the limitations of minimum oil breakers?
4. (a) Describe with a neat sketch the axial blast type of air-blast circuit breaker, its principle of operation and its limitations.
   (b) Compare the performance and characteristics of minimum oil breakers and air-blast breakers.
5. (a) Discuss the performance of a circuit breaker when capacitive currents are interrupted.
   (b) What are the merits and drawbacks of air-blast circuit breakers over bulk oil circuit breakers?
6. Write technical notes on the following:
   (i) Resistance switching in HV circuit breakers.
   (ii) Arc control devices in oil circuit breakers.
   (iii) Multibreak circuit breakers.

(b) *Arcing contacts.* Arcing contacts have to undergo the effect of arcing and they open after and close before main contacts. Their shape is such that electrodynamic blow-on forces are used to compensate repulsion forces resulting in increased contact pressure to avoid any beat phenomenon, whatever be the time-delay of tripping.

Arc Chutes. All arc chutes are made of an insulating arc-resisting material, and surround each pole unit. The dimensions of the chute depend on the number of arcing contacts. The chute is shaped like a funnel with a restricted area at its lower part. At the top, the arc chute houses a grid of steel plates the function of which is to increase the speed of rise of the arc into the chute by magnetic action. It also splits the arc and results in increasing the arcing voltage and deionizing the plasma by a strong cooling action.

Operating Mechanism. The mechanism for a.c. circuit breakers is usually designed for manual operation, but electrical operation such as electrieal spring charged mechanism can be provided for remote control. The duties expected of a modern apparatus are: trip-free operation, independent opening, lockout feature preventing closing and, in the event of stored-energy operating-mechanism, independent closing.

Most types of operating mechanism have as their basis either the lever-and-toggle or the cam-and-roller system. The moving contact arm and its associated members are made as light as practicable in order to achieve the high breaking speed. Powerful springs are used to give rapid acceleration. Mechanisms are invariably of the trip-free type, and in some designs for manual closing there is included a device that causes immediate tripping if any reversal occurs in the direction of motion of the operating handle.

Automatic Releases

The releases provided are:

(i) Overcurrent release
(ii) Earth-fault release
(iii) Undervoltage release
(iv) Shunt-trip release
(v) Instantaneous short-circuit release.

The overcurrent release performs two important functions: (a) to trip the breaker on the occurrence of a short circuit, this is a short time delayed operation; (b) to trip the breaker in case of sustained overloads, whereas the instantaneous short-circuit release trips the circuit breaker when it is closed on a fault.

15.3 Oil Circuit Breakers

Oil circuit breakers are extensively employed in our power systems. In these the properties of the arc are employed for arc extinction. Thus by using arc energy to crack the oil molecules, hydrogen gas may be generated which can be used to sweep, cool and compress the arc plasma and so deionize it in a self-extinguishing process.

Earlier it was thought that the oil acted as an insulator when the breaker was closed and then it flowed into the arc gap when the contacts separated and smothered the arc. But later on experiments showed that it would be quite impossible in the very short time of 1/2 to 1/4 cycle available for oil to flow and smother the arc.

15.3.1 Arc Rupture Under Oil

It should be noted that by immersing the interrupting contacts in oil, the production of an arc during contact separation cannot be prevented. However the heat of arc immediately evaporates the surrounding oil and dissociates it into carbon and a substantial volume of gaseous hydrogen at high pressure. Hydrogen gas has high heat conductivity and this results in cooling the arc column and the contacts, which in turn increases the ignition voltage and thus the arc extinguishes. Hydrogen by its high heat conductivity cools the arc so fast that the voltage required for reignition is 5–10 times as high as that required for air, and thus is best suited for interruption. Moreover it is produced spontaneously in arcs under oil. The arc is embedded deep enough under oil, lest the rising gases may set the surface of the oil on fire. This is an important design consideration.

Interruption of heavy short-circuit currents generate extremely high pressures, which are to be released safely or are to be controlled properly. As a matter of fact, these high pressures can be used to extinguish the very arc which is responsible for high pressures. In addition to the mechanical forces caused by gas pressure and oil movement, there are also present substantial electrodynamic forces on the arc. They tend to increase the area of any loop formed by the current in the circuit breaker and therefore drive the arc to the outside and away from the generating source.

15.3.2 Advantages of Oil

Oil has the following advantages as an arc extinguishing medium.

(i) During arcing, the oil acts as a producer of hydrogen gas which helps extinguish the arc as already discussed.
(ii) It provides the insulation for the live exposed contacts from the earthed portions of the container.

(iii) It provides insulation between the contacts after the arc has been finally extinguished and there has been time for the oil to flow into the gap between contacts.

15.3.3 Disadvantages of Oil

Oil has the following disadvantages as an arc extinguishing medium:

(i) It is inflammable and may cause fire hazards, if a defective oil circuit breaker should fail under pressure and cause an explosion.
(ii) Possibility of its forming an explosive mixture with air.
(iii) Because of the decomposition of oil in the arc, the oil becomes polluted by carbon particles, which reduce its dielectric strength. Hence it requires periodical maintenance and replacement.

15.3.4 Evolution of Oil Circuit Breakers

The development of oil circuit breakers has taken place in three major directions:

(a) Plain break oil circuit breakers.
(b) Arc control circuit breakers.
(c) Minimum oil circuit breakers.

15.3.5 Plain Break Oil Circuit Breakers

The early forms of high-voltage designs using oil were of plain-break construction, which did not have a special arc extinction system. In this type the arc is confined only within the oil tank. Deionization of arc is due entirely to turbulance and increase of pressure. For successful interruption, a comparatively long arc-length is essential so that the turbulance in the oil caused by the pressures generated by the arc, may assist in quenching it. Because of the absence of effective control over the arc, the arcing times and the amount of energy released before interruption often vary over a wide range, thus making a large factor of safety necessary, in the design of the tank. The tank must be weathertight to keep moisture out. In case there is an air cushion above the oil, the hydrogen gas formed may pass through the oil to mix with the air, to form an explosive mixture unless sufficient pressure is maintained. The head of oil above the contacts must be large enough to prevent the escape of gas in the form of a column to the surface.

It is clear that if the contacts are separated at high speed, the arc length can be greatly increased because of the greater distance the moving contacts travel between current zeros at which interruption occurs.

Welding of contacts may result on short-circuit interruption if the speed of contact movement is slow.

The main features that have an important bearing upon the performance of a plain-break oil circuit breaker are:

(i) Length of break.
(ii) Speed of contact movement.
(iii) Head of oil above contacts.
(iv) Clearance to earthed metal adjacent to contacts.

By increasing the size of the tank, head of oil, length of break and insulation, it is possible to obtain breakers for higher voltage and larger interrupting capacities. However, circuit breakers of this type are not considered satisfactory above 11 KV and 250 MVA.

In principle this type of breaker with two interruptions in series is shown in Fig. (15.5).

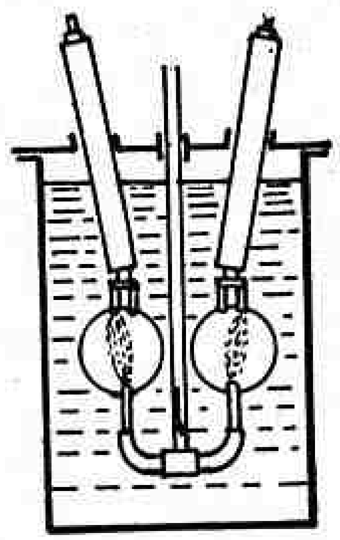


FIGURE 15.5 Plain break oil circuit breaker.

15.3.6 Arc Control Circuit Breakers

The bulk oil circuit breakers generally employed in our power systems are of this type. In these the gases produced during arcing are confined to small volumes by the use of an insulating, rigid arc chamber surrounding the contacts. Thus, higher pressures can be developed to force the oil and gas through or around the arc to extinguish it. These small, high pressure resistant chambers are known as arc control pots or sometimes as explosion pots. Apart from their efficiency of arc interruption these explosion pots have substantially brought down the risks of fire hazard. With the improvement in the design of the arc control pots, great reductions have been effected both in arc duration and total break time.

15.3.7 Types of Arc Control Pots

There has been a continuous development in the types of arc control pots, the two basic forms of which are shown in Fig. (15.6). As the arc itself develops the pressure necessary to produce the blast for arc extinction it is to be expected that the pressure will increase as the arc current increases.

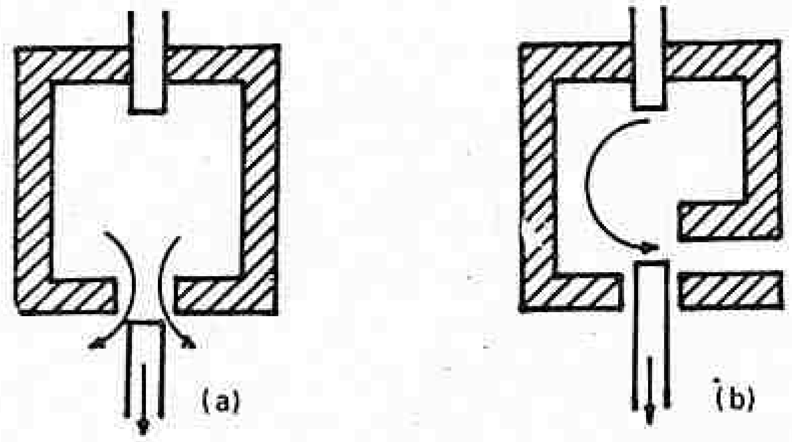


FIGURE 15.6 Types of arc control pots: (a) axial-blast pot; (b) cross-blast pot.

This increased pressure gives a more powerful blast and a greater electrical strength per unit length of arc path, with the result that the restriking voltage transient can be withstood by shorter gaps between moving and stationary contacts. Thus, arc extinction occurs with shorter and shorter arcs as the current increases. Figure (15.7) shows typical characteristics of such a pot. Examination of these curves shows that the limiting rating of a pot can be reached either by the arcing time at the hump X becoming infinite, i.e. the pot failing to clear, or because the pressure at Y becomes so high that the pot bursts.

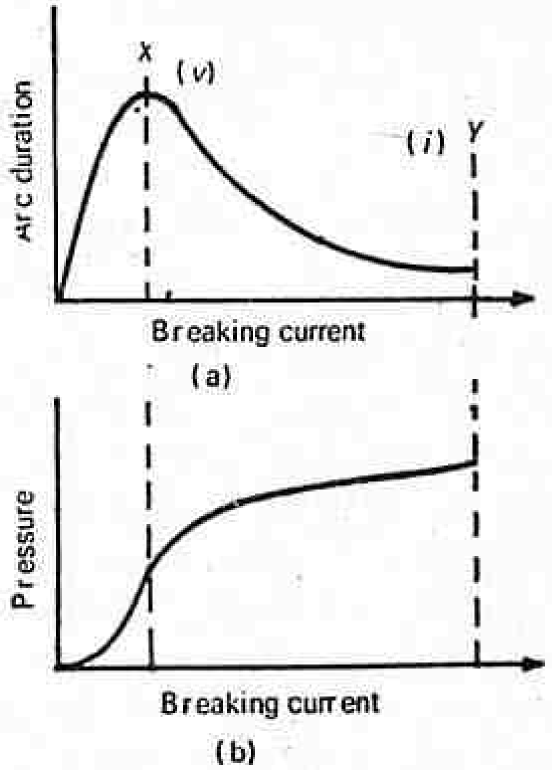


FIGURE 15.7 Typical characteristics of explosion pots.

For a given pot, the maximum arc duration attained at X is mainly a function of the magnitude and rate of rise of restriking transient voltage whilst the maximum pressure attained at Y is mainly a function of the magnitude of the current and is independent of the restriking transient voltage over a very wide range.

Thus the limiting voltage rating is reached when the pot fails to clear a short-circuit at region X, whilst the limiting breaking-current rating is reached when the pot bursts at Y. The design of high-voltage pots becomes essentially a problem of ensuring that there is sufficient pressure at X to ensure that the arc is positively broken and yet that the pressure at Y is not high enough to burst the pot.

Modified arrangements of pot are shown in Fig. (15.8). In Fig. (15.8a) the arc takes place in two stages: arc first appears in the upper chamber and builds up high pressure; when the spring of the intermediate contact unit is fully extended the lower contact opens in oil already at a high pressure and this, in being forced out down the hollow moving contact sweeps across the arc. The same principle is applied to the cross-jet pot in Fig. (15.8b).

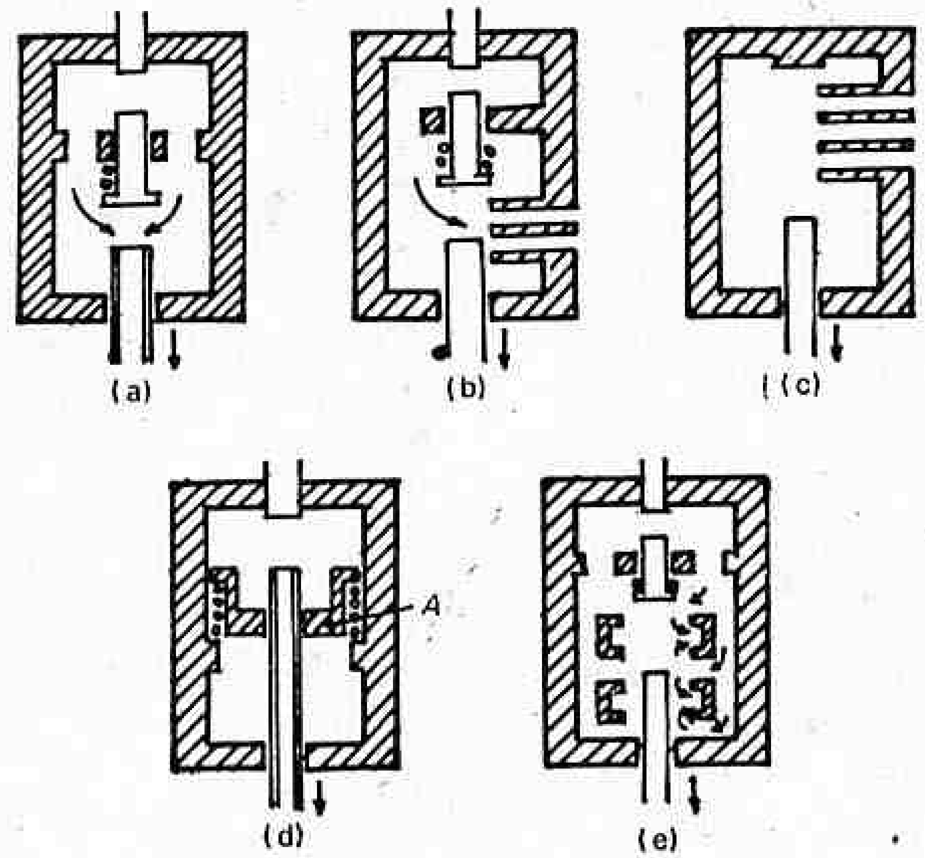


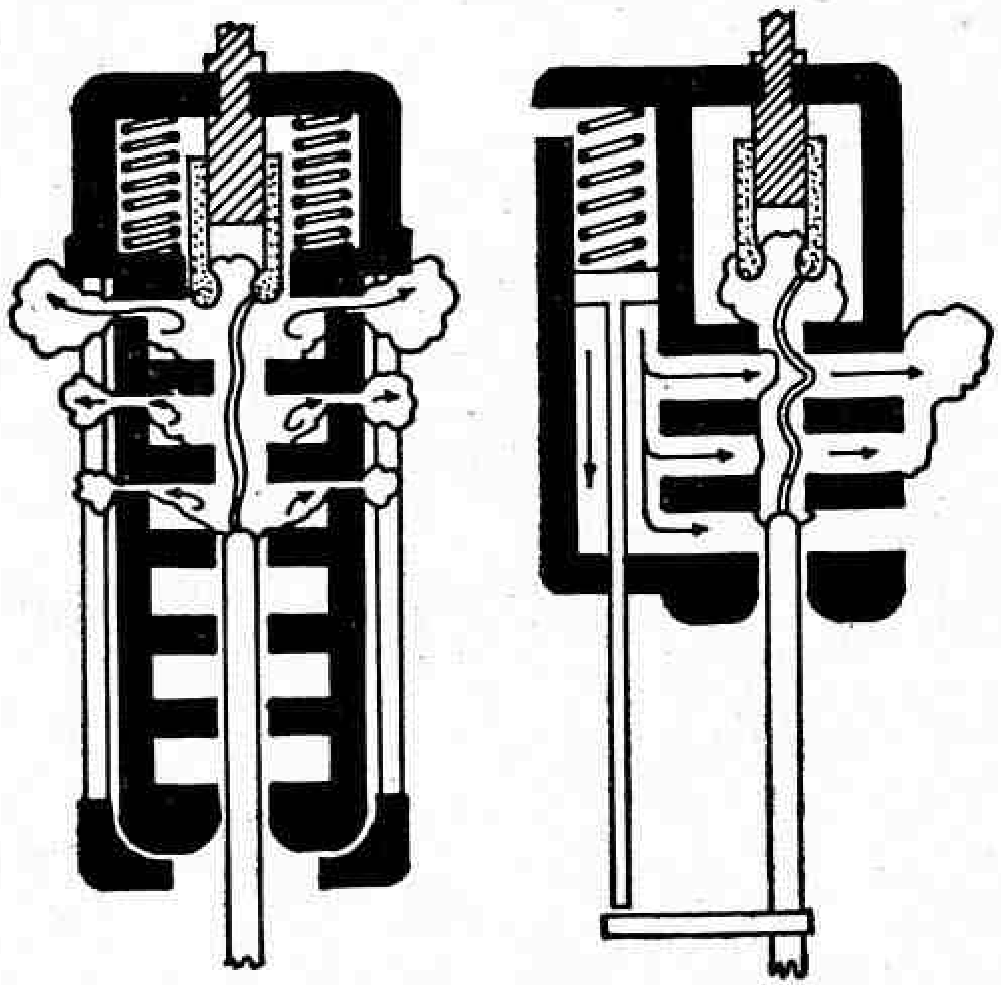
FIGURE 15.8 Modified forms of arc control pots.

In Fig. (15.8c) the vents are placed immediately adjacant to the stationary contacts, but the pot enclosure continues after the vents cease, forming what is called the *compensating chamber*. With this arrangement high currents can be extinguished with a minimum travel after contact separation. This also improves the low-current operation, i.e. the current continues to flow until the arc is drawn into the compensating chamber, thus building up the pressure. In other words the arrangement increases the voltage rating at X without decreasing the current rating at Y (Fig. (15.7)).

In Fig. (15.8d) the arc in the upper chamber forces the piston A against the oil in the lower chamber and also forces some oil down the hollow moving contact; as soon as the contact has passed through the piston the pressure in the upper chamber forces the piston down and expels oil from the lower into the upper chamber through the orifice in the piston thereby causing considerable turbulence and rapid deionization.

In Fig. (15.8e) oil is delivered by pressure due to the initial break to several points along the arc path and flow axially with the arc before being discharged.

Still in other forms of explosion pots, to avoid explosion at very high currents, pressure limiting valves are used to protect the so called *elastic* arc chambers; at very low currents. a mechanically driven piston guarantees sufficient flow, (Fig. (15.9)).



(a) (b)

FIGURE 15.9 (a) Elastic expulsion chamber; (b) expulsion chamber with auxiliary piston.

An alternative arrangement is the deion grid shown in Fig. (15.10). The grids surround the arcing contacts and consist of a series of insulating plates made usually of asbestos having interspersed plates of magnetic material, all so disposed and vented that the arc is moved laterally into

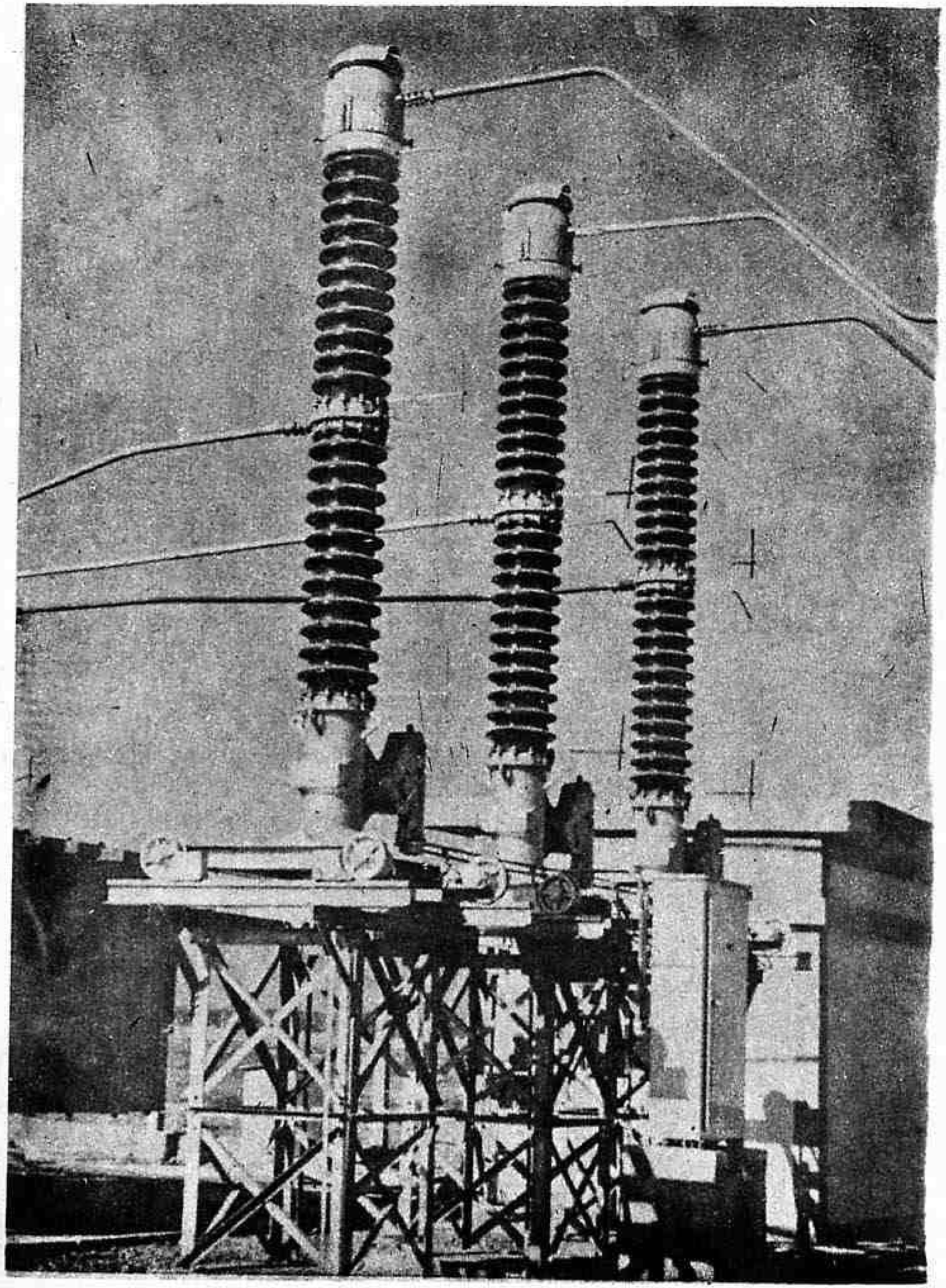


PLATE III 110 kV 3500 MVA minimum oil circuit breaker (*Courtesy :* Jyoti Limited, Baroda)

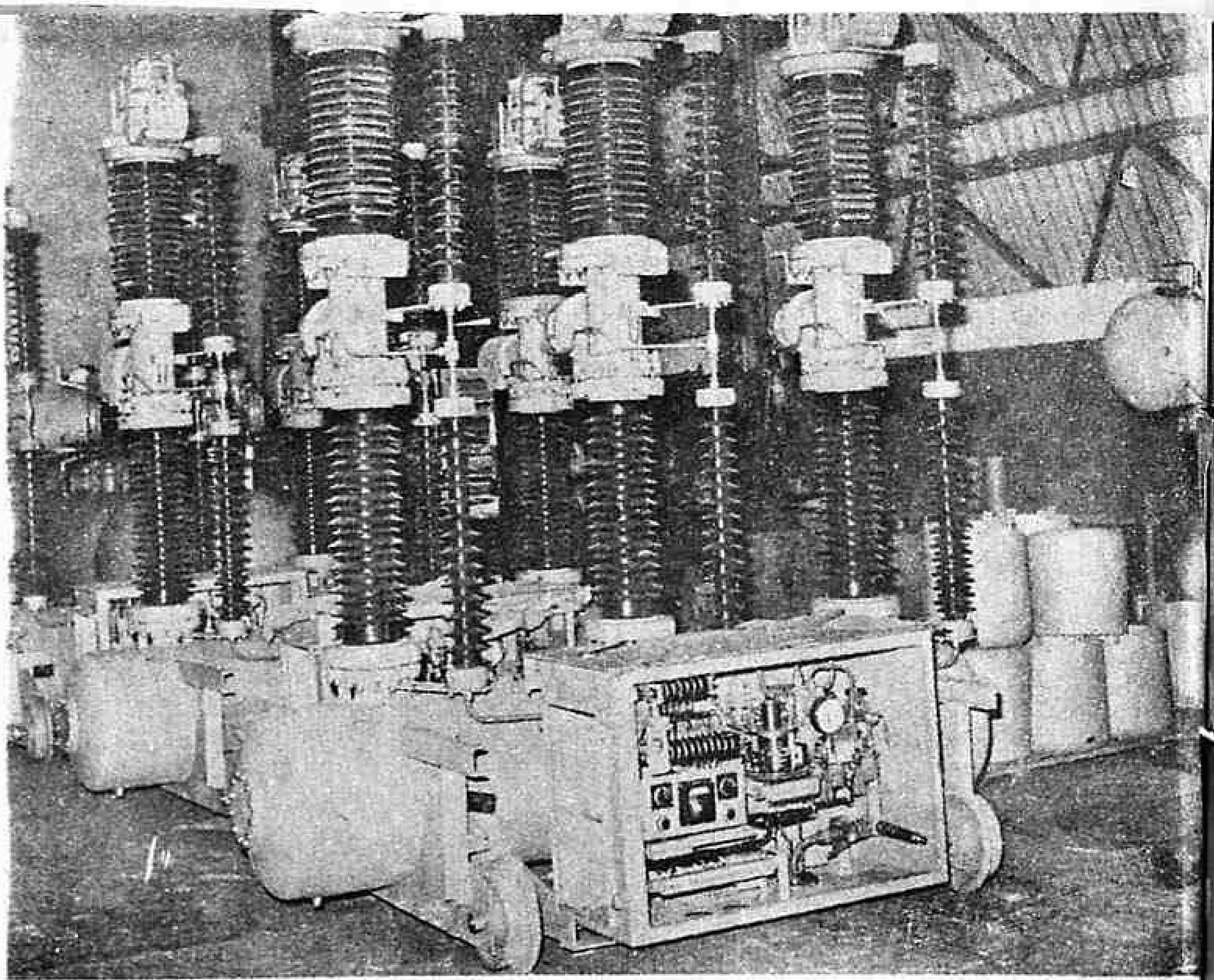


PLATE IV 66 kV 3500 MVA air-blast circuit breakers, Type : PPM63D
(*Courtesy* : Tata-Merlin & Gerin Limited, Bombay)

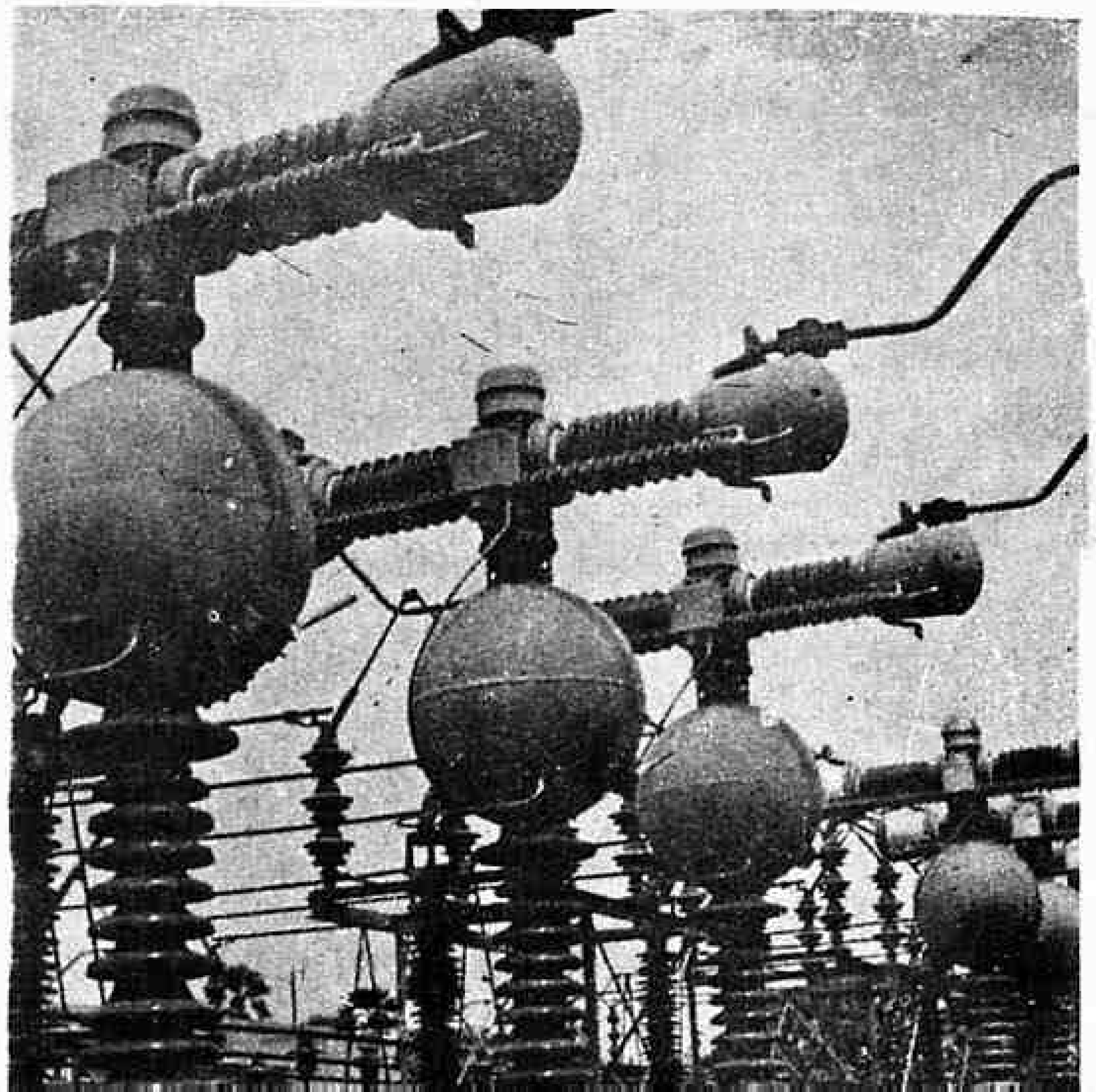


PLATE V 110 kV 5000 MVA air-blast circuit breakers, Type : PPT×74KB (*Courtesy* : Tata-Merlin & Gerin Limited, Bombay)

oil pockets by the electromagnetic force due to the flux in the magnetic grids, where it vaporizes the oil. The resulting gases can only escape by sweeping across the arc path.

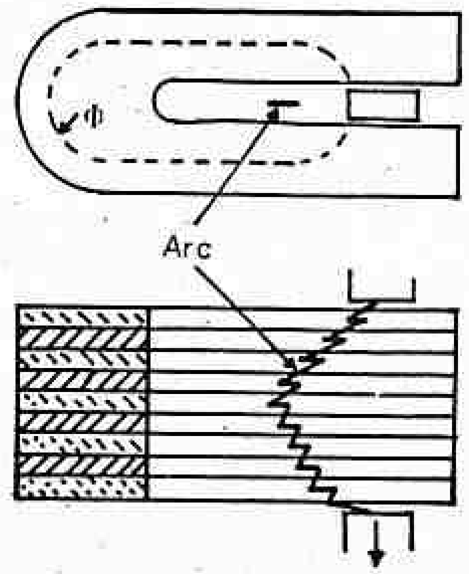


FIGURE 15.10 Deion grid.

15.3.8 Minimum Oil Circuit Breakers

For higher voltages and higher breaking capacities large amounts of oil are required and the size of the bulk oil circuit breaker described above becomes inordinately large. For example, a 110 KV 3500 MVA breaker takes 8 to 12 thousand kg of oil, while a breaker of the same rating qut for 220 KV takes 50 thousand kg of oil. The minimum oil circuit breaker uses solid materials for insulating purposes and uses just enough oil for arc quenching. The interrupting device is enclosed in a tank of insulating material, the whole of which is at line voltage in normal operation. These are also known as live tank breakers as against dead tank breakers of the bulk oil type. The minimum oil circuit breakers may be of self-blast type, external blast type or a combination of the two.

In self-blast circuit breakers the force with which the arc is quenched adapts itself to the current to be broken; larger the short-circuit current more is the oil decomposed and more is the amount of gas developed for cooling the plasma. For this reason self-blast type minimum oil circuit breaker quenches the arc more effectively as the current increases. However the gas pressure in the chamber also increases with the increasing short-circuit current, which imposes a mechanical stress limitation on the circuit breaker. The limit of breaking capacity is therefore not set by the principle of arc quenching but by the mechanical strength of the arcing chamber. With the use of modern insulating materials for the manufacture of arcing chambers such as glass fibre reinforced synthetic resins, the minimum oil circuit breakers are able to meet easily the increased fault levels of the systems.

Most of the current designs employ self-generating blast principle.

Two types of venting are used in the design of their arcing chambers, viz. axial venting and radial venting. In axial venting the gases sweep the arc in longitudinal direction while in radial venting the arc is blown in trans- verse direction. Axial venting has the advantage that it generates high pressures and also has high dielectric strength. Axial venting is mainly where low currents are to be interrupted at high voltages. Radial venting generates low pressures and also has low dielectric strength. It is mainly suitable for breaking heavy currents at low voltages. At times a combina- tion of both is used so that arcing chamber is equally efficient at low as well as at high currents. These arcing chambers however suffer from the disadvantage that at very low currents, called *critical current*, they have a long arcing period. These critical currents generally lie between 10 to 100 A. In certain designs in addition to self-blast, separate oil injection devices are also used. This method eliminates critical currents, making arcing time virtually independent of the value of interrupted current. The various arrangements of the arcing chambers used in the minimum oil circuit breaker are shown in Fig. (15.11). The contacts are usually operated by pull rods or rotating insulators actuated in turn by pneumatic or solenoid mechanisms.

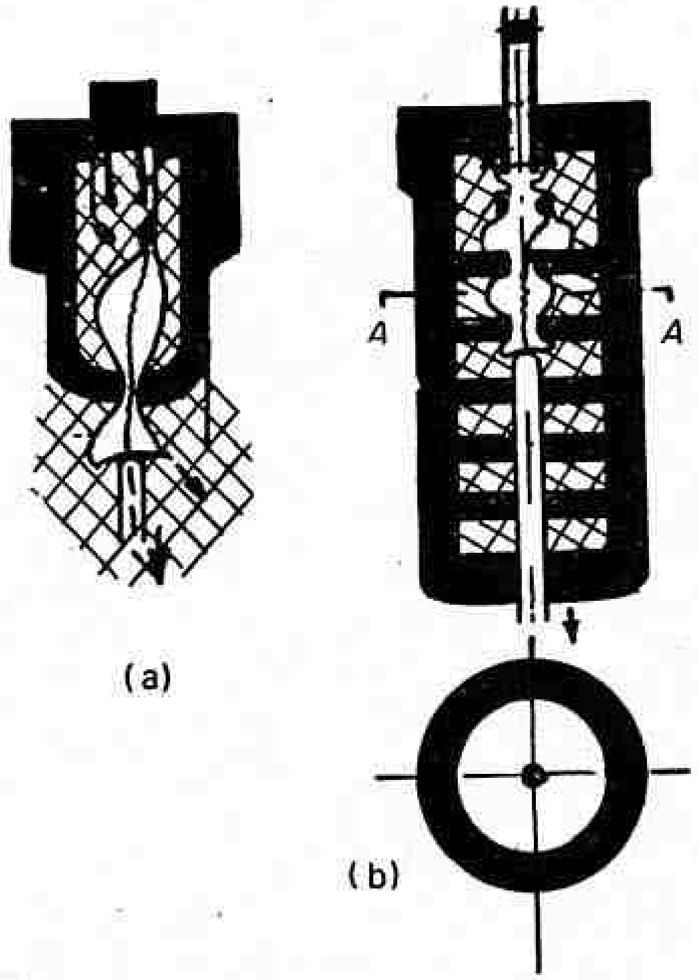


FIGURE 15.11 Arcing chambers used in minimum oil circuit breaker: (a) simple arcing chamber called explosion chamber; (b) axial venting arcing chamber.

The single break minimum oil circuit breaker offers the most simple and

economic solution for moderate fault levels where very short interruption timings are not required. This type is available up to 8,000 MVA at 245 KV with a total break time of 3 to 5 cycles.

15.4 Single and Multibreak Construction

It has been pointed out earlier that a circuit breaker may comprise a single pair of contacts or a number of pairs in series operating simultaneously. Undoubtedly the single-break is the simplest arrangement, a single-break is generally desirable up to the economic limit of rating, which is usually about 66 KV and 1,000 MVA although these figures have been exceeded in a number of designs. However, the multibreak construction has the following advantages:

(i) The transient restriking voltage is divided over a number of breaks so that only a fraction appears across each.
(ii) Each break can be separately tested at a voltage lower than that of the breaker as a whole (unit testing).
(iii) The effective speed of arc lengthening is increased in proportion to the number of breaks.

The main difficulty with multibreak circuit breakers is to ensure that the restriking voltage distributes itself evenly across the breaks so that full advantage of item (i) above can be obtained. One of the main reasons of this uneven voltage distribution is the presence of capacitance between line and grounded parts of the circuit breaker. This phenomenon will be quantitatively dealt with later in this chapter.

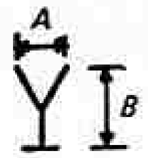
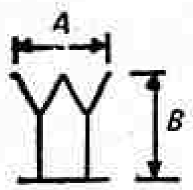
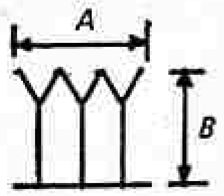
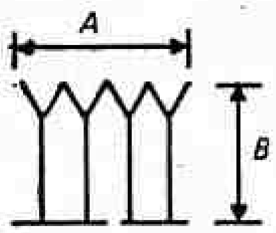
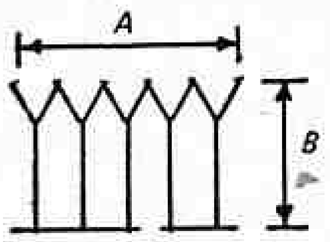
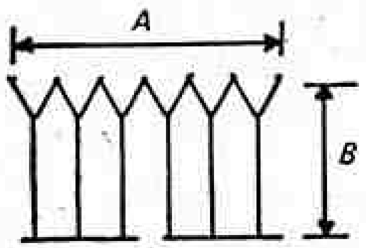
Multibreak type of circuit breakers have been developed for installations where rupturing capacities are high and very high speed operations are called for. The construction of multibreak type circuit breaker is based on the unitized design principle in which one unit consists of a vertical support insulator surmounted by a single or a pair of interrupting units in *Y* formation. By connecting the units in series, requirements for the network for different voltages and rupturing capacities can be met. This type has 2 to 3 cycles as total break time. The arcing time is 10 to 15 ms. Table (15.1) shows the typical design and ratings for minimum oil circuit breakers. It shows that 765 KV, 55,000 MVA breaking capacity minimum oil circuit breakers have been designed having 25 breaks per pole.

15.5 Air-Blast Circuit Breaker

15.5.1 Introduction

The modern demand for ultra-high speed operation of switchgear has

Table 15.1 *Design plan and ratings of minimum OCBs*

Voltage 72.5–765 KV rated normal current FS 2000/2500A Rated normal current FT 2500/3150A Withstand test voltage to ICE	FS / FT	Rated voltage to IEC KV	25	FS 40	FT 40	FT 50	FT 63	Overall dimension A (mm)	Overall dimension B (mm)
			Rated banking capacity KA						
			Equiualent MVA						
	4	72.5		5,000			8,000	2,000	2,800
	5	100 123	5,000		8,500	8,500		2,000	3,200
	8	145 170		10,000 11,500			16,000 18,500	3,400	3,700
	9	245	10,000		17,000			3,400	4,500
	12	245 300 362	15,000	17,000	25,000	25,000	27,000	4,800	4,500
	16 17	300 420	18,000	20,000		36,000	33,000	6,200	4,500 5,400
	20 21	420 525	22,500	29,000		45,000	46,000	7,600	5,400 6,300
	24 25	525 765		35,000	53,000		57,000	9,000	6,300 6,700

Breaking capacity proved by unit testing.

Earthing factor 1.5.
Natural freq. up to 20 KHz.

CHAPTER 16

Recent Developments in Circuit Breakers

16.1 Modern Trends

Generating capacity the world over has been increasing at phenomenal rates. Compared to the increase in generated power the breaking capacities of circuit breakers show an even faster rise. Figure (16.1) shows, for instance, the increase in breaking capacities of circuit breakers, which indicates a growth rate of 10% per annum. This development is essentially determined by two factors: first, the growth in generating capacity and, secondly, the increasing trend towards interconnection of systems.

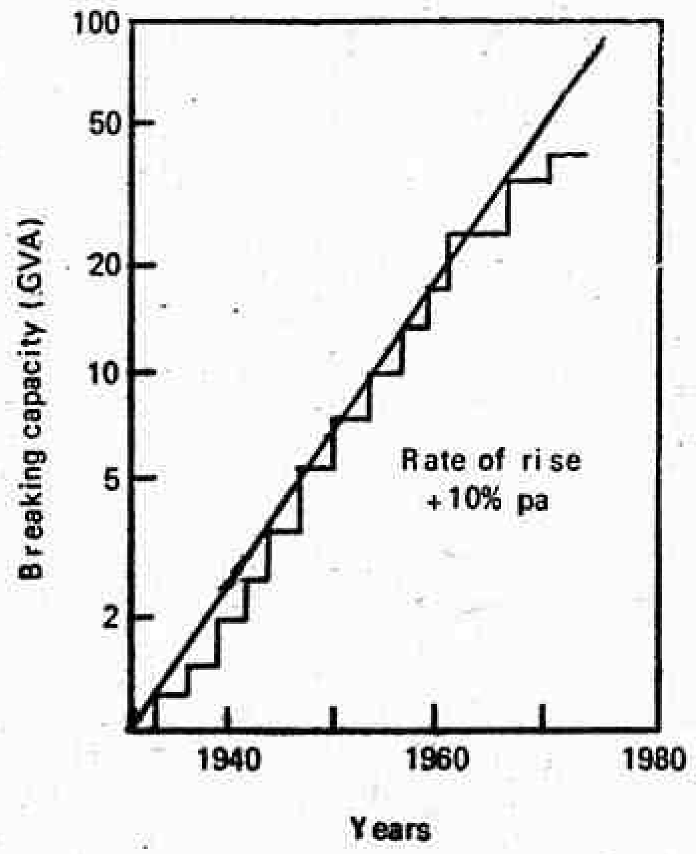


FIGURE 16.1 Development of breaking capacity of high voltage circuit breakers.

The high energy density in the large cities today also forces the power supply undertakings to supply HV direct into the distribution systems, and the space taken up by switchgear must be kept to an absolute minimum owing to the high price of land. Switchgear installed in builtup areas must also have a very low noise level. When a breaker interrupts heavy fault currents, which today may attain values as high as 60,000A, the temperature inside may rise up to 30,000°K. Circuit breakers of the latest design are capable of interrupting currents under these conditions with an arc duration of 5 to 20 ms.

Oil, an obviously inflammable substance for extinguishing the hot arc is a well proven medium because it releases hydrogen which by virtue of its low mass and high velocity is an excellent cooling medium. On the other hand modern circuit breakers employ heavy gas—SF_6 as the medium for quenching the arc. This noncombustible heavy gas has strong affinity for electrons, which tend to capture free electrons and thus prevent them from forming an electron avalanche that promotes reignition of the arc after it had lost its conductivity. Air-blast circuit breakers use air as medium at very high pressures up to about 100 atmospheres whereas recently vacuum as medium at very low pressures of the order of 10^{-6} torr has been used with increasing success. This is mainly because the medium has virtually no particles present of any kind to be ionized and to provide a pathway between the open contacts. An arc in a d.c. circuit of any voltage could be interrupted by a device that would introduce ample deionizing effects. However, practical limitations make it very difficult to design circuit breakers for use in d.c. circuits above a few thousand volts.

16.2 Vacuum Circuit Breakers

16.2.1 Introduction

Although the advantages of interrupting the arc in a vacuum were recognized as early as the nineteenth century, this did not find wide application till a few years ago. This was because the knowledge of problems in material science, vacuum technology and plasma physics was not sufficiently advanced to provide solution to the many technological problems encountered in the design and construction of a reliable vacuum circuit breaker.

High vacuum has two outstanding properties: (1) the highest insulating strength known, and (2) when an a.c. circuit is opened by the separation of contacts in a vacuum, interruption occurs at the first current zero with the dielectric strength across the contacts building up at a rate thousands of times higher than that obtained with conventional circuit breakers. These properties obviously make the vacuum circuit breakers more efficient, less bulky and cheaper. The service life also is much greater than that of temperatures are likely to fall below 5°C. Resistance heaters are provided in the auxiliary reservoir to maintain the gas temperature above the liquefication point. Figure (16.13) shows the SF_6 gas circuit and control as fitted to a circuit breaker.

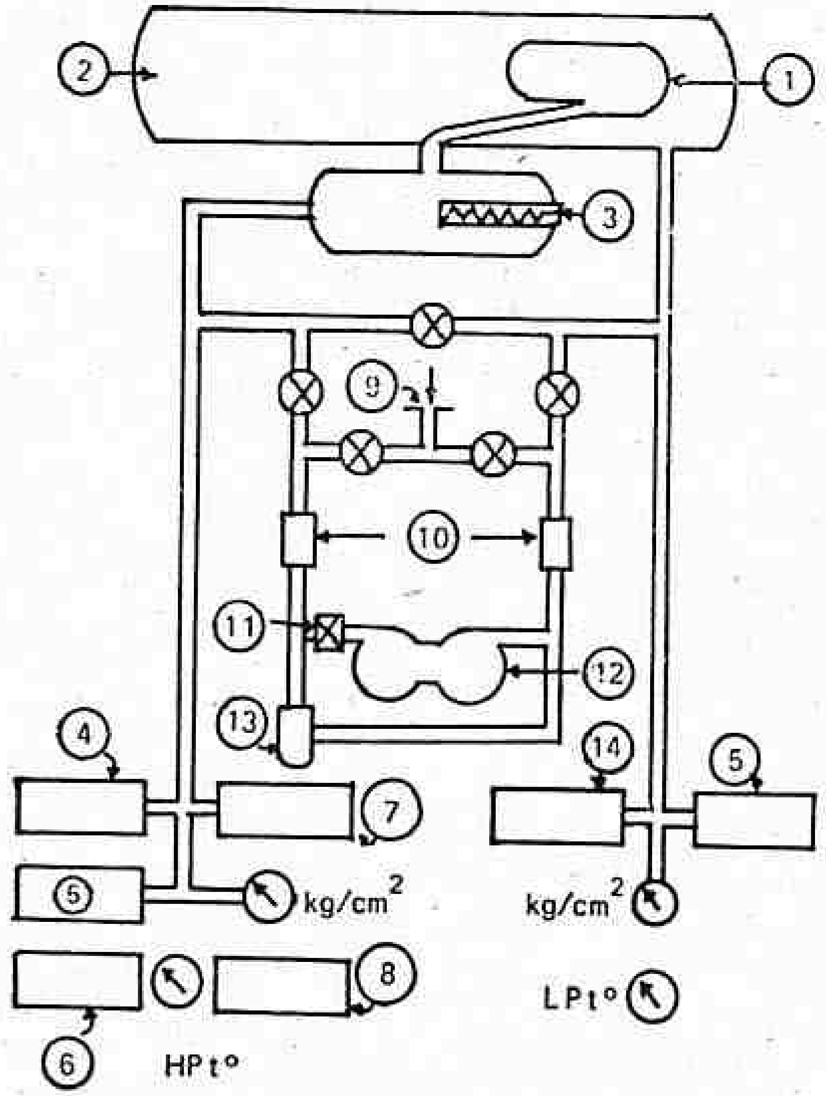


FIGURE 16.13 SF_6 gas circuit and control as fitted to a circuit breaker: (1) high pressure reservoir; (2) low pressure tank; (3) heater resistance; (4) HP alarm; (5) compressor control; (6) HP thermostat; (7) gas control; (8) temperature alarm; (9) test cock; (10) filters; (11) nonreturn valve; (12) compressor; (13) relief valve; (14) LP alarm.

16.3.6 Puffer Type Breaker

Figure (16.14) illustrates the mode of operation of a puffer type breaker. The drawings show the contacts in the closed position, opening of the contacts with the gas being initially compressed, the instant of arc extinction with the hot gases flowing through the hollow contacts, and the fully open position. Among the known Puffer type breakers this design has the following outstanding properties.

A relatively small contact clearance is used by taking full advantage of the high dielectric strength of SF_6 gas. Together with short contact travel from contact separation to the extinguishing position, this results in a

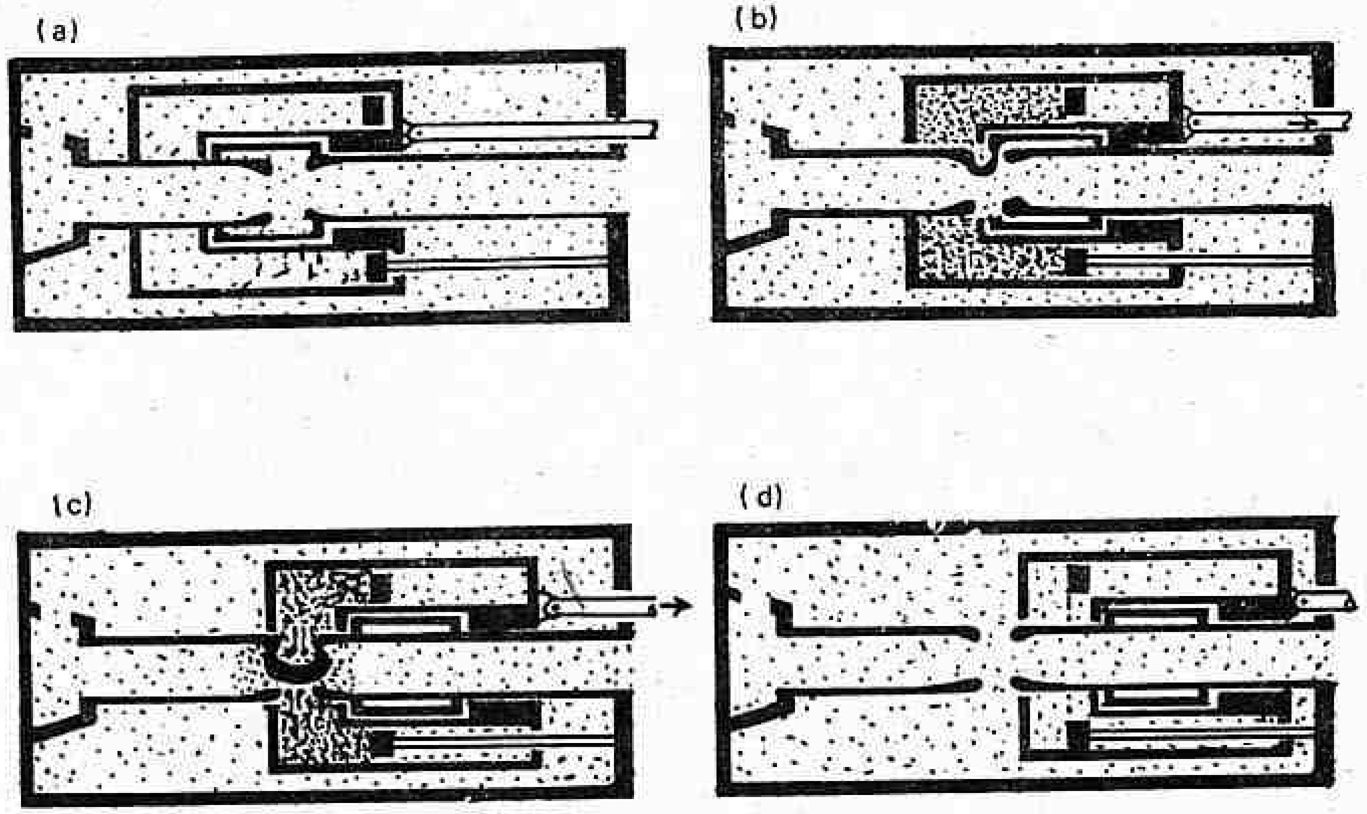


FIGURE 16.14 Operation of a SF_6 puffer-type circuit breaker. Four different interrupting positions are shown: (a) 'closed': equal pressure conditions in the interrupter: (b) contacts just opened: gas in the puffer chamber being compressed by the moving cylinder and fixed piston; (c) contacts at breaking distance: the compressor SF_6 flows through the nozzles, cools and interrupts the arc; (d) 'open': equal pressure conditions in the interrupter.

small arc energy, high extinguishing ability and short interrupting time. A wide clearance between the arc and the insulation material, the transport of plasma and arcing products to regions with zero or low dielectric stress and a contact clearance not bridged by insulation material make use of the full dielectric properties of the SF_6 gas during and after arc extinction.

16.3.7 Metalclad HV Switchgear

All items of equipment including busbars, isolators, breakers, etc. are assembled in a self-contained unit. The individual elements are arranged as standardized building blocks allowing diverse combinations to be made to suit the requirements of a given installation. The complete metal enclosure is earthed to provide a safe gas-tight encasement for all line parts. The installation consists of several gas-tight compartments, SF_6 pressure is kept at an average of about 4 atmospheres at 20°C. The breaker has also a high pressure section with about 14 atmospheres at 20°C for quenching the arc and operating the contacts. After every operation gas is raised to the required pressure in a closed circuit by the compressor. The operating mechanism consists of a spring and rewind motor but a hand crank is provided for emergencies. A specially designed cable-end box provides the isolation between the SF_6 insulation and cable insulation. It is so designed as to permit all usual types of cables to be connected.

16.3.8 Recent Results and Prospects of Future Development

Whether these techniques based on new principles will succeed is more difficult to estimate. It is not probable that a better multiatomic gas than SF_6 will be found, but perhaps a better liquid than oil is feasible. There are attractive possibilities of the combination of SF_6 insulation with vacuum interrupters. Another recent suggestion is to use liquid SF_6 in a container much like oil in minimum oil breakers. This may provide a solution to the problem of higher speed of operation.

On the basis of the results obtained so far and in view of the fact that future development looks promising, a paper dealing with switchgear for a maximum operating voltage of 1300 KV has been drafted for CIGRE (Muller, 1971; Boeck and Troger, 1972).

In Fig. (16.15) a comparison is made between SF_6 insulated switchgear and a conventional design for 1300 KV. SF_6 insulated tubular bus

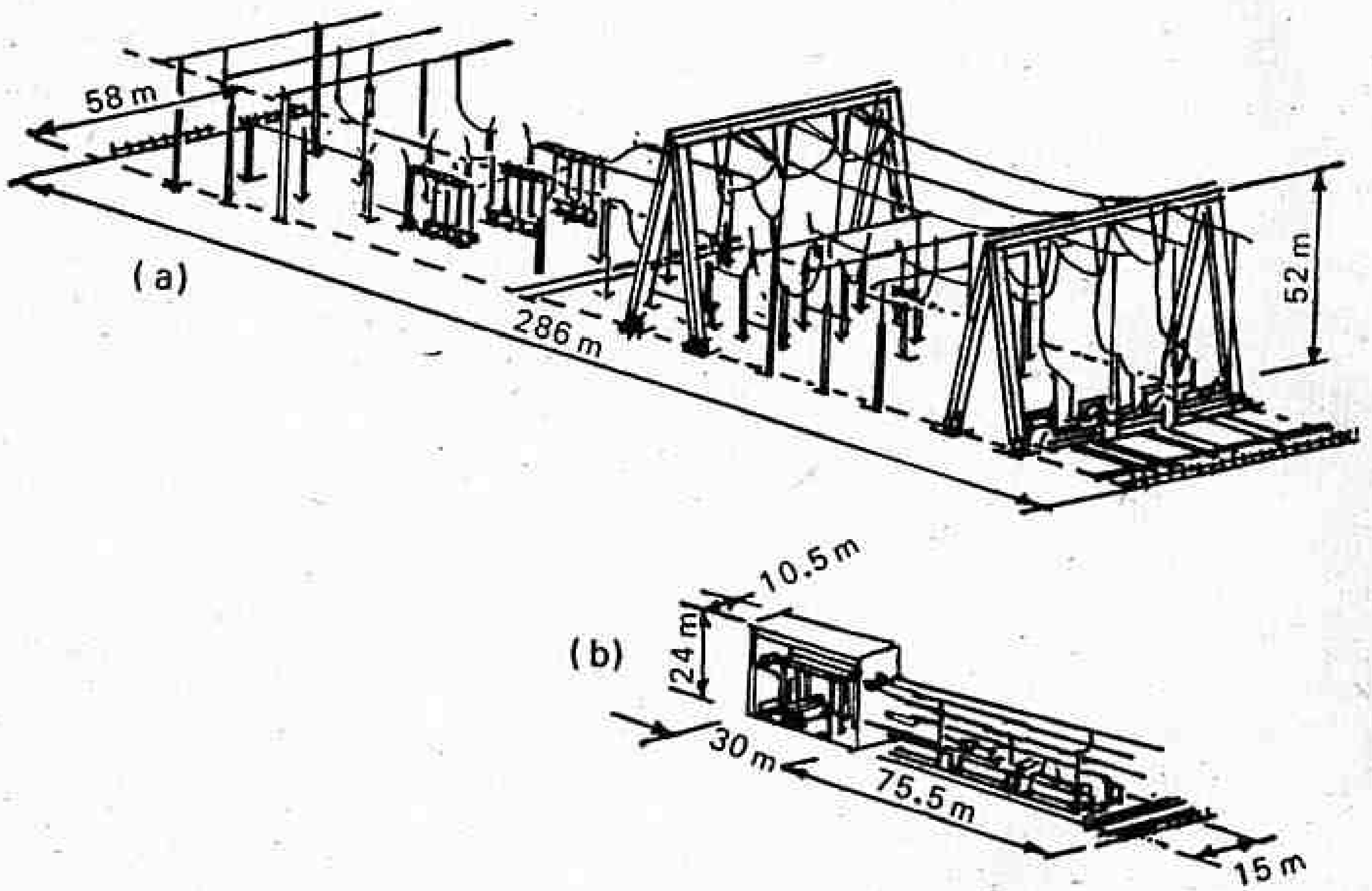


FIGURE 16.15 1300 KV switchgear transformer feeder 3000 MVA, single busbar with auxiliary bus: (a) conventional switchgear: area requirement 16700 m², volume 887800 m³; (b) SF_6 insulated switchgear: area requirement 1500 m², volume 36000 m³.

systems for power transmission will moreover be used to an increasing degree.

16.4 D. C. Circuit Breaker

16.4.1 Introduction

Light duty d.c. circuit breakers have been in use since long. However, with the latest developments in HVDC transmission there would naturally be the necessity of the HVDC circuit breaker. The two major problems of HVDC circuit breaking are:

(a) The amount of energy to be dissipated during the short interval of breaking is very high as compared to the conventional a.c. circuit breakers.

(b) The natural zero current does not occur as in the case of a.c. circuit breakers.

Resistance switching and efficient cooling by forcing the liquid or air blast are used to dissipate the high amount of energy, whereas artificial means are provided to bring the current to zero.

16.4.2 D. C. Breaking

The d.c. arc extinction can be explained with the help of a circuit shown in Fig. (16.16) which is a simple d.c. circuit having a circuit breaker B

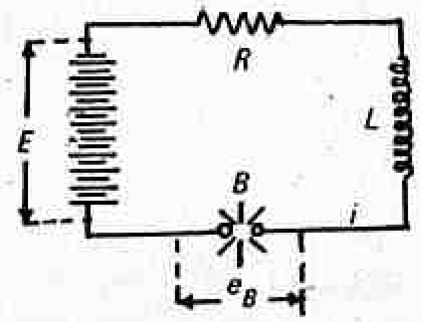


FIGURE 16.16 An inductive d.c. circuit showing the burning arc.

assumed to break the current $I=E/R$. The arc characteristics is shown in Fig. (16.17). It can be noted that the voltage e_B across the burning arc depends on the current I flowing through the arc.

$$e_B=e_B(i) \tag{16.1}$$

The differential equation of the circuit is

$$L\,di/dt+Ri+e_B=E \tag{16.2}$$

This can be written as

$$L\frac{di}{dt}=(E-Ri)-e_B(i)=\Delta e \tag{16.3}$$

This can now be represented in characteristic diagram of Fig. (16.17) by plotting the resistance line. The magnitude of Δe determines the inductive voltage and thereby the rate of change of current. To the right of point '1', Δe is negative, thus the current will decrease and approach point 1. To the left of point '1', Δe is positive and hence this will increase the current and hence again reach point '1'. Hence this point represents a stable burning point of the arc.

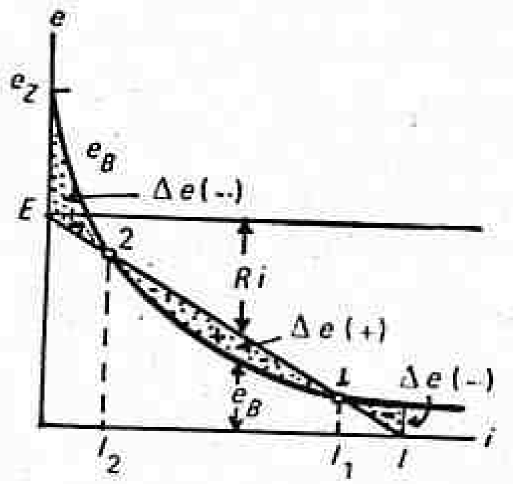


FIGURE 16.17 Arc characteristics.

Examination of point '2' shows that to the left of point '2' there is steadily negative Δe which gives a steady decrease of current until zero. This therefore is the condition for the extinction of the arc. However to the right of point '2' Δe is positive and the current increases and thus has no tendency of coming to point '2' which unlike point '1' is unstable for the maintenance of arc.

Lengthening of the arc has the effect of raising the arc characteristic so that it lies above the resistance line. Progressive lengthening of arc is a basic requirement of d.c. circuit breakers. Raising of arc characteristics helps in the interruption level. Moreover the loss of energy increases with increasing length of arc and more power will be required to maintain the arc.

16.4.3 Light Duty D.C. Air-Break Circuit Breakers

The chief requirement of a d.c. circuit breaker is that it should interrupt the fault current in the shortest possible time. Contacts are separated at the initiation of the fault, the arc is transferred from the main contacts to the arcing contacts where the arc lengthens and then extinguishes. During this process the voltage across the arc exceeds the supply voltage. For faster actions magnetic blowouts are provided. As already explained above the idea to shift the arc characteristic above the resistance line.

16.4.4 General Design and Construction

These are usually constructed as a single-pole unit suitable for mounting on a flatback switchboard of insulating material such as slate. However double-pole and three-pole breakers are possible by mechanically interlinking two or three single pole units. The single-pole breaker consists essentially of two main fixed contacts bridged by a brush with arcing contacts above it may be arranged to close either mechanically or by a solenoid, and to trip either by a series overcurrent coil, a reverse current coil, and under-voltage release, or by a relay-operated shunt release; or by combinations of these methods.

The breaker closes by means of a toggle normally, and is of the free-handle type, i.e. the breaker cannot be held closed against the action of the automatic releases; neither can it be opened slowly. The fast action is obtained by gravity or by springs.

Low current breakers up to 500 A are usually fitted with series overcurrent coils operating on a cylindrical plunger. Breakers rated above 500 A up to about 1000 A are generally fitted with an overcurrent release actuated by an iron yoke round a single-turn primary conductor, which attracts a hinged armature. For breakers exceeding 1000 A ratings overcurrent protection and reverse current protection are obtained by a shunt release coil energized by a suitable relay.

16.4.5 High Speed D.C. Air-Break Circuit Breakers

In order to reduce the risk of flashover on the commutators of rotating machines, or of backfire in rectifiers the time of interruption in large capacity d.c. system should be very short. The high speed of interruption automatically ensures economics in design of associated apparatus, such as rectifiers, transformers and cables.

The ordinary light duty d.c. breakers described earlier have an opening time of 0.15 to 0.4 s. An opening time of the order of 0.002 s is required for a high-speed d.c. air-break circuit breaker. In order to achieve high speed the following features are incorporated in the design.

(i) Light moving parts are provided.
(ii) Only one set of breaking contacts is used because there is insufficient time in which the arcing contacts can be allowed to open after main contacts.
(iii) Powerful springs provided for opening movement.
(iv) Arc chute is provided for arc lengthening and extinction.
(v) The contacts are held closed against the action of the opening springs by an armature attracted to a shunt-excited electromagnet, and are released by the demagnetizing effect of a suitably

positioned conductor (known as bucking bar), which itself carries the fault current.

One such arrangement employing the above features is shown in Fig. (16.18). The mechanism uses two sets of contacts, for making and breaking respectively, the breaking contacts which are in series with the making contacts, close first and are, therefore, ready for a tripping operation before making contacts close. The breaker is normally tripped by deenergizing the holding magnet; for this purpose a control switch, push button, or relay may be used.

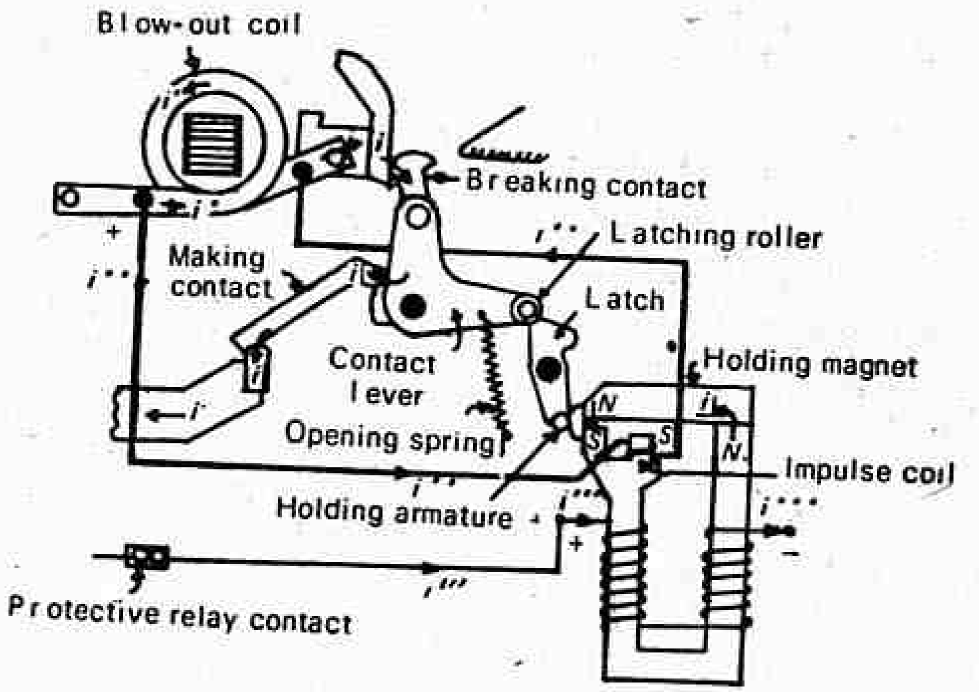


FIGURE 16.18 Contact arrangement of a high speed circuit breaker: $i=i'+i''$; i=total current through breakers; i'=main circuit current; i''=impulse coil current; i'''=holding coil current.

16.4.6 HVDC CIRCUIT BREAKERS

The greatest limitation is the difficulty in breaking large d.c. currents at high voltages. In the case of alternating current, the current passes through zero value twice every cycle. A.C. circuit breakers exploit this property to interrupt the current and the problem for the circuit breaker reduces to prevention of restriking after a current zero. D.C. circuit breakers do not have this natural advantage and therefore have to force the current to zero from the short-circuit value by some means. In addition to this another problem with d.c. circuit breakers is the dissipation of large amount of electromagnetic energy stored in the circuit.

In designing an HVDC circuit breaker there are three main problems to be solved:

(a) How to produce a current zero?
(b) How to prevent restriking?
(c) How to dissipate the stored energy?

Each of these problems will be discussed in turn.

(a) *Producing Current Zero.* A fundamental problem in the design of d.c. circuit breakers is the production of current zero artificially. This approach involves changing the form of arc current by commutation principle and using the quenching gear of the well proven HVAC circuit breakers for arc clearance.

One such scheme is based on the principle of oscillatory circuit shown in Fig. (16.19). A series resonant circuit with L and C connected across the main contacts M of a conventional a.c. circuit breaker through an auxiliary contact S_1. Resistance R is connected through contacts S_2. Under normal conditions M and S_2 are closed thus C is charged to line voltage, contacts S_1 are open and have line voltage across them. In order to interrupt the d.c. current the contacts S_2 are opened and S_1 is closed, thus discharging the capacitor C through L, M and S_1 which sets up an oscillatory current shown in Fig. (16.19b). This creates artificial current zeros and the circuit breaker M can be opened. Thereafter contacts S_1 are opened and S_2 are closed.

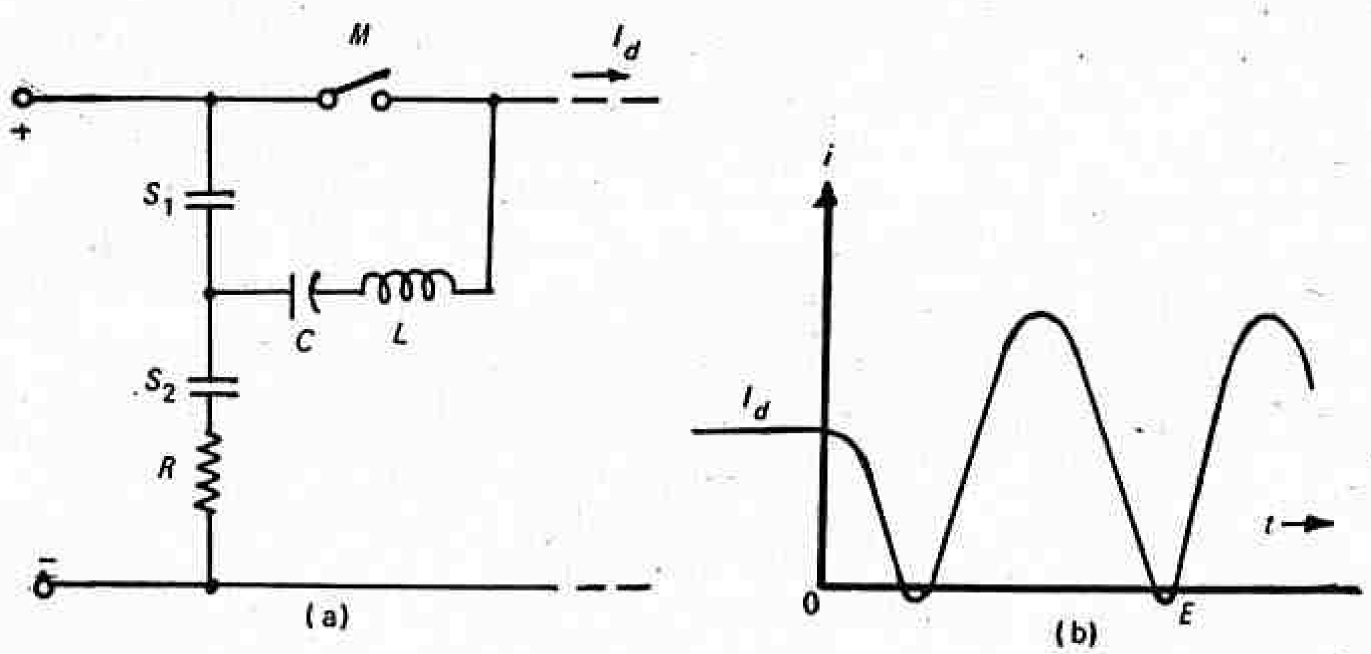


FIGURE 16.19 Principle of oscillating current technique: (a) schematic circuit; (b) waveform of current through main contacts M.

Another method is to divert the main current to the capacitor with the result that the current to be interrupted by M is small. This is illustrated in Fig. (16.20). The rate of rise of recovery voltage across M is $dV_c/dt=I_d/C$. The nonlinear resistor absorbs energy without greatly adding to the voltage across M.

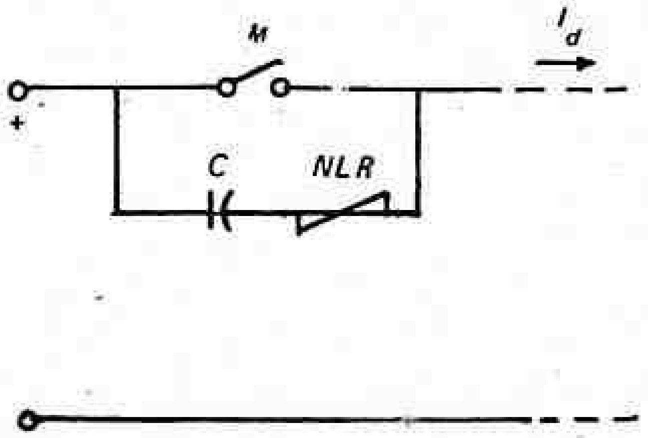


FIGURE 16.20 D.C. breaking using nonlinear resistance (NLR).

(b) *Prevention of Restrikes.* This problem is more acute in oscillating current d.c. circuit breakers, where the time in which the current is chopped is very small (of the order of 100 μs). This causes a steep surge of restriking voltage across the terminals. The circuit breaker must be able to withstand this voltage.

To produce a good deionizing arc the space between two walls of arc chute can be narrowed to restrict the arc and at the same time it can be broken into a number of smaller arcs by inserting a grating of vertical metal plates.

(c) *Dissipation of Stored Energy.* A large amount of energy stored in the circuit inductance at the beginning of the interruption plus that supplied by the rectifier during the time of interruption has to be dissipated by some means. If it is not, it will transfer to the system capacitance and create overvoltages. The method used to dissipate this energy determines to a large extent the cost of the scheme. A protective spark gap can be used across the circuit breaker to reduce the size of commutating capacitor. Further, it will keep the abnormal voltage produced at the switching time below undesired levels. By means of high frequency currents the spark gap acts as an energy dissipating device.

16.4.7 HVDC Vacuum Circuit Breaker

The effectiveness of the commutation principle, has been demonstrated by using vacuum interrupters as a means for interrupting high direct current at high voltage. Currents in excess of 15 KA at 20 KV have been interrupted by a single device in an inductive circuit.

Because of the fact that extremely fast interruption is required for d.c. breakers, the vacuum interrupter constitutes an ideal device for a circuit breaker where extremely rapid response is required. In the first instance, the critical contact separation to achieve interruption is quite small (of the order of 5 to 10 mm). Moreover, the inertia mass of the moving system

is relatively low, essentially comprising only the contacts. Ultra high speed for the mechanism can be achieved by means of a high-pressure hydraulic system.

As the arc plasma diffuses in vacuum at a very rapid rate so the vacuum interrupters are ideal, because otherwise the interruption will become difficult because of the plasma in the contact gas when the recovery voltage is rising.

Experimental HVDC vacuum circuit breakers have been built and tested.

QUESTIONS

1. What are viscous flow and molecular flow? How does high vacuum help in interrupting the arc?
2. (a) Enumerate the chief requirements of the contact material for a vacuum breaker.
   (b) Why is current chopping not a serious problem with vacuum circuit breakers?
3. What are the possible applications of vacuum circuit breakers? Point out the main limitations which have prevented their widespread use.
4. Give the properties of SF_6 gas that make it more useful for circuit breaking. How does the electronegative nature of SF_6 contribute towards its high dielectric strength.
5. Describe the essential features of an SF_6 metal-clad switchgear.
6. Explain the construction of an SF_6 breaker. How does it essentially differ from an air-blast circuit breaker?
7. What is the principle of breaking d.c. currents? In what respect does it differ from a.c. current breaking?
8. What are the practical limitations of breaking high voltage direct current circuits? Explain some of the means of overcoming these difficulties?

conventional equipment and hardly any maintenance is necessary. Vacuum breakers are ideally suited for most duties encountered in typical electric utility and industrial applications. Their voltage and interrupting rating is such that with little modifications, they may be made to perform specific switching duties on high-voltage a.c. systems. Field experience has proved the unique performance and reliability characteristic of vacuum devices.

16.2.2 The Vacuum Medium

Every medium that has a pressure below atmospheric (760 mm of mercury) is known as vacuum. Torricelli is known to be the first man who succeeded in evacuating a space by building his mercury barometer. Low pressures are measured in terms of torr, where 1 torr=1 mm of mercury. Now with various improved techniques pressures as low as 10^{-7} torr can be achieved.

The value of the pressure of the medium has a marked effect on the molecular structure of the medium. In the high pressure ranges of vacuum system the mean free path is very small and the molecules are in a constant state of intercollision, the gas behaves as a fluid and is known to be in a state of *viscous flow*. As the pressure is reduced the mean free path increases. Eventually a point is reached at which the mean free path is equal to or greater than the dimensions of the confining chamber. Under this condition the molecules will collide more frequently with the walls of the chamber than with each other. In this region the gas is said to be in a state of *molecular flow*.

The division between the two regions is specified by a dimensionless parameter called the *Knudsen number*. For a cylindrical tube the Knudsen number is defined as the ratio of the mean free path (L_m) of the gas molecules to the radius (R). When L_m/R is less than 0.01 gas flow is viscous; if the ratio is greater than 1, the flow is molecular. The range between these two limits is called the transition range. Table 16.1 shows the value of mean free path for N_2 at various values of pressure. The gaseous medium in vacuum interruption devices is usually in the molecular flow range.

Table 16.1 *Gas kinetic data for N_2 at 25°C*

Pressure (torrs)	*Density at 25°C (molecules/cm³)*	*Mean free path (cm)*
760	2.5×10^{19}	6.3×10^{-6}
10^{-3}	3.3×10^{13}	4.8
10^{-4}	3.3×10^{12}	48
10^{-5}	3.3×10^{11}	480
10^{-6}	3.3×10^{10}	4.8×10^{3}
10^{-7}	3.3×10^{9}	4.8×10^{4}

16.2.3 The Vacuum Arc

When contact separation takes place in air the ionized molecules are probably the main carriers of electric charges and responsible for low breakdown value. In vacuum arc the neutral atoms, ions and electrons must ultimately come from the electrodes themselves, and not from the medium in which the arc is drawn. As the current carrying contacts are parted, the current concentrates at a few local high spots on the contact surfaces. Normal conduction through metal ceases when the last bridge between the two contacts is vaporized. The phenomena at the active spots on the electrodes of a vacuum circuit breaker are similar to those of conventional high pressure arcs where the current density is in the range of 10^5–10^6 amps/cm². In vacuum arc the emission occurs only at the cathode spots and not from the entire surface of the cathode. For this reason the vacuum arc is also known as the cold cathode arc. In fact the emission of electrons and ions from the cathode spots may be due to any or the combination of the following mechanisms:

(a) Thermionic emission.
(b) Field emission.
(c) Thermionic and field (TF) emission.
(d) Secondary emission resulting from positive ion bombardment.
(e) Secondary emission by photons.
(f) Pinch effect emission.

At high currents the ionized metal vapour spreads through quite a large volume surrounding the electrodes. At lower currents the quantity of vapour produced is greatly reduced. Since the vapour evolved from the cathode spots expands rapidly in vacuum, the probability of maintaining a charge carrier density sufficient to retain adequate conductivity in the column and sustain the emission process becomes increasingly small. At current zero the cathode spots extinguish in times of the order of 10^{-8} second.

16.2.4 Vacuum Arc Stability

In a 50 Hz a.c. network the current decreases to zero once every 10 ms. If the circuit is interrupted at a zero current point no overvoltage will result. Hence for a successful interruption it is necessary that the arc be stable for a half-cycle duration and particularly that it continues to exist at currents approaching zero. It has been found that the arc stability depends on (1) the contact material and its vapour pressure and (2) circuit parameters such as voltage, current, capacitance and inductance. In low current circuits most of the evaporation takes place at discrete points known as cathode spots; at higher currents the gas evaporates from cathode and anode spots. In addition to these sources gas is added to the contacts enclosure when it is stripped from other parts of the enclosure because of high temperature and impinging metal vapour.

It was shown that vapour pressure and arc stability are interrelated. The higher the vapour pressure at lower temperatures, the longer the life time of the arc. Figure (16.2) shows average arc lifetime for some pure

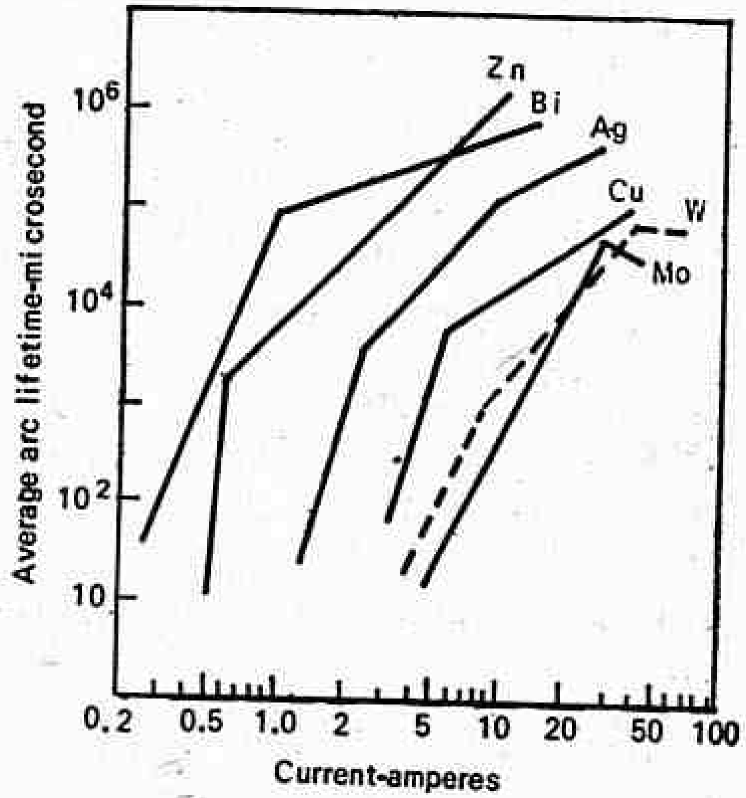


FIGURE 16.2 Average arc lifetime vs. current for various pure metals.

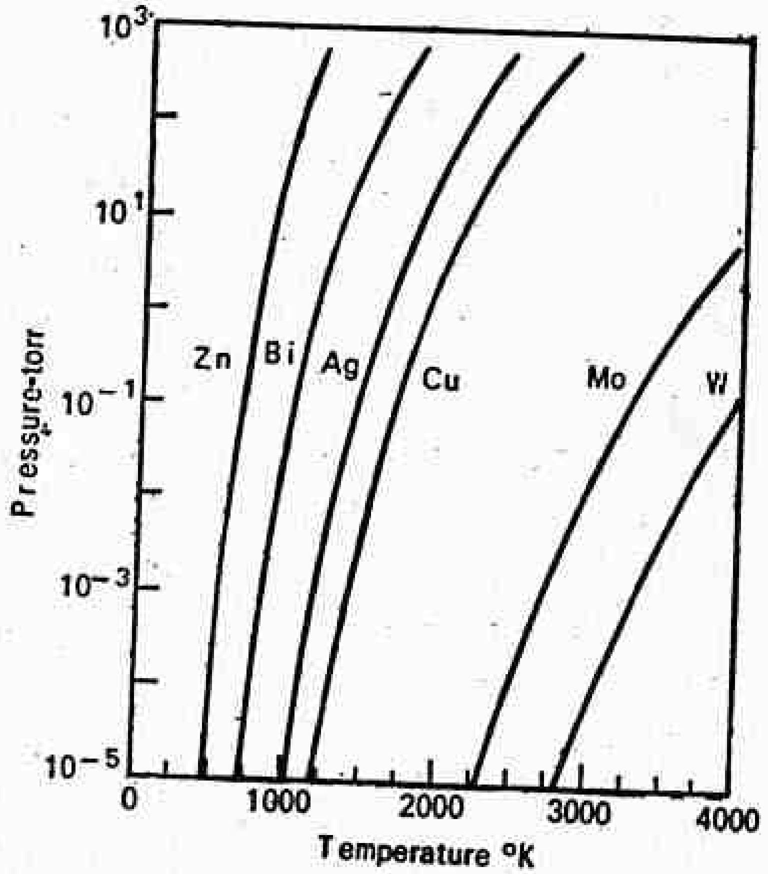


FIGURE 16.3 Vapour pressure vs. temperature for various pure metals.

metals, and Fig. (16.3) shows relationship between pressure and temperature for various metals.

Shunting the contacts with different values of capacitance demonstrates that the larger the capacitance the lower the average lifetime of the arc. Adding a large inductance in series with Cu—Bi contacts results in an increase of the arc duration. The chopping level depends upon the vapour pressure and the thermal conductivity of the cathode material. A good heat conductor will cool very rapidly and its contact surface temperature will fall. This will reduce the evaporation rate and the arc will be chopped because of insufficient vapour. On the other hand a bad heat conductor will maintain its temperature and vaporization for a longer time and the arc will be more stable.

16.2.5 Vacuum Breakdown

The major insulating media are atmospheric air, oil, paper and porcelain. These can withstand appreciable voltage but they are minute as compared to the withstand voltage of a gap in vacuum. Figure (16.4) illustrates the breakdown strength of various insulating materials.

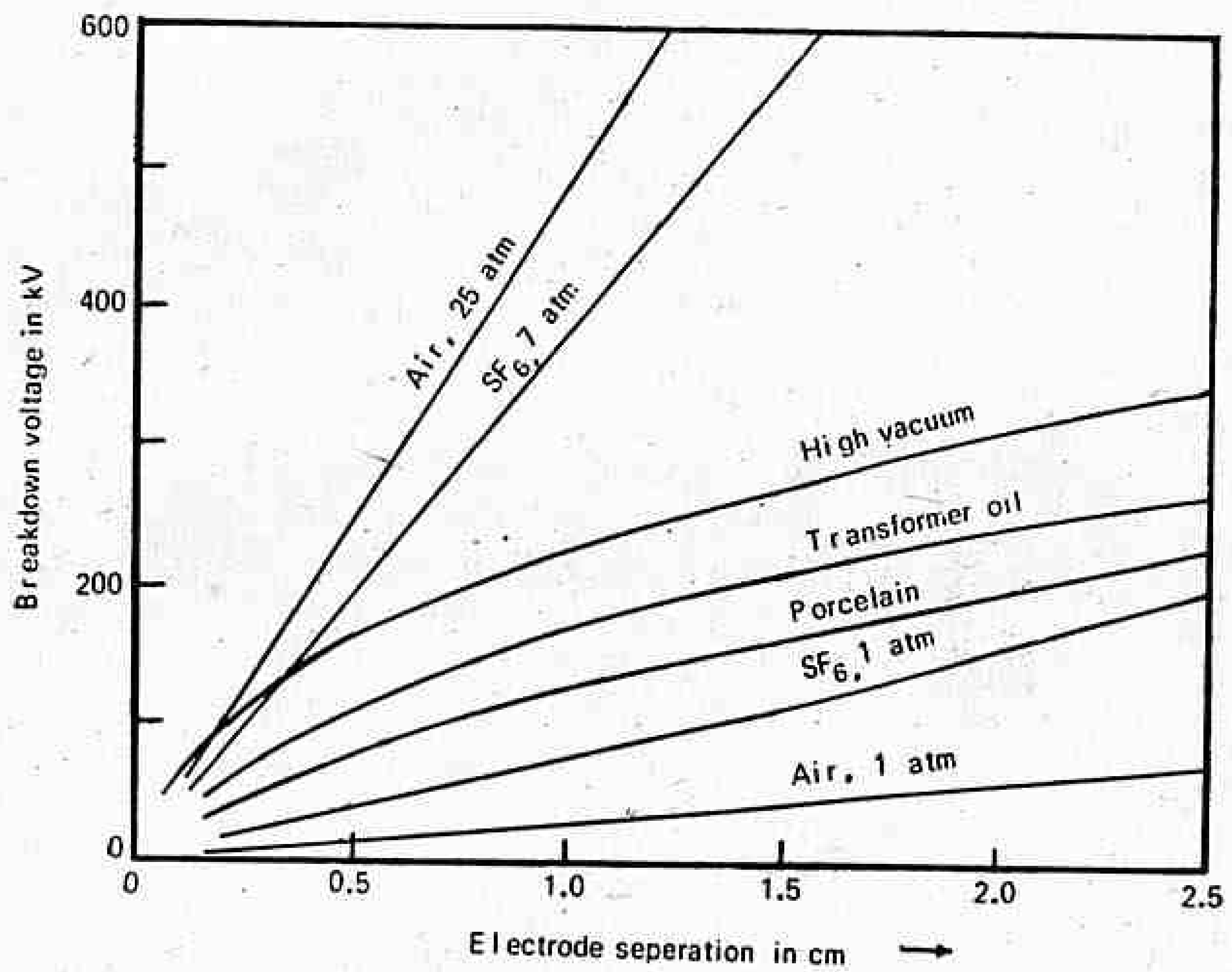


FIGURE 16.4 Breakdown strength of various insulating materials.

Typically the voltage a gap can withstand decreases with reduced pressure (actually density) to a minimum and then begins to rise rapidly with further reduction of ambient gas density. This is illustrated in Fig. (16.5), which shows an idealized *Paschen Curve* where breakdown voltage is plotted as a function of pressure times gap length.

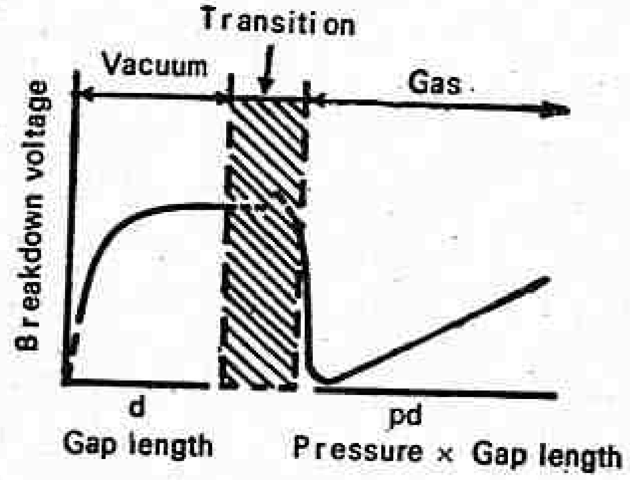


FIGURE 16.5 Schematic Paschen curve and its relation to breakdown in vacuum as a function of gap length.

When pressure is reduced below the point where the mean free path of the residual gas molecules is of the order of the tube dimensions, approximately 1 micron in many practical cases, the breakdown voltage ceases to depend upon the gas within vessel and is influenced most strongly by composition, condition and arrangement of the electrode surfaces and walls of the tube. This transitional range is shown shaded in the Fig. (16.5). Below the transitional range it is high vacuum of the order of 10^{-4}—10^{-6} torr and the mean free path of the residual gas molecules becomes very large compared to the gap between the electrodes (see Table 16.1). In a gap of 1 cm only a few electrons in a million get to collide with molecules and form ions. It is this fact which is responsible for the very high breakdown strength of vacuum. In this range the breakdown strength is independent of the gas density, but varies with gap length only. Hence the breakdown strength is plotted against gap length only in this region.

Vacuum breakdown initiation like the vacuum arc must depend upon products evolved under the action of high fields from the electrodes and walls which are bombarded by field emitted electrons, rather than upon the medium in which the electrodes are immersed.

The actual value of breakdown voltage for a given gap depends quite strongly upon the condition of the electrode surfaces. Highly polished and thoroughly degassed electrodes have shown particularly high breakdown voltages. Contacts get roughened after arcing and thus the breakdown strength decreases. Generally improvement in breakdown strength after arcing can be obtained by applying successive high voltage impulse sparks. This does not alter the arc roughened surfaces to any noticeable degree but probably does remove loosely adhering metal particles from the electrodes deposited there by the vapour blast during arcing.

Figure (16.6) shows the average static breakdown voltage vs. gap length

for several rough surface of electrode material in a vacuum of the order of 10^{-6} torr. Similar breakdown data for N_2 (air) are shown for comparison. Most of the materials shown here gain much of their ultimate breakdown strength in less than 3 mm gap for the particular geometry shown. Such a characteristic permits the use of short gaps in vacuum switches which results in simplifying the operating mechanism and in increasing the speed of operation over conventional switches.

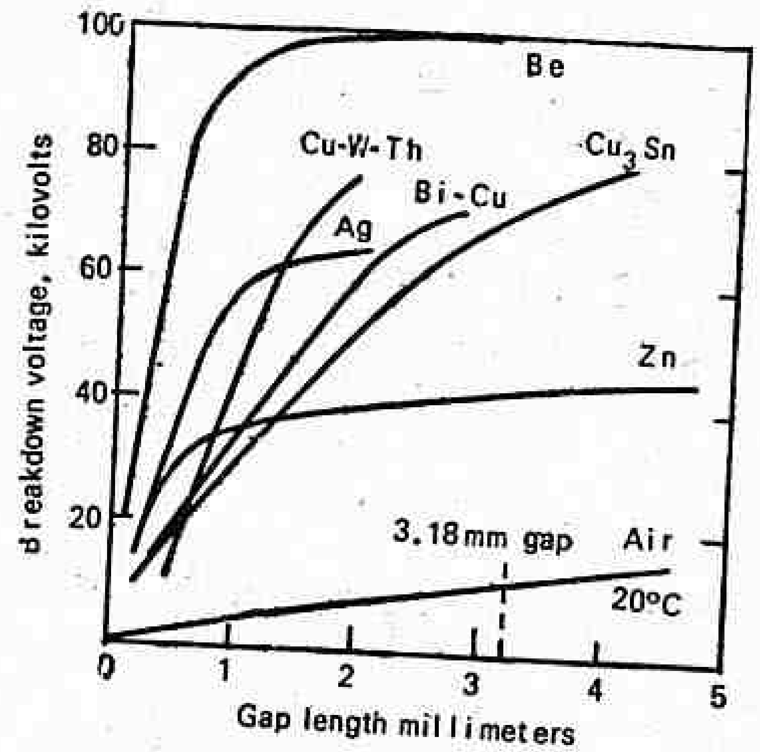


FIGURE 16.6 Static breakdown characteristic curves for various electrode materials in vacuum.

16.2.6 Current Chopping

As the current falls, the arc tends to extinguish at a finite current level whose value depends on the vapour pressure and the electron emission characteristics of the contact material, unlike in oil or air-blast circuit breakers where it is generally agreed that the current chopping arises from an instability in the arc column. Chopping leads to excessive overvoltages endangering the system insulation and causing reignition of the arc. It is desirable to dissipate energy in the arc itself and from this point of view, reignition occurring after chopping is welcome. Basically, however, chopping should be avoided. It is possible to reduce the current level at which chopping occurs by chosing a contact material which gives out sufficient metal vapour to allow the current to come to a very low value or zero value, but this is rarely done since it is likely to affect other properties notably the dielectric strength.

16.2.7 Recovery Characteristics of Vacuum Devices

It has already been stated that high vacuum possesses extremely higt dielectric strength. At current zero the cathode spot extinguishes within 10^{-8} second and after this the original dielectric strength is established. This quick return of high dielectric strength is, of course, due to the fact that the vaporized metal which is localized between the contacts, diffuses rapidly due to the absence of gas molecules. The metal molecules are blown at high speeds to the glass walls and condense there.

The rate of dielectric recovery of a vacuum gap in first few microseconds after arc interruption is approximately 1 KV/μ sec for an arc current of 100 A, as compared with 50 V/μ sec in the case of air gap. Figure (16.7) shows rates of recovery of different gases and of vacuum. The gases are at atmospheric pressure and current is 1600 A with an open gap distance of 6.35 mm.

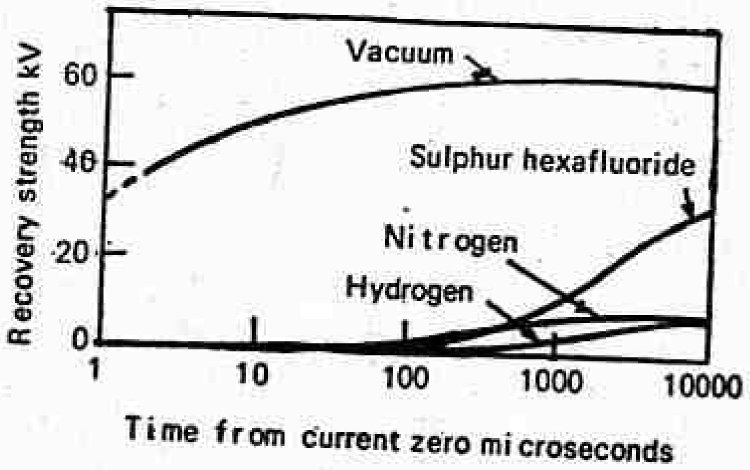


FIGURE 16.7 Recovery strength for vacuum and gas, 1600 amperes, 6.35 mm gap, gas pressure 1 atmosphere.

Because of the above-mentioned attributes of vacuum interrupters, vacuum circuit breakers can be used without reservations for fault clearing in any location on a system. They can handle the severe recovery transients associated with short line faults or faults close to a transformer without difficulty. All forms of load switching can be performed with the same ease.

16.2.8 Contact Materials

The preceding considerations reveal that the most important part in a vacuum circuit breaker is the selection of contact material. The desirable properties of a vacuum circuit breaker contact material can be enumerated as follows.

(a) Good electrical conductivity to pass normal load currents without overheating.
(b) Good thermal conductivity to dissipate rapidly the large heat generated during arcing.
(c) High cold and hot hardness to prevent wear and tear during normal opening and closing operations.

(d) High density.
(e) Sufficiently low vapour pressure to reduce the amount of inseparable metal vapour in the chamber.
(f) The heat of vaporization should be such that (i) arc energy generates enough metal vapour to sustain arcing till the first natural current zero, and (ii) there is insufficient vapour present to cause reignition after first current zero.
(g) High thermoinic function to enable early arc extinction.
(h) Resistance to welding together.
(i) High boiling point to reduce arc erosion. High boiling point means high heat of vaporization and greater dissipation of arc energy in vaporizing the material at the cathode spot.
(j) The material should preferably not have a surface film. If the film cannot be avoided then it should be conducting.
(k) Low gas content. Gas content of the material should be one part in 10^7 or lesser to ensure longer service life.
(l) Sufficient mechanical strength to retain structural integrity under high voltage gradients at the surface.

The most essential requirement of contact material is that it gives out low pressure vapour at the time of arcing. Whereas low vapour pressure metals are better from the arc extinction points of view, the high vapour pressure and low conductivity metals seem to be more desirable to limit the unfavourable consequences due to current chopping.

In view of the multiplicity of requirements that a vacuum switch contact material must meet and in view of the wide range of metals now available, one may say that there is no single metal which combines all the conflicting properties listed above. Metals with good thermal and electrical conductivities invariably have low melting and boiling points, high vapour pressure at high temperature, low electron functions and are considerably soft.

Materials which have high melting and boiling points have low vapour pressures at high temperatures, but are poor conductors. Therefore to combine these contradictory properties in one single material composites of two or more metals or a metal and a nonmetal have to be made. Copper-bismuth, copper-lead, copper-tellurium, copper-thallium, silver-bismuth, silver-lead, and silver-tellurium are some of the examples. Figure (16.8) shows the characteristics of some of these metals.

Figure (16.2) may also be referred for pure metals for similar characteristics.

The commercially produced metals have traces of other elements and trapped gases in them. Once a circuit breaker is sealed it is not possible to take out the gaseous products released during repeated operations, because this will destroy the vacuum of the switch. Moreover the characteristics like breakdown voltage and rate of recovery are affected by the presence of gases. Methods have been evolved to degas metals which are commonly used in electrical and electronic industries. Gas free metals are prepared by vacuum melting in induction furnaces and subsequently deoxidized with sulphur or carbon.

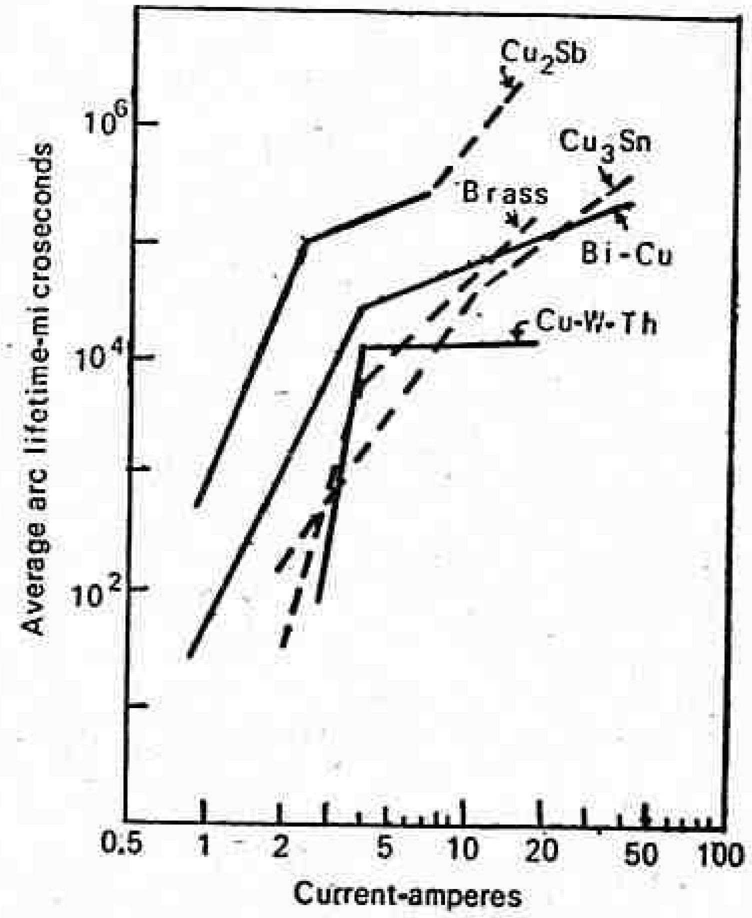


FIGURE 16.8 Average arc lifetime vs. current for multi-component metals.

16.2.9 Vacuum Switch Construction

The vacuum circuit breaker is a very simple device as compared to the oil or air-blast circuit breakers. Two contacts are mounted inside an insulating vacuum sealed container. One is fixed and the other may be moved through a short distance. A metallic shield surrounds the contacts and protects the insulating container. A typical assembly of vacuum switch is shown in Fig. (16.9). It consists of two sub-assemblies: (a) the vacuum chamber, and (b) the operating mechanism.

(a) *Vacuum Chamber*. It is made of synthetic material such as urathane foam which is enclosed in an outer glass fibre reinforced plastic tube or of simple glass or porcelain, two contacts, a metal shield and a metal bellows are sealed inside the chamber. For reasons already mentioned the contacts must be pure and thoroughly degassed.

The metallic bellows, generally made of stainless steel is used to move the lower contact and provides a gap of the order of 5 to 10 mm depending upon the application of the switch. The design of the bellows is of particular significance because the life of the switch depends upon the ability of this part to perform repeated operations satisfactorily.

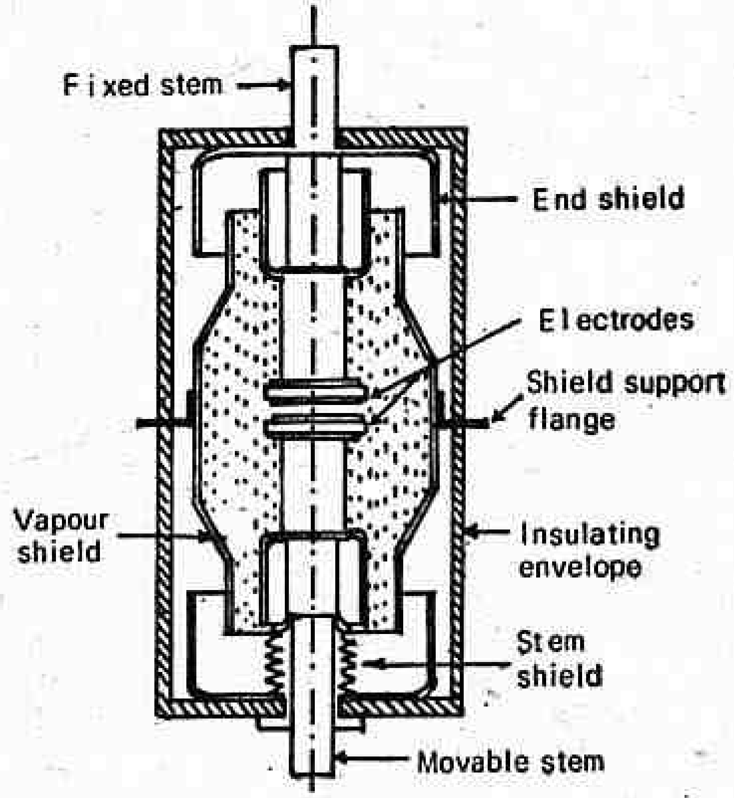


FIGURE 16.9 Vaccum interrupter schematic diagram.

One end of the fixed contact is brought out of the chamber to which the external connection can be made. Similarly provision is made with the lower contact also for external connections but it is firmly joined to the operating rod of the mechanism.

(b) *Operating Mechanism*. The lower end is fixed to a spring operated or solenoid operated mechanism, so that the metallic bellows inside the chamber are moved upward and downward during closing and opening operations respectively. The contact movement should be such as to avoid *bounce*. However there should be sufficient pressure to allow a reasonable wipe for a good connection between the two contacts.

16.2.10 Application of Vacuum Switches

These have promising application to the high voltage switchgear field, specifically where requirements are for a low cost switch having low fault interrupting capacity, but capable of large number of load switching operations without maintenance and in some applications, capable of interrupting line charging or capacitor current without restrike. If the cost is low such switchgear would be ideal for controlling high voltage shunt capacitor banks at small substations or in large substations where fault interruption can be handled by other switchgear. These are very high speed making switches and can be used for many industrial applications.

For a country like India, with 11 to 33KV network extending into vast rural complex, a vacuum circuit breaker should prove a definite advantage. Even with limited MVA rating of say 60 to 100 MVA, it should be suitable for a majority of applications in rural areas.

16.3 Sulphur Hexafluoride (SF_6) Circuit Breakers

One of the recent developments in the field of high voltage switchgear is the SF_6 circuit breaker. In this a gas called sulphur hexafluoride is used as the medium of insulation and arc interrruption.

16.3.1 Basic Features of SF_6 Breaker

SF_6 is about 5 times heavier than air. It is chemially very stable, odourless, inert, noninflammable and nontoxic. The gas has a high dielectric strength and outstanding arc-quenching characteristics.

In SF_6 the arc voltage remains low until immediately before current zero so that the arc energy does not attain a high value. Moreover the arc time constant for SF_6 is also very low. Furthermore, SF_6 and its decomposition products are electronegative, permitting electron capture at relatively high temperature. Thus the dielectric strength rises rapidly and enables the breaker to withstand the recovery voltage even under extreme switching conditions. In air-blast circuit breakers air is allowed to escape following the quenching operation. This obviously would be uneconomical in the case of SF_6 breakers. Hermetically sealed circuit breaker chambers are therefore developed in which even the gas pressure remains practically constant over long periods. Owing to the low contact erosion in SF_6 and almost negligible decomposition of the gas in arc, the breaker can be operated for several years without having to be opened for the purpose of overhauling.

16.3.2 Dielectric Properties of SF_6

At atmospheric pressure the dielectric strength of SF_6 is about 2.5 times that of air. Actually speaking this value will depend upon the nature of field existing between the electrodes, which in turn will depend on the shape and configuration of electrodes, and the gap between the electrodes. The dielectric strength may actually increase to about 5 times depending upon the nonhomogeneity of the field. Figure (16.10) shows the relation of dielectric strength vs. pressure.

It may be seen from the curves that dielectric strength which is 30% less than that of oil at atmospheric pressure increases rapidly with increase of pressure. It attains a value equal to that of oil at a pressure of 650 gm/cm² and at a pressure of 1.25 kg/cm² it is about 15% higher.

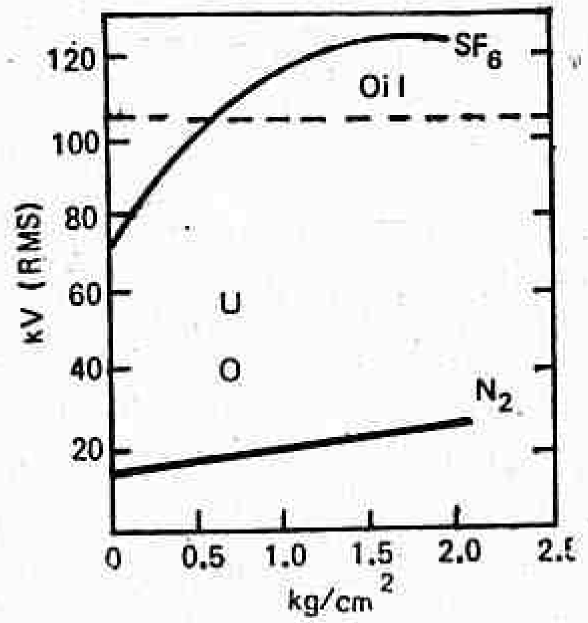


FIGURE 16.10 Dielectric strength vs. pressure for air, oil and SF_6.

For an insulator with an overall height of 160 mm the impulse and power frequency withstand voltages are shown in Fig. (16.11 a) as a function of the SF_6 pressure.

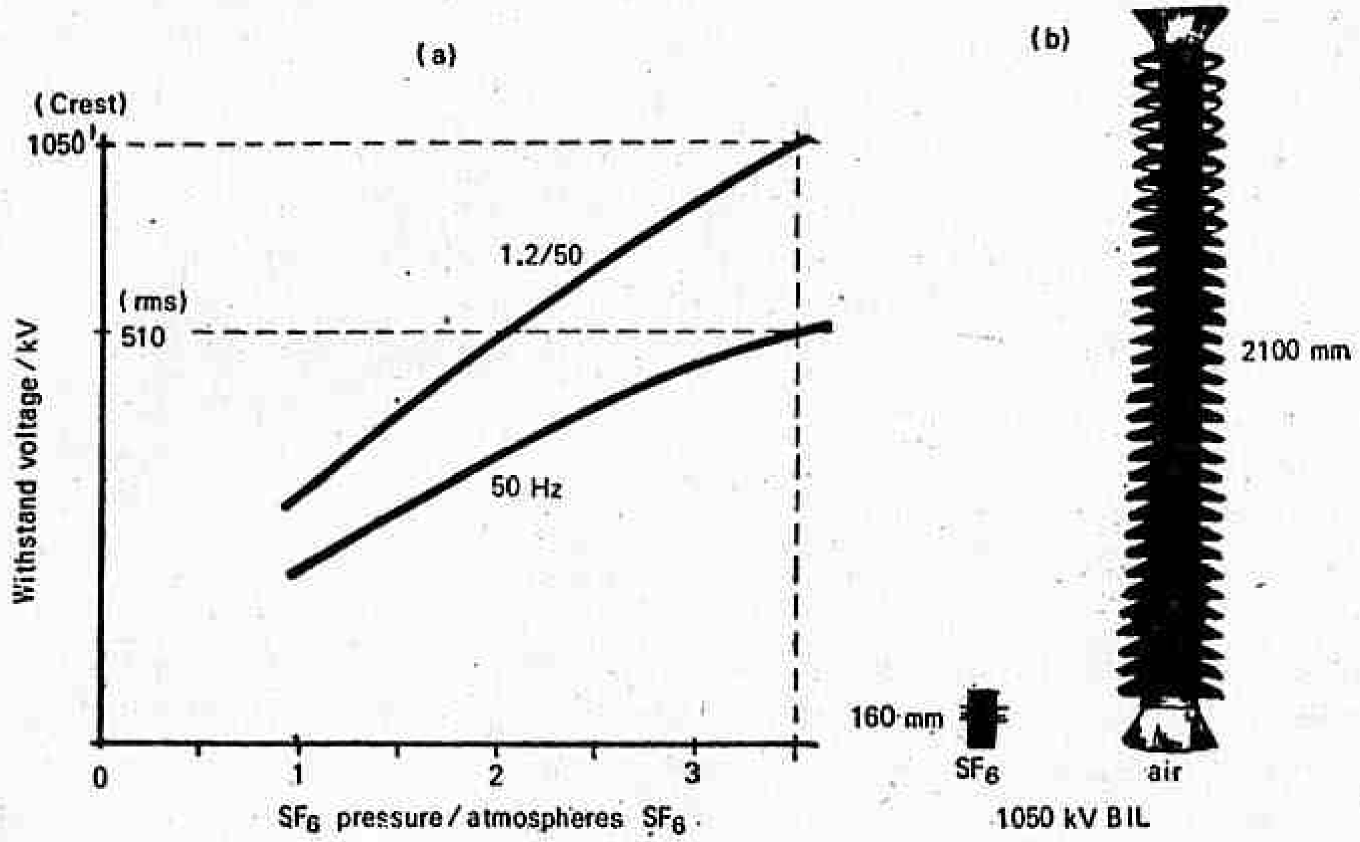


FIGURE 16.11 (a) Insulator in SF_6: impulse and a.c. withstand voltage; (b) comparison of 245 KV insulators in SF_6 and air 1050 KV BIL.

At a pressure of 3.5 atmospheres the withstand voltages are almost equal to those for outdoor post-insulators measuring 2100 mm (Fig. (16.11 b)).

This gas is strongly electronegative, which means that free electrons are readily removed from a discharge by the formation of negative ions through processes by which a free electron is attached to a neutral gas molecule. The attachment may occur in two ways:

(a) As direct attachment

$$SF_6+e^-=SF_6^-$$

(b) As dissociative attachment

$$SF_6+e^-=SF_5+F^-$$

The resulting ions which are heavy and relatively immobile are thus ineffective as current carriers so that ionized SF_6 has as high an electric strength as unionized gases such as N_2 at equal density.

16.3.3 Quenching Properties of SF_6

The extinction of a.c. arc at the instant of current zero is primarily influenced by the speed with which the dielectric strength in the contact gap regenerates immediately before and after the passage of current zero.

Its efficacy as an arc quenching medium can be explained by the low dynamic time constant (about 1 μs compared with about 100 μs in N_2) of arcs drawn in it. In the case of cylindrical arcs, the time constant (H) is a function of the square of arc radius (r). The radius of an arc approaching zero should, therefore, be kept to a minimum.

Now SF_6 has a favourable thermal characteristic which is a function of temperature, i.e. the thermal conductivity is low between 3000°K and 7000°K whereas it is high below 3000°K.

The low time constant of SF_6 is due to its ability for free electrons to be captured by molecules of SF_6 gas. These SF_6 ions surround the arc and form an insulating barrier. This reduces the diameter of arc column and hence results in reduction of time constant, which aids arc quenching. Figure (16.12) shows time constants of SF_6 and air as functions of pressure.

Conditions are much less favourable where the arc burns in nitrogen. No thin core forms in the critical temperature range between 3000°K and 7000°K because of the good thermal conductivity of nitrogen. The diameter of the arc approaching extinction remains considerably larger and its time constant, which varies as the square of the radius, is therefore, very much greater. The boundary regions below the ionization temperature do not have the same dielectric strength as SF_6, because nitrogen is not electronegative. SF_6 and almost all its decomposition products are electronegative and have an affinity for electrons. During cooling the dielectric strength of the breaker, therefore, rises more rapidly than, for example, with air.

The influence of low arc time constants on circuit breakers can be seen as follows.

Mayer's equation for the limiting value of recovery voltage after the current has passed through zero above which arc restrikes is given by

$$E=\frac{E_a}{2\sqrt{3}\,(H\omega_0)^2} \text{ volts}$$

where

E_a=arc voltage.

$\omega_0=2\pi f_0$ where f_0 is the natueal frequency of the mains.

H=arc time constant.

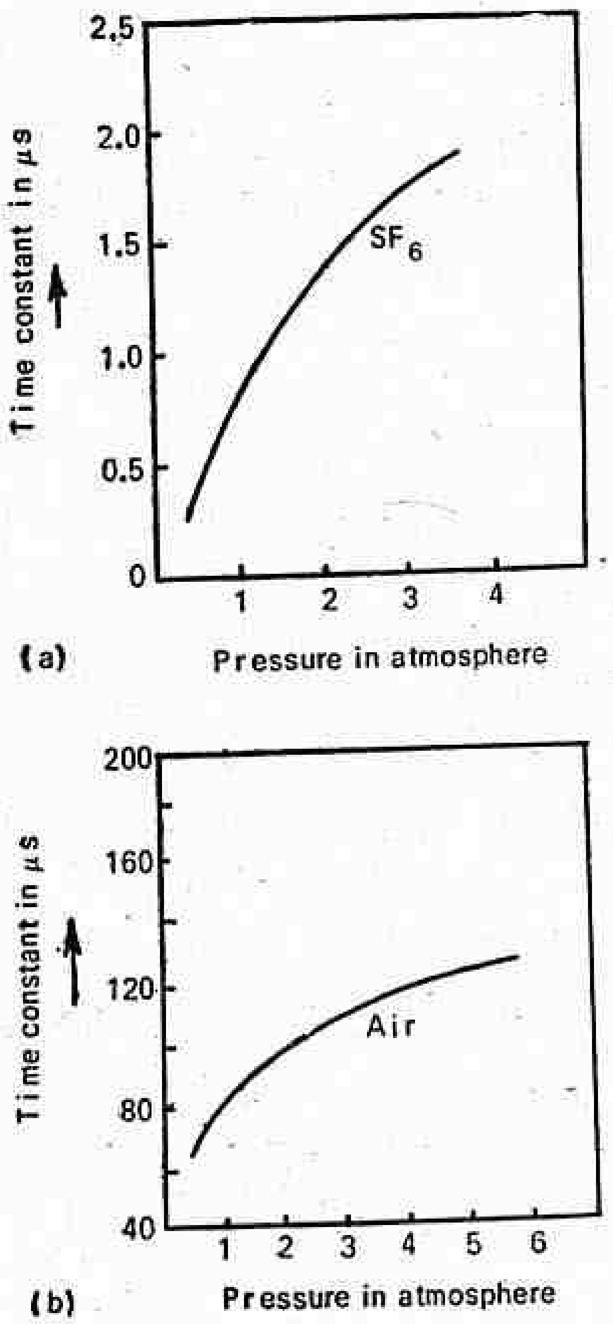


FIGURE 16.12 Time constants of SF_6 and air as a function of pressure.

Since H is 100 times smaller for SF_6 than air, for the same value of limiting voltage the natural frequency of mains may be 100 times greater. In other words SF_6 breakers can withstand severe RRRV, and thus are most suitable for short line faults without switching resistors, and can interrupt capacitive currents without restriking.

16.3.4 Behaviour of SF_6 Gas in Arc

The high temperature of arc causes all molecular gases, including SF_6, to be decomposed into atoms, electrons and ions. These atomic components do not recombine completely to the original SF_6 gas on cooling. They form low molecular gaseous sulphur fluorides and compounds with the contact metals, e.g. copper fluorides. Extensive tests have shown that the percentage of gaseous decomposition products is extremely small. These products and any other secondary gaseous reaction products are removed from the gas circuit by filters containing activated aluminium oxide (Al_2O_3) when the gas is pumped back into the high-pressure tank. The metal fluorides are deposited as a thin nonconductive and harmless layer of fine dust.

16.3.5 Essential Parts of a SF_6 Breaker

The essential parts of a SF_6 breaker are: (a) the tank, (b) the interrupter units, (c) the operating mechanism, (d) the bushings, and (e) the gas system.

(a) *Tank.* The distance between line and earthed parts inside the tank is very much reduced due to better insulating properties of SF_6. As already illustrated in Fig. (16.11) at 3.5 atmospheres, the dielectric withstands 510 KV at 50 Hz and a 1050 KV BIL test. Even at atmospheric pressure, the insulation distances are sufficient to withstand nearly twice the rated voltage to earth. No large pressure rises are caused due to the operation in SF_6, the tanks being designed for a pressure of nearly four times and tested at six times the pressure. Special neoprene gaskets are used in the inspection doors for ensuring protection against leaks. The rotating shaft which transmits mechanical motion to the outside of the tank is sealed by teflon 'V' rings which are unaffected by change in ambient temperature.

(b) *Interrupter Units.* Organic insulation like fibre or micarta should not be located in the arc path since they will be decomposed thus diluting the gas. Teflon which is resistant to arcing and produces negligible gas contamination is generally used.

The interrupter arrangements range from plain break contacts to gas blast designs. Because of its superior arc interrupting ability SF_6 gas flow in the orifice is very small, also the flow producing pressures required for arc extinction are only $\frac{1}{3}$ to $\frac{1}{2}$ the values required for air.

The arc is extinguished by SF_6 gas under a pressure of 14 kg/cm^2 which reduces the mechanical energy for operation of the breaker. The important parts of the interrupter are: (i) main reservoir containing gas at 14 kg/cm^2, (ii) blast valve and control mechanism, (iii) piping for the gas under pressure, (iv) axial flow interrupter units and (v) tripping spring. Capacitor units are placed across each break to ensure equal voltage distribution. Metallic parts are surrounded by electrostatic shields which provide correct distribution of electric field between the interrupter and tank. The various parts are supported by two insulating bars running the whole length of the interrupter.

(c) *Operating Mechanism.* In operation the tripping spring drives the moving contacts and simultaneously opens the valve of the pressure reservoir. The gas under pressure flows into the breaking chambers and extinguishes the arc. At the end of the operation the mechanism releases the valve of the pressure reservoir which is closed by the action of a set of springs.

It has been conventional to provide high voltage circuit breakers with compressed-air drives, i.e. switching on by means of compressed air, and switching off by means of charged spring, which is charged during the switching on of the circuit breaker. However, electrical drives can also be provided for the operating mechanisms in circuit breakers.

(d) *Bushings.* These contain SF_6 at a pressure of 2 kg/cm^2 and are much simpler than the condenser bushings. They contain a hollow conductor, a fixing flange, the upper and lower porcelain insulators and the springs which hold the assembly together. The SF_6 gas in bushings communicate with that in the tank through small holes in the upper part of the hollow conductor. The gas in the bushing is thus unaffected by any disturbances in the tank at the instant the current is broken. A filter containing activated alumina is placed at the bottom of the hollow conductor eliminating all chance of contamination of SF_6 inside the bushing.

Toroidal type CTs are located outside the breaker, being threaded on to the bushing externally. The windings are contained in a metal frame and embedded in epoxide resin.

(e) *Gas System.* A compressor sends the gas back after each break to the high pressure reservoir. Being a closed circuit, no gas escapes to the atmosphere. An auxiliary reservoir of SF_6 at 14 kg/cm^2 is located below each tank, containing enough gas for four consecutive breaks without the need for starting up the compressor.

The principal components of the SF_6 system are: a filter for removing traces of impurities by the contact of the gas with the arcs, the compressor for circulation of the gas, filter for removal of traces of oil in the gas, a relief valve for holding the valve of the high pressure within correct limits, and safety control devices for maintaining the operating pressure, for rendering the mechanism inoperative when the pressure is low, where the

CHAPTER 17

Basic Considerations for the Design of Circuit Breakers

17.1 Introduction

It is well known that a circuit breaker in an electrical power system has to perform the following four major operations.

(1) When the contacts are closed and the rated current passes, there should be least voltage drop across the contacts.
(2) When the contacts are open it should behave almost like an insulator.
(3) When under closed condition it is required to open its contacts, it should do so within the least possible time and without causing any dangerous disturbances like overvoltages to the system.
(4) When open, it should be able to close its contacts even when there is already a fault on the line.

These four major operations obviously call for many contradictory requirements to be fulfilled. Thus the problem of designing a circuit breaker has considerable difficulties to begin with. To complicate matters the phenomenon of electric arc is not uniquely explained by the available scientific data. There are several theories about the initiation of the arc and consequently as many suggested methods of extinguishing the arc. The material given in this chapter therefore gives the broad outlines of how these different contradictory requirements are taken into account and the various parts are to be designed.

17.2 Basic Steps Recommended for Design of Circuit Breaker

The following are the main points to be considered for the design of a circuit breaker:

1. Finalizing the basic data and specifications.
2. Choice of the type of circuit breaker.
3. Preliminary design of the arc extinguishing system.
4. Calculation of the insulating system of the circuit breaker.
5. Design of independent elements in the breaker.

Under the last point listed above, the following conditions will have to be taken into account.

(a) Calculation of the electrodynamic forces in the current carrying parts.
(b) Calculation of dimensions of the current carrying parts taking into account the temperature rise not only when carrying the rated current continuously, but also while carrying through fault current for a certain specified period.
(c) Design of the contacts should be such that they do not get overheated under normal working and also do not get welded together when closing on a faulted system.
(d) In case of air-blast circuit breakers the complete calculation of the pneumatic forces.
(e) The design of the mechanical system which opens and closes the contacts, etc.

17.2.1 Basic Data and Specifications

As far as the basic data to begin the design are concerned the following information should be available:

(a) Nominal voltage.
(b) Nominal current.
(c) Fault current which could be opened.
(d) Rupturing capacity.
(e) Time of operation.
(f) The thermal stability in other words allowable temperature rise.
(g) Permissible through fault current.
(h) Highest closing current.
(i) Time of closing.
(j) The operating cycle.
(k) The type of location of the installation.

17.2.2 Selection of Type of Circuit Breaker

The choice of a circuit breaker for a given power system of known parameters like operating voltage and the line constants, is a complicated problem. Unless the exact requirements of the circuit breaker are clearly spelt out, the choice cannot be uniquely made. For example, in a system where automatic reclosing is not installed, the choice would naturally be very wide because all the three conventional types of the circuit breakers could perhaps be utilized in this case. Apart from the considerations of initial cost we take into account the availability of properly trained personnel to operate the breakers and the free supply of high grade insulating oil to the various substations whenever required. As mentioned in Chapter 15 the air-blast circuit breakers have very high rupturing capacities and can be designed to have extremely small operating times. Thus at important receiving stations and generating sets of a large interconnected power system working at voltages of 220 KV and above, the choice of air-blast circuit breakers becomes almost inevitable. However, in smaller substations working at 110 KV and below where the duty of the breaker is not very demanding, the oil circuit breakers have as much possibility as air-blast circuit breakers. Another point to be considered is location of the circuit breaker. For example, in several circuit breakers used in connection with high voltage feeder lines, the demand may be to have totally enclosed switchgear. In other cases for breakers used in connection with electrical furnaces the number of closing and opening operations may be much more than in the case of a circuit breaker used in a substation. Thus a proper coordination between the characteristics of the known types of circuit breakers and the demands of the operation in the power system have to be attempted before the type is decided finally.

17.2.3 Basic Design of Arc Extinguishing Chamber

The considerations for design for the arc extinguishing chamber used in oil circuit breakers and air-blast circuit breakers would naturally be different. As far as the oil circuit breakers are concerned, the design of the arc extinguishing chamber would involve:

(1) Calculation of the arc voltage at various instances of time.
(2) A clear analysis of the process of gas formation under the influence of the arc.
(3) Calculation of pressure inside the arc extinguishing chamber due to liberation of the gases.
(4) Velocity with which the gases move in the zone around the arc.
(5) Calculation of recovery voltage in the gap between contacts both for very high currents as well as for very low currents.
(6) Evaluation of the time of arc extinction for different values of current.
(7) Calculation of the amount of oil expended by burning during one opening operation.

(8) An analysis of the process by which the arc extinction chamber is filled up with oil after the burnt gases escape.

The arc extinguishing chamber in an air-blast circuit breaker has to satisfy the following basic requirements:

(1) Reliable extinction of the electric arc at the nominal voltage and the maximum rated current which may sometimes by 10,000 amp or more.
(2) Successful arc extinction within an extremely short duration of the order of two cycles or less.
(3) Reliable and quick extinction without restriking when opening capacitive currents of unloaded transmission lines and highly inductive currents of unloaded transformers.
(4) Suitable operation without any change in operating characteristics over a long period of time and when operating repeatedly.
(5) Contact system should be simple and have easy access.
(6) Quantity of arc extinguishing medium (compressed air in the case of air-blast circuit breakers and special electronegative gases like SF_6 in the case of some of the modern circuit breakers) should be minimum for the given operation.

Taking the above requirements into account, the design of arc extinguishing chamber in an air-blast circuit breaker would therefore involve:

(a) Design of the complete pneumatic system like pipes, valves, etc.
(b) Proper choice of the arc extinguishing medium (at the present time the choice is between compressed air and SF_6).
(c) Calculation of the voltages appearing across the various gaps in a multibreak system.
(d) Calculation of the air pressure and velocity.

17.2.4 Insulation Design

Design of insulation system of a circuit breaker requires solution of the following problems:

1. Choice and calculation of the various clearances to be provided between the live parts and the dead parts in a circuit breaker.
2. Calculation of voltages that will appear across each of the gaps in a multibreak system.
3. Calculation of the minimum insulating levels to be provided for current carrying parts.

The choice of clearances to be provided around the live parts in a circuit breaker depends upon a study of the probable paths of electrical discharge. Care must be taken in defining these parts to take into account the possibility of the electric arc jumping out of the arc extinguishing chamber due to its faulty design, the inadequate knowledge we have about the quantity, and the rate of gas production, etc. In Fig. (17.1) the various arc discharge paths that can be anticipated in a bulk oil

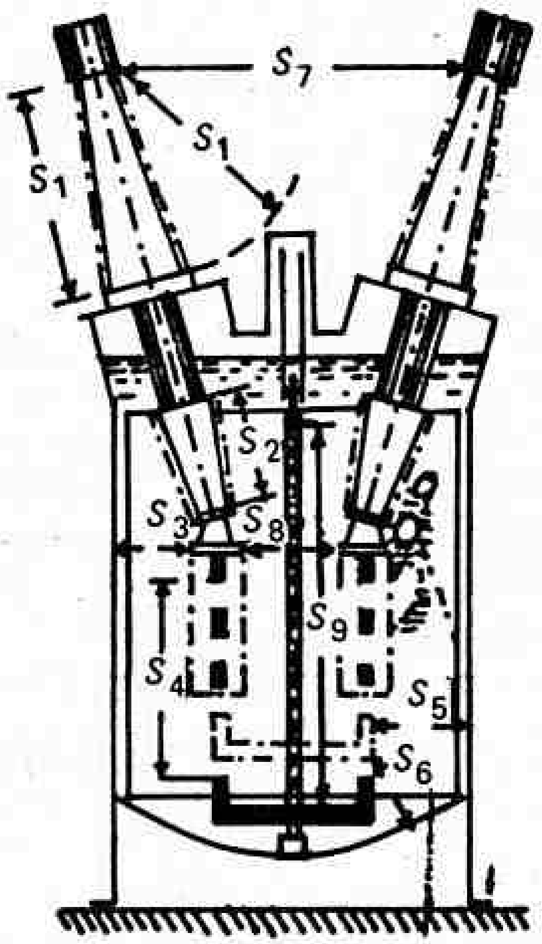


FIGURE 17.1 Discharge paths in a bulk oil circuit breaker.

circuit breaker are shown. Breakdown voltages of the paths have to be carefully decided taking into consideration the shape and condition of the various live parts. Further, certain special problems like the possibility of corona around some of the high voltage parts should also be considered.

Wherever multibreak systems are used the voltage distribution across each of the breaks will not be the same. For example, in an oil circuit breaker with two breaks, on a single phase to ground fault as much as 85% of the voltage may appear across one of the breaks. Figure (17.2) shows the percentage of the voltage appearing across each of the breaks in a six break system which clearly indicates the wide variations in voltages appearing across individual gaps. Steps should be taken in the design to evaluate the values of shunting resistance to be used in multibreak systems in order to equalize to some extent the gap voltages.

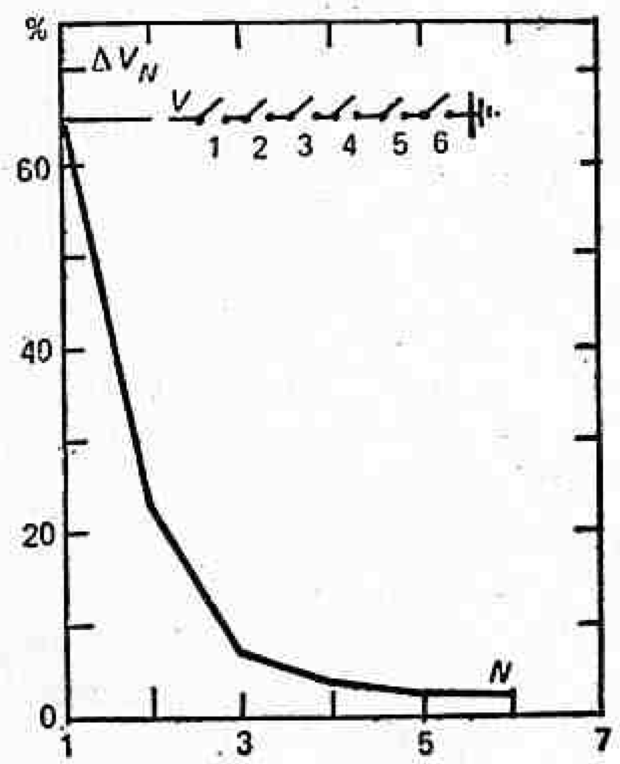


FIGURE 17.2 Distribution of voltage across different gaps in a multibreak system.

17.2.5 Design of Current Carrying Systems

The current carrying system of a circuit breaker consists not only of electrical conductors but also of mechanical devices like springs which do the dual job of passing the current as well as making and breaking contacts. In designing current carrying system it is, therefore, necessary to consider both the thermal problems like overheating and the electrodynamic problem due to the forces between conductors carrying current. For calculating the electrodynamic forces we require information of linear dimensions of each element in the current carrying system, their physical location with respect to each other and maximum permissible current which is likely to flow through this system. The actual values of the forces exerted by different components on each other are generally calculated on the basis of grapho-analytical methods. For example, Fig. (17.3) shows the current carrying system of the incoming conductor (1), the bridge (2) and outgoing conductor (3). Any two of these parts will be exerting forces on the third and the total force experienced by any part would be the sum of these two forces; this is clearly shown in Fig. (17.4). It will, therefore, be necessary while designing current carrying parts to consider not only their ability to carry current without overheating but also their mechanical strength to withstand the electrodynamic forces. If the latter is not properly taken into account, the contact system is likely to be distorted which will affect alignment of the fixed and moving contacts. This would result in the two contacts not locking properly and may create contact bounce.

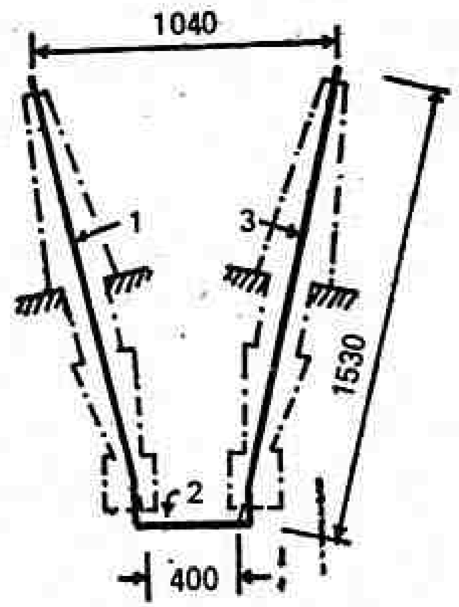


FIGURE 17.3 Current carrying system in an oil circuit breaker.

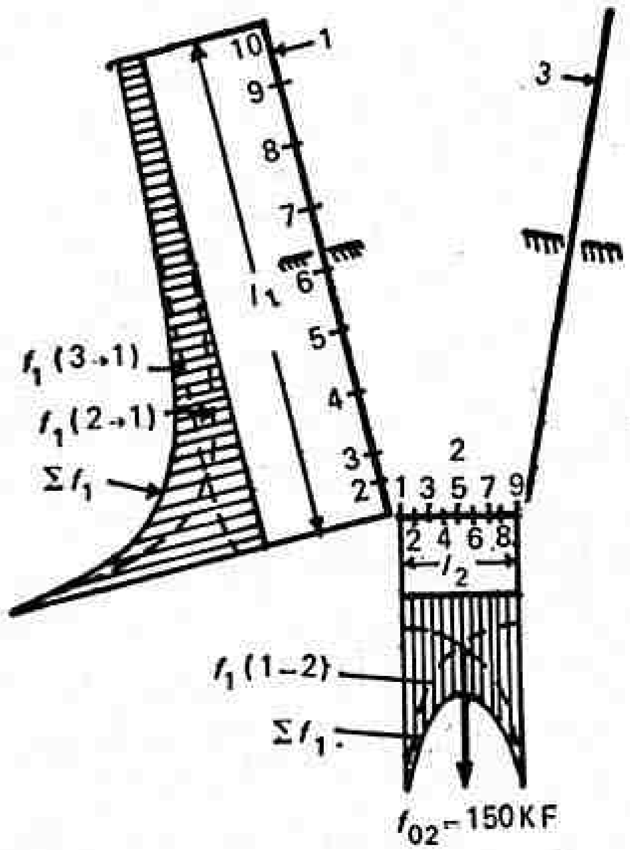


FIGURE 17.4 Electrodynamic forces mutually exerted by the current carrying parts.

Thermal Calculations. Under this the following steps are generally indicated:

1. Calculation of temperature rise under normal current for prolonged periods; and
2. Temperature rise while carrying large fault current during very short periods.

From electrical point of view the current carrying system can be divided into two sections. One consists of incoming and outgoing conductors and the other consists of main contacts. Incoming and outgoing conductors in

the case of oil circuit breaker are located partly in oil and are surrounded partly by the bushings. While oil is a good conductor of heat, bushings are not. Thus part of the conductor is likely to be cooled faster than the other part producing thermal shocks on the material. On the other hand, the lower part of conductor which is immersed in the oil is at much higher temperature than the outer part which is in the bushing. As for the conductors in the air-blast circuit breakers are concerned they are mostly enclosed by porcelain insulators which once again are bad conductors of heat. The insulators are, therefore, provided with many more petticoats than normal, to provide a greater surface area for radiating heat.

The contact system must reliably meet the following requirements:

1. Temperature rise within the acceptable limits not only during normal operation but also when carrying through fault currents.
2. Absence of local melting and globule formation.
3. Absence of welding together of contacts particularly when closing them on a faulted line.
4. Absence of film formation.

QUESTIONS

1. Why is the design of a circuit breaker more complicated as compared to any other electrical equipment?
   Enumerate the basic design steps for a circuit breaker.
2. Discuss the basic considerations for the design of current carrying system of a circuit breaker.

CHAPTER 18

Testing of Circuit Breakers

18.1 Introduction

In the historical development of circuit breaker from its primitive knife switch to the most modern circuit breaker the short-circuit testing of circuit breaker has played a very definite and decisive role. A thorough experimental investigation of problems involved in circuit breaker operation would not have been possible without testing.

Service conditions impose many varied duties on a circuit breaker, as some special types of load can prove difficult to interrupt, and the voltage produced by the breaker during interruption may be greater than what the system insulation may permit. In particular the breaking of line charging current or low value reactive current or the energizing of long lines can cause problems of this type. It is important from this point of view that the proving tests made are comprehensive to cover all foreseable circumstances.

18.2 Classification

Testing of circuit breakers can be classified into two main groups, viz. (i) type tests and (ii) routine tests.

18.2.1 Type Tests

These are performed solely for the purpose of proving the correctness of general design and the results of such tests conducted on a randomly selected breaker, are applicable to all others of identical construction.

Under this class fall mostly the short-circuit tests, which again can be performed either by (a) direct testing or (b) indirect testing methods.

18.2.2 Routine Tests

The routine tests are performed on each individual circuit breaker of proven design, the purpose is to prove the correctness of the assembly and the material used.

The routine tests include the following tests:

(a) Operational tests.
(b) Measurement of resistance of the main circuits.
(c) One minute power frequency voltage dry withstand tests.

The test procedures, methods of finding results, tests to be performed, etc. are specified by Standards Organizations. The information regarding the tests given here is based on the recommendations of the International Electrotechnical Commission (IEC) vide publication No. 56-1 on the testing of a.c. circuit breakers.

It is commonly accepted and provided in various standards that the certificates of type tests shall be considered as evidence of the compliance of the circuit breakers with the relevant clauses of the specifications and the manufacturer shall make available such certificates together with the detailed drawings of the circuit breakers and a record of any alteration that may have been made in them subsequent to the type tests.

Type tests can be broadly classified as:

(a) Mechanical tests.
(b) Thermal tests.
(c) Dielectric tests.
(d) Short-circuit tests: (i) making capacity test, (ii) breaking capacity tests, (iii) duty cycle tests and (iv) short time current tests.

Short circuit tests are of utmost importance and will be dealt in detail in the next section. However, a brief account of other tests is given below.

(a) *Mechanical Tests.* These are mechanical endurance type-tests involving repeated opening and closing of the breaker. The circuit breaker is opened and closed several times (500) without any current in the current carrying parts. Some operations (50) are by energizing the relay, remaining are by closing the trip circuit by other means. No adjustments are permissible during testing. After the test there should be no distortion or wear of the parts.

(b) *Thermal Tests.* These are conducted by passing alternating current of normal frequency through the current carrying parts of the circuit by the oscillatory transient recovery voltage appearing at the terminals of the transformer with essentially a single frequency. Capacitances are connected in parallel with the blocking and test breakers which transmit the transient recovery voltage of the high current source to the breaker on test and enable the delivery of necessary energy for the arc gap in case a post-arc current occurs. These capacitances are so distributed that the test breaker is subjected to the maximum applied voltage. The charged condenser of the high voltage circuit can be switched in with practically no time delay by means of a triggering gap in conjunction with a switching gap.

Compound Circuit. A compound circuit has been installed by the International General Electric, Philadelphia, U.S.A. for proving and development testing of circuit breaker modules and circuit breakers upto 50,000 equivalent three-phase module MVA. The compound circuit in theory is similar to the Weil-Dobke synthetic circuit with some additions to the Weil-Dobke circuit. The purpose of the compound circuit facility is to create laboratory conditions equivalent to those in the field by matching high short-circuit current from the test generators with high voltage recovery voltage from energy storage capacitors. The synchronization of recovery voltage to final current zero is accomplished with great precision by connecting the voltage source into the circuit about 8000μ sec before current zero and disconnecting the current source about 400μ sec before current zero so that when current zero does occur synchronization is the same as if the current had come from the high voltage source throughout the test.

A simplified schematic diagram of the compound circuit is shown in Fig. (18.12).

Validity of Synthetic Tests. Because the synthetic circuit is not identical with that of direct, differences may be reflected in circuit breaker performances. From a knowledge of the process involved in arc rupture, it is possible to assess the significance of dissimilarities. There are circuit breakers (e.g. air-break, arc-chute type) where the arc voltage is high in relation to the circuit voltage, and any reduction in the latter may result in an appreciable departure from the normal current form. On the other hand other types of circuit breakers for instance axial air-blast circuit breakers which can have low arcing voltage characteristics, are well suited to the synthetic test. It would seem highly desirable in an investigation in which it is intended to develop synthetic testing to a stage where it can be used as a supplement or an alternative to the direct testing.

However, following are some of the conclusions of various synthetic testing techniques.

1. Basic principle of synthetic test using parallel current injection is sound.

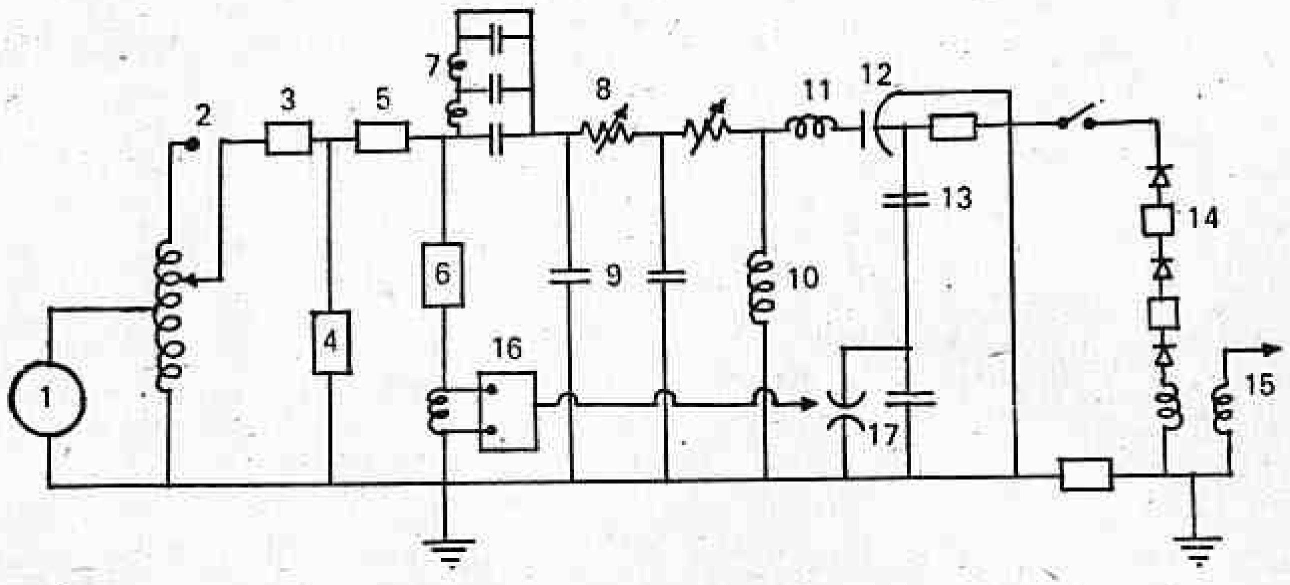


FIGURE 18.12 Schematic diagram of a compound circuit: 1. test generator; 2. auto-transformer; 3. synchronous closing switch. 4. surge protector. 5. isolation breaker. 6. test breaker. 7. transmission line. 8. tuning reactor 3.2–76.9 mH. 9. wave shaping capacitance banks 0.144–0.084 μF and 0.099–0.66 μF. 10. shunt reactor 0.25–5.5 mH. 11. series reactor 0.5 mH. 12. trigatron switch. 13. main capacitor bank. 14. high voltage rectifier. 15. high voltage transformer. 16. trigger control circuit. 17. trigger gap and capacitance surge column.

2. In all cases where the synthetic test circuit has been set up with particular attention given to the values and forms of the voltages and currents around the current zero period, no significant difference in severity has been found between the direct and synthetic tests conducted on air-blast circuit breakers over a range of 33–1200 MVA.

3. Validity of parallel current injection of synthetic testing will hold for powers beyond 1200 MVA.

4. The frequency of the injected current is not unduly critical over the 350–1000 Hz range. This range over which validity of synthetic test has been shown to hold is adequate for most practical purposes.

5. The time of injection of current loop is important but if injection is such that the peak of injected current loop lies within ±100μ sec of the 50 Hz current zero, severity will remain unaltered. No difficulty has been experienced in maintaining injection timing well within these limits.

QUESTIONS

1. What are the different tests carried out to prove the ability of a

breaker? State the difference between type tests and routine tests.

2. Describe short-circuit testing stations. What are the advantages of laboratory type testing station?
3. Describe with a schematic diagram the equipment and procedure of testing a breaker in a testing station.
4. What is the importance of testing of a circuit breaker? Describe direct testing method of a circuit breaker.
5. Why is indirect method of testing a breaker resorted to? Explain the principle of synthetic testing and enumerate its limitations.

breaker. The temperature is measured by thermometers or thermocouples with temperature indicators or self-resistance methods.

The temperature rise for rated current should not exceed 40°C for currents less than 800 A normal current and 50°C for normal value of current 800 A and above.

An additional requirement in the type-test is the measurement of contact resistances between the isolating contacts and between the moving and the fixed contacts. These points are generally the main sources of excessive heat generation. The voltage drop across the breaker pole is measured for different values of d.c. currents. The voltage drop gives a measure of resistance of current carrying parts, hence that of contacts.

(c) *Dielectric Tests.* These are conducted for testing the insulators of the breaker. These can be classified as:

Power frequency tests. Conducted on a clean new circuit breaker, the test voltage varies with circuit breaker rated voltage. The test voltage with a frequency between 15—100 Hz is applied as follows: (i) between poles with circuit breaker closed, (ii) between poles and earth with circuit breaker open, and (iii) across terminals with circuit breaker open.

The voltage is gradually increased and maintained at test value for 1 minute.

Impulse tests. In this test impulse voltage of specified shape and magnitude is applied to the breaker. For outdoor circuit dry and wet tests are conducted.

(d) *Short-Circuit Test.* These [are conducted in short-circuit testing stations and are mainly meant to prove the ratings of the circuit breaker. Before discussing the tests proper it would be worth while to discuss about the short-circuit testing stations.

18.2.3 Short-Circuit Testing Stations

There are two types of short-circuit testing stations:

(a) *The Field Type Testing Station.* In this the tests are conducted taking power directly from the system. While it provides the most convincing method of testing high voltage circuit breakers, it suffers from the drawback that flexibility of the system available is limited. It is difficult to set the system for the specified RRRV for breakers of high voltages. It is also not suitable for research and development work as it is always not possible to repeat the test again and again without disturbing the networks. The power available in the field testing station varies according to the machinery running on the network and the layout of the network.

Table 18.1 *Some important testing stations of the world*

S.No.	*Country*	*Place*	*Name*	*Rating three-phase (MVA)*
1	Belgium	Charleroi	ACEC	1900
2	Czechoslovokia	Praga	State Laboratory Electric Power Engg.	3000
3	West Germany	(a) Kassel	AEG	5000
		(b) West Berlin	Siemens	4500
4	France	Paris Fountenoy	Electricite de France (field testing station)	4000
5	Italy	Milan	CESI (field testing station)	3300
6	Japan	Tokyo	Tokyo Shibana Elec. Co.	1300
7	Netherlands	Arnhem	KEMA	4800
8	Sweden	Ludvika	ASEA	3500
9	Switzerland	(a) Baden	Brown Boveri & Co.	4000
		(b) Zurich	Oerlikon Engg. Co.	2500
10	United Kingdom	(a) Habburn	The British Short-circuit Testing Station, Reyrolle	2500
		(b) Birmingham	(i) The GEC	1750
			(ii) George Allison	300
		(c) Manchester	Switchgear Testing Co.	3000
		(d) Stafford	English Electric.	3000
		(e) Chelmsford	Crompton Parkinson	350
		(f) Henley	AEI	250
11	U.S.A.	(a) Philadelphia	(i) General Electric	1800
			(ii) ITE	500
		(b) East Pitzburg	Westinghouse	2500
		(c) Milwankee	(i) Line Material	500
			(ii) Allis Chalmers	500
12	U.S.S.R.	Moscow	Short Circuit Testing Laboratory	4000
13	India	(a) Bhopal	Power Research Institute, CW&PC	1250
		(b) Bombay	IIT Short Circuit Testing Laboratory	10

(b) *Laboratory Type Testing Station.* It has special generators to supply power for the short-circuit testing. In this it is possible to vary the test conditions at will. Such a station is most suited from the point of view of the design engineer and supply engineer. The designer can study the behaviour of arc rupture and make improvements for higher voltages and higher breaking capacities. He can repeat his tests again and again in order to show the reproducibility of his results which is very important. The supply engineer is mostly interested in the operation of the breaker ready for delivery. He wants to be satisfied whether his breaker fulfils the requirements enunciated by certain specifications.

To establish a short circuit plant particularly of the laboratory type is an exceedingly costly project, and it is not possible for all switchgear manufacturers to have such a facility of their own.

The testing station at Bhopal is of laboratory type and barring Japan it is likely to remain the only switchgear testing station in Asia for some time to come. Another small but a unique short-circuit testing laboratory is available at the Indian Institute of Technology (IIT) Bombay.

Table (18.1) shows the position of testing stations of the world at a glance.

The facilities necessary for testing depend very largly on the limits of both voltage and MVA for which the plant is designed.

18.3 Description of a Simple Testing Station

In these testing stations the short-circuit power is supplied by specially designed short-circuit generators, driven by induction motors. A simplified diagram of such a testing station is shown in Fig. (18.1).

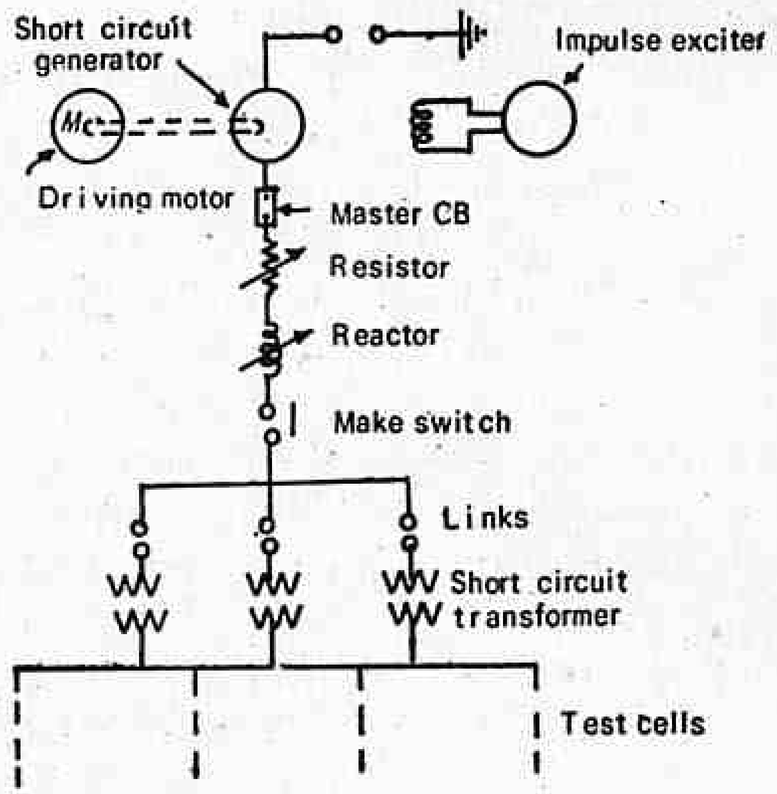


FIGURE 18.1 Basic circuit of short-circuit test plant.

The magnitude of the test voltage and the short-circuit current can be selected within wide limits by adjusting generator excitation and connection of the transformers. Further limitation and variation of current independent of voltage can be effected by means of tapped resistors and reactors. This also serves to control the power factor. The circuit is closed by a specially designed make switch, designed for closing on very heavy currents, but never called on to break currents. Synchronized closing is controlled by means of a small pilot generator coupled to the generator shaft and can be very accurately set to occur at any instant within the voltage wave. In this way the phase position at the commencement of short circuit can be selected and a short-circuit current either fully symmetrical or with any degree of symmetry can be produced. In order to avoid unnecessary destruction in the event of failure of circuit breaker under test, the master circuit breaker is provided as a backup protection and opens. The testing stations are of very compact design with short connection for short circuit so that the generator output may be utilized to full extent. They have very high natural frequency and by adding capacitors any desired frequency can be obtained. The breaker to be tested is enclosed in a test cell made of reinforced concrete having a provision of observation while test is in progress.

The recording equipment is located in a control room which is suitably remote from the test cell but situated so as to allow the test breaker to be observed. The control operations are carried out from the control room.

18.4 Equipments Used in the Station

18.4.1 Short-Circuit Generator

This is of a special design having very low reactance in order to give the maximum short-circuit output. The leakage reactance is reduced by reducing the depth of slots and the length of coil ends. The terminals are brought to a board where different connections can be made. Each winding in a phase is divided in two halves which can be connected either in series or parallel. The three windings in turn can be connected in star or delta to give different terminal voltages.

Due to heavy electrodynamic forces involved the generator foundation is specially designed and is isolated by means of materials like cork, neoprene and thermocole in order to prevent the vibrations being transmitted to the other parts of the building. The windings are also specially braced and made rugged. The short-circuit generator is provided with closed circuit air cooling. The cooling equipment consists of axial flow fans and air/water coolers. The generator is driven by a three-phase induction motor connected through a resilient shaft. The generator is equipped with a built-in flywheel which provides the kinetic energy during short circuit and speed regulation of the set.

18.4.2 Impulse Excitation

Normal excitation is supplied by the main exciter coupled to the test set, although the main generator is equipped with a damper winding, impulse excitation or super excitation is provided to counteract the demagnetizing effect of armature reaction. The short-circuit currents which are at lagging power factor have demagnetizing effect. This results in a reduction of total field, hence in reduced induced emf. As a result recovery voltage is less than the voltage before short circuit. It is overcome by shorting out a resistor in the generator field circuit, a moment before the short circuit, resulting in a surge of field current 8 to 10 times its normal value. This takes care of the demagnetizing effect of short-circuit current and gives desired recovery voltage.

18.4.3 Pilot Generator

This is a small three-phase synchronous generator directly coupled to the main shaft of the short-circuit generator and synchronized in phase with the latter. Any present voltage is maintained constant by an automatic voltage regulator during short-circuit tests. This dependable voltage is necessary to supply control power to the sequence timer, electromagnetic oscillograph and various other actuating circuits for conducting the test.

18.4.4 Short-Circuit Transformers

These transformers are designed to withstand repeated short circuits and their windings are often arranged in sections for voltage adjustment in series and parallel combinations. The leakage reactance of the short-circuit transformer is kept low. For stepping down the voltage to lower values a three-phase transformer is normally used. For voltages higher than the generated voltage the normal practice is to use banks of single-phase transformers. Depending on the type of test to be carried out in the test cells, different types and ratings of transformers are connected in different cells, e.g. a high voltage testing transformer in one and a low voltage high current transformer in the other.

18.4.5 Resistors and Reactors

For regulation of the short-circuit test current, three-phase banks of resistor and reactor are used. The reactor being used to adjust the magnitude and the resistor to control the rate of decay of the d.c. component of current. The short-circuit power factor is also controlled by this means. There are a number of coils per phase and by connecting them in series parallel combinations many variations can be obtained.

18.4.6 Master Circuit Breaker

It has been provided mainly as a backup circuit breaker. If the object under test fails the current will be interrupted by the master breaker. This is normally an air-blast type, of capacity more than the breakers under test. This is set to open at a predetermined time after the initiation of the short circuit and must be capable of clearing faults up to the highest level of each generator or other power source and have a substantial margin of safety.

18.4.7 Make Switch

The short circuit is applied by this switch, which makes an exceptionally high short-circuit current surge from the generator at a predetermined point of the voltage wave. At the moment of making, the backup circuit breaker and the test circuit breaker are already closed. As such on closure if there is even a slight contact rebound the contacts might get burnt or even welded together. In order to ensure, that the contact separation is minimum on closure, a high air pressure is maintained in the chamber. The closing speed is also so high that the contacts are fully closed before the short-circuit current reaches its peak value.

18.4.8 Capacitors

These are used for two purposes.

(a) *Capacitive breaking*, which normally occurs in case of line charging duty.
(b) *Controlling* the rate of rise of restriking voltage given by

$$f_n = \frac{1}{2\sqrt{LC}}$$

In synthetic testing and other indirect tests, capacitors are an important element of the test circuit. These are single-phase banks and can be connected in series or parallel as desired, both individually and in any combination of the three.

18.4.9 Test Cells

Covered bays are provided for testing circuit breakers. These bays are box shaped structures of reinforced concrete with an open front facing the control and observation rooms. Separate test bays are provided for testing LV; HV; and EHV circuit breakers. The test cells are supplied with compressed air and oil purification system to facilitate testing of air-blast circuit breakers and oil circuit breakers. Each test cell has got an end box where control and measuring cables are terminated.

18.4.10 Test Control Room

It is situated nearly at a distance of 20 m from test cells. It is provided with a control desk for remote control operation of the excitation of the short-circuit generators, etc. there are also an oscillograph, distribution panel, an electromagnetic oscillograph; a CRO, an electric sequence switch and an electronic sequence switch. The control room is designed to provide facilities for the observation of tests by both the station staff and visitors. For this purpose observation slits covered with thick perspex sheet are provided in the otherwise closed wall of the control room building facing the test cells.

18.4.11 Safety and Signalling System

A fool proof interlocking system is provided to ensure the safety of the working personnel, as enormous electrodynamic forces are brought into play during short-circuit testing. By this system it is impossible to excite the machines, if any of the doors leading to machine hall basement reactor room, etc. remain open. A system of audiovisual alarms are also provided as a warning before short-circuit tests.

18.5 Testing Procedure

A preliminary check up of various equipments is made before the actual test commences. The correct values of resistance and reactance coils are inserted as per the magnitude of the short-circuit current. Proper settings of transformers are made. The measuring circuits are connected and oscillograph loops are calibrated.

The succession of operations carried out during the testing, is governed by the drum. To begin with, the main and the exciting machinery are started, the generator is excited, isolating switches are disconnected which previously have been earthed. The button is then pressed and the control drum begins to rotate, setting into motion individual devices and machines. The following is an example of automatic sequence of operation during a test.

1. Driving motor of the short-circuit generator and the exciting machines is switched off.
2. Overexcitation switch is closed.
3. Master circuit breaker is closed.

4. Oscillograph is switched on.
5. Making switch is closed.
6. Circuit breaker under test is opened.
7. Master circuit breaker is switched off.
8. Generator field circuit breaker is tripped.

These operations take place in very short time, about 0.2 second. After the completion of short circuit the starters of the driving motors of the short-circuit generator and the exciting machines are automatically reset to a lower degree. The motors are then switched on and are allowed to run at full speed, so that in a short time a further short circuit can be initiated. A schematic representation of test circuit is shown in Fig. (18.2).

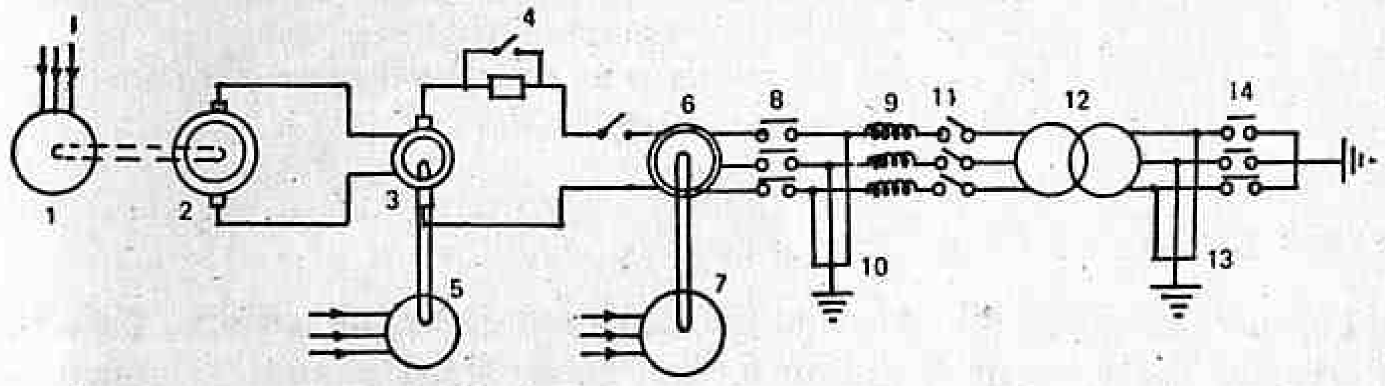


FIGURE 18.2 Schematic representation of test circuit: 1. driving motor for the auxiliary exciter; 2. auxiliary exciter; 3. impulse exciter; 4. impulse resistance; 5. driving motor for impulse exciter; 6. main generator; 7. driving motor for main generator; 8. master breaker; 9. reactor; 10. earth switch on primary side of the transformer; 11. make switch; 12. HV power transformer; 13. earth switch on secondary side of the transformer; 14. test breaker.

18.6 Direct Testing

The direct testing of circuit breakers in a plant enables us to test under conditions largely representing those in actual network as well as tests of greater severity. The circuit breaker to be tested is subjected to the value of transient restriking voltage to which it is expected to be put in practice rather than testing it under most severe conditions. Value of the transient restriking voltage is adjusted by means of R, L, and C, the constants of the circuit.

The circuit for direct testing is shown in Fig. (18.3). After making the preliminary adjustments of the constants, etc. the contacts on the sequence switch are adjusted to get desired timings. The oscillographs are also adjusted and calibrated. The operations of test follow automatically by means of sequence switch as already mentioned.

The various tests carried out for circuit breakers are described below:

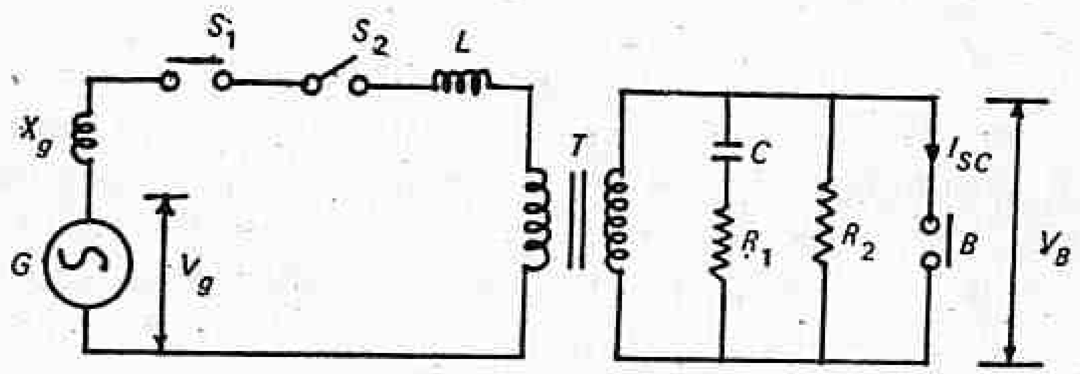


FIGURE 18.3 Circuit for direct testing: V_g–generator voltage; V_B–voltage across test breaker; I_{SC}–short-circuit current; X_g–generator reactance; S_1–master breaker; S_2–make switch, L–current control reactor; T–transformer; B–breaker under test; C, R_1, R_2–capacitance, resistance for adjusting the transient restriking voltage; G–short-circuit generator.

18.6.1 Making Capacity

The master circuit breaker and the make switch are closed first, then the breaker under test is closed on a three-phase short circuit. The making current is determined as explained in Chapter 14. This is a peak value of the first major loop of the current wave after the instant of contact make when current starts to flow. The measurement is made from the current zero line to the peak of the wave.

18.6.2 Breaking Capacity

The master circuit breaker and the breaker under test are closed first, short circuit is applied by closing the make switch. The breaker under test is opened at desired moment and the following values are measured from the oscillogram as explained in Chapter 14.

(a) Recovery voltage obtained during the test.
(b) Symmetrical breaking current.
(c) Asymmetrical breaking current.
(d) Amplitude factor, natural frequency and RRRV

18.6.3 Duty Cycle Tests

Unless the rated operating duty as marked on the name plate differs from that specified, it shall consist of the following test duties.

Test duty (1) B–3′–B–3′–B at 10% of rated symmetrical breaking capacity.
Test duty (2) B–3′–B–3′–B at 30% of rated symmetrical breaking capacity.
Test duty (3) B–3′–B–3′–B at 60% of rated symmetrical breaking capacity.
Test duty (4) B–3′–MB–3′–MB at not less than 100% of rated symmetrical breaking capacity and not less than 100% of rated making capacity. Test duty (4) may be performed as two separate duties as follows.
Test duty (4a) M–3′–M (Make test)
Test duty (4b) B–3′–B–3′–B (Break test)
Test duty (5) B–3′–B–3′–B at not less than 100% rated asymmetrical breaking capacity.

B and M in the above duty cycle denote break and make operations respectively. MB denotes a making operation followed by a breaking operation without any intentional time lag. 3′ denotes the time in minutes between successive operations of an operating duty.

18.6.4 Short-Time Current Tests

Good contact should be maintained in spite of forces produced by the short-circuit current so as to avoid welding. The heat generated by the short-circuit current over the period of the test (1 sec or 3 sec) should not cause damage to any insulation in contact with the current carrying parts. When the breaker has cooled down to the ambient temperature, it should be capable of carrying full-load current continuously without excessive temperature rise.

The breaker is tested for this by means of a separate high current and

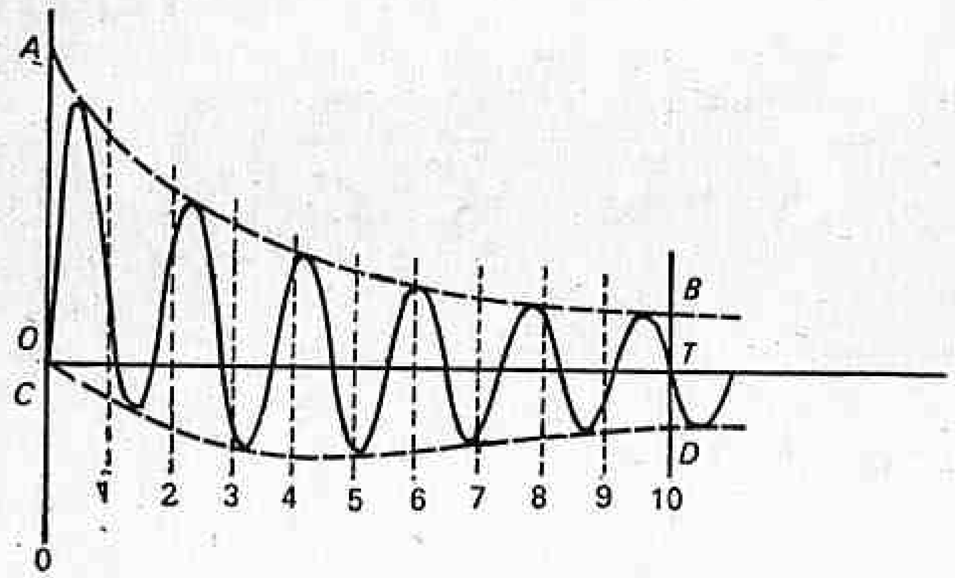


FIGURE 18.4 Determination of short-time current.
$\left.\begin{matrix}AB\\CD\end{matrix}\right]$—envelope of current wave;
OT—duration of short circuit;
$I_0, I_1, \ldots, I_{10}$—rms value of asymmetrical currents at each instant.

low voltage transformer. The current is measured by electromagnetic oscillograph. The equivalent steady rms value of current during a short circuit is evaluted as follows. Referring to Fig. (18.4) which illustrates a short-time current carrying test short-circuit duration is divided into ten equal parts. The asymmetrical rms value of the current at each of these eleven instants of time is calculated by the same method as that of breaking current. If these currents are $I_0, I_1, \ldots, I_{10}$, the equivalent steady rms value of current during the time or is given by Simpson formula.

$$I=\sqrt{\tfrac{1}{3}\{I_0^2+4(I_1^2+I_3^2+I_5^2+I_7^2+I_9^2)+2(I_2^2+I_4^2+I_6^2+I_8^2+I_{10}^2)\}}$$

18.7 Test Report

Test report is issued under the seal of the testing authority as an authoritative statement on the performance of apparatus tested, irrespective of its compliance or non-compliance with standards.

Report of performance is a complete record of all tests done and may include development research and proving tests. The report includes details of the conditions under which the tests were made, the condition of the apparatus before and after tests and its performance during the tests. The tests which it covers will be those called for by the client (who may be a manufacturer or his customer) in addition to those which are necessary to prove the apparatus adequately.

18.8 Indirect Testing

With the increase in the breaking capacity of the HV circuit breakers, it has become uneconomical and unpracticable to increase the short-circuit capacity of the testing station. It is consequently necessary to utilize some form of indirect testing.

The important indirect methods of testing are:

1. Unit testing.
2. Synthetic testing.

18.8.1 Unit Testing

It is a common practice to design breakers with a number of rupturing units in series, each having a capacity within the available testing power. A test on one unit can be accepted as proof for all units. Such tests are known as Unit tests. Up to short-circuit levels of some 35,000 MVA this method has proved satisfactory as this design limitation has not seriously affected the cost of the circuit breakers, but recently the rupturing capacities of the modern circuit breakers have exceeded this limit and is of the

order of 50,000 MVA which calls for units of higher rupturing capacities for greater economy.

18.8.2 Synthetic Testing

Synthetic testing is a practical and economical solution for the testing of circuit breakers of high rupturing capacities, without actually employing the corresponding short-circuit capacity of the testing station. Although there is much to indicate that synthetic test could be made to give conditions as severe as those of the direct test, there is little evidence of a conclusive nature to show in any general way the steps necessary to predetermine its relative severity.

The synthetic circuit is designed to simulate as accurately as possible the electrical stresses impressed on the circuit breaker during the interruption of a fault current under system conditions.

Principle of Synthetic Testing. When switch S in Fig. (18.5) is closed short-circuit current I flows through the breaker B and when the test

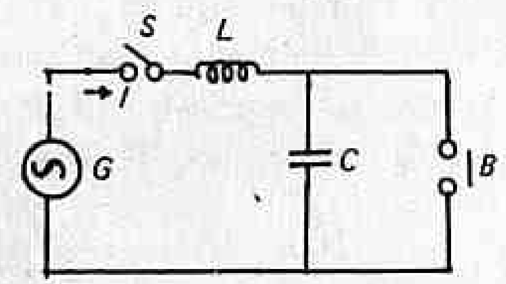


FIGURE 18.5 Basic circuit for testing circuit breaker: G—short-circuit generator; B—test breaker; S—short-circuit make switch.

breaker B begins to open an arcing voltage V_a appears across the breaker terminals as shown in Fig. (18.6). At current zero when the arc is extinguished a transient voltage V_{tr} appears across the breaker whose form is determined by the generator characteristics and the circuit constants L

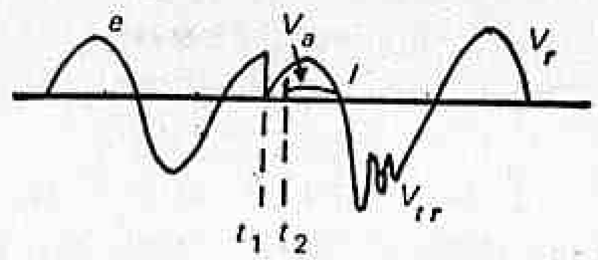


FIGURE 18.6 Voltage wave forms across the test breaker: e—generator open circuit voltage; I—short-circuit current; V_a—arc voltage; V_{tr}—transient restriking voltage; V_r—recovery voltage; t_1—instant of short circuit; t_2—instant of contact separation.

and C. The breaker has to withstand this transient recovery voltage if it is to clear the circuit.

It is seen that during the period of main current flow there is comparatively small arcing voltage across the breaker and that during the period of transient recovery voltage little or no current flows through the breaker. It can be inferred that for testing the breakers rupturing ability there is no need to use a single high power source. Instead the current can be supplied by a comparatively low voltage source, since the arc voltage is usually very small of the order of 1/20th of the rated voltage of the breaker, and the voltage can be applied from a low energy HV source at the point of current zero to simulate recovery voltage.

By this method, it is therefore possible to obtain an effective gain in testing power. This is generally referred to as the magnification factor or the multiplication factor which is approximately equal to the ratio of the test recovery voltage to the voltage of the current source.

Synthetic testing therefore attempts to secure artificially a large rupturing power by superimposing on a normal frequency test current from a conventional generator, a very high voltage of an impulse wave at the time of break. In effect only a voltage source is required in addition to the existing plant equipment making the cost a fraction of the additional generator plant to give similar increase in power. The capacity of the existing short-circuit testing stations can in this way be increased many times.

Types of Synthetic Testing. The synthetic testing circuits can be of two types: (a) current injection, (b) voltage injection.

During the current interruption process, there is a period though small (1–25 μ sec) when arcing occurs. This is termed as energy balance period in the arc column in the proximity of current zero. The recovery voltage will therefore get switched on either before or after current zero. Depending on whether V_r is switched on before or after current zero the type of synthetic testing is known as current injection or voltage injection respectively.

Synthetic Testing Circuits. A description of various circuits of synthetic testing, their advantages and disadvantages are given below.

(a) *Current Injection Method.* This again is of two types: (i) parallel current injection and (ii) series current injection. The two methods are different only in the manner in which the voltage circuit is closed on to the test breaker. In the first method the voltage circuit is inserted in parallel with the test breaker, while in the second method it is inserted in series. The first method is popular in Germany and is known as *Weil-Dobke circuit* and the second method was suggested by Koplan Bashatyr (U.S.S.R.) and is known as ***Russian circuit.***

(i) *Parallel current injection* (*Weil-Dobke circuit*). The essential features of Weil-Dobke circuit are illustrated in Fig. (18.7). The accurate simulation of the stresses on the switch are achieved by connecting the HV circuit to it, a comparatively long time before the short-circuit current zero when exact timing is less critical. With suitable HV oscillating circuits this superposition of currents without any extraneous control produces the required stresses on the breaker.

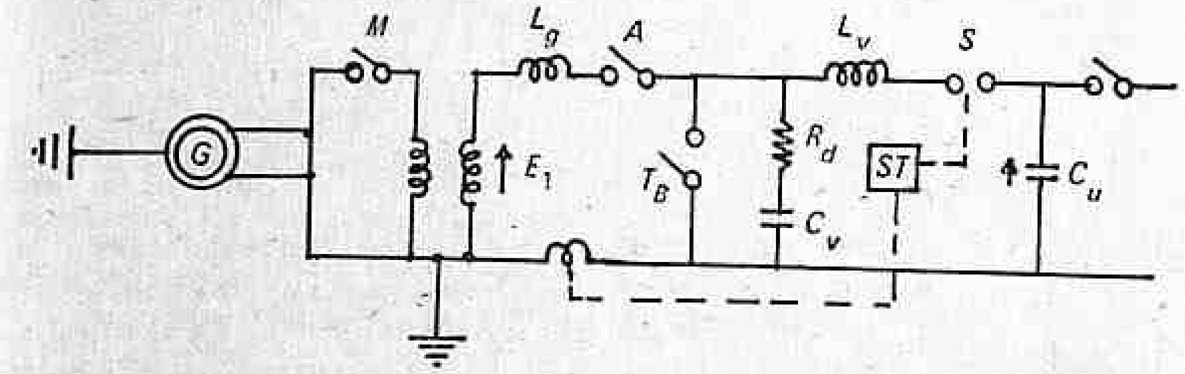


FIGURE 18.7 Parallel current injection (Weil-Dobke circuit): G—generator; A—auxiliary circuit breaker; T_B—test breaker; S—trigger spark gap; ST—control apparatus; E_1—heavy current circuit voltage; L_g—current limiting reactor; C_u, R_d, C_v, L_v—Variable components of the HV, oscillatory circuit.

Initially generator G is excited and L_g set to give the required test current, make switch M open and the auxiliary breaker A and test breaker T_B are closed.

In the voltage circuit capacitor C_u is charged to give the required recovery voltage and the spark gap S is set ready to be fired. L_v is so chosen that when i_v flows consequent to the triggering of the gap, the rate of change of current through zero is the same as that of the test current. C_v is chosen to give the required transient restriking voltage frequency.

At time t_0, the make switch M is closed and the normal frequency 50 Hz current i_g flows in the circuit breaker. At time T_1 the auxiliary breaker A and test breaker T_B begin to open so that they are fully open at the following current zero (t_3) (Fig. (18.8)). At time t_2 the spark gap S is fired and the current i_v flows in the test breaker. The frequency of this current is determined by L_v and C_v and timed so that its peak approximately coincides with zero of current i_g. At time t_3 when the current i_g becomes zero it is interrupted by the auxiliary breaker A and the test breaker carries current i_v from the voltage circuit. When this current becomes zero at t_4 the restriking voltage transient e_r appears across the breaker. The magnitude and frequency of this e_r depend on the voltage to which the capacitor C_u is charged and the parameters C_v and L_v. This

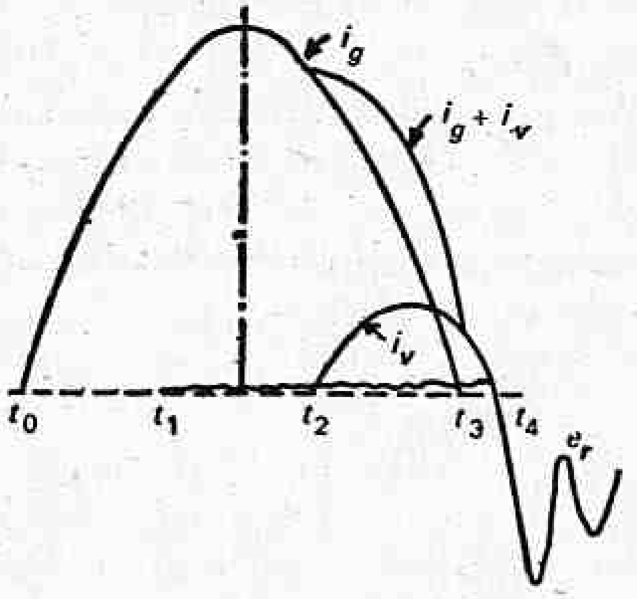


FIGURE 18.8 Current and voltage wave forms: i_g—main current with current zero at t_3; i_v—oscillatingcurrent injected at t_2 with current zero at t_4; e_r—restriking voltage caused.

enables the supply of current and voltage at the moment of zero current from one and the same source.

In this way breaking capacities up to ten or more times the short-circuit capacity of the short-circuit generator can be achieved and the test breaker can be subjected to exactly the same stresses as in an actual system.

(ii) *Series current injection method* (*U.S.S.R. circuit*). It differs from the Weil-Dobke circuit in the way in which the small loop of current from the

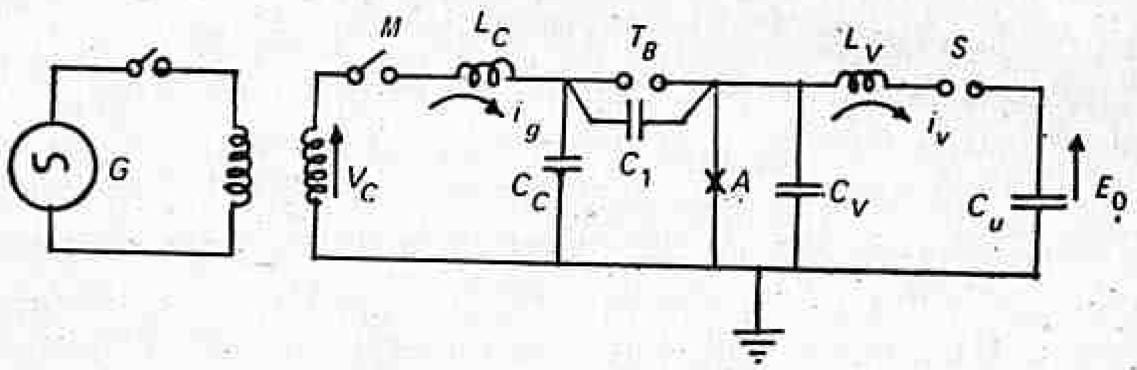


FIGURE 18.9 Circuit arrangement for series current injection.

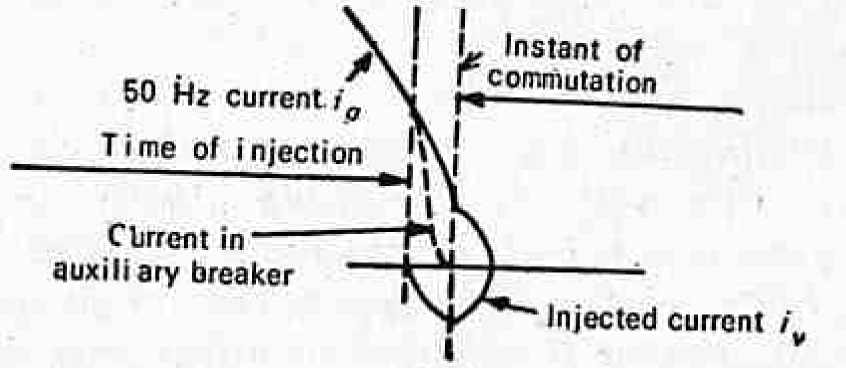


FIGURE 18.10 Current waveforms.

voltage source is introduced. The voltage circuit is connected across the auxiliary breaker, instead of the test breaker and the source capacitance. C_u is charged to the opposite polarity, with the result that the injected current flows in the opposite direction to the 50 Hz current, and thus subtracts from it (Fig. (18.10)). As the current and voltage circuits are series connected, it is rather difficult to select circuit parameters to suit both the current and voltage circuits which would at the same time give required restriking voltage transient. The arrangement is particularly well suited for low frequency circuits.

(b) *Voltage Injection Method.* In this method employed by Siemens, Germany, the voltage circuit is closed on to the test breaker after current zero. It advantageously uses the high current circuit to supply part of the transient voltage impressed on the test piece. By selecting voltage natural frequency suitably and damping the high current circuit has a transient recovery voltage with a definite characteristic which is required for the initial phase of the transient recovery voltage. The high voltage source is to be switched into action approximately at the time of the first peak of the recovery voltage of the high current source, so that the required voltage stresses are continued without any zero pause.

Figure (18.11) shows the circuit in a simplified form. High current circuit is fed from the short-circuit generator through a make switch,

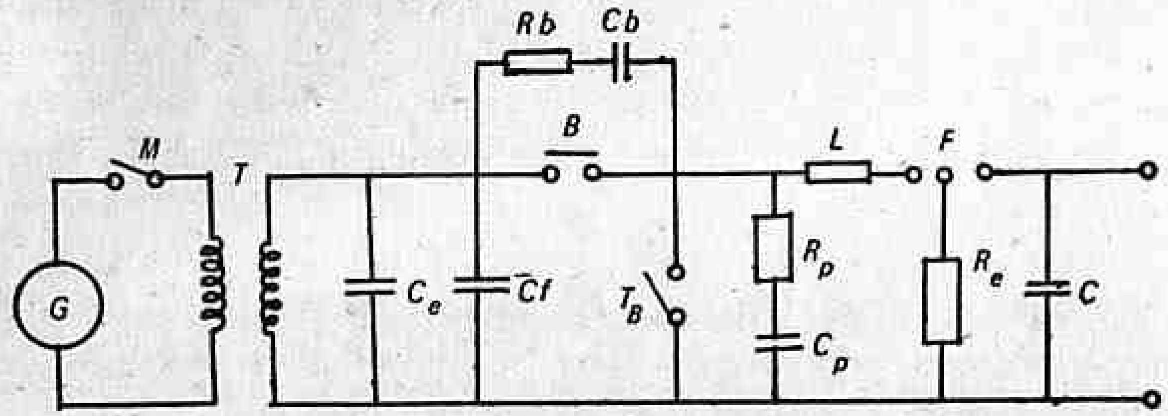


FIGURE 18.11 Circuit arrangement: G—generator; T—transformer, T_B—test breaker; R_e—high ohmic resistance, M—make switch; B—blocking circuit breaker; F—spark gap; C_e—capacitance of the high current circuit; R_p, C_p, L—adjustable elements of high voltage circuit; C_f, R_b, C_b—adjustable elements of circuit.

which is initially open to the transformer T. On the high voltage side are the blocking circuit breaker and the test breaker. The circuit is closed through the closing switch (at about the crest value of the driving voltage) and about the same time the blocking circuit breaker and the test breaker receive either simultaneously or nearly at the same time tripping impulses and interrupt the short-circuit current shortly thereafter. This is followed

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CHAPTER 10

Basic Components of Static Relays

Electron devices operate either as switches or as control devices, controlling an output current or voltage in response to an input signal. Either the switching or control can be very rapid and can be accomplished with very little input energy. Since the controlled energy may be large, the concept of power gain or amplification is important. In some cases a small energizing signal may grow or regenerate into a very large output signal from power supplied by a d.c. or a.c. power source. Semiconductors have now become very popular and effective in performing various functions. Some of the commonly used components in static relays are discussed briefly in the sections that follow.

10.1 Semiconductor Diodes

The *pn* junction has rectifying characteristics as shown in Fig. (10.1). If a source of emf is connected to the *pn* junction in the polarity shown in Fig. (10.1 a), then the spare holes in the *p*-type region are drawn easily to the negative pole and the electrons are drawn from the *n*-type to the source positive. If the source potential is reversed then the holes are repelled from the positive pole and likewise the electrons from the negative pole. Consequently, little current flows until such time as the electric stress is so high that a process similar to an electric discharge occurs.

The approximate static behaviour of either the silicon or germanium *pn*-junction diode is given by

$$I=I_s\,(\epsilon^{Vq/KT}-1) \tag{10.1}$$

where

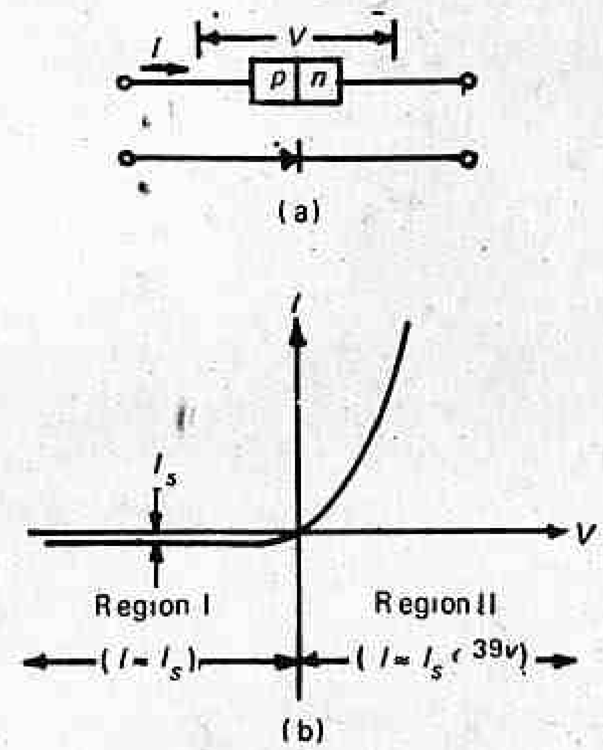
I_s=reverse saturation current, amperes

V=applied voltage in volts

q=charge on electron ($1.59\times10^{-19}\,C$)

K=Boltzmann's constant ($1.37\times10^{-23}\,W\text{-}S/^\circ K$)

T=Absolute temperature, degrees Kelvin



FIUGRE 10 1 (a) *pn* junction; (b) rectifying characteristics.

At the normal room temperature of about 300°K

$$I=I_s\,(\epsilon^{39V}-1). \tag{10.2}$$

In the forward direction, when V becomes larger than a few tenths of a volt, the forward current becomes

$$I\cong I_s\,\epsilon^{39V} \tag{10.3}$$

Correspondingly, in the reverse direction the current expression becomes

$$I\cong -I_s \tag{10.4}$$

In the reverse direction the silicon diode has a very small reverse current which increases slowly as V is made more negative until a critical or breakdown voltage is reached. The voltage at which this breakdown occurs is controllable in the manufacture of diode, and a variety of diodes are commercially available with breakdown voltages from about 2 V to 2,000 V. In a rectifier circuit the reverse breakdown is undesirable, and the diode is chosen to have a higher breakdown voltage than any voltage likely to appear across it. In other applications the breakdown is actually used, and the diode is chosen for a specific voltage. Diodes so used are variously called *zener*, *avalanche*, *regulator*, *reference* or just *breakdown diodes*.

The practical semiconductor diodes fall short of the ideal in three respects.

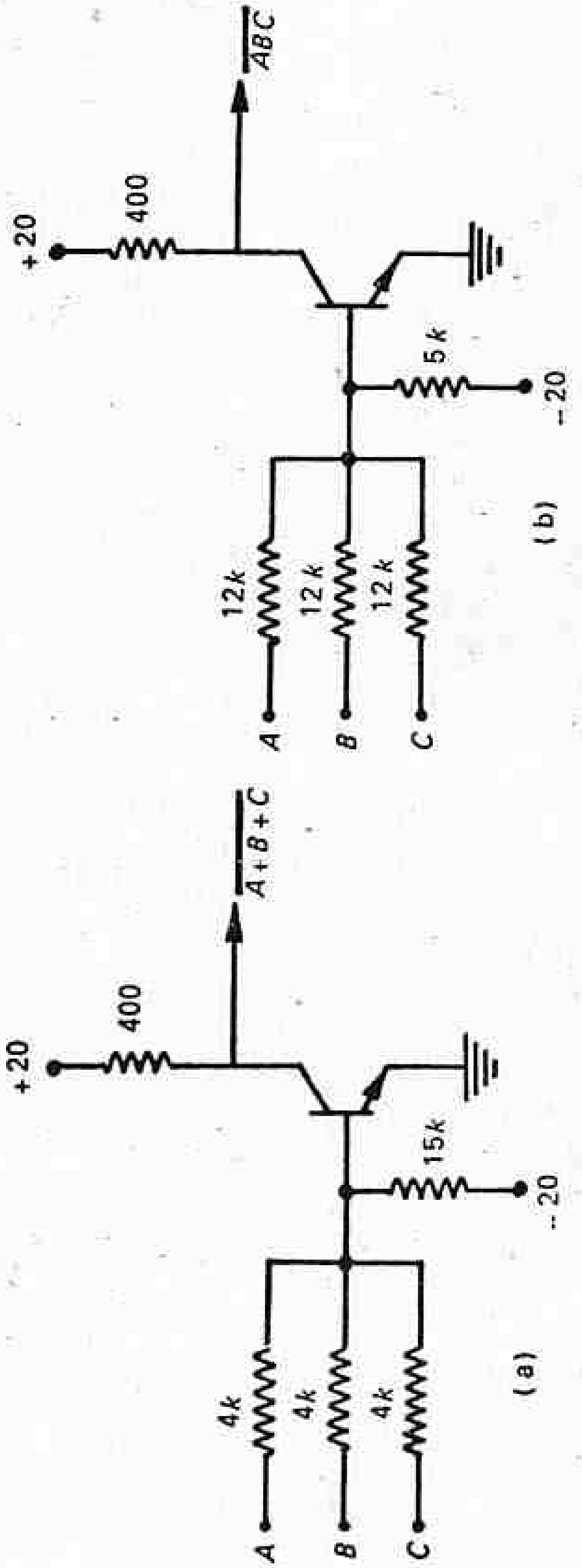


FIGURE 10.23 RTL circuits: (a) OR, NOT or NOR circuit; (b) AND, NOT or NAND circuit.

By using capacitances across the input resistors, the switching speed of the circuit can be increased. In such a case they are called resistance capacitance transistor logic (RCTL).

10.7 Smoothing Circuits

The rectified a.c. consists of a series of undirectional half waves of current or voltage. It is generally desirable to smooth this output. The various filters used for smoothing are the conventional RC filter, RC chain filter, transistorized filter, bucking transformer filter, phase splitting circuits, etc., some basic filter circuits are shown in Fig. (10.24). In the bucking transformer filter a transformer is used to cancel out the a.c. component. This method is not suitable where the input is limited because the primary winding provides a low resistance shunt path for the d.c. diverting it from the output.

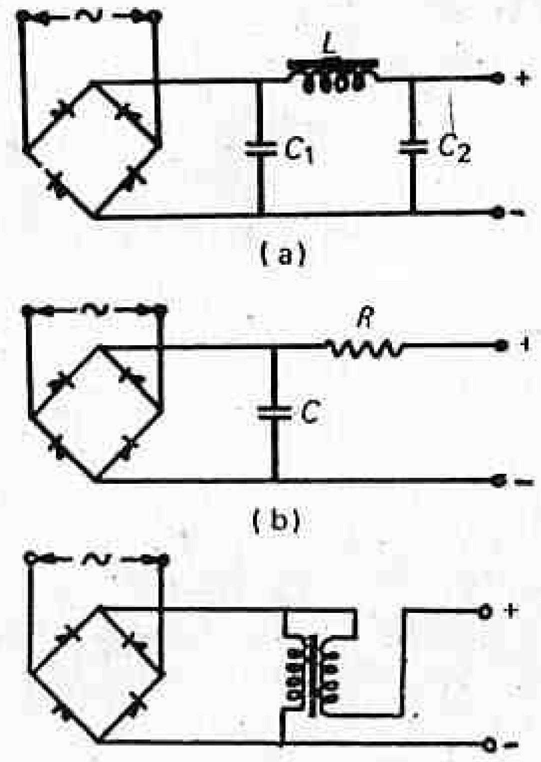


FIGURE 10.24 Smoothing circuits: (a) LC circuit; (b) RC circuit; (c) bucking transformer.

If the speed requirement is not too stringent the conventional capacitor filters could be used. A faster method is phase splitting before rectification where the input single phase quantity is split into a multiphase system and thus greatly réduces the harmonic currents after smoothing (Fig. (10.25)).

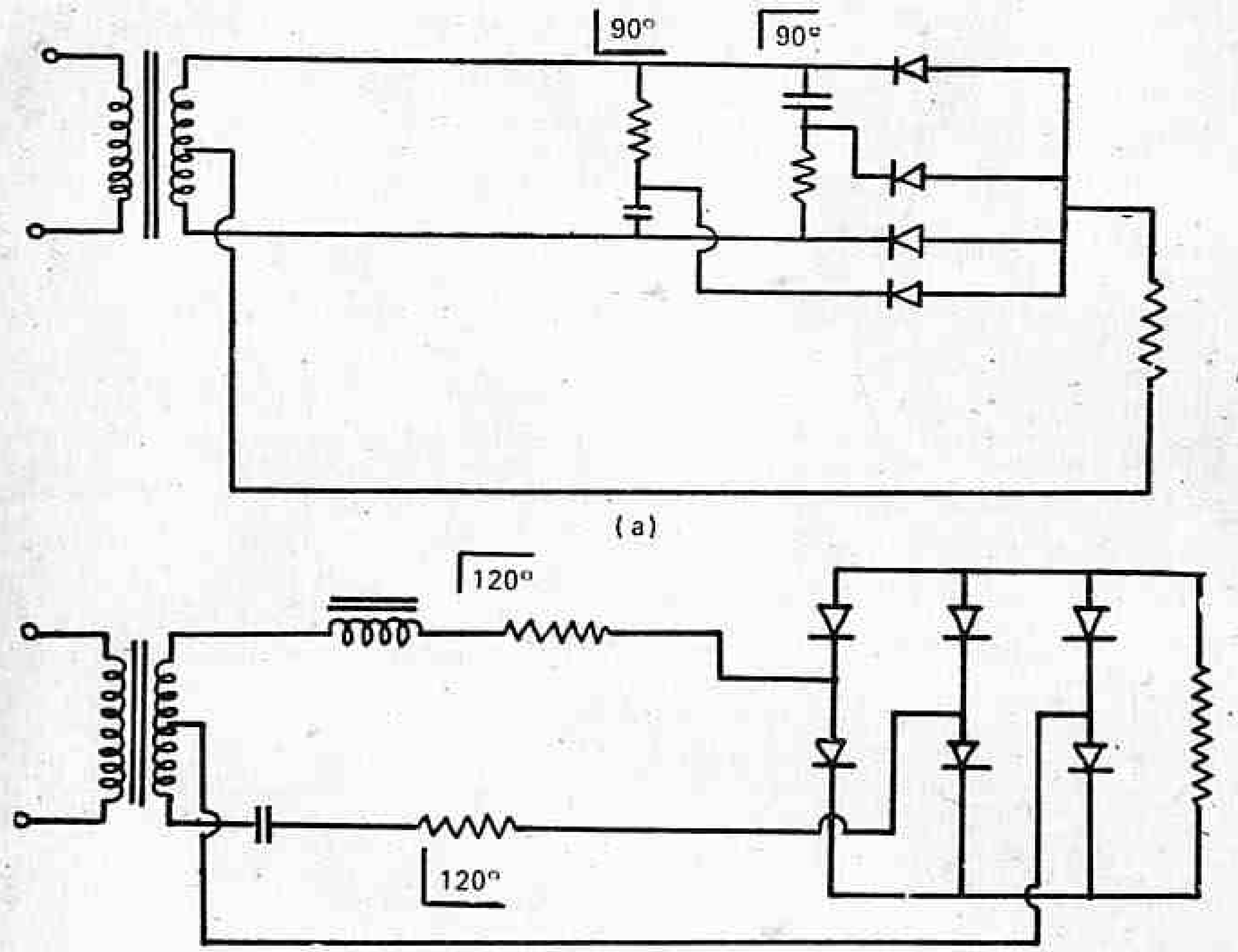


FIGURE 10.25 Phase splitting circuits.

10.8 Voltage Regulators

It has already been pointed out that many diodes are designed and constructed for operation on the breakdown (avalanche) portion of the characteristic curve. These diodes are known as zener diodes or reference diodes. As is obvious from their characteristics they are used for holding a voltage constant over a wide range of applied voltage. A simple circuit is shown in Fig. (10.26).

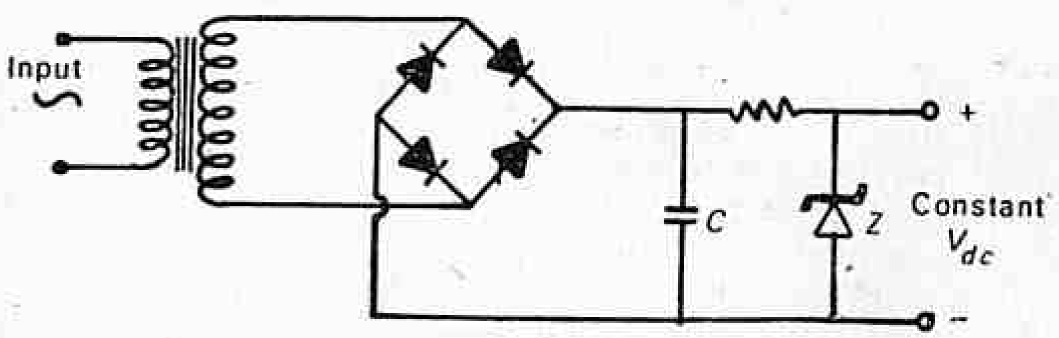


FIGURE 10.26 Zener diode for regulating d.c. supply voltage.

One or more transistors can be used in conjunction with the reference diode, however, to greatly increase the efficiency of the regulator by

reducing the current through the reference diode. A typical circuit of this type is shown in Fig (10.27). This circuit is known as emitter-follower regulator because the output voltage follows the reference voltage. Filters are also introduced to reduce the ripple in the output wave.

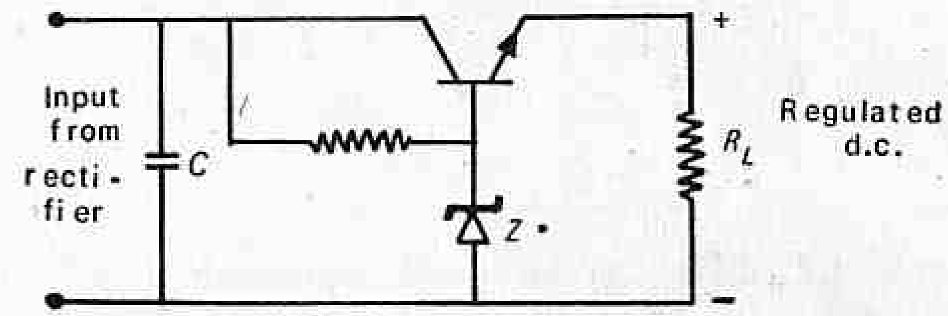


FIGURE 10.27 An emitter-follower regulator.

Although the emitter-follower regulators provide satisfactory performance for many applications their output resistance cannot be reduced below a particular limit, large value of filter capacitance (C_F) are required to provide very low values of ripple. On the other hand, regulators that employ the principle of negative feedback can provide almost any desired value of output resistance and ripple quite easily. The block diagram of a closed-loop regulator is shown in Fig (10.28). A fraction of the output voltage ηV_0 is compared with the reference voltage V_{ref}, and their difference is amplified and used to control the series regulator, which in turn controls the output voltage.

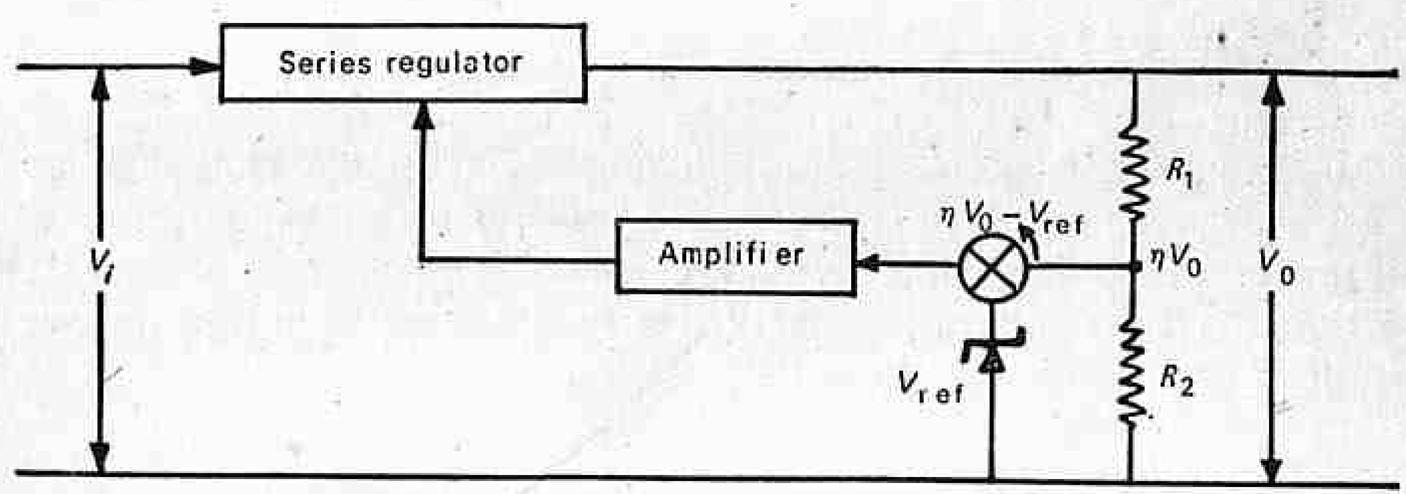
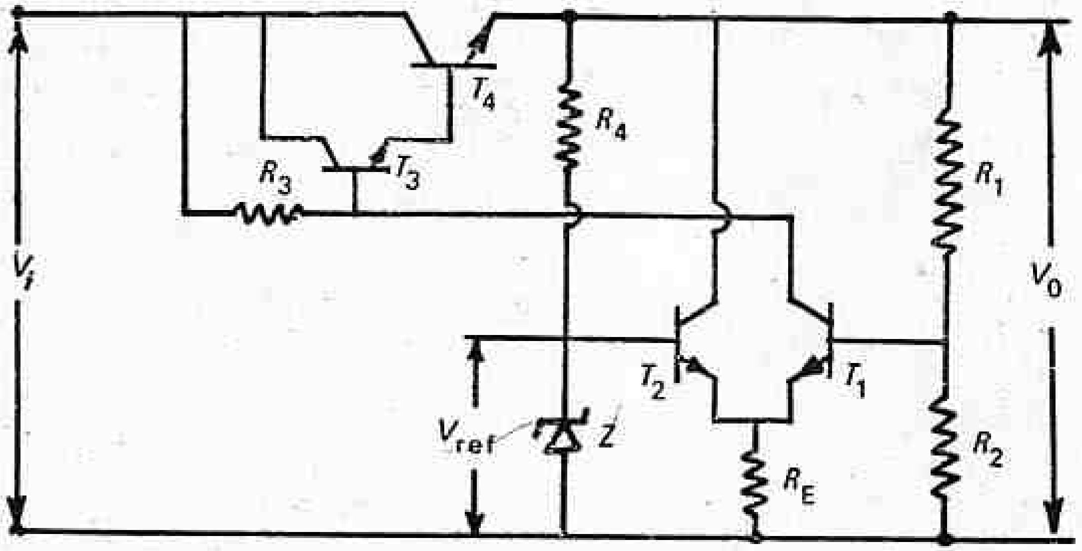


FIGURE 10.28 Block diagram of a closed-loop regulator.

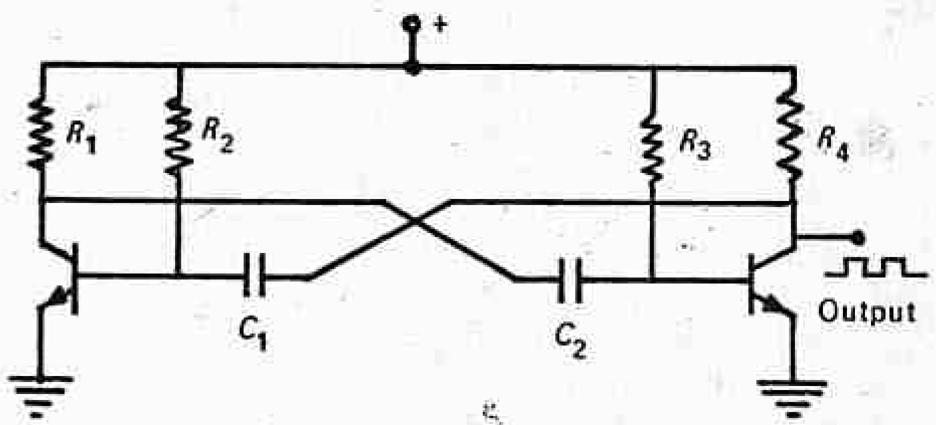
A typical circuit diagram that will perform this basic function is shown in Fig. (10.29). The differential amplifier consisting of T_1 and T_2 provides both the voltage comparison and the amplification functions.



FI GURE 10.29 A typical closed-loop regulator circuit.

10.9 Square-Wave Generators

Diode clippers can be used to remove the curved portion of the sinusoidal wave to give square waves. The operational amplifier together with an integrator, can be used to generate a square wave. The simplest form of the square wave generator is the astable multivibrator shown in Fig. (10.30)



FI GURE 10.30 An astable or free-running multivibrator.

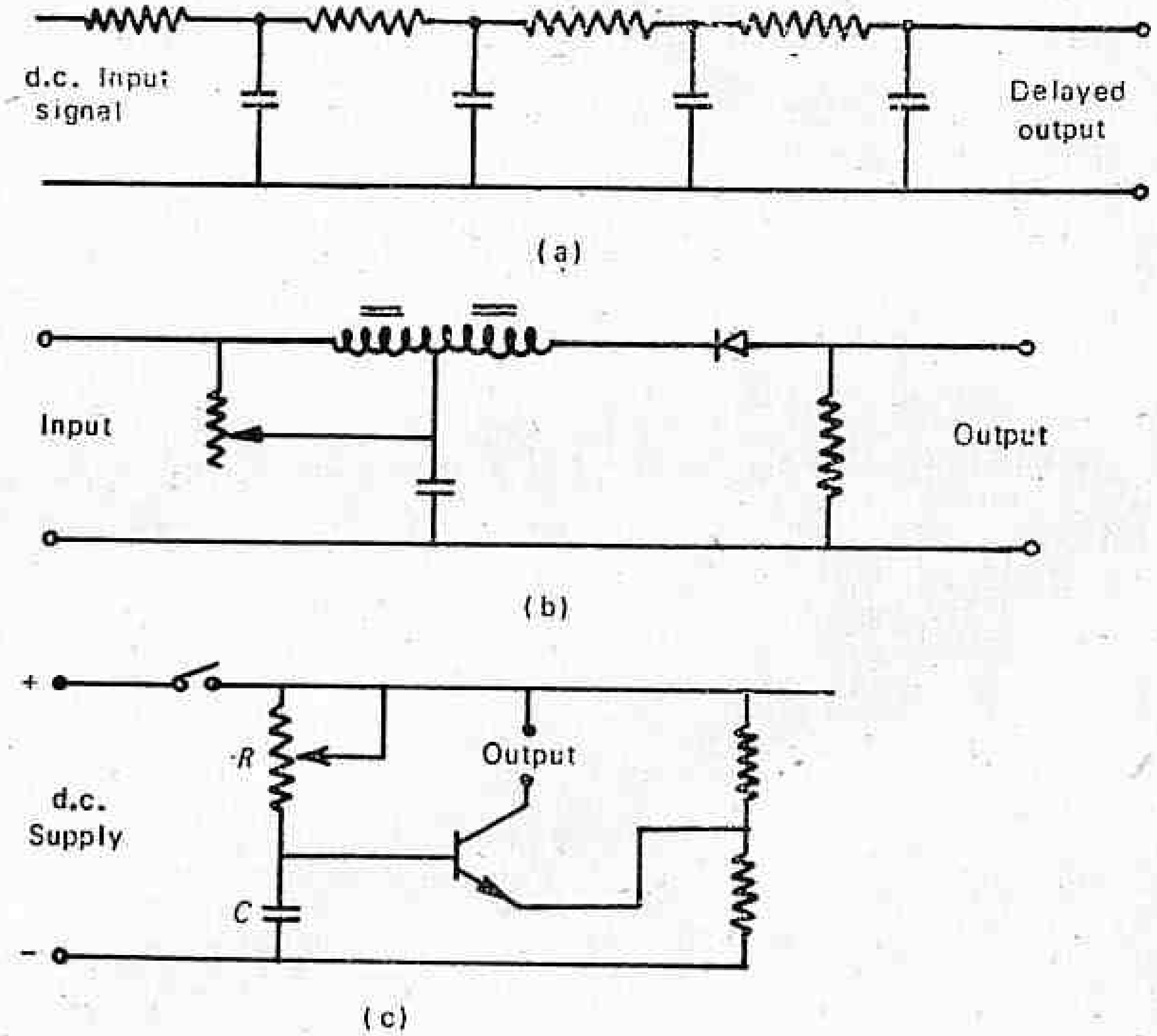
where two junction transistors are cross-coupled. The transistors conduct alternately with very fast regenerative transitions owing to the presence of the cross-coupling capacitors. The circuit is symmetrical if $R_2=R_3$, $R_1=R_4$ and $C_1=C_2$. A rectangular voltage wave form can be obtained across either of the collector load resistors.

10.10 Time Delay Circuits

A variety of time delay circuits are available such as delay lines, resonant circuits, RC circuits, timer circuits employing transistors, thermistors, etc. The order of time delay provided by each is different, e.g. a delay line is generally used to provide very short delays of the order of microseconds; for medium delays of the order of ms, a resonant circuit is used; RC circuits

are more common for longer delays. Time delays of the order of minutes or even hours are possible with RC circuits.

Some of the time delay circuits are shown in Fig. (10.31).



FICURE 10.31 Basic time delay circuits: (a) a delay line; (b) a resonant circuit; (c) RC circuit.

10.11 Level Detectors

The critical level detector compares an alternating or unsmoothed rectified signal against a d.c. datum, and is intentionally designed to have a low reset ratio. For peak inputs below the datum, the output is zero, but at the critical peak input there is a finite output pulse, the width of which is determined by the reset ratio as illustrated for the half-wave case in Fig. (10.32).

The simplest form of level detector is shown in Fig. (10.33) where the input voltage must exceed the opposing bias voltage before any output is produced.

A practical self-energized circuit using these principles is shown in Fig. (10.34). The full wave unsmoothed input signal feeds two alternative paths I_1 and I_2. Below the critical level the measuring and switching circuit is fully conducting, so that the current I_2 is for all practical purposes zero. The datum V_z, derived from the zener diode Z_1, is substantially d.c. at the

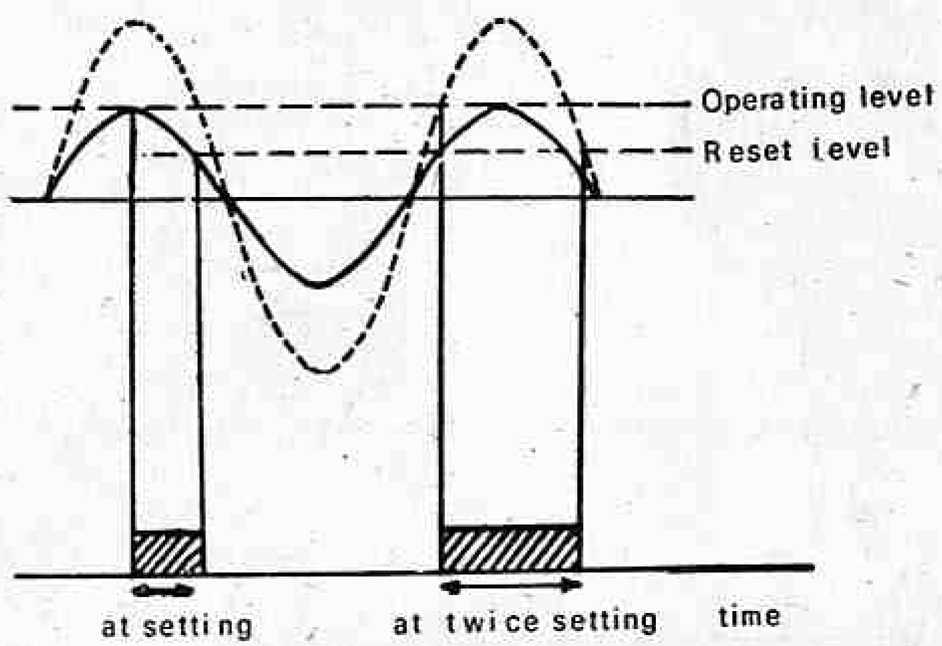


FIGURE 10.32 Operative period of critical level detector related to level of input signal.

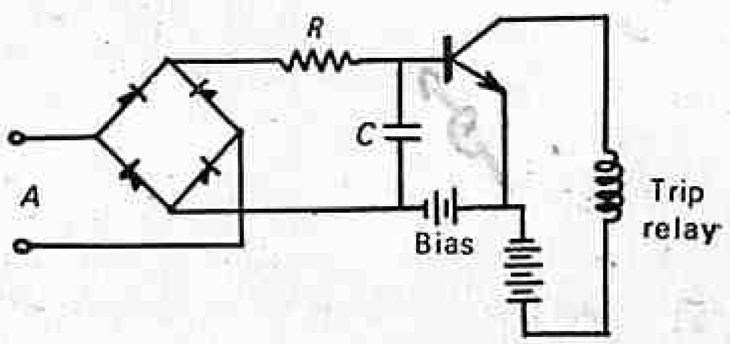


FIGURE 10.33 Level detector circuit.

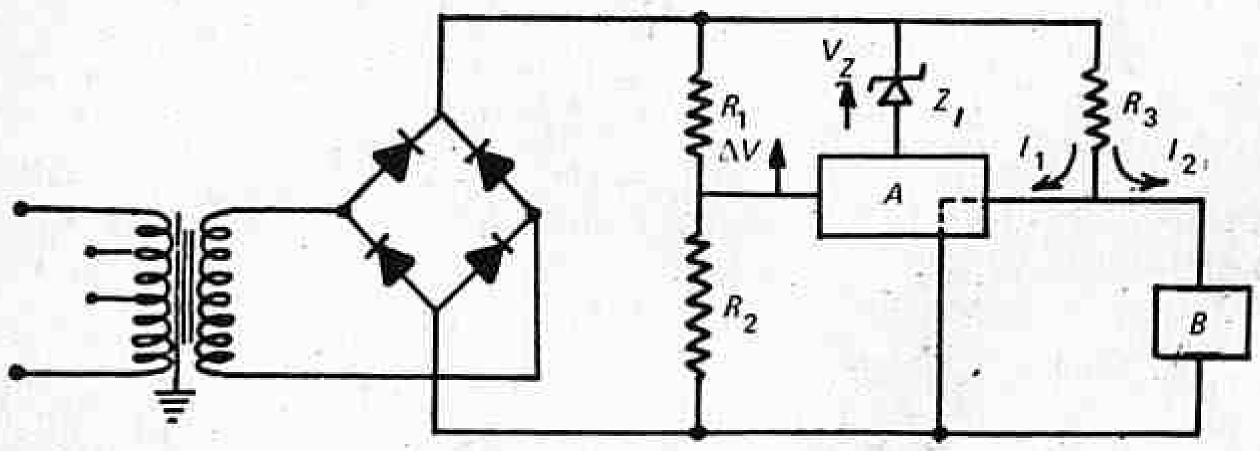


FIGURE 10.34 Practical critical level detector.
A—measuring and switching circiut;
B—pulse-integrating circiut.

critical input level. The loading on the input circuit, up to critical level is controlled solely by R_3, which provides the voltage for the measuring and switching circuit through R_1R_2. The critical level occurs when the voltage across R_1 exceeds V_z by the small amount of ΔV required to operate the switching circuit, which then switches to a high output impedance and diverts the current I_2 into the pulse-integrating circuit. At the instant of switching the input through R_1 increases to a value dependent on the input impedance of the pulse-integrating circuit, relative to R_3. This provides positive feedback to the measuring circuit, which controls the instantaneous reset level. The choice of this reset level is a compromise between the extraction of reactive power from the CT and other requirements, such as transient-free properties.

10.12 Summation Devices

Summation transformers and sequence networks as already discussed in Chapter 2 can combine a number of electrical quantities into a single quantity.

The operational amplifier is commonly used as a *mixer* or *summer* as shown in Fig. (10.35). The arrangement is used to obtain an output which is a linear combination of a number of input signals.

$$i=\frac{v_1}{R_1}+\frac{v_2}{R_2}+\frac{v_3}{R_3}+\frac{v_4}{R_4}$$

and $$v_0=-R'i=-\left(\frac{R'}{R_1}v_1+\frac{R'}{R_2}v_2+\frac{R'}{R_3}v_3+\frac{R'}{R_4}v_4\right)$$

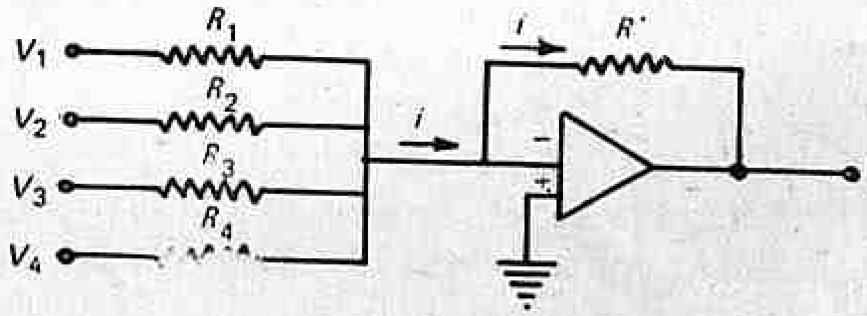


FIGURE 10.35 Operational adder or summer.

Any desired number of inputs can be used. If a simple summer or adder operation is desired, then $R_1=R_2=R_3=R_4=R'$, such that

$$v_0=-(v_1+v_2+v_3+v_4)$$

Many other methods may, of course, be used to combine signals. The present method has the advantage that it may be extended to a very large number of inputs requiring only one additional resistor for each additional input. The result depends, in the limiting case of large amplifier gain, only on the resistors involved, and because of the virtual ground, there is a minimum of interaction between input sources.

10.13 Sampling Circuits

Sampling technique is one which allows a comparison of instantaneous values derived at different instants of time, thereby dispensing with the need to phase shift and mix signals derived from the primary line quantities.

Figure (10.36) shows a sampling circuit in conjunction with an amplitude pulse width convertor (A/W convertor), this complete circuit forms the measuring unit for a relay. The circuit works as follows.

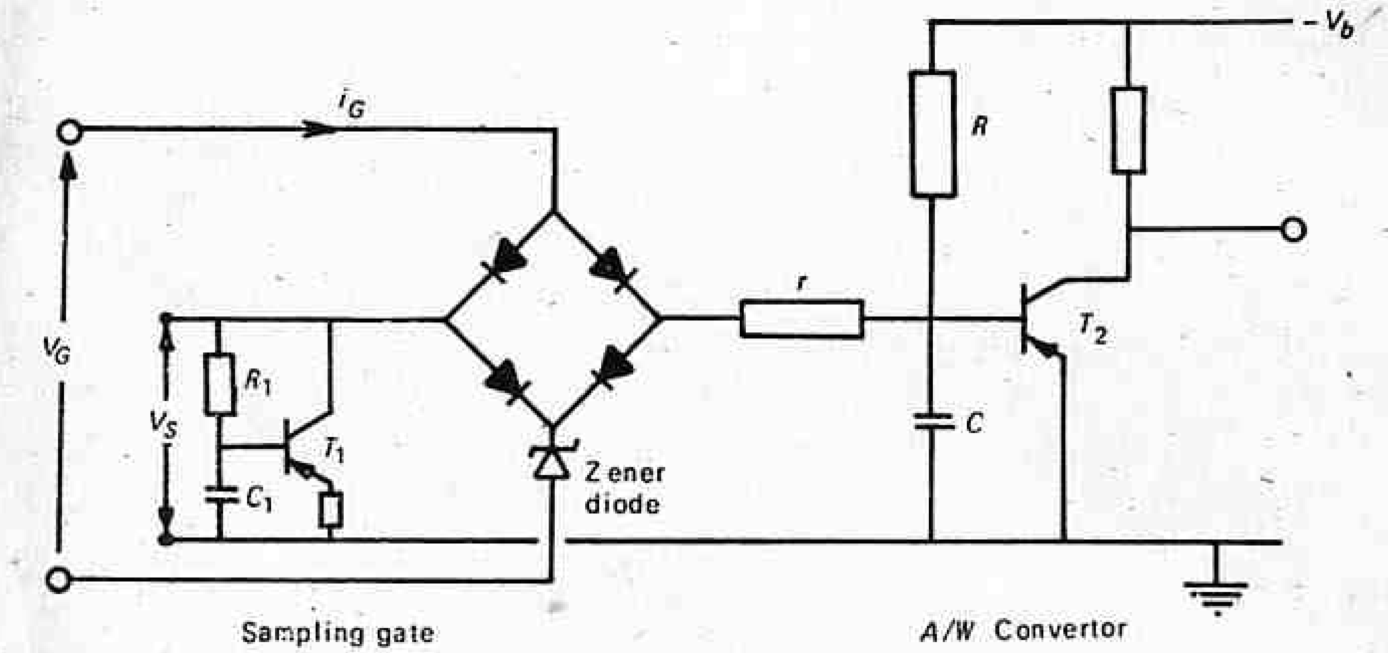


FIGURE 10.36 Measuring circuit.

When i_G is zero, a very high impedance is inserted between the signal voltage V_S and A/W convertor. The maximum V_S must be less than the breakdown voltage of the zener diode, otherwise conduction can take place via the zener diode and the V_G source impedance. When i_G is nonzero, i.e. during the 50μs sampling period provided that $i_S<i_G$ the resistance of the bridge between V_S and the A/W convertor is small. The current i_G is caused by the application of a rectangular 50μs voltage pulse V_G to the diode bridge, where V_G is large enough to break through the zener diode. It is found that the stray capacitance of the bridge diodes and the zener diode are such as to allow a very fast positive going edge to produce a spike at the output, even though i_G is zero. The circuit comprising T_1, R_1 and C_1 is added to deal with this contingency. The time constant $R_1 C_1$ is such that T_1 is held off except when V_S attempts to increase rapidly. Purely by considerations of cause and effect this circuit cannot remove a spike from V_S, but by switching on T_1 and drawing a spike of current through the signal source impedance, the rate of rise of discontinuity is slowed down sufficiently to prevent it getting through the diode bridge.

During the 50μs sampling period, C charges up through the resistance $r+R_S$, where R_S is the signal source resistance. $R \gg r+R_S$ and can therefore be neglected during the charging period. At the end of the sampling period, C commences to discharge through R towards the negative supply voltage. The diode bridge resistance is now very much larger than R and can be neglected during the discharge period. The transistor T_2 is normally on and is switched off at the start of the sampling period as the voltage on C goes positive. It switches on again when the voltage on C is approximately zero. The output at the collector of T_2 is therefore a pulse of length T' which is proportional to V_S at the instant of sampling provided that $T' \ll CR$.

10.14 Zero Crossing Detector

It basically involves the sine to square wave conversion by a level detector circuit followed by a pulse circuit, which consists of one shot monostable circuit or a differentiator. The zero crossing detection is associated with the production of a pulse at the particular zero crossing. Figure (10.37) shows the circuit for zero crossing detector.

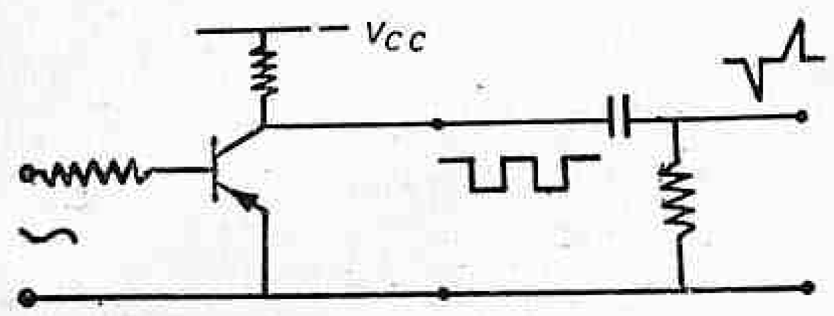


FIGURE 10.37 Zero crossing detctor.

10.15 Output Devices

The output devices have to perform many duties such as operation of breaker, intertripping, alarm and remote indication, etc. noncritical switching units are most suitable as output devices since they are associated with two or more electrically separate contact operations.

Amongst the static units the thyristor is an excellent means for tripping the circuit breaker from a low power signal of short duration. It operates with signals of microsecond duration but once triggered stays in conduction until broken by a switch. A typical thyristor tripping circuit is shown in Fig. (10.38). R_1 and C_1 are included to prevent excessive surges appearing across the thyristor. The small resistance R_1 limits the capacitor-discharge current on operation. The filter circuit connected to the gate electrode bas the capacitor C_2 connected immediately adjacent to the thyristor, to minimize pickup voltages on the gate electrode.

Reed relays though not static strictly speaking are very much suitable to semiconductor circuits. If properly designed they can also perform fast tripping of circuit breaker, provided the power factor and ratings of trip circuit are specified. The reed relays being very light in weight are susceptible to maloperation due to shock and vibrations.

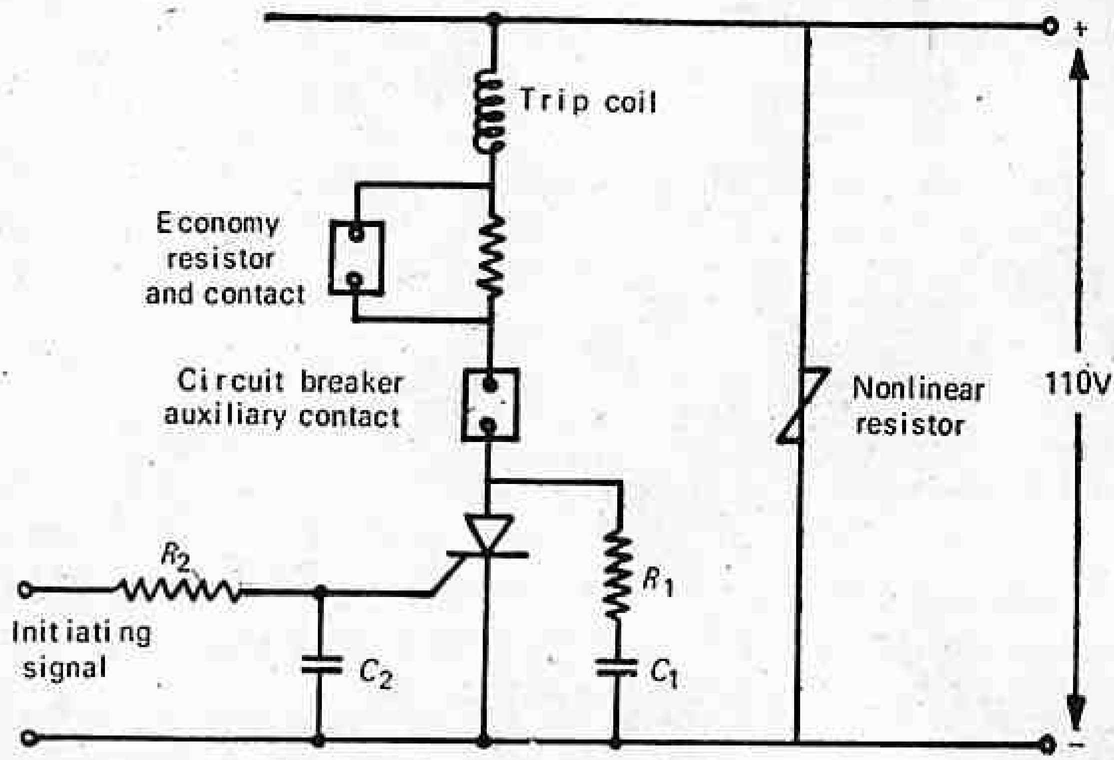


FIGURE 10.38 Thyristor tripping circuit.

QUESTIONS

1. Describe the use of the following components in static relays:
   (a) Transistor as a switch.
   (b) D.C. amplifiers.
   (c) FET as a switch.
   (d) Thyristor.
2. How are the logic gates applied in protective relaying? Explain clearly the relay logic with the help of logic gates.
3. Describe a summation device to combine large number of signals. What is its application in relaying.
4. Write technical notes on the following:
   (a) Sampling circuits.
   (b) Time delay circuits.
   (c) Level detectors.
   (d) Zero crossing detectors.

(a) They do not provide a perfect short circuit in the forward (Region II) direction.

(b) They do not provide a perfect open circuit in the reverse (Region I) direction.

(c) They possess *inertial* effects, i.e. the voltage or current cannot change instantaneously from one value to another; for instance, certain of the semiconductor devices are relatively slow to switch from *on* to *off* (Region II to Region I).

10.2 Transistors

In its simplest form, it consists of two *pn* junction diodes coupled together by a very thin common base, either of *p*-type or *n*-type semiconductor material. It is possible to separate input and output circuits, which may be controlling circuit and controlled circuit respectively. It has many advantages like small size, ruggedness, absence of filament heating power, etc., as compared to vacuum tubes. Another main advantage of transistors is that it can be made in two types; *pnp* transistor in which a region of *n*-type is sandwiched between two regions of *p*-type and vice versa in *npn*-type. The symbolic representation and the nomenclature used are shown in Fig. (10.2).

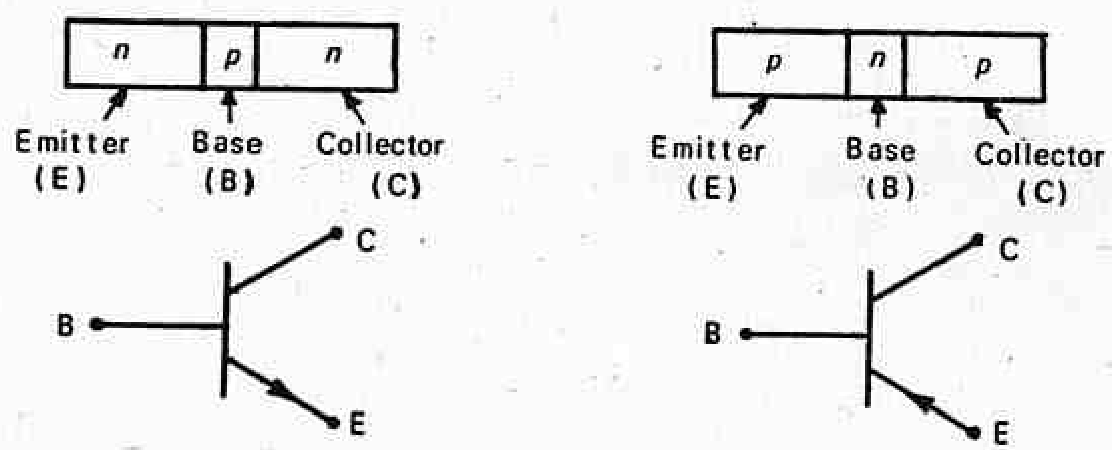


FIGURE 10.2 Symbolic representation of junction transistors.

Two factors are important in relation to transistor characteristics; one is the *collector-emitter amplification factor* (α) which is defined as the negative of the ratio of a change in collector current Δi_c to a given change in emitter current Δi_e, with collector-to-emitter voltage held constant, i.e.

$$\alpha = \left.\frac{-\partial i_c}{\partial i_e}\right\} v_{ce} = \text{constant} \tag{10.5}$$

The other important factor is *current amplification factor* (β) which is the ratio of a change in collector current Δi_c to a given change binase current Δi_b, with collector-to-base voltage held constant, i.e.

$$\beta = \left.\frac{\partial i_c}{\partial i_b}\right\} v_{cb} = \text{constant} \tag{10.6}$$

The value of α lies between 0.95 to 0.99 and β may reach values as high as several hundred.

The common-emitter configuration or grounded-emitter configuration is usually employed in most of the transistors. Figure (10.3) shows such a configuration.

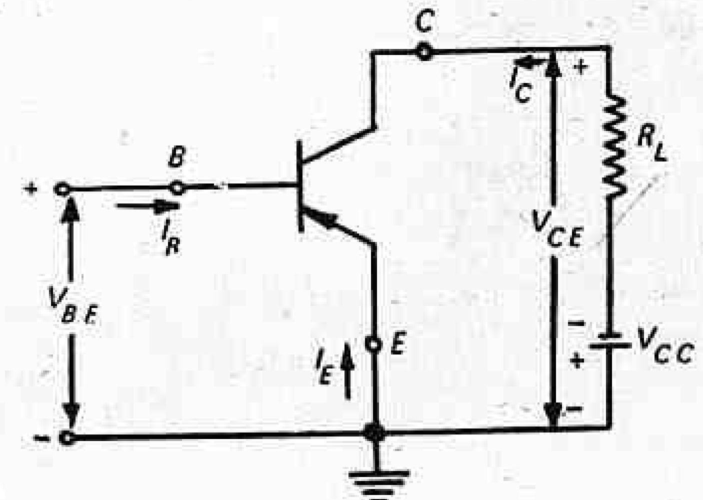


FIGURE 10.3 A transistor common-emitter configuration.

The base-emitter terminals are often employed as the controlling terminals, whereas the collector-emitter terminals are the controlled terminals.

The input current and the output voltage are taken as the independent variables, whereas the input voltage and output current are the dependent variables. Therefore, we have

$$V_{BE} = f_1(V_{CE}, I_B) \tag{10.7}$$

$$I_C = f_2(V_{CE}, I_B) \tag{10.8}$$

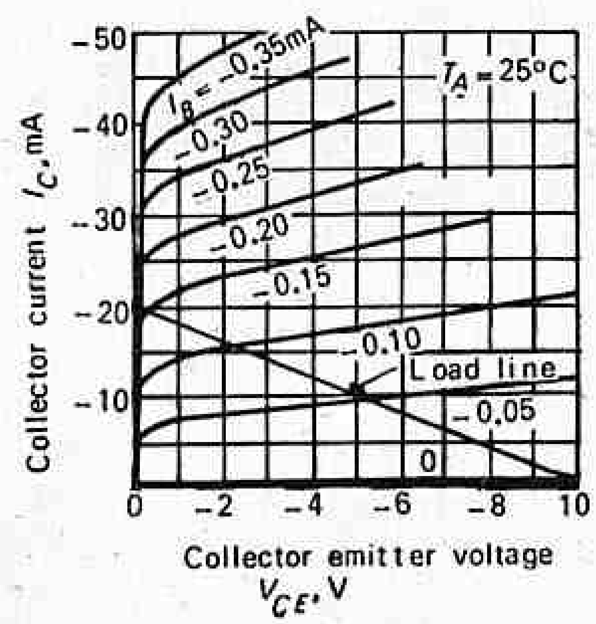


FIGURE 10.4 Typical common-emitter output characteristics of *pnp* germanium junction transistor.

Equation (10.7) describes the family of *input characteristic curves*, and Eq. (10.8) describes the family of *output characteristic curves*. Typical output and input characteristic curves for *pnp* junction, germanium transistor are given in Fig. (10.4) and (10.5) respectively.

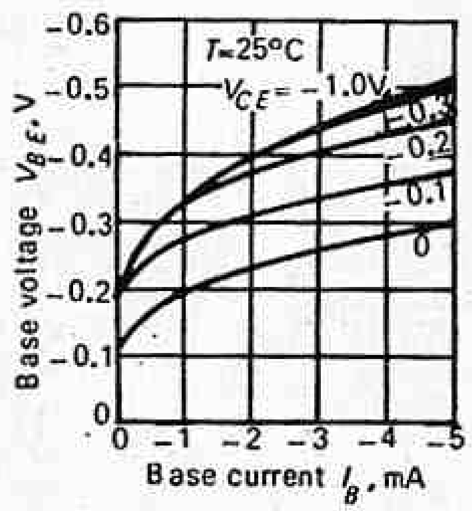


FIGURE 10.5 Typical common-emitter input characteristics of *pnp* germanium junction transistor.

The idealized collector characteristics shown in Fig. (10.6) have three regions of operation. Region I where virtually zero collector current flows and the base current $I_B \leqslant 0$, this is also known as cut off region. It is not enough to reduce I_B to zero for cut off, instead it is necessary to reverse-bias the emitter junction slightly. In region II the collector current is a linear function of base current, this is the active region of operation. In the active region the collector junction is reverse biased and the emitter junction is forward biased.

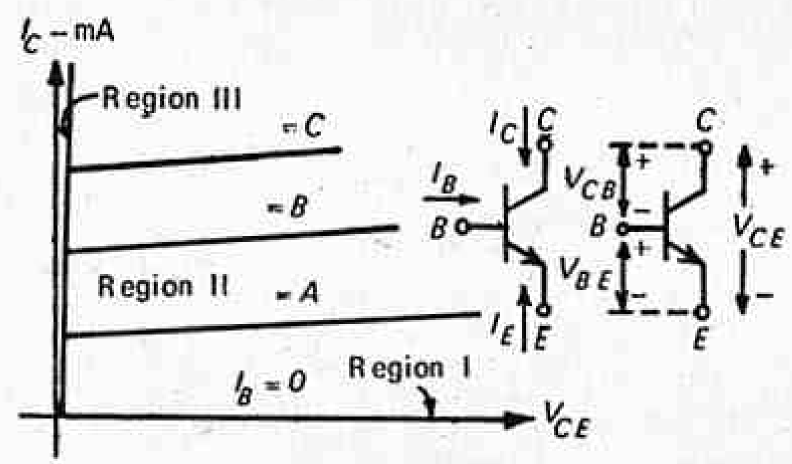


FIGURE 10.6 Idealized collector characterictics for an *npn* transistor.

In this region the transistor output current responds most sensitively to an input signal. If the transistor is to be used as an amplifying device without appreciable distortion, it must be restricted to operate in this region. In region III which is the saturated region the collector junction (as well as the emitter junction) is forward biased by at least the cut in voltage. V_{CE} is only a few tenths of a volt at saturation. Hence in Fig. (10.6) the

saturation region is very close to the zero voltage axis where all the curves merge and fall rapidly toward the origin.

10.2.1 Transistor as a Switch

The switching capabilities of a transistor stem from the capability of the device to rapidly change the d.c. resistance between its output terminals, the collector and emitter, from a very high to a very low value, in response to a small current injected into the control (base) terminal.

A schematic of a basic transistor switching circuit is shown in Fig. (10.7). A voltage pulse (V_i) applied to the input terminal causes a current flow (i_B) through the base resistance (R_K) which in turn reduces the collector-emitter resistance to a very low value and permits a large current flow (i_C) from the battery through the load. The transistor gets saturated and operates in region III. If the input voltage is removed, the reverse bias voltage (V_{OB}) causes the collector-emitter resistance to increase greatly, and significantly reduces the load current.

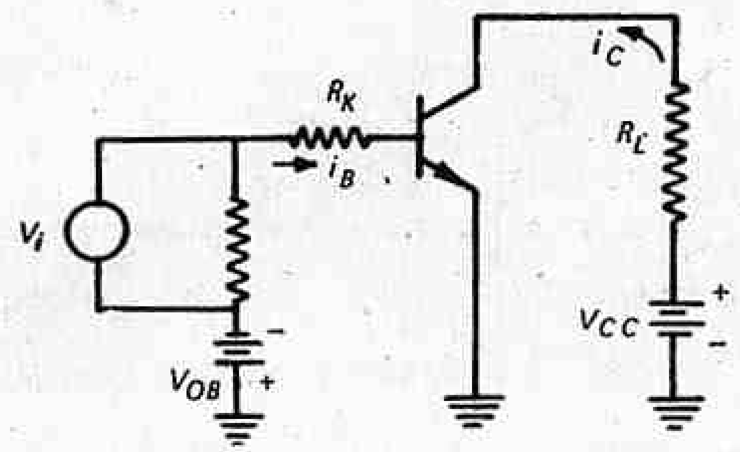


FIGURE 10.7 Basic transistor switching circuit.

Transistors, though they fall short of perfection represent the best available components for switching applications, especially in high-speed equipment. Factors that prevent a transistor from duplicating an ideal switch are:

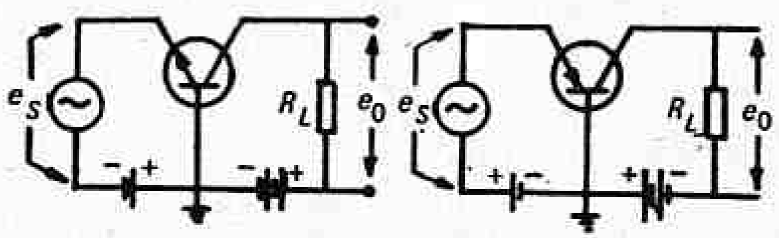
(a) A residual leakage current when the transistor is off.

(b) A residual collector-emitter saturation voltage when the transistor is on.

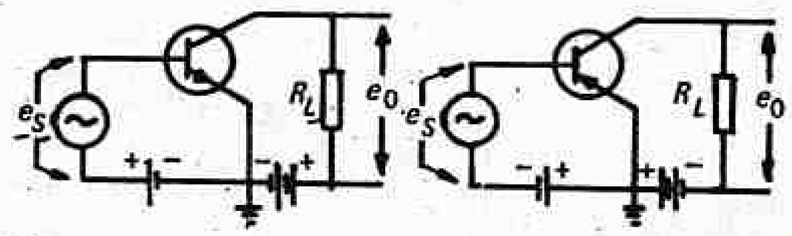
(c) Time delays involved in the response of collector current to changes in the input signal.

10.2.2 Transistor Amplifiers

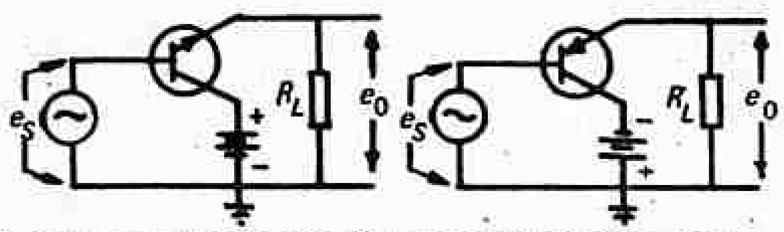
There are three basic methods of connection of a transistor in an amplifier circuit. Figure (10.8) shows these connections for both *pnp* and *npn* transistors. The emitter-base junction is always forward biased and the collector-base junction is always reverse biased. By sending a current through the emitter-base junction at a low voltage, almost the same amount of current is made to flow in the comparatively high voltage collector circuit. This accounts for the power amplification achieved. Because of its high gain, the common emitter circuit is most commonly used.



(a) common-base circuit; grounded-grid analogy



(b) common-emitter circuit; grounded-cathode analogy



(c) common-collector circuit; grounded-plate analogy

FIGURE 10.8 Transistor amplifier circuits.

The fact that current amplification is linear, whereas the voltage amplification depends upon the load impedance, means that transistor amplifiers are linear only as current amplifiers, i.e. the input must be a current source or the source impedance must be high compared with the transistor input impedance if a voltage source is used.

Table 10.1 gives in short the various features of the three different amplifier connections.

Table 10.1 *Comparative study of different configurations of transistor amplifiers*

Grounded electrode	Emitter	Base	Collector
Input electrode	Base	Emitter	Base
Current gain	High	None	High
Voltage gain	High	High	None
Power gain	High	Medium	Low
Input impedance	Medium	Low	High
Output impedance	Medium	High	Low
Phase shift	180°	0°	0°

10.2.3 D.C. Amplifiers

These are amplifiers which have zero frequency as the lower band limit to retain the initial displacements, d.c. components and low-frequency transient offsets that may accompany the a.c. and time-varying signals. It is not possible to use reactive coupling elements to separate signals and bias quantities. Any drift in the quiescent operating values cannot be distinguished from signals which are to be amplified. Direct-coupled amplifiers, therefore, have special problems in long-time stability. The main reasons for the drift are (i) variation of emitter-to-base voltage, (ii) variation in the gain of the transistor and (iii) variation in the power supply voltage. Temperature variation is one of the main causes of these variations. Numerous compensation techniques and circuits have been developed and are in use.

Two principal schemes of direct-coupled amplifiers are shown in Fig. (10.9). The only difference between the two schemes is that the resistance potential divider of Fig. (10.9a) is replaced by a battery in series with a resistance in Fig. (10.9b).

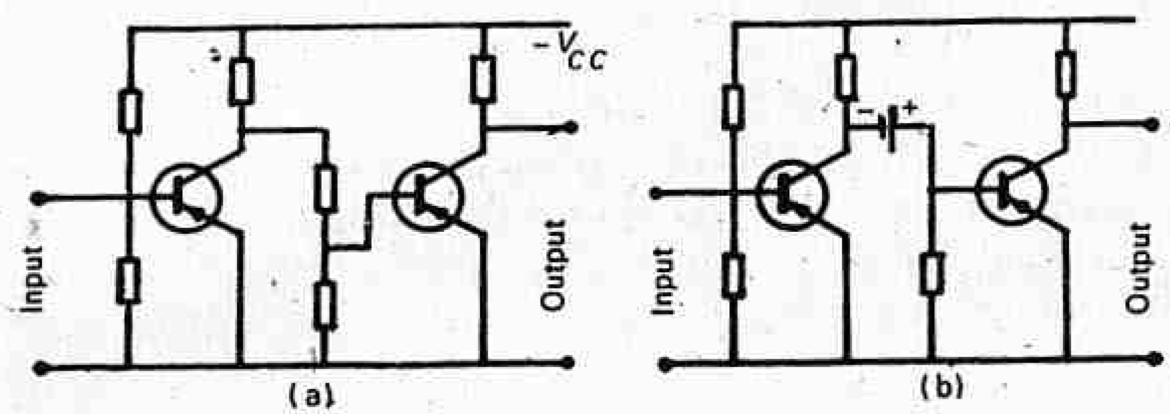


FIGURE 10.9 Direct coupled amplifiers.

An alternative method is to use a chopper which converts a slowly varying direct current to an alternating form, which is amplified by an a.c. amplifier, and its output is either used in a.c. form or rectified back to direct current again.

Typical transistor chopper circuits are shown in Fig. (10.10). The circuit shown in Fig. (10.10a) is suited for general use. When the base is driven positive by the square-wave output of the driving transformer, the transistor closes the circuit and the d.c. input voltage appears across R_2. When the base is driven negative, the transistor is switched open and the voltage across R_2 is zero. The circuit of Fig. (10.10b) uses two transistors, and it is useful with low-resistance sources since it has an on-off switch in series and an off-on switch in shunt with the source. When T_A is on, the collector-to-base junction of T_B is reverse-biased; and for the succeeding half cycle of switching frequency, when T_B is on, the junction of T_A is reverse-biased.

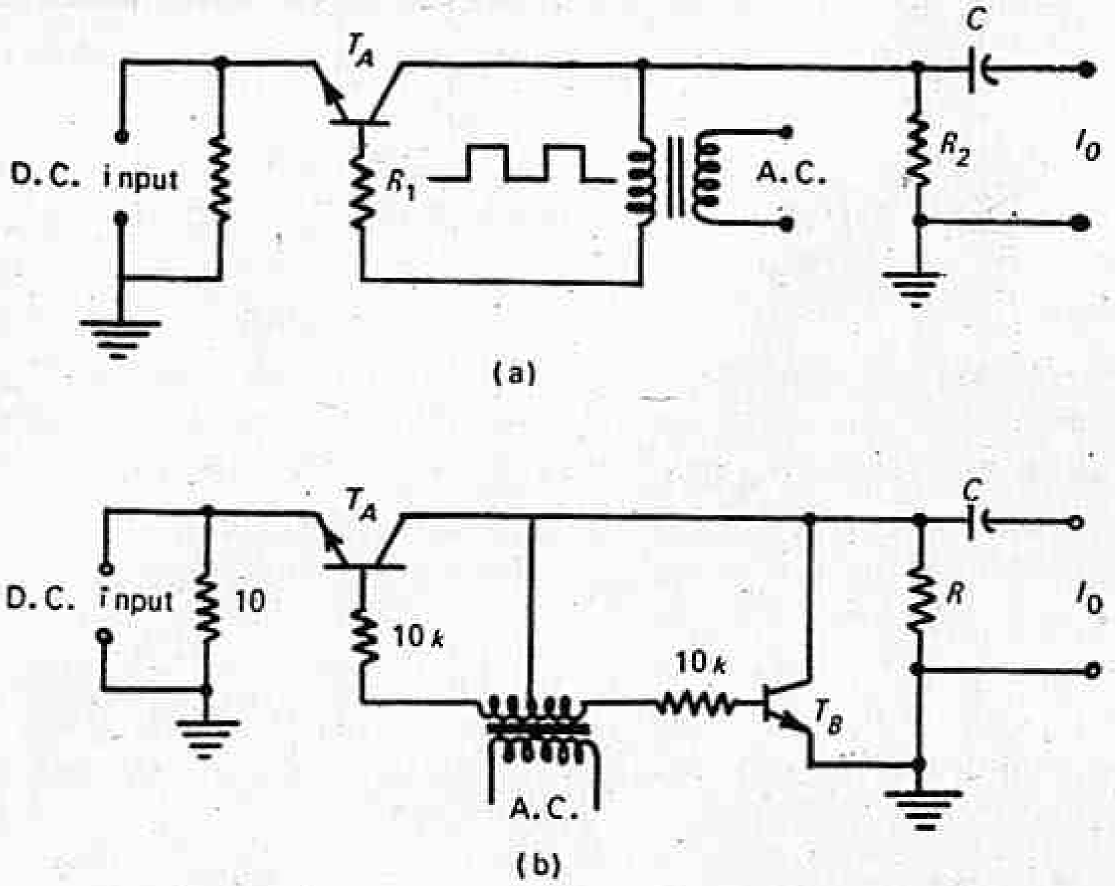


FIGURE 10.10 Typical transistor chopper circuits.

The leakage current of T_A is shorted out of the load by T_B during the half cycle in which T_A is open, and leakage current of T_B passes largely through T_A on the reverse half cycle, if R is large. The offset or threshold voltages of both transistors are identically applied across R on successive half cycles, but this voltage does not reverse and thus acts as a d.c. component which is removed by C.

10.3 The Field-Effect Transistor (FET)

The field-effect transistor (FET) is a unipolar device as compared to bipolar transistor already discussed. It consists of a bar of semiconductor material whose resistance is modulated by varying either the cross-sectional area of the bar or the density of current carriers in it, or both, by some electrical means. Two structures are used. One is an all-junction device in which the controlled modulation involves only the cross-section of the conducting channel. This is usually called junction FET. The other structure, called an insulated-gate FET (IGFET) or metal-oxide silicon FET (MOSFET) involves modulation of both the channel cross-section and the density of current carriers in it.

Junction FET is illustrated in cross-section in Fig. (10.11). An n-type bar of germanium is flanked by two regions of p-type germanium. The conduction current to be modulated is carried between the ends of n-type bar. The cross-sectional area available for conduction between the two p-type regions is a function of the magnitude of the reverse bias

between the two p-type regions and the n-type bar. The input impedance of this device is quite high, and the output impedance is moderately high.

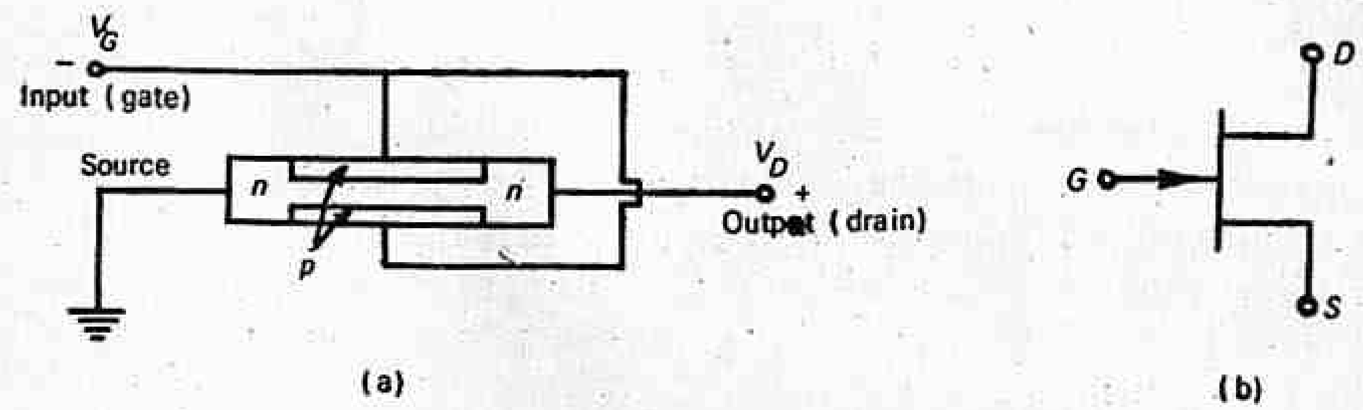


FIGURE 10.11 (a) A cross-sectional view of junction n-channel FET device; (b) symbolic representation.

This type of device shows less internal feedback between the input and output than the conventional transistor. Typical characteristic curves of junction FET are shown in Fig. (10.12). It has characteristics similar to pentode tube. A few volts negative bias on the gate blocks the current between drain and source by virtue of the field effect.

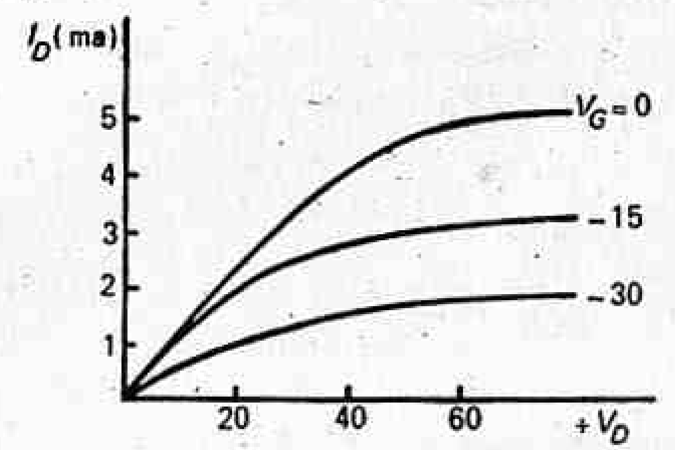


FIGURE 10.12 Typical junction FET characteristics.

The MOSFET structure is shown in Fig. (10.13). Here it can be seen that two diffused p-regions, the source and drain are separated by the n-type material of the starting crystal. On top of this insulating oxide between the source and drain regions a metal gate electrode of aluminium is deposited. Aluminium contacts are also made to the source and drain regions. If a negative charge of several volts is placed upon the gate

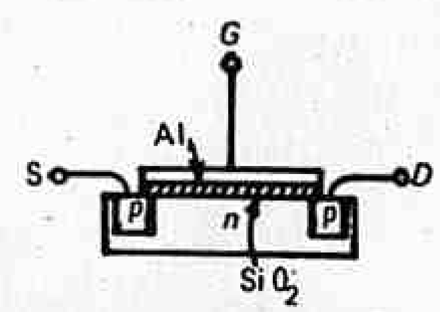


FIGURE 10.13 MOSFET structure.

electrode, an equal positive charge will gather on the surface of the semiconductor crystal just beneath the oxide. This positive charge now connects the *p*-type source and drain regions, and since it is mobile it forms a thin conducting channel between them. It has a very high input impedance. The major advantage of the device is that the high input impedance is retained for either a positive or negative input voltage, since the gate is insulated from the rest of the structure by the SiO_2 layer. This behaviour contrasts with the junction FET where the gate is a reverse biased junction for one input polarity but a forward biased junction for the other input polarity.

10.3.1 The FET as a Switch

At low frequencies the FET has no offset voltage. There is no threshold required of the signal being switched. In an ordinary bipolar transistor the signal being switched must exceed the voltage of the knee in the forward diode characteristic of the collector before there is appreciable signal through the switch in the on state. Here the channel, when opened by the gate, is a linear resistance requiring no such threshold. At a high frequency of switching there is a current due to the rapid charging and discharging of the gate capacitance through the channel, creating an *IR* drop in the channel which acts like an offset voltage.

10.4 Unijunction Transistor (UJT)

It is a three terminal device with only one *pn*-junction. It is made up of *n*-type silicon wafer having two base controls and a *p*-type alloy junction which acts as emitter electrode. In normal operation the lower ohmic contact (base B_1) is grounded. If the emitter junction is left open circuited, the voltage between B_1 and B_2 sets up a current proportional to the conductance of the wafer. The base B_2 is made positive with respect to B_1 by voltage V_{BB} and a fraction η of this voltage appears between the emitter E and B_1. Under the conditions of no current in the emitter, the UJT between B_1 and B_2 has the characteristics of an ordinary resistance called the interbase resistance R_{BB}. At 25°C this resistance lies between 4 and 10 $K\Omega$, and increases linearly with temperature up to about 140°C. The normal biasing conditions for the UJT and its symbol are indicated in Fig. (10.14). If V_E applied is less than ηV_{BB}, the emitter will be reverse biased and only leakage current will flow. If V_E is greater than ηV_{BB} the junction becomes forward biased and large emitter current flows with a low forward voltage drop between emitter and B_1.

The characteristics show that there is a large negative resistance region for fast switching action. The use of UJT is in generating trigger input to SCRs. For such an application, the basic circuit of Fig. (10.15) is

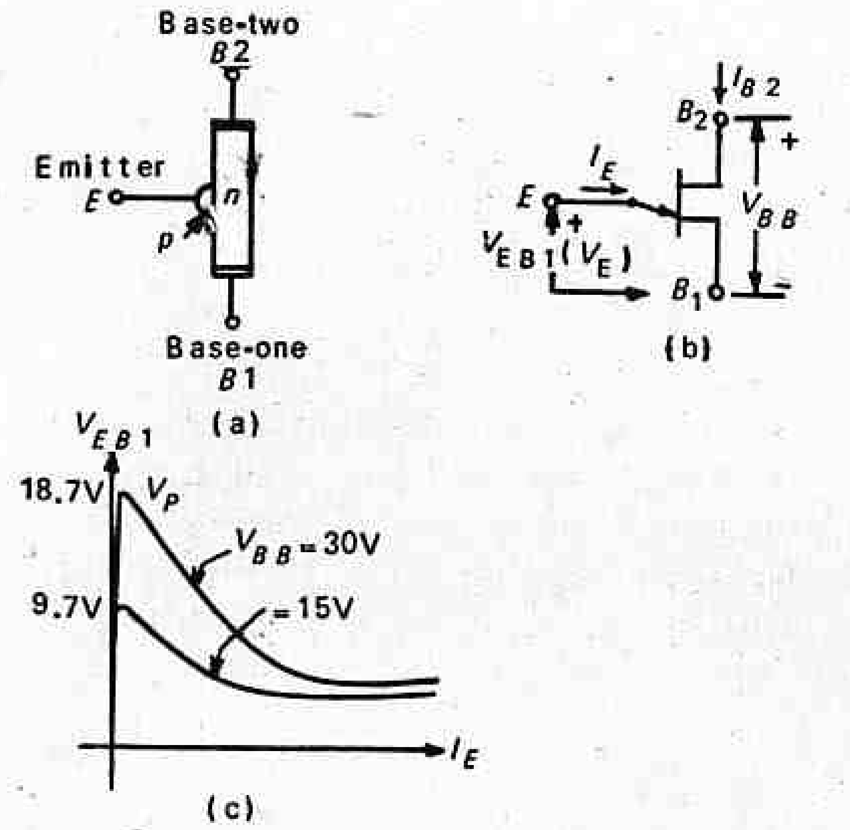


FIGURE 10.14 The unijunction transistor (UJT): (a) the construction; (b) the symbol for the device; (c) the V-I characteristics at the emitter terminal.

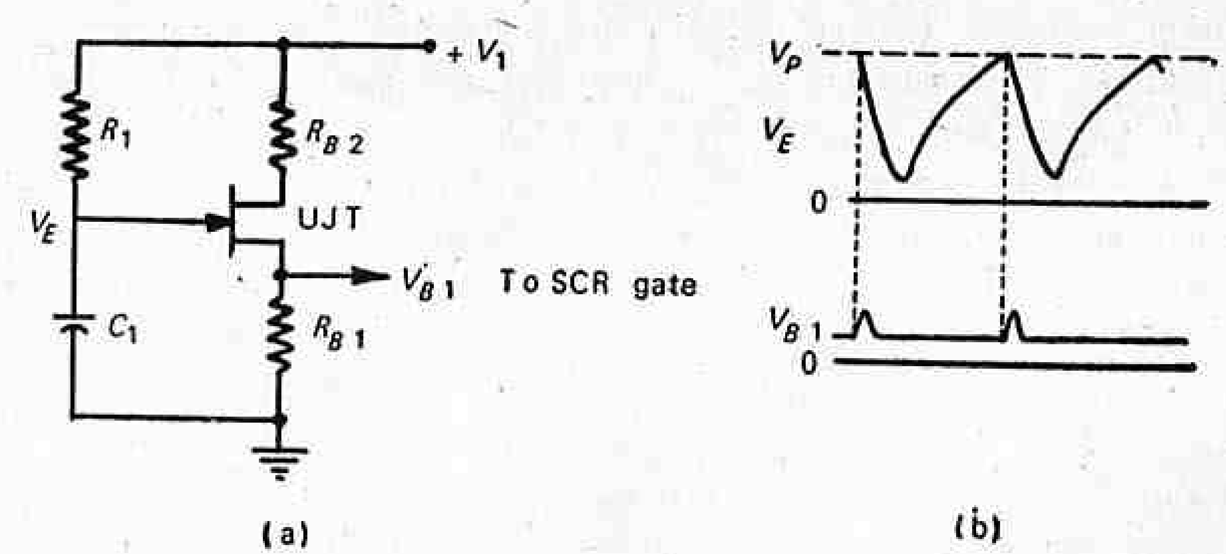


FIGURE 10.15 Triggering SCR with UJT.

used. The capacitor C_1 charges through R_1 until V_E reaches the peak-point voltage V_P, when the UJT triggers and discharges C_1 through R_{B_1}. When V_E reaches a low value, perhaps 2V, the capacitor can no longer supply the necessary emitter-base current, and UJT turns off. Base resistor R_{B_1} provides an output-voltage pulse during the very short high-current transition through the negative reistance region as shown in Fig. (10.15b). This pulse is coupled to the gate of an associated SCR and provides precise triggering.

10.5 Thyristor

The structure of thyristor consists of four alternate *p*-and *n*-type layers. In the thyristor (also called a silicon controlled rectifier—SCR) connections are made available to the inner layers. It acts like two transistors in tandem, one *pnp* and another *npn*. Figure (10.16) shows the circuit symbol for the SCR.

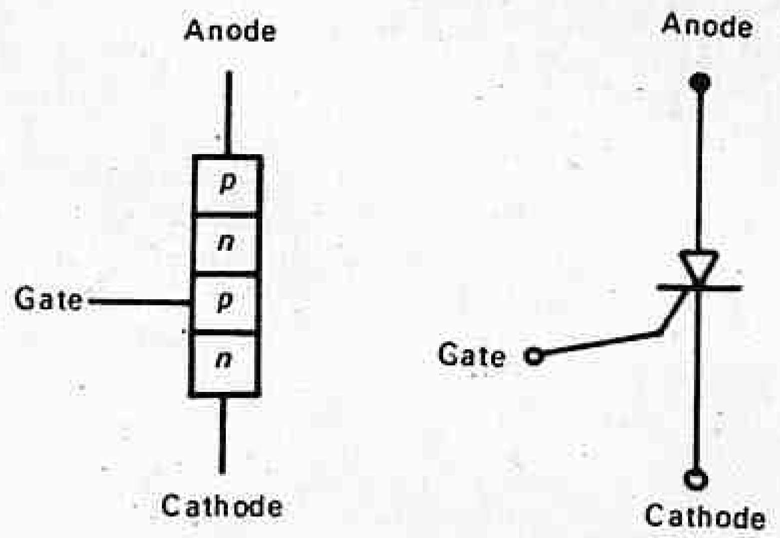


FIGURE 10.16 Circuit symbol for SCR.

The usefulness of the gate terminal rests on the fact that current introduced into the gate may be used to control the anode to cathode breakover voltage. In Fig. (10.17) the volt-ampere characteristic of an SCR is shown for various gate currents. It can be observed that the firing voltage is a function of the gate current, decreasing with increasing gate current and increasing when the gate current is negative and consequently in a direction to reverse-bias the cathode junction. The current after breakdown may well be larger by a factor of 1000 than the current before breakdown. When the gate current is very large, breakover may occur at so low a voltage that the characteristic has the appearance of a simple *pn* diode.

Suppose that a supply voltage is applied through a load resistor between anode and cathode of a SCR. Consider that the bias is such that the applied voltage is less than breakover voltage. Then the rectifier will remain

off and may be turned on by the application to the gate of a triggering current or voltage adequate to lower the breakover voltage to less than the

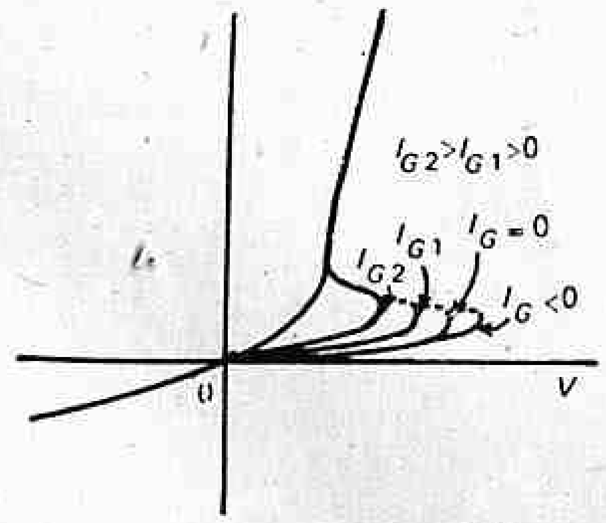


FIGURE 10.17 Volt-ampere characteristics of an SCR.

applied voltage. The rectifier having been turned on, it latches, and it is found to be impractical to stop the conduction by reverse-biasing the gate. For example, it may well be that the reverse gate current for turn off is nearly equal to the anode current.

Because of its high speed a thyristor is easily triggered by a small voltage signal (5V, 0.1m A). To prevent wrong operation it is customary to design the circuit so that the tripping signal will not trigger the thyristor unless it lasts for at least 2 mS. This prevents operation on interference spikes since they are momentary in nature (of the order of microseconds).

10.6 Logic Circuits

The concept of static relaying can be better understood by considering the *logic* operations performed by the devices rather than the actual happenings that occur during their operation. This makes complex static relay operation also simple, because the interest then is only on *what* happens rather than *how* it happens, and the *logic* part of the operation is independent of devices used to realize the events dictated by the logic.

Basically, all relays are *bistable devices*, i.e. they have two stable states; either they operate or they do not operate. Consequently Boolean algebra can be applied to study and analyze protection schemes consisting of a number of relays. Using these techniques simplified block schemes can be drawn according to the logical functions performed by the various units.

In a d.c., or level-logic, system a bit is implemented as one of two voltage levels. The more positive voltage is the 1 level and the other is the 0 level, the system is said to employ d.c. positive logic. On the other hand, a d.c. negative logic system is one which designates the more negative voltage state of the bit as the 1 level and the more positive as the 0 level.

Figure (10.18) illustrates these two types of logic systems. Positive logic is usually followed.

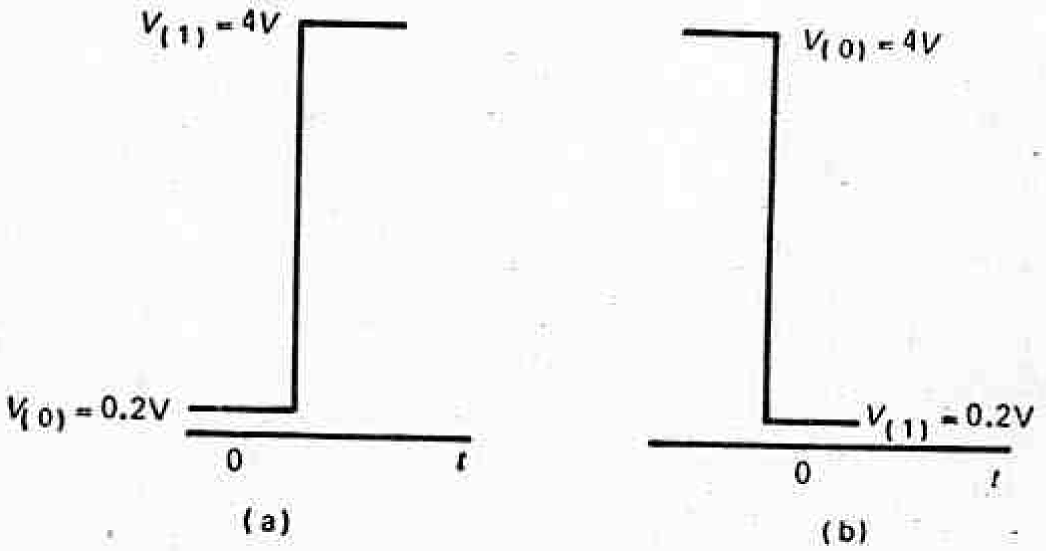


FIGURE 10.18 (a) Positive logic; (b) negative logic.

10.6.1 Basic Operations

The three basic operations of Boolean algebra are:

(i) Logical sum—OR circuit.
(ii) Logical product—AND circuit.
(iii) Negation—NOT circuit.

The output of an OR assumes the 1 state if one or more inputs assume the 1 state.

The output of an AND assumes the 1 state if and only if all the inputs assume the 1 state.

The output of a NOT circuit takes on the 1 state if and only if the input does not take on the 1 state.

These basic operations are represented block schematically in Fig. (10.19) along with their truth table which contains a tabulation of all possible input values and their corresponding outputs. Different combinations of these circuits can result in other logic circuits such as NOR and NAND circuits.

10.6.2 Relay Logic

To start with, to make a connection between relay circuits and their logic operations, the basic operations mechanized using relays are shown in Fig. (10.20). All contacts are shown in their normal position, i.e. deenergized position. Thus each relay operation could be subdivided into basic switching functions which in turn can be represented by a suitable logic circuit.

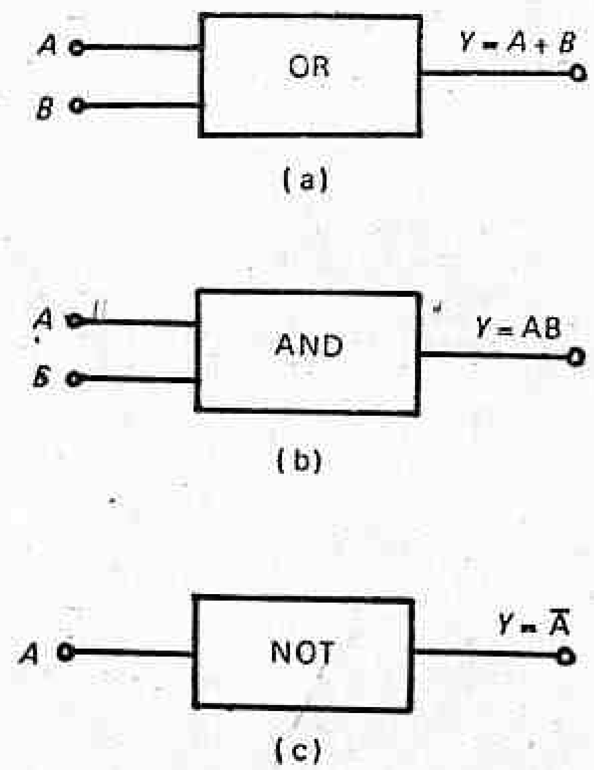


FIGURE 10.19 Block schematics of basic operations.
(a) Logical sum—OR circuit

Input		Output
A	B	Y
0	0	0
0	1	1
1	0	1
1	1	1

(b) Logical product—AND circuit

Input		Output
A	B	Y
0	0	0
0	1	0
1	0	0
1	1	1

(c) Logical negation—NOT circuit

Input	Output
A	Y
0	1
1	0

In the following section, it will be shown that these logic circuits can be obtained using semiconductor devices such as diodes or transistors.

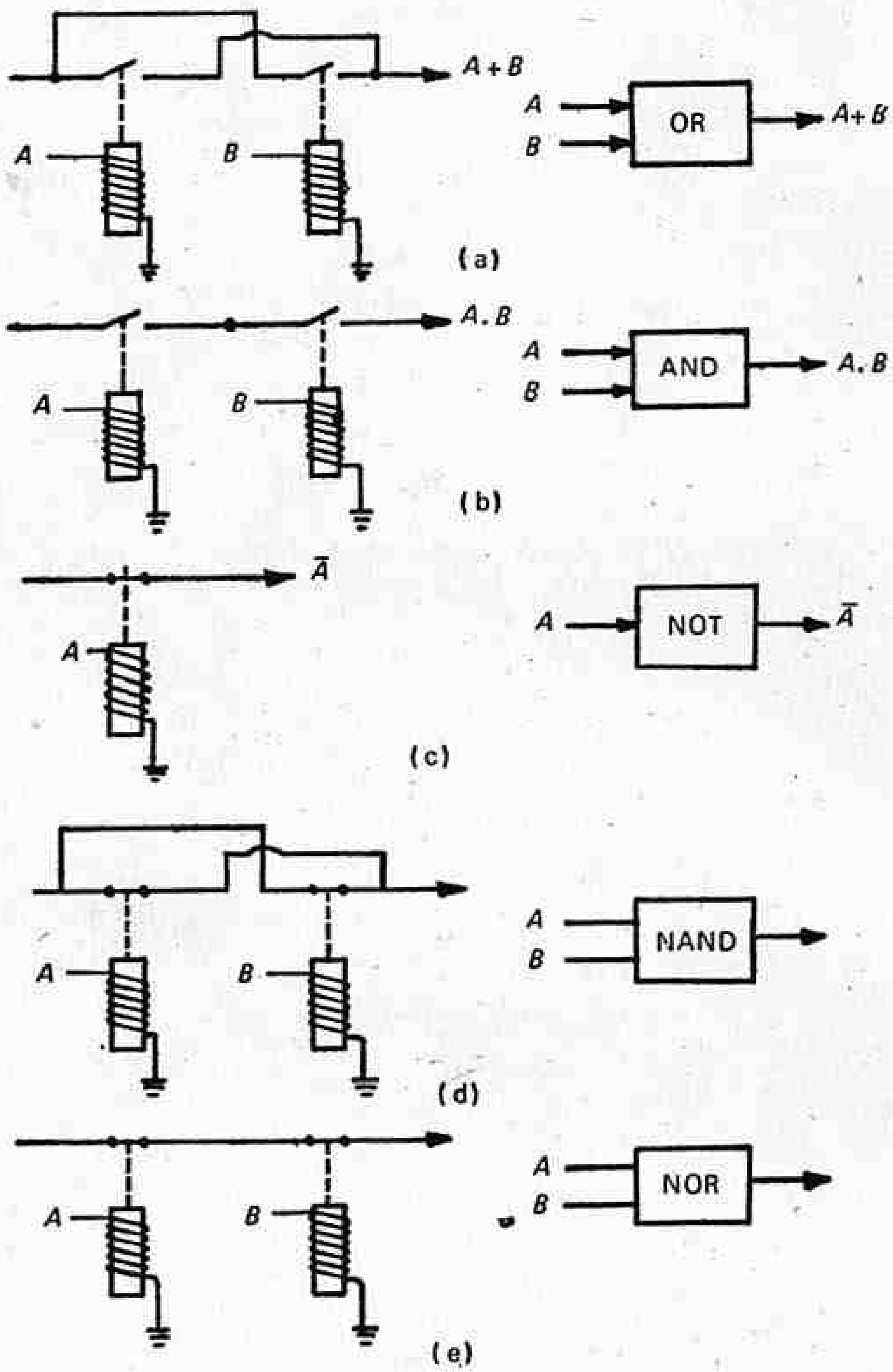


FIGURE 10.20 Logic operations using relays.

10.6.3 Diode Logic (DL)

The two stable states of the diode are *conducting* (i.e. forward bias) and *nonconducting* (i.e. reverse bias) states. Conventional diode OR gate (circuit) and AND gate are shown in Fig. (10.21).

One of the disadvantages of diode logic is that *negation* cannot be performed using diodes and this is where transistors are helpful.

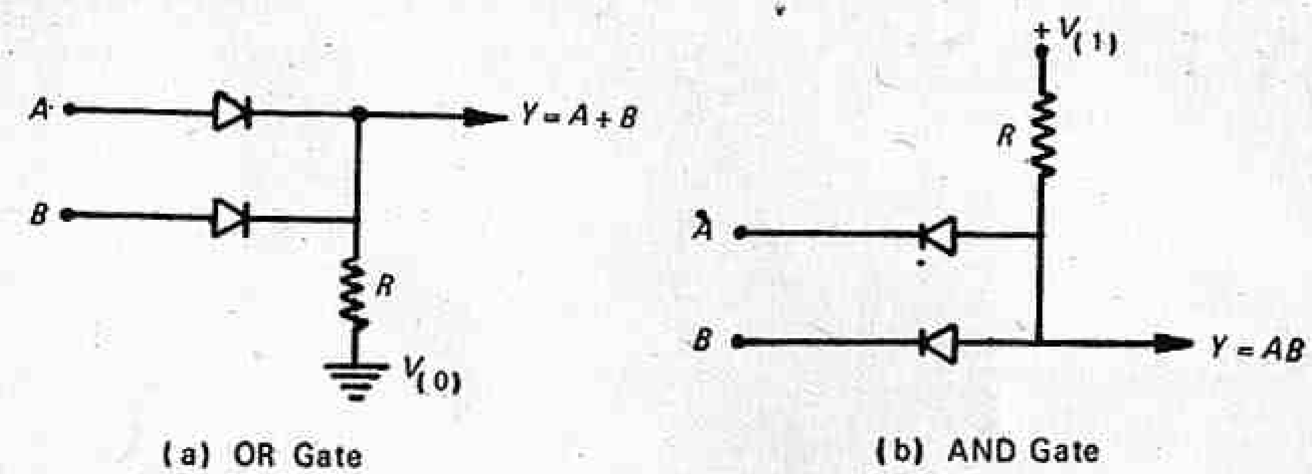


FIGURE 10.21 DL circuits.

10.6.4 Transistor Logic

A number of logic circuits can be designed using transistors, specially because of the two types (*npn* and *pnp* types). Logic circuits using transistors could be developed in two forms, viz. *resistor transistor logic* (RTL) and *direct coupled transistor logic* (DCTL).

Basic NAND and NOR circuits based on the latter scheme (DCTL), are shown in Fig. (10.22).

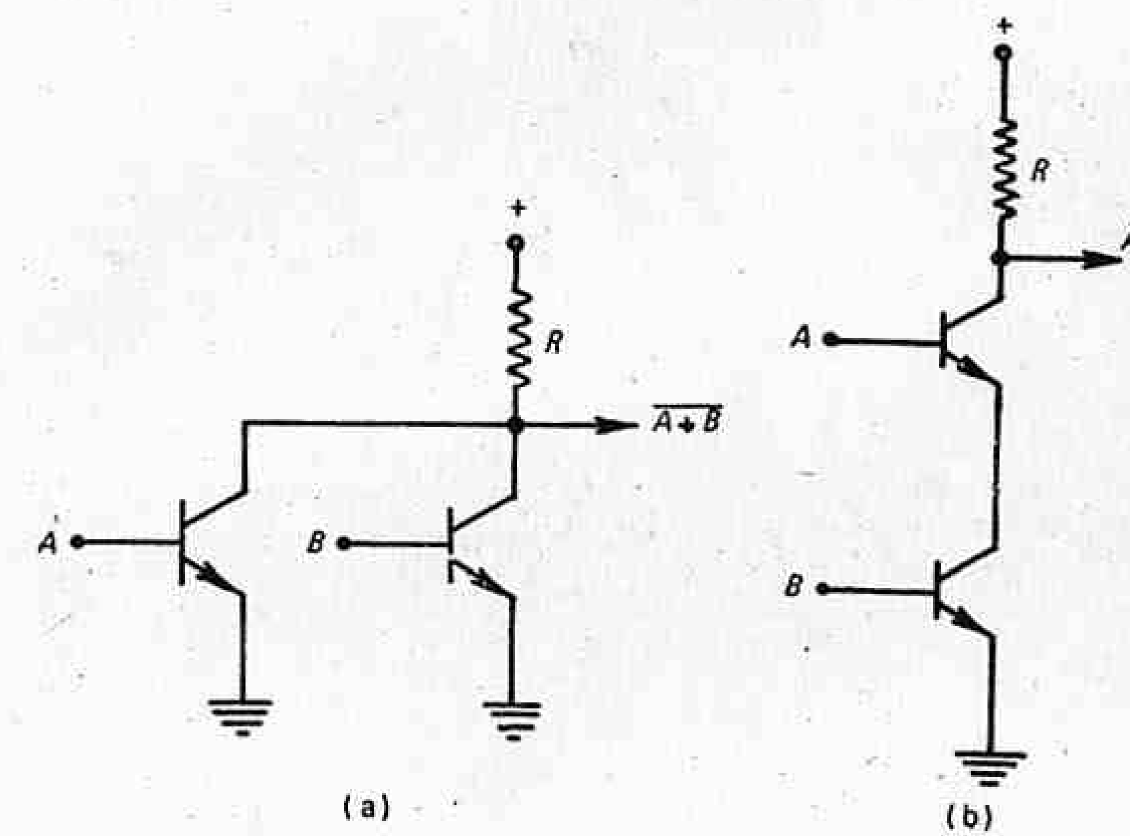


FIGURE 10.22 DCTL circuits.

The RTL class of circuits were developed to achieve improved stability of operation. In addition, it simplifies the general gate circuitry and does not require stringent control of transistor parameters. Commonly used RTL circuits are shown in Fig. (10.23).

CHAPTER **11**

Comparators

A relay detects the change between normal and abnormal conditions by comparing two electrical vector quantities, both of which are derived from the system voltages and currents at a particular relay location. A variety of characteristics can be obtained on the complex plane with the help of multi-input devices. The comparator is also a basic form of multi-input device, although more than two inputs increase the range of complex characteristics so that special characteristics of the form: ellipse, parabola, quadrilateral, parallelogram, etc., can be obtained. Most of the protective schemes employ two-input devices only. The function is generally defined by the relationship between the inputs, which govern the boundary conditions of operation. Depending on the specific method of comparison all comparators can be grouped as either (a) *amplitude comparator* or (b) *phase comparator*.

The analysis of amplitude and phase comparators has already been dealt with in Chapter 4, where it was shown that basically there is no difference between the two. The semiconductor comparator affords great freedom of design for specific laws of operation and/or characteristics, this has no counterpart in the electromechanical relay, where the basic characteristics are prescribed by the behaviour of the element itself.

11.1 Amplitude Comparator

If the two input signals are S_1 and S_2 the amplitude comparator gives positive (yes) output only if $S_2/S_1 \leqslant K$ (Fig. (11.1)), S_1 is the operating quantity and S_2 is the restraining quantity. Ideally, the comparison of the two input signals is independent of their level and their phase relationship. The function is represented by a circle in the complex plane, with its centre at the origin; this defines the boundary of the marginal operation.

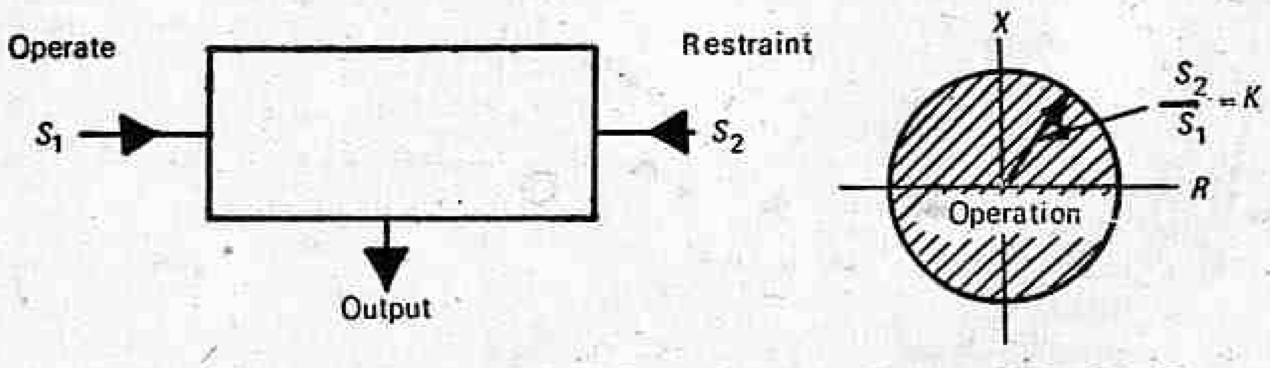


FIGURE 11.1 Amplitude comparator. Output when $|S_2/S_1| \leqslant K$.

Static amplitude comparators may be of the following types: (i) integrating comparators, (ii) instantaneous comparators, and (iii) sampling comparators.

11.1.1 Integrating Comparators

It is possible to arrange rectifier bridge networks as amplitude comparators. Rectifier bridge comparator can either be of circulating current type or opposed voltage type.

Basic circuit for the circulating current type is shown in Fig. (11.2). The polarized relay operates when $S_1 > S_2$, where $S_1 = K_1 i_1$ and $S_2 = K_2 i_2$. This arrangement provides a sensitive relay whose voltage may be ideally represented by Fig. (11.2b). The relay voltage will never exceed twice the forward voltage drop of one of the rectifiers, and typically will be of the order of 1 volt.

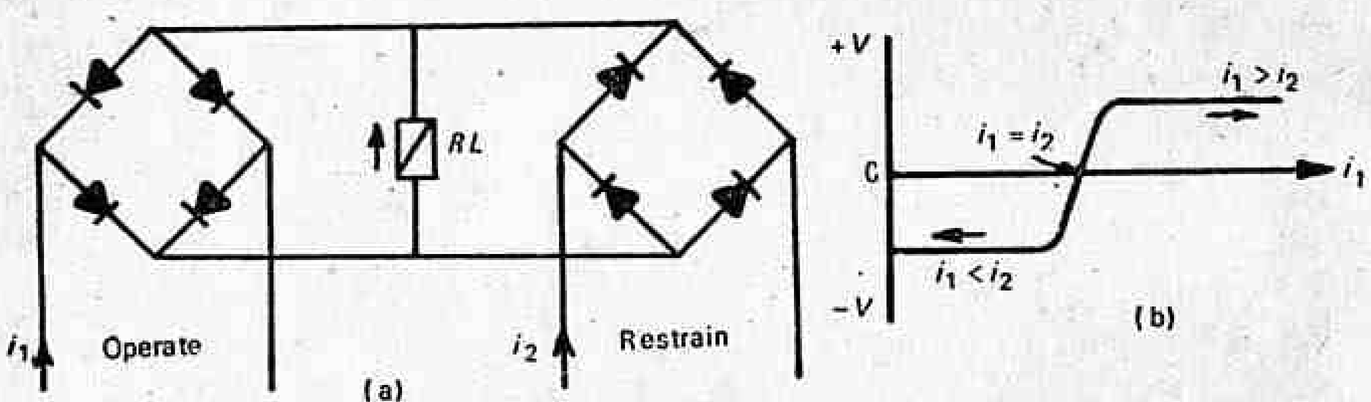


FIGURE 11.2 Circulating current type rectifier bridge comparator: (a) basic circuit; (b) output voltage. RL—polarized relay operates in direction shown.

Instead of the polarized relay a static integrator can be used consisting of an averaging circuit and the polarity detector circuit as shown in Fig. (11.3). The two currents i_1 and i_2 are rectified and their difference $(\bar{i}_1 - \bar{i}_2)$ is averaged. The output is obtained only if the averaged value is positive.

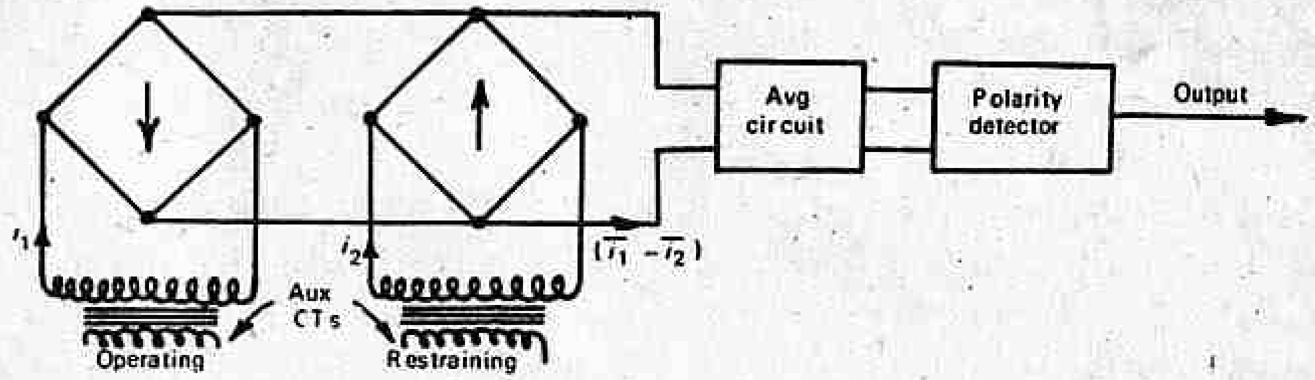


FIGURE 11.3 Rectifier bridge comparator with static output device.

An integrator circuit is shown in Fig. (11.4). The tripping occurs when the capacitor voltage reaches the setting value of the level detector and triggers a thyristor.

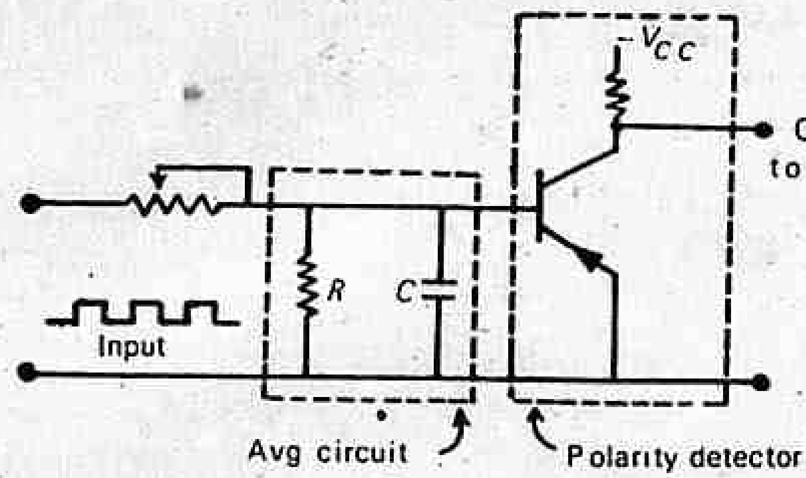


FIGURE 11.4 Integrating circuit.

The opposed voltage type comparator shown in Fig. (11.5) works with voltage input signals derived from PTs. The operation in this case depends on the average of the difference of the rectified voltages $(\bar{v}_1 - \bar{v}_2)$. In this case the limiting action is the wrong way, as the rectifiers have higher resistance at lower voltages. Also the rectifiers are not protected at higher currents.

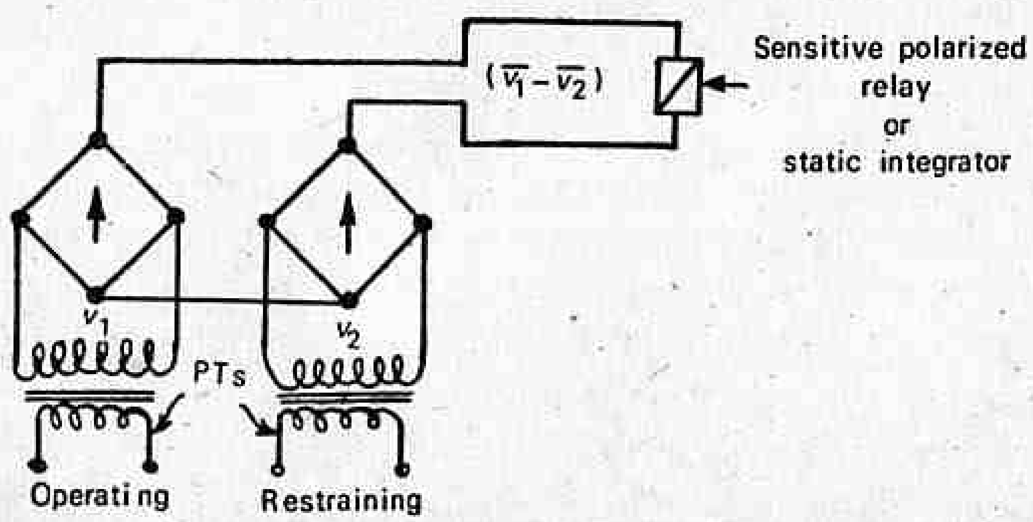


FIGURE 11.5 Opposed voltage type rectifier bridge comparator.

11.1.2 Instantaneous Comparators

Instantaneous or direct amplitude comparators can be of two types: *averaging* type and *phase splitting* type.

In the averaging type instantaneous amplitude comparator the restraining signal is rectified and smoothed completely in order to provide a level of restraint. This is then compared with the peak value of the operating signal, which may or may not be rectified, but is not smoothed. The tripping signal is provided if the operating signal exceeds the level of restraint. The block schematic diagram is shown in Fig. (11.6). The wave shapes are shown in Fig. (11.7).

Since the above method involves smoothing the operation is slow. A faster method is phase splitting before rectification as shown in Fig. (11.8).

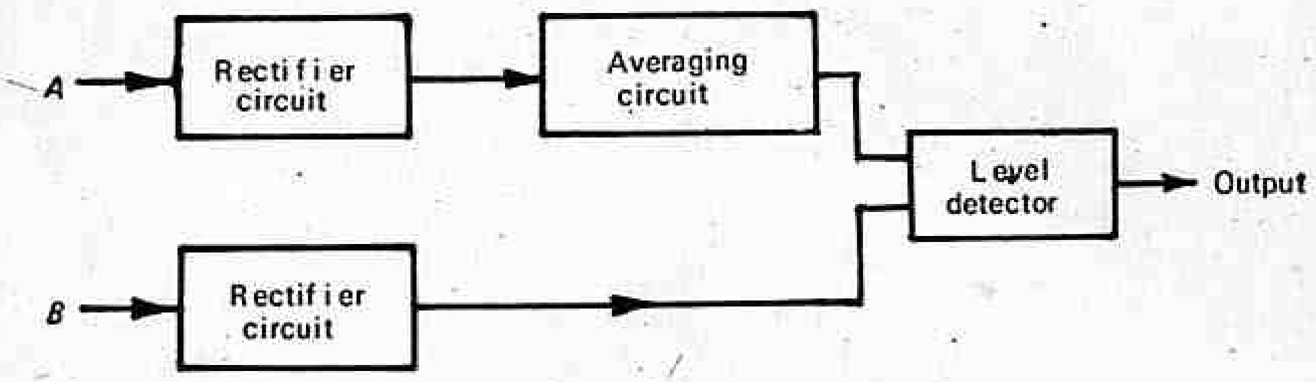


FIGURE 11.6 Block diagram of averaging type instantaneous amplitude comparator.

Here the input is split into six components 60° apart, so that it is smoothed within 5%. The averaging circuit can be eliminated. The operating time here is determined by the time constant of the slowest arm of the phase-splitting circuit and by the speed of the output device.

11.1.3 Sampling Comparators

Sometimes it is convenient to get the required characteristics by comparing the magnitude of one input signal at a certain point on its wave against the rectified and smoothed value of the second signal. Reactance characteristic is one such case where the instantaneous value of the voltage at the moment of current zero is compared against the rectified and smoothed value of current. If current I lags behind voltage V by an angle ϕ then the value of voltage at current zero is $V_m \sin \phi$.

The reactance relay operates for $X<K$, i.e.

$$Z \sin \phi < K$$

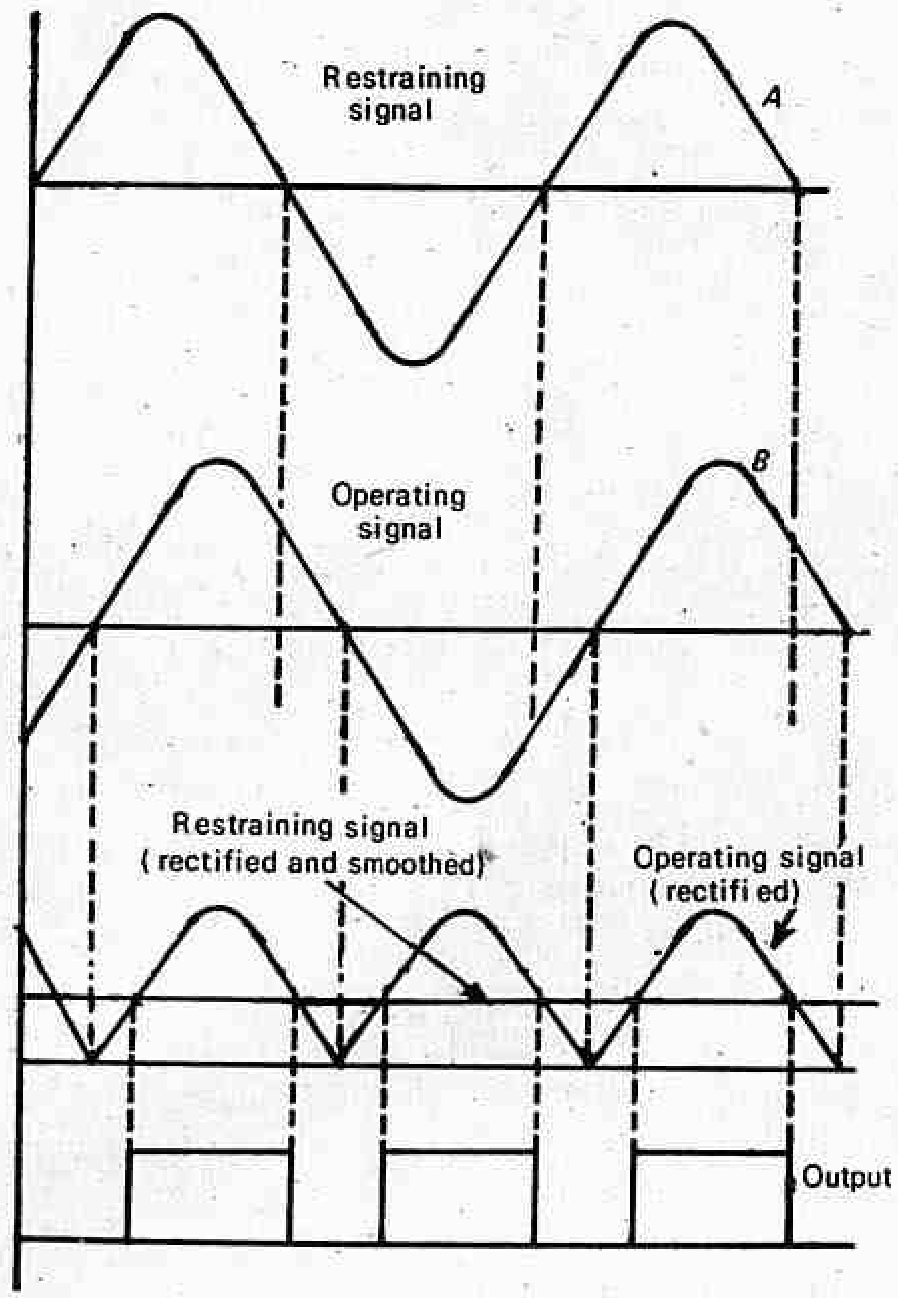


FIGURE 11.7 Wave shapes of an instantaneous amplitude comparator.

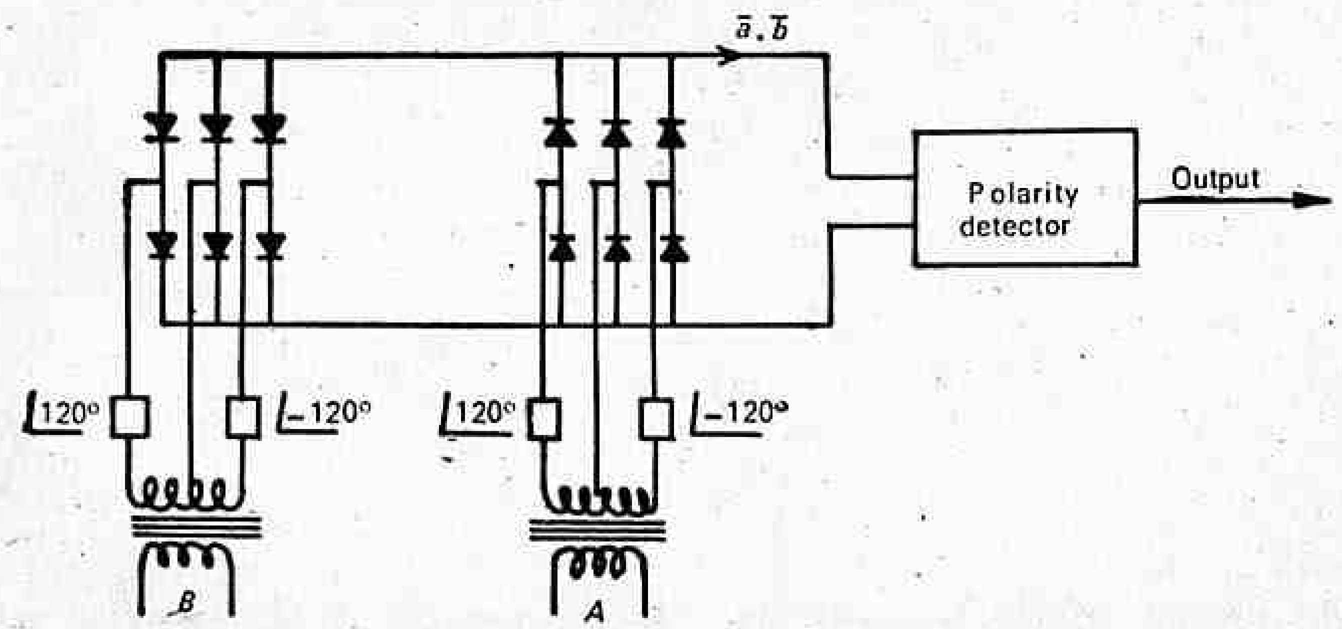


FIGURE 11.8 Phase splitting of inputs to amplitude comparator.

or $$\frac{V}{I}\sin\phi<K$$

or $$\frac{V_m}{\sqrt{2}}\sin\phi<KI_{avg}\times 1.11$$

or $$V_m\sin\phi<K'I_{avg}$$

The block schematic diagram is shown in Fig. (11.9).

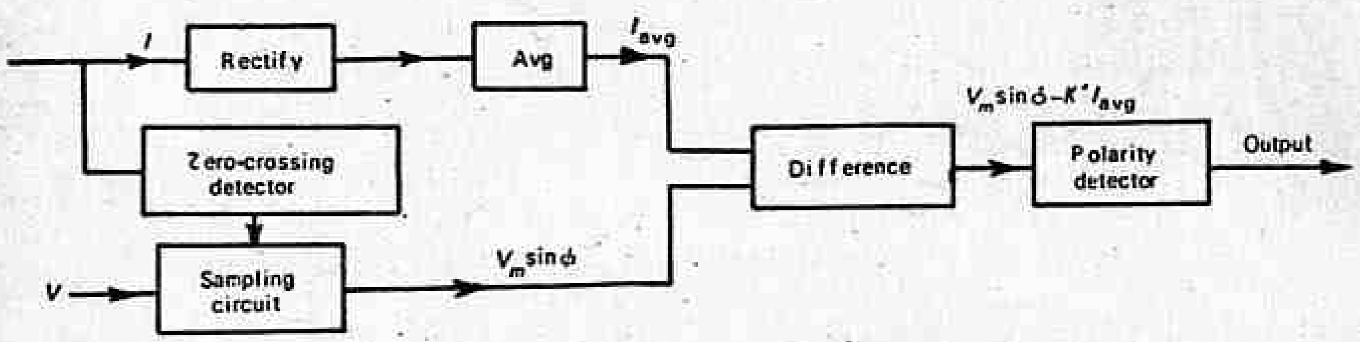


FIGURE 11.9 Block diagram for a reactance relay comparing the instantaneous value of voltage at current zero with average current.

It is also possible to compare the instantaneous magnitude of one signal at a certain moment with the instantaneous magnitude of the second signal at that very moment or at certain other moment. It simply means that one or both signals can be sampled.

For the same reactance relay of the previous case, for operation, we have

$$X<K$$

i.e. $$Z\sin\phi<K$$

or $$\frac{V}{I}\sin\phi<K$$

or $$\frac{V_m}{\sqrt{2}}\sin\phi<K\frac{I_m}{\sqrt{2}}\cdot\frac{\sin\alpha}{\sin\alpha}$$

or $$V_m\sin\phi<K'I_m\sin\alpha$$

Figure (11.10) shows the voltage and current waveforms.

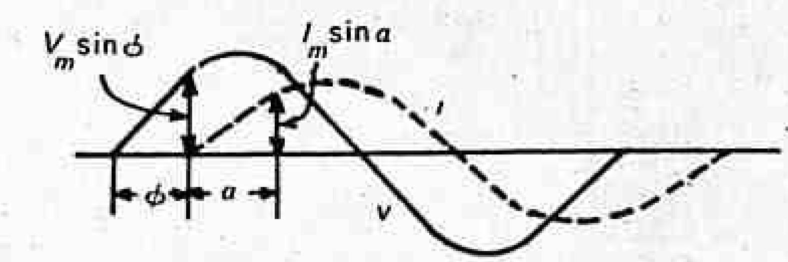


FIGURE 11.10 Voltage and current waveforms of reactance relay.

Comparison of two instantaneous magnitudes here is made by converting the magnitudes into proportional pulse widths and then comparing with

the help of an AND gate. If the two samples are taken at different instants, the pulse width representing the one taken first in time sequence is delayed by the time difference between the two sampling instants, before feeding to the AND gate. The scheme is represented in block diagram in Fig. (11.11), and Fig. (11.12) shows the wave forms.

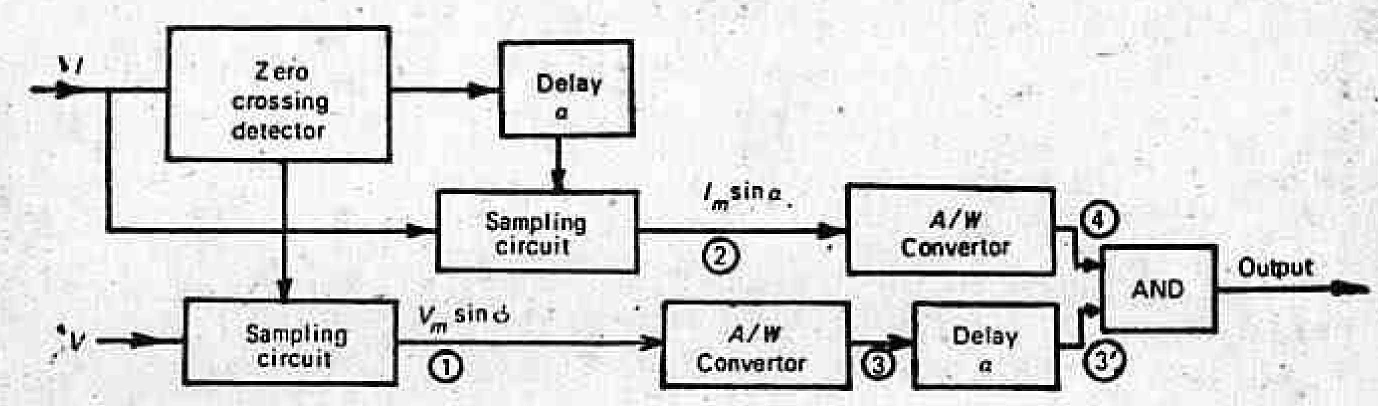


FIGURE 11.11 Block schematic of sampling technique.

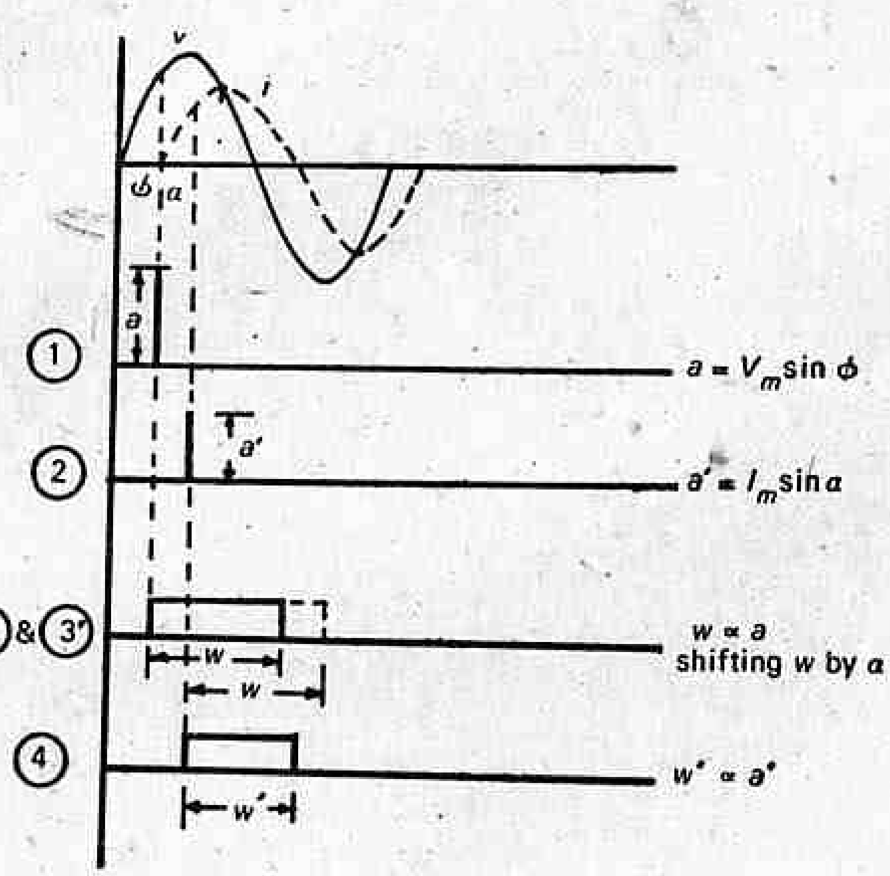


FIGURE 11.12 Wave forms illustrating sampling technique principle.

By using sampling techniques we can dispense with the phase shifting and mixing circuits. The elimination of phase shifting and mixing facilities requires a greater degree of sophistication in the relay circuitry but achieves a saving in both space and cost. The measuring circuits are isolated from the transformer secondaries, except during the 50 μs sampling period in each half cycle, and the possibility of maloperation due to spikes on the input wave forms is remote.

11.2 Phase Comparator

Phase comparison technique is the most widely used for all practical directional, distance, differential and carrier relays. If the two input signals are S_1 and S_2 the output occurs when the inputs have a phase relationship lying within specified limits. Both inputs must exist for an output to occur; ideally, operation is independent of their magnitudes, and is dependent only on their phase relationship. Fig. (11.13) illustrates the phase comparator in its simple form. The function as defined by the boundary of marginal operation is represented by two straight lines from the origin of the complex plane.

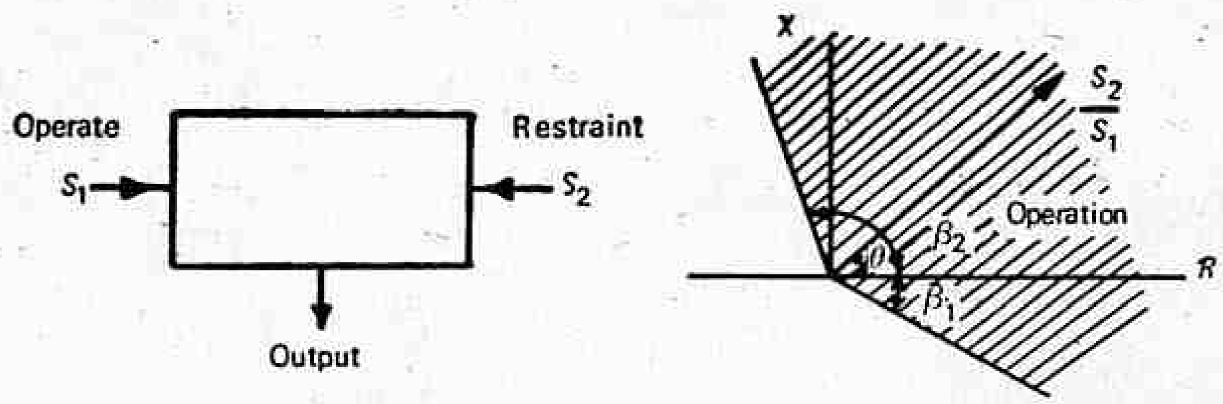


FIGURE 11.13 Phase comparator output when angle θ between S_1 and S_2 is within limits β_1 and β_2.

The condition of operation can be put mathematically as

$$-\beta_1 \leqslant \theta \leqslant +\beta_2$$

where θ is the angle by which S_2 leads S_1. If $\beta_1 = \beta_2 = 90°$ the comparator is known as cosine comparator and if $\beta_1 = 0$ and $\beta_2 = 180°$ it is a sine comparator.

Static phase comparators may be of the following types:

(a) Vector product comparator.
(b) Coincidence type phase comparator.

Amongst the vector product comparators are the Hall effect phase comparator and the magneto-resistivity phase comparator. These have already been discussed in Chapter 9.

11.3 Coincidence Type Phase Comparator

The basic concept of phase comparison is simpler in that it is possible to deal with signals of equal strength whose coincidence (or noncoincidence) is readily measurable. Considering two sinusoidal signals S_1 and S_2, the period of coincidence of S_1 and S_2 will depend on the phase difference

between S_1 and S_2. Figure (11.14) illustrates the coincidence of signals for different phase relationships.

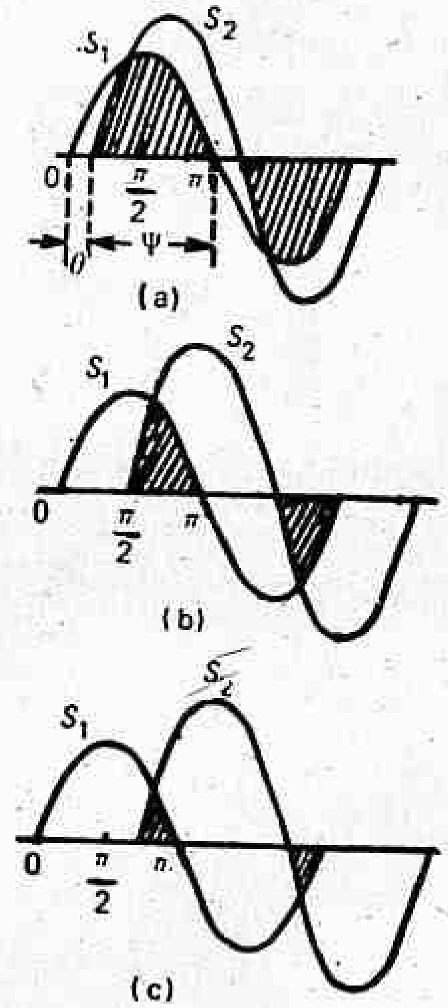


FIGURE 11.14 Coincidence of signals: (a) S_2 lagging S_1 by less than $\pi/2$; (b) S_2 lagging S_1 by $\pi/2$; (c) S_2 lagging S_1 by more than $\pi/2$.

It can be seen that the period of coincidence is equal to the period of noncoincidence for a phase difference of $\pm 90°$, the period of coincidence is less than the period of noncoincidence and vice versa when the phase difference is less than $\pm 90°$.

Depending upon the phase relation of the input signals it is possible to design the circuit to give an output a Yes or a No, by measuring the period of coincidence.

The period of coincidence of two signals with a phase difference of θ is $\psi = 180 - \theta$. Different techniques can be employed to measure the period of coincidence; the more important ones are described below.

11.3.1 Direct Phase Comparison

The number of basically different methods of obtaining useful characteristics from a direct phase comparator circuit is confined to the following:

(i) *Block instantaneous comparison* in which the duration of polarity coincidence determines the output. The tripping criterion is that the duration of the first coincidence should exceed a specified time, usually one quarter of the power-frequency period.

(ii) *Pulse comparison* in which the polarity of one signal is measured during a short interval in the cycle of the second signal, usually, but not necessarily at the latter's peak.

The block diagram of the pulse type of relay is shown in Fig. (11.15). Line voltage and current are applied to two measuring circuits, which produce complex output voltages.

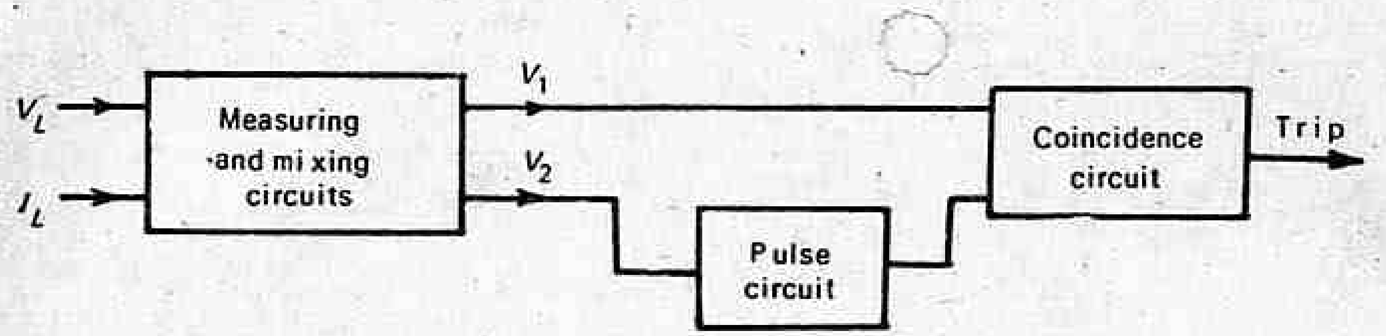


FIGURE 11.15 Block schematic of pulse relay.

Voltage V_2 is applied to a pulsing circuit which produces a positive pulse once every cycle, when V_2 is at its positive maximum. V_1 and the pulse derived from V_2 are then applied to the terminals of a coincidence circuit of the type requiring both input terminals to become positive before producing any potential change at its output terminals. The criterion for relay operation is thus defined, since the coincidence circuit only yields an

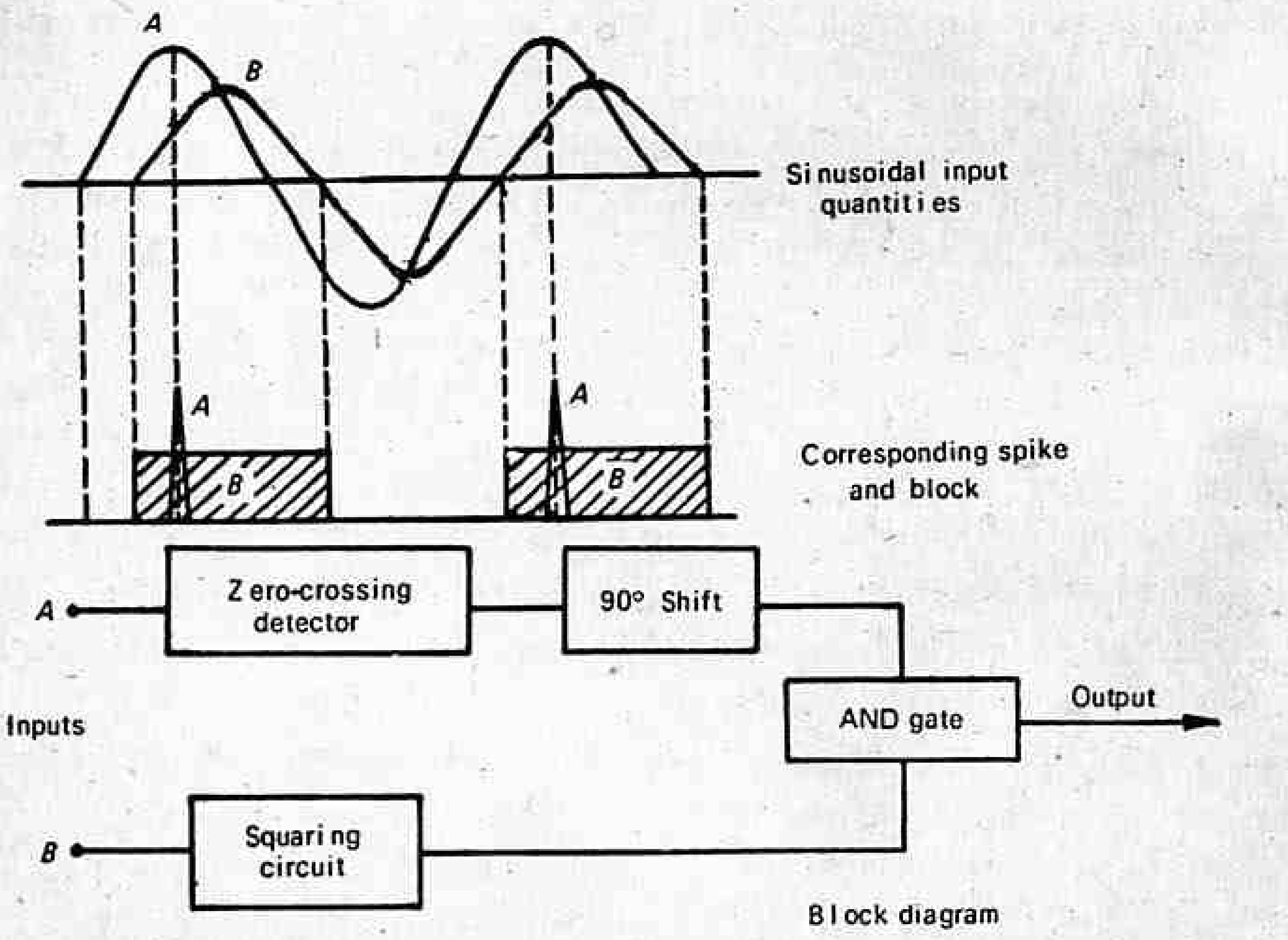


FIGURE 11.16 Block diagram and wave forms of block spike method.

output when the pulse is present, and then only if V_1 is positive at this instant. If θ is the angle between V_1 and V_2, it follows that $-90° \leqslant \theta \leqslant +90°$ for V_1 to be positive at the instant of V_2 maximum.

Another method for direct phase comparison is by block spike method. In this method one input is *squared* and the other turned into a spike preferably at the instant of its peak value; the spike and block signals are then fed through an AND gate. Coincidence of input signals occurs only for $-90° \leqslant \theta \leqslant +90°$. Figure (11.16) illustrates the schematic block diagram and wave forms.

11.3.2 Phase Splitting Technique

In this method two phase shifted components ($\pm 45°$) are obtained for each of the input signals and, these four components are fed to an AND gate. An output results if all the four are simultaneously positive at any time in the cycle. Referring to Fig. (11.17) it can be seen that output will be obtained for $-90° \leqslant \theta \leqslant +90°$. The block schematic is also shown in Fig (11.17).

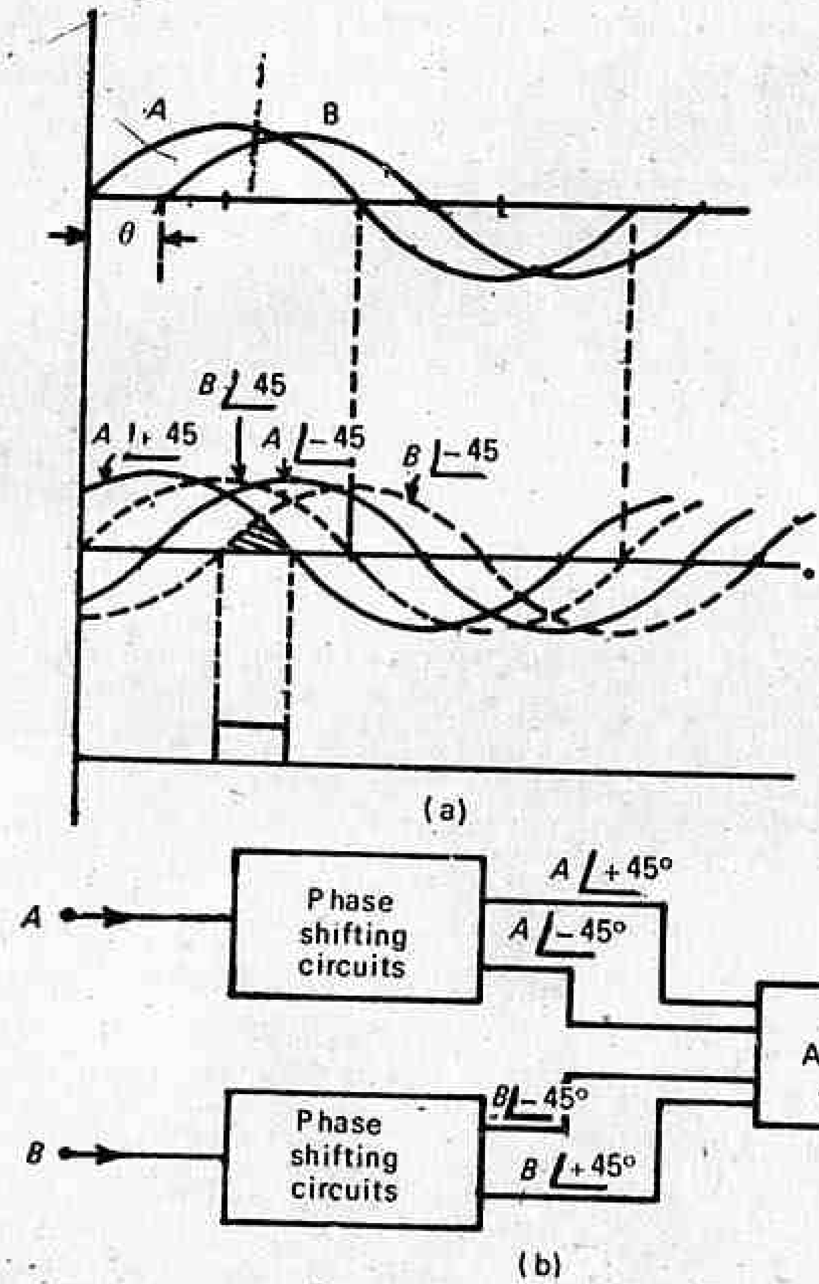


FIGURE 11.17 Phase comparator with phase split inputs: (a) wave forms; (b) block schematic.

Because of the time constants of the phase shifting circuits the method is slightly slower than the previous method. By using two such comparators —one for each polarity—the time of operation can be reduced to less than half a cycle.

11.3.3 Integrating Phase Comparison

In this method the time overlap of the two sinusoidal inputs is measured for each cycle by integrating the output of an AND gate through which they are fed. The period of coincidence is measured, and only if it exceeds 90° (for a symmetrical comparator) the output is obtained, so that the condition is $-90° \leqslant \theta \leqslant +90°$.

In earlier integrating phase comparators transistor-type AND gate was employed. In recent types the periods of coincidence are integrated and then fed into a level detector, the critical operating threshold of which occurs when the periods of coincidence and noncoincidence are equal, i.e. $\theta = \pm 90°$. Figure (11.18) shows the basic arrangement for the integration of coincidence blocks.

The input quantities S_1 and S_2 are compared in a coincidence circuit producing standard output pulses, which are positive when S_1 and S_2 are of the same polarity and negative when they are of opposite polarity. The pulses are applied to an integrating circuit whose output increases linearly

FIGURE 11.18 Block schematic for integration of coincidence blocks.

during the time when the pulse is positive and falls at the same rate when the polarity reverses. The level detector switches when the integrator output exceeds some preset value; and resets when the output falls below some second value. The operation resulting from differing coincidence periods is illustrated in Fig. (11.19). The rise and fall rates in the integrator are at the designer's disposal, so that the critical phase angle may be set to any desired value. Both the level detector set and reset levels are critical in relation to the total excursion limits of integrator linearity and also to the slope of the output.

Another integrating phase comparator uses rectifier bridge AND gate. This has advantage in its simplicity and economy. This uses a rectifier

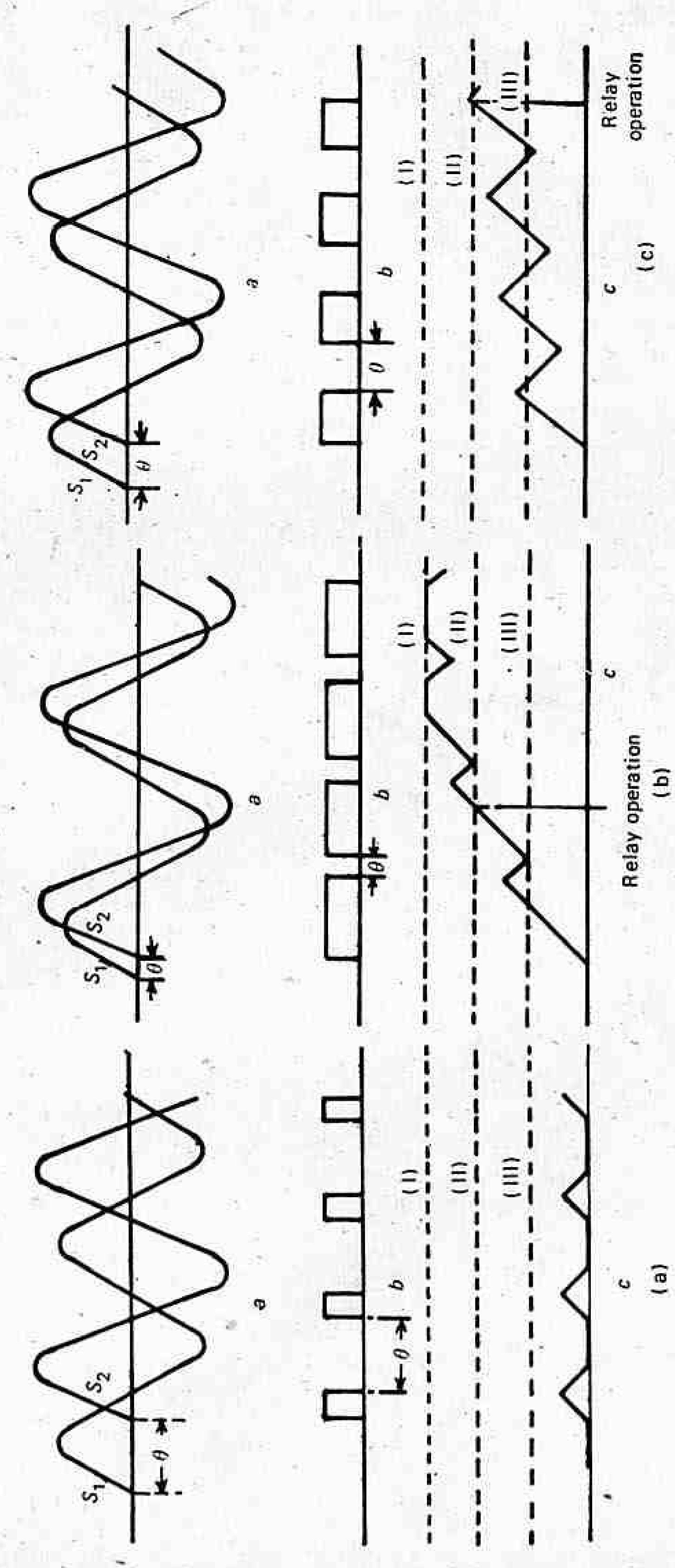


FIGURE 11.19 Effect of varying periods of coincidence: (a) $\theta > \pi/2$; (b) $\theta < \pi/2$; (c) $\theta = \pi/2$; (a) input signals to coincidence circuit; (b) output from coincidence circuit; (i) upper limit; (ii) set level; (iii) reset level; (c) integrator output;

bridge with a consequent polarity, detection circuit. The basis circuit is shown in Fig. (11.20) which uses inputs in the current form.

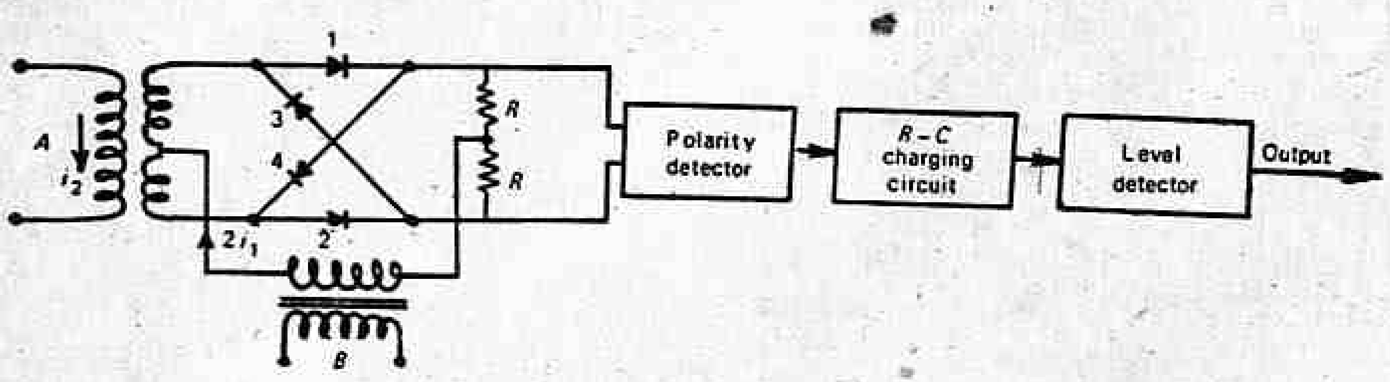


FIGURE 11.20 Basic circuit of an integrating phase comparator using rectifier bridge AND gate.

The output current of the rectifier bridge supplied to a centre tapped resistance *R-R* is at any moment equal to the smaller of the two input currents. The path of the current through the bridge is established by the larger of the two currents and depends upon their relative instantaneous polarity. If $i_1 > i_2$ the current will flow in rectifiers 1 and 2 if i_1 is positive, and in rectifiers 3 and 4 if i_1 is negative. If $i_2 > i_1$ the current flows in rectifiers 1 and 4 if i_2 is positive and rectifiers 2 and 3 if i_2 is negative. If i_1 and i_2

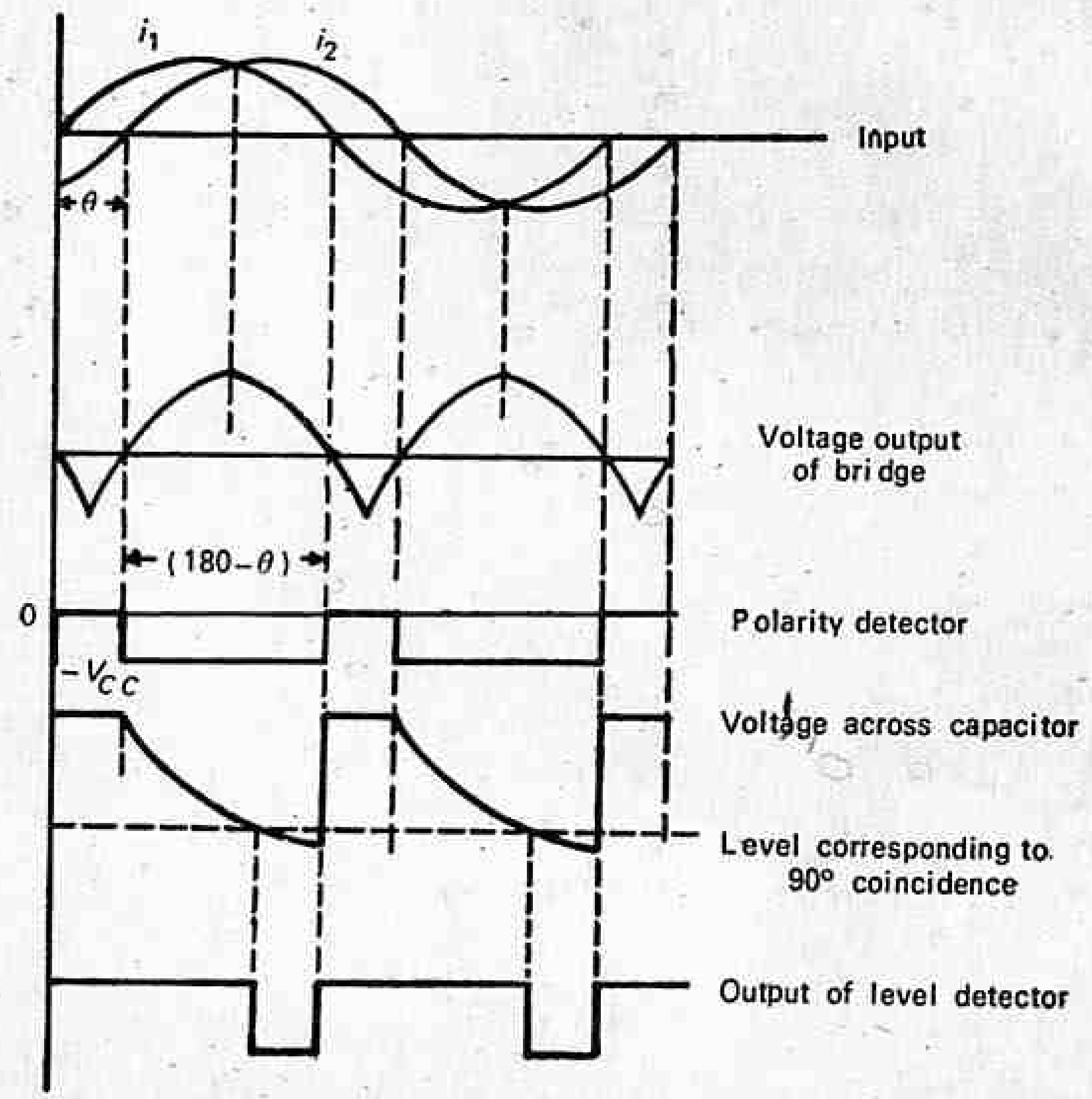


FIGURE 11.21 Waveforms of an integrating phase comparator.

have the same polarity the voltage across *R-R* (output voltage) is positive, whereas this is negative if the two currents have opposite polarities (see Fig. (11.21)). In other words the output voltage is positive during positive and negative coincidence periods; and negative during the period of anti-coincidence (opposite polarities). The time of operation with single bridge is less than half a cycle.

QUESTIONS

1. Describe different types of static amplitude comparators. Discuss their relative advantages and disadvantages.
2. In what respect are static comparators more convenient than electromagnetic comparators? How are the composite signals derived in a system to be fed to the comparator?
3. What are the different types of phase comparator? Describe the coincidence type of phase comparator.
4. What are the special applications of phase comparators? Discuss the characteristics of sine and cosine comparators.

CHAPTER **12**

Basic Static Relays Used in Protective Schemes

It has been pointed out earlier that the static relays are very flexible, and are so suited to rationalization that the concept of a range of standardized functional elements, with its advantage to both manufacturer and user becomes a practical aim. Static relays can achieve such a high performance that the practical departures from the ideal may be negligible.

12.1 Basic Elements of a Static Relay

The basic elements of a static relay are described below.

12.1.1 Input Element

Mixing circuits are needed to sum the input singals in a convenient form. Semiconductor circuits are suited to the use of summing junctions, well-known in the analog computing field. Use of operational amplifier as a summer or mixer has already been discussed in an earlier chapter. These input singnals are derived from CTs and PTs.

12.1.2 Measuring Element

This is the most important element as far as relay operation is concerned since this sends the deciding signal to the output circuit for operation or nonoperation of the relay.

Measuring element may be either (i) single-input device, (ii) two-input device or (iii) multi-input device.

Two-input devices are most common and are basically comparators, which have already been discussed in detail; multi-input devices are the extension of two-input devices to extend the range of complex characteristics.

Special characteristics such as parabolic, elliptical, quadrilateral, etc., can be obtained. A detailed discussion on this will be done at a later stage. Here only single-input device will be considered in brief.

Single-input devices form the basis of many protection and control schemes and may be subdivided as follows.

(a) *Noncritical Repeat Function* (*All or Nothing Relay*). These are either completely unenergized or energized considerably in excess of marginal conditions, to ensure a fast response with robust contact pressure. In Fig. (12.1), therefore, S is either zero or greater than marginal operation level. Devices of this type are generally instantaneous (20 ms or less) but they may be associated with a time function. They usually involve a switching power gain of 10^3, and have several outputs; i.e. contacts as shown in Fig. (12.1).

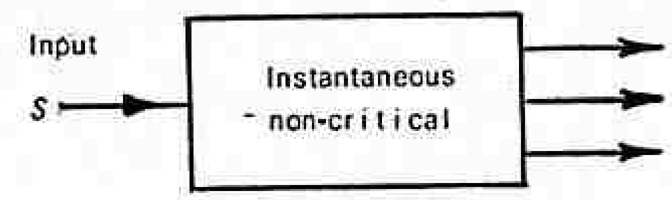


FIGURE 12.1 Noncritical repeat function.

The two main duties of these units in protection are:

(i) The provision of a final tripping signal to the circuit breaker and possibly supplementary functions of intertripping, alarm and indication.
(ii) acting as intermediate switching stages within an assembly of functional elements, i.e. a protective system.

(b) *Critical or Measuring Function.* This involves a response to an input when it exceeds a prescribed critical level.

For operation $S \geqslant A$ (critical level)
For reset $S \leqslant KA\ (K \leqslant 1)$

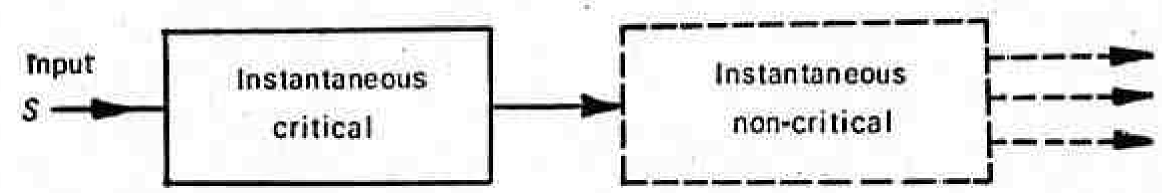


FIGURE 12.2 Critical or measuring function.

Switching gain need not be high as repeat devices can be provided.

Table 12.1 *Derived voltages for amplitude and phase comparators*

S. No.	Distance schemes	Amplitude comparator Operating	Amplitude comparator Restraining	Phase comparator Operating	Phase comparator Restraining
1	Directional	$\left\lvert I_L+\frac{V_L}{Z_R}\right\rvert$	$\left\lvert I_L-\frac{V_L}{Z_R}\right\rvert$	I_LZ_R	V_L
2	Plain-impedance	$\lvert I_L\rvert$	$\left\lvert \frac{V_L}{Z_R}\right\rvert$	$(I_LZ_R-V_L)$	$(I_LZ_R+V_L)$
3	Angle-impedance	$\left\lvert I_L-\frac{V_L}{Z_R}\right\rvert$	$\left\lvert \frac{V_L}{Z_R}\right\rvert$	$(I_LZ_R-V_L)$	I_LZ_R
4	Reactance	$\left\lvert I_L-\frac{V_L}{X_R}\right\rvert$	$\left\lvert \frac{V_L}{X_R}\right\rvert$	$(I_LZ_R-V_L\sin\theta)$	I_LZ_R
5	Conductance	$\left\lvert I_L-\frac{V_L}{R}\right\rvert$	$\left\lvert \frac{V_L}{R}\right\rvert$	$(I_LZ_R-V_L\cos\theta)$	I_LZ_R
6	Mho	$\lvert I_L\rvert$	$\left\lvert I_L-\frac{V_L}{Z_R}\right\rvert$	$(I_LZ_R-V_L)$	V_L
7	Offset mho	$\lvert I_L\rvert$	$\left\lvert \frac{V_L}{Z_R}-nI_L\right\rvert$	$[(I_LZ_R-V_L)\cos(\phi-\theta)]$	$(V_L+nI_LZ_R)$

discrimination at the relay location. A tripping output is derived only when both relays operate simultaneously and the resultant characteristic of the combination is then that area in the impedance axis that is common to the individual relay characteristics. Both mho and reactance relays give initial high-speed relaying, and then after a preset time delay the setting of the reactance relay is increased to give the zone 2 value and finally the mho relay trips on its own in zone 3 after the zone 3 time delay has elapsed.

Of particular importance to the correct operation of the scheme is the time coordination between the reactance and starting relays. If for example, a fault initially covered by the zone 3 characteristic, which prepares the protection to trip after the appropriate time delay, is then cleared from another location, and the system is consequently returned to healthy load conditions which correspond to a point in the impedance plane outside zone 3 but below the zone 1 reactance setting, clearly the zone 3 relay should reset before the zone 1 relay is permitted to measure.

The interconnection of the relays is shown in Fig. (12.22a). The zone 1 relay trips directly through contacts A, and the reach of this relay is increased after the zone 2 time delay. As in the directional-reactance scheme, the zone 3 characteristic initiates the zone time control, from which the zone 1 reach is switched to zone 2, and the zone 3 relay then trips through contacts B after the zone 3 time delay.

As each characteristic is derived from only one relay, the time coordination of the two relays that is required in directional-reactance scheme does not arise. However, the scheme may require reexamination in

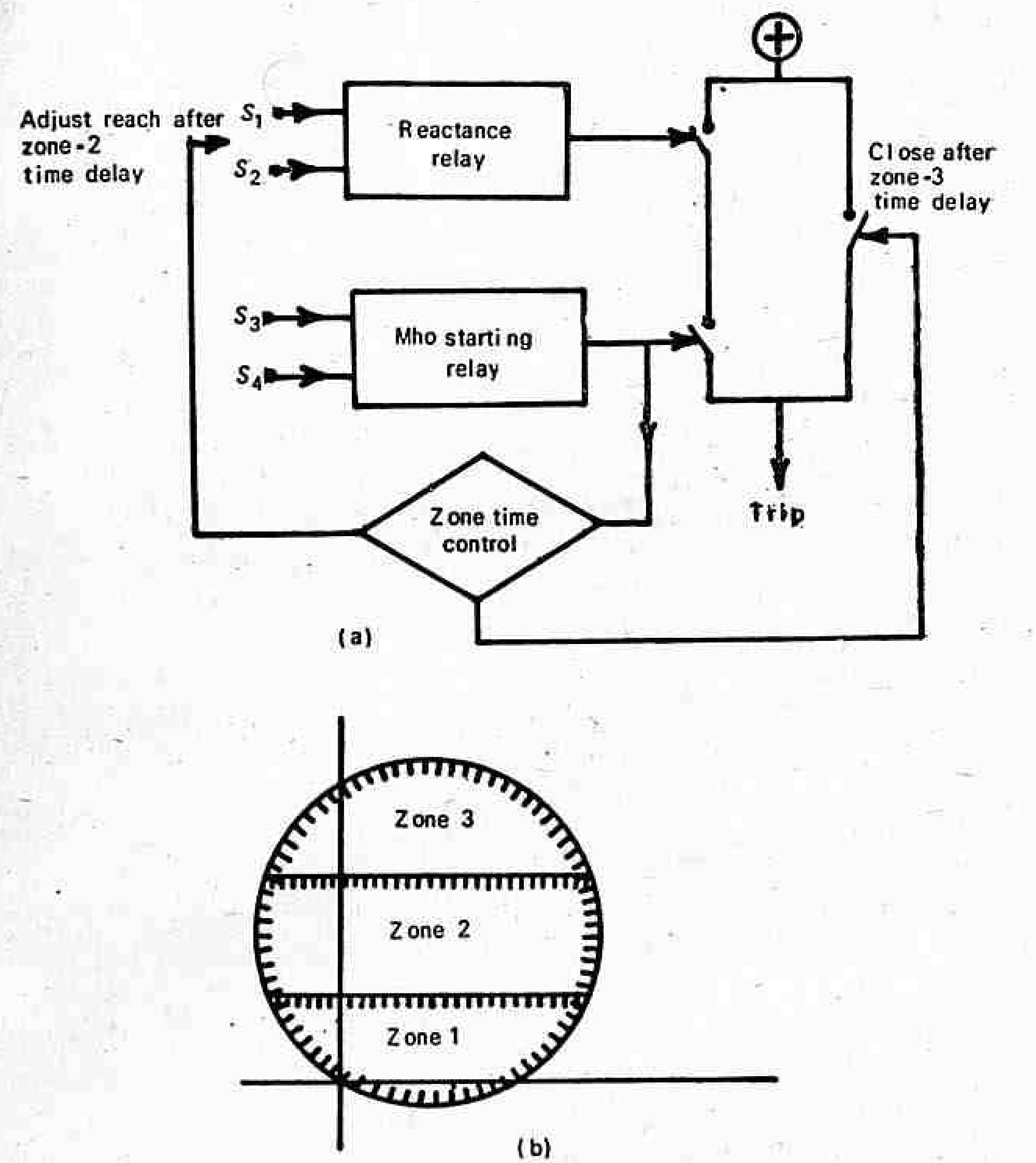


FIGURE 12.21 Elements of 3-zone directional reactance protection: (a) single-phase relay interconnections; (b) 3-zone polar characteristics.

relation to its application to primary transmission circuits having high power ratings, where the low impedance levels encountered under heavy load conditions may encroach upon the zone characteristics, particularly that in zone 3, and the protection may become more prone to incorrect tripping on fault recovery when synchronous plant is in an oscillatory mode of operation.

12.4.2 Complete Relay Interconnections

The combinations of relays shown in Figs. (12.21) and (12.22) may be repeated for each phase of the protected circuit for earth-fault protection,

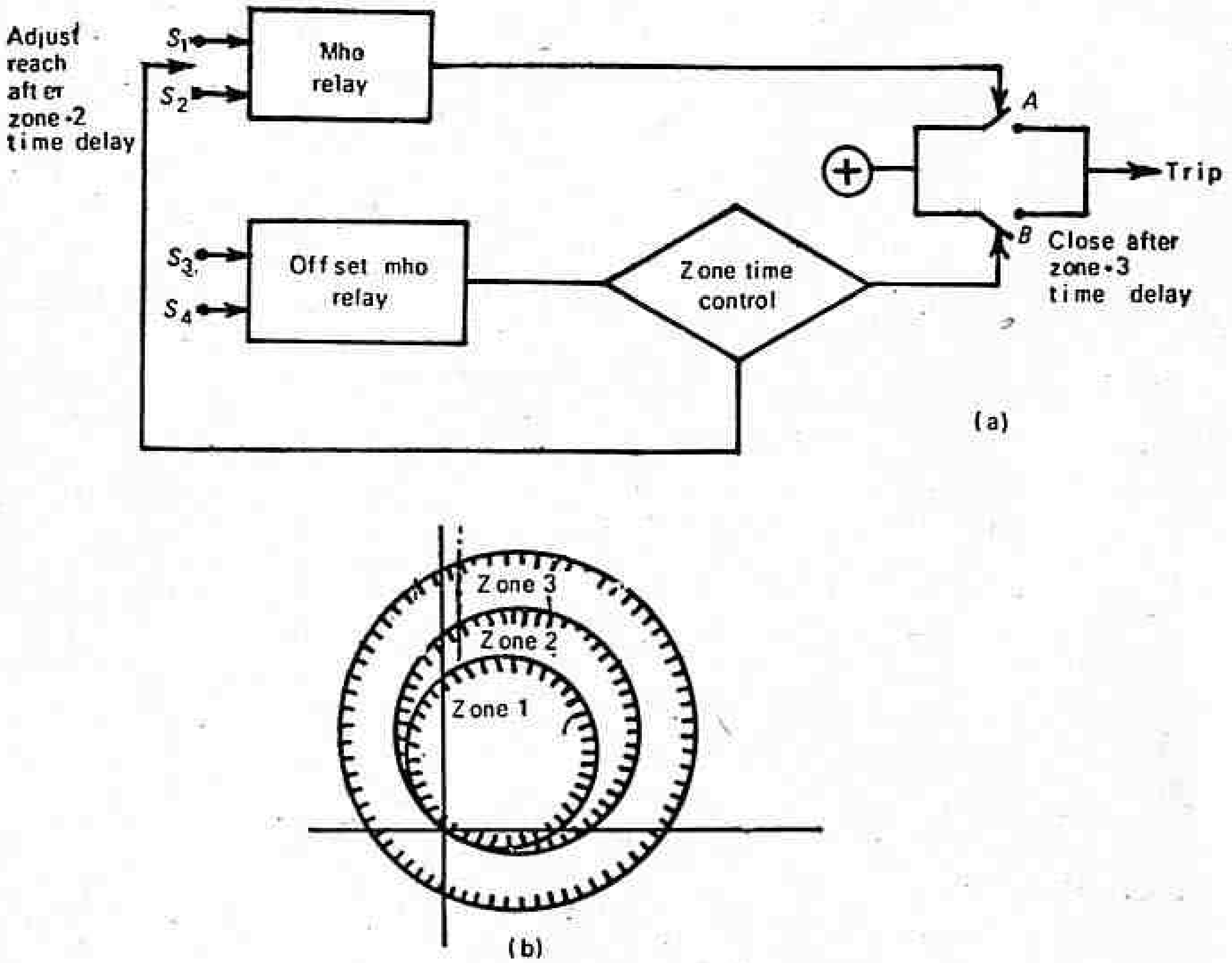


FIGURE 12.22 Elements of 3-zone mho protection: (a) single-phase relay interconnections; (b) 3-zone polar characteristics.

and a separate group of relays may be used for phased-fault protection to give a complete scheme. Some economy in relays may be achieved by switching relaying signals to fewer relays, according to the type of fault and the phase or phases involved.

12.4.3 Special Characteristics

Distance relay characteristics discussed so far are either straight lines or circular on the complex plane. Other figures or combination of straight lines and circle are also possible to achieve as operating characteristics. An example of this is shown in Fig. (12.23). Many special impedance characteristics have resulted, because of the limitations of the characteristics of distance relays already studied, for long lines which are heavily loaded and are operating at or near the stability limit, these may cause incorrect operation because they may fail to distinguish between power swings and faults. Some of the best known special characteristics are the swivelling characteristic, the conic section characteristic and the quadrilateral characteristic.

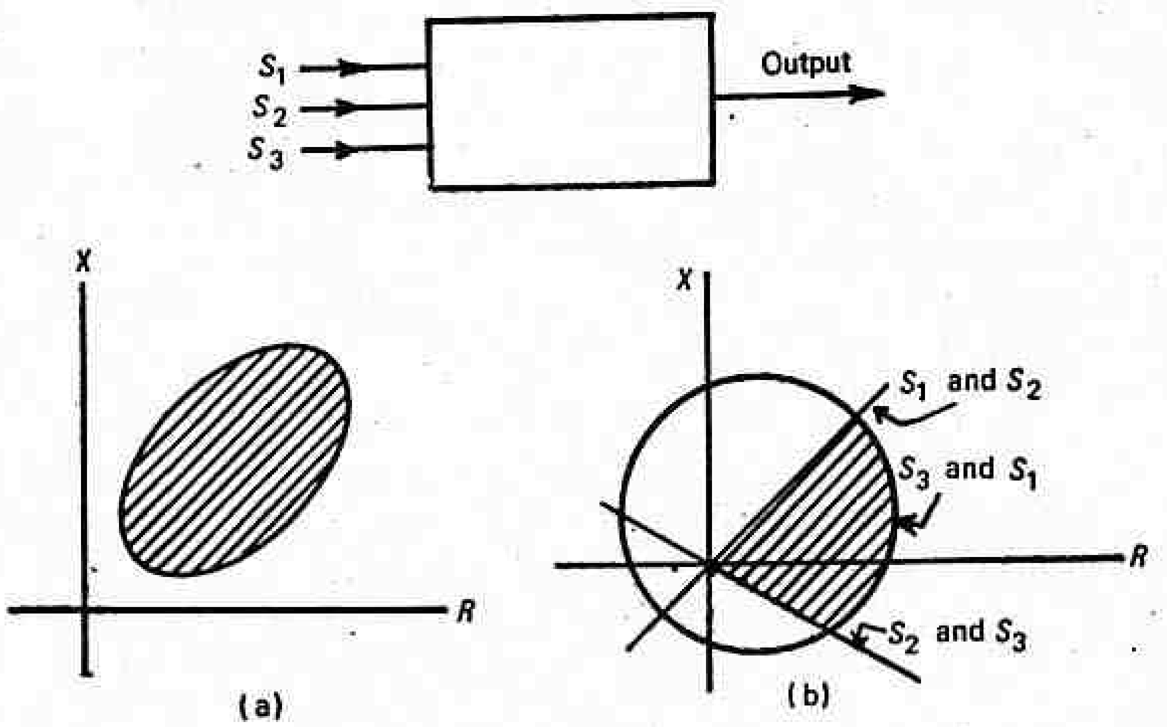


FIGURE 12.23 Multi-input device: (a) 3-input amplitude comparator; (b) 3-input phase comparator.

(a) *The Swivelling Characteristic.* The suitability of relay characteristics for the protection of transmission line depends on the nature of the line or the ratio Z_S/Z_L. For low Z_S/Z_L ratio, the impedance characteristics of the relay should be the circle and for high Z_S/Z_L ratio it should be a straight line. It would therefore be most desirable if the characteristics could be varied to suit the length of the line or Z_S/Z_L ratio. This is possible with the help of a polarized mho relay.

The polarized mho relay has an offset characteristic, in the case of unbalanced faults, which encloses the origin and hence enhances the relay

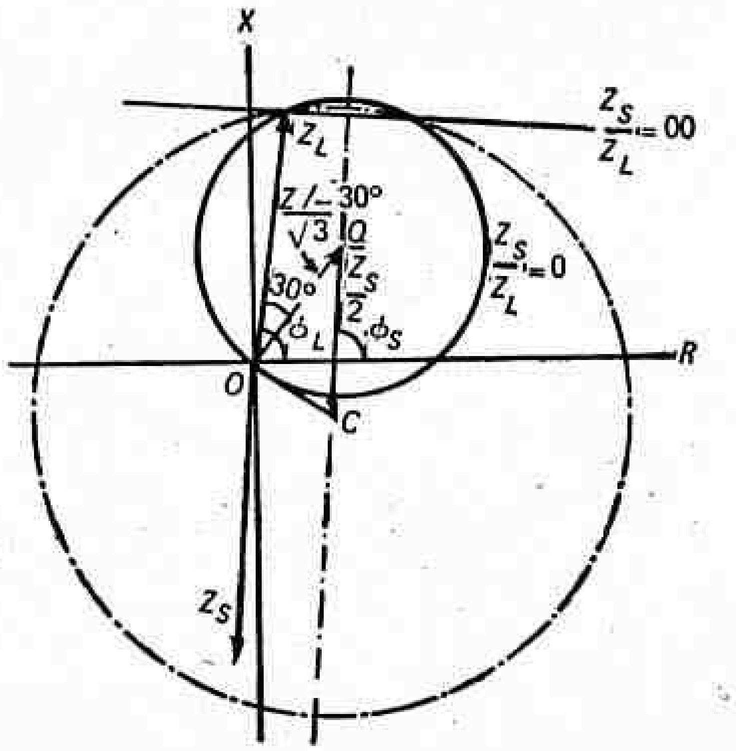


FIGURE 12.24 Swivelling mho characteristics interphase faults.

reach in the direction of resistance axis. The degree of offset is a function of Z_S/Z_L. Figure (12.24) shows the swivelling mho characteristic for interphase faults. Swivelling is not so effective with single phase ground faults, because the Z_S/Z_L ratio can be reduced by high ground resistance and there would be a tendency towards the mho characteristic just when the reactance characteristic is essential. Figure (12.25) illustrates swivelling mho characteristic for single-phase ground faults.

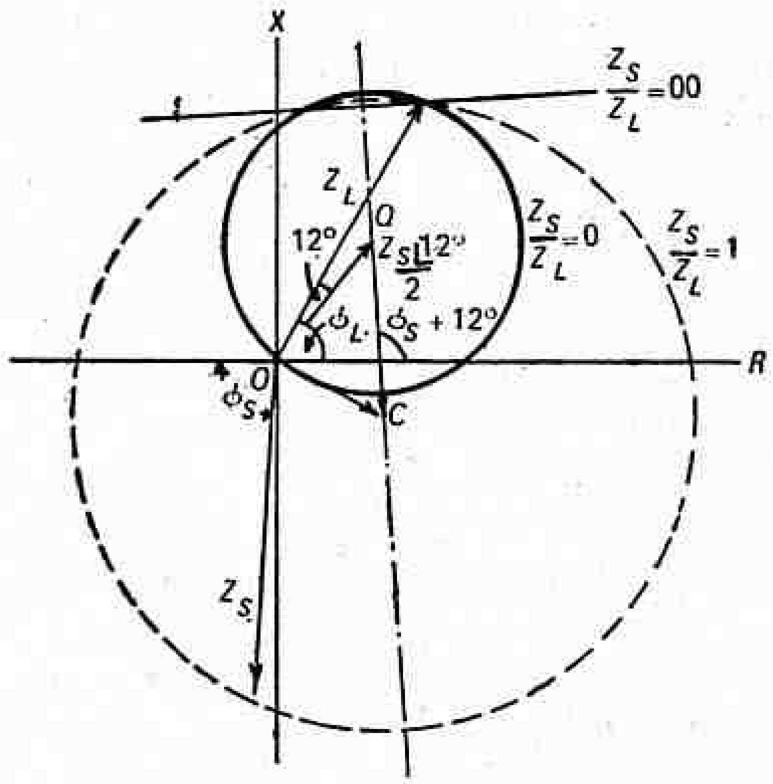


FIGURE 12.25 Swivelling mho characteristics for single-phase earth-faults.

(b) *Conic Section Characteristics.* Many of the limitations of the conventional distance relay characteristics are overcome by the use of other conic characteristics such as ellipses, parabolas, etc. This characteristic can be achieved by a three-input amplitude comparator or by hybrid comparator (combination of phase and amplitude comparator). The basic circuit for three-input amplitude comparator is shown in Fig. (12.26).

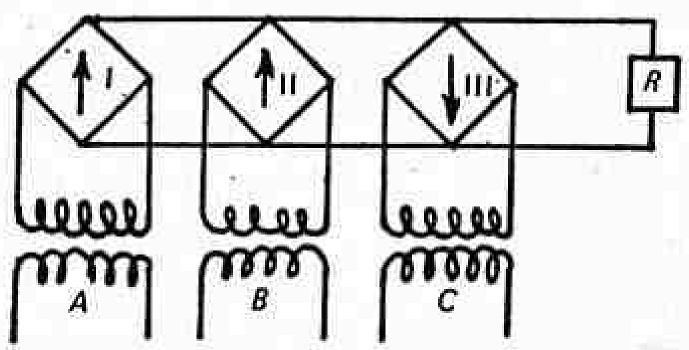


FIGURE 12.26 Three-input amplitude comparator.

$$A=\frac{V_r}{Z_1+Z_2}-I\frac{Z_1}{Z_1+Z_2}$$

$$B=\frac{V_r}{Z_1+Z_2}-I\frac{Z_2}{Z_1+Z_2}$$

$$C=I$$

where

V_r = fault voltage at the relay point

Z_1 and Z_2 = replica impedances

I = fault current

If Z_1 and Z_2 represent the vectors the tips of which coincide with the foci of the ellipse drawn on complex plane, and if $2a$ represents the major axis of ellipse then

$$|Z_L-Z_1|+|Z_L-Z_2|=|2a| \tag{12.14}$$

where Z_L is the line impedance.

If the characteristic is passing through origin as in Fig. (12.27) then

$$|Z_L-Z_1|+|Z_L-Z_2|=|Z_1+Z_2| \tag{12.15}$$

Multiplying Eq. (12.15) by I

$$|IZ_L-IZ_1|+|IZ_L-IZ_2|=|I(Z_1+Z_2)|$$

Putting $IZ_L=V_r$, we can write

$$|V_r-IZ_1|+|V_r-IZ_2|=|I(Z_1+Z_2)|$$

or

$$\left|\frac{V_r}{Z_1+Z_2}-I\frac{Z_1}{Z_1+Z_2}\right|+\left|\frac{V_r}{Z_1+Z_2}-I\frac{Z_2}{Z_1+Z_2}\right|=|I| \tag{12.16}$$

Equation (12.16) represents the operating characteristics of such a relay.

In the case of a hybrid comparator the general equation for a conic section is

$$Z=\frac{Z_r}{1-K\cos(\phi-\theta)} \tag{12.17}$$

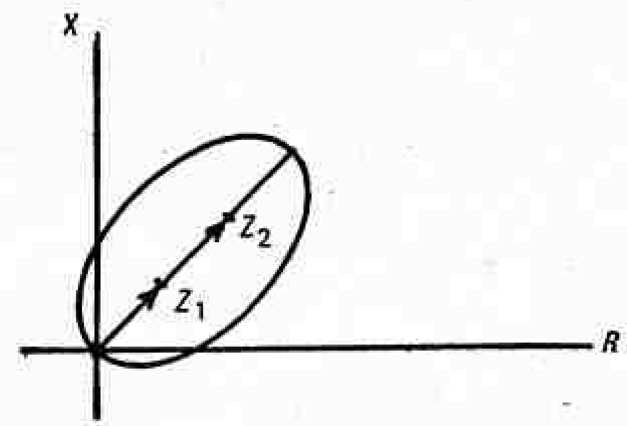


FIGURE 12.27 Elliptical characteristic.

Equation (12.17) represents an ellipse if $K<1$, a parabola if $K=1$, a hyperbola if $K>1$ and a circle if $K=0$.

The inputs necessary for obtaining the elliptical characteristic of Eq. (12.17) are IZ_r, V and $KV\cos(\phi-\theta)$. The first two inputs are fed directly to the amplitude comparator but the cosine term is obtained from an auxiliary phase comparator which uses the voltage IZ_r to polarize the line voltage V. The block schematic for this is shown in Fig. (12.28).

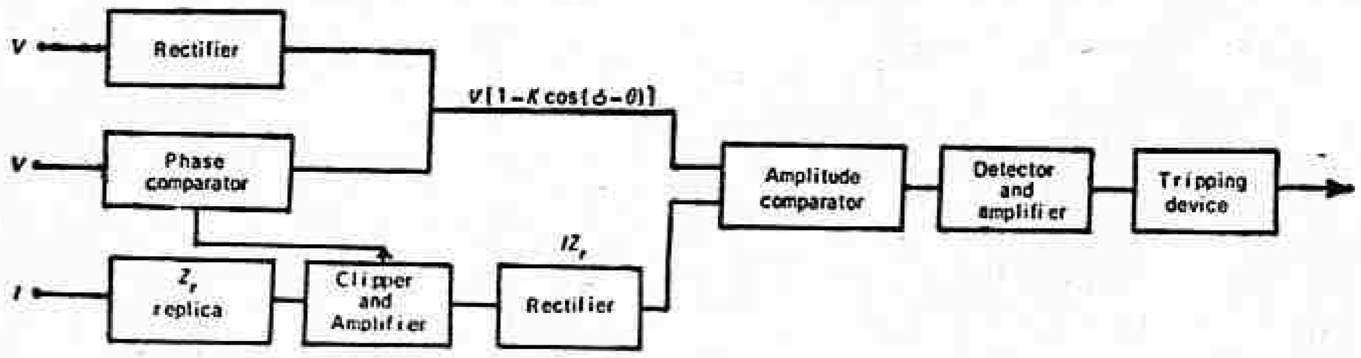


FIGURE 12.28 Block schematic of hybrid comparator for conic section characteristics.

(c) *Quadrilateral Characteristics.* It is possible to get this characteristic with four relays having straight line characteristic. The static arrangement for such a characteristic is very flexible and is easily realizable in two ways: (i) combination of two phase comparators and (ii) multi-input comparator.

(i) *Combination of two-phase comparators.* The quadrilaterial characteristic is obtained by two restricted directional units, one offset from the origin by the replica impedance Z_r. The relay trips if the impedance Z seen by the relay lies between the two relay characteristic, i.e. within the area $OBAC$ (Fig. (12.29)). Hence Z must be between OB and OC and $Z-Z_r$ must be between AB and AC. Such a comparator is not entirely free from transient overreach for faults occurring at voltage zero because Z_r is not a true replica impedance of the line. However this is not serious.

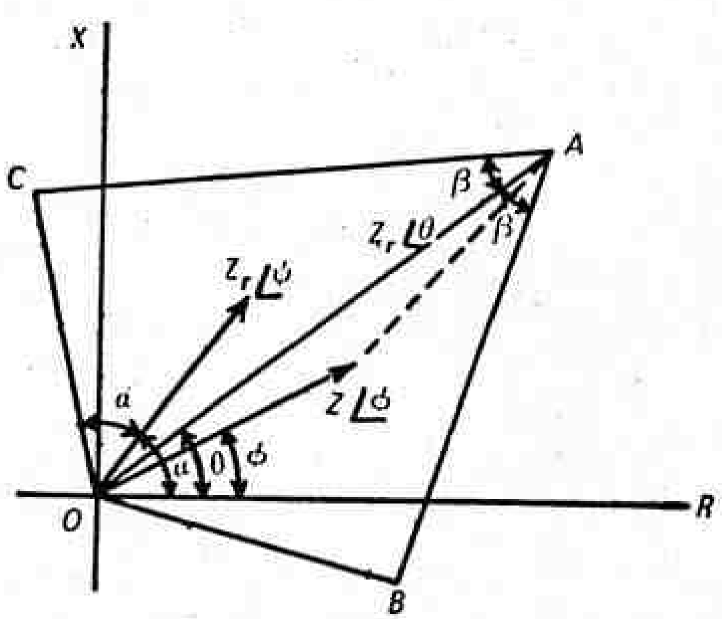


FIGURE 12.29 Quadrilateral characteristic.

(ii) *Four-input phase comparator.* The difficulty with the two comparators being used each with two-input is that the output of each comparator has to be prolonged for a short time because they may not occur at the same time. This results in wrong tripping. The single multi-input comparator avoids this trouble without loss of time. It trips immediately when all the conditions are satisfied simultaneously.

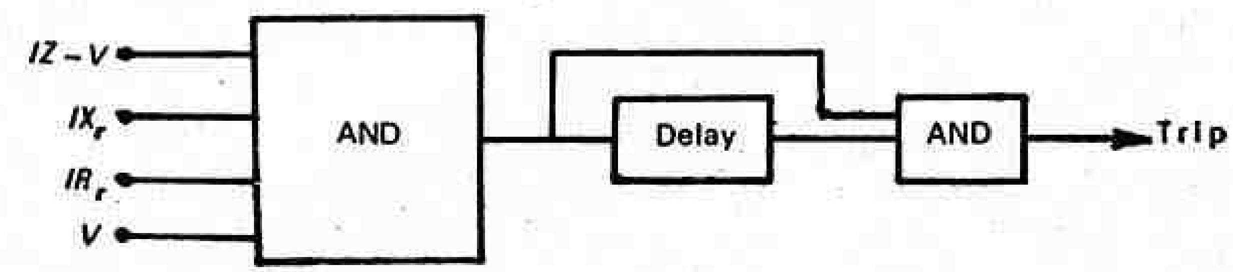
The four inputs required for a quadrilaterial characteristics are

$$S_1=Z_1I\angle(\theta_1-\phi)-K_1\angle\alpha_1 V$$
$$S_2=Z_2I\angle(\theta_2-\phi)$$
$$S_3=Z_3I\angle(\theta_3-\phi)$$
$$S_4=K_4\angle\alpha_4 V$$

To enclose the fault area:

$$Z_2=X_r,\ Z_3=R_r \text{ and } Z_1=R_r+jX_r=Z_r$$

This gives a composite impedance characteristic as shown in Fig. (12.30). The mho circle caused by the intersection of S_1 and S_2 will not



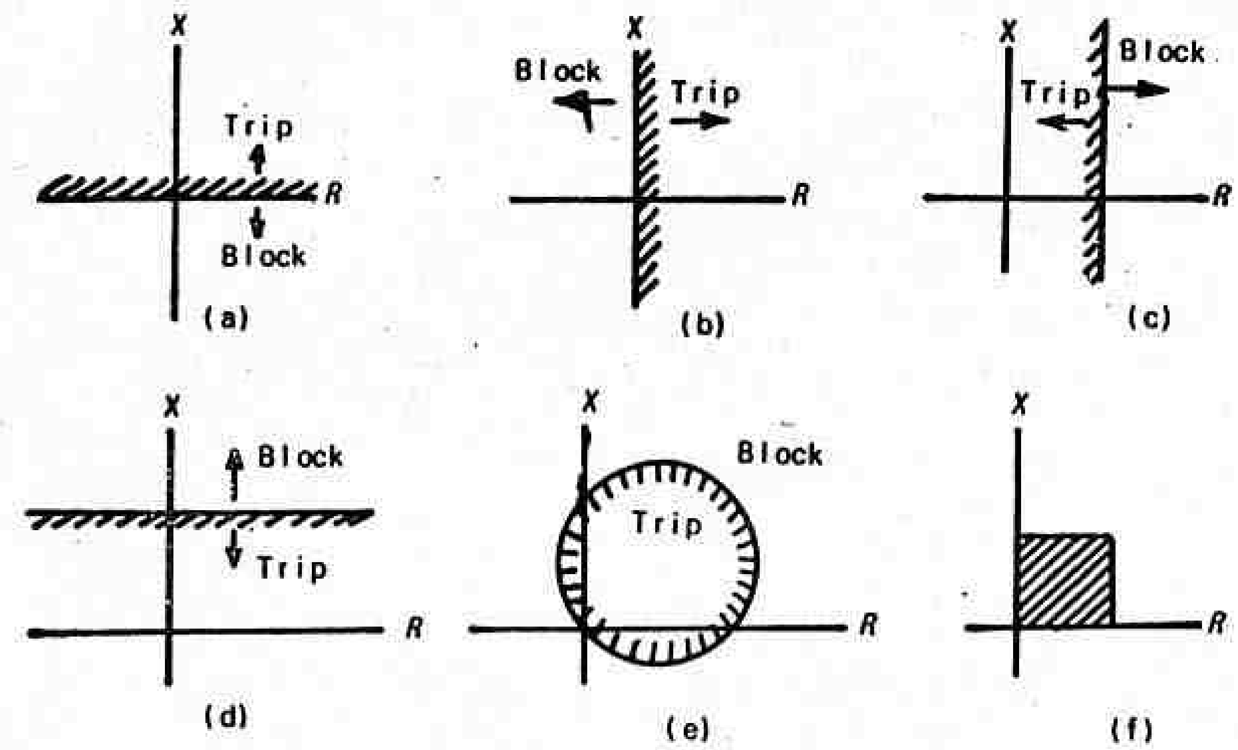


FIGURE 12.30 Four-input phase comparator: (a) IX_r and V; (b) IR_r and V; (c) IR_r and (IZ_r-V); (d) IX_r and (IZ_r-V); (e) V and (IZ_r-V); (f) composite characteristics.

interfere with the rectangular tripping area if $Z_r = R_r + jX_r$ because the circle of diameter Z_r goes through the corners of the rectangle bounded by R_r and X_r. Tripping occurs if all the equations resulting from comparison of all the inputs in pairs are simultaneously satisfied for the length of time set by the delay unit.

The unwanted mho circle resulting from the interaction of V and $(IZ_r - V)$ can be eliminated by making at least one of them a pulse. A quadrilaterial can be obtained by using a multi-input sine comparator with the following inputs:

Pulse input	IZ_r
Control input	V
	$V\angle -90°$
	$(IR_r - V)$

Tripping occurs if the IZ_r pulse occurs during the coincidence period of the three sinusoidal inputs. It can easily be seen that this occurs only for an internal fault.

QUESTIONS

1. What are the basic elements of a static relay? Describe the function of each element.
2. Describe the block schematic of static time-current relay. Discuss the time current characteristics mathematically for the standard time-current characteristics.
3. How can different distance relay characteristics be achieved with the help of amplitude as well as phase comparators?
4. Discuss the directional reactance scheme for distance protection.
5. Explain the advantages of elliptical and quadrilateral characteristics for distance protection. How is a quadrilateral characteristic obtained with the help of static comparators?

Practical requirements are accuracy, long term consistency, fast operation and a controllable reset ratio which should generally be high.

(c) *Fixed or Definite Time Function.* This function involves a fixed time delay between input and output. The delay may be between the application of an input and the occurrence of the output, or between the removal of the input and the resetting of the output. The input is noncritical, being either nothing or greatly in excess of the critical level. Practical requirements are accuracy of time setting and repeatability under successive energizations.

FIGURE 12.3 Fixed time function.

Practical static timers generally use the controlled charging time of a capacitor, and usually need an auxiliary d.c. supply.

(d) *Time Functions Dependent on Input.* The commonest form of characteristic is

$$t=f(S^n)$$

where n is negative (Fig. (12.4)). The relays in this category are the inverse definite-minimum-time lag (IDMT) overcurrent and earth-fault

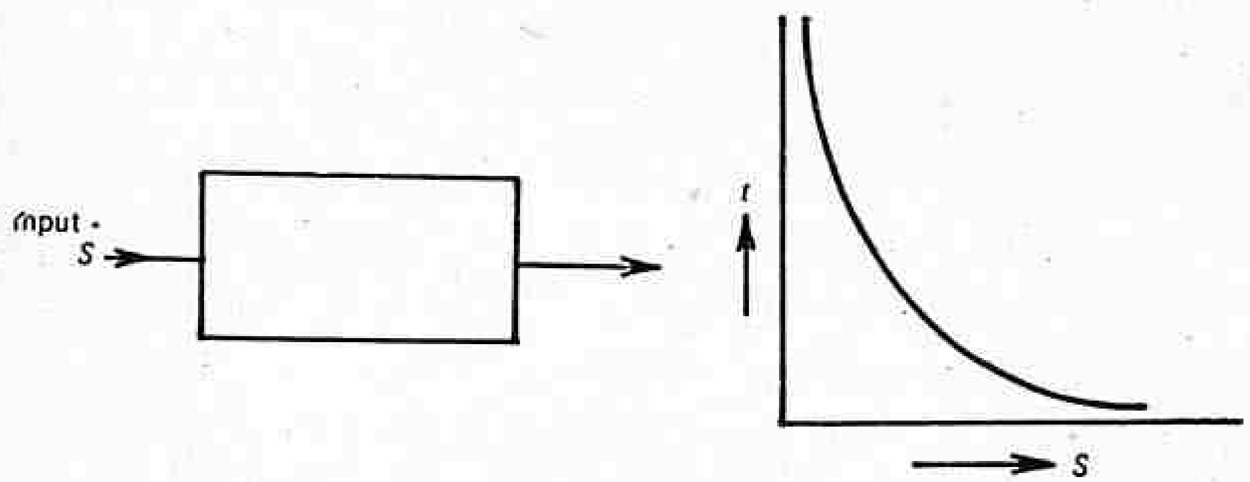


FIGURE 12.4 Time function dependent on input.

relays. The essential feature of such relays is that the operating time is inversely related to some power of the input signal magnitude. It is advantageous to choose a circuit which can accommodate a wide range of alternative inverse time characteristics, precise minimum operating levels, definite minimum times and, where necessary, additional high-set features as shown in Fig. (12.5).

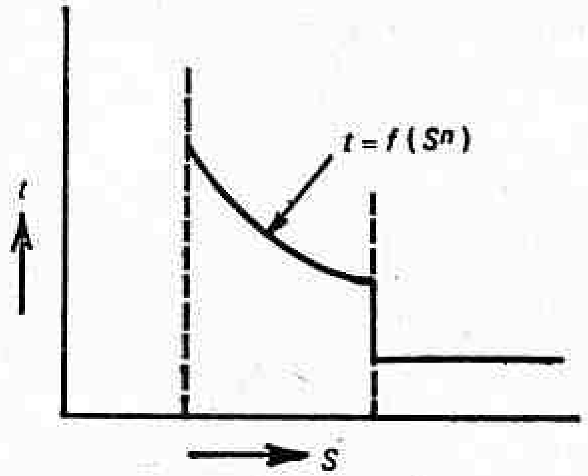


FIGURE 12.5 Combined functions.

12.1.3 Output Element

This element amplifies the binary signal, multiplies it and combines it with certain signals and delays it. It processes only binary signals, the quality requirements in relation to the measuring element are much less. This element can be constructed in a much more rugged and less trouble prone form.

12.1.4 Feed Element

This element provides the d.c. voltage required for transistors. Alternative means of the d.c. power supply are: (a) potentiometer across the station battery, (b) an auxiliary trickle charged battery and (c) rectification of PT or CT output.

12.2 Overcurrent Relays

The technique of overcurrent relaying is still widely used as a means of detecting faults on distribution system and on transmission lines fed from one end. In the case of lines fed from both the ends it is used along with directional relays. Overcurrent relays are also used in conjunction with distance relays to provide backup protection.

Fault current level detectors are termed overcurrent relays; in their static form they are more complicated as compared to their electromagnetic counterpart. The static form offers the following advantages over the electromagnetic form:

(i) Low burden on CT, so that smaller CTs are required.
(ii) Compactness of the unit and reduction in panel space.
(iii) Instantaneous reset possible because of the absence of moving parts, which facilitates the application of automatic reclosing of breakers.

(iv) Less maintenance, long life and not affected by shock and vibration.

(v) No overreaching tendencies and great accuracy of the characteristics.

In conventional overcurrent relays, it is assumed for all practical purposes that the time of tripping varies inversely as the operating current of the relay.

12.2.1 Operating Principles of Static Time-Current Relays

The static overcurrent relay consists of a rectifier unit which converts the a.c. signals to d.c. levels, followed by overload level detector timing circuit, level detector and a trip. Figure (12.6) represents the block schematic of a time-current relay.

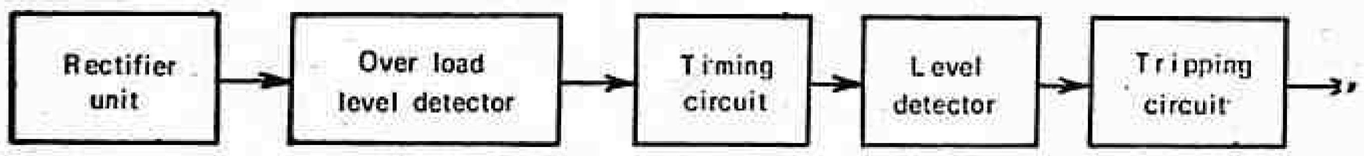


FIGURE 12.6 Block diagram of a time-current relay.

The current from the line CT is reduced to 1/1000th by an auxiliary CT, the auxiliary CT has taps on the primary for selecting the desired pickup and current range and its rectified output is supplied to an overload level detector and an RC timing circuit. When the voltage on the timing capacitor has reached the value for triggering the level detector, tripping occurs.

Several methods for timing and curve shaping are available. The timing capacitor is generally charged by a voltage derived from the CT current, e.g. from the voltage across a nonlinear resistor through which the rectified current flows. This also facilitates the shaping of the time-current characteristic to a desired curve by nonlinear resistors and RC networks.

12.2.2 Time-Current Characteristics

A general expression for the operating time of a time-current relay is:

$$t=\frac{KM}{I^n-I_P^n} \qquad (12.1)$$

where

t=time of operation in second

K=design constant

M=time multiplier setting (TMS)

I=multiple of tap current

I_P=multiple of tap current at which pickup occurs

n=index number which is empirical.

The nature of the curves and their degree of inverse characteristics have been standardized. According to British Standards following are the specified curves:

Standard inverse (IDMT), $t=\dfrac{0.14}{I^{0.02}-1}$ (12.2)

Standard very inverse, $t=\dfrac{13.5}{I-1}$ (12.3)

Standard extremely inverse, $t=\dfrac{80}{I^2-1}$ (12.4)

It can be seen that near about both the axes the curve become asymptotic in nature. This gives rise to two terms; the pickup current below which the relay practically does not operate and a definite minimum time of operation, which cannot be reduced further however high the relay current may be. These are clear from Fig. (12.7).

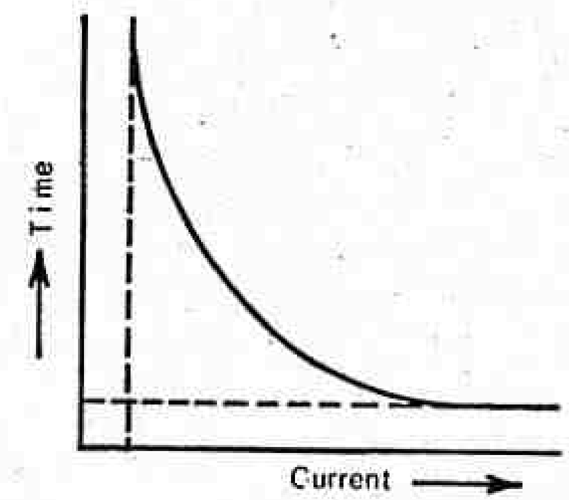


FIGURE 12.7 Inverse time current characteristics.

It is possible that future characteristics will be of the form $t=k/I^n$ which will give a straight line on a log t/log I graph. This curve therefore will no longer be asymptotic to the pickup value of current, the pickup will be controlled by a separate device, similarly the definite time portion of the characteristic can be provided by a separate unit.

12.2.3 Directional Overcurrent Relays

For obvious reasons of obtaining selectivity overcurrent relaying is made directional. The device reacts to the sign of the power which depends on the position of fault in relation to the point where the protective gear is installed. As the static comparators are very sensitive and it is comparatively easier to make a static directional unit reliable down to a voltage well below the minimnm fault voltage there is not much of a problem of discrimination at a low voltage.

Directional Units. Hall effect generator described in Chapter 9 which gives a linear cosine product output, and the rectifier bridge phase comparator described in Chapter 11 which has a cosine output limited by the rectifier characteristics are normally used as directional units. The Hall crystal as phase comparator has gained popularity only in U.S.S.R.

The operation of a rectifier bridge phase comparator has already been explained in Chapter 11. Figure (12.8) shows the block schemetic of a directional overcurrent relay.

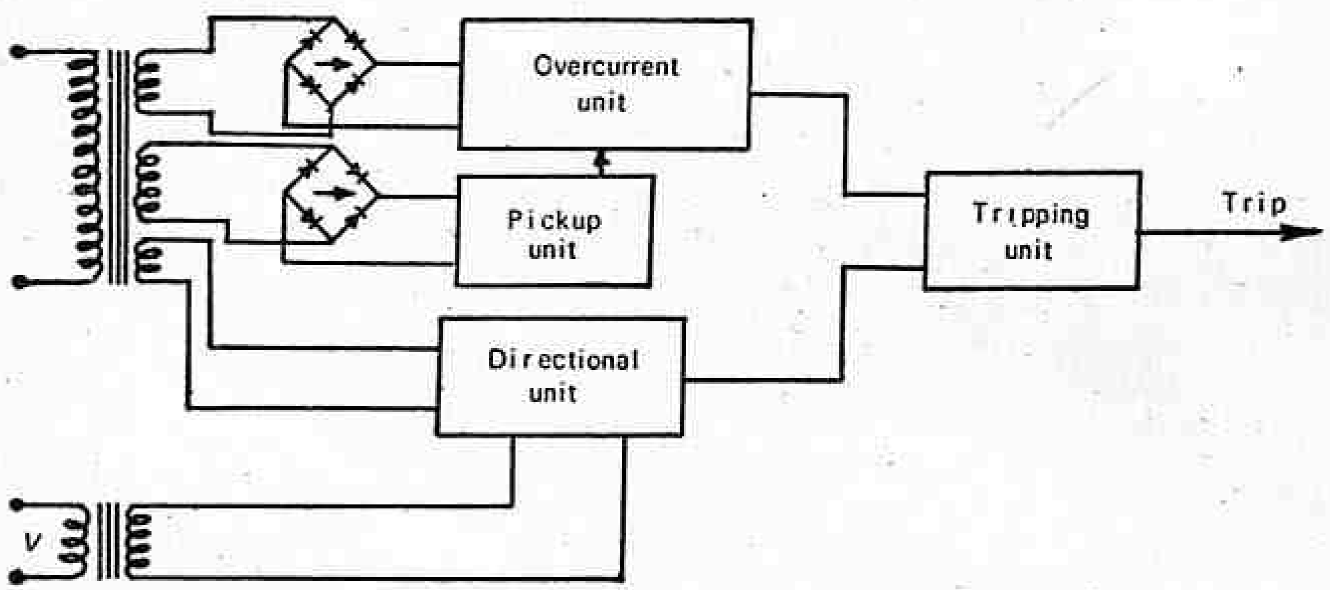


FIGURE 12.8 Directional overcurrent relay.

12.3 Differential Protection

A differential protection scheme compares quantities derived from the input and output currents of the protected circuit in such a manner that, for all healthy system and through fault conditions, the quantities balance and the protection is inoperative, while for internal fault conditions the balance is disturbed and the protection operates.

For small lengths of the order of 25 km, pilot wires are used for transmission of information from one end to the other so that the relays can effect a continuous comparison of quantities derived at the two ends. However, for long lengths the method becomes impracticable and costly and so carrier schemes are usually applied. Such schemes have a great deal in common with pilot wire schemes. The pilot wire differential and the carrier differential protections are unit type of protection, where absolute selectivity is obtained.

Since all differential feeder protection systems utilize a summation device to produce a single-phase output from the three-phase system at the two ends, the protection characteristic is best expressed in terms of the complex ratio of these summated outputs. In practice, a summation transformer or a sequence network is used to derive a single phase relaying quantity from the three-phase currents at each end of the primary circuit.

12.3.1 Effectiveness of Comparison

The use of summation device which is an integral component of every differential feeder protection, results in an overall reduction in the discriminating margins, owing to the condensation and consequent reduction of information contained in the compared quantities.

Idealized characteristics of differential feeder protection scheme, under conditions of normal load or through fault, neglecting primary circuit capacitance current and leakage current together with errors in transformation are shown in Fig. (12.9). The relaying quantities at both ends of the transmission circuit will be identical in magnitude and phase, so that their phasor ratio $\alpha = I_A/I_B = 1 + jo = 1\angle 0°$. Two types of characteristics are plotted showing the threshold boundaries in terms of the effective ratio of outputs from the summation devices at the two ends A and B of the protected line. Figure (12.9a) shows phase comparison while Fig. (12.9b) shows both phase and amplitude comparison. Pilot wire systems may employ either of the above characteristics while carrier current systems employ pure phase comparison.

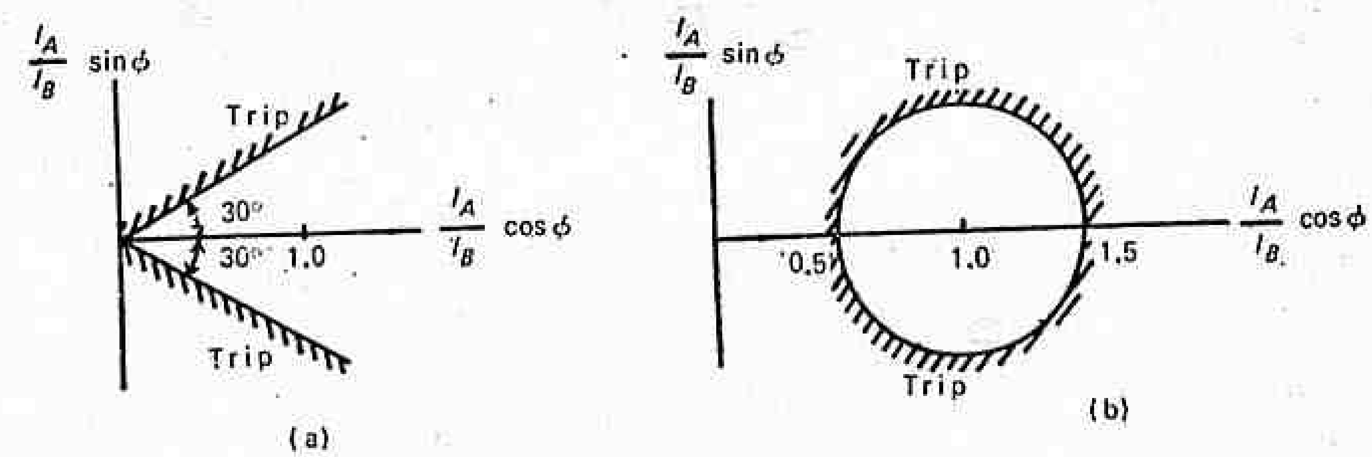


FIGURE 12.9 Ideal characteristics: (a) phase comparison; (b) phase and amplitude comparison.

In practice the pilot wire protection system characteristics tend to be variable and unpredictable because a relay having a closed—threshold characteristic under lightly loaded conditions may present a pure phase—comparison characteristic under saturated fault conditions. This is because of the fact that the pilot circuit parameters are often inadequately considered, with the result that the discriminating margins are seriously affected.

12.3.2 Basic Pilot-Wire Protection Scheme

A system of pilot-wire differential protection is shown schematically in Fig. (12.10), for simplicity only one phase is shown. A single-phase relaying signal is derived from the three phases of the protected circuit at each end of protected zone, and they are compared in the pilot link. When conditions at each end of the circuit are the same, corresponding to healthy or through-fault conditions, the relaying signals should be of near equal amplitude and phase and a balance should be achieved between them, thereby giving rise to only a small residual signal in the protection system.

Under internal fault conditions, on the other hand, the balance should be disturbed to an extent that permits the derivation of reliable control signals to trip the circuit breakers associated with the protected circuit. High degree of stability in the balance condition for the wide range of external loading and fault conditions is required without impairing its ability to detect all internal fault conditions.

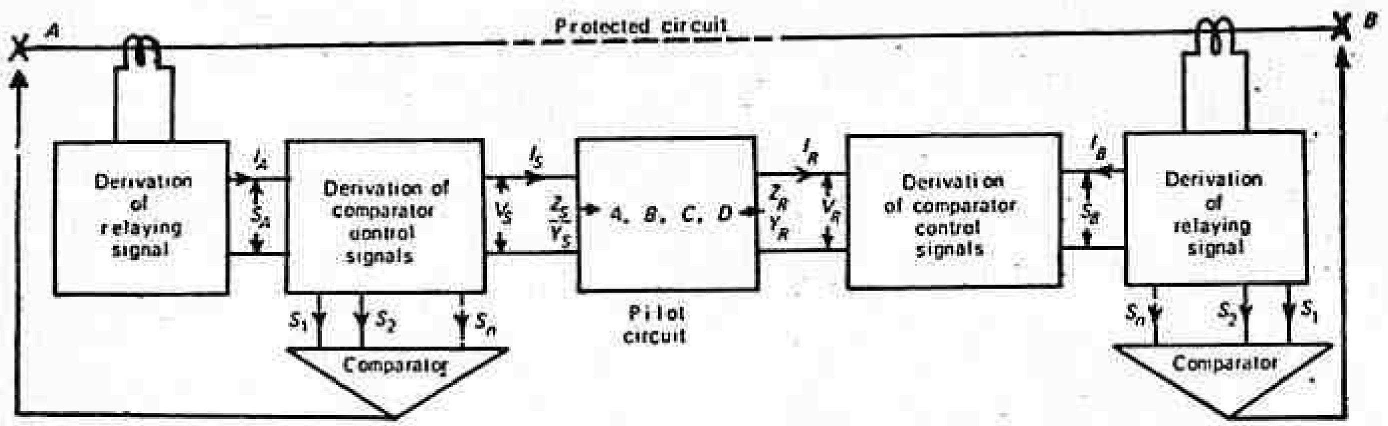


FIGURE 12.10 Basic arrangement of pilot-wire differential protection scheme.

12.3.3 Fundamental Characteristics of Pilot-Wire Differential Systems

In Fig. (12.10) keeping the current I_A fixed and assuming that an output voltage V_S is produced directly proportional to this current, the corresponding voltage V_R at the remote end can be considered to vary in phase and magnitude. As it does so the input current I_S to the pilot circuit will vary, and it is required to investigate the locus of this current to determine the discriminating margin available between internal and external fault conditions. A relay characteristic must then be chosen such that the change in pilot-circuit current produced by the primary-circuit currents under internal and external fault conditions can be used to provide definite discrimination.

The characteristics of the pilot circuit can be represented by the 4-terminal network having constants A, B, C, D, these being related by the wellknown equations

$$V_S = AV_R + BI_R \tag{12.5}$$

$$I_S = CV_R + DI_R \tag{12.6}$$

For an equivalent π-network the values of A, B, C, D are:

$$A = 1 + Y_R Z$$

$$B = Z$$

$$C = Y_R + Y_S + Y_S Y_R Z$$

$$D = 1 + Y_S Z$$

Taking the case where V_R is fixed and V_S varying in phase and magnitude, then $V_S = KV_R \angle\theta$, where K is the modulus of the ratio V_S/V_R and θ is the phase angle between the two voltages. Then substituting in Eq. (12.5) for V_S we have

$$KV_R\angle\theta - AV_R = BI_R \tag{12.7}$$

from which, we get

$$\frac{V_R}{I_R} = Z_R = \frac{B}{K\angle\theta - A} \tag{12.8}$$

or

$$Y_R = \frac{K\angle\theta - A}{B} \tag{12.9}$$

Similarly for the remote end

$$Z_S = \frac{B}{D - 1/K\angle\theta} \tag{12.10}$$

and

$$Y_S = \frac{D - 1/K\angle\theta}{B} \tag{12.11}$$

Since the current at end R is reversed, then the impedance and admittance looking into the pilot circuit is given by

$$Z_R = \frac{B}{A - K\angle\theta} \tag{12.12}$$

$$Y_R = \frac{A - K\angle\theta}{B} \tag{12.13}$$

These expressions give a locus diagram in terms of input impedance or admittance for a generalized 4-terminal network. For the impedance equation the locus of input impedance is a circle of radius $BK/(A^2 - K^2)$ at a distance of $AB/(A^2 - K^2)$ from the origin (Fig. (12.11)). The admittance equation also represents a circle and is more convenient where the radius is K/B and the distance of centre from the origin is A/B. It can be noted that by varying K, different concentric circles can be drawn. Obviously to draw these circles constants A and B are required, which can be calculated by the open and short-circuit impedance of the pilot-wire circuit.

From these measurements $A/B=Y_{SCR}$ (short-circuit admittance viewed from end R) and

$$\frac{1}{B}=\sqrt{\{Y_{SCS}(Y_{SCR}-Y_{OCR})\}}$$

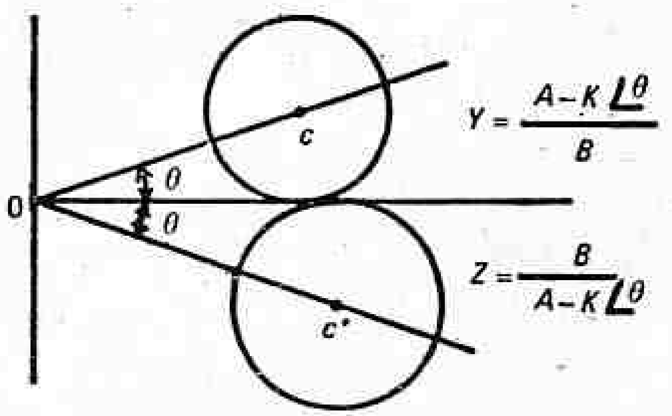


FIGURE 12.11 Locus diagram for input admittance and input impedance of 4-terminal network.

where Y_{SCS} is the short-circuit admittance of the pilot circuit viewed from end S and Y_{OCR} is the open-circuit admittance viewed from end R. On this diagram can also be plotted the relay characteristics expressed in terms of impedance or admittance measurement. The relay characteristic can then be adjusted to embrace the actual phase and magnitude variations of the input from the power system under healthy conditions.

The input-admittance locus diagram of Fig. (12.12a) is plotted for a typical practical pilot-wire circuit, when θ is zero and K is unity, the conditions at the two ends of the protected circuit are the same, and the protection should therefore restrain. If K remains unity but θ increases to 180°, this represents an internal fault fed equally from the two ends, and presents the ideal antiphase condition of the relaying signals for a fault legitimately within the protected zone. For the range of fault conditions encountered in normal practice, as manifested at this stage in the K and θ quantities, there will be a correspondingly wide range of apparent pilot-circuit admittances, for which the protection should positively operate. In meeting these requirements, one possibility, for example, is for the restraining zone to be circular, the centre of the circular characteristic coinciding with the ideal through fault condition for which $K=1$, $\theta=0$, as shown in Fig. (12.13).

Tripping is then effected everywhere in the admittance plane without and only without the defined restraining zone.

12.3.4 Admittance Characteristics of Two-Input Comparators

A generalized two-input comparator circuit is shown in Fig. (12.14), where alternative signal inputs can be derived and compared in various

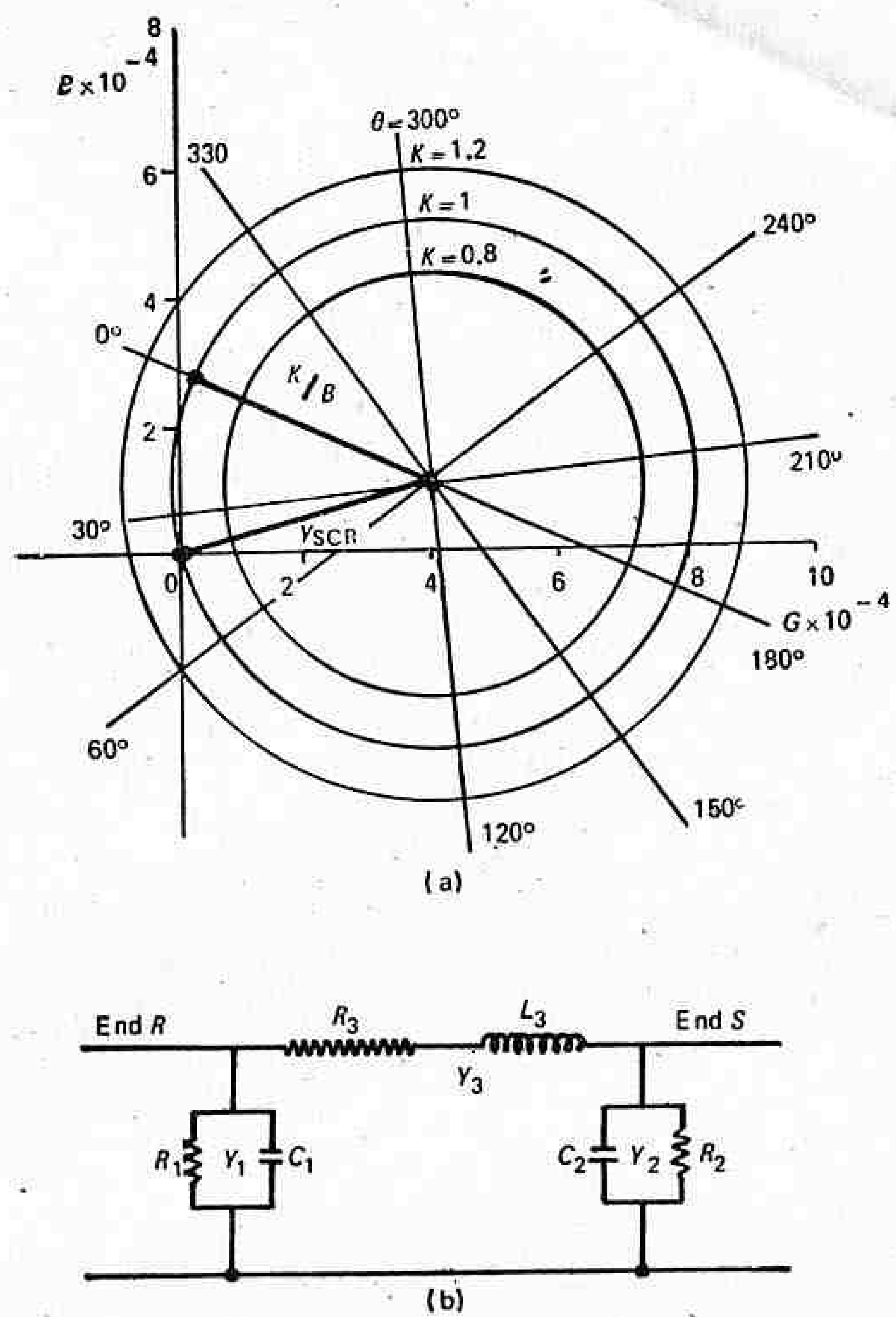


FIGURE 12.12 Characteristics of typical 40 km long practical pilot-wire circuit.
(a) Input admittance diagram (end R) for all values of

$$V_S/V_R=K\angle\theta$$

(b) Nominal π-network at 50 Hz.

$R_1=22.5\ K\Omega$	
$C_1=0.864\ \mu F$	$Y_1=(A-1)/B$
$R_2=30.3\ K\Omega$	
$C_2=0.804\ \mu F$	$Y_2=(D-1)/B$
$R_3=2330\ \Omega$	
$L_3=3.03\ H$	$Y_3=1/B$

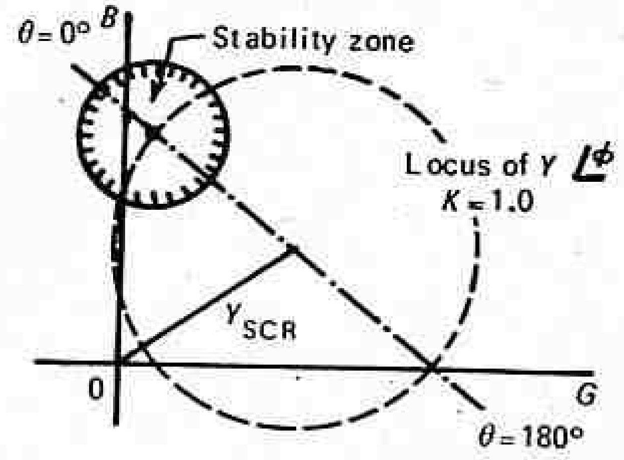


FIGURE 12.13 Circular protection characteristic superimposed on pilot-circuit input admittance diagram.

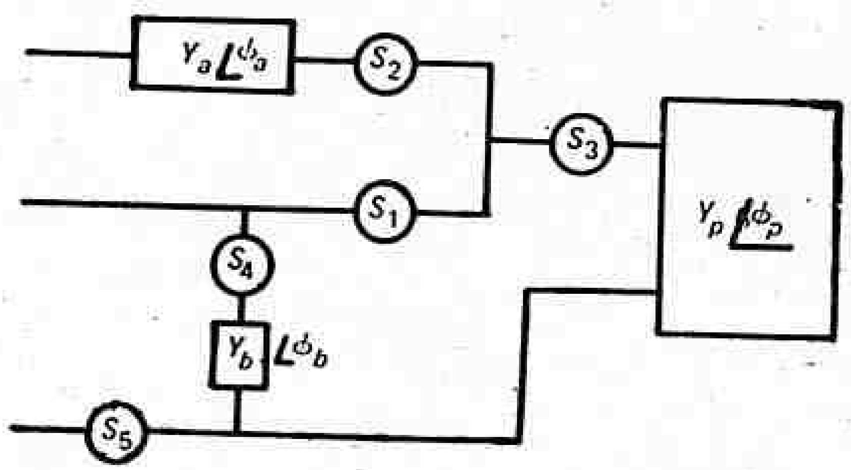


FIGURE 12.14 A generalized two-input comparator circuit

combinations. The different available signal inputs are:

$$S_1 = Y_p\angle\phi_p - Y_a\angle\phi_a$$

$$S_2 = Y_a\angle\phi_a$$

$$S_3 = Y_p\angle\phi_p$$

$$S_4 = Y_b\angle\phi_b$$

$$S_5 = Y_p\angle\phi_p + Y_b\angle\phi_b$$

Irrespective of the number of signals, the comparison may be of the amplitudes of the control quantities, independent of their phase relationships, or alternatively, of their phase relationships, independent of their amplitudes. Figure (11.1) shows the range of characteristics available from an amplitude comparator whilst Fig. (11.13) shows the characteristics obtained from a phase comparator for similar signal inputs. In each case the shaded portion represents the stability or restraining zone. By interchanging the operating and restraining inputs of the amplitude comparator, or reversing the sign of one input for the phase comparator,

the shaded area becomes the operating zone of the protection characteristic.

12.3.5 COORDINATION WITH REMOTE-END CHARACTERISTIC

Transformation from Admittance Plane to the Plane of the Complex Ratio of Relaying Signals. It is possible to interpret the admittance diagram of Fig. (12.12) in the plane of the ratio of relaying signals. Using the input admittance of Fig. (12.12), the origin of the latter plane shown at zero, '0', in Fig. (12.15a) is given by the condition of the S voltage being zero, and so coincides with the input admittance at end R with end S short circuited. The real axis of the signal ratio plane must pass through the points at which the relaying signals are in phase and in antiphase, and the new plane is then as shown in Fig. (12.15). Furthermore, where the system is operating in a linear mode, the ratio V_S/V_R is identical to the ratio S_A/S_B and so the protection characteristics may be shown directly in the plane of the complex ratio of the relaying signals S_A and S_B, as derived from the phase-current summator. Although in Fig. (12.15a) negative values of the real part of the ratio V_S/V_R are drawn to the right of the origin, this is reversed in Fig. (12.15b) so that positive values appear to the right in the ordinary way.

Inverse Characteristics. The characteristics so far derived from applications of the appropriate restraining criteria are those that obtain at each end of the protected circuit, without giving consideration to the effect that the characteristic at one end has on that at the other. Now the characteristic at end A may be shown directly in the S_B/S_A plane, and similarly that at end B in the S_A/S_B plane, which is the local one at that end. The characteristic at one end, therefore, appears as its inverse at the other, and it is the combination of the local and the referred remote-end characteristics which defines the resultant zone of stability for the protective scheme as a whole. Figure (12.16) represents the local end circular characteristic and the equivalent far end characteristic. For conditions completely outside the local and inverse characteristics, both ends of the protection trip together. In the range that is covered by only one characteristic, the two ends trip sequentially. The common local area represents the range of conditions for which both ends restrain.

Where the pilot-wire schemes are applied over long pilot circuits, particularly where these employ low insulation telephone-type cores, some part of the protection characteristic is influenced by the action of the voltage limiter.

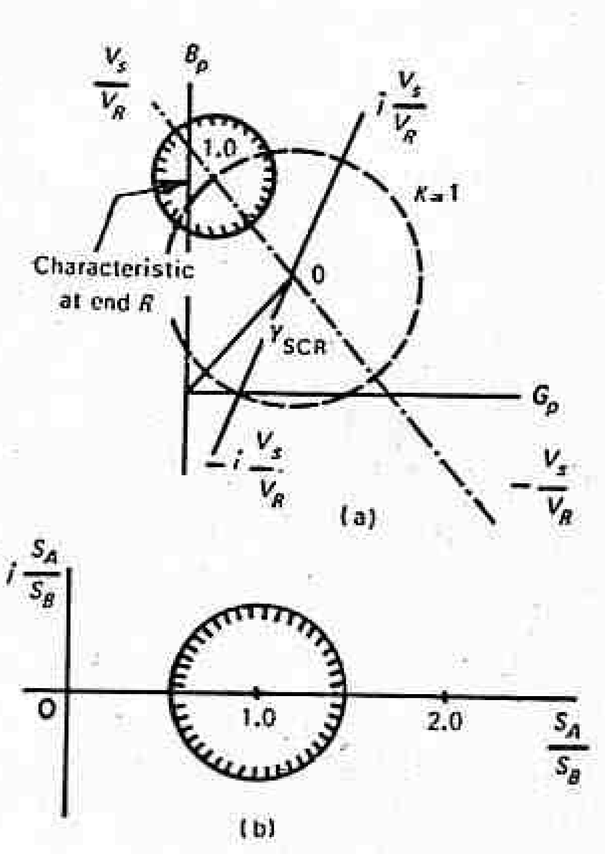


FIGURE 12.15 Transition from plane of pilot-circuit admittance to plane of complex ratio of relaying signals: (a) relationship between Y_p and V_S/V_R planes; (b) stability zone in S_A/S_B plane.

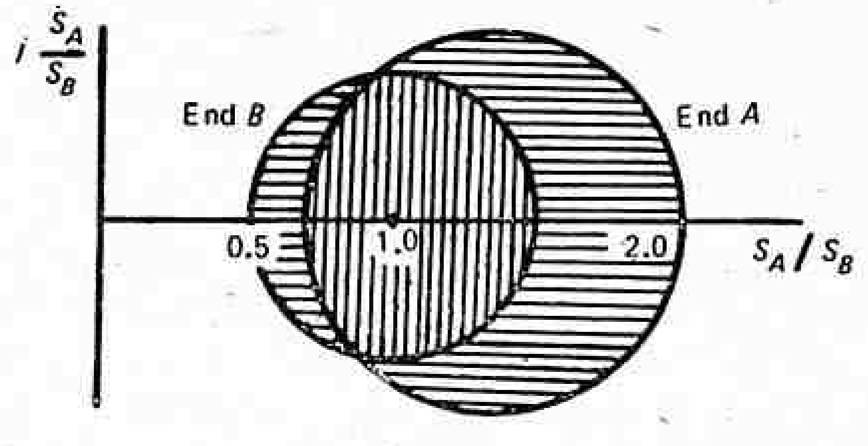


FIGURE 12.16 Local end and referred remote end characteristics. Vertical shading: overall stability zone. Horizontal shading: zone of sequential tripping. Simultaneous tripping occurs in all space outside the two superimposed characteristics.

12.3.6 Performance of Pilot-Wire Protection Systems

The basic pilot-wire protection systems may employ either the balanced voltage or the circulating current principles. Balanced voltage schemes are *voltage driven* whereas circulating current schemes are *current driven.* The former method finds wider application to feeder protection because it does not impose limitations on pilot length and linearity of summation

devices like the latter. Figure (12.17) shows the basic circuit of an uncompensated balanced-voltage and circulating-current schemes. It may be noted that the position of the operating and restraint circuits have been interchanged.

Bridge-Comparator Method Used in Balanced-Voltage Schemes. For a practical balanced-voltage protection scheme with shunt compensation and

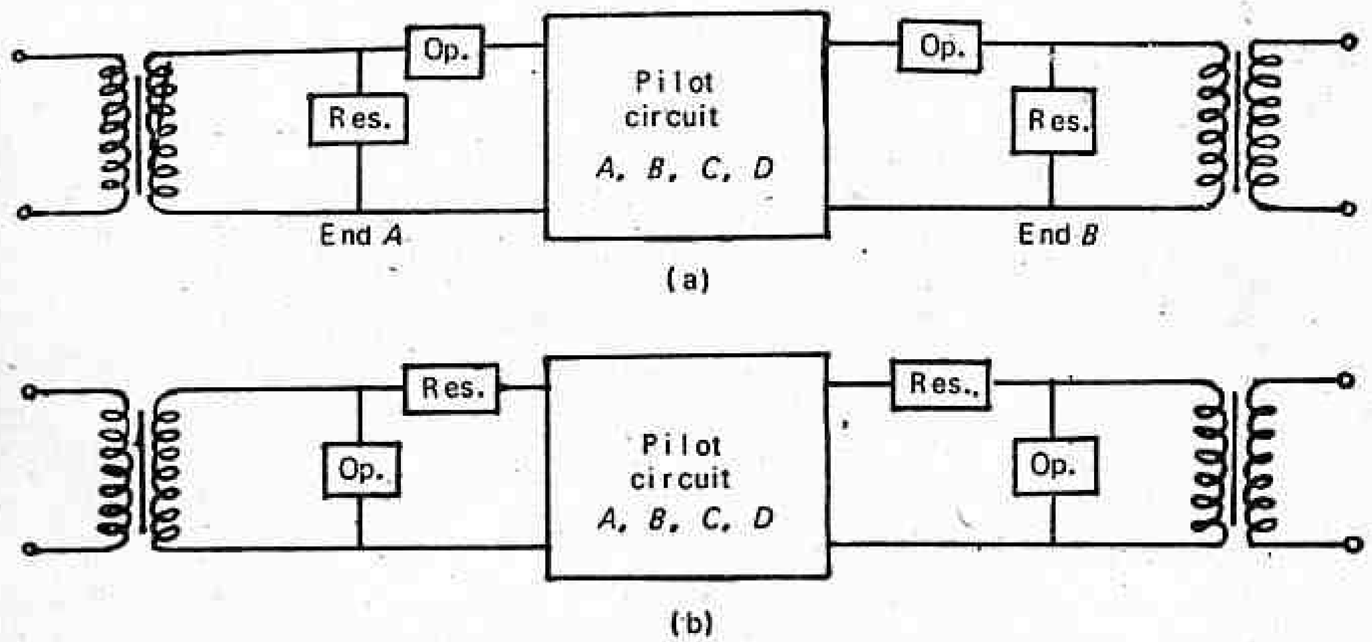


FIGURE 12.17 Pilot-wire protection: (a) basic arrangement of balanced voltage; (b) basic arrangement of circulating current. OP—operating circuit; Res—restraint circuit.

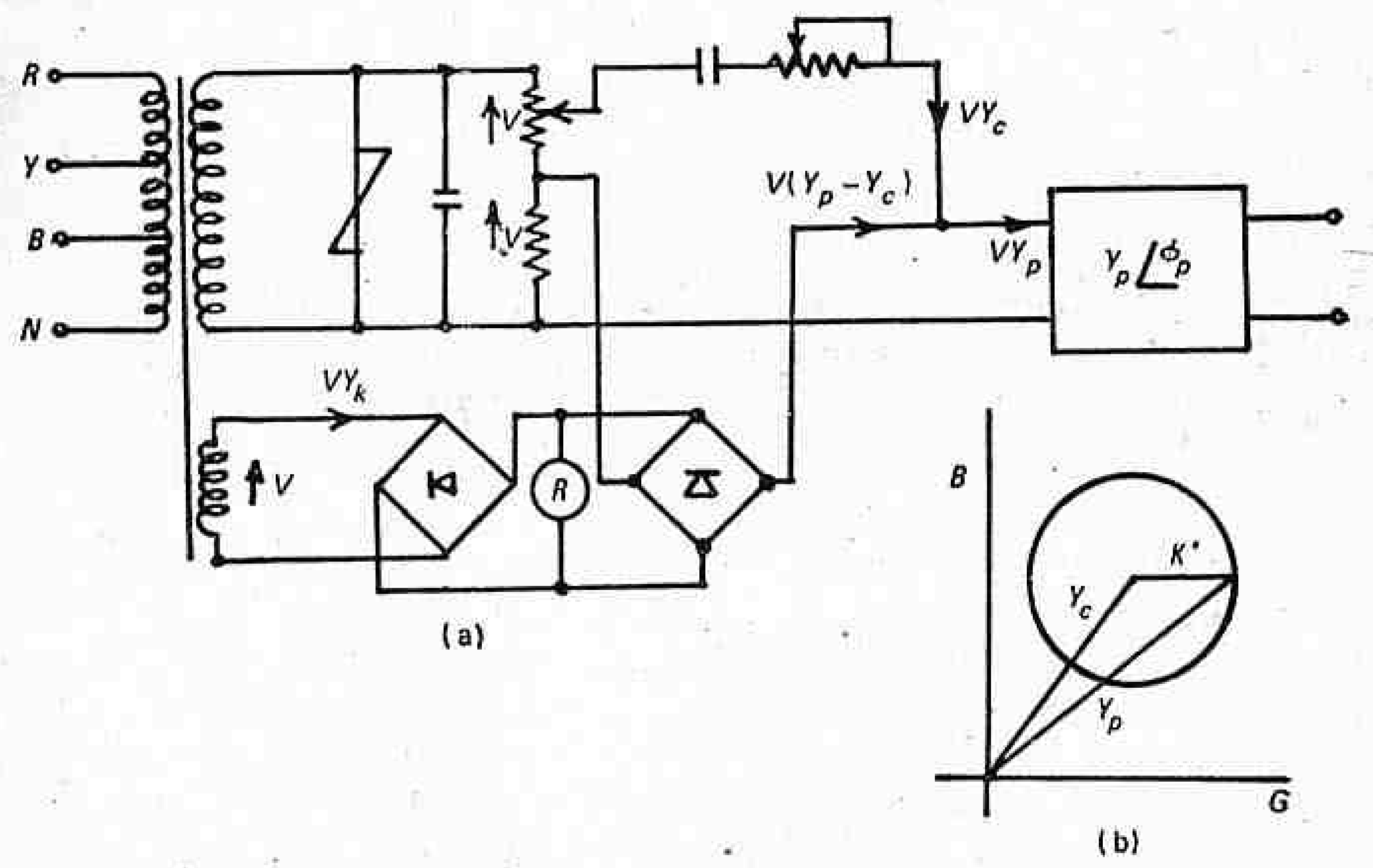


FIGURE 12.18 Bridge comparator relay: (a) general arrangement of practical circuit; (b) admittance locus.

utilizing amplitude comparison between the operating and restraint quantities, it is desirable that the circuit should be tuned so that the overall compensated pilot circuit $Y_{(P+C)}$ presents zero admittance to the relays for the condition $V_S/V_R=1\angle 0$.

12.4 Static Distance Protection

Distance relays are characterized by having two input quantities respectively proportional to the voltage and current at a particular point in the power system, referred to as the relaying point. The ideal forms of such relays have characteristics which are not dependent on the actual values of voltage and current, but only on their ratio and the phase angle between them. The basic measurement of impedance is done in comparators of the type already discussed which pass on the signal to tripping circuit through suitable timing unit.

12.4.1 Typical Distance Relay Characteristics

A schematic block diagram showing the general scheme to get a characteristic equation which directly fits any sort of relay is shown in Fig. (12.19). Voltage V_L and current I_L are fed into measuring circuit M which produce voltages:

$$S_1=K_1V_L+K_2I_L$$

$$S_2=K_3V_L+K_4I_L$$

These voltages are then fed to a comparator C (amplitude or phase) so as to produce a desired pickup characteristic, the constants of K_1 through K_4 being selected accordingly. Typical distance characteristics are shown

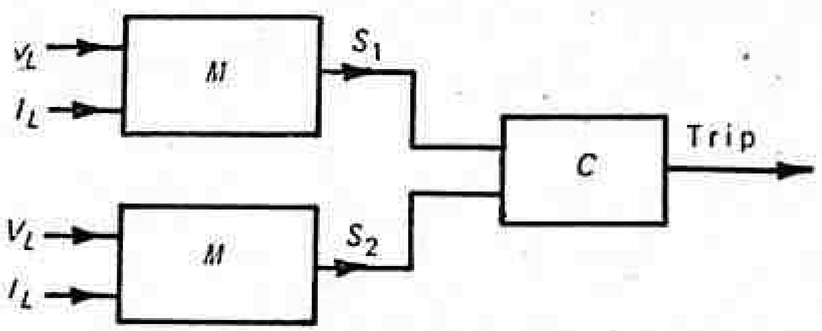


FIGURE 12.19 Generalized block diagram of a relay. M—measuring circuit; C—comparator.

in Fig. (12.20) on the complex plane. For these characteristics Table 12.1 lists derived voltages S_1 and S_2 both for amplitude and phase comparators.

The polar characteristic of a distance relay defines the range of impedance values of the protected primary circuit for which the relay gives circuit breaker tripping, whilst beyond this range, the relay remains inoperative. In this way the polar characteristic of the relay provides its main discriminative features, and the underlying basis on which distance protection is

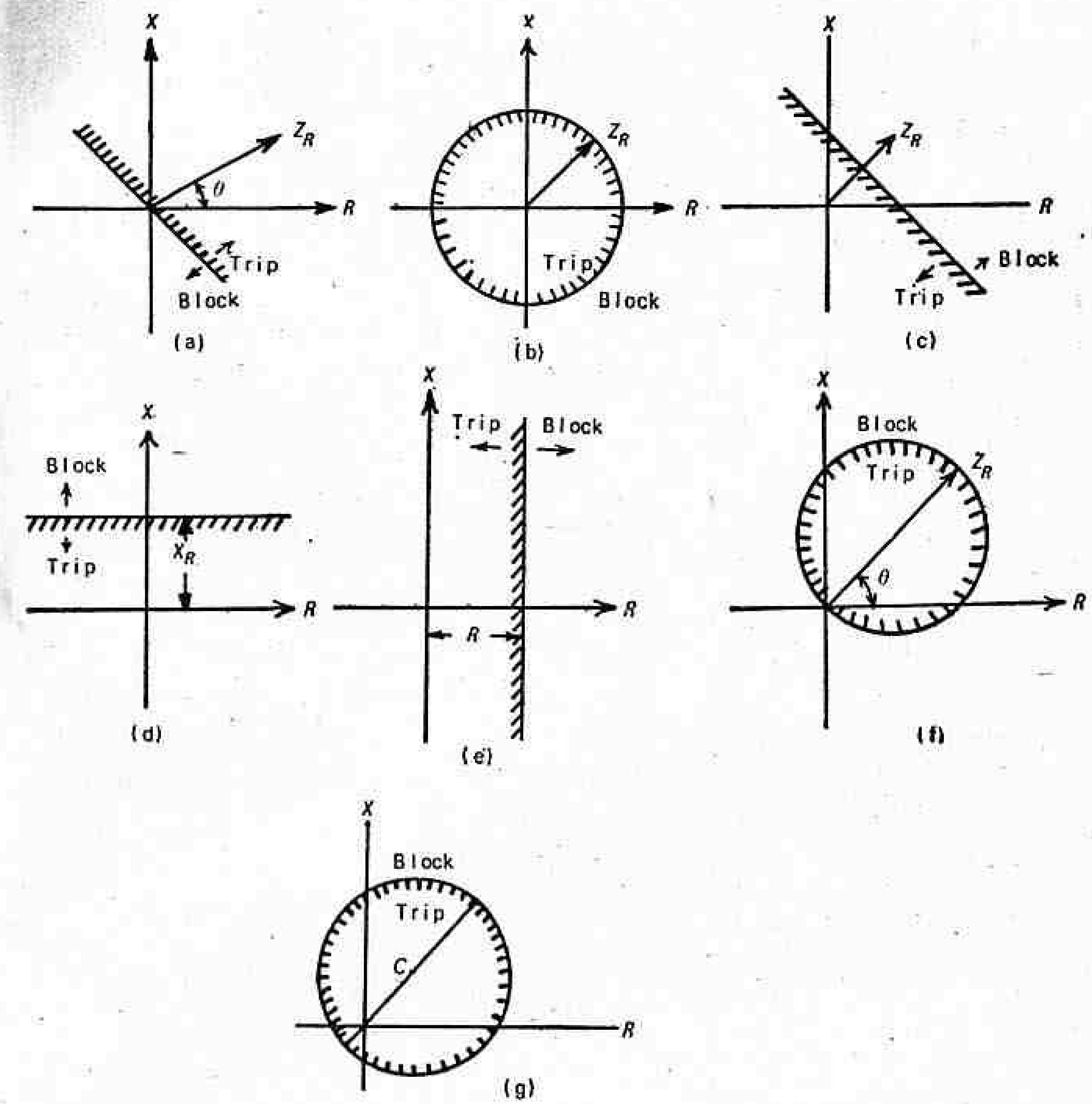


FIGURE 12.20 Typical distance characteristics: (a) directional; (b) plain impedance; (c) angle impedance; (d) reactance; (e) conductance; (f) mho; (g) offset mho.

applied is that of matching the polar characteristic to the anticipated range of primary-circuit fault conditions.

As already discussed a large range of distance protection schemes are possible, which differ basically in speed of operation, characteristic of measuring unit and the type of fault covered. Directional reactance and the mho-scheme for distance protection are discussed here.

Directional Reactance Scheme. Figure (12.21) represents the block schematic of this scheme. The reactance relay provides the main forward-reach characteristic in the first and second zones, and the characteristic derived from the mho relay is added to this in order to avoid operation of the protection under ordinary loading conditions and to give directional

PART I Protective Relays

CHAPTER 1

Introduction

1.1 Basic Ideas of Relay Protection

An electric power system should ensure the availability of electrical energy without interruption to every load connected to the system. When the electric power supply is extended to remote villages the power system would consist of several thousand kilometres of distribution lines. The high voltage transmission lines carrying bulk power could extend over several hundred kilometres. Since all these lines are generally overhead lines and are exposed, there are many chances of their breakdown due to storms, falling of external objects, damage to the insulators, etc. These can result not only in mechanical damage but also in an electrical fault. One of the sources of trouble to continuous supply is the shunt fault or short-circuit, which produces a sudden and sometimes violent change in system operation.

Protective relays and relaying systems detect abnormal conditions like faults in electrical circuits and operate automatic switchgear to isolate faulty equipment from the system as quickly as possible. This limits the damage at the fault location and prevents the effects of the fault spreading into the system. It is the function of the protective relays in association with the switchgear to avert the consequences of faults. The switchgear must be capable of interrupting both normal currents as well as fault currents. The protective relay on the other hand must be able to recognize an abnormal condition in the power system and take suitable steps to ensure its removal with the least possible disturbance to normal operation.

It should be noted that a protective relay does not prevent the appearance of faults. It can take action only after the fault has occurred. It would be most desirable if protection could anticipate and prevent faults, but this is obviously impossible except where the original cause of a fault creates some effect which can operate a protective relay. However, there are some devices which can anticipate and prevent major faults, e.g. Buchholz relay, a gas operated device which is capable of detecting the gas accumulation produced by an incipient fault in a transformer.

1.2 Nature and Causes of Faults

The nature of a fault simply implies any abnormal condition which causes a reduction in the basic insulation strength between phase conductors, or between phase conductors and earth, or any earthed screens surrounding the conductors. Actually the reduction of the insulation is not considered as a fault until it produces some effect on the system, that is until it results either in an excess current or in the reduction of the impedance between conductors or between conductors and earth to a value below that of the lowest load impedance normal to the circuit.

In a power system consisting of generators, switchgear, transformers, transmission and distribution circuits, it is inevitable that sooner or later in such a large network some failure will occur somewhere in the system. The probability of the failure or occurrence of abnormal condition is more on the power lines, simply because of their greater length and exposure to the atmosphere as already mentioned.

Before proceeding to the examination of the several causes of failures, it would be well to classify them according to the causes of their incidence. These are mentioned below.

(a) Breakdown may occur at normal voltage on account of (i) the deterioration of insulation and (ii) the damage due to unpredictable causes such as the perching of birds, accidental short circuiting by snakes, kite strings, tree branches, etc.

(b) Breakdown may occur because of abnormal voltages, though the insulation is otherwise healthy to withstand normal voltage. This may happen because of either (i) switching surges or (ii) surges caused by lightning.

The presentday practice is to provide a high insulation level of the order of 3 to 5 times the nominal value of the voltage. But still the pollution on an insulator string which is commonly caused by deposited soot or cement dust in industrial areas and by salt deposited by wind-borne sea-spray in coastal areas cause the insulation strength to decrease. This will initially lower the insulation resistance, and cause a small leakage current to be diverted, thus hastening the deterioration. Even if the installation is enclosed, such as sheathed and armoured cables as well as metal-clad switchgear, deterioration of the insulation occurs because of ageing. Void formation in the insulating compound of underground cables due to the unequal expansions and contractions caused by the rise and fall of temperatures is another cause of insulation failure.

The line and apparatus insulation may be subjected to transient over-voltages because of the switching operations. The voltage which rises at a rapid rate, may achieve a peak value which approaches three times phase to neutral voltage. It is for this purpose that a higher insulation level is provided initially. If the insulation levels have been correctly chosen and they have not been impaired in the manner described under (a) above, the system will withstand these routine over-voltages. But if the insulation has developed some form of weakness, it is at the time of switching that failure may be expected. The problems of circuit breaking under faulted conditions and the magnitude of rise of voltages encountered will be discussed in Chapter 14.

Lightning produces a very high voltage surge in the power system of the order of millions of volts and thus it is not feasible to provide an insulation which can withstand this abnormality. These surges travel with the velocity of light in the power circuits, the limiting factors are the surge impedance and the line resistance.

1.3 Consequences of Faults

The most serious result of a major uncleared fault is fire which may not only destroy the equipment of its origin but may spread in the system and cause total failure. The most common type of fault which is also the most dangerous one is the short circuit which may have any of the following consequences:

(1) A great reduction of the line voltage over a major part of the power system. This will lead to the breakdown of the electrical supply to the consumer and may produce wastage in production.
(2) Damage caused to the elements of the system by the electrical arc which almost always accompanies a short circuit.
(3) Damage to other apparatus in the system due to overheating and due to abnormal mechanical forces setup.
(4) Disturbances to the stability of the electrical system and this may even lead to a complete shutdown of the power system.
(5) A marked reduction in the voltage which may sometimes be so great that relays having pressure coils tend to fail.
(6) Considerable reduction in the voltage on healthy feeders connected to the system having fault. This may cause either an abnormally high current being drawn by the motors or the operation of no-voltage coils of the motors. In the latter case considerable loss of industrial production may result as the motors will have to be restarted.

1.4 Fault Statistics

It is useful to have some idea of the frequency of the incidence of faults on the different items of equipment in a power system. This information is of help in considering the problems of design and application of protection. Table 1.1 gives an idea of how faults are distributed in the various sections of a power system.

Table 1.1 *Frequency of fault occurrence in different links of a power system*

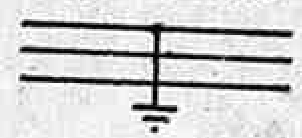
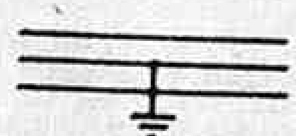
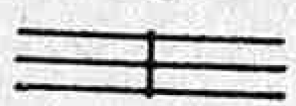
Equipment	*% of total*
O.H lines	50
Cables	10
Switchgear	15
Transformers	12
CTs and PTs	2
Control Equipment	3
Miscellaneous	8

It is of interest to note that faults on overhead lines account for nearly half of the total number of faults. It would be worthwhile therefore, to analyse the nature of faults on the overhead lines. On a three phase system the breakdown of insulation between one of the phases and earth is known as line to ground fault or a single phase earth fault, the breakdown of insulation between either of the two phases is known as line to line fault, the breakdown of insulation between two phases and earth is known as double line to ground fault, and the breakdown of insulation between the three phases is known as three phase fault.

Table 1.2 is a rough guide to the occurrence of these faults.

CORRIGENDUM

Table 1.2 *Frequency of different types of faults occurring in overhead lines*

Type of fault	*Representation*	*% occurrence*
1. L–G		85
2. L–L		8
3. L–L–G		5
4. L–L–L		2 or less

Note. The L–L–L fault, called the symmetrical three-phase fault, generally occurs due to the carelessness of operating personnel. Usually the phase lines are tied up together with a bare conductor in order to protect the lineman working on the lines against inadvertent charging of the line. Occasionally after the work is over, the lineman forgets to remove the tie-up and when the circuit breaker is closed a three-phase symmetrical fault occurs.

It is evident, therefore, that the line to ground fault occurs most commonly in overhead line practice. Fortunately a large number of these faults are transitory in nature and may vanish within a few cycles—as would be the case when a twig falls across a line and a cross-arm and burns itself out or just falls down.

In our country where the neutral is not kept isolated, these earth faults do produce fairly large magnitudes of fault current. So in designing a system of protection greater attention should be paid to the reliable operation of relays under line-to-ground fault conditions.

1.5 Zones of Protection

The protected zone is that part of a power system guarded by a certain protection and usually contains one or at the most two elements of the power system. The zones are arranged to overlap so that no part of the system remains unprotected. Figure (1.1) shows a typical arrangement of overlapping zones of protection.

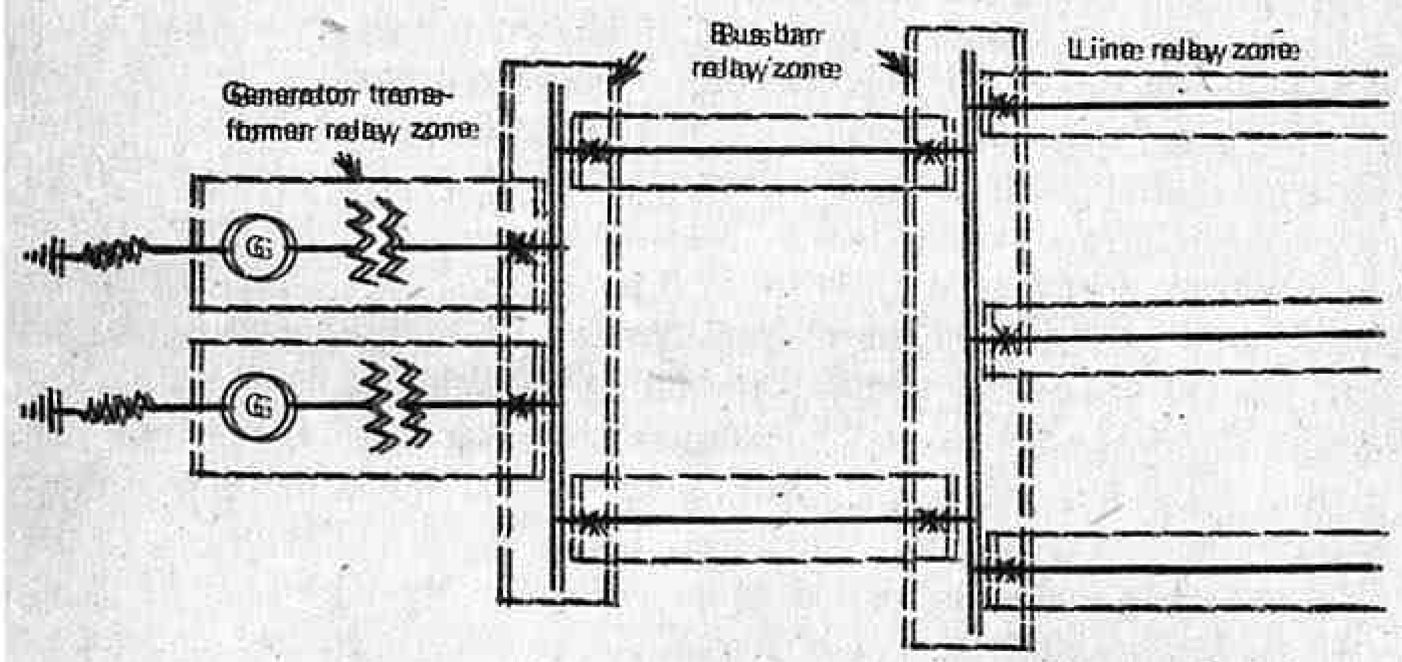


FIGURE 1.1 Overlapping zones of protection.

When it becomes desirable for economic or space saving reasons to overlap on one side of a breaker blind spots occur as shown in Fig. (1.2).

It can be seen that for a fault at X the circuit breakers of zone B, ncluding breaker C will be tripped; however, this does not interrupt the flow of fault current from zone A, the relaying equipment of zone B must also trip certain breakers in zone A. This is all right for fault at X, but

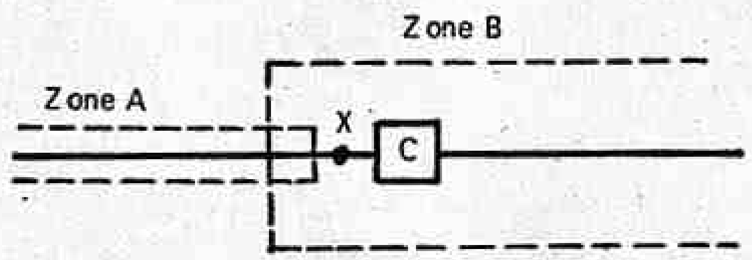


FIGURE 1.2 Blind spots.

for faults in zone B to the right of breaker C the operation of breakers in zone A is not useful. How far this unnecessary operation can be tolerated will depend on the particular application.

1.6 Essential Qualities of Protection

Every protective system which isolates a faulty element is required to satisfy four basic requirements: (i) reliability; (ii) selectivity; (iii) fastness of operation; and (iv) discrimination. Without reliability and selectivity the protection would be rendered largely ineffective and could even become a liability.

1.6.1 Reliability

Reliability is a qualitative term. Quantitatively it can be expressed as a probability of failure. Failure is not confined to protective gear but may also be due to breaker defects. Therefore every component and circuit involved in fault clearance must be regarded as a potential source of failure. Failure can be reduced to a small calculated risk by inherently reliable designs backed by regular and thorough maintenance. Quality of personnel must not be overlooked when considering reliability, for mistakes by personnel are among the most likely causes of failure. Some features of design and manufacture which make relays inherently reliable are high contact pressures, dust free enclosures, well braced joints and impregnated coils. Precautions in manufacture and assembly reduce liability to failure. Components should be treated to prevent contamination. Acid fluxes and acid producing insulation should be avoided. On assembly direct handling of components should also be avoided as far as possible.

Records show that the order of likelihood of failure is: relays, breakers, wiring, current transformers, voltage transformers and battery. When relays using transistors are considered, the failure rate goes up still further.

1.6.2 Selectivity

This is the property by which only the faulty element of the system is isolated and the remaining healthy sections are left intact. Selectivity is absolute if the protection responds only to faults within its own zone, and relative if it is obtained by grading the settings of the protections of several zones all of which may respond to a given fault.

Systems of protection which in principle are absolutely selective are known as *unit systems*. Systems in which selectivity is relative are *non-unit systems*. Examples of the former are differential protection and frame leakage protection, and of the latter current time graded protection and distance protection.

1.6.3 Fastness of Operation

Protective relays are required to be quick acting due to the following reasons:

(a) Critical clearing time should not be exceeded.
(b) Electrical apparatus may be damaged if they are made to carry fault currents for long.
(c) A persistent fault will lower the voltage resulting in crawling and over-loading of industrial drives.

The shorter the time a fault is allowed to persist the more load can be transferred between given points on the power system without loss of synchronism. Figure (1.3) shows typical values of power which can be transmitted as a function of fault clearing times for various types of fault.

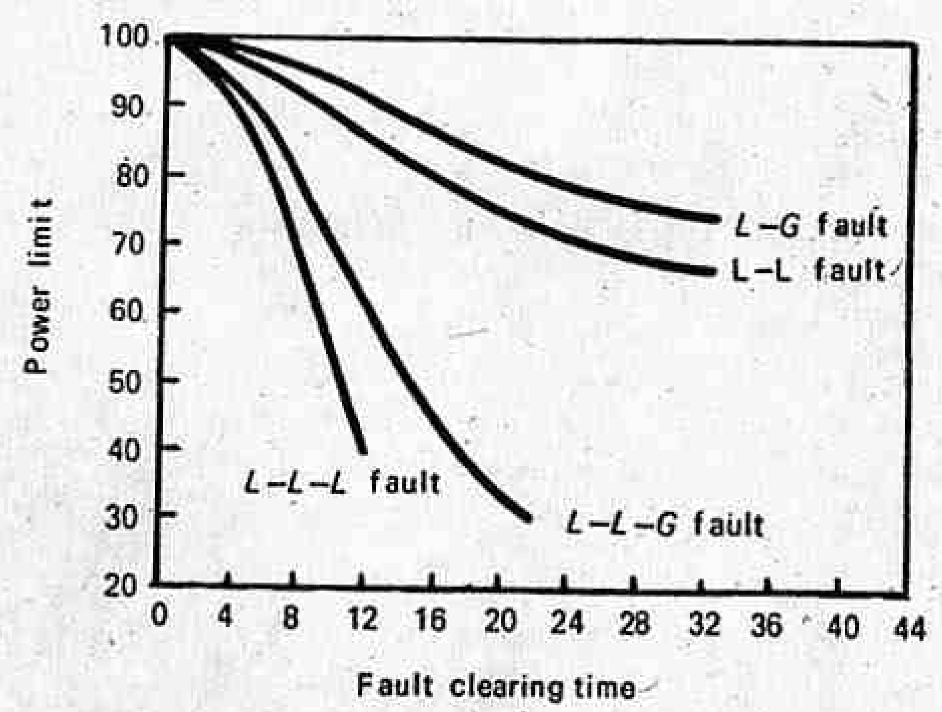


FIGURE 1.3 Power limit for different types of faults.

It can be seen that three phase faults have a more marked effect on the ability of the system to remain in step and hence they must be cleared faster than the single earth fault.

On the other hand relays should not be made extremely fast, i.e. less than 10 milliseconds. This is because when there is any lightning surge on the line the surge diverters must have sufficient time to discharge the lightning to the ground; otherwise the relay will operate unnecessarily for transient conditions.

1.6.4 Discrimination

Protection must be sufficiently sensitive to operate reliably under minimum fault conditions for a fault within its own zone while remaining stable under maximum load or through fault conditions. A relay should be able to distinguish between a fault and an overload. In the case of transformers the inrush of magnetizing current may be comparable to the fault current, being 5 to 7 times the full load current. The relay should not operate for inrush currents. In interconnected systems, there will be power swings, which should also be ignored by the relay. This discrimination between faults and overcurrents may either be an inherent characteristic of the relay or may be achieved by connecting auxiliary devices like the minimum voltage relay. It may be noted that the word discrimination is sometimes used to include selectivity.

1.7 Primary and Backup Protection

The system is divided into protective zones as explained earlier, each having its protective relays for determining the existence of a fault in that zone and having circuit breakers for disconnecting that zone from the system.

The relays operate usually from currents and voltages derived from current and potential transformers or potential devices. A station battery usually provides the circuit breaker trip current. Successful clearing depends on the condition of the battery, the continuity of the wiring and trip coil, and the proper mechanical and electrical operation of the circuit breaker as well as the closing of the relay trip contacts.

In the event of failure of one of these elements, so that the fault in a given zone is not cleared by the main or the primary protection scheme, some form of backup protection is ordinarily provided to do the next best thing. This means first of all to clear the fault automatically if at all possible, even though this requires disconnection of a considerable portion of the system. The measures taken to provide backup protection vary widely depending on the value and importance of the installation and the consequence of failure.

The backup protection is normally of a form different from the main protection and should preferably be of the nonunit type, e.g. over current or distance protection. It is usually for economic reasons not so fast or as discriminative as the main protection.

1.8 Basic Principle of Operation of Protective System

Each relay in a protection scheme performs a certain function and responds in a given manner to a certain type of change in the circuit quantities. For example one type of relay may operate when the current increases above a certain magnitude, while another may compare current and voltage and operate when the ratio V/I is less than a given value. The first relay is known as an *overcurrent relay* while the latter an *under-impedance relay*. Similarly various combinations of these electrical quantities could be worked out according to the requirements at a particular situation, because for every type and location of failure there is some distinctive difference in these quantities, and there are various types of protective relaying epuipments available, each of which is designed to recognize a particular difference and to operate in response to it.

1.9 Economic Considerations

We are quite familiar in day-to-day life that there is an economic limit to the amount that can be spent on different types of insurances in order to safeguard life and property. Similarly in a power system there is an economic limit to the amount that can be spent on the protection of the system. Usually this is a very complex affair since the probability of failure or fault is a function of component, location, time, etc. All these factors can lead to different alternatives for the same problem, and a choice has to be made keeping in view the economic justifiability. The cost of protection is linked with cost of the plant to be protected and increases with cost of the plant. Usually the protective gear should not cost more than 5% of the total cost. However, when the apparatus to be protected is of paramount importance like the generator or the main transmission line, economic considerations are often subordinated to reliability. Table 1.3 shows the average costs in units per circuit.

Table 1.3 *Average costs in units per circuit*

	Indoor 33 KV	*Outdoor* 132 KV	275 KV	400 KV
Total avg. circuit cost	10.0	50.0	100.0	230.0
Relays	0.7	2.5	2.4	4.6
Relay panels	0.4	0.6	1.5	2.3
Wiring (metal-clad)	0.9	2.0	0.8	0.9
Relay room	0.32	0.5	0.5	1.0
CTs	0.4	4.7	12.0	25.7
PTs	1.0	3.4	7.0	9.0

1.10 Basic Terminology

We define below some of the important terms used in the study of protective relays and switchgear.

Protective Relay. An electrical device designed to initiate isolation of a part of an electrical installation, or to operate an alarm signal, in the event of an abnormal condition or a fault.

Unit or Element. A self-contained relay unit which in conjunction with one or more other relay units performs a complex relay function, e.g. a directional unit combined with an overcurrent unit gives a directional overcurrent relay.

Energizing Quantity. The electrical quantity, i.e. current or voltage either alone or in combination with other electrical quantities required for the functioning of the relay.

Characteristic Quantity. The quantity to which the relay is designed to respond, e.g. current in an overcurrent relay, impedance in an impedance relay, phase angle in a directional relay, etc. Some relays have a calibrated response to one or more quantities, such quantities are called *characteristic quantities.*

Setting. The actual value of the energizing or characteristic quantity at which the relay is designed to operate under given conditions.

Power Consumption (Burden). The power consumed by the circuits of the relay at the rated current or voltage. It is expressed in volt-amperes for a.c. and watts for d.c.

Pickup. A relay is said to pickup when it moves from the *off* position

to the *on* position. The value of the characteristic quantity above which this change occurs is known as *pickup* value.

Dropout or Reset. A relay is said to dropout when it moves from the *on* position to the *off* position. The value of the characteristic quantity below which this change occurs is known as *dropout* or *reset* value.

Operating Time. The time which elapses between the instant of application of a characteristic quantity equal to the pickup value and the instant when the relay operates its contacts.

Resetting Time. The time which the operated relay takes to come back to its initial position as a result of a specified sudden change of the characteristic quantity, the time being measured from the instant at which the change occurs.

Overshoot Time. The time during which stored operating energy is dissipated after the characteristic quantity has been suddenly restored from a specified value to the value which it had at the initial position of the relay.

Characteristic Angle. The phase angle at which the performance of the relay is declared.

Characteristics (of a Relay in Steady State). The locus of the pickup or reset when drawn on a graph. In some relays the two curves are coincident and become the locus of balance or zero torque.

Reinforcing Relay. Relay which is energized by the contacts of the main relay and with its contacts in parallel with those of the main relay relieves them of their current carrying duty. The seal-in contacts are usually of higher current rating than those of the main relay.

Seal-in-Relay. Similar to the reinforcing relay described above except connected to stay until its coil circuit is interrupted by a switch on the circuit breaker.

Primary Relays. Those which are connected directly in the protected circuit.

Secondary Relays. Those connected to the protected circuit through current and potential transformers.

Auxiliary Relays. Relays which operate in response to the opening or closing of its operating circuit to assist another relay in the performance of its function. The auxiliary relay may be instantaneous or may have a time lag and may operate within large limits of the characteristic quantity.

Backup Relay. A relay which operates usually after a slight time delay if the normal relay does not operate to trip its circuit breaker. A backup relay acts as a second line of defence.

Consistency. Accuracy with which the relay can repeat its electrical or time characteristics.

Flag or Target. A device used for indicating the operation of a relay, it is usually spring or gravity operated.

Reach. Remote limit of the zone of protection provided by the relay used mostly in connection with distance relays to indicate how far along a line the tripping zone of the relay extends.

Overreach or Underreach. Errors in relay measurement resulting in wrong operation or failure to operate respectively.

Blocking. Preventing the protective relay from tripping either due to its own characteristic or due to an additional relay.

QUESTIONS

1. Explain briefly the role of protection in a power system.
2. Describe the essential features of a protective relay with reference to reliability, selectivity, speed of operation and discrimination.
3. What are the principal types of faults in a power system? In what way is a fault harmful to the power system?
4. Define the terms: burden, pickup, reset, operating time.
5. Explain what is meant by primary protection and backup protection.

CHAPTER 2

Basic Principles and Components of Protection

2.1 Methods of Discrimination

The main requirements and qualities of protection have been outlined in Chapter 1. Now a brief idea of the methods of discrimination of a fault so as to cause the appropriate and *only the appropriate* disconnecting device to function will be discussed. These methods will, however, be taken up in detail in subsequent chapters. These methods are basically of two types: (a) those which discriminate as to the location of fault, and (b) those which discriminate as to the type of fault.

2.1.1 Methods Discriminative to Fault Location

The main aim is that the faulty section of the system be isolated and in the minimum time. The various methods under this category are those in which the behaviour of the protective apparatus is dependent upon where it is situated in the system relative to the point of fault occurrence.

(a) ***Discrimination by Time.*** By adding time lag features to the controlling relays of a number of circuit breakers it is possible to trip the breaker nearest the fault prior to those farther off the point of fault. This simple scheme may be applied in a radial feeder shown in Fig. (2.1). The breakers

FIGURE 2.1 Radial feeder.

at *A*, *B*, *C* and *D* are identical and are set to operate for a given value of current. For a fault in any section, say *CD*, if the fault current exceeds

EXAMPLE 2.1

A 100/1 A bar primary CT supplies an overcurrent relay set at 10% pickup and having a burden of 1VA. It is required to cater for a current of 10 times the relay setting. Determine the knee point voltage and cross-section of the core if the CT has 10 secondary turns. Assume the flux density in the CT core to be 1 wb/m².

Solution. Secondary operating current of the relay=0.1 A

$\therefore$ Secondary volts=1/0.1=10 V.

For 10 times the current setting the CT secondary voltage is 100 V.

The knee point voltage must be slightly higher than 100 V.

The voltage induced in the winding is given by

$$E=4.44\times\phi\times f\times N,$$

i.e.
$$\phi=\frac{100}{4.44\times 50\times 10}$$

or area of cross-section$=\dfrac{100}{4.44\times 50\times 10\times 1}$

$$=0.045 \text{ m}^2$$

EXAMPLE 2.2

A summation transformer used for deriving relaying quantities for a protective system is supplied with an unsymmetrical three-phase input of phase sequence *RYB*. Obtain an expression for the ampere-turn output of the summation transformer in terms of the input turns ratio between primary tappings, and the *B*-phase sequence currents, if system conditions are such that $I_{B_1}=I_{B_2}$. Hence find the minimum value of n to be used with a $1:1.3:n$ primary-turns-ratio summation transformer, if positive outputs are to be maintained when $I_{B_1}/I_{B_0}=4$. What would be the effect on the value of n if a ratio $1:1:n$ were used?

Solution. Let the input-turns-ratio of the summation transformer be $l:m:n$ as shown in Fig. (2.20). Using *R*-phase as the reference, according to symmetrical component theory:

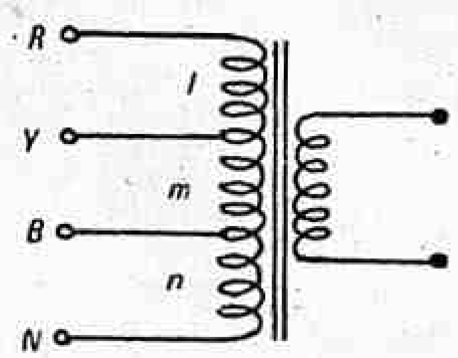


FIGURE 2.20

$$I_R=I_0+I_{R_1}+I_{R_2}$$
$$I_Y=I_0+a^2I_{R_1}+aI_{R_2}$$
$$I_B=I_0+aI_{R_1}+a^2I_{R_2}$$

Taking B as the reference phase we can write

$$I_{R_1}=a^2I_{B_1};\ I_{Y_1}=aI_{B_1}$$
$$I_{R_2}=aI_{B_2};\ I_{Y_2}=a^2I_{B_2}$$

Ampere turns output$=I_R(l+m+n)+I_Y(m+n)+I_Bn$

$$=I_0(l+2m+3n)+I_{B_1}(a^2l-m)+I_{B_2}(al-m)$$

If $\quad I_{B_1}=I_{B_2}$

Ampere turns output$=I_0(l+2m+3n)-I_{B_1}(2m+l)$.

If $\quad l:m:n=1:1.3:n$, for zero output

$$0=I_0(3.6+3n)-I_{B_1}\times 3.6$$

or
$$n=\frac{3.6}{3}\times\frac{I_{B_1}}{I_{B_0}}-\frac{3.6}{3}$$

If
$$\frac{I_{B_1}}{I_{B_0}}=4$$
$$n=3.6$$

If $\quad l:m:n=1:1:n$

$$0=I_0(3+3n)-3I_{B_1}$$

then
$$n=\frac{I_{B_1}}{I_0}-1$$

Therefore for
$$\frac{I_{B_1}}{I_0}=4$$
$$n=3$$

QUESTIONS

1. Describe briefly various methods of fault detection.
2. Explain briefly the principle of time grading in a simple radial system equipped with instantaneous overcurrent and earth-fault relays, and definite time-delay relays. Show how, by the use of directional relays, this same principle may be applied to the protection of a ring system, assuming the latter to be supplied at one point only.
3. What is a *unit protection*? Explain the principle of current-balance protection as applied to a simple two-ended circuit. Show how this principle can be employed in (a) the circulating-current system; and (b) the balanced voltage system.

4. Distinguish between time overcurrent relays, directional relays and differential relays.
5. Find the output of CT having a transformation ratio of 100/5 and secondary resistance of 0.1. ohm. Its secondary terminals are connected to a relay whose burden is 4.5 VA. The resistance of the connecting leads is 0.15 ohm. (10.75 VA)

the set value the breakers at A, B and C will trip and the whole feeder beyond A becomes dead.

For providing time lag to the circuit breakers at A, B, C, and D the tripping is delayed in the following manner:

D—no added time lag

C—0.4s added time lag

B—0.8s added time lag

A—1.2s added time lag

With such a scheme obviously if the fault occurs in the section CD the breaker at C will trip after a time of 0.4s and thus will clear the fault with the result that the feeder up to C will remain alive. A 0.4s step time lag is necessary to account for the time of operation of circuit breaker and its relay operation times.

(b) *Discrimination by Current Magnitude.* This depends on the current magnitudes as the magnitude of the fault current will also vary with the location of the fault. If the relays are set to pickup at a progressively higher current towards the source then a simple feeder system of the type shown in Fig. (2.1) can be protected. Such a scheme is known as current graded scheme.

(c) *Discrimination by Time and Direction.* In the case of a ring main which forms a closed loop it is not possible to isolate the faulty section with the help of time alone. Consider the ring main shown in Fig. (2.2). In one case nondirectional relays with same current setting but different time lags are

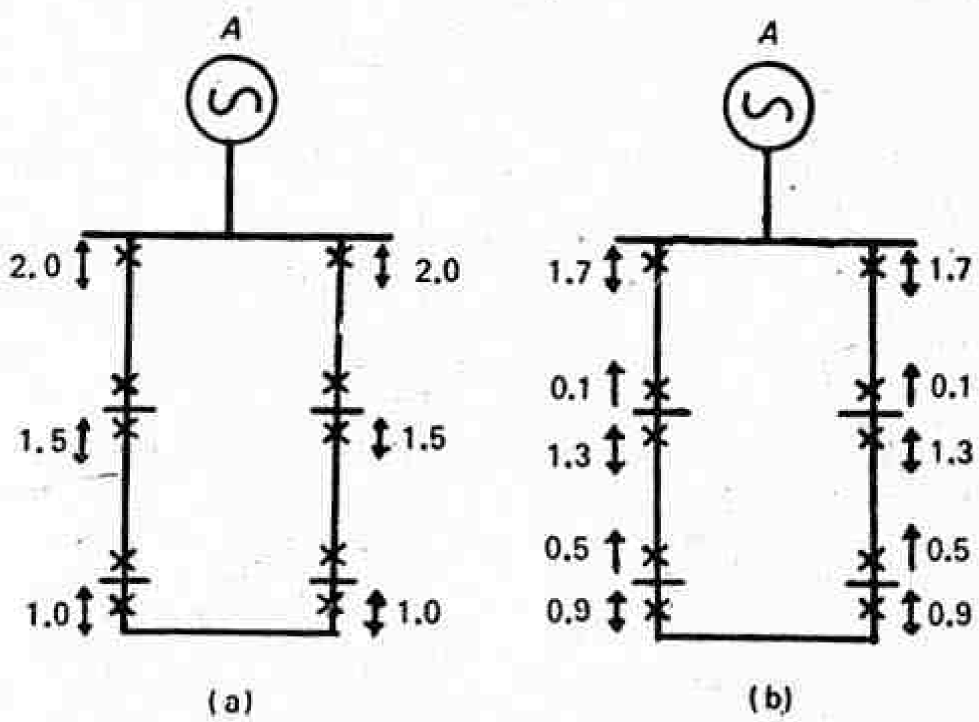


FIGURE 2.2 Ring main feeder: (a) with nondirectional relays; (b) with directional and nondirectional relays.

provided which shows that proper discrimination cannot be obtained nor can this position be improved by varying the time lags from those shown in the diagram.

In the second case for the same ring main directional feature is also introduced as shown by arrows. Now it can be seen that a fault occurring on any section will be discriminatively cleared without loss of supply.

(d) *Discrimination by Distance Measurement.* The methods described above which discriminate by time and current magnitude have limitations of being applicable to simple systems. Moreover the faults nearer to the source which are more severe take longer time to clear in the case of time discrimination systems.

Now if the relays are designed to measure the distance from the breaker location to the fault and if this distance happens to be less than that to the next breaker out from the source, the fault is within the section controlled by the breaker concerned and this trips. If the distance is greater than that to the next breaker out from the source, the fault is beyond the section controlled by the breaker concerned and therefore it does not trip. All successive breakers are controlled in this way and are set to operate only for faults in their own section.

The measurement of distance is achieved in various ways by what are known as *distance relays* to be discussed later.

(e) *Time as an Addition to Current Magnitude or Distance Discrimination.* Combination of time with current magnitude discrimination or with distance discrimination gives practical dimension to protection. It will be seen later that combination of time and current grading gives the most practical protection schemes and similarly the time distance discrimination forms another practical protection scheme. These schemes will be discussed at length in Chapter 5.

(f) *Current-Balance Discrimination.* The discriminative methods outlined above may not be adequate for a complex system having interconnections and alternative parallel paths, etc. This calls for a form of discrimination which is limited in its scope to one system element which will cause isolation of this element only in the event of fault in this element and will not respond to any other fault external to this element, even though the fault current passes through it. Such a protection is known as *unit protection*.

This form of protection is based on one of the following two principles: (a) circulating current principle; (b) opposed voltage principle or balanced voltage principle.

The circulating current principle compares the currents at the two ends of the protected section. This is illustrated in Fig. (2.3a), the difference of the current magnitude at the two ends flows through the relay. For an external fault the balance of currents is not disturbed and the section or apparatus is not isolated, whereas for a fault within the apparatus or the protected section the balance of currents is disturbed and the relay trips the breakers at the two ends and isolates this section completely.

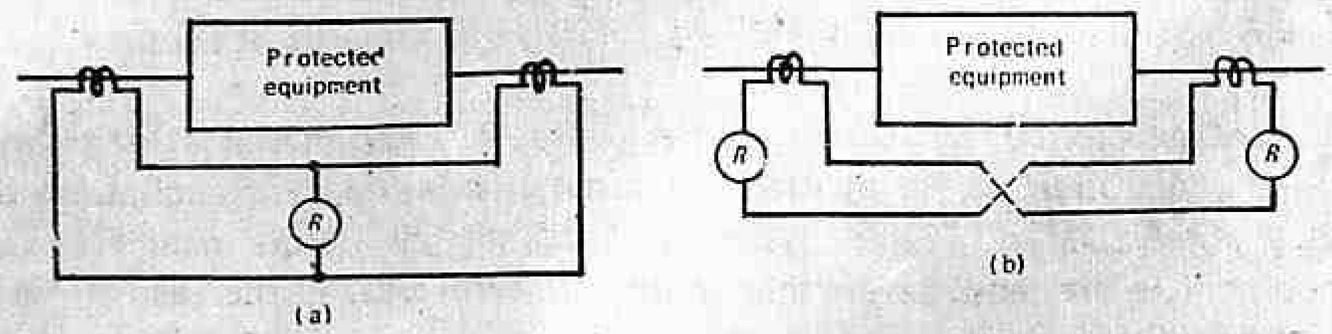


FIGURE 2.3 Unit protection scheme: (a) circulating current protection; (b) balanced voltage protection.

The principle of balanced-voltage protection is shown in Fig. (2.3b). Here the relative polarity of the CTs at the two ends is such that there is no pilot current for the conditions of load or external fault. The CT secondary voltages will no longer balance and current will flow in the relays which will trip the circuit breakers at the two ends.

(g) *Power-Direction Comparison Discrimination.* In this case the comparison of the direction of fault power at the two ends of the protected section is done by directional relays. Under external fault conditions the direction of the fault power is outwards at one end of the protected section. Under internal fault conditions, fault power is fed only into the section either at both ends or at one end, depending upon whether the source of power supply is on both sides or only on one side of the protected section. Figure (2.4) illustrates the principle of power directional comparison.

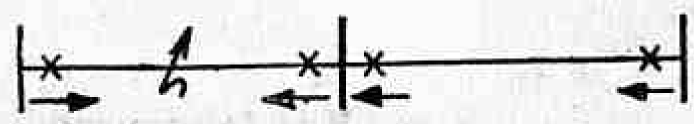


FIGURE 2.4 Directional comparison.

Considering one end of the line only and assuming that power flows into the line at this end, one of the following three things simultaneously applies:

(i) Power flows out at the other end, which means either load conditions or external fault conditions obtained; so tripping should be prevented.
(ii) Power also flows in at the other end, which means an internal fault condition and both breakers should trip.
(iii) No power flows either in or out at the other end, meaning thereby that there is no source on the other end and thus if the power flow is of sufficient magnitude it is due to fault in the section and the local breaker on this side only should trip.

The scheme outlined needs considerable elaboration to give it a practical shape. This will be discussed later in power line carrier protection.

(h) *Phase Comparison Discrimination.* This is another form of power line carrier protection. In this case the phase angle of current at the two ends of the protected section is compared, which gives an indication whether the fault is internal or external. Information about the phase angle of the primary current is transmitted to the other end over the carrier link.

2.1.2 Methods Discriminative to Type of Fault

There can be cases when the fault currents may not be very high or may differ little in magnitude from load currents with the result that current magnitude detection fails to point out such a fault. Such a fault current however has some peculiarity which distinguishes itself from the normal load currents. For instance, in a three phase system the currents and voltages can be resolved into their phase sequence components which would ultimately give some idea about the nature of the currents or voltages present.

(a) *Zero-Phase Sequence Networks.* These networks are commonly used for the detection of earth faults. By providing a relay at such a place where it will be energized only by zero-sequence currents an indication obtained of an earth fault as shown in Fig. (2.5). Such a relay will

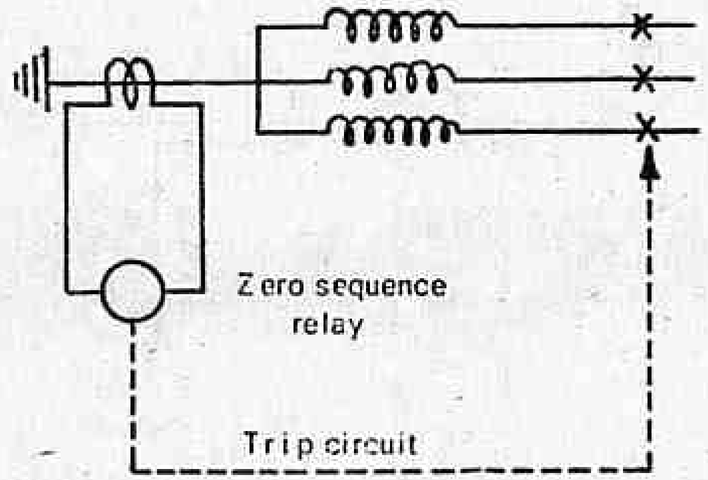


FIGURE 2.5 Zero-sequence relay.

ignore load currents or phase-to-phase short circuits. Hence the setting of such a relay will have no bearing on the load current values which is often essential for discrimination or even for adequate protection when earth currents are limited.

(b) *Negative-Phase Sequence Networks.* The presence of negative-phase sequence current represents some form of unbalanced condition such as phase-to-phase faults other than the symmetrical three-phase faults, broken conductors, etc. A typical negative phase sequence network is shown in Fig. (2.6).

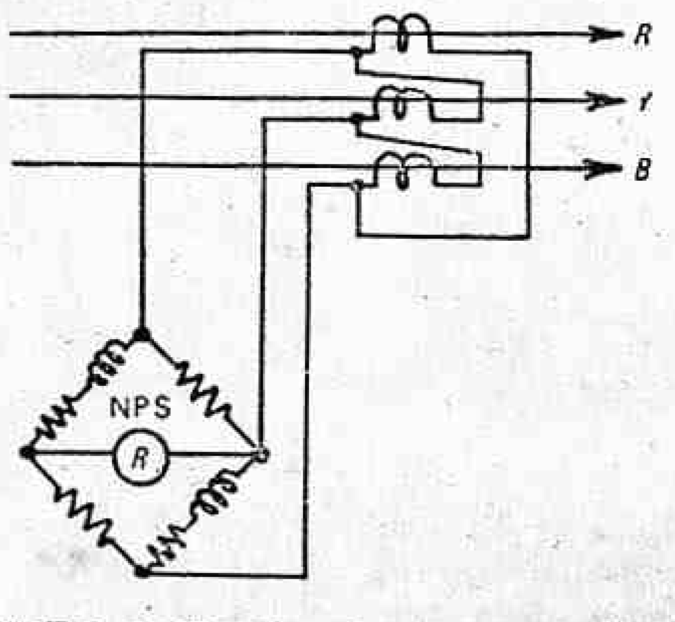


FIGURE 2.6 Negative-phase sequence network.

2.1.3 Discrimination by Combinations of Methods Sensitive to Location and Type of Fault

A combination of the methods discriminative to fault location and the methods discriminative to type of fault is very useful in actual practice. An example of such a combination is a protective scheme providing protection by overcurrent and earth fault relays. This uses time current discrimination and zero sequence device. Such a scheme is shown in Fig. (2.7).

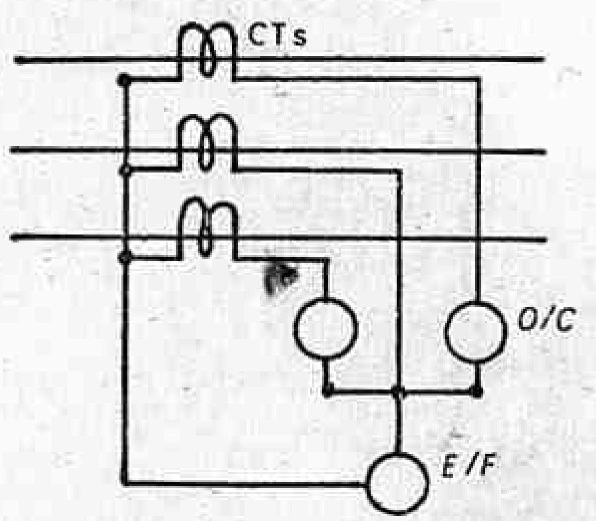


FIGURE 2.7 Combination of overcurrent and earth fault relays.

2.2 Derivation of a Single-Phase Quantity from Three-Phase Quantities

It will be seen later that auxiliary channels or pilot wires are used to transmit information from one end of the line to the other end. For a normal three-phase system three pilots would ordinarily be required which would

obviously be a very costly affair for longer systems, particularly transmission circuits. It would naturally be preferable to have a means of deriving a single-phase quantity which under both normal and abnormal conditions will be representative of the three-phase conditions. Sometimes it becomes necessary to segregate the sequence currents or voltages from corresponding line currents or voltages in order to simplify the protection scheme by reducing the number of relays required.

There are two commonly used methods for deriving single-phase quantity from a three-phase system.

(a) *Summation Transformers.* The three line current transformers (CTs) are connected to the primary of an auxiliary current transformer (summation transformer) as shown in Fig. (2.8). Each line CT energizes a different number of turns on the primary with a resulting single-phase output from the secondary. Thus for the typical case shown in Fig. (2.8) the output is seen to be proportional to the vector sum

$$(n+2)\,I_R+(n+1)\,I_Y+nI_B.$$

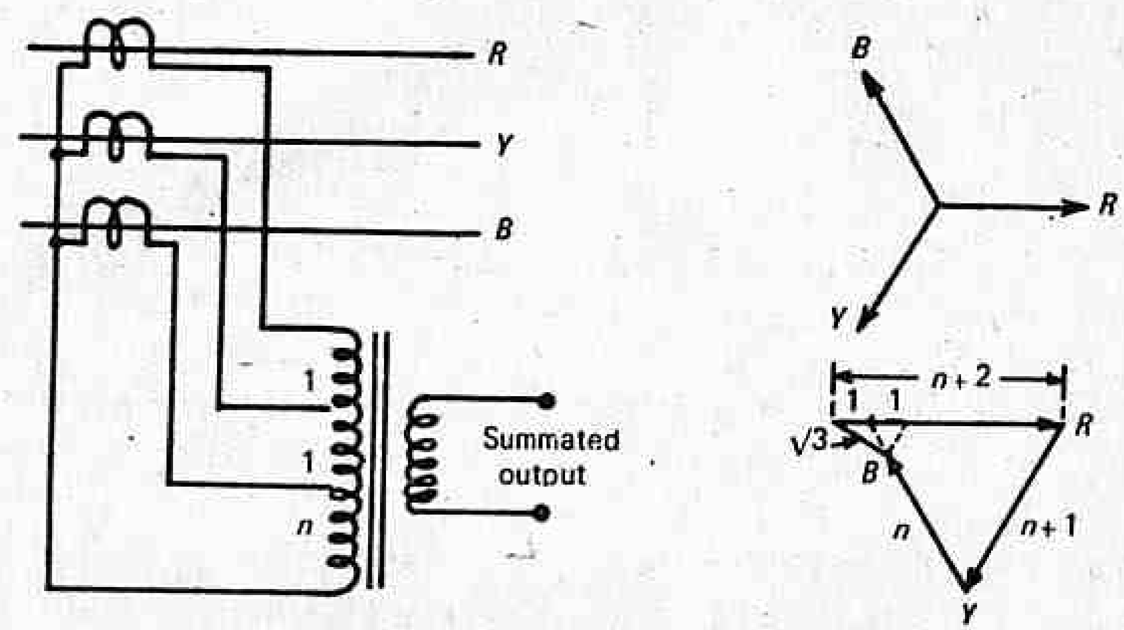


FIGURE 2.8 Summation transformer.

It is also possible to control independently the outputs for earth faults and phase faults. The output on earth faults is usually considerably more than that on phase faults so as to provide more sensitive action on earth faults. Consequently, the pickup setting can be expressed in terms of combinations of n and 1 for the various faults.

Table 2.1 shows the output current for a given fault current magnitude in each type of fault in terms of the rated current of CT.

Table 2.1 *Effect of summation on pickup settings*

Type of fault	*R–E*	*Y–E*	*B–E*	*R–Y*	*Y–B*	*B–R*	*R–Y–B*
Summation CT turns	$n+2$	$n+1$	n	1	1	2	$\sqrt{3}$
Pickup current	14%	16.5%	20%	90%	90%	45%	52%

Zero output or a negligibly small output may occur under through fault conditions when there is a phase-to-phase fault on the star side of the delta/star transformer giving a 1:2:1 current distribution in the protected feeder as shown in Fig. (2.9). In general, however, it is possible to choose tappings which make such cases very unlikely.

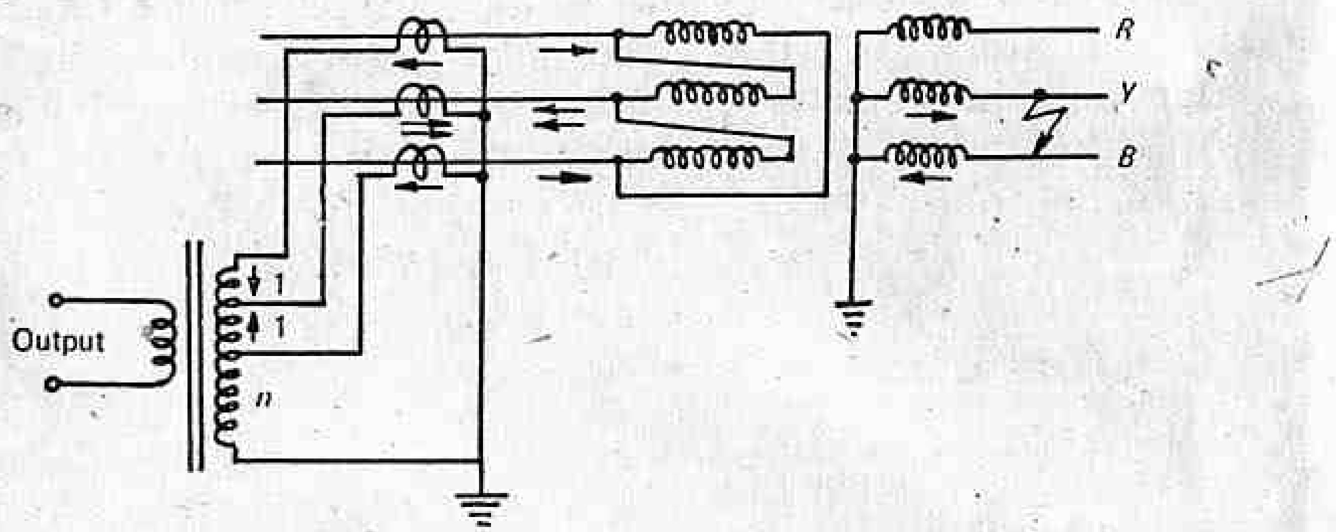


FIGURE 2.9 1:2:1 Current distribution.

(b) *Sequence Networks.* In some cases it is desirable to make the protection respond to a particular phase-sequence component of the three-phase system of currents or voltages. Zero-sequence and negative-sequence networks are frequently used in power system protection.

Zero-sequence networks are extensively used for earth fault protection. The connections of such a network are shown in Fig. (2.10). During

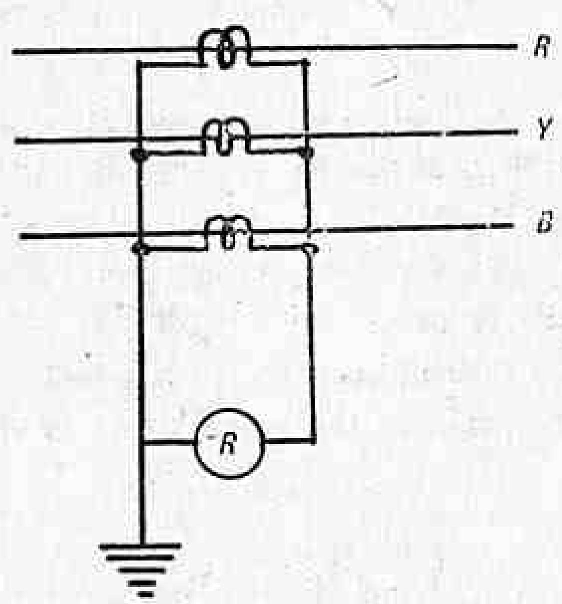


FIGURE 2.10 Zero-sequence network.

normal operation and for three-phase and phase-to-phase faults the current passing through the relay is zero. When a single or double earth fault occurs, the zero-sequence current flows through the relay.

For unbalanced conditions or unsymmetrical faults negative-phase sequence networks are used. One simple negative-sequence network is shown in Fig. (2.11). The values of r and C are such as to give a phase shift of 60°. It can be seen from the vector diagrams that for the

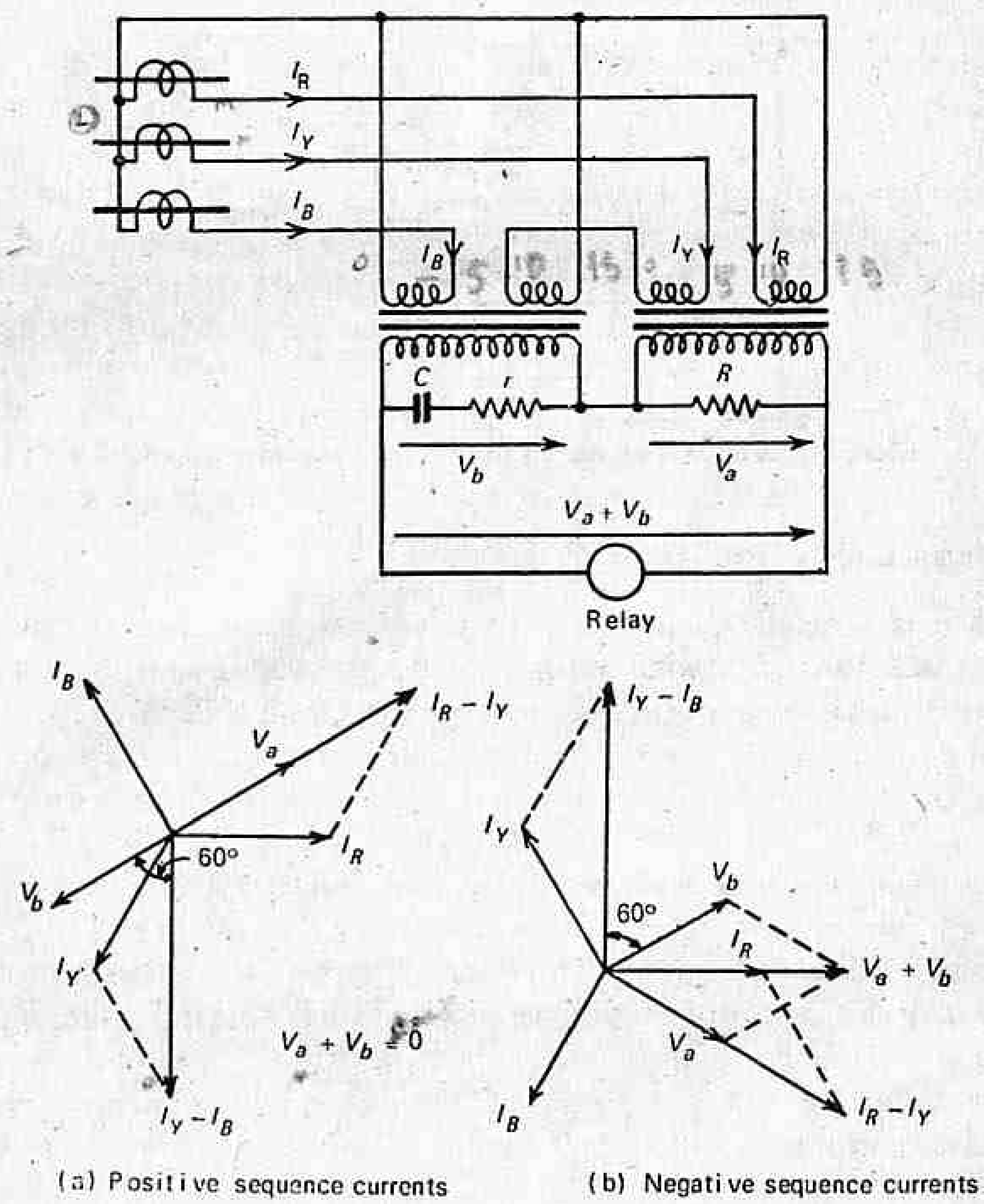


FIGURE 2.11 Negative-phase sequence network.

positive-sequence currents the output voltage $V_a + V_b$ applied to the relay is zero whereas for the negative-sequence currents the output voltage $V_a + V_b$ is of considerable magnitude to operate the relay.

However protection responding to positive-phase sequence components alone is not used in relaying practice, because under unsymmetrical faults, such a protection will have less sensitivity due to the fact that the positive-phase sequence component is only a part of the fault current.

It is possible however to use a combination of the positive-sequence, negative-sequence and zero-sequence networks as a general rule as shown in Fig. (2.12). A combination of positive and negative sequence networks is more common.

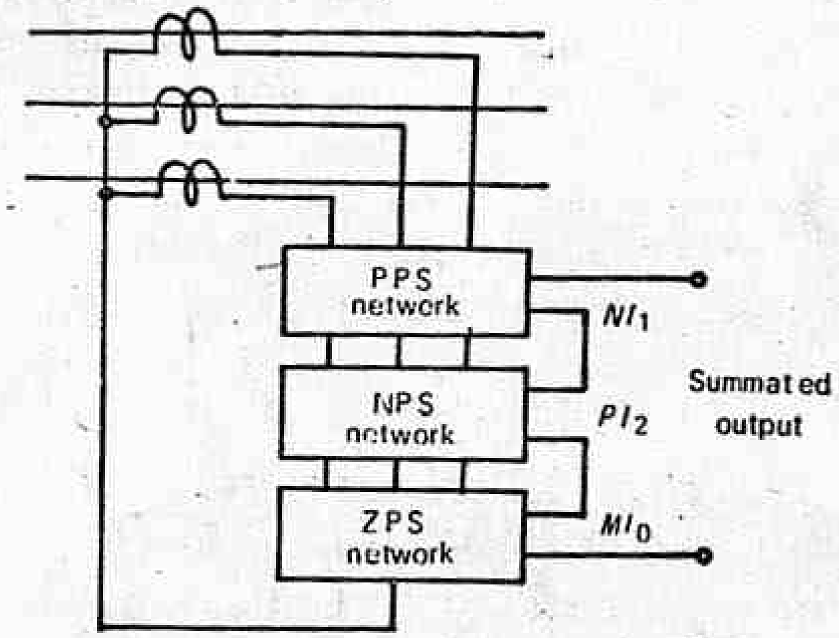


FIGURE 2.12 Combination of the three sequence networks.

2.3 Components of Protection

The various protective schemes to be described in the chapters to follow would make use of a wide range of components. Some of the more commonly used components will be described here in brief.

2.3.1 Relays

The main function of a protective relay is to isolate a faulty section with the least interruption to service by controlling the circuit breaker, when abnormal conditions develop. Thus the relays may be designed to detect and to measure abnormal conditions and close the contacts in the tripping circuit.

The following two categories of relays are most commonly used in protective relaying:

(a) *Secondary indirect-acting relays*: a group including practically all kinds of relays, e.g. current, voltage, power, impedance, reactance and frequency, whether minimum or maximum.

(b) *Secondary direct-acting relays*: a group of overcurrent and under-voltage relays designed to operate instantaneously or with time lag. These are primarily relays of the electromagnetic type which are built into circuit breaker operating mechanisms.

2.3.2 Circuit Breakers

Circuit breakers of various types are installed in all power circuits to open and close them under normal load conditions. Circuit breakers must correspond to nominal current and voltage rating and MVA breaking capacity to the load and fault power conditions at the given point of the circuit where they are incorporated. To isolate a fault from the power system one or more circuit breakers are required in conjunction with the protection.

Circuit breakers may be operated either manually or automatically. For our consideration here we will assume that it is controlled by a protective relay, so that when opening (tripping) is required a trip coil is energized, which releases energy stored in the mechanism thus causing the main contacts to part. The relay usually closes its contacts directly or via an auxiliary relay to close the trip coil circuit through a battery thus energizing the trip coil. When more than one breaker is to be tripped or where the trip coil current exceeds the relay-contact rating, an auxiliary relay of proper contact rating must be used.

While closing the trip coil circuit which is highly inductive the duty on the relay contacts is not so severe; but while breaking the trip coil current considerable damage would be done to these contacts. In order to overcome this difficulty an auxiliary switch operated by a mechanical link mechanism of the circuit breaker is connected in series with the trip coil and relay contacts. This auxiliary switch opens when the breaker contacts open. This action, however, takes place before the contacts of the relay open. This ensures that any inductance voltage would appear across the auxiliary contacts only and not across the relay contacts. The latter are thus saved from any possibility of burning.

The time of operation of circuit breaker actually depends on its design and usually lies between 0.05 and 0.25s. This must be accounted for while calculating final fault clearance time.

2.3.3 Tripping and Other Auxiliary Supplies

It is quite evident that a source of power supply other than the supply circuit being protected is required for the operation of the relays and the circuit breakers. It also goes without saying that such an auxiliary supply should be the most reliable one. Protective relay and automatic control schemes, in power system practice use two kinds of auxiliary supply: d.c. or a.c.

D.C. auxiliary power supply is provided from storage batteries maintained continuously charged by some type of supply set or a charger. The advantages of storage batteries are their high reliability and independence of a.c. power circuit conditions and of the existence of faults. Usually the voltage of the auxiliary supply is maintained at 110 V. All possible means are exploited in designing the auxiliary supply circuits to make them most reliable, such as by dividing all the receivers of the auxiliary d.c. according to their responsibility into different categories. Of these the most important are the protective relays, automatic control and the circuit breaker tripping circuits. Use of sectionalized buses is frequently made for such supplies. Separate buses may also be provided for supplying power to relays, circuit breakers and other indicating circuits such as alarm or warning signals.

All d.c. auxiliary supply circuits must have their insulation resistance maintained at an adequate level, as any breakdown in the insulation with respect to earth may lead to false tripping due to formation of a path for bypass of the current round the control devices. Because of this danger every d.c. auxiliary supply installation must include a unit for constantly monitoring the condition of the insulation (insulation resistance to earth). A simple circuit providing such a test is shown in Fig. (2.13). When the insulation is healthy the voltage of each pole relative to earth V_1 and V

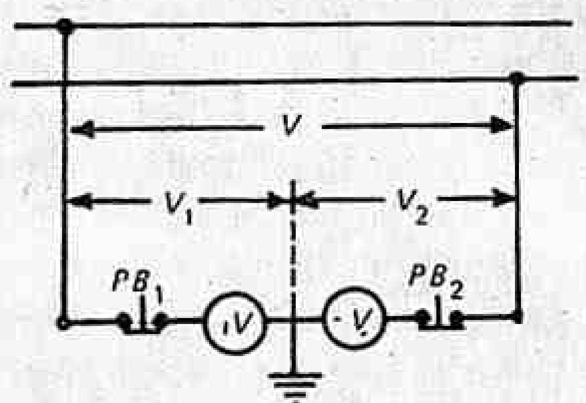


FIGURE 2.13 Insulation test of d.c. supply.

will be equal and half the voltage between both the poles. In case the insulation of one pole drops in value with respect to earth, the voltage to earth of this pole will also drop, but the voltage to earth of the other pole of the circuit will increase by the same amount.

Wherever conditions permit, it is of decided economic advantage to use a.c. instead of d.c. auxiliary supply for circuit breaker control and for energizing the protective relay. A.C. auxiliary supply for the protective relay scheme is mainly derived from the CTs. Under fault conditions, the current passing through the secondary of properly selected CTs, will always be sufficient to reliably trip the associated circuit breaker.

Figure (2.14) shows feeder overcurrent protection using a.c. auxiliary supply from CT. In this scheme the relay has normally-closed contacts. During normal operation the relay contacts continuously shunt the circuit-breaker trip coil and thus keep the breaker closed. As and when abnormal conditions are approached the relay operates to open its contacts. This puts the trip coil into CT circuit and the circuit-breaker trips. Many other schemes are also possible.

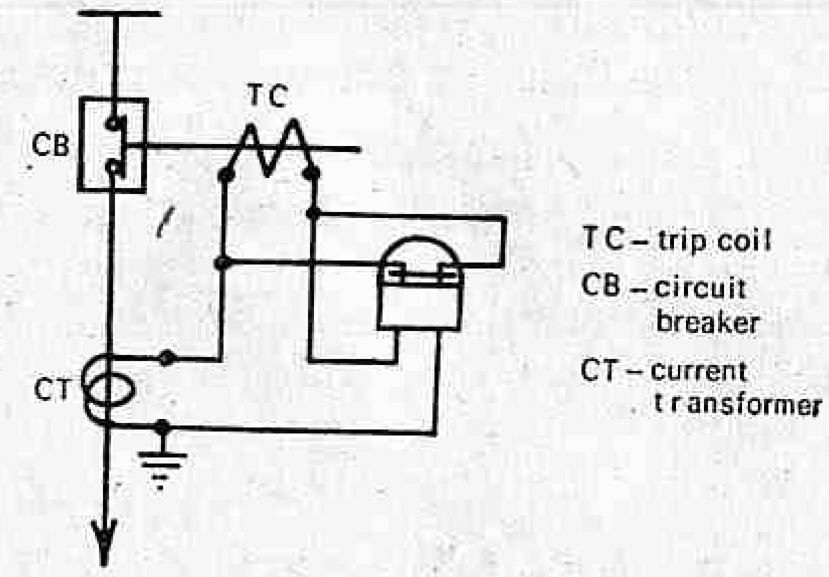


FIGURE 2.14 Relay with a.c. operative power from current transformer

2.3.4 Current Transformer (CT)

The primary circuit currents which are of high-magnitudes are to be reduced to values suitable for relay operation with the help of current transformers (CTs). Thus the CTs essentially insulate the secondary (relay) circuits from the primary (power) circuits and provide currents in the secondary which are proportional to those in the primary. The primary winding of the CT is connected in series with the load and carries the actual power system currents (normal or fault). The secondary is connected to the measuring circuit or the relay, which together with the winding impedance of the transformer and the lead resistance constitutes the burden of the transformer.

The CT is similar in operation to any other transformer so that the primary current consists of two components, viz. the secondary current which is transformed in the inverse ratio of the turns ratio and the exciting current which magnetizes the core. The latter current is not transformed and is the cause of the transformer errors. It is because of this reason that certain values of secondary currents could never be produced whatever the value of primary current, this happens when the core saturates and disproportionate amount of primary current is required to magnetize the core.

The general shape of a CT magnetization curve is shown in Fig. (2.15). The shape will change for different core materials. The characteristic is divided into three regions defined by the ankle point and the knee point. The boundary between the saturated and unsaturated regions is marked by the knee point which is defined as the point at which a 10% increase in secondary voltage produces a 50% increase in exciting current. The other characteristic curve shown in the diagram is the phase angle of exciting current which is not of much importance for protective CTs. It may, however, be noted that the working range of a protective CT extends over the full range between the ankle and the knee points and beyond, whereas the measuring CT usually operates in the region of the ankle point. This

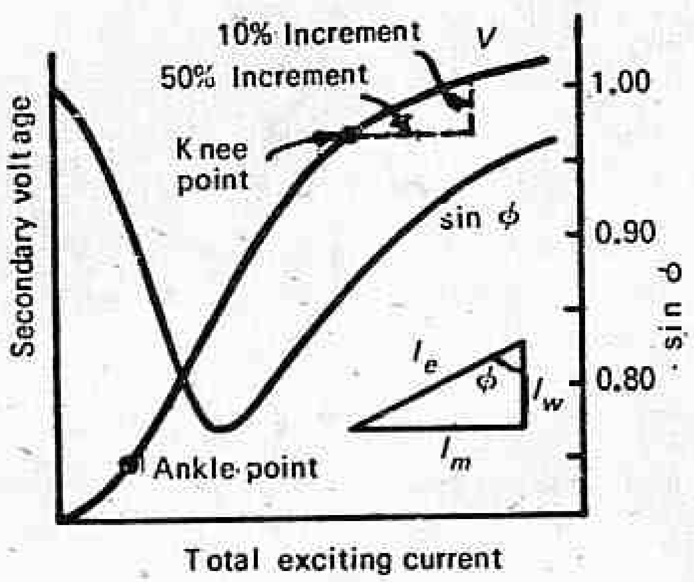


FIGURE 2.15. CT magnetizing characteristics.

is because of the radical difference in their basic functions. Measuring CTs require comparatively high accuracy over the range of 10% to 120% rated current, and it is an advantage if the CTs saturate for currents above this range in order to protect the instruments. Protection CTs, on the other hand, require linear characteristics up to the secondary voltage corresponding to maximum fault current flowing in the connected burden. Figure (2.16) shows the characteristics of two CTs both for the same rated burden, but one for protection and the other for measurement. It is quite

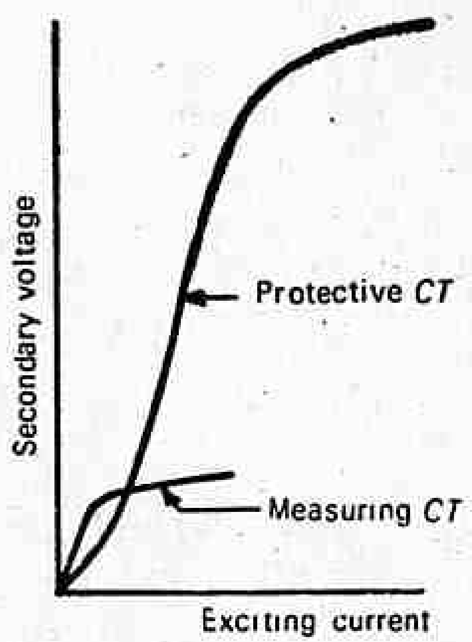


FIGURE 2.16. Protective and measuring CTs.

obvious that a core of larger cross section would be required for a protective CT if the material has to be the same. Grain oriented steels having high saturation levels are used as core materials for protective CTs and nickel-iron alloys having low exciting ampere-turns per unit

length of the core are used for measuring CTs and the knee point occurs at a relatively low flux density.

It is common practice to use 1A secondary rating CTs. There is a practical limit to the number of turns which can be wound on the bar primary CT which is usually about 1500 secondary turns. When rated primary currents much in excess of 1500 A are encountered then the main bar primary CT with rated secondary current of 5A or 10A along with auxiliary CTs of 5/1 or 10/1 A respectively, are used.

2.3.5 Voltage Transformers

It is not possible to connect the voltage coils of the protective devices directly to the system in case of high voltage systems. It is therefore necessary to step down the voltage and also to insulate the protective equipment from the primary (power) circuit. This is achieved by using a voltage transformer (VT) also known as a potential transformer (PT) which is similar to a power transformer. The voltage transformer is rated in terms of the maximum burden (VA output) it delivers without exceeding specified limits of error, whereas the power transformer is rated by the secondary output it delivers without exceeding a specified temperature rise. The output of VTs is usually limited to a few hundered volt amperes and the secondary voltage is usually 110 V between phases.

Ideally a VT should produce a secondary voltage exactly proportional to the primary voltage and exactly in phase opposition. This cannot obviously be achieved in practice owing to the voltage drops in the primary and secondary coils due to the magnitude and power factor of the secondary burden. Thus, ratio errors and phase angle errors are introduced.

The limits of ratio and phase angle errors for VTs used for protection are much larger than those required for measurement purposes only. The acceptable limits of error for protective VTs as specified by IS:3156 (Part III)–1966 are shown in Table 2.2. A three-phase residually connected VT is shown in Fig. (2.17), where all the three phases

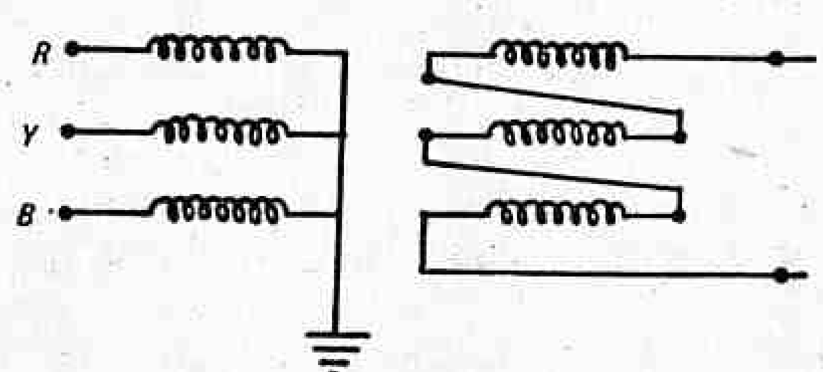


FIGURE 2.17. Three-phase residual VT.

Table 2.2 *Limits of voltage errors and phase displacement*

Accuracy class	*Voltage (ratio) error (%)*	*Phase displacement (minutes)*
3.0	±3.0	±120
5.0	±5.0	±300

of the primary windings are connected between line and earth and the secondary windings are connected in an open delta. In this case the residual voltage is equal to three times the zero sequence voltage. In order to have a voltage in the secondary circuit there must be zero sequence voltages in the primary circuit. Hence such an arrangement is used in neutral displacement schemes and for supplying the voltage circuit of directional earth fault relays.

There are two types of voltage transforming devices: the conventional wound type voltage transformer and the capacitor voltage transformer. The wound type VT is conveniently used for system voltages up to or below 132 KV for economic reasons, and the capacitor VT is used for voltages above 132 KV. The capacitor VT is essentially a capacitance potential divider with the basic circuit shown in Fig. (2.18a). If the current flowing in the output circuit (i.e., in the connected burden) is negligible then

$$V_{\text{output}} = V_{\text{input}} \times \frac{C_1}{C_1+C_2}.$$

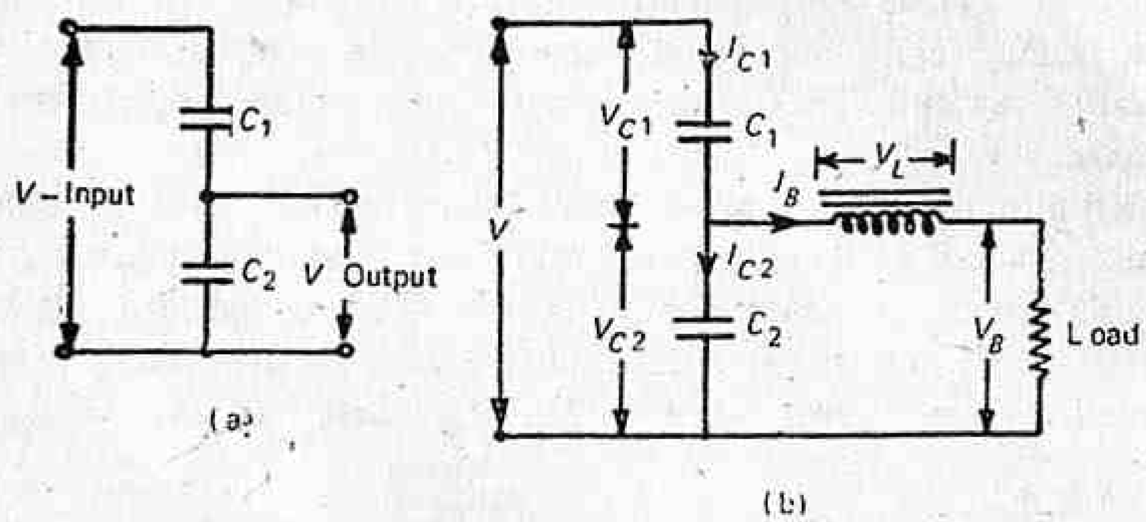


FIGURE 2.18. Capacitor voltage divider: (a) basic circuit; (b) compensated circuit.

But when appreciable current flows in the burden, errors, both in ratio and phase, are introduced, because of the load current flowing through the capacitor C_1. The voltage drop on load due to reactance of the capacitors can be compensated by inserting an inductive reactance in series with the load as shown in Fig. (2.18b). The requirement is that a current flowing in the burden shall meet zero impedance in the capacitor divider. In other words, the circuit must offer zero impedance to the load current with the line and

earth terminals short circuited, i.e., $\omega L = 1/(\omega C_1 + \omega C_2)$. Values of C_1 and C_2 are so chosen that a major part of the voltage drops across C_1, i.e. $C_1 \ll C_2$ so that $\omega L \simeq 1/\omega C_2$. The vector diagram of the compensated circuit for a unity power factor (upf) load is shown in Fig. (2.19). The following three conditions are of interest:

(i) For constant voltage V and a constant voltage V_B a change in burden, i.e. I_B changes V_{c1}, V_{c2} and V_L.
(ii) For zero burden impedance, i.e. output terminals short circuited, the circuit has C_1 in series with L and C_2 in parallel forms an acceptor circuit tuned to the fundamental frequency. This results in increasing V_{c1}, V_{c2}, I_{c1}, I_{c2} and I_B to infinity. To protect from these conditions a protective spark gap is connected across C_2.
(iii) For infinite burden impedance or for output terminals open circuited V_L is zero and $V_B = V_{c2}$.

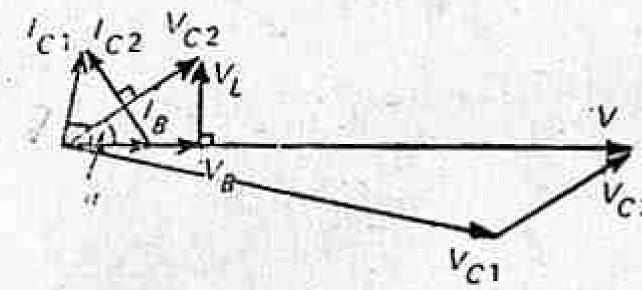


FIGURE 2.19 Capacitor VT with upf burden.

2.3.6 Linear Coupler

An iron-cored CT has the limitation of saturation and owing to d.c. offset transient component present in the fault current, the stability on heavy through faults may be difficult to obtain.

With air-cored CTs, also known as linear couplers, the problem of saturation and d.c. offset transient are overcome. Two major difficulties with relay transient problems are differential saturation and the transference of d.c. through the iron-cored CT. These are obviously solved; firstly because iron has been removed, and secondly because this device transforms the exponential waveform with a high degree of attenuation of the d.c. offset in the output wave form.

Assuming the primary current i_p to have 100% d.c. offset, i.e.

$$i_p = I_m(\cos \omega t - e^{-Rt/L})$$

The secondary voltage is given by $M\,di/dt$,

$$v_s = -\omega M I_m \left(\sin \omega t - \frac{R}{\omega L} e^{-Rt/L} \right)$$

It can thus be seen that the d.c. component voltage has been attenuated by a ratio R/X which may be 1/10 to 1/20 depending on the system.

CHAPTER 3

Operating Principles and Constructional Features of Relays

3.1 Relay Classification

There are various types of relays used for power system protection. Normally the actuating quantity is an electrical signal, although sometimes the actuating quantity may be pressure or temperature. The electrical type of protective relays can be classified in a number of ways.

(1) According to the function in the protective scheme, relays may be divided into main, auxiliary and signal relays.

The main relays are the protective elements which respond to any change in the actuating quantity, e. g. current, voltage, power, etc.

The auxiliary relays are those which are controlled by other relays to perform some auxiliary function such as introduction of a time delay, increasing the number of contacts, increasing the making or breaking capacity of the contacts of another relay, passing a signal from one relay to another, tripping of circuit breaker, energizing a signal or an alarm, etc.

Signal relays function to register the operation of some relay by flag indication, simultaneously it can also actuate an audible alarm circuit. The choice of signal relay depends upon the importance of the associated switchgear, the method of control and the number of alarm indications to be displayed.

(2) According to the nature of actuating quantity to which the relay responds: current, voltage, power, reactance, impedance, frequency, and the direction of the change they respond to. Such relays are differentiated as over and under relays. Relays which respond to the actuating quantity when it exceeds a predetermined value are overrelays and if they operate when the value of the actuating quantity drops below a predetermined value, they are known as underrelays. Hence an overcurrent relay is one which operates when the value of current exceeds a predetermined

value and an under voltage relay is one which operates when the voltage falls below a particular level.

(3) According to the connection of sensing element primary relays are those whose sensing elements are directly connected in the circuit or element they protect, and secondary relays are those whose sensing elements are connected through a current or voltage transformer. Normally secondary relays are used in power system protection because of the high values of line voltages and currents.

(4) According to the method by which the relays act upon the circuit breaker relays are divided into direct acting relays whose control element acts mechanically to operate a circuit breaker and an indirect acting relay whose control element switches in the auxiliary power source to operate the circuit breaker.

Generally speaking the electrical protective relays can be broadly classified into two categories: (a) *electromagnetic relays*, (b) *static relays*. In this chapter electromagnetic relays are discussed. The study of static relays is taken up in Chapter 9.

3.2 Principal Types of Electromagnetic Relays

There are two principal types of electromagnetic relays: (a) *attracted armature type*; and (b) *induction type*.

(a) *Attracted Armature Type*. This includes plunger, hinged armature, balanced beam and moving iron polarized relays. These are the simplest type which respond to a.c. as well as d.c. Figure (3.1) illustrates these types of relays.

All these relays have the same principle, that is, an electromagnetic force is produced by the magnetic flux which in turn is produced by the operating quantity. The electromagnetic force exerted on the moving element is proportional to the square of the flux in the air gap or the square of the current. In d.c. electromagnetic relays this force is constant; if this force exceeds the restraining force, the relay operates reliably. In a.c. electromagnetic relays the electromagnetic force is given by

$$
\begin{aligned}
F_e &= KI^2 \\
&= K(I_{\max} \sin \omega t)^2 \\
&= \tfrac{1}{2} K (I_{\max}^2 - I_{\max}^2 \cos 2\omega t) \qquad (3.1)
\end{aligned}
$$

It shows that the electromagnetic force consists of two components, one constant independent of time ($\frac{1}{2} KI_{\max}^2$) and another dependent on time and pulsating at double the frequency of the applied alternating quantity ($\frac{1}{2} KI_{\max}^2 \cos 2\omega t$). The total electromagnetic force thus pulsates at double

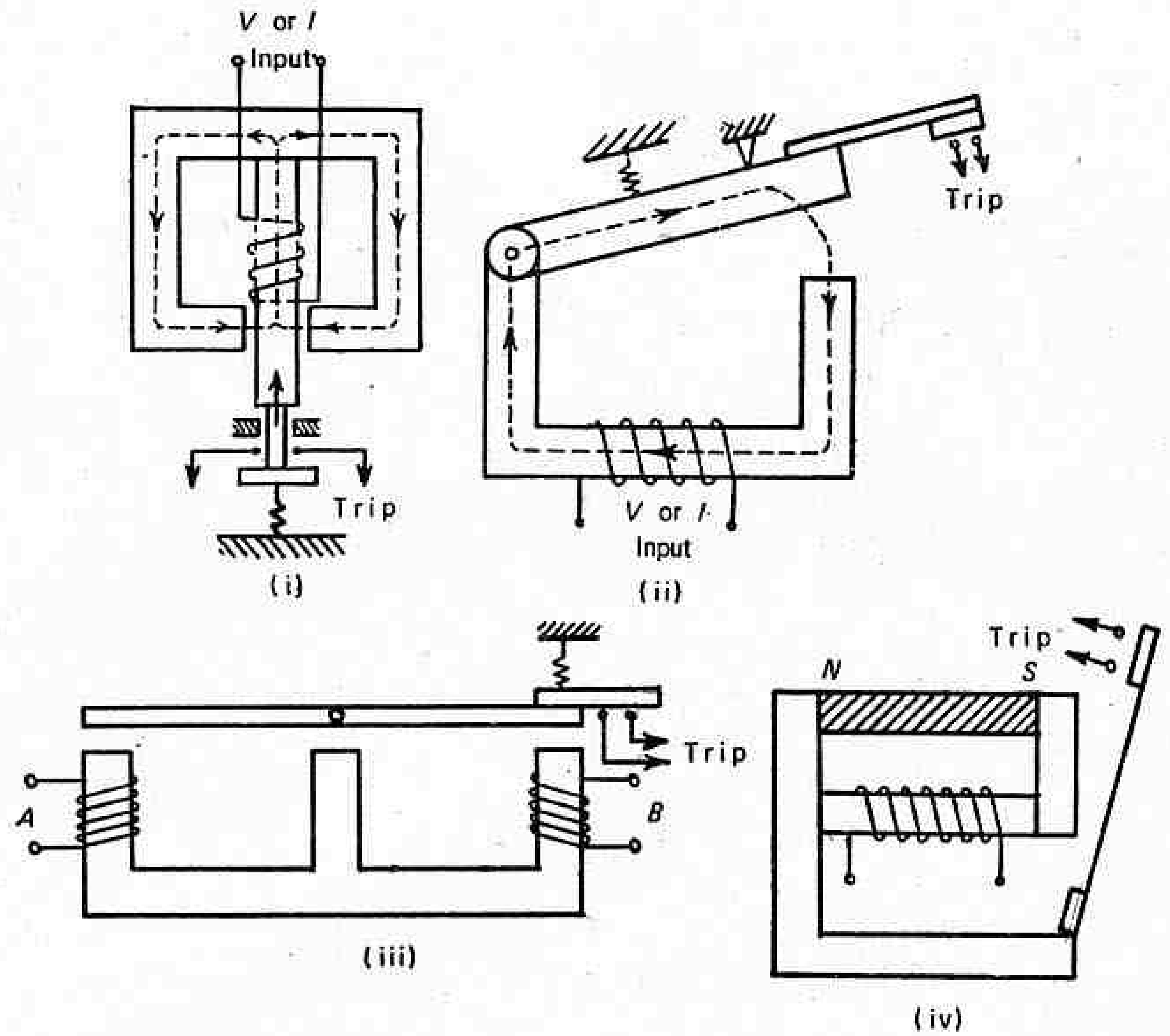


FIGURE 3.1 Attracted armature relays; (i) plunger type; (ii) hinged armature type; (iii) balanced beam type; (iv) polarized moving iron type.

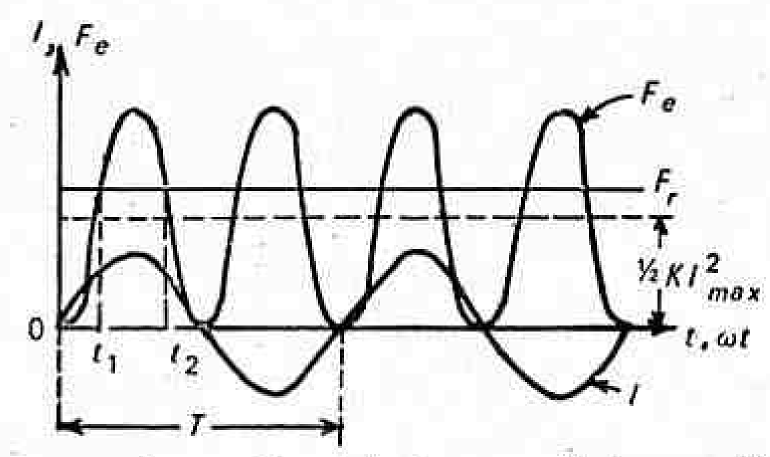


FIGURE 3.2 Curves of current and electromagnetic force applied to armature.

the frequency. The force Eq. (3.1) is plotted graphically in Fig. (3.2) which shows that F_e equals zero every half period.

If the restraining force F_r which is produced with the help of a spring is constant, the relay armature will be picked up at t_1 and the armature drops off at t_2. Hence the relay armature vibrates at double the frequency. This causes the relay to hum and produces noise and also is a source of damage to the relay contacts. This leads to sparking and unreliable operation of the relay operative circuit contacts due to make and break of the circuit.

To overcome this difficulty in a.c. electromagnetic relays the flux producing the electromagnetic force is divided into two fluxes acting simultaneously but differing in time phase, so that the resultant electromagnetic force is always positive and if this is always greater than the restraining force F_r then the armature will not vibrate. This is easily achieved by providing shading in the electromagnet as shown in Fig. (3.3).

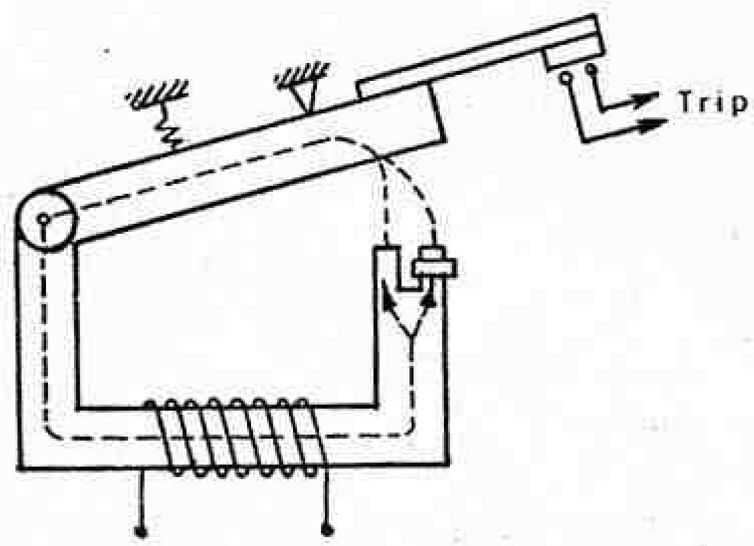


FIGURE 3.3 Electromagnetic relay with shading.

The flux through the shaded pole lags behind the flux through the unshaded pole.

The same thing can also be achieved by providing two windings on the electromagnet having a phase shifting circuit. One simple circuit is shown in Fig. (3.4a) having two windings W_1 and W_2 on the same electromagnet. Figure (3.4b) shows the vector diagram. However, the shading coil method is more simple and is used widely.

Hinged armature relays are mainly used as auxiliary relays, e.g. tripping relays, a.c. and d.c. voltage and current relays. Their volt-ampere consumption is low being of the order of 0.05 watt at pickup with one contact. The volt-ampere consumption increases with the number of contacts.

In the case of balanced beam type two quantities A and B are compared. Actually $|A|^2$ and $|B|^2$ are compared because the electromagnetic forces are proportional to (ampere-turn)^2. It has low ratio of reset/operating

current. If set for fast operation, there is a tendency to overreach on transient conditions.

The sensitivity of the hinged armature relays can be increased for d.c. operation by the addition of a permanent magnet. This is known as a polarized moving iron relay. It is more robust in construction; most of these use leaf-spring supported armatures.

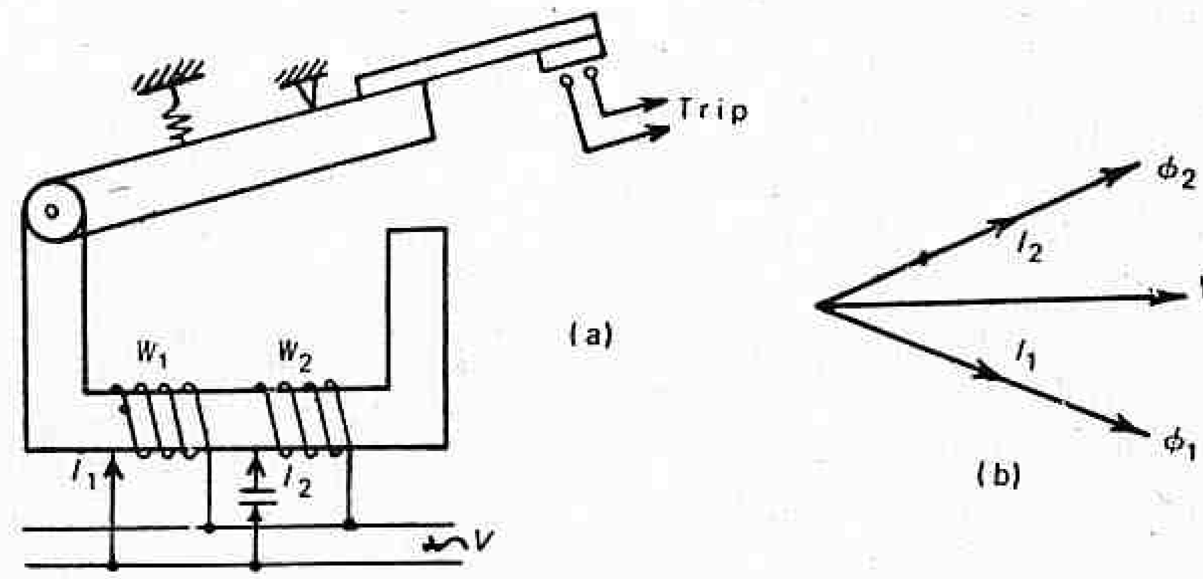


FIGURE 3.4 · Electromagnetic relay with two windings: (a) schematic diagram; (b) vector diagram.

(b) ***Induction Relays.*** Torque is produced in these relays when one alternating flux reacts with the current induced in the rotor by another alternating flux displaced in time and space but having the same frequency. Induction relays are widely used for protective relaying involving a.c. quantities. High, low and adjustable speeds are possible, and various shapes of time/operating quantity curves can be obtained. Depending on the type of rotor whether a disc or a cup the relay is known as an *induction disc* or an *induction cup* relay.

Various features of construction of an induction relay are shown in Fig. (3.5). Figures (3.5a and b) show the most common type of induction disc type relays which are also known as *shaded pole type* and *wattmetric type* of induction disc relays respectively. In the shaded pole relay the main flux is split into two fluxes displaced in time and space with the help of a shading ring, the air gap flux of the shaded poles lags behind that between the nonshaded poles. In the wattmetric type there are two magnetic systems. A phase displacement between the fluxes is obtained either by having different resistance and inductance for the two circuits or by energizing them from two different sources whose outputs are relatively displaced in phase. Many variations in the design and construction are possible to suit the required conditions. The disc may be of aluminium or copper or it may be a hollow cylinder open at one end, i.e. cup shaped as shown in Fig. (3.5c). Normally the relay contacts are operated directly by an arm carried on the rotor spindle but in some time lag types the rotor runs at

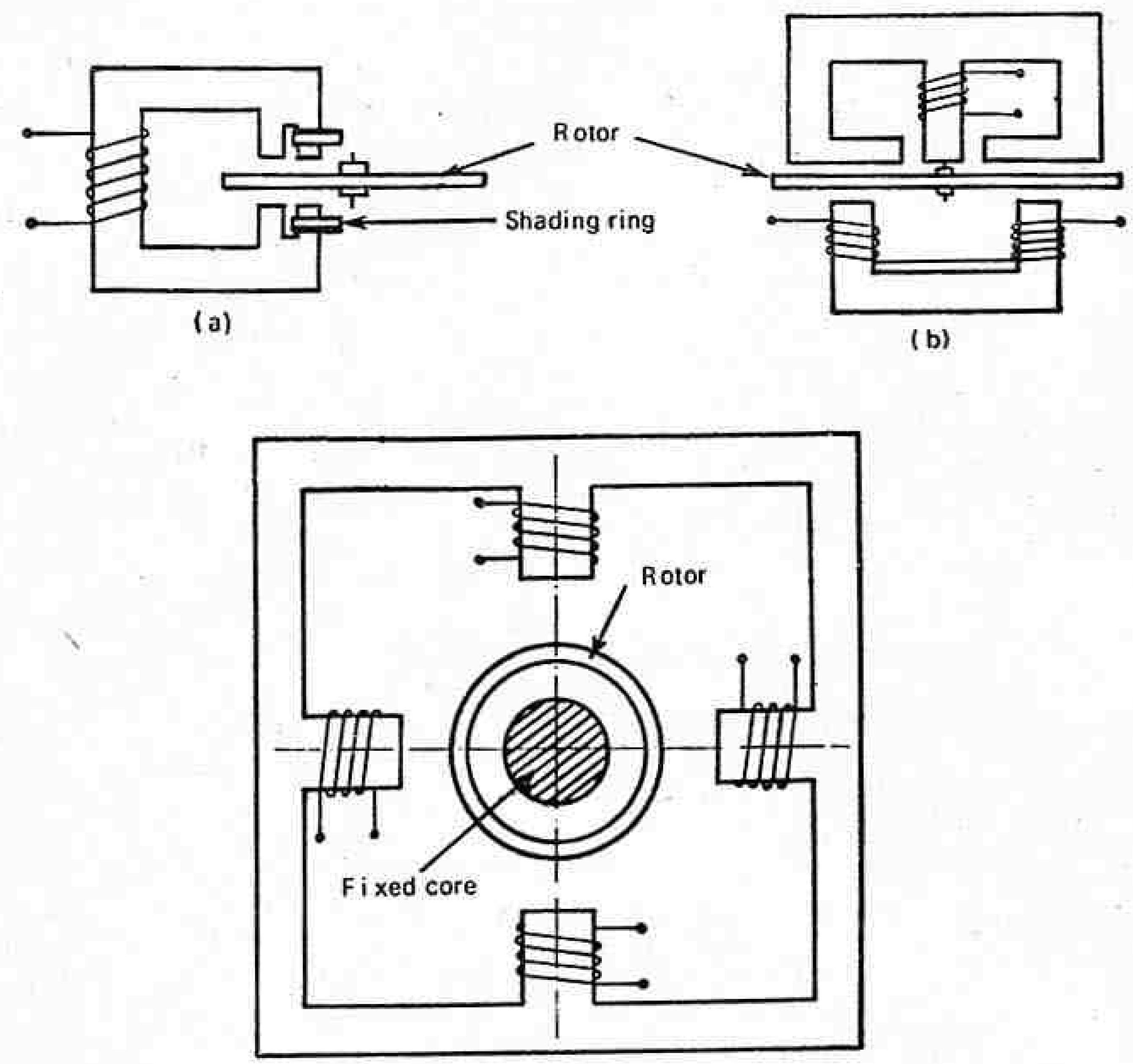


FIGURE 3.5 Induction relays: (a) shaded pole type induction disc relay; (b) wattmetric type induction disc relay; (c) induction cup relay.

a comparatively high speed and the contacts are driven through gears.

The distance of travel of the arm carrying the bridging contact to the relay contacts can be adjusted with the help of the time multiplier setting. Taps are provided on the input side of the operating quantity which can be adjusted with the help of inserting the plug. This is known as the plug multiplier setting. A permanent magnet is provided to give eddy current breaking to the disc. This is necessary to reduce to a minimum the over-run of the disc in case the current or voltage providing the driving torque stops before the operation has been completed. A modern induction disc relay will have an overrun of not more than 2 cycles on interruption of 20 times the setting quantity.

Induction cup relays operate on the same principle as the induction motor. A rotating field is produced by the two pairs of coils shown in Fig. (3.5c). The rotating field induces currents in the cup causing it to rotate in the same direction. A control spring, and the back stop or closing of the contacts carried on an arm attached to the spindle of the cup, prevent continuous rotation. The rotation depends on the direction of rotation of the field and the magnitude of the applied voltage and/or currents and the phase angle between them. This type is very fast in operation owing to the light rotor and minimum magnetic leakages in the magnetic circuit. Relays of this type may have an operating time of less than 0.010 second. They can be made to have linear operating characteristics and a very high ratio of resetting to operating values. These are best suited where normal and abnormal conditions are very close together, so that it can be set to trip instantaneously up to 90% of the protected section as a distance relay. These are also ideal as directional relays because of their high sensitivity, speed and nonvibrating steady torque, the parasitic torques due to current or voltage alone are small.

3.3 Theory of Induction Relay Torque

Two magnetic fluxes ϕ_1 and ϕ_2 differing in time phase penetrate through a disc. These alternating fluxes induce emfs e_1 and e_2 in the disc which lag their respective fluxes by 90°. These emfs lead to the flow of eddy currents i_1 and i_2. By the interaction of ϕ_1 with i_2 and ϕ_2 with i_1 a driving torque is produced. The currents i_1 and i_2 lag the voltages e_1 and e_2 by the impedance angle λ of the disc. Figure (3.6) shows the vector diagram.

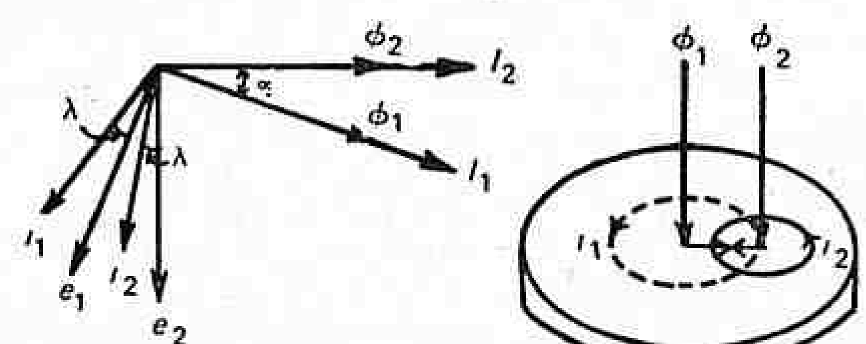


FIGURE 3.6 Principle of induction relay torque.

Let
$$\phi_1 \propto |I_1| \sin \omega t \tag{3.2}$$
$$\phi_2 \propto |I_2| \sin (\omega t+\alpha) \tag{3.3}$$
$$e_1 \propto \frac{d\phi_1}{dt} \propto \omega |I_1| \cos \omega t \tag{3.4}$$
$$e_2 \propto \frac{d\phi_2}{dt} \propto \omega |I_2| \cos (\omega t+\alpha) \tag{3.5}$$
$$i_1 \propto \omega |I_1| \cos (\omega t-\lambda) \tag{3.6}$$
$$i_2 \propto \omega |I_2| \cos (\omega t+\alpha-\lambda) \tag{3.7}$$

Therefore, the resultant torque is given by.

$$T \propto \phi_2 i_1 - \phi_1 i_2$$
$$\propto \omega |I_1||I_2| [\sin(\omega t+\alpha)\cos(\omega t-\lambda) - \sin\omega t \cos(\omega t+\alpha-\lambda)]$$
$$\propto \omega |I_1||I_2| \sin\alpha \cos\lambda$$

or
$$T \propto \omega |I_1||I_2| \sin\alpha \tag{3.8}$$

Thus the induction relay is a sine comparator in which the maximum torque is developed when α is 90° or 270° and zero torque when α is 0° or 180°.

3.4 Relay Design and Construction

The design of protective relay is normally divided into the following stages:

(a) Selection of the operating characteristics.
(b) Selection of proper construction.
(c) Design of the contact movement from the point of view of utmost reliability.

The relay operating characteristic must match with the abnormal operating characteristic of the system. In other words it should clearly show the conditions for tripping under various abnormal operating conditions.

The most important considerations in the design for construction are reliability, simplicity of construction and circuitry. The construction of the relay is divided into the following: (i) contacts; (ii) bearings; (iii) electromechanical design; and (iv) terminations and housing.

Contacts. Contact performance is probably the most important item affecting reliability of the relay. Corrosion or dust deposition can cause nonoperation of relay, consequently the material and shape of the contacts are of considerable importance.

A good contact system design provides restricted contact resistance as well as reduced contact wear. The contact materials used are gold, gold alloys, platinum, palledium and silver. The selection of the contact material depends on a number of factors like the voltage per contact break, the current to break as well as the type of atmospheric pollution under which these contacts are operated. However there is no one ideal contact material which can be used universally under all conditions. There is also no method by which the suitability of contact material for use under any condition can be derived. The following factors are to be considered for selecting a suitable contact material.

1. The nature of the current to be interrupted, i.e., direct or alternating.
2. Voltage at break and make operations.
3. The value of the currents to be interrupted.
4. Frequency of operation.
5. The actual speed of contact at make or break (this covers the arc duration and contact bounce).
6. The contact shape.
7. The contact closing force.

On the basis of practical experience the following are some of the rules recommended in the design of contact system of a relay:

(a) The contacts should be bounce proof to avoid arcing at the contacts thereby reducing the maintenance which ultimately results in increasing its life.
(b) Contact pressure is another very important factor to be kept in view. An increase in contact pressure leads to decrease in voltage drop or contact resistance.
(c) To promote accuracy and avoid sticking after long periods of inaction, the relay should be designed to maximum torque/friction ratio.
(d) The value of current that can be interrupted by a pair of contact in a.c. circuit is 2 to 8 times than that in a d.c. circuit.

In general domed shaped contacts or the cylindrical contacts at right angles give the best performace.

Bearing. The various arrangements in use are:

(i) *Single ball bearings*: Used for high sensitivity and low friction, a single ball bearing between two cup-shaped sapphire jewels is in use.
(ii) *Multi-ball bearings*: Miniature types of less than 1.6 mm diameter are available. These provide low friction and greater resistance to shock and combine side-thrust and end-thrust in a single bearing.
(iii) *Pivot and jewel bearings*: This is the most common type for precision relays, e.g. induction relays. Modern relays have spring-mounted jewels so that shocks are taken on a shoulder and not on the jewel.
(iv) *Knife edge bearings*: These are used for hinged armature relays which normally operate many contacts.

Electromechanical Design. It consists of the design of the magnetic circuit and the mechanical fixtures of core, yoke and the armature.

The reluctance of the magnetic path is kept to a minimum by enlarging the pole face which makes the magnetic circuit more efficient.

D.C. electromagnets are usually less expensive and more efficient than a.c. electromagnets. But small a.c. electromagnets made from soft iron, low carbon steel core having a slot for mounting a shaded ring are quite common.

The relay coil current is usually limited to 5A and the coil voltage to 220V, but still the insulation for the relay coil is designed to withstand at least 4 KV.

The relay coil is designed to carry about 15 times the normal current for one second. From the mechanical strength considerations it is desirable that the conductor diameter must not be less than 0.05 cm even if the above considerations are satisfied.

Terminations and Housing. The assembly of armature with magnet and the base is done with the help of a spring. The spring is insulated from the armature by moulded blocks. These moulded blocks provide dimensional stability and better appearance economically. Materials used for springs are stainless steel, nickel silver, phosphorous bronze and berillium copper, whereas for moulded blocks nylon is used. The fixed contacts are usually rivetted or spot-welded on to the terminal link.

QUESTIONS

1. What are the different types of electromagnetic relays? What are their fields of application?
2. Describe the construction and principle of operation of an induction type of overcurrent relay. Derive the torque equation.
3. Give reasons for the following:
   (i) Bounce proof contacts are used in relays.
   (ii) Pressure at the relay contacts is kept high.
   (iv) The relay is designed for maximum torque/friction ratio.

CHAPTER 4

Relay Application and Characteristics

4.1 Introduction

The application of a particular relay is decided by its characteristics and other factors like accuracy, operating time, burden, method of setting adjustment, etc. Above all the relay must be reliable.

The relay in general is expected to sense the change between healthy and faulted conditions and send a signal when fault occurs. This, in general, is achieved by comparing two quantities either in amplitude, or in phase. The amplitude or phase relation depends on the system conditions and for a predetermined value of this relation, indicative of a particular type and location of fault, the relay operates. Except in relays such as overcurrent relays, where only one electrical quantity overcomes a mechanical quantity such as the restraint from a spring, it is usual to compare two electrical quantities. As such the device performing the comparison part is the heart of a protective relay and is known as a comparator. It decides the operating characteristics of the relay.

4.2 General Equation of Comparators

Taking a very general case to cover the complete range of conventional relay characteristics, let S_1 and S_2 be the two input signals such that when the phase relationship or magnitude relationship obeys predetermined threshold conditions, tripping is initiated. The input signals are derived from the primary power system via current and voltage transformers. These signals may be derived from the primary voltage or current or from both, the latter necessitating some form of mixing device such as a current voltage transactor as shown in Fig. (4.1). Let of the potential coil. If the impedance angle of the potential coil is λ, then $\theta=90-\lambda$. This is shown in Fig. (4.13), where ϕ_I and ϕ_V are two fluxes produced by current coil and pressure coil. Maximum torque is

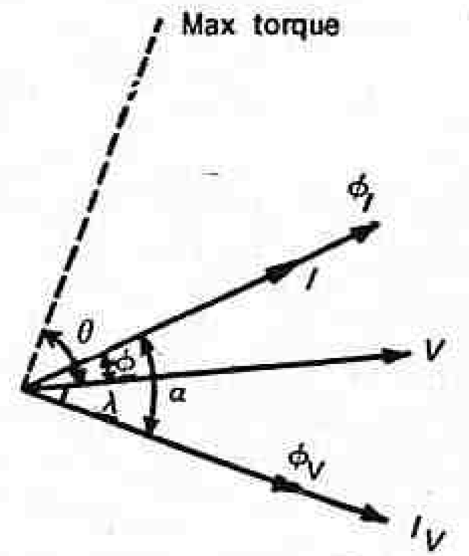


FIGURE 4.13 Characteristics of a voltage-current directional relay.

produced when angle α between two fluxes is 90°, i.e. when $\theta=\phi$ or

$$\theta+\lambda=90^\circ$$

i.e. $$\theta=90^\circ-\lambda$$

This suggests that external phase shifting circuits can be used to change the value of θ.

The characteristics of such a directional relay is shown in Fig. (4.14).

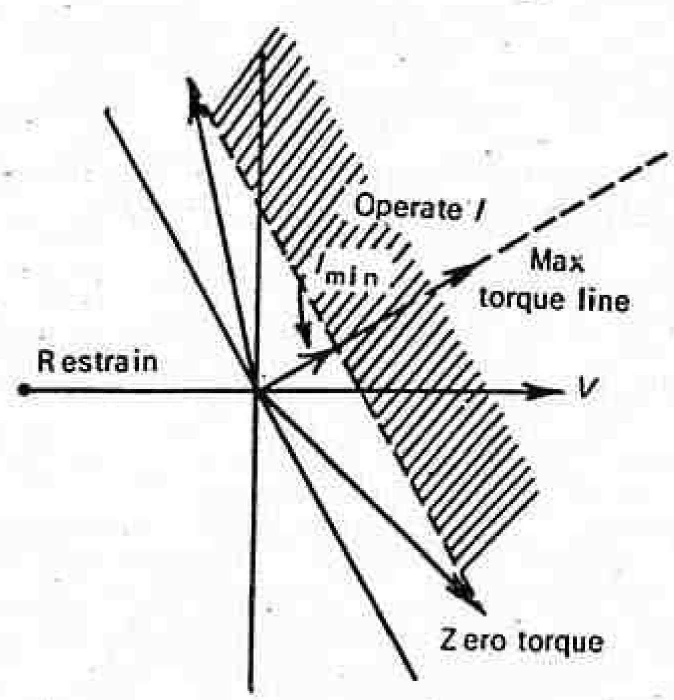


FIGURE 4.14 Directional characteristics of a relay with external phase shifting circuits.

Maximum torque position can be changed by inserting resistance or capacitance or a combination of the two in series with the voltage circuit. Each value of polarizing (i.e. reference) voltage will have a constant torque line. Because of the control spring force and friction, there is a minimum value of current I_{min} required to operate the relay.

4.7.2 Directional Overcurrent Relays and Their Connections

Relay connections must be made so that the currents and voltages applied to the relay during the various fault conditions which may arise on the protected circuit section afford the relay a positive and sufficiently large operating torque. To achieve this for all types of faults the relays cannot be connected to operate on true watts since for some faults the voltage will be extremely small and also the power factor will be very small which will result in a negligibly small torque. To overcome this, and thus ensure that sufficient torque is always available, each relay is supplied with current and voltage as described below.

The four most commonly used connections are illustrated in Table 4.3 and their vector diagrams shown in Fig. (4.15).

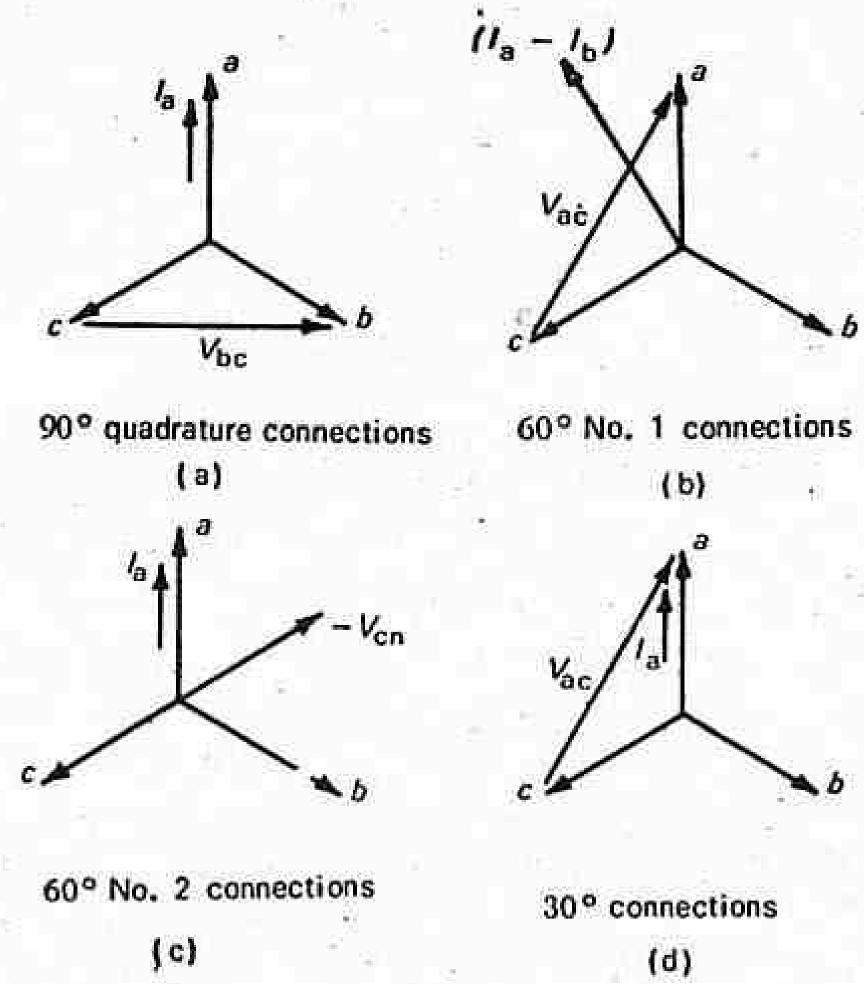


FIGURE 4.15 Different connections of single-phase directional relays for relay A.

Directional element connections are conveniently and popularly described in terms of the angle by which unity power factor (UPF) balanced load current flowing in the tripping direction leads the voltage applied to relay potential coil with due consideration given to the polarity of the relay coils.

Table 4.3 *Different connections for single-phase directional overcurrent relays*

Connections	Relay A		Relay B		Relay C	
	Voltage	Current	Voltage	Current	Voltage	Current
90°	V_{bc}	I_a	V_{ca}	I_b	V_{ab}	I_c
60° No. 1	V_{ac}	I_a-I_b	V_{ba}	I_b-I_c	V_{cb}	I_c-I_a
60° No. 2	$-V_{cn}$	I_a	$-V_{an}$	I_b	$-V_{bn}$	I_c
30°	V_{ac}	I_a	V_{ba}	I_b	V_{cb}	I_c

4.8 Distance Relays

In applying relays to a transmission system it is necessary to state the relay characteristic in the same terms that the system conditions are stated. This is especially true of distance type of relays. If the relay characteristics are thought of in terms of volts and amperes, then the system conditions should be stated in the same terms. With the distance relays, however, it is difficult to think in terms of volts and amperes, because these values vary widely for the same relay response. This relay response is some function of the ratio between volts and amperes and for any given value of the ratio there may exist an infinite number of values of the volts and amperes. It, therefore, simplifies matters greatly to think of the distance relay response in terms of the ratio of volts to amperes or in other words to think of impedance, reactance, resistance or combination thereof to which the relay responds. However in designing distance relays it is necessary to think in terms of the volts, amperes and phase angle to which it must respond because these are the quantities which actually operate the contact actuating parts.

Relay Types and Their Application. Principal types of distance relays are: (i) impedance; (ii) reactance; (iii) admittance (mho); (iv) ohm; and (v) offset mho.

The common types compare two input quantities either in magnitude or in phase. Any of the relay characteristics can be obtained either by an amplitude comparator or by a phase comparator as explained earlier.

4.8.1 Impedance Relay

This is a device which measures distance by comparing the fault current I with the voltage V across the fault loop. It is simple in this case to have an amplitude comparator and the balanced beam type structure is most common. The equation for the amplitude comparator at threshold as derived already in Eq. (4.4) is

$$(K_1^2-K_3^2)|A|^2+2|A||B|\{K_1K_2\cos(\theta_2-\phi)-K_3K_4\cos(\theta_4-\phi)\}$$
$$+(K_2^2-K_4^2)|B|^2=0.$$

If the constants are so adjusted that the input signals are

$$S_1=K_1V$$

and

$$S_2=K_4I$$

i.e.

$$K_2=K_3=0 \text{ and } A=V \text{ and } B=I$$

Substituting these conditions in the above equation, we get

$$K_1^2|V|^2=K_4^2|I|^2$$

or

$$\frac{V}{I}=\frac{K_4}{K_1}$$

i.e.

$$Z=\text{constant } K \qquad (4.13)$$

The characteristics when plotted on the R-X plane is shown in Fig. (4.16) which is a circle with origin as its centre, signifying that a simple

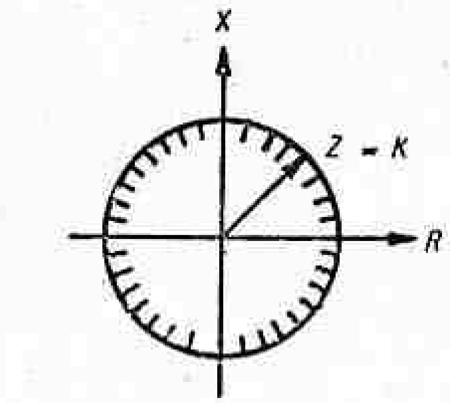


FIGURE 4.16 Characteristics of impedance relay.

impedance relay would operate for any value of impedance lying within the circle. The characteristic also depicts that the relay is not directional and it is essential to provide a directional relay along with an impedance relay. The combined characteristics of an impedance and directional relay are shown in Fig. (4.17) where DD represents the directional relay characteristic and the operating region is the shaded portion.

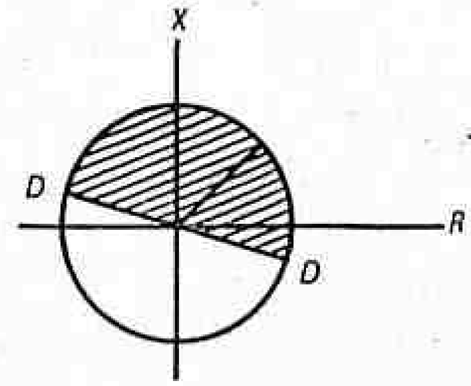


FIGURE 4.17 Combined characteristics of impedance with directional relay.

4.8.2 Reactance Relay

All other relays except the impedance relay are conveniently obtained by a phase comparator. The basic equation for a phase comparator already derived in Eq. (4.6) at threshold is

$$K_1K_3|A|^2+\{K_1K_4\cos(\theta_4-\phi)+K_2K_3\cos(\theta_2-\phi)\}|A||B|$$
$$+K_2K_4|B|^2\cos(\theta_2-\theta_4)=0$$

Using the input signals in the following manner

$$S_1=-KV+K'I\angle(\theta-\phi)$$
$$S_2=K'I\angle(\theta-\theta)$$

i.e. $K_1=-K$

$K_2=K_4=K'\angle\theta$

and $K_3=0$

$A=V$ and $B=I$

Substituting these conditions in the above equation, we have

$$-KK'\cos(\theta-\phi)|V||I|+K'^2|I|^2=0$$

or

$$Z\cos(\theta-\phi)=\frac{K'}{K} \qquad (4.14)$$

Now if θ is $\pi/2$ the above equation reduces to the reactance form, i.e.

$$Z\sin\phi=\frac{K'}{K}$$

or

$$X=\frac{K'}{K} \qquad (4.15)$$

When plotted on the R-X diagram the characteristic is represented by a straight line parallel to the horizontal axis R as in Fig. (4.18).

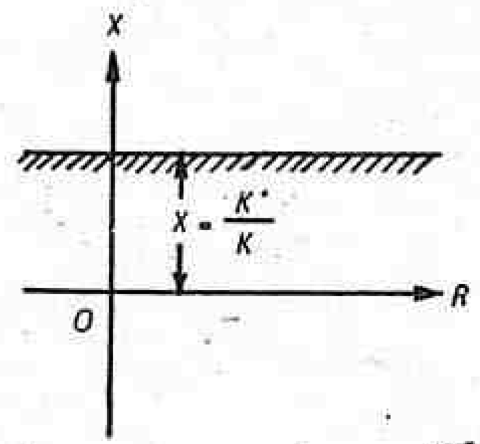


FIGURE 4.18 Characteristics of reactance relay.

With some predetermined setting of value of X, the relay will measure any value of reactance below the setting. A reactance relay responds only to the reactive component of system impedance; consequently it is unaffected by fault arc resistance. However, when fault resistance is such a high value that load and fault current magnitudes are comparable the reach of the relay is modified by the value of the load and its power factor and may either overreach or underreach.

Voltage-restrained starting relays are used in a reactance measuring scheme to give directional response and to prevent operation on load. The reactance relay as seen by Eq. (4.15) is a particular case of an ohm relay, in which the angle of compensation θ is 90°.

4.8.3 Admittance (mho) Relay

If the signals S_1 and S_2 given to the phase comparator are

$$S_1=-KV+K'I\angle(\theta-\phi)$$

and $S_2=KV$

i.e. $K_1=-K$

$K_2=K'\angle\theta$

$K_3=K$

$K_4=0$

$A=V$ and $B=I$

Substituting these conditions in Eq. (4.6) we have

$$-K^2|V|^2+KK'\cos(\theta-\phi)|V||I|=0 \qquad (4.16)$$

or

$$\frac{I}{V}\cos(\theta-\phi)=\frac{K}{K'}$$

or

$$Y\cos(\theta-\phi)=K/K' \qquad (4.17)$$

This represents the admittance or the mho characteristic and when plotted on the R-X diagram is a circle passing through the origin and when plotted on the G-B diagram is a straight line as illustrated in Fig. (4.19).

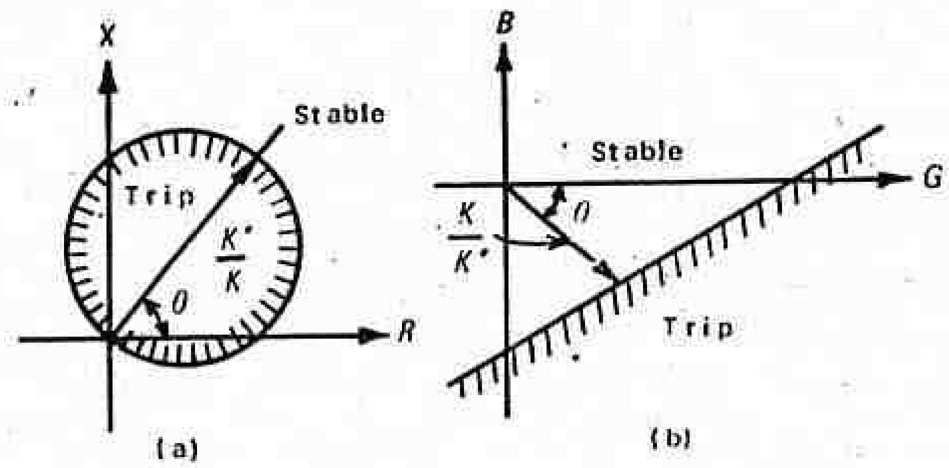


FIGURE 4.19 Characteristics of mho relay: (a) R-X plane; (b) G-B plane.

The circle passing through the origin makes it inherently directional. With such a characteristic the relay measures distances in one direction only.

From the expression (4.16) it is evident that the relay is inoperative if the voltage falls to zero, because both terms contain V. A memory circuit may be used to prevent the immediate decay of voltage applied to the relay terminals when a closeup three-phase short circuit occurs. This enables high speed mho protection to operate correctly on closeup faults, provided that the protected circuit is energized before the short circuit is applied.

4.8.4 Ohm Relay

As explained earlier a reactance relay is a particular case of an ohm relay. Its characteristic is represented by Eq. (4.14) when plotted on the R-X plane is a straight line (Fig. (4.20)). The ohm relay is used as a supplementary element to modify the operating region of the other types of measuring elements.

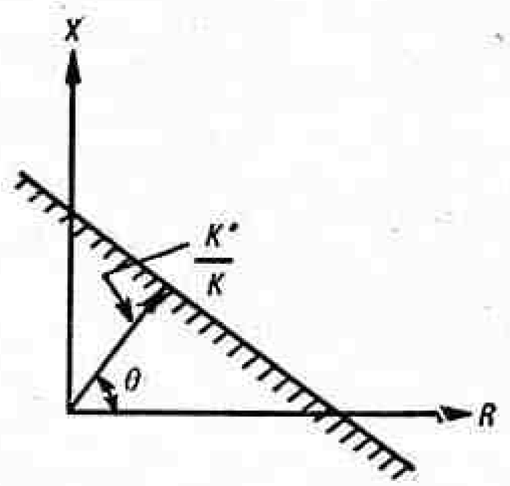


FIGURE 4.20 Ohm characteristics.

4.8.5 Offset Mho Relay

Let the signals S_1 and S_2 given to the phase comparator be

$$S_1=-KV+K_2I\angle(\theta-\phi)$$
$$S_2=KV+K_4I\angle(\theta-\phi)$$

i.e

$$K_1=-K$$
$$\bar{K}_2=K_2\angle\theta$$
$$K_3=K$$
$$\bar{K}_4=K_4\angle\theta$$
$$A=V \text{ and } B=I$$

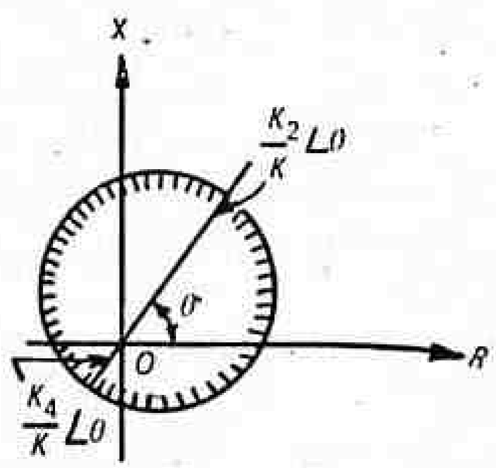


FIGURE 4.21 Offset mho characteristics.

Substituting these conditions we have

$$-K^2V^2+\{-KK_4\cos(\theta-\phi)+K_2K\cos(\theta-\phi)\}VI+K_2K_4I^2=0$$

Writing $\frac{V}{I}$ as Z, we get

$$-K^2Z^2+K_2K_4+KZ(K_2-K_4)\cos(\theta-\phi)=0$$

Writing $Z^2=R^2+X^2$, we get

$$R^2+X^2-\frac{K_2K_4}{K^2}-\frac{(K_2-K_4)}{K}(R\cos\theta+X\sin\theta)=0$$

or

$$\left\{R-\frac{(K_2-K_4)\cos\theta}{2K}\right\}^2+\left\{X-\frac{(K_2-K_4)\sin\theta}{2K}\right\}^2\leqslant\left\{\frac{K_2+K_4}{2K}\right\}^2 \quad (4.18)$$

This equation represents a circle, with centre at $(K_2-K_4)/2K\angle\theta$ on the R-X plane, the radius being of magnitude $(K_2+K_4)/2K$. The offset threshold characteristic is shown in Fig. (4.21).

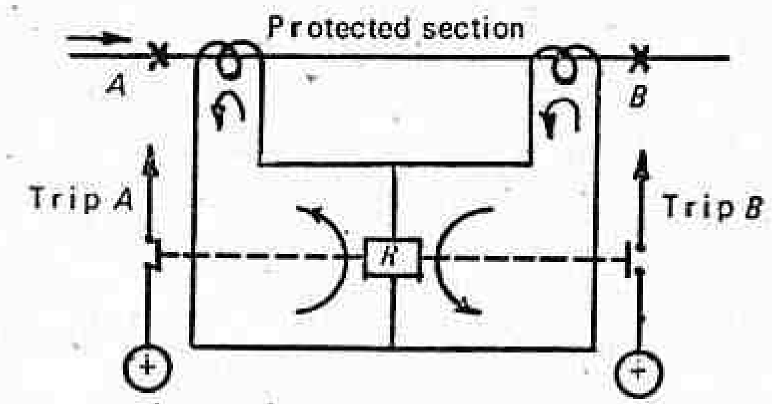


FIGURE 4.22 Discrimination on the circulating current principle.

4.9 Differential Relays

The principle of operation depends on a simple circulating current principle where the difference of the currents of the two CTs flows through the relay under normal conditions or even under faults outside the protected section. This is illustrated in Fig. (4.22). The relay R is a simple comparator which compares current magnitude, power direction or relative phase of the currents at the ends of the protected zone. In the electromagnetic form it consists of two electromagnets exerting torques in opposition on an armature carrying contacts. These electromagnets are excited by the currents from the two CTs. Faults inside the protected zone however cause the two currents to flow in the same direction through the relay R, thus producing a resultant positive torque which closes the contacts of the trip circuit of the circuit breakers A and B on the two ends. This is commonly known as *Merz Price principle*.

Pilot wires are generally necessary between relaying points, and the provision of these is a major consideration in the application of this form of protection.

In the basic circuit of Fig. (4.23a) the CTs are connected in series by means of pilot wires. The whole of the secondary emf of both CTs is used to overcome the combined impedance of the CTs and pilot wires. The voltage distribution is illustrated in Fig. (4.23b), where AB and CD

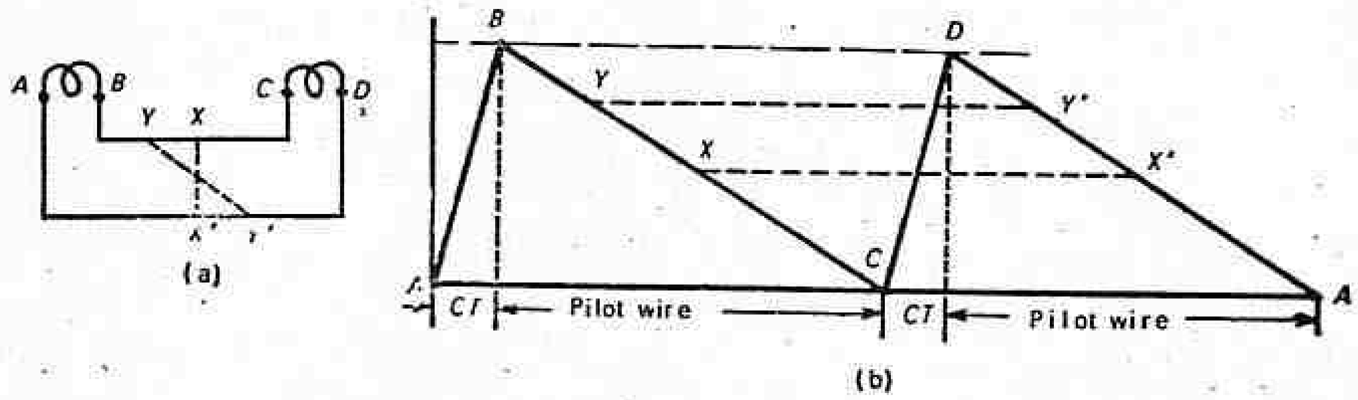


FIGURE 4.23 Circulating current system.

are secondary emfs of the CTs which are equal and BC and DA represent the voltage drops in the two pilot wires. It can be seen that there are an infinite number of corresponding points at the same potential on the two pilot wires such as XX' and YY'. It is also clear that the pilots constitute the only burden on the CTs, this burden being shared equally so long as there is no connection between the pilot wires other than at equipotential points such as XX' and YY' etc.

In practice the relay is connected across the pilot wires and if the connections are not at equipotential points the burdens on the two CTs are unequal, although the current in the two CTs is same. This may cause the heavily loaded CT to saturate during through-fault conditions. This results in dissimilarity of voltage and phase angle characteristics of the CTs producing an out-of-balance current which causes spurious operation of the relay. The problem can be tackled in two ways. The first is by biasing the relay and the second is by using a high impedance relay with a low current setting. This is illustrated below.

The effect of the bias is to enable the impedance of the relay operating circuit to be reduced for a given value of through-fault stability. The bias is obtained by circulating the through-fault secondary current through an additional winding which exerts a restraining force or bias on the movement. The basic circuit connections are shown in Fig (4.24). Normally no current flows in the operating coil under through-fault conditions, but owing to imperfect matching of the CTs some spill current may be present. This spill current will flow in the relay operating circuit but will not cause operation unless the operating bias current ratio for which the relay is set is exceeded. The magnitude of the current to cause operation is not constant but automatically increases as the circulating current increases and a definite ratio exists between the two quantities.

This ratio can be determined by considering the forces acting on the relay movement:

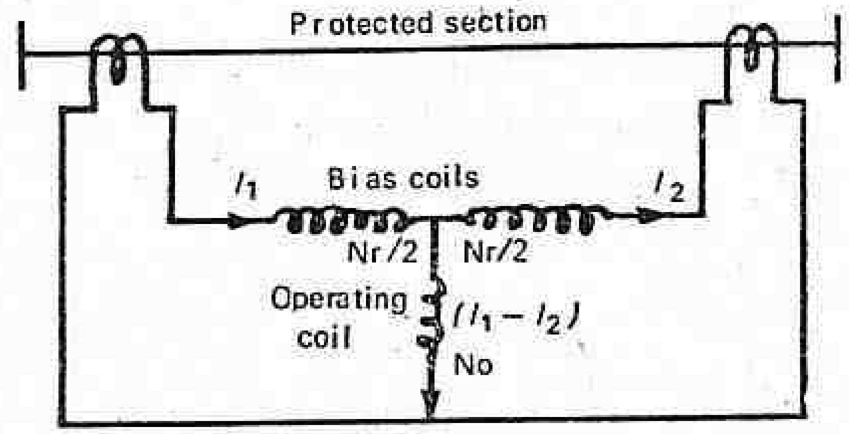


FIGURE 4.24 Basic circuit of biased differential protection.

$$\text{Operating force}-K(I_1-I_2)N_0 \tag{4.19}$$

$$\text{Restraining force}=K(I_1+I_2)\frac{N_r}{2}+S \tag{4.20}$$

where

N_0 = number of turns of operating coil
N_r = number of turns of restraining coil
K = constant
S = mechanical restraint

The electrical operating and restraining forces are equal at the balance point of the relay; neglecting the mechanical restraint we have

$$\frac{I_1-I_2}{1/2\,(I_1+I_2)}=\frac{N_r}{N_0} \tag{4.21}$$

This equation shows that the characteristic has a slope determined by the ratio N_r/N_0 or with given relay constants the per unit bias is defined as the difference current divided by the mean circulating current and is a constant ratio for all current magnitudes (Fig. (4.25)). This ratio is more commonly expressed as percentage bias, where percentage setting or bias is in terms of the nominal current rating of the CTs. With an internal fault a current proportional to the fault current flows in the relay operating winding, and the protection setting is usually stated for the condition of an infeed from one end only. Any simultaneous *through* load current flows in the relay bias winding and thus increases the setting. In the simplest electromagnetic form the relay is shown in Fig. (4.26).

The high impedance relay requires 50 to 100 V and only a small current to cause operation (in effect a voltage operated relay). The maximum voltage developed during through-fault conditions can be computed and the relay voltage setting arranged to be above this value. In the application of high speed differential protection the transient d.c. component of fault current must be considered. Its effect is to cause a unidirectional buildup of flux in the CT core producing saturation and

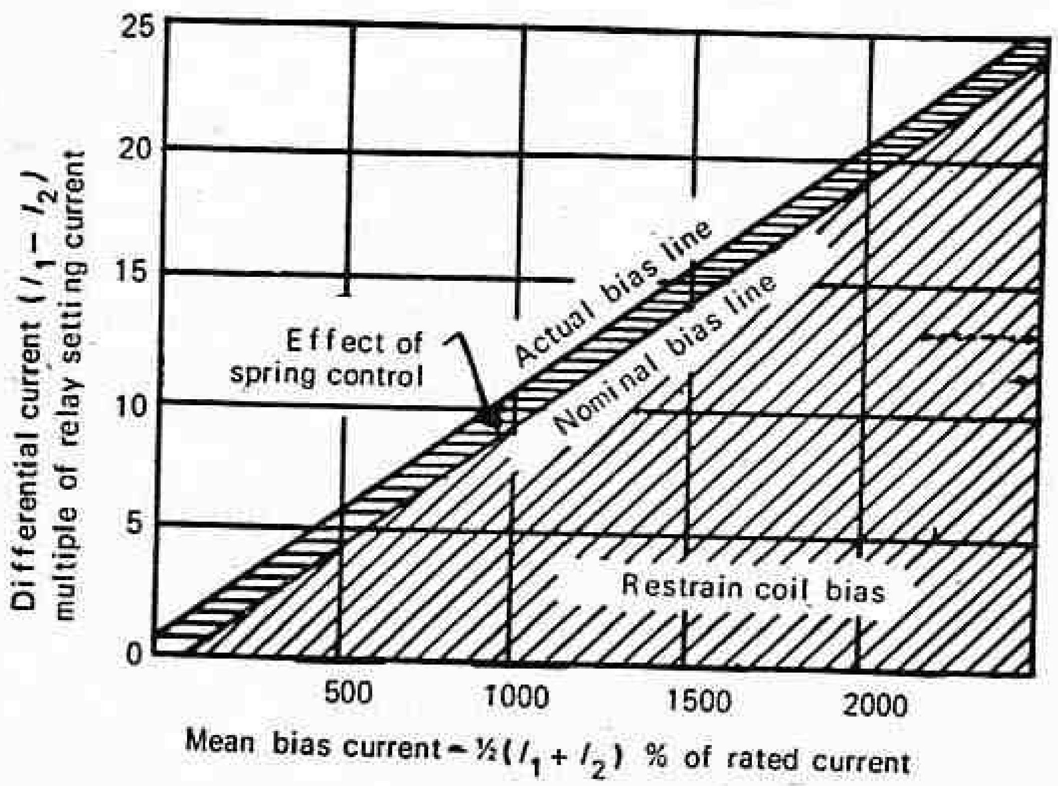


FIGURE 4.25 Characteristics of biased differential relay.

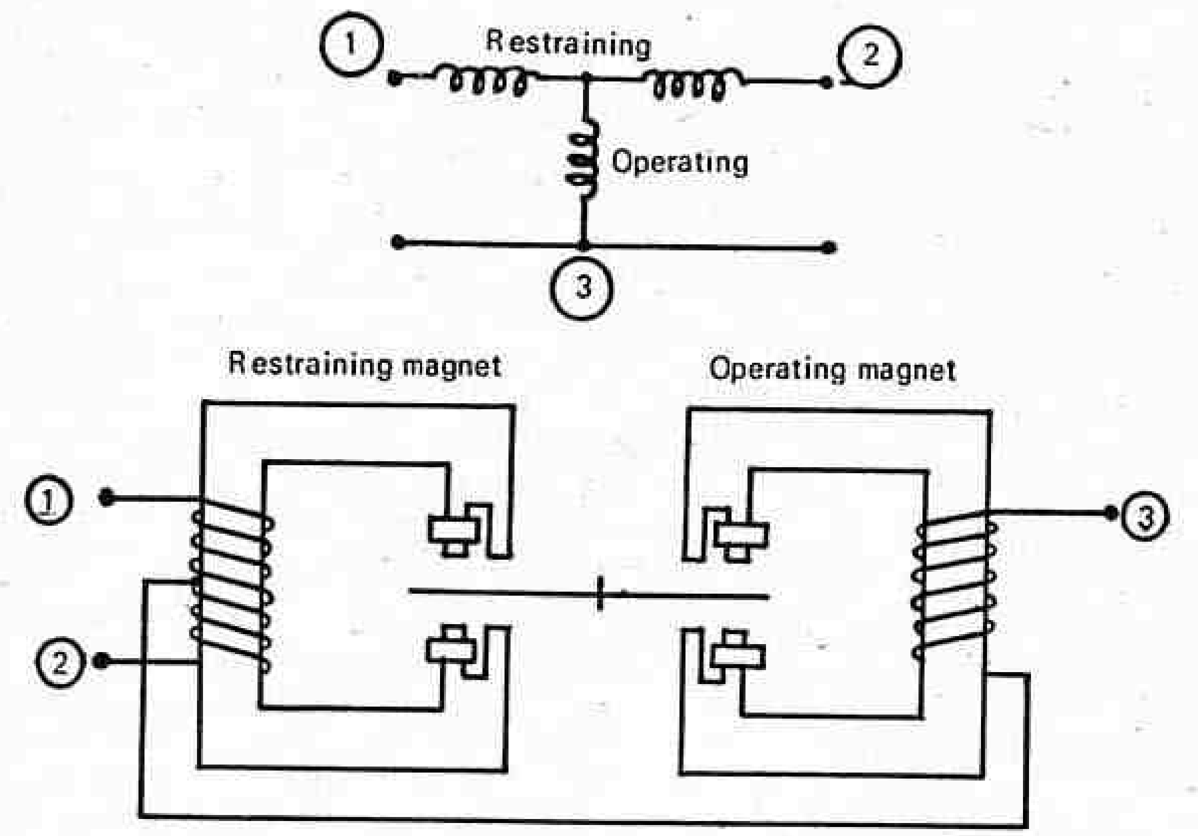


FIGURE 4.26 Electromagnetic representation of biased differential relay.

consequent large ratio errors. Where more than one circuit is involved (e.g. with bus bar protection) the asymmetry may cause a different degree of saturation in each of the balancing CTs.

Referring to Fig. (4.27) R_1 and R_2 are the resistances on each side of the relay, i.e. lead resistance plus CT secondary resistance (for wound-type CTs

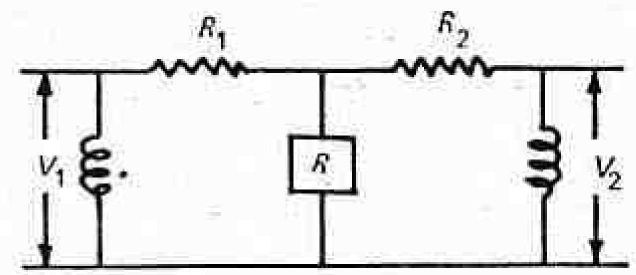


FIGURE 4.27 Basic circuit of circulating current protection.

the leakage reactance must be included). Let us consider the most adverse condition for through-fault balance, viz. one CT completely saturated by the d.c. component of the fault current balancing against an ideal current transformers. The saturated CT then contributes nothing to maintain the relay connection points at zero voltage and behaves as a low impedance connected in parallel with the relay operating coil. So either the saturation should be avoided by air cored CTs which will mean large size or the relay should be accordingly designed.

Assuming the right-hand CT to be fully saturated, i.e. $V_2=0$ and the left-hand CT to be ideal with a relay of Z_0 operating circuit impedance, we get

$$I_1-I_2=\frac{I_1R_2}{R_2+Z_0} \tag{4.22}$$

Substituting $N_r/N_0=B$ in Eq. (4.21)

we get
$$I_2=I_1\left(\frac{2-B}{2+B}\right) \tag{4.23}$$

Simplifying Eqs. (4.22) and (4.23)

$$B=\frac{2R_2}{R_2+2Z_0} \tag{4.24}$$

or the relay operating circuit impedance

$$Z_0=R_2\left(\frac{1}{B}-\frac{1}{2}\right) \tag{4.25}$$

Thus for a given CT secondary resistance, stability can be ensured by adjustment of either the relay bias slope or by increasing the impedance of the relay operating coil circuit.

The relay setting voltage is given by

$$I_sZ_0=I_sR_2\left(\frac{1}{B}-\frac{1}{2}\right) \tag{4.26}$$

where I_s is the relay setting current.

By using a relay which is insensitive to the d.c. component and which operates on rms values, the maximum operating voltage across the unbiased relay under the conditions of maximum through-fault is I_1R_2. The relay setting voltage for stability must be at least equal to this value. Thus the ratio of setting voltages for the biased and unbiased relays is

$$I_s\left(\frac{1}{B}-\frac{1}{2}\right)\Big/I_1$$

For a typical case of through-fault stability up to 15 times CT rated current and a biased relay having a setting of 5% and a slope of 5%. This ratio becomes 0.05 (20—0.5)/15 or approximately 1:15, i.e. for a given through-fault stability limit the setting voltage of the unbiased relay is 15 times that of the 5% slope relay. This ratio increases as the bias slope increases and for a 20% slope relay having the same 5% setting it becomes 1:66. The effect of the bias feature is thus to enable the relay setting voltage to be reduced for a given value of through-fault stability.

An alternative solution to the problem of a suitable relaying connection is the use of a *voltage-balance arrangement*. The principle of voltage balance protection is shown in Fig. (4.28). Relays are connected in series with the pilots, and the relative polarity of the CTs is such that there is no pilot current for the conditions of load or through-fault. The scheme is no longer used in its elementary form, but it has led to the development of a wide range of schemes using biased relays which will be described in Chapters 6 and 12.

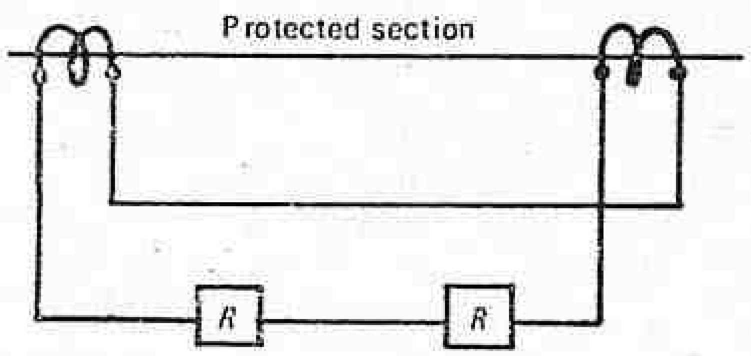


FIGURE 4.28 Basic circuit of voltage balance protection.

Pilot channels are very expensive and hence it is customary to combine the currents at each terminal into a single current which is possible by using summation transformers or by phase sequence networks. Only two wires are required with high impedance relays, the relays at each end responding to the common voltage between wires. A resistance of the order 1 $K\Omega$ can be tolerated, so that telephone wires can be used.

Differential schemes are ideally suited for the protection of compact items of electrical plant such as generators, busbars, transformers, reactors, capacitors, motors, short transmission lines, etc.

QUESTIONS

1. What is an amplitude comparator? How can this be used as a protective relay? Derive the general equation of an electromagnetic relay.
2. Show that the amplitude and phase comparators are dual to each other. Describe one electromagnetic phase comparator.
3. What are inverse time characteristics for overcurrent relays? Explain how the IDMT characteristic is achieved in practice for an electromagnetic relay.
4. Explain the term *directional*. Give the 90-degree method of connecting directional relays.
5. Discuss the different types of distance relay characteristics. How are these characteristics derived in an electromagnetic comparator?
6. What is the principle of differential relays? What are their limitations? Explain their characteristics.

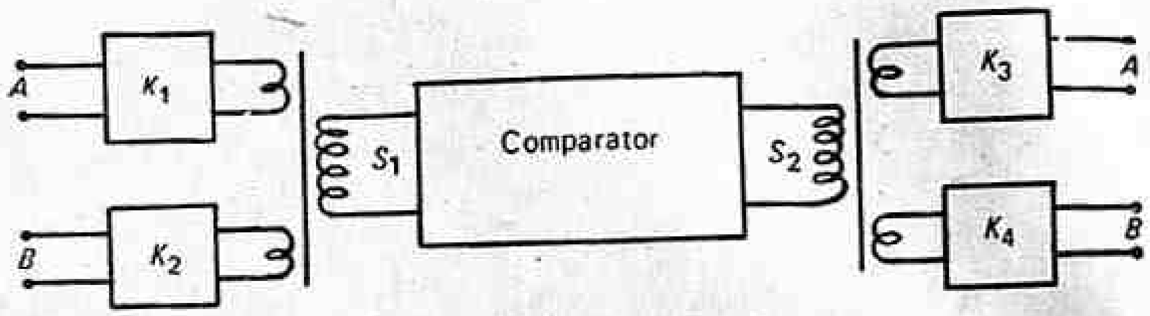


FIGURE 4.1 Comparison of mixed signals.

$$\left.\begin{aligned}\dot S_1 &= K_1\dot A+\dot K_2\dot B\\ \dot S_2 &= K_3\dot A+\dot K_4\dot B\end{aligned}\right\} \tag{4.1}$$

where K_1 and K_3 are scalar constants and K_2 and K_4 vector constants with angles θ_2 and θ_4, respectively. Taking A as the reference vector and vector B to lag A by an angle ϕ, Eq. (4.1) reduces to

$$S_1=K_1\,|A|+K_2\,|B|\,\{\cos(\theta_2-\phi)+j\sin(\theta_2-\phi)\}$$

and
$$S_2=K_3\,|A|+K_4\,|B|\,\{\cos(\theta_4-\phi)+j\sin(\theta_4-\phi)\} \tag{4.2}$$

4.2.1 Analysis for Amplitude Comparator

If the criteria for operation is given by $|S_1|\geqslant|S_2|$, then at the threshold of operation $|S_1|=|S_2|$, equating the moduli of expression (4.2)

$$\{K_1\,|A|+K_2\,|B|\cos(\theta_2-\phi)\}^2+\{K_2\,|B|\sin(\theta_2-\phi)\}^2$$
$$=\{K_3\,|A|+K_4\,|B|\cos(\theta_4-\phi)\}^2+\{K_4\,|B|\sin(\theta_4-\phi)\}^2 \tag{4.3}$$

Rearranging the terms

$$(K_1^2-K_3^2)\,|A|^2+2\,|A|\,|B|\,\{K_1K_2\cos(\theta_2-\phi)-K_3K_4\cos(\theta_4-\phi)\}$$
$$+K_2^2\,|B|^2\cos^2(\theta_2-\phi)-K_4^2\,|B|^2\cos^2(\theta_4-\phi)+|B|^2$$
$$\{K_2^2\sin^2(\theta_2-\phi)-K_4^2\sin^2(\theta_4-\phi)\}=0$$

or
$$(K_1^2-K_3^2)\,|A|^2+2\,|A|\,|B|\,\{K_1K_2\cos(\theta_2-\phi)-K_3K_4\cos(\theta_4-\phi)\}$$
$$+(K_2^2-K_4^2)\,|B|^2=0 \tag{4.4}$$

Dividing by $(K_2^2-K_4^2)\,|A|^2$

$$\left|\frac{B}{A}\right|^2+2\left|\frac{B}{A}\right|\left\{\frac{K_1K_2\cos(\theta_2-\phi)-K_3K_4\cos(\theta_4-\phi)}{K_2^2-K_4^2}\right\}$$
$$+\frac{K_1^2-K_3^2}{K_2^2-K_4^2}=0$$

$$\left|\frac{B}{A}\right|^2+2\left|\frac{B}{A}\right|\frac{\{(K_1K_2\cos\theta_2-K_3K_4\cos\theta_4)\cos\phi+(K_1K_2\sin\theta_2-K_3K_4\sin\theta_4)\sin\phi\}}{K_2^2-K_4^2}$$
$$+\frac{K_1^2-K_3^2}{K_2^2-K_4^2}=0$$

or
$$\left|\frac{B}{A}\right|^2+2\left|\frac{B}{A}\right|[a_0\cos\phi+b_0\sin\phi]+c_0=0 \tag{4.5}$$

where
$$a_0=\frac{K_1K_2\cos\theta_2-K_3K_4\cos\theta_4}{K_2^2-K_4^2}$$

$$b_0=\frac{K_1K_2\sin\theta_2-K_3K_4\sin\theta_4}{K_2^2-K_4^2}$$

$$c_0=\frac{K_1^2-K_3^2}{K_2^2-K_4^2}$$

Equation (4.5) represents the equation of a circle on the β-plane having $|B/A|\cos\phi$ and $j\,|B/A|\sin\phi$ as coordinates represented as $|B/A|_p$ $j\,|B/A|_q$. This circle has

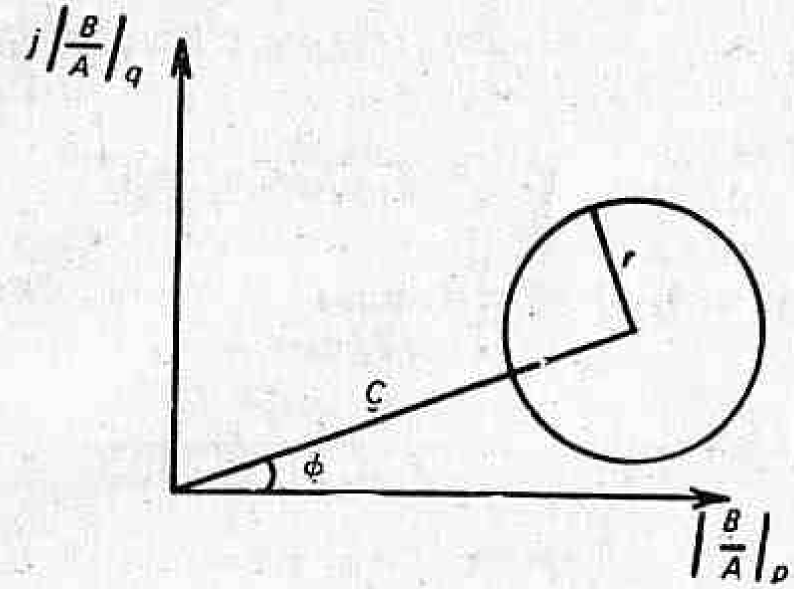


FIGURE 4.2 Threshold characteristics of a comparator.

Radius
$$r=\frac{\sqrt{K_1^2K_4^2+K_2^2K_3^2-2K_1K_2K_3K_4\cos(\theta_2-\theta_4)}}{K_2^2-K_4^2}$$

and
$$c=\frac{\sqrt{K_1^2K_2^2+K_3^2K_4^2-2K_1K_2K_3K_4\cos(\theta_2-\theta_4)}}{K_2^2-K_4^2}$$

Similarly Eq. (4.4) can be plotted in the α-plane by dividing it by $(K_1^2-K_3^2)\,|B|^2$.

4.2.2 Analysis for Phase Comparator

The two quantities to be compared are $\dot S_1$ and $\dot S_2$. If α is the phase angle of input S_1 and β that of S_2, the relay operates when the product of $\dot S_1$ and $\dot S_2$ is positive. The product is maximum when the two quantities are in phase. All the conventional characteristics of relays can be obtained with a symmetrical phase comparator with $(\alpha-\beta)=\pm90°$. Therefore, this is the threshold condition, i.e.

$$\tan(\alpha-\beta)=\pm\infty$$

$$\frac{\tan\alpha-\tan\beta}{1+\tan\alpha\tan\beta}=\pm\infty$$

that is, when

$$1+\tan\alpha\tan\beta=0$$

or $$1+\frac{K_2|B|\sin(\theta_2-\phi)}{K_1|A|+K_2|B|\cos(\theta_2-\phi)}\times\frac{K_4|B|\sin(\theta_4-\phi)}{K_3|A|+K_4|B|\cos(\theta_4-\phi)}=0$$

or $$K_1K_3|A|^2+[K_1K_4\cos(\theta_4-\phi)+K_2K_3\cos(\theta_2-\phi)]|A||B| +K_2K_4|B|^2\cos(\theta_2-\theta_4)=0 \quad (4.6)$$

This equation is again similar to Eq. (4.4) and can be plotted on the β-plane. Dividing Eq. (4.6) throughout by $K_2K_4|A|^2\cos(\theta_2-\theta_4)$ we get

$$\left|\frac{B}{A}\right|^2+\left|\frac{B}{A}\right|\frac{1}{K_2K_4\cos(\theta_2-\theta_4)}[K_1K_4\cos(\theta_4-\phi)+K_2K_3\cos(\theta_2-\phi)] +\frac{K_1K_3}{K_2K_4\cos(\theta_2-\theta_4)}=0$$

or

$$\left|\frac{B}{A}\right|^2+\left|\frac{B}{A}\right|\left[\frac{(K_1K_4\cos\theta_4+K_2K_3\cos\theta_2)\cos\phi+(K_1K_4\sin\theta_4+K_2K_3\sin\theta_2)\sin\phi}{K_2K_4\cos(\theta_2-\theta_4)}\right] +\frac{K_1K_3}{K_2K_4\cos(\theta_2-\theta_4)}=0$$

or $$\left|\frac{B}{A}\right|^2+\left|\frac{B}{A}\right|[a_0'\cos\phi+b_0'\sin\phi]+c_0'=0 \quad (4.7)$$

where $$a_0'=\frac{K_1K_4\cos\theta_4+K_2K_3\cos\theta_2}{K_2K_4\cos(\theta_2-\theta_4)}$$

$$b_0'=\frac{K_1K_4\sin\theta_4+K_2K_3\sin\theta_2}{K_2K_4\cos(\theta_2-\theta_4)}$$

$$c_0'=\frac{K_1K_3}{K_2K_4\cos(\theta_2-\theta_4)}$$

The circle has

$$\text{Radius } r=\frac{\sqrt{K_1^2K_4^2+K_2^2K_3^2-2K_1K_2K_3K_4\cos(\theta_2-\theta_4)}}{2K_2K_4\cos(\theta_2-\theta_4)}$$

and $$c=\frac{\sqrt{K_1^2K_4^2+K_2^2K_3^2+2K_1K_2K_3K_4\cos(\theta_2-\theta_4)}}{2K_2K_4\cos(\theta_2-\theta_4)}$$

Values of r and c for plot on the α-plane can be obtained, similarly.

In most relays at least one of the constants K (i.e. K_1, K_2, K_3, K_4) is zero and two of them are often equal. Also the angle of the two vector constants is usually the same. This makes the practical case relatively

simple. If $\theta_2=\theta_4$ the values of r and c in the two cases are tabulated in Table 4.1.

Table 4.1 *Comparative values of r and c for amplitude and phase comparators*

Quantity	*Amplitude comparator*	*Phase comparator*
r	$\frac{K_1K_4-K_2K_3}{K_2^2-K_4^2}$	$\frac{K_1K_4-K_2K_3}{2K_2K_4}$
c	$\frac{K_1K_2-K_3K_4}{K_2^2-K_4^2}$	$\frac{K_1K_4+K_2K_3}{2K_2K_4}$

4.2.3 Duality between Amplitude and Phase Comparators

Equations (4.4) and (4.6) represent the general operating characteristics of the relays using the amplitude and phase comparators respectively. These are equations of a circle on complex planes and indicate that an operating characteristic equation can be obtained either by a phase comparator or by an amplitude comparator through proper selection of the four constants K_1 through K_4. This further suggests the possibility of a simple relation between the two comparators and it can be proved that an inherent amplitude comparator becomes a phase comparator and vice versa, if the input quantities are changed to the sum and difference of the original two input quantities.

Consider the operation of an amplitude comparator with input signals A and B. It operates, say, when

$$|A|>|B|$$

If the inputs are changed to $(A+B)$ and $(A-B)$ so that it operates when

$$|A+B|>|A-B|$$

It has now become an inherent phase comparator as shown in Fig. (4.3) vector diagram, i.e. if the inputs are changed to $(A+B)$ and $(A-B)$ the original amplitude comparator would compare phases of A and B.

Similarly, a phase comparator working with inputs A and B, operates when A and B have same directional sense. If now the inputs are changed to $(A+B)$ and $(A-B)$ it would operate when $(A+B)$ and $(A-B)$ have the same directional sense, i.e. $|A|>|B|$ as shown in Fig. (4.4). Such comparators are known as converted comparators.

Though a given relay characteristic can be obtained using either of the comparators, consideration of the constants calculated for required ...teristics would indicate which type of comparator is preferable. In ...an inherent comparator is better than the converted type, because ...ntity is very large compared with the other, a small error in the large quantity may cause an incorrect comparison when their sum and difference are supplied as inputs to the relay.

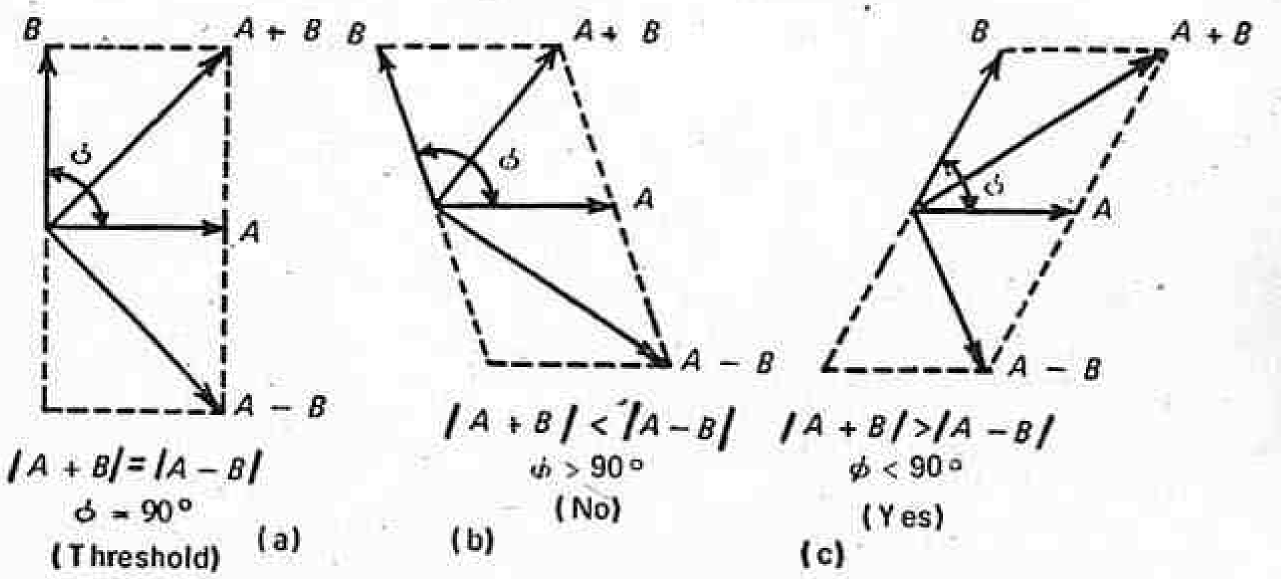


FIGURE 4.3 Phase comparison using an amplitude comparator.

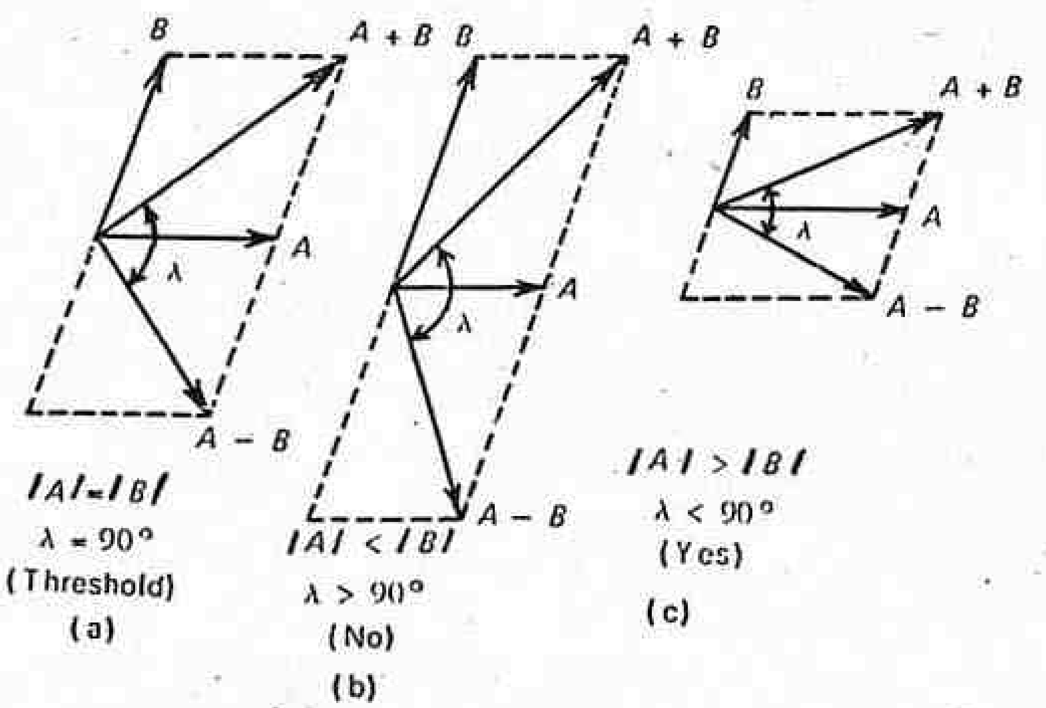


FIGURE 4.4 Amplitude comparison using a phase comparator.

4.2.4 Electromagnetic Comparators

Electromagnetic relays that work inherently as amplitude comparators are: hinged armature structure, plunger structure, balanced beam structure, induction disc structure with shaded pole driving magnets; those working inherently as phase comparators are: induction cup structure, induction disc structure with wattmetric type driving magnets, induction dynamometer structure.

4.3 General Equation for Electromagnetic Relays

It has already been shown that when not more than two quantities are involved, the equation for the characteristic of the relay at the threshold of operation under steady state conditions, when plotted on complex planes is a circle. The equation can be represented in a general form as

$$K\,|A|^2 - K'\,|B|^2 + |A|\,|B|\cos(\phi-\theta) - K'' = 0 \tag{4.8}$$

where

$|A|$ and $|B|$—two quantities being compared

ϕ—electrical angle between A and B

θ—relay characteristic angle, which is the value of ϕ for maximum torque

K and K'—scalar constants

K''—mechanical restraining torque

This Eq. (4.8) is similar to Eqs. (4.4) and (4.6) in nature and is applicable to most of the common types of relays. If the two input quantities are current I and voltage V then the equation for threshold operation becomes:

$$K\,|I|^2 - K'\,|V|^2 + |V|\,|I|\cos(\phi-\theta) - K'' = 0 \tag{4.9}$$

which can also be explained as: the current winding produces a torque KI^2 and the potential winding a torque $K'V^2$, while the torque due to interaction of current and potential windings will be $VI\cos(\phi-\theta)$.

K'' is finite only in single quantity relays, where it is used as a level indicator; it is made negligibly small in relays with more than one input so $K''=0$ and dividing throughout by $K'\,|I|^2$ Eq. (4.9) reduces to

$$\frac{K}{K'} - \left|\frac{V}{I}\right|^2 + \left|\frac{V}{I}\right|\frac{\cos(\phi-\theta)}{K'} = 0 \tag{4.10}$$

or

$$\left|\frac{V}{I}\right|^2 - \left|\frac{V}{I}\right|\frac{\cos(\phi-\theta)}{K'} + \left|\frac{1}{2K'}\right|^2 = \left|\frac{K}{K'}\right| + \left|\frac{1}{2K'}\right|^2$$

Equation (4.10) is similar to Eqs. (4.5) and (4.7).

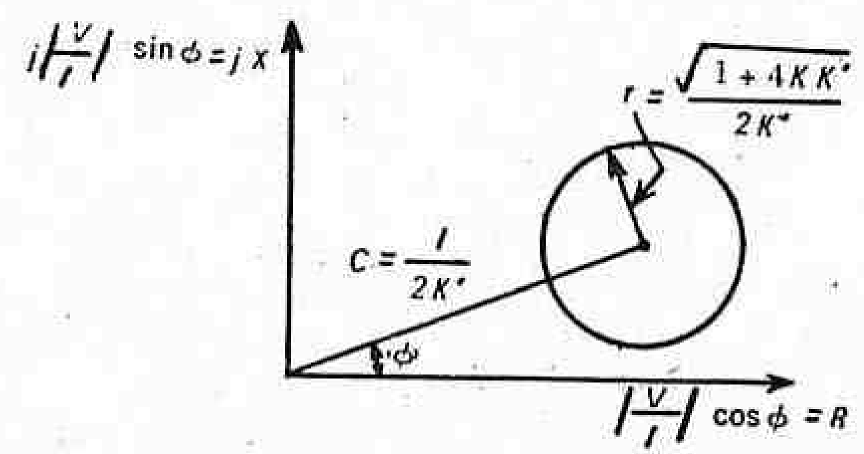


FIGURE 4.5 Characteristics on a complex plane.

This represents a circle on a complex plane, having

$$|V/I| \cos\phi \text{ and } j|V/I| \sin\phi$$

as coordinates, i.e. on the $R-X$ plane (Fig. (4.5)).

4.4 Overcurrent Relays

The operating time of all overcurrent relays tends to become asymptotic to a definite minimum value with increase in the value of current. This is inherent in electromagnetic relays due to saturation of the magnetic circuit. So by varying the point of saturation different characteristics are obtained; these are:

(a) Definite time.
(b) Inverse definite minimum time (IDMT).
(c) Very inverse.
(d) Extremely inverse.

These characteristics are obtained by induction disc and induction cup relays.

The torque of these relays as shown earlier is proportional to $\phi_1\phi_2 \sin\alpha$ where ϕ_1 and ϕ_2 are the two fluxes cutting the disc or cup and α is the angle between them. Where both fluxes are produced by the same quantity, as in current or voltage operated relays, then below saturation the torque is proportional to I^2, the coil current, or $T=KI^2$. If the core is made

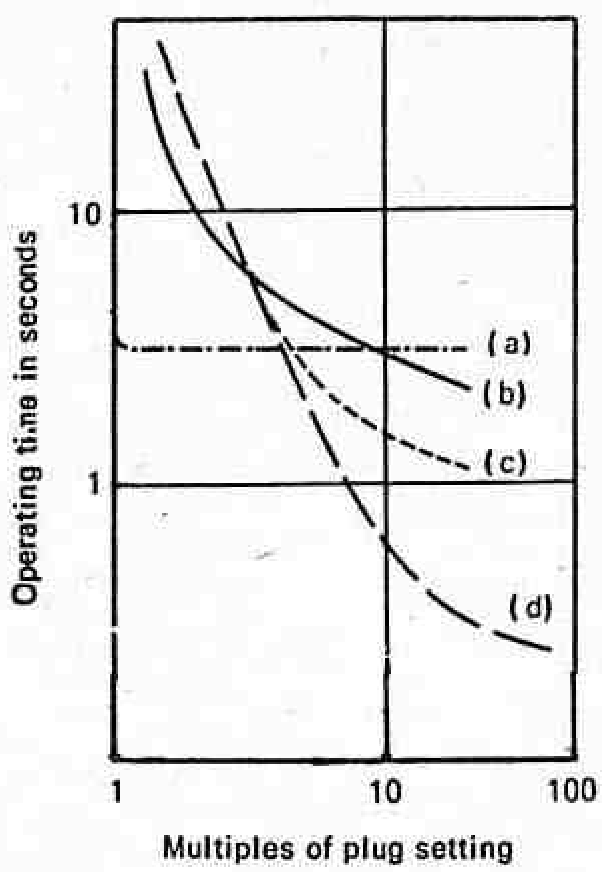


FIGURE 4.6 Characteristics of various overcurrent relays: (a) definite time; (b) IDMT; (c) very inverse; (d) extremely inverse.

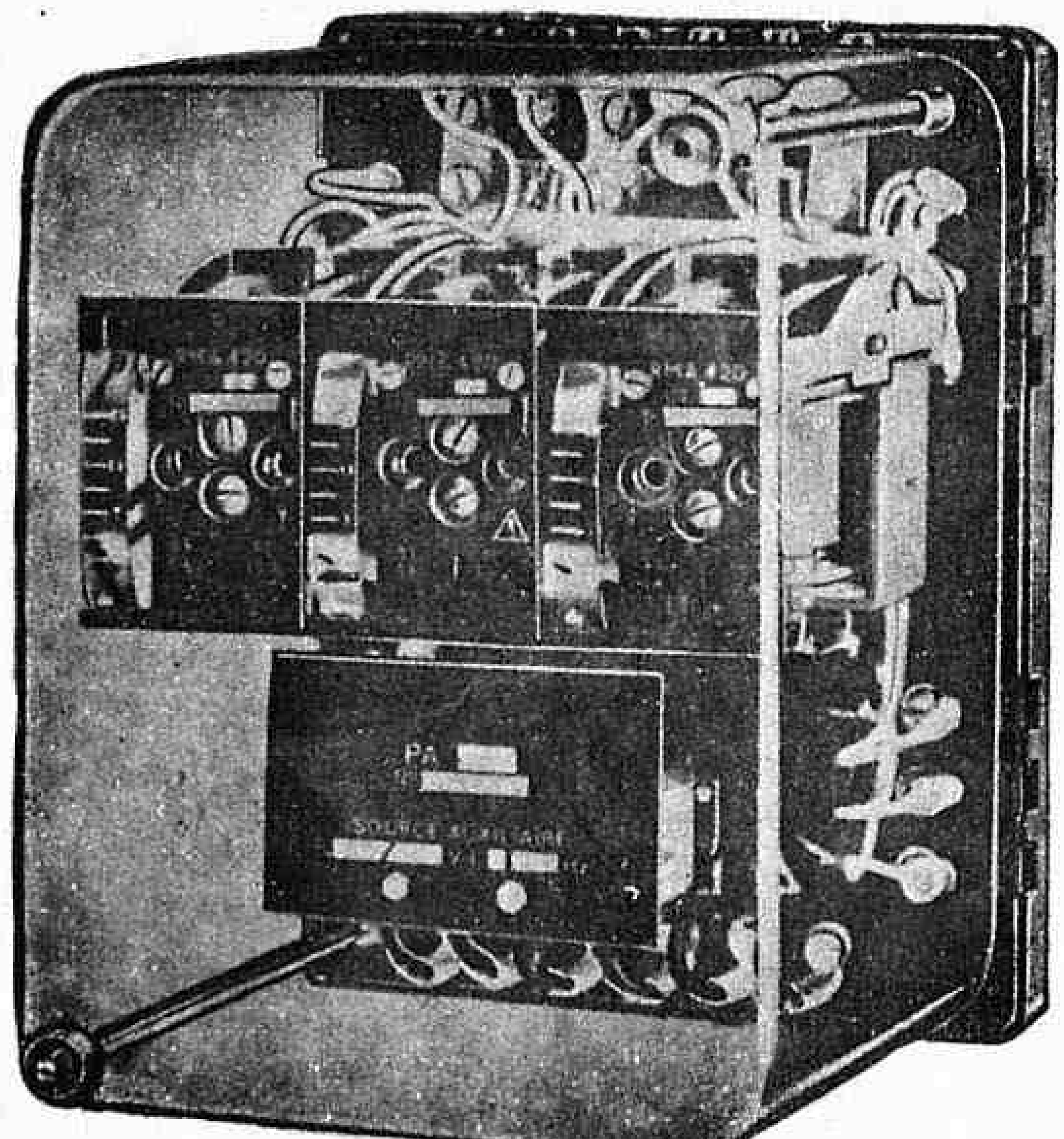


PLATE I Current measuring relays, Type : PA
(Courtesy : Jyoti Limited, Baroda)

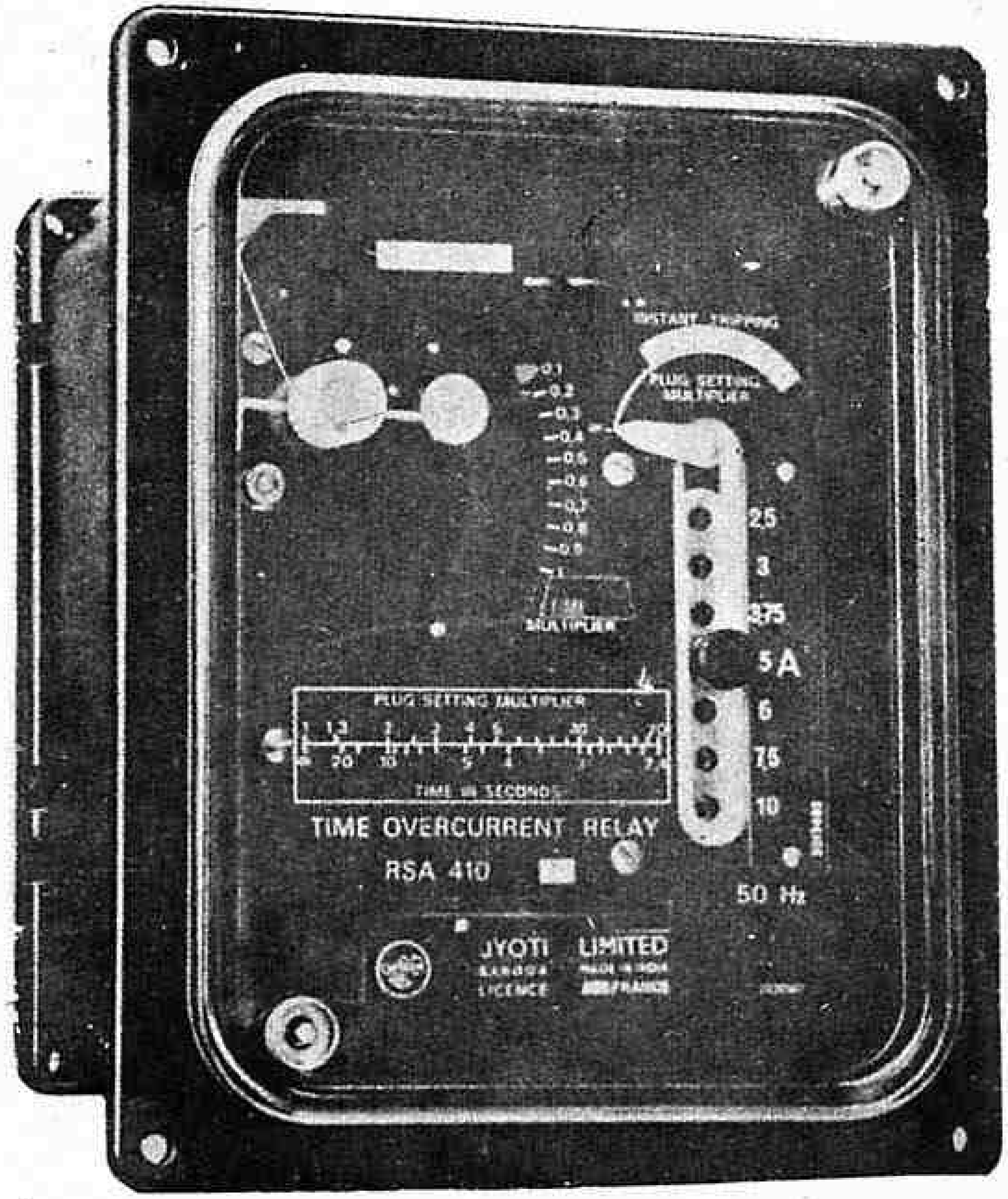


PLATE II Inverse time over current relay, Type : RSA-410
(*Courtesy* : Jyoti Limited, Baroda)

to saturate at a very early stage with the result that by increasing I, K decreases so that the time of operation remains same over the working range. The characteristic is shown by curve (a) in Fig. (4.6) and is known as *definite time*.

Now if the core is made to saturate at a later stage, the characteristics assume the shape shown by curve (b) Fig. (4.6) known as IDMT. The time-current characteristic is inverse over some range and then after saturation assumes the definite time form. At low values of operating current the shape of the curve is determined by the effect of the restraining force of the control spring, while at high values the effect of saturation predominates. Different time multiplier setting (TMS) are obtained by varying the travel of the disc or cup required to close the contacts. The higher the time multiplier setting, the greater will be the spring restraining force. In order to make the relay operate at a constant value of minimum trip current for any TMS, graded holes are cut in the disc or a disc with spiral cut edge is used. Thus, as the disc moves in the tripping direction, winding up the spring, more and more conducting metal of the disc comes into play in the active air gap of the electromagnet to increase the electric torque, thus compensating the increasing spring torque.

If the saturation occurs at a still later stage the characteristics assume the shape shown by curve (c) in Fig. (4.6) known as very inverse. The time-current characteristics is inverse over a greater range and after saturation tend to definite time.

The curve (d) in Fig. (4.6) shows extremely inverse characteristics, i.e. the saturation occurs at a very late stage and the equation of the curve is roughly of the form $I^2t=K$ where I is the operating current and t is the time of operation.

Out of all these characteristics IDMT is the only characteristic which is specified by Indian Standards (IS: 3231–1965) the rest are all relative curves. Table 4.2 shows the time-current characteristics of an IDMT relay.

Table 4.2 *Time-current characteristics of IDMT relay*

Operating current expressed as a multiple of the setting	*Operating time in seconds at the maximum time setting* (TMS=1.0)
20	2.2
10	3.0
5	4.3
2	10.0

The time-current characteristic is conveniently plotted on a log-log scale. Figure (4.7) shows the IDMT characteristics with different time multiplier settings (TMS).

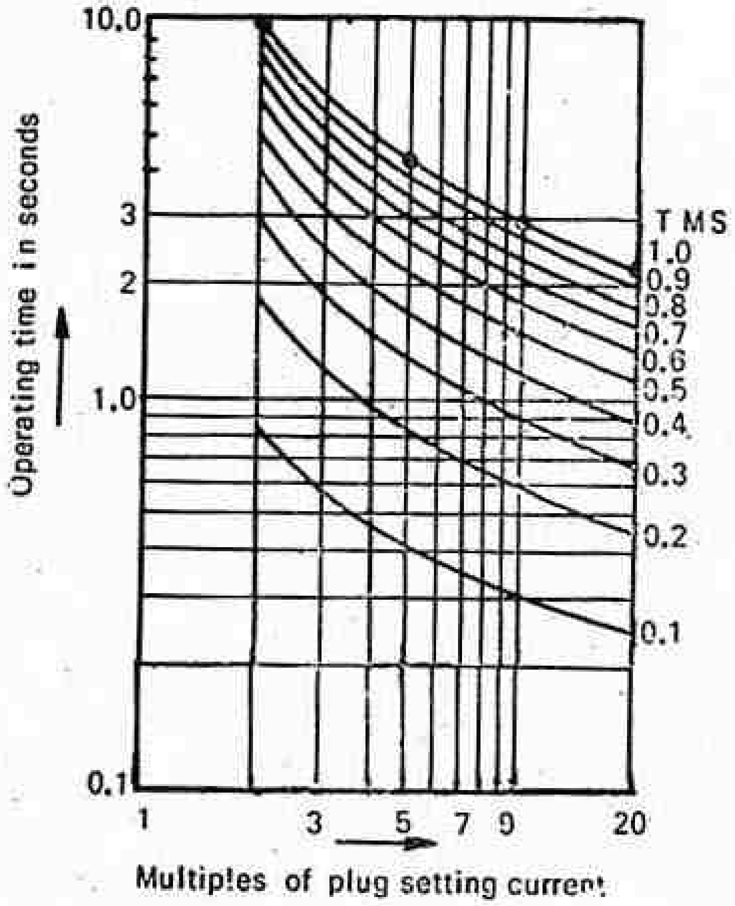


FIGURE 4.7 Typical IDMT characteristics with different time multiplier settings (TMS).

Theoretically their time ordinates should be proportional to the time multiplier setting so that, if the times for a given current were divided by the TMS all the curves should coincide. Owing to the inertia of the disc

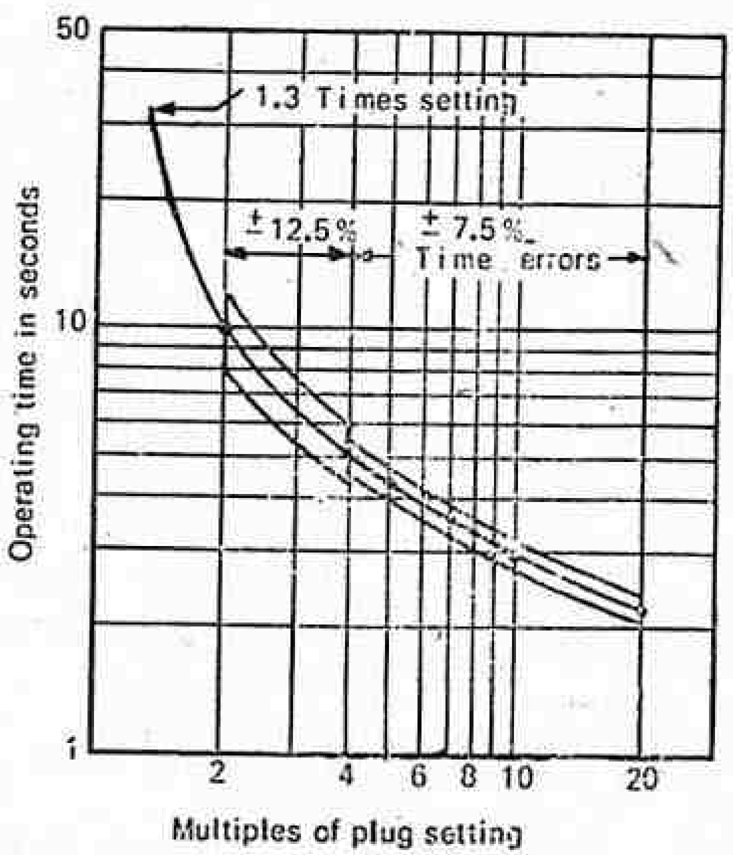


FIGURE 4.8 Limits of accuracy set by ISS at TMS=1.

which takes a little time for the disc to accelerate from standstill to its steady speed at low current values they may not exactly coincide. It introduces some error in time which might affect the discrimination of the whole scheme. The errors permissible as per IS: 3231–1965 are shown in Fig. (4.8).

At any other time setting, and with a current equal to 10 times the prescribed current setting, the relay shall conform to accuracy class 7.5 in respect of its operating time. However, if the error corresponding to the accuracy class does not exceed 0.1 second, the latter may be taken as the permissible error.

At any other current setting, and with a current equal to 10 times the current setting, the setting of time multiplier being the highest (TMS=1), the relay shall conform to accuracy class 10 in respect of its operating time.

The relays shall not operate at a current equal to or less than the setting; the minimum operating current shall not exceed 130% of the setting.

4.5 Instantaneous Overcurrent Relays

If the relay operates instantly without any intentional time delay, this characteristic can generally be satisfied by a relay of the nonpolarized attracted armature type. This relay has a special advantage of reducing the time of operation to a minimum for faults very close to the source, where the fault current is the greatest. The instantaneous relay is effective only where the impedance between the relay and source Z_s is small compared to the protected section impedance Z_l.

One of the most important considerations in overcurrent and overvoltage applications is speed of operation. With hinged armature relays, operating times of 0.010 second at three times the setting can be obtained. Such relays are used for restricted earth-fault and other forms of circulating current protection. With so fast an operation it is likely that the relay may operate on transients beyond the normal range of setting.

A relay is said to overreach when it operates at a current which is lower than its setting. Now at the time of fault occurrence the current wave is not symmetrical but offset as shown in Fig. (4.9). The relay is set for symmetrical currents but responds to both symmetrical and offset current waves which persist for a few cycles. The overreach depends on the design of the relay as well as on the parameters of the power system on which it is used. The X/R ratio of the system from the source to the fault, controls the degree of offset and rate of decrement of the current wave, and the ratio Z_s/Z_l determines the degree of overreach which will occur.

The current setting is proportional to $1/(Z_s+Z_l)$ so that with 100% offset the pickup would occur with half the symmetrical value of current, i.e. the operating current is now proportional to $1/\,2(Z_s+Z_l)$

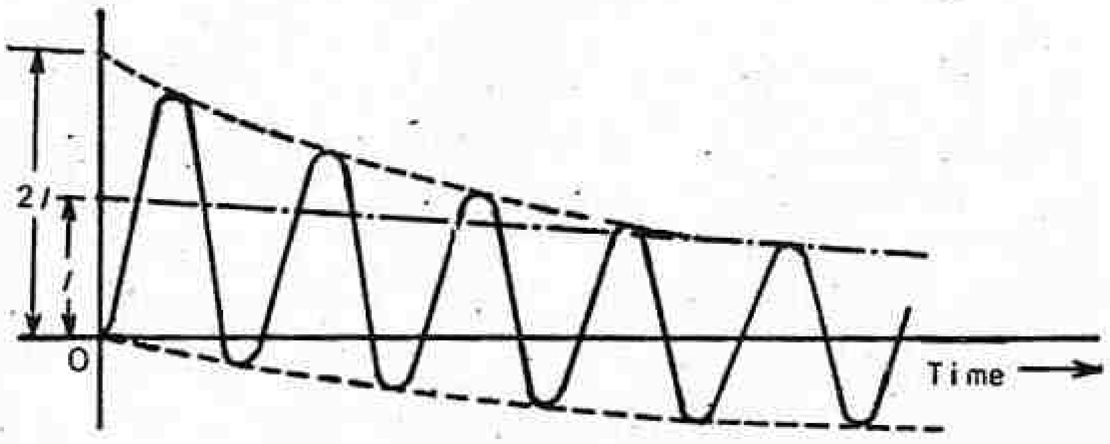


FIGURE 4.9 Offset current wave.

Since Z_s is fixed, the effective length of the line protected is increased, consequently the overreach may be more than twice the length of the protected section. If K is the overreach, then

$$Z_s+KZ_l=2(Z_s+Z_l)$$

or

$$K=2+\frac{Z_s}{Z_l}$$

i.e. with 100% offset current wave the instantaneous overcurrent relay will overreach to more than twice the length of the protected section.

Actually the overreach will be reduced by the operating time of the relay because the d.c. component of the fault current will be decaying exponentially, so that

$$i=\frac{E_{\max}\sin(\omega t+\psi-\phi)}{\sqrt{R^2+(\omega L)^2}}+\frac{E_{\max}\epsilon^{-rt/L}\sin(\psi-\phi)}{\sqrt{R^2+(\omega L)^2}}$$

$$=I_{\max}\left[\sin(\omega t+\psi-\phi)+A\epsilon^{-rt/L}\right]$$

where ϕ is the phase angle of the circuit ($\tan^{-1}\omega L/R$), ψ is the time in radians after time zero at which the fault occurs and t is the time after the inception of the fault. Modern compensated relays are available which have a very low transient overreach (approximately 5%), they do not respond to offset waves by the use of a d.c. filter. In the U.S.A. induction cup instantaneous units are used, because they are less sensitive to the d.c. offset component.

Another simple arrangement to achieve low transient overreach designed for high set overcurrent protection is shown in Fig. (4.10). The capacitor across the auxiliary winding on the operating magnet causes the circuit to resonate at 50 H_z so that the current takes a short time to build up to the setting value. The potentiometer adjustment of the setting provides a setting range maximum to minimum of 4 to 1.

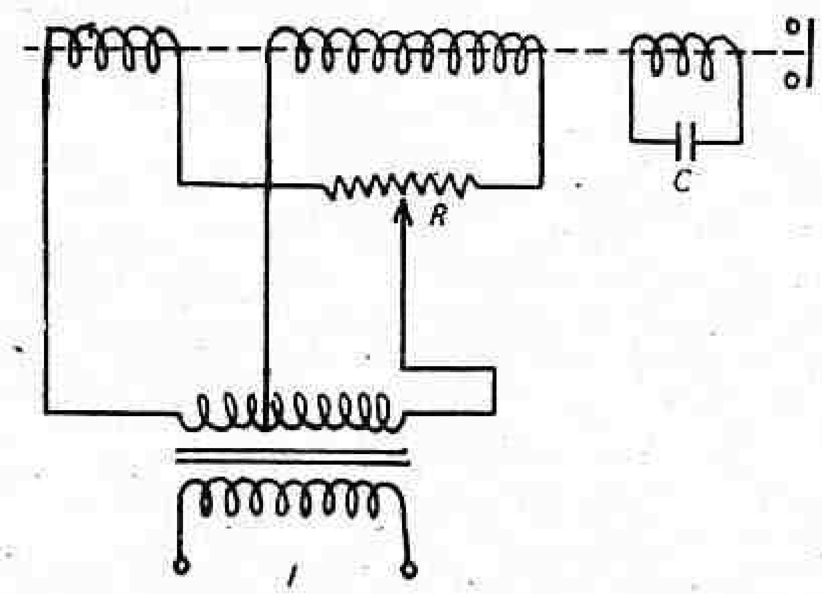


FIGURE 4.10 Instantaneous overcurrent relay with negligible overreach.

4.6 Application of Time-Current Relays

Overcurrent and earth fault protective gear can be made discriminative by grading the operating times of successive devices. The pickup currents are adjusted in such a way that the protection nearest the fault operates in a shorter time than the protection in the succeeding section towards the power source. On feeders each relay backs up the one in the next section further from the power source so that the time-current characteristics of the backup relay should be intermediate between the characteristics of the relays on each side of it. Naturally the scheme is inflexible insofar as system development is concerned, and where ultimate system arrangement is unpredictable its use may prove to be false economy.

4.6.1 Time-Graded Protection with Overcurrent Relays

The time interval necessary between successive relays is governed by the following factors:

1. Fault clearance time of circuit breaker.
2. Finite contact gap to ensure nonoperation.
3. Overtravel of the relays.
4. Relay and CT tolerances.

The fault clearance time of modern circuit breakers may be of the order of 0.08 second but it is advisable to allow 0.15 second. The residual contact gap necessary to ensure that the next relay nearer the power source does not operate is represented by a time interval of 0.1 second. The overshoot or overtravel of relays is less than 0.05 second. Tolerances are covered by a further margin of 0.1 second. This gives the total time allowed for the grading of successive relays as 0.4 second. The time interval for discrimination, with any graded scheme, is usually taken as approximately 0.5 second. Where separate earth-fault and phase fault relays are used they are graded independently.

As overcurrent relays are single input relays substituting the threshold conditions in the general Eq. (4.8) we get

$$KI^2-K''=0$$

or

$$I=\sqrt{\frac{K''}{K}} \tag{4.11}$$

4.7 Directional Relays

Selective protection cannot be achieved with time graded overcurrent protection systems in ring or loop systems as well as in radial circuits with two end power supply. A directional feature is incorporated in the relay as shown in Fig. (4.11). Figure (4.11a) shows how an induction disc

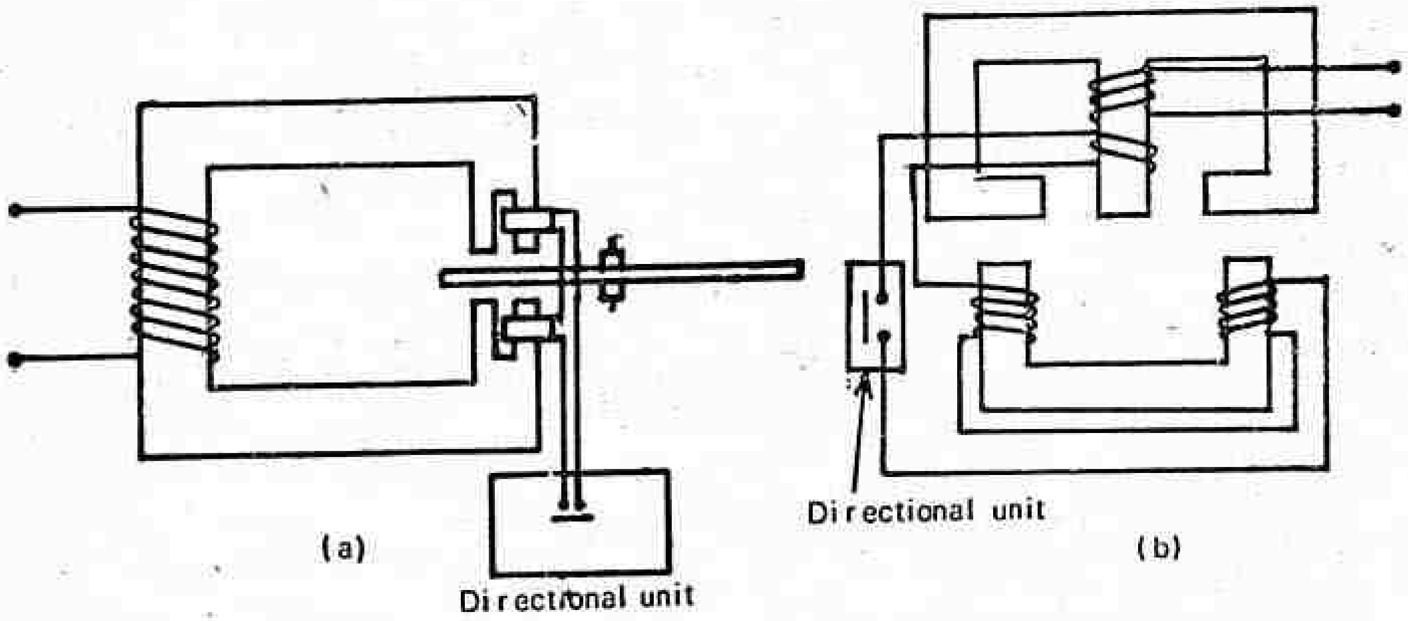


FIGURE 4.11 Overcurrent relay with directional unit.

type overcurrent relay with split-pole magnet, having in addition a directional unit consisting of capacitance or a resistance capacitance circuit works. Figure (4.11b) shows the wattmetric type of induction disc relay. Here the directional unit controls the angle between the two fluxes by varying the RX parameters of the lower electromagnet. Another method of control in the wattmetric element is to supply the lower winding from a separate voltage source. When the voltage of this source is equal and opposite to the output of the upper magnet secondary winding there is no current in the lower coil, and therefore no torque is produced. If it opposes and is less than the secondary output, or if it assists the secondary output, there is an operating torque. Conversely, if this source voltage opposes and exceeds the secondary output the current in the lower coil is reversed, giving a reverse torque. This latter method of control is the basis of the Translay balanced-voltage unit protection which will be described in a subsequent chapter.

Directional relays must have the following features:

(i) high speed of operation;
(ii) high sensitivity;
(iii) ability to operate with low values of voltage;
(iv) adequate short-time thermal rating;
(v) burden must not be excessive; and
(vi) there should be no voltage creep and current creep. That is, if either the voltage coil alone or the current coil alone is energized with the other one unenergized there should be no movement.

Induction cup units satisfy these requirements and are therefore very popular.

4.7.1 Single-Phase Directional Relays

The general Eq. (4.8) suggests that for directional control the individual torques, viz. $K|A|^2$ and $K'|B|^2$ should be eliminated. Considering a voltage current directional relay the general Eq. (4.8) reduces to

$$VI\cos(\phi-\theta)-K''=0$$

The spring constant K'' has no function and can be reduced to zero, so

$$VI\cos(\phi-\theta)=0 \tag{4.12}$$

or

$$\phi-\theta=\pm 90^\circ$$

The directional characteristic when plotted is shown in Fig. (4.12) which shows that the maximum torque occurs when $\theta=\phi$. In a voltage-current directional relay, θ will not be 90° because of the impedance angle

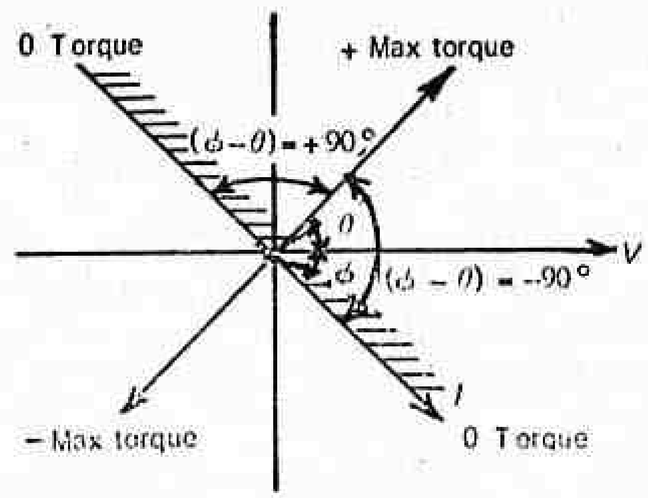


FIGURE 4.12 Directional characteristics.

CHAPTER 5

Feeder Protection

5.1 Introduction

The term *feeder* in this chapter will be used in a broad sense to mean overhead lines or underground cables for the transmission and distribution of electric power. The feeder as such forms a very important link in the power system. There are many alternatives to achieve the objective of protection but the choice of protective scheme depends upon the cost of the scheme and requires a thorough knowledge of the system to be protected and the method of operation:

5.1.1 Types of Protection and Their Selection

A composite transmission system may use one or more of the following types of protection.

(a) *Overcurrent Protection.* This is of two types: (i) nondirectional time and current graded schemes; (ii) directional time and current graded schemes.
(b) *Distance Protection.* This uses high speed distance relays.
(c) *Pilot Protection.* This is of three types: (i) wire-pilot protection; (ii) carrier-pilot protection; (iii) microwave-pilot protection;

The factors governing the selection of a particular scheme of protection can be enumerated as follows:

1. Economic justifiability of the scheme to ensure 100% continuity of supply.
2. Types of feeders whether radial or ring mains.

3. Number of switching stations in series between supply point and the far end of the system.
4. Availability of pilot wires.
5. System earthing—whether the neutral is earthed or insulated.

Time graded overcurrent relays are normally used for backup protection in large transmission systems or where a time lag can be permitted and instantaneous operation is not necessary. In distribution feeders, they play a more important role and may be coordinated with fuses. Overcurrent relays are also used for ground faults. Distance protection is applied where time lag cannot be permitted from stability considerations. Again there are many forms of distance protection each form having its own field of applications, e.g. for very short lines reactance type is preferred; for medium length lines impedance relay is suitable but is likely to operate erroneously on severe reactive power surges; mho relays are suitable for phase faults of longer lines. Distance relaying is a high speed form of protection. The pilot type of protection is a unit form of protection which would operate only for faults occurring within the protected section giving no backup protection. The advantage of this form of protection is that it gives the fastest discriminative clearance of all faults occurring anywhere within the protected feeder. Pilot wire protection is used for short lines where cost of pilot wires is not prohibitive. Carrier and microwave-pilot protection is used for long lines and interconnected lines.

Main transmission lines working on 220 KV or above are equipped with the fastest and the most reliable protection. Carrier-pilot or high speed distance protections are necessarily used on main transmission lines, whereas the 33 KV circuits are provided with directional time lag over current relays or high-speed distance relays. Radial feeders working on 11 KV or lower are usually equipped with time-lag overcurrent relays supplemented by instantaneous relays. Sometimes only *HRC* fuses are used on these lines.

5.2 Overcurrent Protection

Overcurrent relays offer the cheapest and the simplest protection for lines. The maximum load currents must be known to determine whether the ratio of the minimum fault current to maximum load current is high enough to enable simple overcurrent operated relays to be used successfully. This criterion is chosen in order to prevent the possibility of misoperation under normal operating conditions. This form of protection can be applied only to simple systems. The relays need readjustment or even replacement whenever a change in the system is made. The operating times are generally large.

and the total capacitive current of the system under fault conditions nI_{cap}. Assuming the direction of flow away from the busbars as the positive direction a current of nI_{cap} flows in phase A of the faulted feeder. Then the residual current in the faulted feeder is given by

$$I_r = nI_{cap} + I_a - I_{ab} - I_{ac}$$
$$= I_a + (n-1)\,I_{cap}$$

5.3 Distance Protection

Due to the complexity of the systems having a number of infeeds from generating stations, and the need for faster clearing times as the fault level increases and also because of difficulty in grading time/overcurrent relays with increasing number of switching stations, the use of high speed distance relays on modern systems has become imperative. It is a nonunit form of protection offering considerable economic and technical advantages on medium voltage and high voltage feeders. Being of the nonunit type distance schemes automatically provide backup protection to adjacent feeder sections. Selectivity is often achieved by a directional feature which is either inherent to the distance relay itself or is provided by supplementary relays. Discrimination between equipments with the same directional response on adjacent feeders is by time grading, but unlike overcurrent protection the times are not cumulative towards the power source.

5.3.1 Principle of Distance Relaying

The performance of distance relays is governed by the ratio of voltage to current at the relay location and the operating time of the relay automatically increases with an increase of this ratio. Now the impedance or the reactance of the circuit between the relay and the fault is proportional to the distance between them provided the relay actuating quantities (voltage and current) are properly chosen. This is the reason why such a relay is known as a *distance relay*. A simple example of measuring impedance of the line up to the point of fault is shown in Fig. (5.15). The relay is connected at point R and the two coils of the relay operating and restraining coils receive current (i_F) and voltage (v_F) proportional to the fault current I_F and the faulted loop voltage V_F. Below a particular value of $Z = V/I$ the relay operates, whereas above this value of Z the relay restrains; it is possible to select a setting comparable to the length of the line to be protected.

Strictly speaking the impedance seen by the relay is not proportional to the distance between the relay and the fault in general, because of the following reasons:

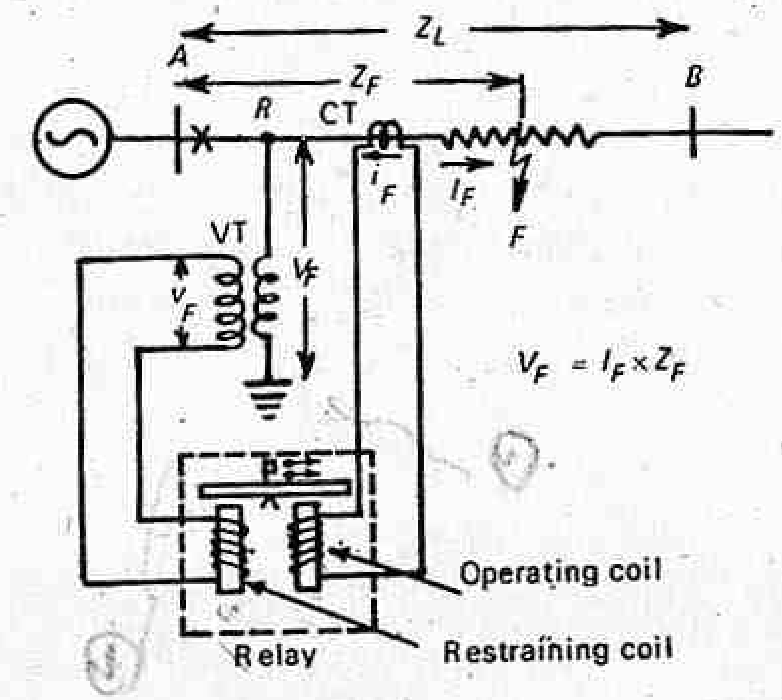


FIGURE 5.15 Simple impedance relay balanced beam type connections.

(i) Presence of resistance at the fault location.

(ii) Presence of loads and/or generating sources between the relay and the fault location, etc. Many a time for selective operation the relay requires the measurement of not only the magnitude but also the angle of the impedance of the line up to the fault point. However, the term distance relay is used to designate the whole group consisting of impedance, reactance, mho, modified impedance, ohm, offset mho, elliptical characteristic and trapezoidal characteristic relays. These relays have already been discussed in Chapter 4.

5.3.2 Effect of the Ratio Source Impedance to Line Impedance (Z_S/Z_L)

Any system could be represented by a single line diagram shown in Fig. (5.16) representing the source and the line to be protected, R being the relay location. This simple impedance loop has a voltage V applied to it

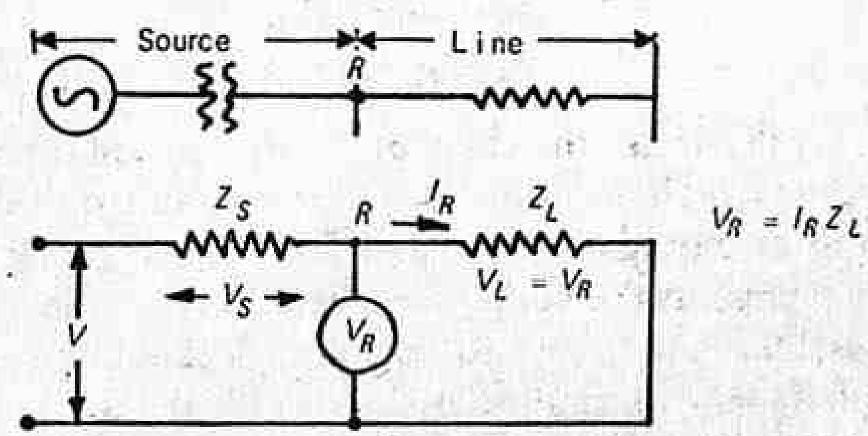


FIGURE 5.16 Power system arrangement.

which actually depends on the type of fault whether phase fault or ground fault. Z_S and Z_L are the source impedance and the line impedance respectively. Z_S is a measure of fault MVA at the relaying point, and for faults involving earth, is also dependent on the method of system earthing behind the relaying point. Z_L is a measure of the impedance of the protected section. I_R and V_R are the current and voltage applied to the relay respectively. The voltage V_R applied to the relay is thus $I_R Z_L$ for a fault at the reach point, and this may be alternatively expressed in terms of Z_S/Z_L ratio:

$$V_R = I_R Z_L$$

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

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

or
$$V_R = \frac{1}{\left(\frac{Z_S}{Z_L} + 1\right)} V \qquad (5.8)$$

Equation (5.8) is true for all types of faults with the following rule being observed:

(1) With phase-faults V is the delta voltage and Z_S/Z_L is the positive sequence source impedance/positive sequence line impedance, i.e.

$$V_R = \frac{1}{\left(\frac{Z_{S1}}{Z_{L1}} + 1\right)} V_\Delta \qquad (5.9)$$

(2) With earth-faults V is the star voltage and Z_S/Z_L is a composite ratio involving positive and zero sequence impedance, i.e.

$$V_R = \frac{1}{\left(\frac{Z_S}{Z_L} + 1\right)} V_Y \qquad (5.10)$$

where
$$Z_S = 2Z_{S1} + Z_{S0}$$
$$Z_L = 2Z_{L1} + Z_{L0}$$

and of course
$$V_Y = V_\Delta/\sqrt{3}$$

Figure (5.17) illustrates the effect of Z_S/Z_L ratio on the voltage at relay position R. Three fault locations are shown: fault outside the zone of protection, fault at setting distance, and fault in the protected zone. The ordinate at R represents the voltage applied to the relay V_R for various fault locations, for the relay to restrain V_R should be greater than the preset value of $V_R = I_R Z_L$ and for operation V_R should be less than the preset value of $V_R = I_R Z_L$.

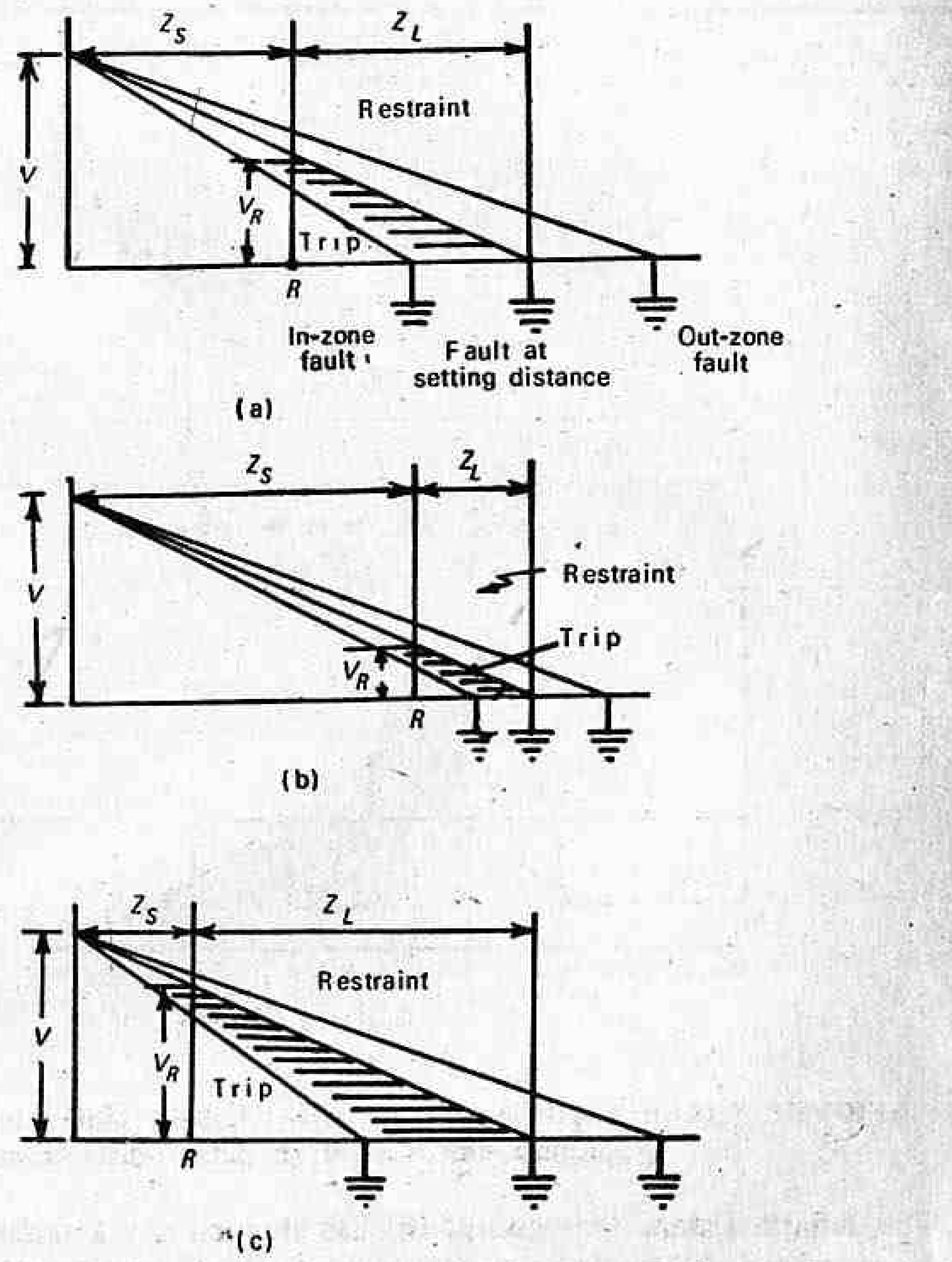


FIGURE 5.17 Effect of Z_S/Z_L ratio on the voltage at relay position: (a) when $Z_S/Z_L = 1$; (b) when $Z_S/Z_L = 7$; (c) when $Z_S/Z_L = 0.33$.

5.3.3 Time Grading of Distance Relays

Two methods of time grading are shown in Fig. (5.18). The distance time method at (a) has the operating time increasing steadily with increasing distance between the relay location and the fault. For coordination of relays on consecutive sections as shown in Fig. (5.18a) $t_A - t_B$ should be equal to $0.5s$ so that for faults on section BC the relay at B operates first and the relay at A acts as a backup protection. Similarly $t_B - t_C$ should be $0.5s$. Obviously this type of protection is a slow-speed protection and is unsuitable for transmission systems where fast fault clearance is essential to maintain stability.

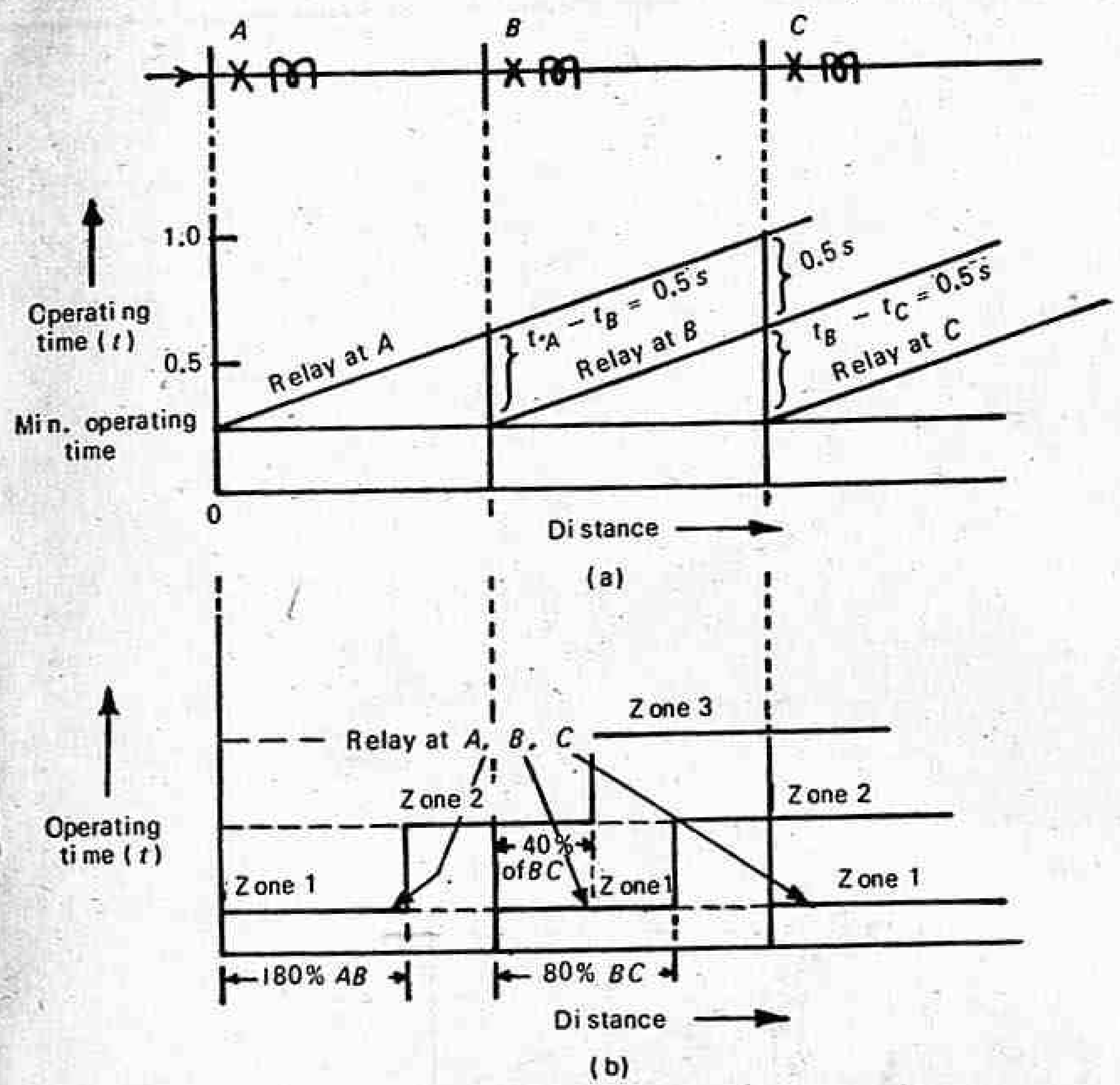


FIGURE 5.18 Time-grading of distance relays on radial feeders: (a) distance-time method; (b) definite-distance method.

The definite distance method at (b) has stepped characteristics in three stages. Zone 1 of the relay provides instantaneous tripping for any fault within a predetermined distance from the relay (generally 80% of the protected feeder). Zone 2 operates with a time delay and covers the remainder of the protected feeder and backs up the protection on the next feeder for about 40% of that feeder. After a further time delay the range of the distance relays is further extended to zone 3, which is used as backup protection only. The time delay between the various zones is chosen according to stepped principle (usual value of time delay step is $0.5s$). Obviously this is a high speed protection and has superseded the distance-time protection. Besides, the construction of definite-distance relays is simpler than distance-time relays. Because of this only high-speed distance relays are widely used in practice. Such relays can be arranged for measuring impedance or reactance and are normally provided with built-in directional feature. Hence the basic features involved in such a relay are (i) impedance or [illegible] measurement, (ii) di[illegible] and (iii) timing.

For finding the pickup value of the impedance in section n let us say zone 1 is 80% of the protected section.

$$Z^{(n)}_{\text{pickup (1)}} = 0.8\, Z^{(n)}_L$$

where

$Z^{(n)}_{\text{pickup (1)}}$ = setting value of pickup impedance of the zone 1 impedance element.

$Z^{(n)}_L$ = line impedance of the protected section n.

Therefore, any phase-fault for which the impedance seen by the relay is less than the setting value of pickup impedance for zone 1 will belong to zone 1 and is cleared instantaneously.

The zone 2 includes the whole length of protected section plus 40% of the next adjacent section. The clearing time for the zone 2 is taken as

$$t_2 = t_1 + \Delta t$$

where t_1 = clearing time of zone 1

$\Delta t = 0.5$ (time delay step)

t_2 = clearing time of zone 2

The pickup impedance for zone 2 is

$$Z^{(n)}_{\text{pickup (2)}} = Z^{(n)}_L + 0.4\, Z^{(n+1)}_L$$

where $Z^{(n)}_{\text{pickup (2)}}$ = setting value of pickup impedance for zone 2 impedance element

$Z^{(n)}_L$ = line impedance of protected section n

$Z^{(n+1)}_L$ = line impedance of the next adjacent section $(n+1)$ to the protected section n.

It is not possible to protect the whole length of the protected section by zone 1, because of the indeterminate nature of the fault resistance which may disturb the selective operation for faults at the end of the protected section and at the beginning of the next section. This is why zone 1 is kept nearly 80% of the protected section and zone 2 protects only a little portion nearly 20% of the protected section, but this provision helps in selective operation.

5.3.4 Requirements of Definite-Distance Schemes

Two feeders BO and OA are represented on the complex plane in Fig. (5.19) considered from the point of view of relays at O. The length OA is thus proportional to the impedance of feeder OA and θ is the impedance angle of the feeder.

Zone 1 of the protection at O is required to reach up to say P. The relays at O therefore must operate for all faults between O and P only.

The effect of fault arc resistance is also shown in Fig. (5.19). The fault resistance increases slightly for faults towards the remote end of the feeder

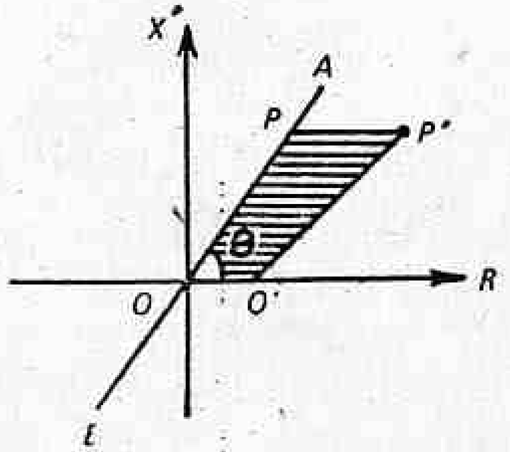


FIGURE 5.19 Ideal tripping area.

because less of the total fault current flows through the relay. The shaded area $OPP'O'$ is known as fault area. The impedance seen for differing fault positions will lie inside the shaded area. To protect against all faults the relay must operate if the measured impedance lies within the fault area. Hence relays at O with characteristics which completely enclose the fault area are suitable for protection of feeder OA.

5.3.5 Fault Resistance

Fault resistance consists of two components, the resistance of the arc and the resistance of earth. The second component is present only when it involves an earth-fault. In such a case the resistance of earth would mean the resistance of fault path through the tower, tower footing resistance and earth return. An approximate value of arc resistance is to be obtained by empirical relations. Warrington gives the expression

$$R_{arc}=\frac{2.9\times 10^{4}L}{I^{1.4}} \text{ ohms}$$

where L=length of arc in metres in still air,

I=fault current in amperes.

In the Soviet Union the expression used is

$$R_{arc}=1050\,\frac{L}{I}$$

L will initially be equal to conductor spacing in the case of phase-faults and distance from conductor to tower in case of earth faults. With cross wind, when there is a time delay in fault clearance such as in zones 2 and 3, the arc is extended considerably, and the resistance is increased. For zone 1 where the tripping is instantaneous, the effect of arc resistance is small and may be neglected except on very short feeders; but for zones 2 or 3 high velocity winds may cause the relay to underreach seriously.

When both wind and time are involved, Warrington's formula for arc resistance is

$$R_{arc}=\frac{50}{I}\,(V_L+47\ vt) \text{ ohms}$$

where V_L=nominal system interphase voltage, KV

v=wind velocity in km per hour

t=time in second

I=fault current in amperes.

5.3.6 Reach of Distance Relay

A distance relay is set to operate up to a particular value of impedance; for an impedance greater than this set value the relay should not operate. This impedance, or the corresponding distance is known as the *reach of the relay*.

To convert primary impedance (impedance of the line referred to the line voltage and current) to a secondary value (line impedance referred to the relay side) for use in adjusting a distance relay the following relation is used:

$$Z_{sec}=Z_{prm}\left(\frac{\text{CT ratio}}{\text{PT ratio}}\right)$$

where the CT ratio is the ratio of the HV phase current to the relay phase current, and the PT ratio is the ratio of the HV phase-to-phase voltage to the relay phase-to-phase voltage all under balanced conditions.

The tendency of a distance relay to operate at impedances larger than its setting value is known as overreach and similarly the tendency to restrain at the set value of impedance or impedances lower than the set value is known as underreach.

An important reason for overreach is the presence of d.c. offset in the fault current wave, as the offset current has a higher peak value than that of a symmetrical wave for which the relay is set.

The transient overreach is defined as:

$$\text{Percent transient overreach}=\frac{Z_{os}-Z_{sy}}{Z_{sy}}\times 100$$

where

Z_{os}=the maximum impedance for which the relay will operate with an offset current wave. for a given adjustment

Z_{sy}=the maximum impedance for which the relay will operate for symmetrical currents for the same adjustment as for Z_{os}.

The transient overreach increases as the system angle $\tan^{-1} X/R$ increases.

Figure (5.20) shows the variation of overreach with system angle.

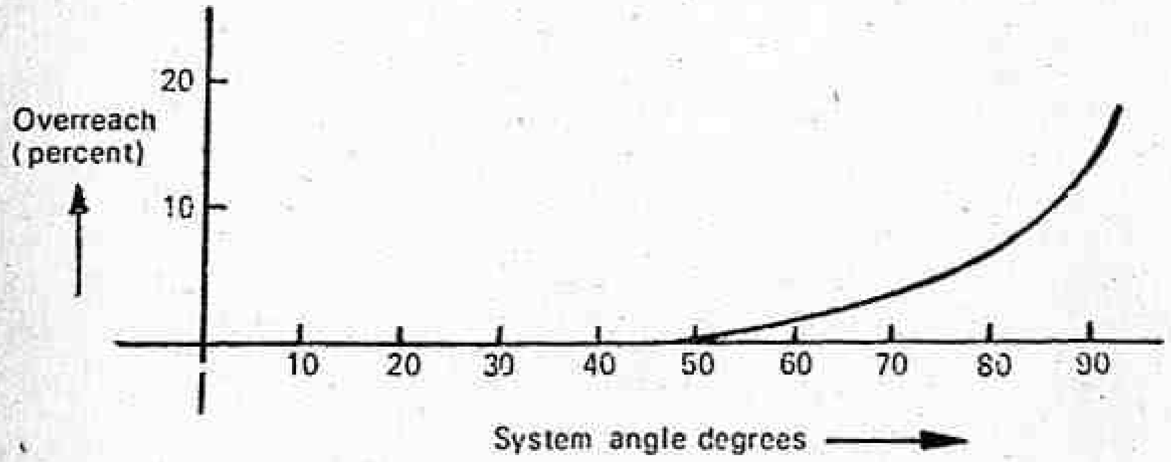


FIGURE 5.20 Overreach characteristics.

A distance relay may underreach because of the introduction of fault resistance as illustrated in Fig. (5.21). Relay at O is set for protection up to P. Now if a fault at P occurs such that fault resistance (PP') is high and by adding this resistance the impedance seen by the relay is OP' such that P' lies outside the operating region of the relay, then the relay does not operate.

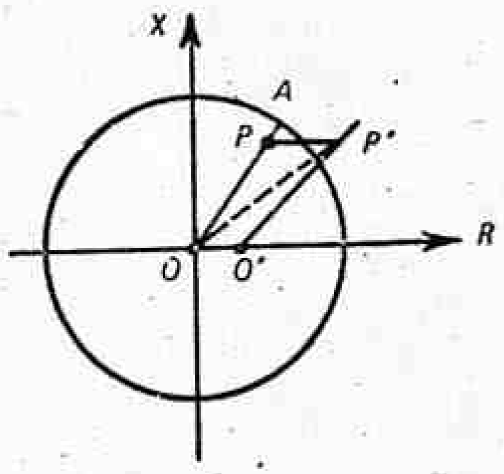


FIGURE 5.21 Underreach of distance relay.

Occasionally a fault may occur in the zone 1 and the relay may begin to operate. If the fault impedance now increases due to the arc resistance the total impedance seen by the relay will be the sum of the line impedance up to the fault and the arc impedance. This sum may be more than the impedance setting of the relay in which case the 1st stage operation will stop and the fault will be cleared as if it is located in the second or third zone. In order to prevent this impedance relays are *locked* once they begin to operate on the basis of the true impedance up to the fault. Any increase in impedance due to arc will not affect the relay once it is locked.

5.3.7 Schemes of Distance Protection

In developing an overall scheme of distance protection, it is necessary to ...ide a number of relays to obtain the required discrimination. Modern

practice is to adopt definite distance method of protection applied in 3 zones (steps). A number of distance relays are used in association with timing relays so that the power system is divided into a number of zones with varying tripping times associated with each zone. The first zone tripping which is instantaneous is normally set to 80% of the protected section. The zone 2 protection with a time delay sufficient for circuit breaker operating time and discriminating time margin covers the remaining 20% portion of the protected section plus 25 to 40% of the next section. Zone 2 also provides backup protection for the relay in the next section for faults close to the bus. Zone 3 with still more time delay provides complete backup protection for all faults at all locations. In practice, the initial pickup of the zone 3 relay may be used as a starter for the equipment, since its own measuring action will take place only after a long time delay.

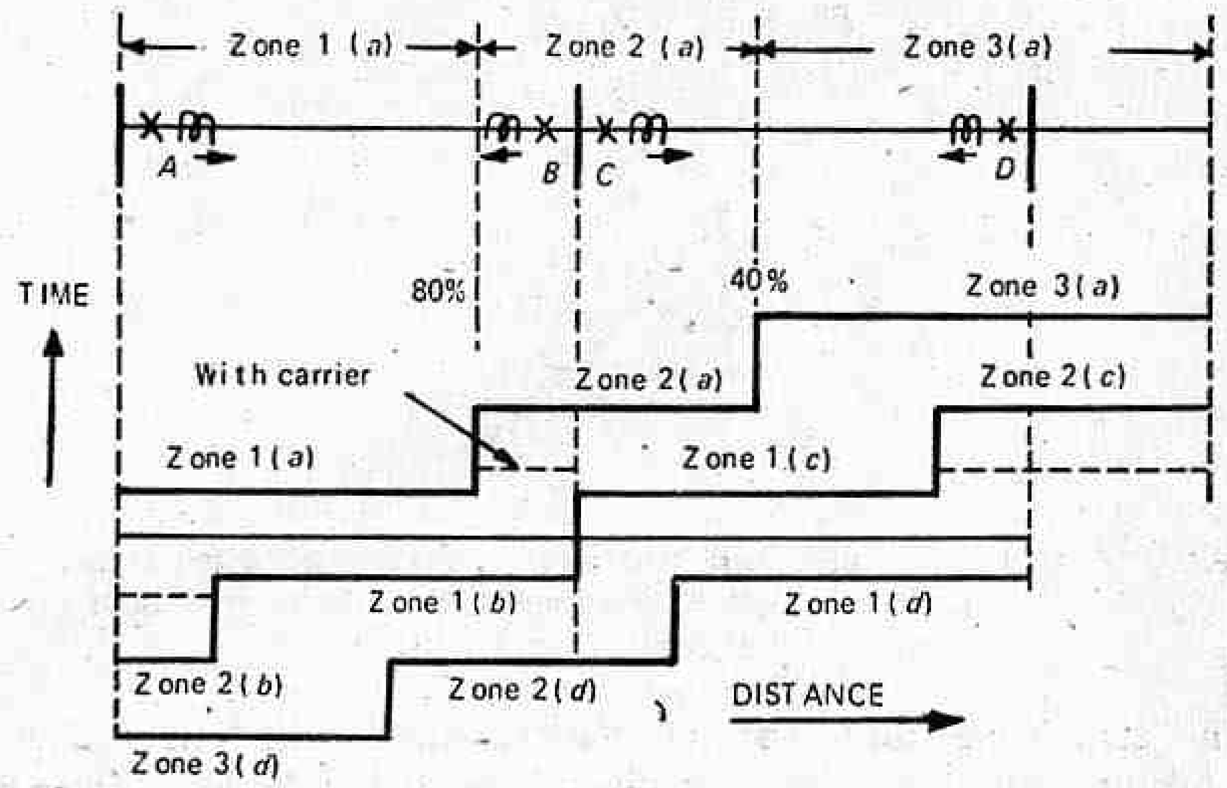


FIGURE 5.22 Typical stepped distance/time characteristic for feeders fed from both ends.

The three stepped characteristics of a definite distance scheme has already been discussed for feeders fed from one end. Now if fault can be fed from both ends as in the case of an interconnected system, assuming zone 1 to be 80% of the protected section then there will be 40% of the feeder on which faults will finally be cleared in the zone 2 time. This is clear from Fig. (5.22). This is undesirable from stability point of view and in general it will be necessary to avoid this delay. This is possible if the distance relay which has tripped instantaneously in zone 1 sends an intertrip signal to remote end of the feeder in order to trip the breaker quickly in preference to waiting for zone 2 tripping. In some distance schemes, carrier acceleration is applied which utilizes a carrier signal transmitted over the power line. The combination of the carrier signal and the position of the starting elements of the remote relay cause tripping without further time lag.

5.3.8 Distance Protection by Impedance Relays

It has already been pointed out that the impedance is directly proportional to the length of the line, and hence an impedance relay which measures impedance can be used to recognize a fault condition and operate. As such an impedance relay has no directional feature and will operate irrespective of the direction of current. Figure (5.23) shows the characteristics for a 3-zone impedance relay with directional unit D. It is usual to make maximum torque angle ϕ of the electromagnetic relays, smaller than the line angle θ. In case of static relays the maximum sensitivity angle is made less than θ. This is done in order to reduce the effect of arc resistance on the reach of the relay.

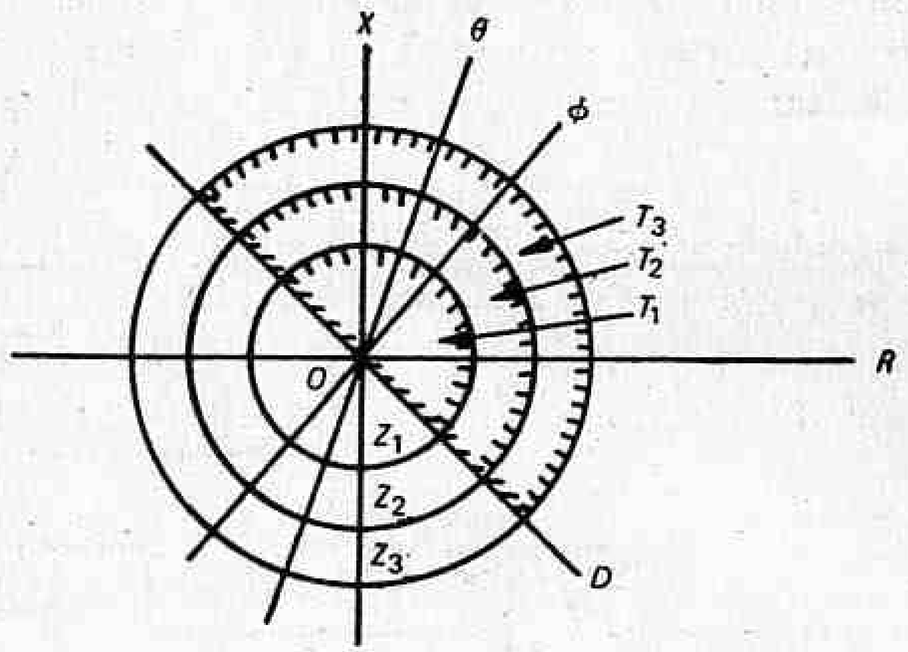


FIGURE 5.23 Impedance characteristics for a 3-zone protection with directional unit. θ—line impedance angle; ϕ—maximum torque angle of starting unit Z_3.

The zone 3 element Z_3 controls the operation of the timer and thus is the starting unit, the contact circuit is shown in Fig. (5.24). The zone 1 element operates without any intentional time delay, but still it has some finite time of operation T_1, whereas Z_2 and Z_3 operate with a time delay of T_2 and T_3 respectively.

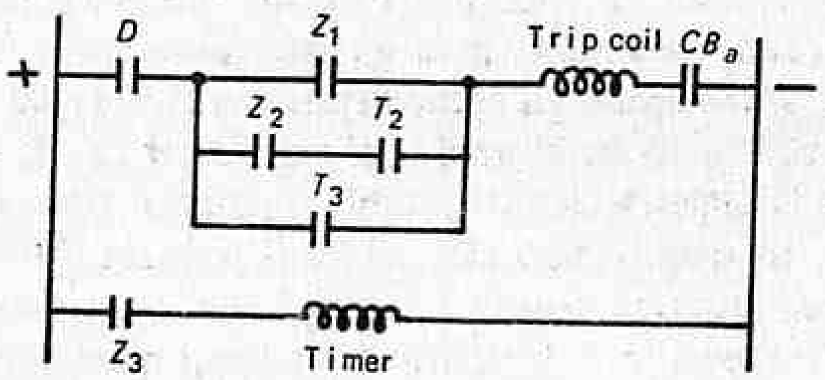


FIGURE 5.24 Contact circuit of a 3-zone impedance protection. D—contacts of directional unit; Z_1, Z_2, Z_3—contacts of zone 1, zone 2, and zone 3 elements; T_2, T_3—timer contacts; CB_a—auxiliary contacts on circuit breaker.

5.3.9 Distance Protection by Reactance Relays

Like impedance relays, reactance relays are also amplitude comparators and thus require an additional directional unit. Although the performance of reactance relays on single-fed systems is not unduly affected by fault resistance, there may be occasions in double-fed systems where errors in reach may occur, particularly when the phase relation between the respective source emfs is widely different and the value of fault resistance high. Figure (5.25) shows the 3-zone characteristics of plain reactance units and two reactance units with an additional mho unit which acts as a directional unit and also as a zone 3 protection and for starting. The mho unit prevents the undersirable operation of reactance units under load conditions. Time coordination is very important in such a scheme, in that care should be taken to ensure that zone 1 and 2 measurement cannot occur after the starting relay has dropped off, since it is possible for reactance relays to operate under load conditions.

The arrangement of contacts is shown in Fig. (5.26). The maximum torque angle or sensitivity angle of the starting unit (ϕ) is made smaller than the line angle (θ) for reducing the effect of fault resistance on the reach of the relay.

It is also possible to have all the three zones as reactance units and a mho unit which acts as directional unit and starting unit. Such a scheme

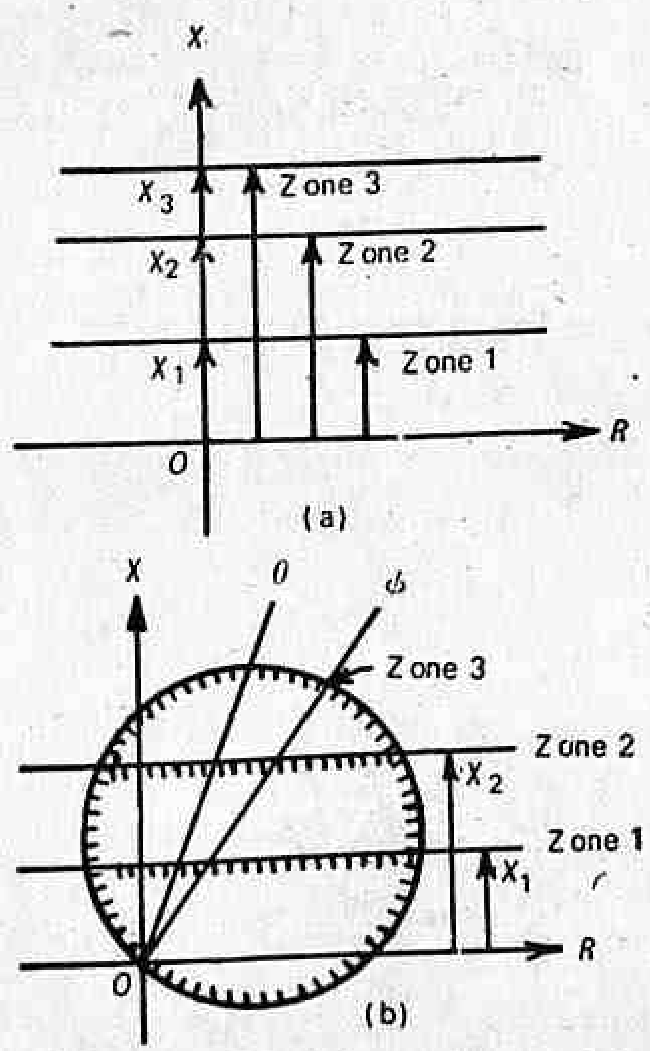


FIGURE 5.25 (a) A plain 3-zone reactance characteristics. (b) Reactance, reactance and mho relay stages. θ—line impedance angle; ϕ—maximum torque angle of starting unit.

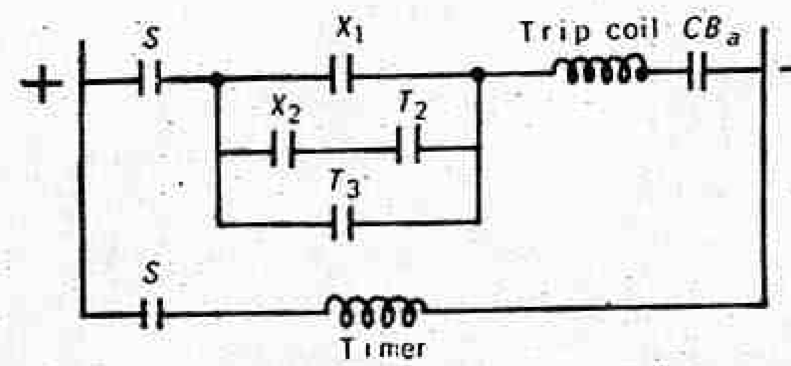


FIGURE 5.26 Contact circuit of a reactance, reactance, mho stages, of distance protection. S—contacts of starting unit (mho unit); X_1, X_2—contacts of zone 1 and zone 2 reactance elements; T_2, T_3—timer contacts; CB_a—auxiliary contacts on circuit breaker.

will also provide tolerance to fault resistance in zone 3.

5.3.10 Mho Distance Protection

The 3-zone mho distance protection does not need any directional unit as the mho unit itself is inherently a directional unit. Figure (5.27) shows 3-zone mho distance operating characteristics. Zone 3 mho unit which acts

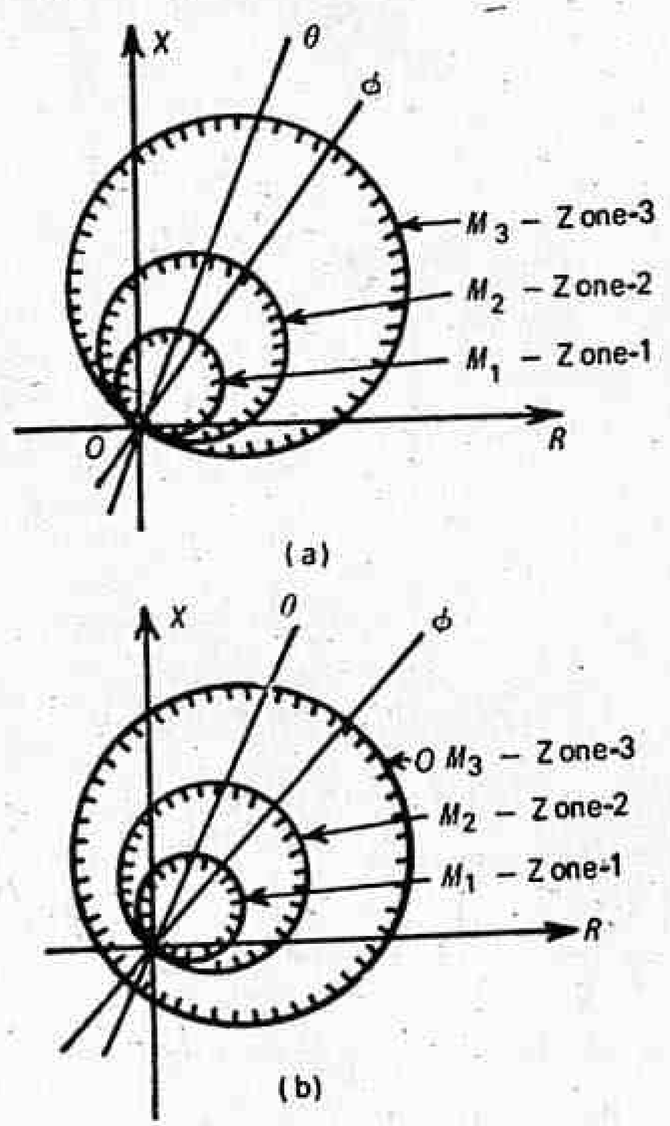


FIGURE 5.27 (a) 3-zone mho protection characteristics; (b) mho, mho and offset-mho protection characteristics. θ—line impedance angle, φ—maximum torque angle of starting unit.

as a starting relay or for controlling the timer can also be replaced by an offset-mho unit which has a definite advantage under closeup fault conditions as it encloses the origin. Contact arrangement is shown in Fig. (5.28).

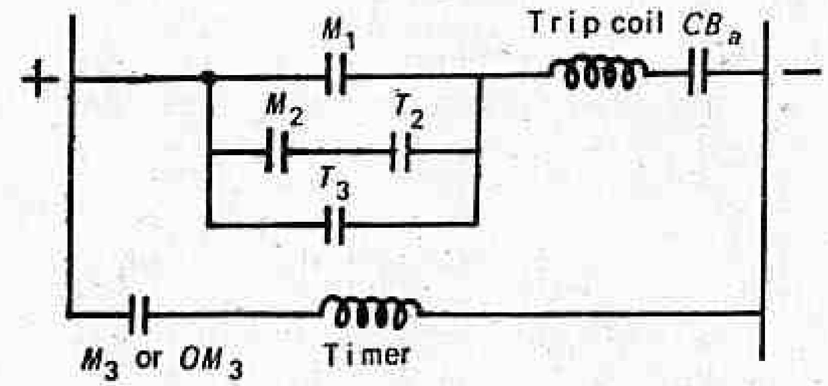


FIGURE 5.28 Contact circuit for 3-zone mho protection.

5.3.11 Overloads and Power Swings

The impedance measured or seen by a distance relay during normal load is shown in Fig. (5.29). Normally this would be outside the tripping zone of the distance relay, but, on a very long line where the length of the line in miles exceeds the system KV, the impedance characteristic may have to be made so large as to involve the point L. Furthermore as the load increases point L moves towards, the relay characteristic in the direction of arrow and during a power swing, it may oscillate up to a point such as PS where it may enter the tripping zone of the relay, even on a medium length line.

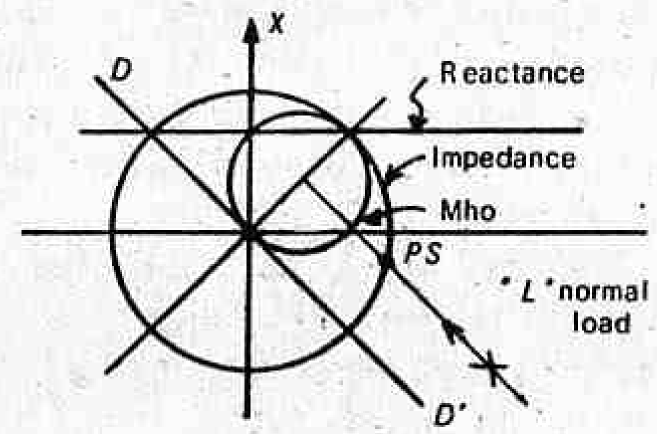


FIGURE 5.29 Impedance seen by a distance relay.

Power swings are surges of power due to the oscillation of generators with respect to each other which may occur because of changes in load, switching or faults. The presence of a power swing does not necessarily mean that the system is unstable. It is of paramount importance therefore that the relay must distinguish between a fault and a power swing, and respond correctly.

For determining the performance of distance relaying during power swings and out of step conditions let us consider a simple case of Fig. (5.30). The feeder to be protected links the two generators A and B

has an impedance Z_L. Z_A and Z_B are the impedances of the generators A and B respectively. Therefore, the total impedance of the system is

$$Z_T=Z_A+Z_L+Z_B$$

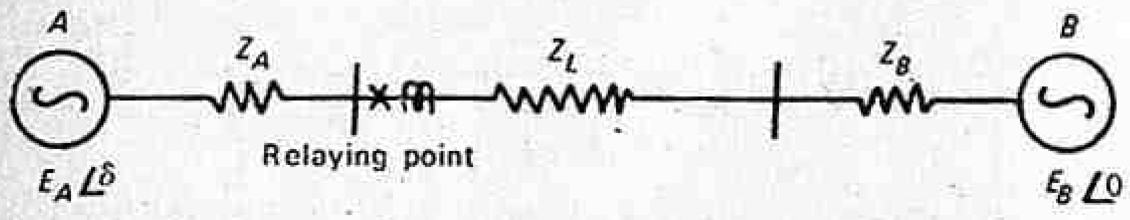


FIGURE 5.30 Two generator equivalent of a power system.

E_A and E_B are the voltages behind the transient reactances and are assumed to be constant in magnitude but varying in phase during swings or out of step conditions. The angle δ between E_A and E_B is therefore a function of the loads on the generators and the system characteristics, taking E_B as a reference and E_A to be leading E_B by an angle δ.

When the steady-state conditions are disturbed due to some reason, power swings occur, and in extreme cases the generators may go out of step. Behaviour of the system during power swings is the same as that during initial stages of out-of-step operation. Under these abnormal operating conditions the angle δ will vary until new equilibrium conditions are established.

For considering the effect of power swings on distance relays, it is better to plot the swing impedance chart on the complex impedance plane. Such a chart represents the swing impedance loci for different values of δ between the emfs of two swinging groups of generators, i.e. E_A and E_B. The relay operating characteristics and the locus of the impedance seen by the relay during fault conditions can also be represented on the same plane. Such a diagram enables us to see the behaviour of relays under different possible conditions such as normal load conditions, power swings, out-of-step operation and faults.

Referring to Fig. (5.30) the impedance seen by the relay during swings and loss of synchronism can be derived as follows:

If Z_r represents the impedance seen during swing by the relay situated at one end as shown in Fig. (5.30), we get

$$Z_r=\frac{V_r}{I_r}$$

where V_r and I_r are voltage and current applied to the relay. Therefore

$$Z_r=\frac{E_A-I_rZ_A}{I_r}=\frac{E_A}{I_r}-Z_A \tag{5.11}$$

But

$$I_r=\frac{(E_A-E_B)}{Z_T}=\text{equalizing current.}$$

Assuming the relationship between the magnitudes of the two emfs to be $|E_A/E_B|=K$ where K is a real number which can be less, equal to or more than unity, Eq. (5.11) becomes:

$$\begin{aligned}Z_r&=\frac{E_A}{I_r}-Z_A=\frac{E_A}{(E_A-E_B)}Z_T-Z_A\\&=\frac{K\,E_B\,e^{j\delta}}{K\,E_B\,e^{j\delta}-E_B}Z_T-Z_A\\&=\frac{K\,e^{j\delta}}{K\,e^{j\delta}-1}Z_T-Z_A\end{aligned} \tag{5.12}$$

In particular when $K=1$

$$Z_r=\frac{e^{j\delta}}{e^{j\delta}-1}Z_T-Z_A=\left(\frac{Z_T}{2}-Z_A\right)-j\left(\frac{Z_T}{2}\cot\frac{\delta}{2}\right) \tag{5.13}$$

where $e^{j\delta}=\cos\delta=j\sin\delta$

Equation (5.12) represents a family of circles with K as parameter and δ as the variable such that $Z_r=f(\delta)$. The centres of these circles lie on the straight line colinear with the impedance Z_T. If $K>1$, the centres of the circles $Z_r=f(\delta)$, i.e. swing impedance loci will be located in the first quadrant; for $K<1$ the centres will be in the third quadrant; and for $K=1$ the swing impedance locus is circle with infinite radius, i.e. a straight line which is the perpendicular bisector of the total impedance Z_T.

It can also be seen that for constant values of δ and K as variable, the swing impedance loci are circular arcs or a straight line for $\delta=180°$, the Z_T itself, with extremities on the ends of the Z_T (i.e. A and B). Both these families of the swing impedance loci are orthogonal to each other and these families form the swing impedance chart; one such is shown in Fig. (5.31).

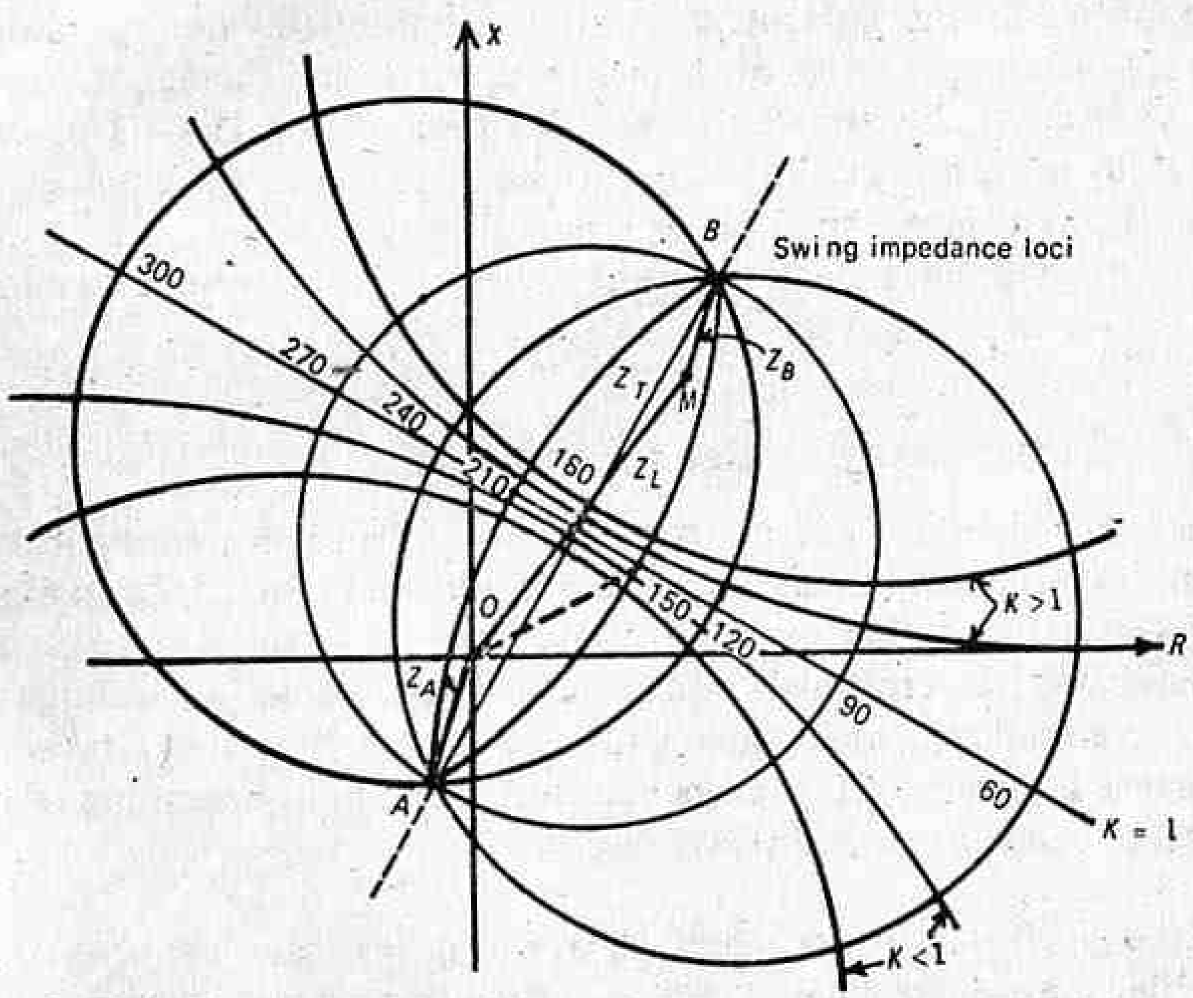


FIGURE 5.31 Fault impedance locus and swing impedance loci.

The vector drawn from the origin (relay location) to any point on the impedance chart will represent the impedance seen by the relay Z_r. For all practical purposes from protection point of view the swing impedance loci for constant K and variable δ in the first quadrant are almost straight lines parallel to locus for $K=1$. The effect of power swing is generally seen from the swing impedance locus corresponding to $K=1$.

The impedance seen by the relay Z_r will move along the swing impedance locus during swinging and wherever the swing impedance locus intersects the fault impedance locus, the Z_r will be exactly the same as under a three-phase fault. This point is known as the electrical centre of the system and lies approximately midway electrically between the ends of the tie line connecting machines A and B.

It may be noted that the value of δ determines the mode of operation of the system: (i) for normal operation $-0° \leqslant \delta \leqslant 60°$; $300° \leqslant \delta \leqslant 360°$; (ii) for swing operation $-60° < \delta \leqslant 120°$; $240° \leqslant \delta < 300°$; (iii) for out-of-step operation $-120° < \delta \leqslant 240°$.

As pointed out earlier, by superimposing the relay characteristics on the swinging chart the effect can be studied.

Prevention of Tripping during Power Swings. If the relay tripping area does not include any part of swing impedance locus, but at the same time is wide enough to include fault resistance, such a relay will not trip during swings, while tripping successfully during faults.

To overcome the maloperation of a distance relay during a swing or overload, the angular range of its pickup characteristic should be reduced so as to enclose only the fault area of a transmission line. This can be achieved by using (a) elliptical relay, (b) use of blinders in conjunction with mho and offset mho units, (c) reversing direction of zone 3 unit of the distance relaying scheme and (d) using a rate of rise of current monitoring relay.

5.3.12 Current and Voltage Connections

It is essential for the distance relay to measure the same distance between the fault and the relay under any type of fault condition. It is possible to supply the relays so that they will always measure Z_1 the positive sequence impedance of the protected feeder, by suitable choice of voltage and current connections, under any fault condition. It is usual to employ three phase fault measuring relays and three earth fault measuring relays—one for each phase-pair and phase respectively.

Connections for Phase Fault Relays. In the case of phase faults ...ising three-phase, phase-to-phase and double-phase-to-earth faults, this ...ved by supplying the relay with voltage across the faulty phases and

the vector difference of the currents in the two faulty phases, i.e.

Relay	Current (I_r)	Voltage (V_r)
a phase	I_a-I_b	V_{ab}
b phase	I_b-I_c	V_{bc}
c phase	I_c-I_a	V_{ca}

With these signals the relay measures Z_1 of the line section up to the fault location for any of the type of phase faults. Basic connections of phase-fault relays are shown in Fig. (5.32).

Sequence network connections are shown for different types of phase faults in Fig. (5.33). For a given phase-pair, say b-c, positive and negative sequence voltages at fault V_{f_1} and V_{f_2} are equal.

Similarly for a three-phase fault also the positive and negative sequence voltages at fault are zero and hence again are equal. At relay location the positive and negative sequence voltages are:

$$\left.\begin{aligned} V_{r_1}&=V_{f_1}+I_1Z_1 \\ V_{r_2}&=V_{f_2}+I_2Z_2 \end{aligned}\right\} \tag{5.14}$$

where I_1 and I_2 are sequence currents and Z_1, Z_2 the sequence impedances of the line. Since $Z_1=Z_2$ for lines and $V_{f_1}=V_{f_2}$, we have

$$V_{r_1}-V_{r_2}=(I_1-I_2)\,Z_1$$

or

$$\frac{V_{r_1}-V_{r_2}}{I_1-I_2}=Z_1 \tag{5.15}$$

Now

$$V_b=a^2V_{r_1}+aV_{r_2}+V_{r_0}$$

and

$$V_c=aV_{r_1}+a^2V_{r_2}+V_{r_0}$$

$\therefore$

$$V_b-V_c=(a^2-a)\,V_{r_1}+(a-a^2)\,V_{r_2}$$

or

$$V_b-V_c=(a^2-a)\,(V_{r_1}-V_{r_2}) \tag{5.16}$$

Similarly

$$I_b-I_c=(a^2-a)\,(I_1-I_2) \tag{5.17}$$

Hence

$$\frac{V_b-V_c}{I_b-I_c}=\frac{V_{r_1}-V_{r_2}}{I_1-I_2}$$

or

$$\frac{V_{bc}}{I_b-I_c}=Z_1 \tag{5.18}$$

This shows that for any type of phase faults the impedance seen by the relay will be the positive sequence impedance of the line up to the fault point.

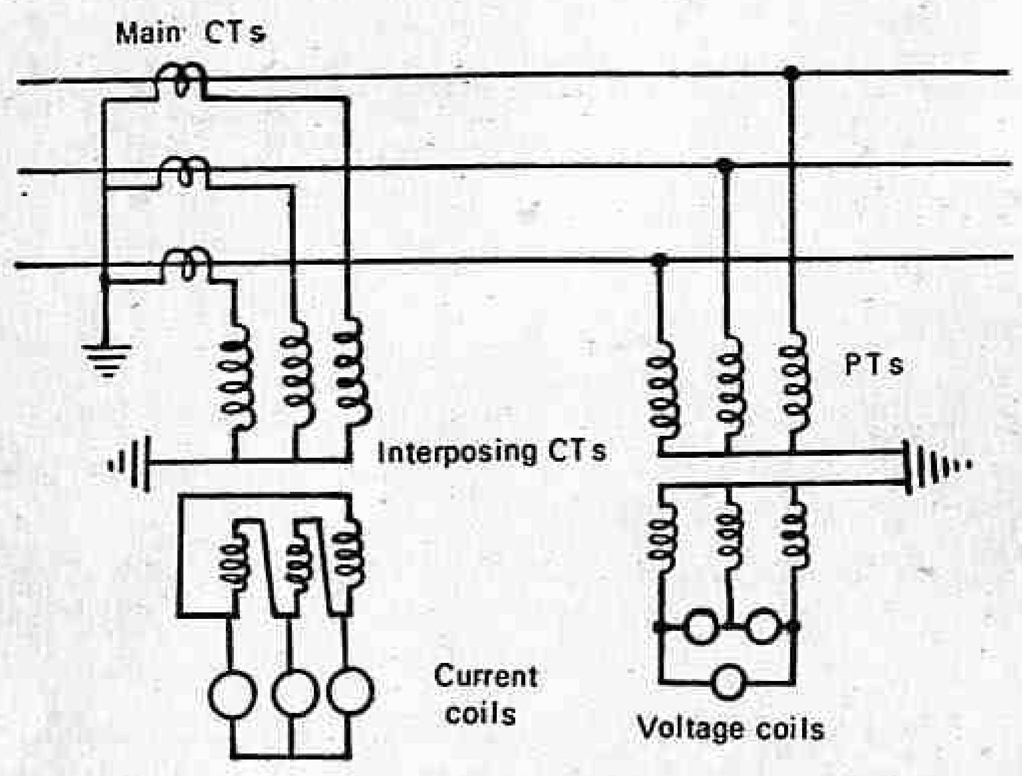


FIGURE 5.32 Basic connections of phase-fault relays.

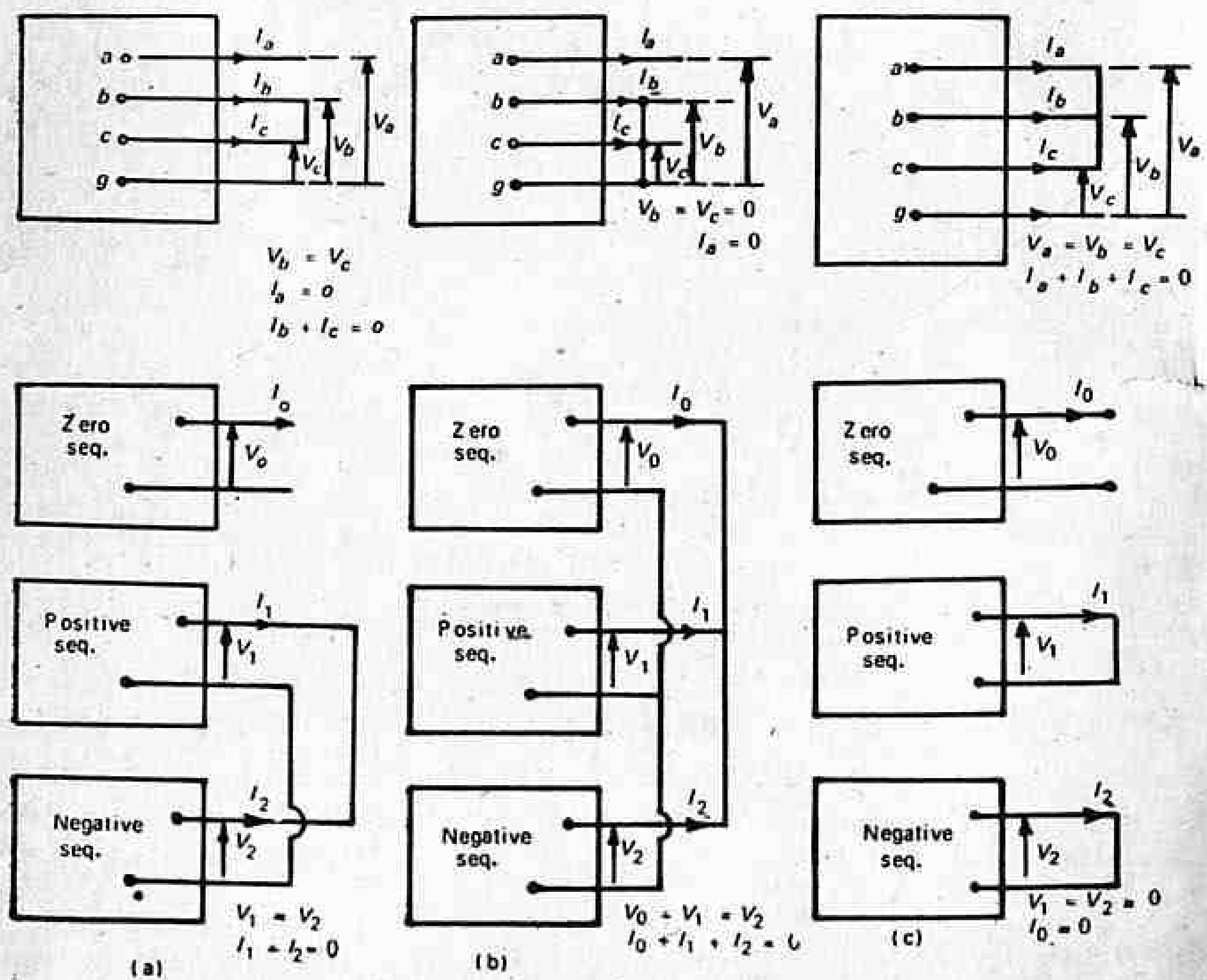


FIGURE 5.33 Sequence network connections for phase faults: (a) phase-to-phase fault; (b) phase-to-phase to earth-fault; (c) three-phase fault.

(ii) *Connections for Earth-Fault Relays.* Under earth-fault conditions the impedance measured by the relay would be equal to Z_e the earth loop impedance if the relay was supplied with phase-neutral volts and phase neutral current on a system earthed at one point only behind the relay location. However, on a system earthed at more than one point the measured impedance would vary depending upon the position and number of earth points. In order that the relays again measure the same impedance Z_1 under earth-fault conditions on a general system, it is necessary to add to the phase-neutral current a proportion of the residual current at the relay point. This is known as residual compensation and is achieved in practice by means of a tapped auto-transformer in the residual circuit of the main CT as shown in Fig. (5.34).

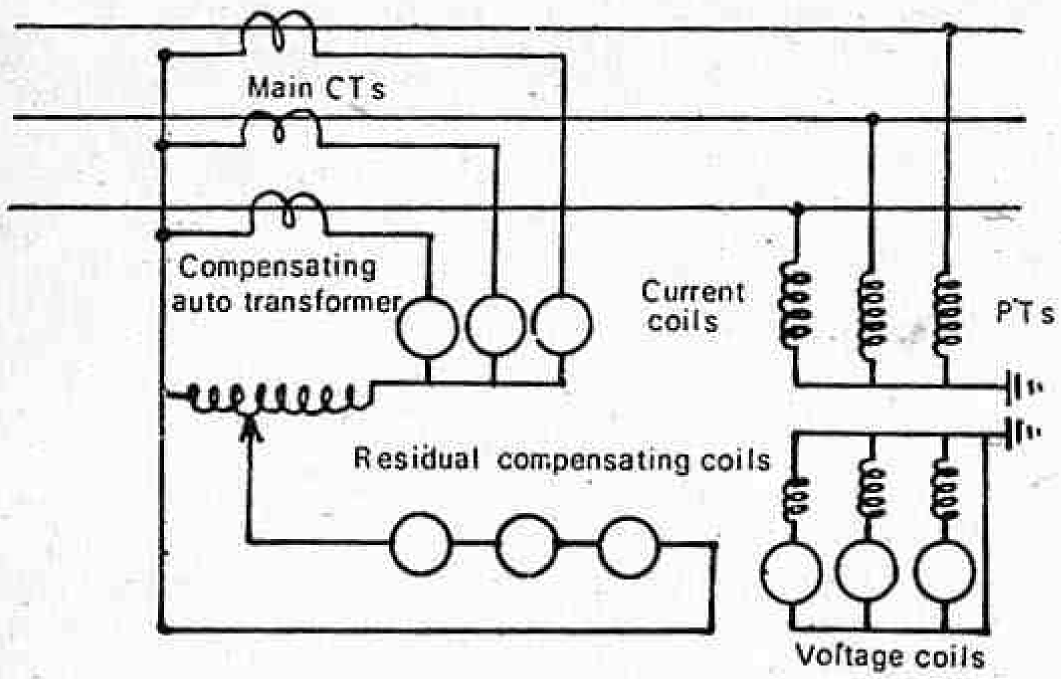


FIGURE 5.34 Method of residual compensation.

The voltage drop to the fault is the sum of the sequence voltage drops between the relaying point and the fault, viz. for fault on phase *a* in reference to Fig. (5.35).

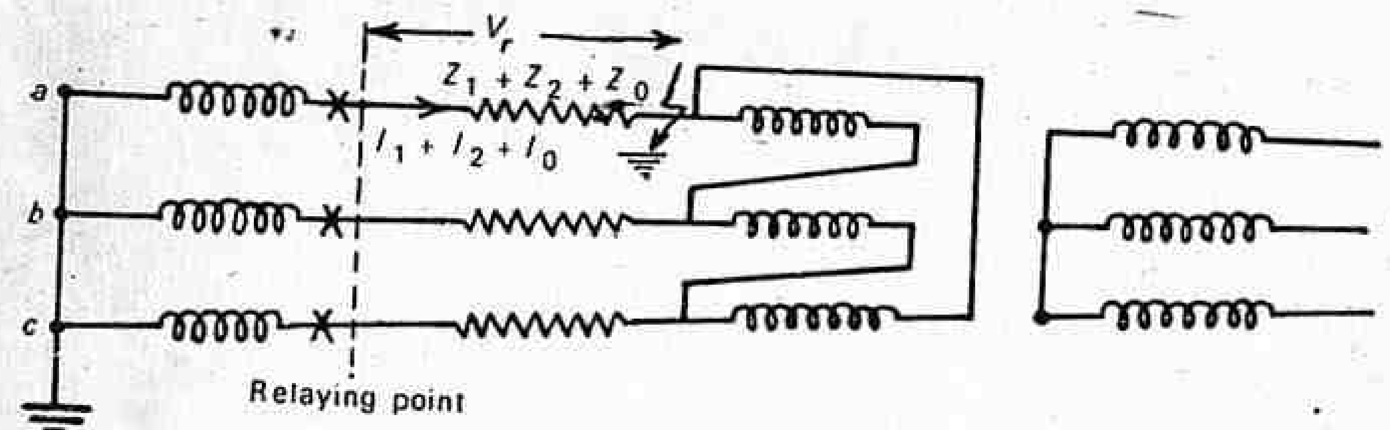


FIGURE 5.35 Earth-fault on system with single earth.

$$V_a = V_{r_1} + V_{r_2} + V_{r_0}$$
$$= I_1Z_1 + I_2Z_2 + I_0Z_0 \qquad (5.19)$$

Overcurrent protection of feeders may be divided into two categories: (i) nondirectional time and current grading; and (ii) directional time and current grading.

5.2.1 Nondirectional Time and Current Grading

It is possible to have time-graded systems, current-graded systems or a combination of the two, i.e. current/time-graded systems.

(a) *Time-Graded Systems.* To ensure selectivity of operation under all circumstances in a radial feeder, the operating time of the protection is increased from the far end of protected circuit towards the generating source. This is very conveniently achieved with the help of *definite-time-delay relays,* which usually consists of an instantaneous overcurrent relay followed by a timing relay the contacts of which trip the breaker. It has a more accurate time setting which is independent of CT saturation thus allowing closer grading times between successive circuit breakers. As the number of relays in series increase, the operating time increases towards the source. Thus the heavier faults near the generating source are cleared after a longer interval of time, which is a drawback. Its main application is in systems where the fault levels at the various locations do not vary greatly and hence the advantage of the inverse type of relay cannot be used.

Figure (5.1) illustrates the principle of time graded overcurrent protection of a radial feeder. The protection is provided at the sending

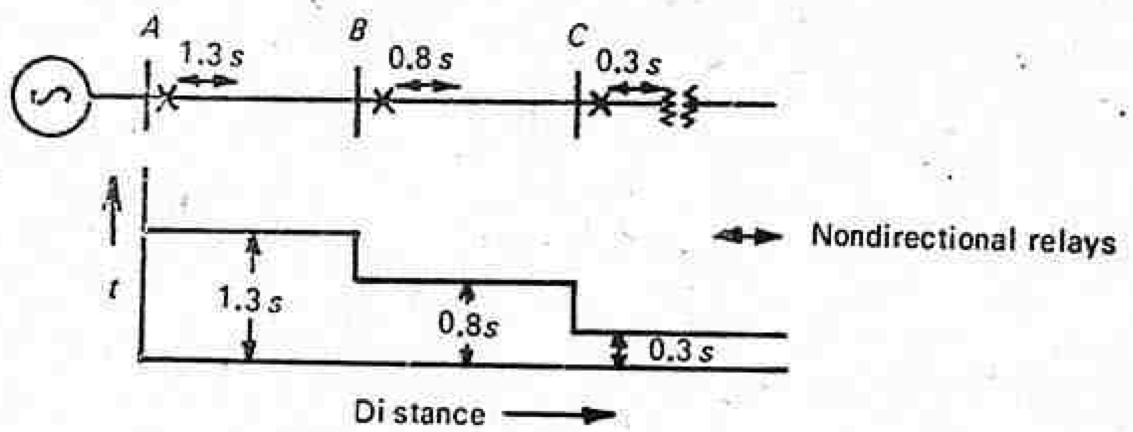


FIGURE 5.1 Time grading for radial feeder.

end of each section A, B and C. For a fault beyond C the breaker at C operates first and the protection at B and A act as backup protection. For faults between B and C the relay at B trips breaker at B and so on. The time setting of the successive relays differ by an interval known as *time delay step,* which is a factor of (i) fault clearance time of circuit breaker, (ii) finite contact gap to ensure nonoperation, (iii) overtravel of relays, and (iv) relay and CT tolerances.

Normally the time delay step lies between $0.3s$ and $0.5s$. A time delay step of $0.5s$ is a safe value which is taken in this illustration.

(b) *Current-Graded Systems.* It is based on the fact that the short-circuit current along the length of the protected circuit decreases as the distance from the source to the fault location increases. If the relays are set to pickup at a progressively higher current towards the source then the disadvantage of the long time delays that occur with time grading can be partially overcome. This is known as *current grading*. Each relay would be set to pickup at a progressively higher current towards the source. Such relays are known as *high-set-overcurrent relays.*

A simple current-graded scheme applied to the system of the form shown in Fig. (5.1) would consist of high-set-overcurrent relays at A, B and C with settings such that the relay at A would operate for faults between A and B, the relay at B for faults between B and C, the relay at C for faults beyond C. In practice the following difficulties are experienced:

(i) The relay cannot differentiate between faults which are very close to, but are on each side of B, since the difference in the current would be extremely small.
(ii) The magnitude of the fault current cannot be accurately determined, since all the circuit parameters may not be known.
(iii) The accuracy of relays under transient conditions is likely to be different.

Hence for discrimination the relays are set to protect only part of the feeder, usually, 80%. For this reason current grading alone cannot be used, but it may, with advantage, be added to a time-graded or IDMT relay system.

Figure (5.2) shows the characteristics of the combined high-set overcurrent (instantaneous) and IDMT overcurrent relays. For correct

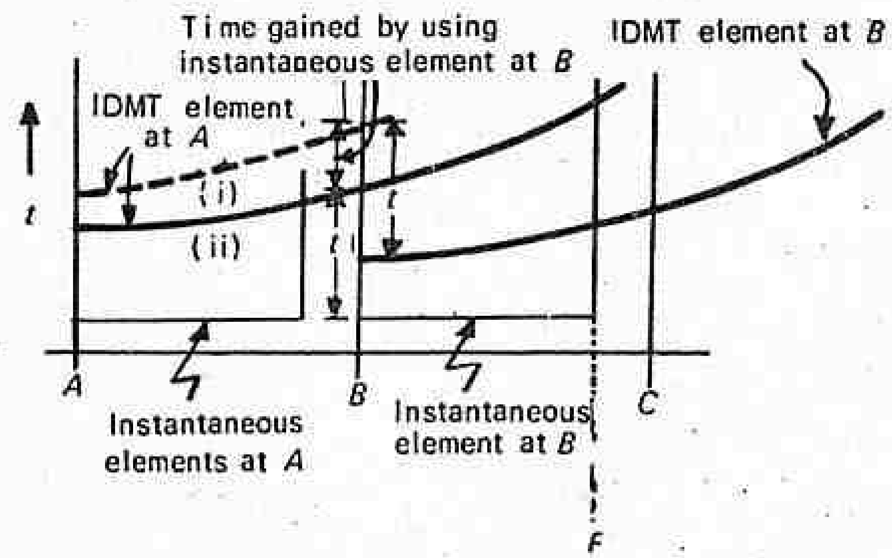


FIGURE 5.2 High-set overcurrent (instantaneous) and IDMT overcurrent relays.

Also

$$I_a = I_1 + I_2 + I_0 \tag{5.20}$$

and

$$I_a + I_b + I_c = 3I_0 = I_{res} \tag{5.21}$$

where I_{res} is the residual current and I_a, I_b, I_c are the phase currents at relaying point.

Substituting $Z_1 = Z_2$ and $Z_0 = KZ_1$ in (5.19), we have

$$V_a = Z_1 (I_1 + I_2 + KI_0)$$

$$= Z_1 (I_1 + I_2 + I_0 + KI_0 - I_0)$$

$$= Z_1 \{I_a + (K-1) I_0\}$$

$$= Z_1 \left\{I_a + \left(\frac{K-1}{3}\right) I_{res}\right\} \tag{5.22}$$

$$\therefore \quad \frac{V_a}{I_a} = Z_1 + \left(\frac{K_1 - 1}{3}\right) Z_1 \frac{I_{res}}{I_a} \tag{5.23}$$

In order to make this equal to Z_1 the second factor in Eq. (5.23) has to be eliminated which is done by adding $(K-I)\, I_{res}/3$ to the phase current.

The combined relay current input arrangement for phase and earth faults can thus be represented as in Fig. (5.36).

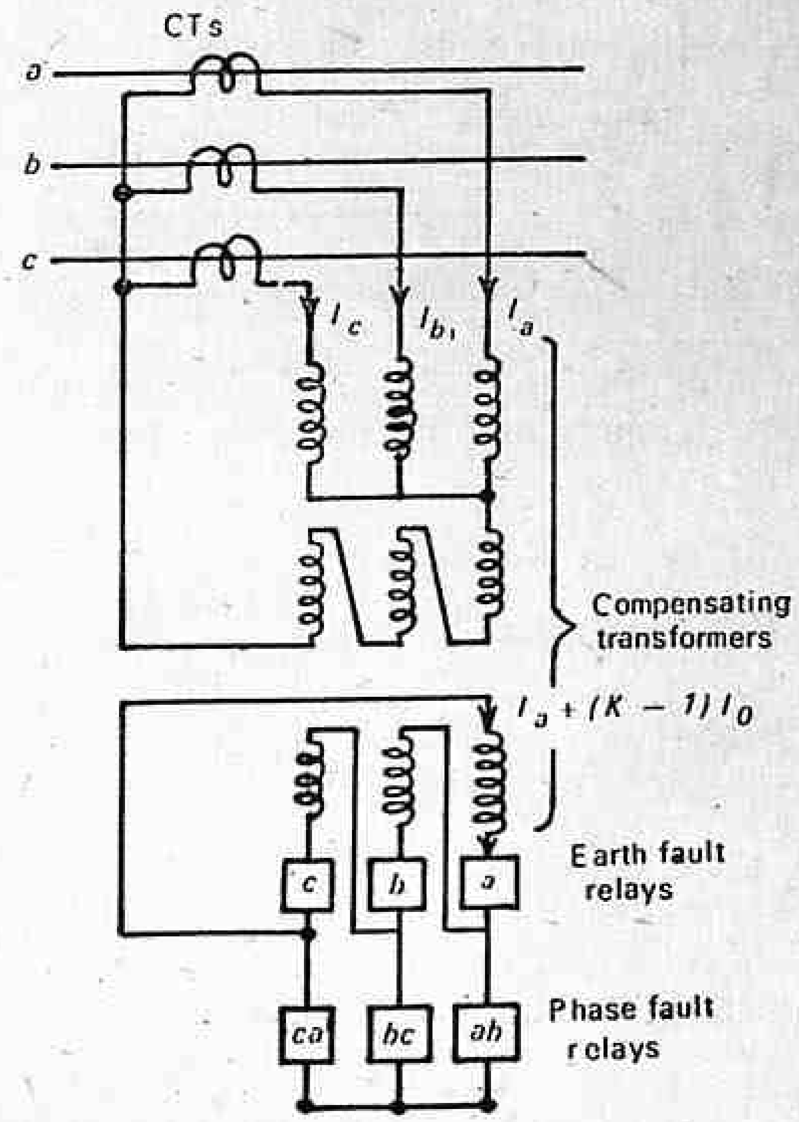


FIGURE 5.36 Relay current input arrangement.

5.3.13 Selection of Distance Scheme

The factors to be considered for the selection of a distance scheme can be enumerated as follows:

(i) Speed of operation.
(ii) Measuring relay characteristics.
(iii) Fault coverage.
(iv) Economic considerations.

(i) *Speed of Operation.* Operating time is of great importance on systems which are liable to become unstable if the fault persists for more than 5 cycles or so. Zone 1 operation in non-switched schemes where separate measuring units for different phases are used is in the region of 2-3 cycles; but about 40% of the protected section viewed from both ends is covered in zone 2 operating time. Such a scheme in conjunction with the power line carrier is used to extend the zone 1 reach for internal faults, thereby ensuring simultaneous high-speed operation of breakers at both ends, the scheme however works as a plain distance backup for external faults.

All switched schemes which use single measuring unit for different phases switched by proper selectors or starters, are slow speed protections. Thus in general non-switched schemes are applied on all important feeders at sub-transmission and distribution voltage levels, and in combination with power line carrier, on all feeders at bulk transmission voltages. Switched schemes are applied as an economic alternative to time graded forms of protection on radial and ring distribution circuits and on less important transmission lines.

Because of the long clearance times with the switched schemes, it is usual to add out-of-step blocking and tripping relays to the scheme to prevent serious shut-down during power swing condition.

(ii) *Measuring Relay Characteristics.* The field of application of various distance relays overlap to a large extent and as such a hard line cannot be drawn for their respective fields. The length of the line to be protected and the voltage of transmission play a very important role in the choice of these characteristics.

Reactance relays are preferred for short line sections because of being insensitive to fault resistances which may be large compared with the line impedance. Since power swings affect reactance relays to a large degree than the other factors these relays are unsuited to long line protection.

The impedance relay is better suited for phase-fault relaying for lines of moderate lengths. The effect of arc on impedance relay is more than in a reactance relay but less than a mho relay. Power swings affect an impedance relay less than a reactance relay but more than a mho relay, but schemes using either may require supplementary relays to prevent maloperation. The impedance relay will always require a separate directional unit.

As the mho relay is less affected by power swings and encircles the smallest area on the complex plane it is best suited for long lines. It has an additional advantage of being inherently directional which renders starting relays unnecessary. For very long heavily loaded lines, mho unit blinders or elliptical relays are better suited.

With cables, it is the sensitivity of the relay rather than the fault resistance that determines the minimum length of cables that can be protected. The conductance relay is more tolerant to fault resistance than mho or plain impedance and more economical than the reactance unit because it needs no directional unit. It is applicable to distribution lines both overhead and cable.

(iii) *Fault Coverage*. Where a system is not effectively earthed or earthed through an arc suppression coil it is only necessary to apply phase-fault schemes of protection; while on effectively earthed systems fault coverage for both phase and earth faults is provided.

(iv) *Economic Considerations.* The foregoing discussion makes it amply clear that there are a number of alternatives to achieve the objective of feeder protection. Maybe time graded overcurrent protection is sufficient under particular circumstances. As far as earth-fault protection is concerned overcurrent earth-fault protection works quite satisfactorily and is normally provided with phase protection as one of the distance schemes. The occasional slower clearing time with overcurrent relays is unimportant because single phase of earth-faults have negligible effect on system stability.

5.3.14 Application to Three-Phase System

In a three-phase system, a wide variety of faults can occur, i.e. phase to phase, phase to earth, 2 phase to earth and 3 phase fault, various combinations in a 3-phase system lead to 10 varieties. Theoretically, 4 fault detectors and 18 measuring units are required for providing 3 stepped characteristics. Some duplication of relays is thus necessary in order to provide complete protection. A number of methods can be adopted such as those described below.

(i) Multiplicity of relays are used to cover all fault conditions. Six sets of relays are required for the three possible phase-to-phase faults and the three possible earth-faults. Other faults are covered by one or more sets of relays. This method involves much equipment but is also the most reliable.

(ii) Three sets of relays are sometimes used, which can be switched on to measure either phase to phase or phase to neutral quantities. The relays

are normally connected for phase-to-phase fault measurement and are switched to earth-fault measurement by a residual current detector. Difficulties arise due to spurious residual currents and on changing faults and the arrangement is not in common use.

(iii) Six elements for phase-faults and six elements for earth-faults (Fig (5.37)). The ohmic reach of zone 1 is increased to that of zone 2 through contacts on a timing unit.

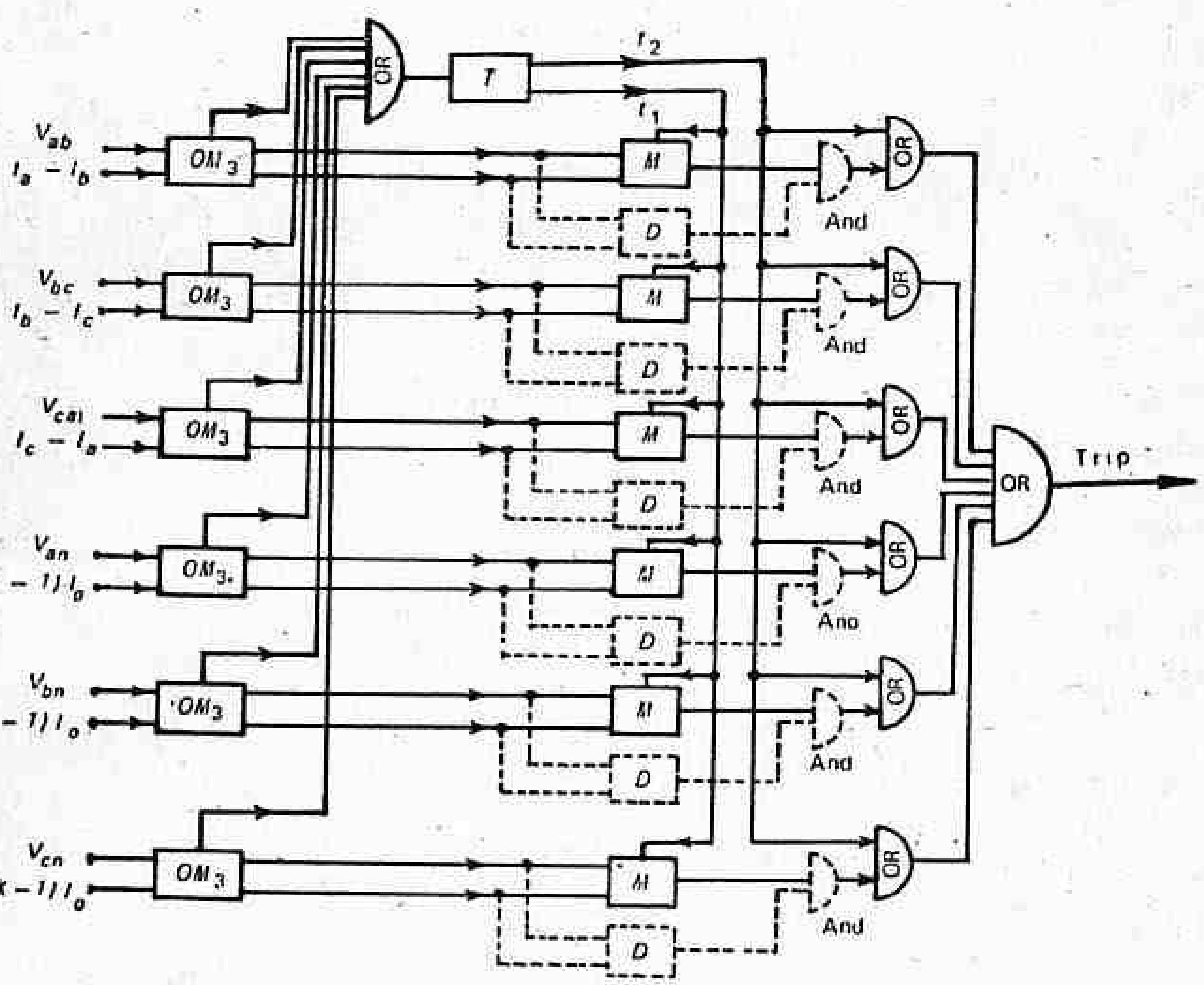


FIGURE 5.37 A scheme of protection in a three-phase system.

(iv) One set of relays is used and can be switched to any one of the six measuring conditions. This phase selection is normally accomplished by overcurrent and residual current relays, but may be supplemented by undervoltage relays. This is commonly known as *switched distance protection scheme*. Such schemes are economical and are common with static comparators.

5.4 Pilot Protection

This is a unit form of protection which compares electrical quantities at the two ends of the protected section. Pilot protection may be of three types as already stated: (a) wire pilot protection, (b) carrier pilot protection, and (c) microwave pilot protection.

5.4.1 Wire Pilot Protection

In this case the auxiliary pilot-wires are provided to carry the information signals from one end to the other. Protective systems requiring the use of pilot wires on transmission lines operate on the principle of differential protection. There are basically two forms of differential protection schemes used for transmission line protection: (i) longitudinal; (ii) transverse.

The *longitudinal differential protection* operating principle is based on the comparison of the magnitude and phase of the currents at the two ends of the protected section.

Some of the commonly used longitudinal differential schemes are described below.

(a) *The Translay Scheme* (*AEI*). The scheme is shown in Fig. (5.38). It is of the balanced voltage type and is suitable for pilot circuits up to a loop resistance of 800 ohms. Associated with the CTs at each end is an induction disc type relay whose secondary circuits are connected in opposition by pilot wires. Summation of the secondary line current is carried out in the tapped winding of the upper electromagnet of the relay. The upper electromagnet system acts as a quadrature transformer and produces at the pilot terminals a voltage which varies with the primary current. No current will flow in the circuit under normal conditions; whereas in the case of a fault there is a discrepancy between the currents flowing at the two ends which will cause a resultant difference between the secondary voltages and thus a current in this circuit. Under such conditions when the current flow occurs in both the upper and the lower magnet the relay operates.

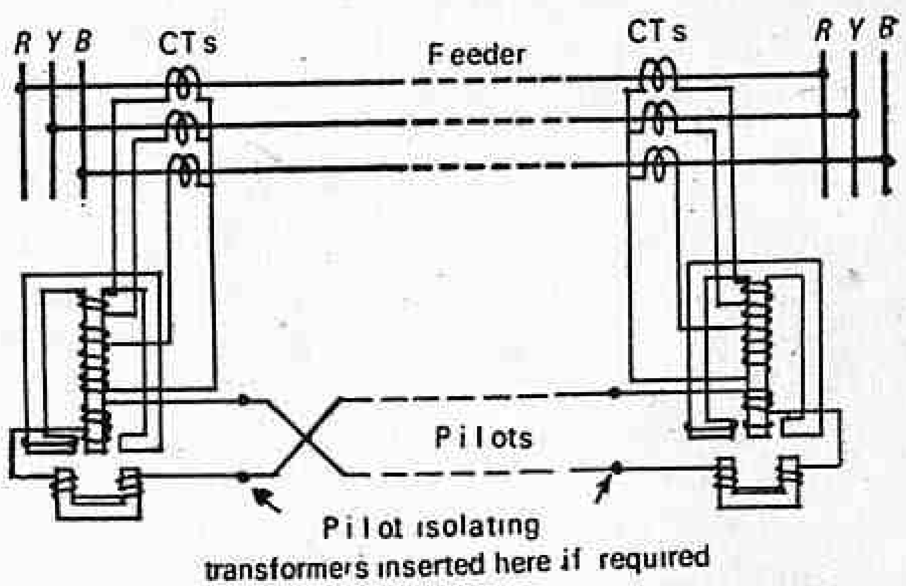


FIGURE 5.38 Translay feeder protection.

Compensation for pilot capacitance currents is made by providing a copper loop fitted to the centre limb of the upper electromagnet. The flux from this magnet leads the pilot voltage (or the secondary voltage)

and produces a flux in the lower magnet in phase with the upper coil flux thus producing no torque in the disc. Because it is necessary for local current to be present for the production of torque, the protection will operate at the fault feeding end only on an internal fault. The overall performance of the scheme is as follows:

Minimum earth-fault settings 22–40%
Minimum phase-fault settings 45–90%
Minimum three-phase fault setting 52%
Operating time at 5 times the fault setting 0.12*s*

It is also possible to provide bias feature by providing a second copper loop fitted on an outer limb of the upper magnet. With such an arrangement when the current flows only in the upper coil the relay behaves as a shaded pole type, but the torque produced is arranged to act in the reverse sense (restraint). This permits to some extent the use of unmatched CTs at the two ends.

(b) *Solkor Scheme* (*Reyrolle*). The Scheme and the characteristics of the relay are shown in Fig. (5.39). This is also essentially a balanced voltage feeder protection scheme. Separate saturable summation transformers are provided which are designed to saturate at about 1.5 times the

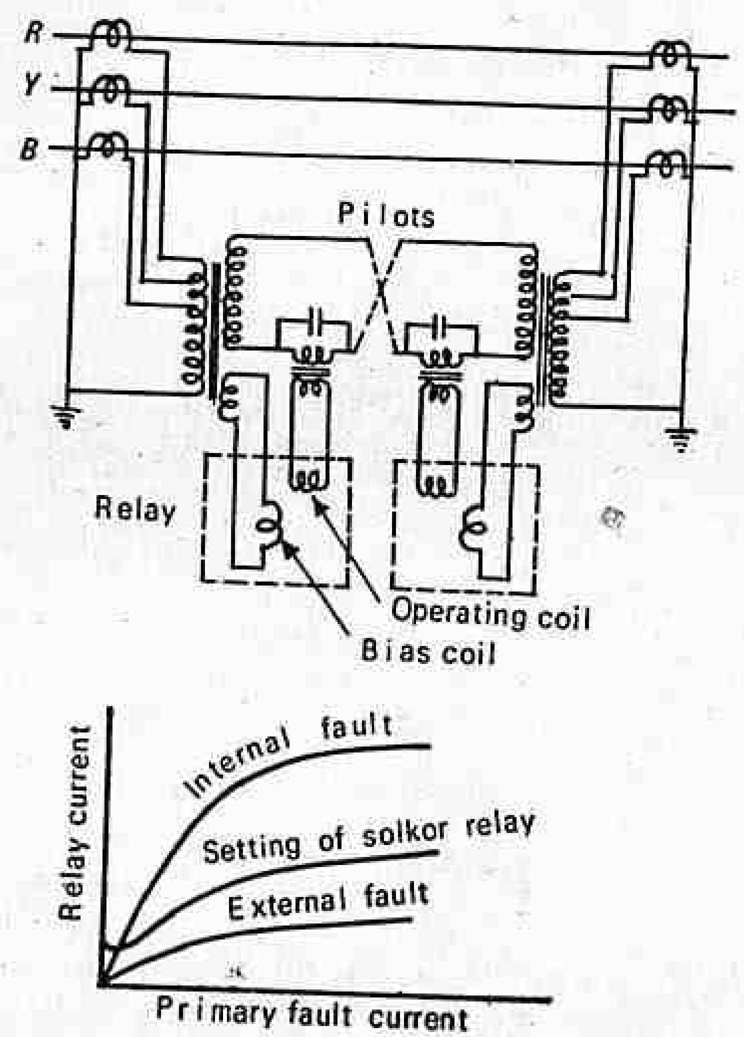


FIGURE. 5.39 Solkor system (Reyrolle).

CT secondary rating for an earth fault energizing the whole summation transformer primary winding. The relays are of the rotary moving iron type. The operating winding of the relay is supplied from a relay transformer in series with the pilots which is shunted by a capacitor. The restraining winding is energized by the pilot voltage through the secondary winding of the summation transformer. At fault currents below saturation the output from the summation transformer is sinusoidal and the system is purely differential taking account of both magnitude and phase angle of the primary currents at the two ends of the line. At high currents when saturation takes place the output wave-form is distorted and peaky, and the comparison is on the basis of phase angle. This peaky voltage would introduce current due to the pilot capacitance on the relay and must be avoided by tuning the pilots to fundamental frequency, i.e. 50 Hz. The fundamental frequency current is related to the phase angle of the primary current in a similar way at the two ends on an external fault. The typical characteristics shown in Fig. (5.39b) indicate the discriminating factors obtainable. The overall performance of the scheme is as follows:

Earth-fault setting 40–60%
Phase-fault settings 120–240%
Three-phase fault setting 140%
Operating time at 5 times fault setting 0.12*s*
Pilot loop resistance for which the scheme is suitable 400 ohms

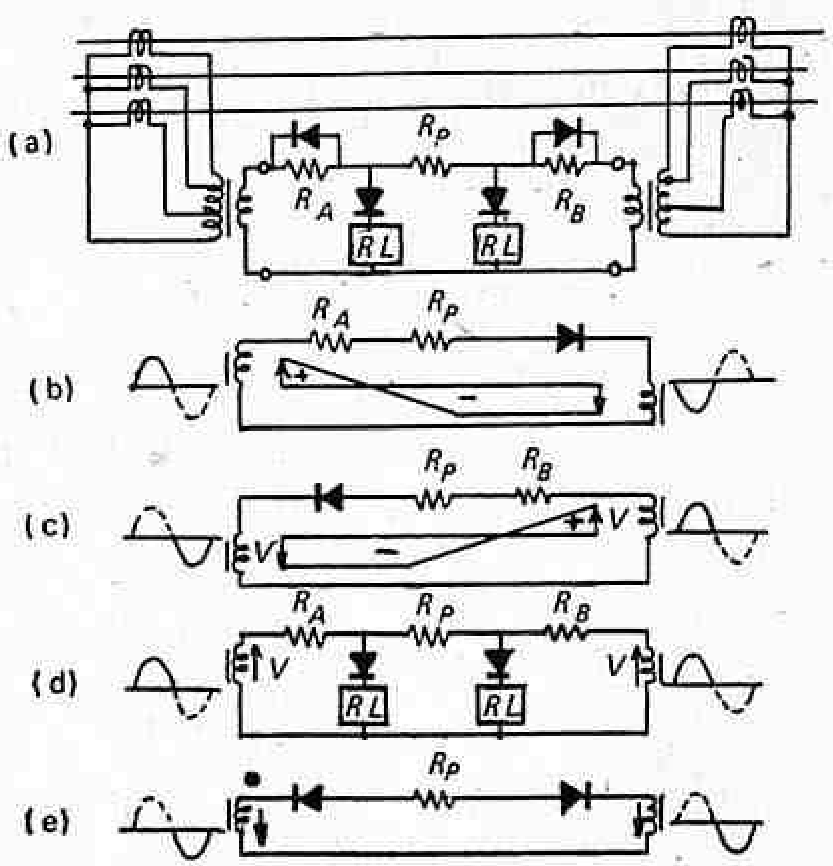


FIGURE 5.40 Solkor R Scheme: (a) basic circuit; (b), (c) external fault conditions at each half-cycle; (d), (e) internal fault conditions at each half-cycle,

(c) *Solkor R Scheme*. This is also known as half wave comparison scheme. Figure (5.40) shows the circuit of this scheme. It can be seen that the basic connections are similar to the circulating current scheme.

The resistances R_A and R_B are made slightly greater than that of the pilot loop resistance R_P. Under through fault conditions either R_A or R_B is short circuited by its rectifier depending on the particular half cycle. It can be seen from Fig. (5.40) that neither relay operates as the voltage is negative. During an internal fault both relays have positive voltage during one half-cycle and zero voltage during the other half-cycle.

Protection of Tee'd Feeders. Pilot wire protection for tee'd feeders is more difficult than for a single feeder. The currents at each feeder end may differ considerably which results in different loading on the CTs which in turn may lead to out-of-balance currents or voltages and thus result in instability. Hence a vectorial comparison of quantities derived from the several feeder ends is resorted to. In other words, the unit protection of a number of parallel circuits is achieved by comparing the impedances of the several parallel paths. Protection using these principles is known as *transverse differential protection.*

5.4.2 Carrier and Microwave Pilot Protection

The problem of providing economically an auxiliary channel by means of pilots for long lines directed attention to carrier techniques. In this case the power line itself is used as the channel for carrying information between the two ends of the transmission line.

Two different types o communication channels presently in use are discussed below.

(a) *Carrier-Current Channel*. High frequency signals in the range of 50 kHz to 400 kHz commonly known as the carrier are transmitted over the conductors of the protected line. To inject the carrier signal and to restrict it within the protected section of the line suitable coupling apparatus and line traps are employed at both ends of the protected section. This obviously makes it quite expensive and justifies its application only on transmission lines of 110 KV and above. The main application of power line carrier has been for the purpose of supervisory control, telephone communication, telemetering and relaying.

(b) *Microwave Channel*. It uses ultra high frequency (450 MHz to 10,000 MHz) transmitter-receiver system for connecting the relaying equipment located at the terminals of the protected line. The communication channel is space in this case; thus the line need not be fitted with additional equipment. Transmission is generally by line of sight and this must take into account the curvature of the earth and topology of the route over which transmission is taking place. This limits the maximum length of the simplest microwave channel to about 40 to 60 km. Channels for long transmission lines use radio relaying techniques; or, in other words, the signals are beamed by antennas from point to point like TV signals.

Carrier-current channels are commonly used for the protection of transmission lines and will be considered hereafter. Microwave protection has similar relaying equipment and operating principles as the carrier-current protection except the channel used for communication.

Advantages of Carrier-Current Channel. High-frequency signal transmission along overhead power lines offers the following advantages over pilot wires:

(i) No separate wires are needed for signalling, as the power lines themselves carry power as well as communication signals. Hence the capital and running costs are lower.
(ii) Transmission path is fully controlled by the operating authority.
(iii) Carrier signals suffer much less attenuation on power lines than on usual telephone lines on account of very low resistance of power lines compared to telephone lines.
(iv) Large spacing between conductors of power lines reduces capacitance which results in smaller attenuation at high frequencies.
(v) The transmission medium is robust and therefore reliable.

The general arrangement of carrier equipment is shown in Fig. (5.41). Transmission instructions are initiated from the protective relays via a control circuit and, conversely, received by the protection relays via a carrier receive relay.

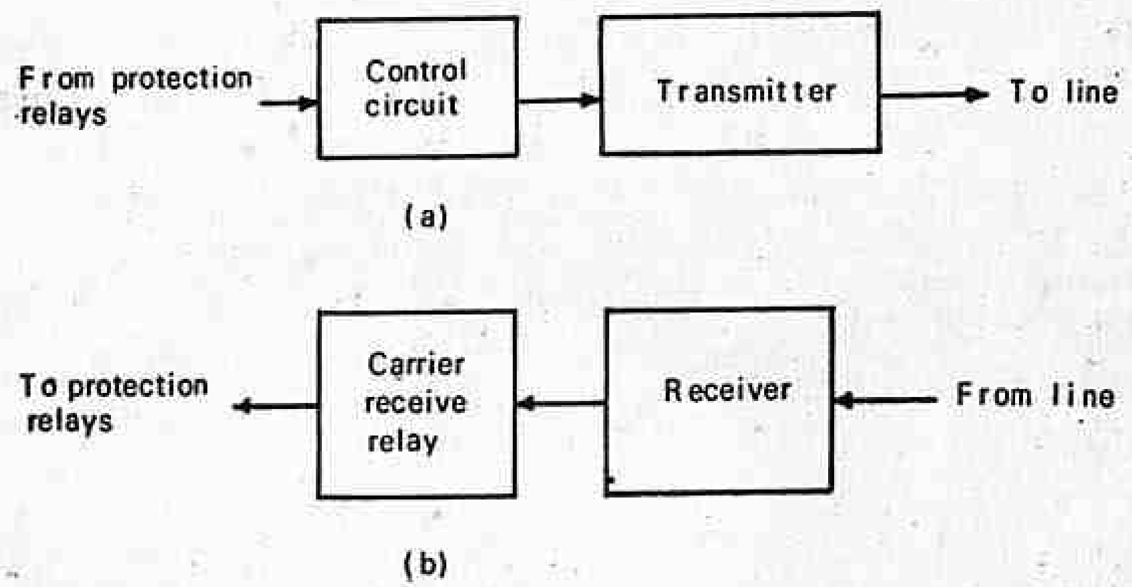


FIGURE 5.41 General arrangement of carrier equipment: (a) transmission requirements; (b) reception requirements.

Carrier Equipment. The main elements of the carrier channel are: (i) transmitter, (ii) receiver, (iii) coupling equipment, and (iv) line trap.

(i) *Transmitter*, The transmitter consists of an oscillator and an amplifier shown in Fig. (5.42). The oscillator generates a frequency signal within 50–500 kHz frequency band. The amplifier provides sufficient radio frequency power (5–40 W) at the operating frequency to overcome

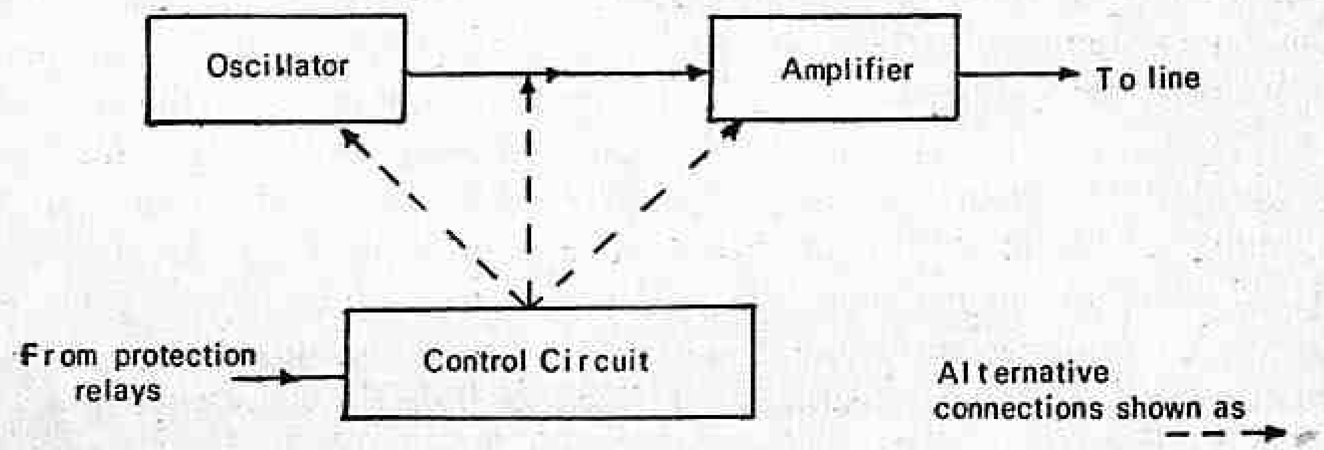


FIGURE 5.42 Transmitter circuits.

losses in the transmission channel between the terminals and to operate the receiver at the remote end. The transmitter control can be effected in various ways shown by dotted arrows in Fig. (5.42). The transmitter is thus required to modulate the carrier with protective signals. The modulation process usually involves taking one half cycle of 50 Hz signal and using this to create blocks of carrier.

(ii) *Receiver.* The receiver usually consists of an attenuator matching transformer, band-pass filter and amplifier-detector as shown in Fig. (5.43a).

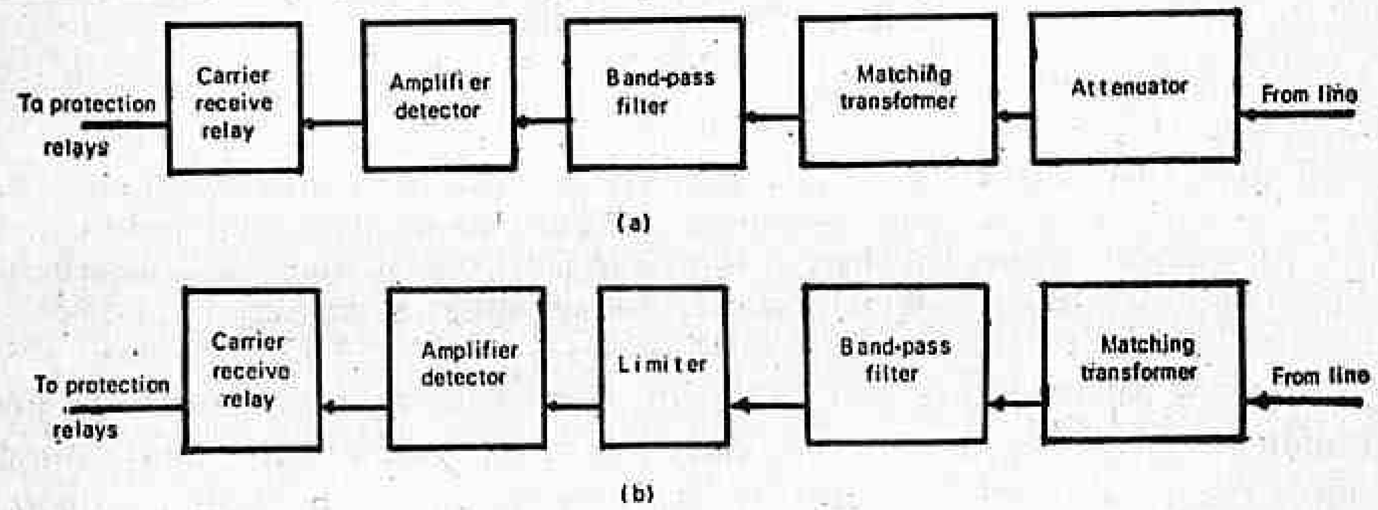


FIGURE 5.43 Receiver circuits: (a) receiver with input attenuators; (b) receiver with input limiter.

The amplifier detector converts a small incoming signal into a signal capable of operating a relatively insensitive carrier receive relay. The matching transformer is necessary to match the low characteristic impedance of the line on one side and a high input impedance of the amplifier-detector on the other. In case of short lines limiting of signal input to the amplifier-detector is necessary to avoid overloading as shown in Fig. (5.43b).

The transmitters and receivers at the two ends of the protected section are tuned to the same frequency so that each receiver responds to local as well as far end transmitters.

(iii) *Coupling equipment*. Coupling of the high frequency transmitter-receiver units to the power line is done through high-voltage capacitors used in conjunction with drainage coils. The high voltage coupling capacitor which has a capacitance of about 0.001 μF is earthed through the drainage coil having inductance of about 100 mH. This provides isolation of the terminal equipment from the power line by providing a very high impedance to power frequency currents and a low impedance to carrier frequency currents. For matching the transmitter and the receiver units to the coupling capacitors and the power line, connecting filters are provided. These filters are normally adjustable air cored transformers with capacitors connected in series with their tune coils. The connection of transmitter-receiver units to the connecting filters is done through coaxial cables. A typical schematic diagram of carrier-current pilot relay system is shown in Fig. (5.44).

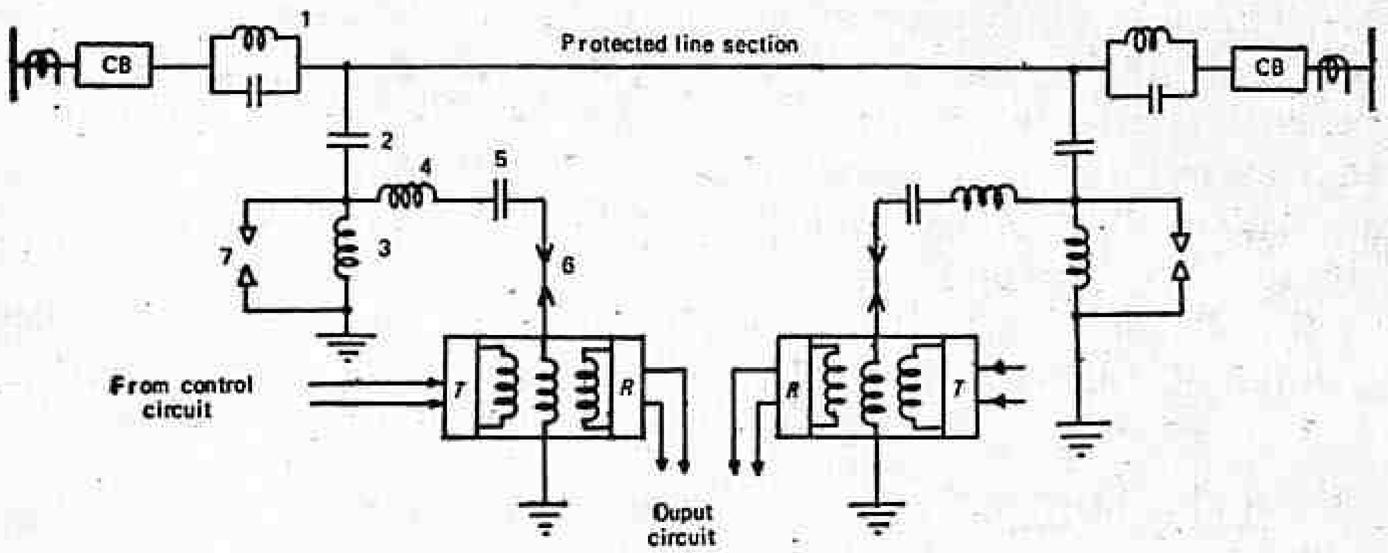


FIGURE 5.44 Carrier-current pilot relay system of phase-to-earth carrier channel. 1—line trap; 2—coupling capacitor; 3—drainage coil; 4—tune coil connecting filters; 5—series capacitor connecting filters; 6—coaxial cable; 7—protective gap; *T*-transmitter; *R*-receiver.

It can be seen that the path for carrier current is through the line conductor, coupling capacitor, connecting filter, coaxial cable and ground, while the power frequency current can flow through the line conductor only. Protective gap protects the high frequency system from line surges and is also used for earthing the coupling capacitor to permit maintenance and inspection of the connecting filter.

(iv) *Line trap*. Rejection filters known as line traps consisting of a parallel resonant circuit (L and C in parallel) tuned to the carrier frequency are connected in series at each end of the protected line. Such a circuit offers high impedance to the flow of carrier frequency currents thus preventing the dissipation of the carrier signal in the neighbouring sections.

It also reduces the interference with the neighbouring carrier channels.

Method of Coupling. Coupling may be either of one phase conductor with earth return, i.e. phase-to-earth coupling, or it may comprise two couplings, one to each of the two phase conductors called phase-to-phase coupling. The phase-to-earth coupling is quite popular on account of its lower cost as it requires only half as many coupling capacitors and wave traps that would be needed for phase-to-phase coupling. Phase-to-phase coupling is superior because of its lower attenuation and lower interference levels than the phase-to-earth coupling, and is preferred for better communication characteristics. Phase-to-phase coupling scheme for one end of the protected three-phase line is shown in Fig. (5.45).

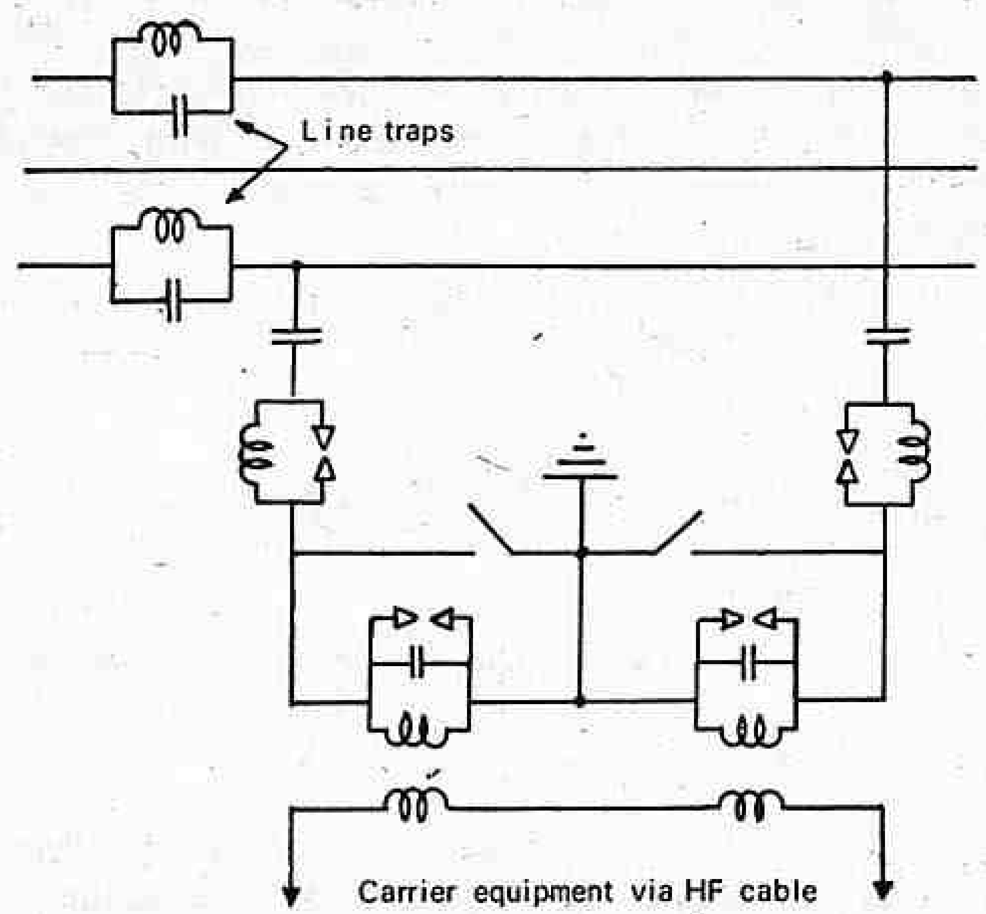


FIGURE 5.45 Phase-to-phase coupling scheme.

Carrier Circuits for Protection. There are two basic forms of carrier protection schemes: (a) directional comparison protection, and (b) phase comparison protection.

(a) *Directional Comparison Protection*. The direction of current flow is compared at the two ends of the protected section by means of directional relays. The conditions for internal and external faults are shown in Fig. (5.46). The relays at both the ends of the protected section respond to fault power flowing away from the bus (tripping direction). For faults in the protected section, power flows in the tripping direction at both ends. Power flows in opposite directions for external faults. A simple signal

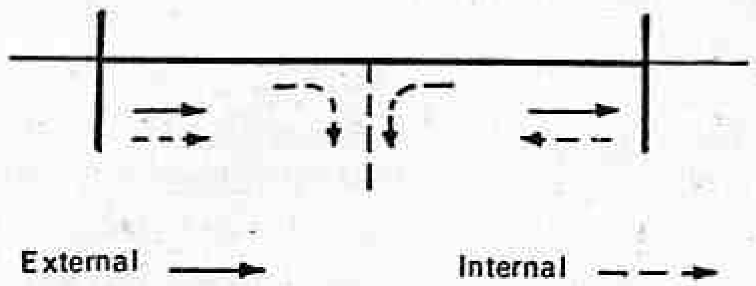


FIGURE 5.46 Direction of currents for internal and external faults.

through the carrier pilot is transmitted from one end to the other during faults.

The pilot scheme can be used for transmitting either blocking, or permitting signals. Hence two types of protection are possible:

(1) Carrier-blocking scheme, in which the presence of carrier prevents or blocks operation of the protection. Carrier is therefore transmitted only upon the occurrence of a fault and is used to prevent tripping in the event of an external fault.
(2) Carrier-permitting scheme, in which the presence of carrier permits operation of the protection.

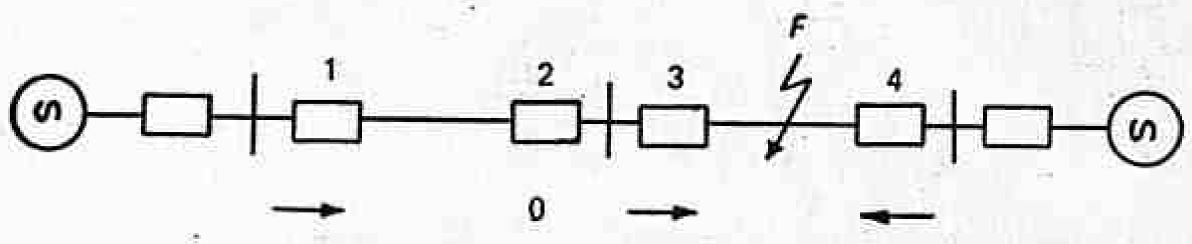


FIGURE 5.47 A power system for illustration of directional comparison protection.

The directional comparison method of relay protection is illustrated by means of Fig. (5.47). The operation of the directional element provided on each breaker is indicated by the arrow and the nonoperation by the letter 0. Abnormal conditions existing on the occurrence of a fault activate relays on each of the breakers near the fault. These relays unless blocked from operation, cause tripping of the breakers. The blocking signal is controlled by the directional relays on each breaker, and is transmitted from one end of a protected section to the other by carrier. If a directional element determines that the fault is not in the protected section, a signal is transmitted which blocks breaker operation at both ends of the section. If the directional elements at both ends show that the fault is in the protected section, no blocking signal is transmitted from either end, and both breakers trip. The sequence of events for a fault at F is made clear by a study of Fig. (5.47).

At breaker 1 the directional element shows that the fault may be in the section 1–2. This breaker trips if no blocking signal is received. No

blocking signal is transmitted to breaker 2.

At breaker 2 the directional element shows that the fault is not in the section 1–2. A carrier signal is transmitted which blocks tripping of both the breakers 1 and 2.

At breaker 3 the directional element shows that the fault may be in the section 3–4. No blocking signal is transmitted. Similarly at breaker 4 the directional element shows that the fault may be in the section 3–4 and hence no blocking signal is transmitted. After a very short time delay (1 to 3 cycles), both the breakers 3 and 4 trip.

The carrier-blocking scheme provides more reliable operation than the carrier-permitting scheme. This is because a failure in the carrier-permitting signal equipment will mean a failure in isolating the fault, whereas a failure in the carrier-blocking signal equipment isolates the section on which no fault exists. However, this type of false operation is preferable to the failure to clear a faulted section.

Carrier-aided distance protection. The directional comparison carrier-pilot relay schemes presently used are built around standard 3-zone step-type distance relays. This enables to speed up fault clearance for internal zone 2 faults. The carrier channel is used either to transmit a stabilizing signal preventing tripping of a remote circuit breaker in the event of a local external zone 2 fault, or to provide a tripping signal in the event of an internal zone 2 fault. The principal features of plain 3-zone distance scheme are illustrated in Fig. (5.48).

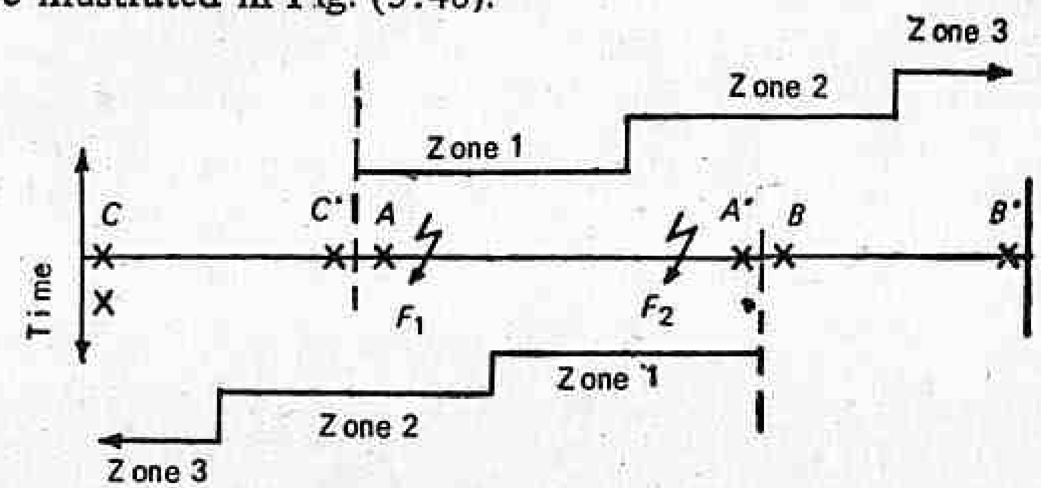


FIGURE 5.48 Conventional 3-zone distance characteristics.

Carrier signalling is concerned with the end zones of a protected section (AA'). Faults at points F_1 and F_2 will be considered. Fault at F_1 will be seen at end A in zone 1 and at end A' in zone 2. Similarly a fault at F_2 will be seen at end A' in zone 1 and at end A in zone 2.

Transfer trip or intertrip technique is adopted to speed up the fault clearance at the end which clears the fault in zone 2. This is achieved by controlling the carrier transmitter and a carrier receive relay by zone 1 contact. For a fault at F_1 the zone 1 relay at A initiates a carrier signal in addition to completing the zone 1 trip circuit of this end. Carrier signal when received at end A' trips it immediately by shunting the zone 2 timer contacts with the help of a carrier receive relay. A fault at F_2 is cleared in a similar way. The tripping circuit of the conventional distance scheme as modified by the carrier intertrip is shown in Fig. (5.49).

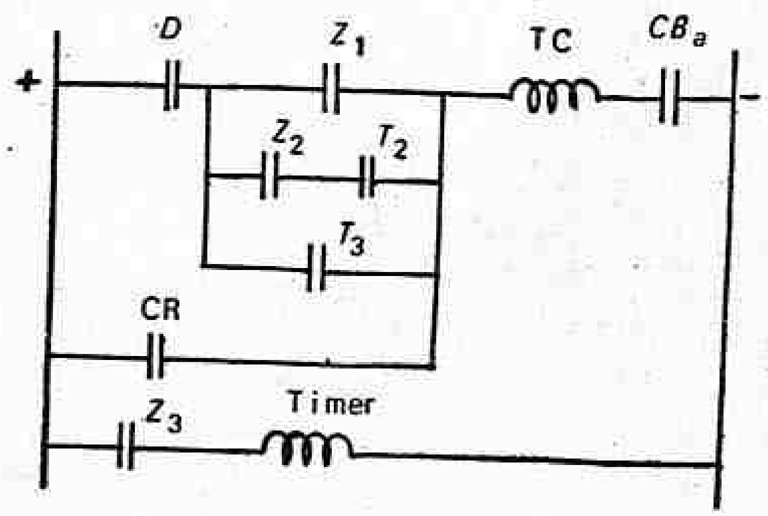


FIGURE 5.49 Trip circuit of carrier intertrip scheme. *D*—contacts of directional unit; Z_1, Z_2, Z_3—contacts of zone 1, zone 2 and zone-3 element; T_2, T_3—timer contacts; CB_a—auxiliary contacts on circuit breaker; *TC*—trip coil; *CR*—carrier receiver relay contacts.

It can be seen that the carrier is transmitted over a faulty section and thus the required strength of the carrier signal may not be received on the other end due to attenuation introduced into the transmission path by the fault. Further, during external fault conditions the receiver may operate because of noise generated within the protected section and undesirable tripping may result. This difficulty is partly overcome by monitoring the carrier receive relay by the fault detector, so that the carrier receive relay performs its function during a genuine internal fault condition. Such an arrangement is shown in Fig. (5.50) and is described as 'permissive intertrip.'

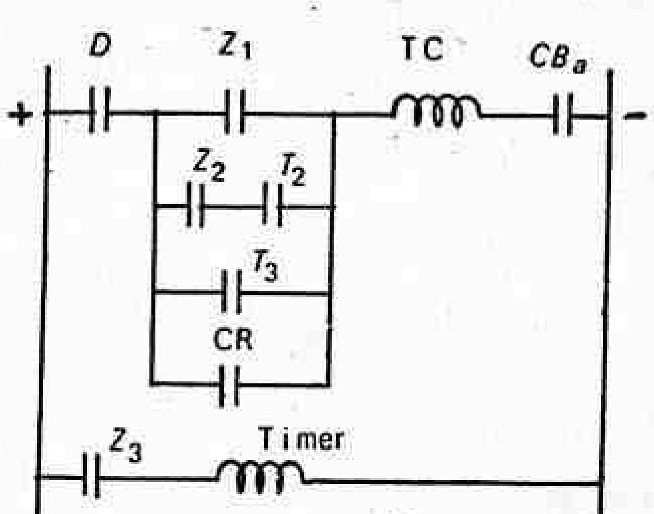


FIGURE 5.50 Trip circuit for distance scheme with carrier permissive intertrip.

If the zone 2 timer contacts are shorted by a normally open carrier receive relay in parallel then all the faults in the protected section can be cleared approximately in first zone time. This is illustrated in Fig. (5.51) and such a scheme is known as Carrier acceleration scheme.

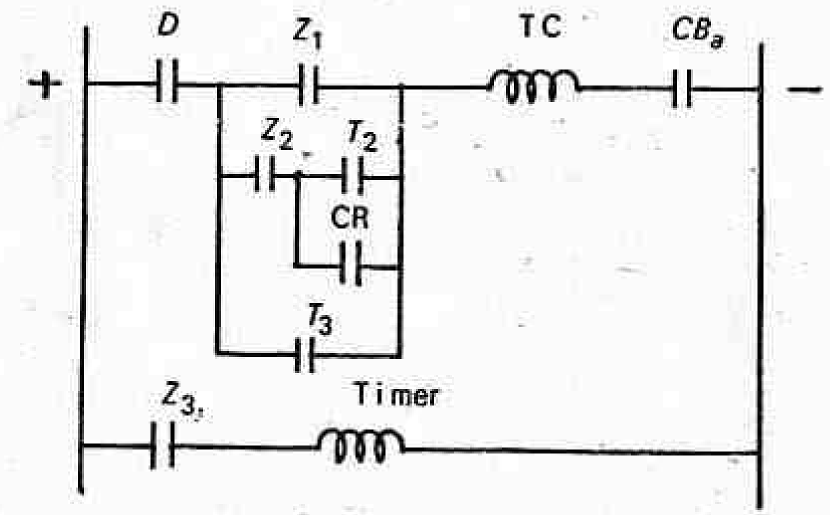


FIGURE 5.51 Carrier acceleration scheme.

Complete scheme of impedance type carrier pilot relays. Westinghouse type *HZ* carrier-pilot relays consist of three impedance relays, each having three impedance elements, a directional element, a timer, and auxiliary relays; a high-speed directional overcurrent ground relay, having two overcurrent elements and a directional element; a ground backup relay; and a carrier auxiliary relay, consisting of a receiver relay and d.c. auxiliary relays.

For phase faults the *HZ* impedance relays operate except that the second zone timer contacts are bypassed during internal faults, so that all internal faults are cleared without delay. During external faults, the presence of carrier on the line prevents bypassing of the timer contacts. However, the second and third-zone impedance elements can still trip with time delay to provide backup protection. Any of the third zone impedance elements start the carrier and closing of the contacts of both the directional element and the second zone impedance element stops the carrier.

For ground faults the carrier is started by an instantaneous zero-sequence overcurrent relay and is stopped by an instantaneous zero-sequence directional overcurrent relay.

In addition to the phase and ground relay there are the receiver relay and two auxiliary relays (CSG and CSP). The receiver relay has an operating coil, RRT; a restraining coil, RRH, operated by the output of the carrier receiver. The restraining coil, when energized, prevents the operating coil from closing the contacts.

Figure (5.52) represents the contact circuits where the trip circuits are shown in the upper part of the diagram. For phase faults there are three tripping paths per phase which are independent of carrier: for first zone faults through *D* and Z_1 with no delay; for second zone faults through *D*, Z_2 and T_2 with delay; for third zone faults through *D* and T_3 with greater delay. Instantaneous tripping is attained through *D*, Z_2 and RRP which shunts the timer contacts T_2, when carrier is used. For ground faults

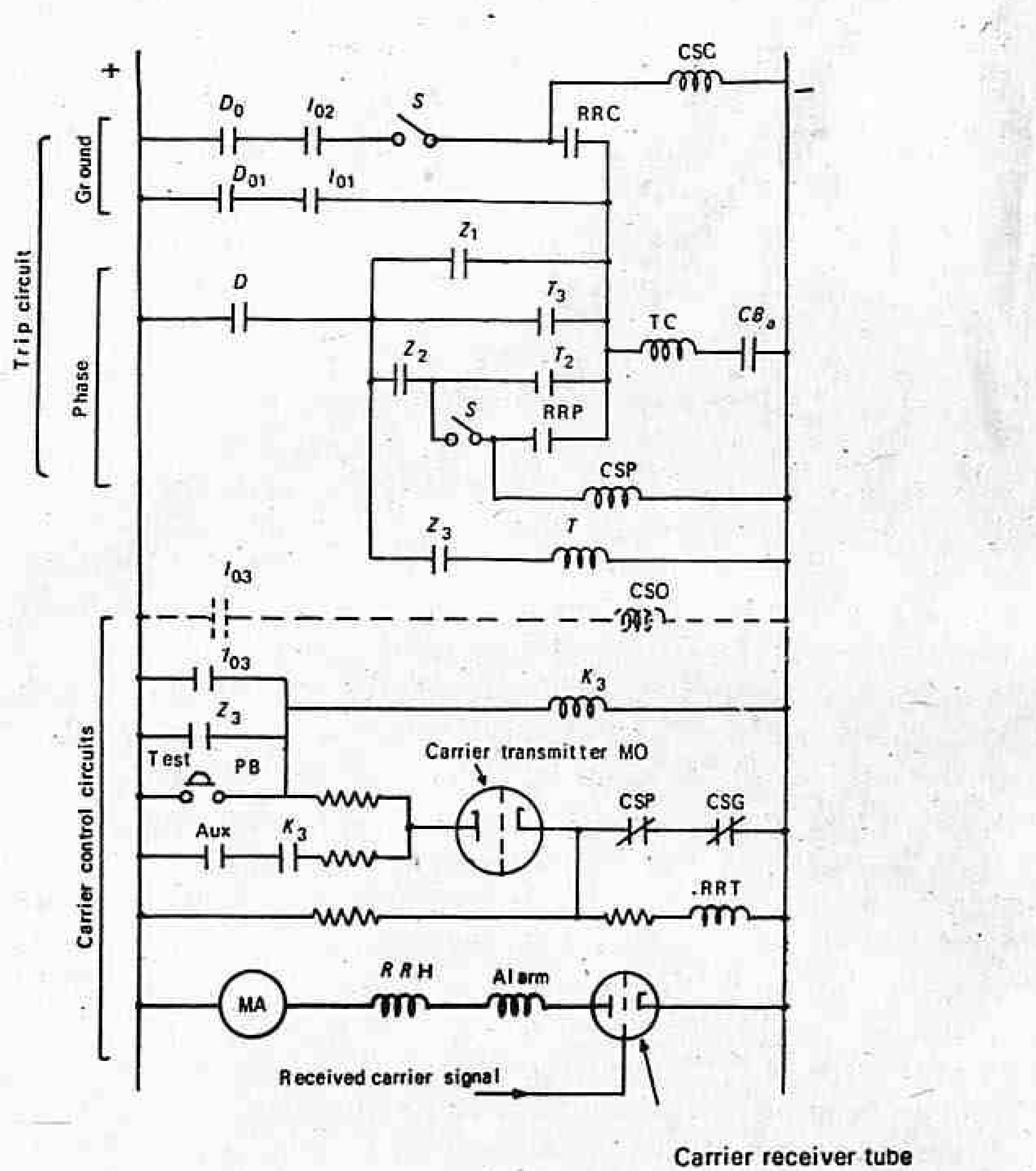


FIGURE 5.52 Westinghouse type HZ carrier pilot relay.
D—directional element of phase relay; D_0—directional element of earth relay; D_{01}—directional element of earth backup relay; I_{01}—Overcurrent element of earth backup relay; I_{02}—instantaneous overcurrent element of earth relay; I_{03}—second instantaneous overcurrent element of earth relay, used to start carrier transmission; TC—trip coil of circuit breaker; CB*a*—auxiliary contacts on circuit breaker used to open trip circuit when breaker opens; Aux—control contacts of the carrier transmitter for auxiliary uses of the carrier channel; CSG—contactor switch (auxiliary relay) used in connection with earth relay; CSP—contactor switch used in connection with phase relay; K_3—relay to prevent the use of carrier channel for other purposes when it is required for relaying; MA—milliammeter for checking carrier channel; MO—master oscillator; PB—push button; RRG—contacts of receiver relay used in connection with earth relay; RRHr—eceiver relay restraining coil; When this coil is energized with received carrier signal it prevents RRT from closing the contacts. RRP—receiver relay contacts used in connection with phase relays; RRT—receiver relay operating coil; *S*—switch which is opened to put the carrier equipment out of service; *T*—timer coil of phase relay; T_2, T_3—timer contacts; Z_1, Z_2, Z_3—first, second and third zone impedance elements of phase relay.

there is a tripping path, independent of carrier, through contacts D_{01} and I_{01} of the time-delay directional overcurrent backup relay. Carrier-controlled path through D_0 and I_{02} of an instantaneous directional overcurrent relay and contacts RRG also exists. The receiver relay is energized by an auxiliary relay CSG or CSP.

The carrier-control circuits are shown in the lower part of Fig. (5.52). Upon the occurrence of a phase fault, contacts Z_3 start carrier transmission by applying positive potential to the plate of the oscillator tube. If the fault is in the tripping direction but not beyond the balance point of the second zone impedance element, relay CSP is energized. This relay opens its back contacts, stopping transmission of carrier signal by raising the cathode potential and energizing the receiver-relay operating coil RRT by removing the short-circuit from it. Unless restrained by RRH, the receiver relay closes its contacts, RRP and RRG, to permit instantaneous tripping. For ground faults contacts I_{03} start carrier transmission. If the ground fault is in the tripping direction, relay CSG is energized, and its back contacts stop carrier transmission and energize coil RRT, just as relay CSP does in case of phase fault. Unless restrained by received carrier signal, the receiver relay closes contacts RRG to permit instantaneous tripping.

Push button PB is provided for testing the carrier. By pressing this the carrier transmitter is turned on and the carrier signal is received at each end energizing an alarm relay and a milliammeter.

(b) *Phase Comparison Carrier Protection.* The phase comparison pilot-relaying operates on the principle of comparing the phase position of the currents at the two ends of the protected section. The comparison of these currents is made over carrier channels. During normal conditions or through faults the currents entering the line at one end differ—in phase by approximately 180° from those entering the line at the other end. Therefore, the relaying quantities at the two ends are about 180° apart. However, during an internal fault the relaying quantities at the two ends have a phase difference of nearly 0°.

Figure (5.53) illustrates the method of phase comparison carrier protection. It can be seen that a carrier signal is transmitted only during the positive half cycle of the current wave.

The current flowing into the line section at breakers *A* and *B* is shown in positions 1 and 2 both for internal and through faults separately. The carrier transmission at *A* and *B* is shown in positions 3 and 4 for the two fault locations. The carrier transmissions at *A* from *A* and from *B* are added and rectified to give an output signal as shown in position 5. When the signal has a zero value for a specified time as at *T*, the circuit breaker is tripped by an auxiliary equipment. Whereas for a nonzero value of the signal throughout the entire cycle the breaker is prevented from tripping.

Similar behaviour at breaker B results in a trip signal for fault at F_1 and no signal to the trip circuit for fault at F_2 as shown in position 6. So for fault between A and B both the breakers at A and B trip, whereas for fault outside A-B none of the breakers at A and B trip.

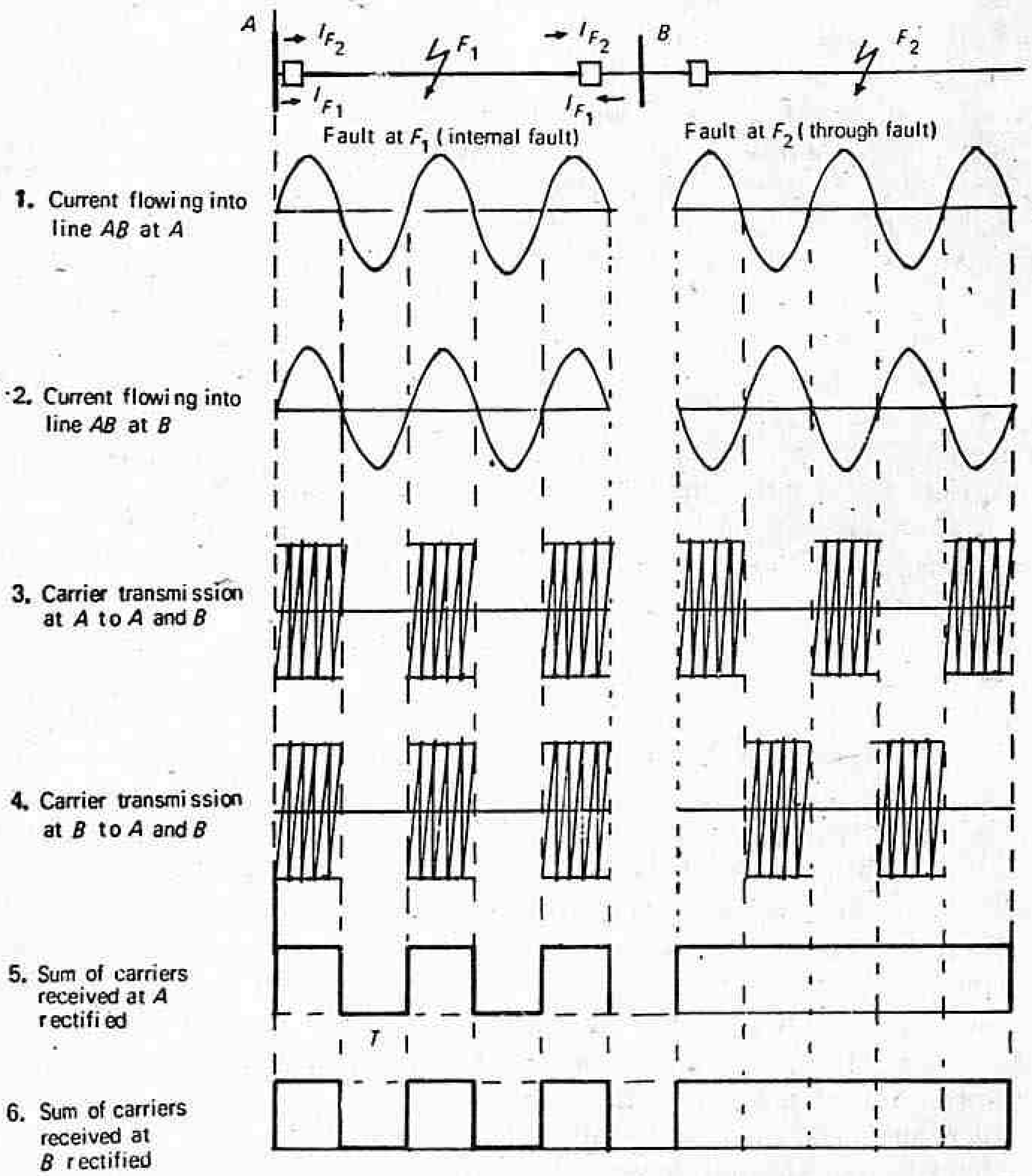


FIGURE 5.53 Carrier phase protection.

It may be noted that with this phase comparison arrangement, a trip signal is available with a fault in the line section, but none is available if the fault is exterior. In the event of failure of the carrier equipment, the affected line section will be opened even though no fault exists on it.

Scheme of phase comparison carrier protection. Phase comparison

carrier relays require a single phase relaying quantity obtained by linear combination of line currents by some filter network or some sequence network. The summation CTs provide a single phase representative value, but has the disadvantage of blind spots in summation CT configuration. By blind spots is meant absence of an output under certain types of internal faults. To overcome this difficulty, the network output normally consists of a combination of positive and negative sequence currents of the type $(I_1 - NI_2)$ where N is adjustable or fixed at 4 or 5.

It must be ensured that the carrier system starts at minimum fault condition and at the same time it does not operate at maximum load conditions. Response to the amplitude only of the negative sequence signal is sufficient for unbalanced faults, whereas response to both amplitude and rate of increase of positive sequence output is necessary for balanced faults. Two settings for each of the positive and negative sequence starting arrangements are provided—a low set and a high set. A low set for starting relay to control transmission and a high set starting relay to control the tripping circuit as shown in Fig. (5.54). One basic reason for

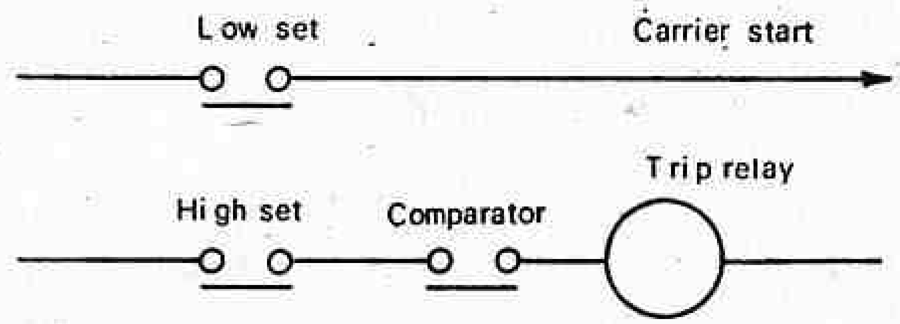


FIGURE 5.54 Low set/high set feature.

employing starting devices is to use the carrier equipment under fault conditions so that the same equipment could be used for communication purposes during healthy conditions. Figure (5.55) shows a schematic diagram of the basic scheme of phase comparison carrier protection.

The three secondary currents from the CTs are fed into a summation network which produces a single 50 Hz output signal, which is fed into a modulator. The modulator is also fed with a carrier signal from the oscillator and thus the combination produces a modulated carrier signal. This signal being relatively at low power level is amplified in the power amplifier so that the power level is about 10 to 20 W. It is then fed to the power line via coupling equipment for transmission to the remote end. Similarly the carrier signal is received via coupling equipment, and separated from other carrier signals by means of a narrow band pass filter, after which it is amplified in the receive amplifier and then supplied to the comparator. The receive signal at this stage contains both the remote signal and the local signal, so that the comparator compares the phase angle of the currents at the two ends of the line by looking at the sum of discrimination the instantaneous elements must be set so that they do **not** operate for faults beyond the protected feeder. As a general rule a margin of 50% is recommended, e.g. the primary operating current of the instantaneous relay at A is not less than 150% of the maximum fault current at B. The margin allows for errors and for the overreach of the instantaneous relay on offset transients.

Transient overreach occurs when the current wave contains a d.c. component and is therefore offset from the zero axis; it is defined as follows:

$$\text{Percentage transient overreach} = \frac{A-B}{A} \times 100$$

where A = relay pickup current in steady state rms amperes.
B = the steady state rms current which when fully offset will just pick up the relay.

The degree of feeder coverage obtained with relays having 5%, 20% and 33% overreach is shown in Table 5.1 for a system where the ratio of fault current at the near and far end is 5:1.

Table 5.1 *Relation between feeder coverage and relay overreach*

% overreach	*% of line protected*	
	Three-phase faults	*Phase-to-phase faults*
5	93	75
20	73	56
33	56	45

It can be seen in Fig. (5.2) that there is a permissible reduction in time interval between the IDMT relays. The IDMT relay at A must discriminate with the instantaneous element at B for a fault at B, and with the IDMT relay at B for a fault at F (the limit of reach of the instantaneous element at B). If there were not an instantaneous relay at B the IDMT relay at A would require the slower characteristic curve (i).

Schemes where speed of fault clearance is proportional to the current are usually preferred, i.e. the higher the current the faster the relay operates. The schemes that follow have this characteristic.

(c) *Current/Time-Graded Systems.* Current/time grading is possible with inverse-time overcurrent relays. The most widely used is the IDMT characteristic where grading is possible over a wide range of currents and the relay can be set, within the design limits, to any value of definite minimum time required. Other inverse characteristics, viz. very inverse and extremely inverse characteristics are also sometimes employed for the same purpose. If the fault current reduces substantially as the fault position

moves away from the source some advantage can be gained by using very inverse relays instead of IDMT relays. The long operating time at low values of overloads of IDMT relays make extremely inverse relays eminently suitable. Where grading with fuses is required it is the ideal choice.

The factors to be considered and the methods of grading IDMT relays are discussed below.

There are two basic adjustable settings on all inverse time relays; one is the *time multiplier setting* (TMS), and the other is the current setting usually known as the *plug setting multiplier* (PSM).

The time setting is adjustable from 0 to 1.0, the value selected being a multiple of the operating time shown on the time/current characteristic curve, which is drawn for a time setting of 1.0 (TMS) shown in Fig. (5.3).

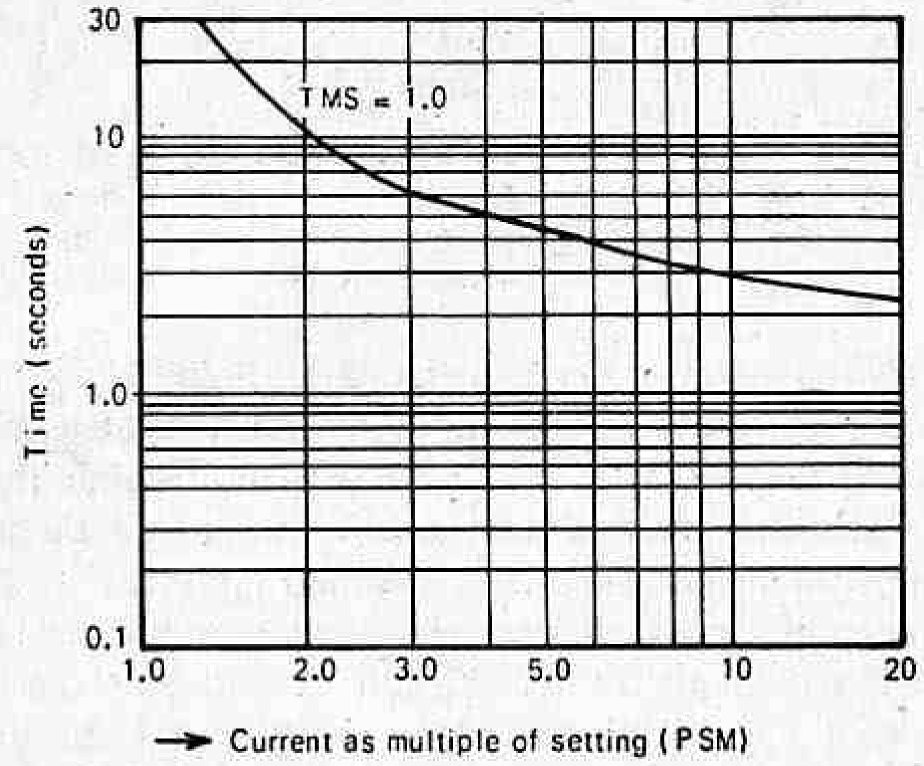


FIGURE 5.3 Standard IDMT curve.

The time multiplier setting for an inverse time relay is defined as:

$$\text{TMS} = \frac{T}{T_m}$$

where T = the required time of operation
and T_m = the time obtained from the relay characteristic curve at TMS = 1.0, and using the PSM equivalent to maximum fault current.

Thus, if the TMS is 0.1 and the time obtained from the curve, for a particular current is 4.0 seconds the actual operating time will be $4.0 \times 0.1 = 0.4$ second. In other words, if the time from the curve is 4.0 seconds and the operating time required is 0.4 second the TMS should be

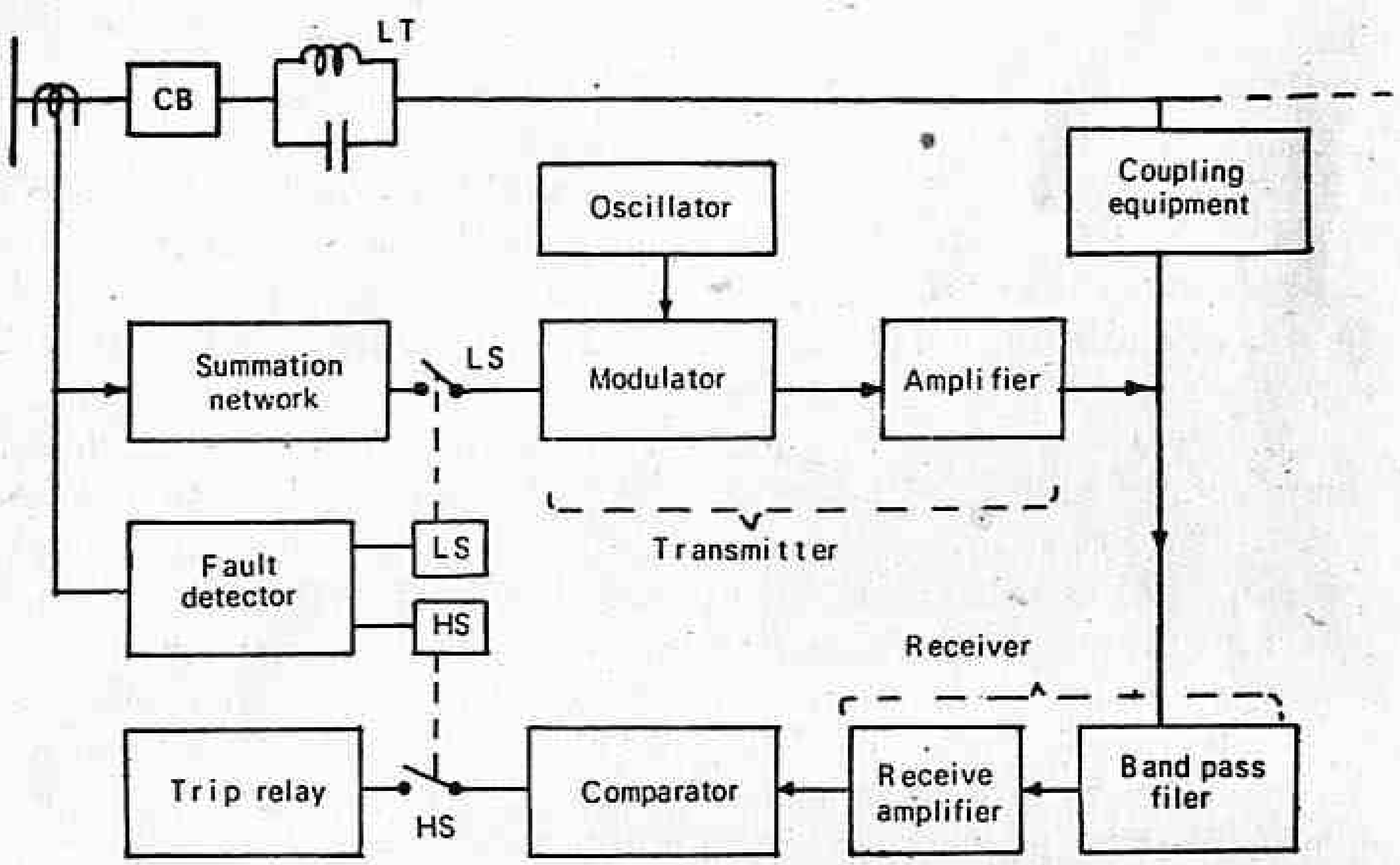


FIGURE 5.55 Schematic phase comparison carrier. Scheme block diagram is shown at one end. CB—circuit breaker; LT—line trap; LS—low set; HS—high set.

the carrier signals. The output of the comparator is fed to the tripping relay.

In general the comparator is a vacuum tube equipment, which for purposes of understanding is represented as a single tube as in Fig. (5.56). When voltage of positive polarity is impressed on the *operating* grid by the

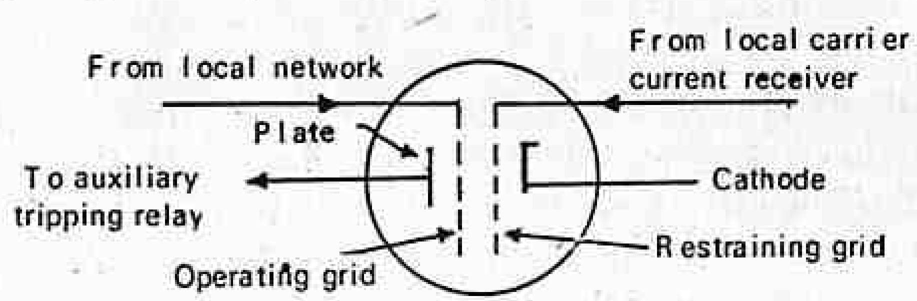


FIGURE 5.56 Schematic representation of the comparator.

local network, the tube conducts if voltage of negative polarity is not concurrently impressed on the *restraining* grid by the local carrier current receiver, by virtue of the carrier current received from the other end of the line. When the tube conducts, an auxiliary tripping relay picks up and trips the local breaker. Positive polarity is impressed on the operating grid of the local comparator during the negative half cycle of the network output when the local transmitter is idle. Therefore, the local transmitter cannot block local tripping. The voltage from the carrier current receiver impressed on the restraining grid makes the tube nonconducting, whether the operating grid is energized or not, whenever carrier current is being received. The comparator could also be a transistorized circuit.

So far we have assumed that the phase difference between the currents at both ends of the protected section during an internal fault is zero. However in actual practice this phase difference ϕ can vary over wide limits, depending upon (i) the phase angle between the emfs at the terminals of the protected section, (ii) the value of the line impedance on either side of the fault, and (iii) the errors in CTs, etc.

It is therefore clear that for $\phi=0°$ (i.e. internal fault) the magnitude of the current flowing through the control relay is maximum and the protection operates, whereas for $\phi=180°$ (i.e. external fault) this current is zero and the protection remains inoperative. In Fig. (5.57) the value of the current in the control relay versus the phase difference between the relaying quantities at the opposite ends of the protected section is shown. If the pickup

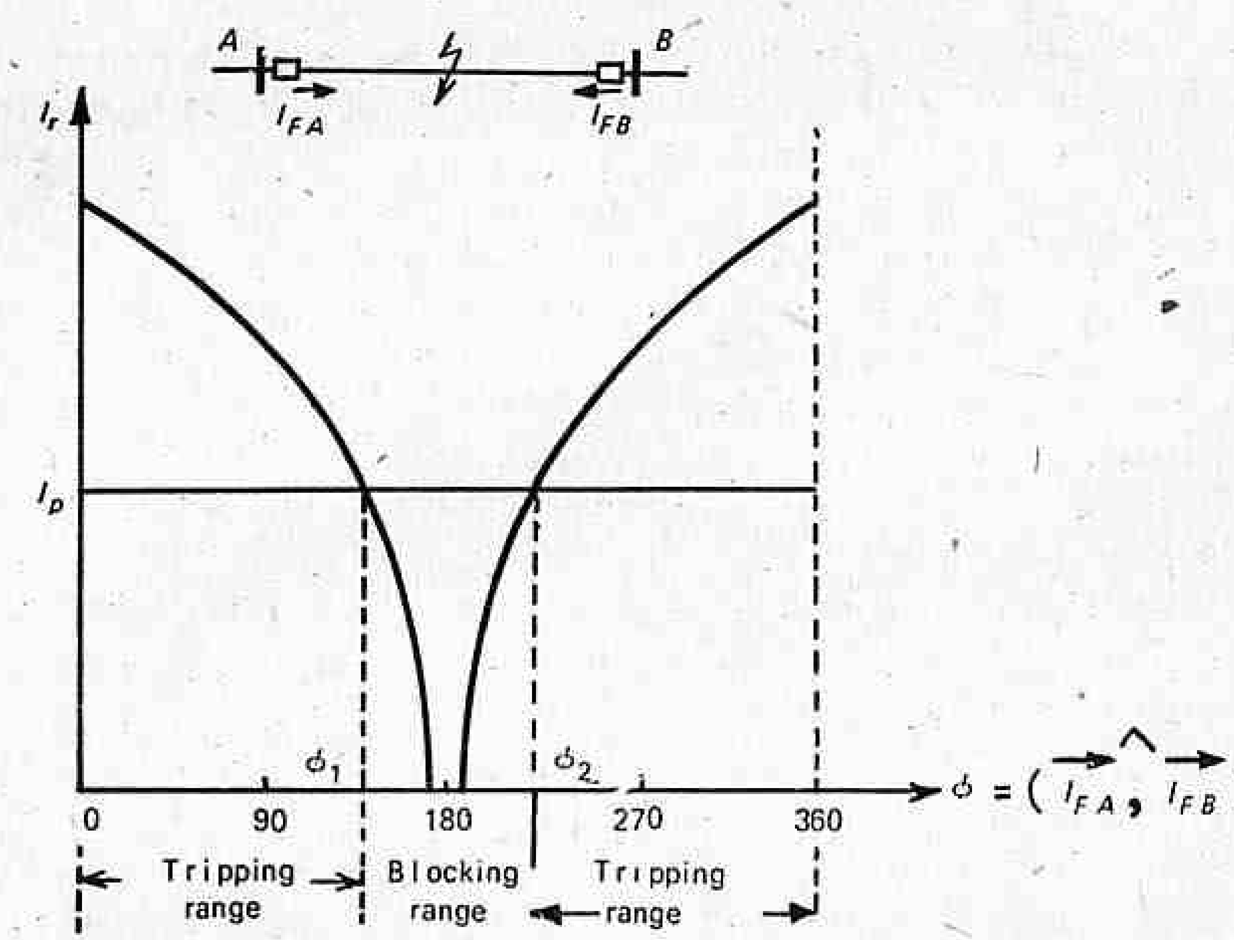


FIGURE 5.57 Phase characteristics of phase-differential carrier-current protection.

current of the relay is I_p reliable tripping occurs for values of ϕ either less than ϕ_1 or greater than ϕ_2 ($\phi_1 \geqslant \phi \geqslant \phi_2$). The value of the pickup current is so adjusted that reliable tripping occurs for $\phi \leqslant 120°$ to $140°$.

Under power swings and out-of-step operation the relaying quantities at both ends of the protected section have a phase difference of nearly 180°. Owing to the inherent characteristics of the phase comparison protection, it will not respond to such operating conditions.

Amplitude comparison techniques similar to the one used in differential relaying are not used in the carrier relaying because of the fact that in a carrier channel the attenuation varies with atmospheric conditions. The length of the pilot wire channel that can be used is limited by the phase shift due to the capacitance between the wires; similarly the length of the transmission line that can be protected by phase comparison carrier is limited by phase shifts caused by the following factors:

(i) The propagation time, i.e. the time taken by the carrier signal to reach the other end of the line (up to 0.1° per mile).
(ii) The response time of the band pass filter (about 5°).
(iii) The capacitance phase shift of the transmission line (up to 10°).

QUESTIONS

1. What do you understand by time multiplier setting and plug multiplier setting in an overcurrent relay? Explain with the help of relay characteristic. Show why an IDMT characteristic is chosen in preference to simple inverse time characteristic.
2. What are the requirements for the satisfactory application of time/current-graded earth-fault protection using IDMT relays?
3. Explain why distance protection is superior to other types of protection for an overhead transmission line. Describe the operating characteristics of distance relays on the impedance plane and discuss their limitations.
4. Explain what is meant by distance protection. Show how three distance relays can be connected to provide equally sensitive protection against three-phase and phase-to-phase faults.
5. Explain what is meant by phase-fault compensation as applied to distance protection. Why is it necessary and how can it be achieved?
6. Discuss briefly the advantages and disadvantages of pilot wire differential protection of long transmission lines.
7. Explain what is meant by carrier system of protection. With a block diagram discuss how the carrier system of protection works. What is the basis for the choice of frequency in power line carrier system?
8. Explain the phase comparison method of carrier current protection?
9. Explain the directional comparison method of carrier current protection. Why is it used in impedance or other type of nonunit protection?
10. Illustrate the basic features of a 3-zone stepped distance protection scheme for a long transmission line, employing mho characteristics for zones 1 and 2, with an offset mho characteristic for zone 3 and starting. Briefly comment on the following: (a) high source-to-line impedance ratio; (b) differing effective impedances with different types of fault at a given point.

$0.4/4.0=0.1$. Increasing the TMS has the effect of moving the curve higher on the time scale.

Current setting is adjusted by means of a tapped plug bridge hence known as PSM.

$$\text{PSM}=\frac{\text{Primary current}}{\text{Primary setting current}}$$

$$=\frac{\text{Primary current}}{\text{Relay current setting}\times\text{CT ratio}}=\frac{\text{Primary current}}{\text{Primary operating current}}$$

where, as is usually the case, the rated current of the relay is equal to the rated secondary current of the CT. For example, if the maximum fault current that can flow through the relay location is 3000 A and the relay is set to operate at 200 primary amperes, then PSM=3000/200=15, or if the primary current is 3000 A and the relay current setting is 50% and the CT ratio is 400/5, then

$$\text{PSM}=\frac{3000}{2.5\times 80}=15 .$$

For the same primary current and a relay current setting of 200%

$$\text{PSM}=\frac{3000}{10\times 80}=3.75$$

Coordination of Inverse-Time Overcurrent Relays. Procedure for the selection of pickup or current setting and the time setting is indicated below.

Selection of current setting. It is necessary to calculate the maximum fault current which can occur at each relay position. A three phase fault under maximum generation gives the maximum fault current and phase to phase fault under minimum generation gives the minimum fault current. These are the two extreme values of fault current and the relay has to respond between these conditions. On a radial system the lowest setting must be at the farthest end; the settings being increased for the subsequent relays towards the source. As per Indian Standards the operating value should not exceed 130% of the setting, hence

$$I_{\text{setting}}=\frac{\text{Minimum short circuit current}}{1.3} .$$

Selection of time setting. For selective operation when there are a number of relays connected in series, the relay farthest from the source should be set to operate in the minimum possible time. For succeeding relays towards the source a time delay step is given. For inverse-time overcurrent relays the time setting should be done at the maximum fault current. If the relay has proper selectivity at maximum fault current, it will automatically have a higher selectivity at the minimum fault current, as the curve is more inverse on lower current region.

The following example illustrates the application of IDMT relays for protection of a radial feeder.

Consider the radial feeder as shown in Fig. (5.4). The CT ratio and maximum fault currents at various substations A, B, C and D are indicated. For all practical purposes we proceed to calculate the time setting of the farthest relay with maximum fault current.

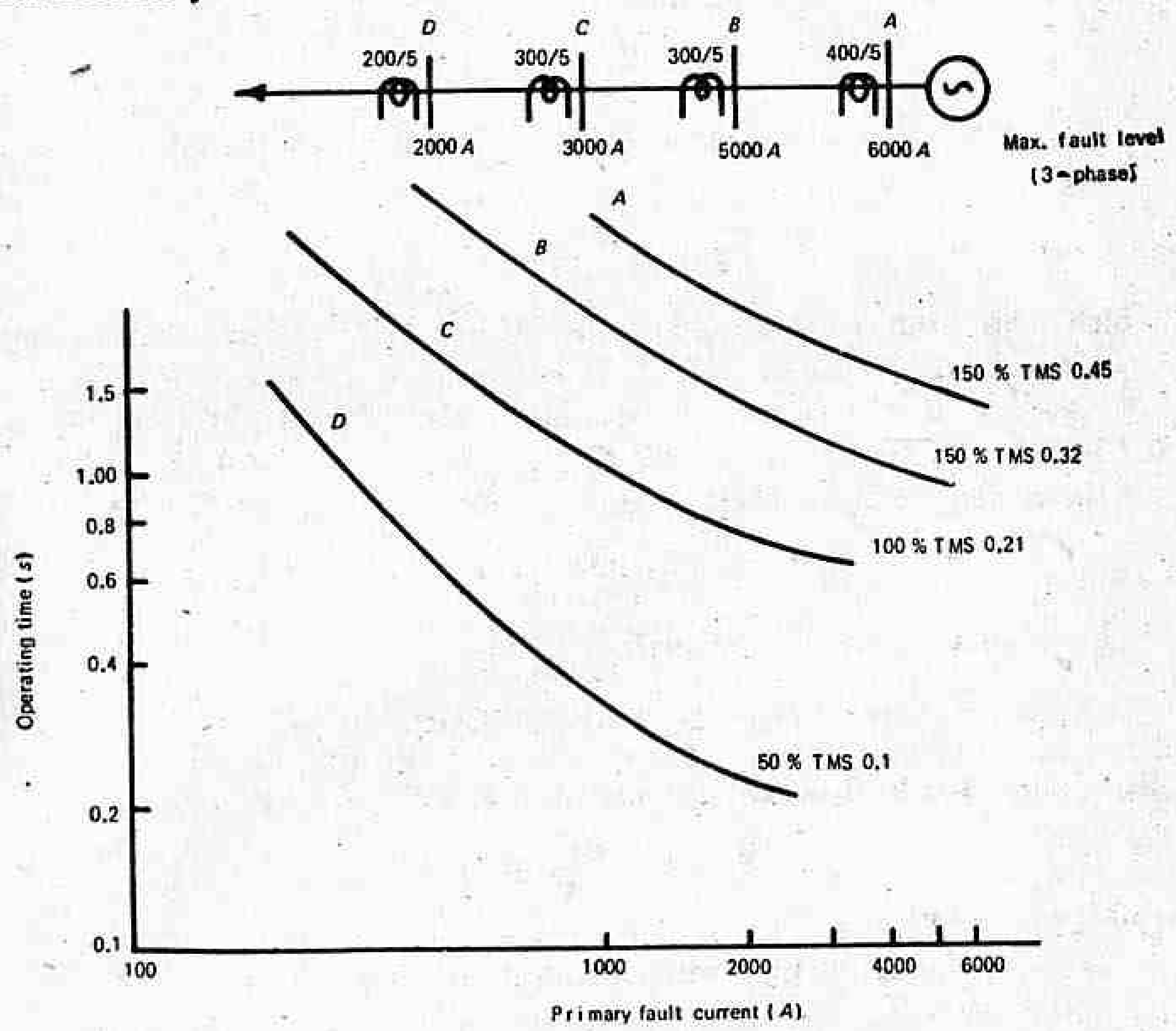


FIGURE 5.4

Starting with the relay at D, the TMS has to be the lowest, let us say it is 0.1. Now if the load current does not exceed 100A then the relay current setting may be set as 50%, i.e. 2.5A. Therefore

$$\text{PSM}=\frac{2000}{2.5\times 40}=20$$

From standard IDMT curve the operating time for a PSM of 20 is 2.2s. But as the TMS is 0.1 the actual time will be $2.2\times 0.1=0.22s$.

Now for the same current (2000A) the relay at C must be set to operate 0.5s (time delay step) longer than the relay at D, i.e. $0.22+0.5=0.72s$.

The current setting at C must be increased as compared to that at D, although some increase is being provided with the help of higher CT ratio at C but still to allow for any increase in load caused by load at D, setting the relay current setting at C as 100%. Thus for 2000A

$$PSM=\frac{2000}{5\times60}=6.66$$

which gives a time of 3.5s from standard IDMT curve. For an operating time of 0.72s the time setting should be

$$TMS=\frac{0.72}{3.5}=0.21.$$

For faults close to C, where the current is 3000A with 100% current setting

$$PSM=\frac{3000}{5\times60}=10$$

which gives a time of 3.0s and with a TMS of 0.21 the actual operating time is $0.21\times3.0=0.63s$.

Now at B the required operating time for a fault at C is $0.63+0.5=1.13s$.

Increasing the current setting at B to 150%

$$PSM=\frac{3000}{7.5\times60}=6.66$$

which gives a time of 3.5s; therefore

$$TMS=\frac{1.13}{3.5}=0.324, \text{ say } 0.32$$

For faults close to B, where the current is 5000A

$$PSM=\frac{5000}{7.5\times60}=11.1$$

giving a time of 2.95s.

At A the operating time with a fault at B will be

$$0.945+0.5=1.445s$$

Now the current setting at A is automatically increased without increasing the setting of the relay by virtue of its CT ratio. So keeping the relay setting at A 150%, same as that of relay at B.

$$PSM=\frac{5000}{7.5\times80}=8.34$$

giving a time of 3.2s. Therefore

$$TMS=\frac{1.445}{3.2}=0.452, \text{ say } 0.45$$

For faults close to A

$$PSM=\frac{6000}{7.5\times80}=10$$

giving a time of 3.0s. Therefore

$$\text{Actual time}=3.0\times0.45=1.35s$$

5.2.2 Directional Time and Current Grading

In the plain radial feeders the discrimination is obtained by means of the relay time and current setting adjustments only. To obtain discrimination where feeders other than radial feeders are employed, it is usually necessary to incorporate a directional feature in the protection, as will be clear from the following cases. Three separate cases will be considered: (a) parallel feeders, (b) tee'd parallel feeders, and (c) ring mains.

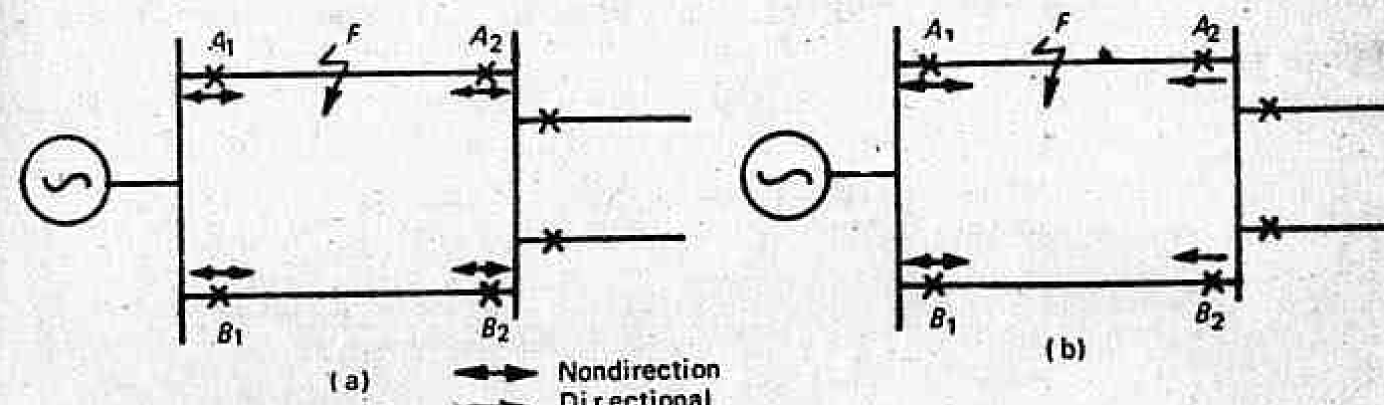


FIGURE 5.5 Protection of parallel feeders: (a) with nondirectional relays; (b) with directional relays.

Figure (5.5) shows the case of parallel feeder; with nondirectional relays it can be seen that with a fault anywhere on the feeder point F the supply will be disrupted completely for both the feeders irrespective of the relay settings chosen. To ensure discrimination it is usual to have relays A_2 and B_2 as direction sensitive such that they operate for faults occurring in the feeder in the direction indicated by the arrows (away from the bus) shown in Fig. (5.5b). Furthermore directional relays A_2 and B_2 should operate before nondirectional relays A_1 and B_1. For this reason they are given lower time and current settings than A_1 and B_1. Usually a directional relay is required at one end of each feeder with a nondirectional relay at the other end. Directional overcurrent relays are graded in the same way as the nondirectional overcurrent relays already explained. Directional overcurrent relays require a voltage source in addition to the current source.

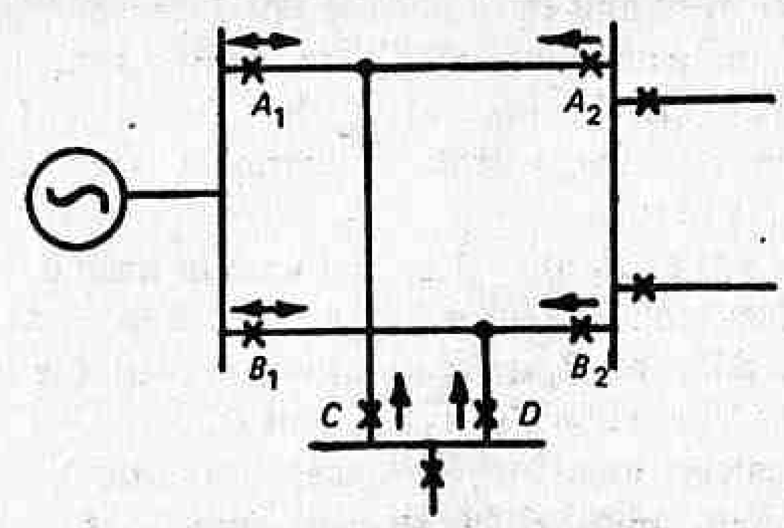


FIGURE 5.6 Tee'd parallel feeder.

The connections of voltage and current supplies to the directional relays have been dealt in Chapter 4.

Figure (5.6) shows the case of a tee'd parallel feeder, where again for discriminative reasons the relays on the source end bus must be nondirectional while the relays on the load end buses must be directional relays with their direction for operation corresponding to fault current flowing into the feeder. Furthermore, directional relays are set for lower time and current settings than the nondirectional ones, so that the former operate before the latter.

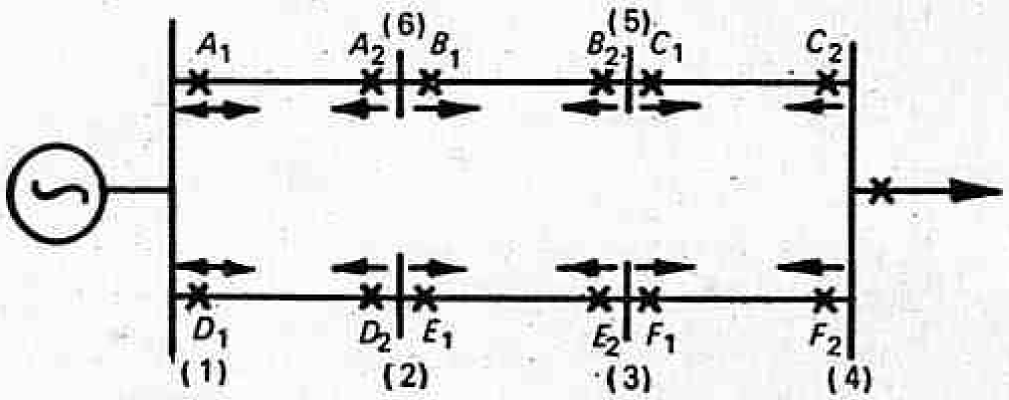


FIGURE 5.7 Ring main system.

Figure (5.7) shows the case of a ring main system. In order to achieve discrimination for faults the relays associated directly with a faulty section of the ring should operate. It will again be noted that the relays at the source bus A_1 and D_1 need not be directional relays. In fact it is advisable that A_1 and D_1 should not be directional. Otherwise for faults close to the source bus there may be nonoperation. The direction of operation for other directional relays is also shown in Fig. (5.7).

Relay settings are determined by considering the grading first in one direction and then in the other, working backwards to the power source. For instance, considering the counterclockwise circuit D_1-A_2 in Fig. (5.7) the relay settings at A_2 are calculated first; the relay must receive atleast twice its setting current for a fault at A_1 end of the A_2A_1 feeder with the A_1 circuit breaker open and the fault current fed around the ring from D_1 with the minimum generating conditions at the source. The minimum setting of the TMS can be used at A_2, but the current setting must be sufficient for the relay to withstand thermally the full load of all the substations, i.e. (1) to (6).

The relay settings at B_2 are calculated next in a similar manner. With a fault at A_2, the circuit breaker at A_1 open and maximum generation connected. The relay at B_2 must discriminate with the relay at A_2. The process is repeated for relays C_2, F_1, E_1 and D_1.

The setting calculations for the relays in the clockwise circuit A_1-D_2 are now undertaken, working backwards from D_2 to A_1. Care must be taken that the midpoint of the ring is fully protected.

5.2.3 Overcurrent Earth-Fault Protection

Earth-fault protection can be provided with normal overcurrent relays, if the minimum earth-fault current is sufficient in magnitude. The magnitude of earth-fault current is usually low compared to the phase-fault currents because the fault impedance is much higher for earth-faults than for phase-faults. It also depends on the type of neutral earthing, i.e. whether solidly earthed, insulated or earthed through some resistance or reactance. Whatever the case may be the earth-fault current will be small compared to the phase-fault currents in magnitude. The relay thus connected for earth-fault protection is different from the ones provided for phase-faults. It has the peculiarity that it is set independent of load current and thus settings below normal load current can be achieved. Hence earth-fault relays are set at low settings between 30% and 70% but low values of current settings impose a higher burden on the relay with rated current in the primary of the CT. It will be seen that unless the earth-fault current is limited or special CTs are used to provide a higher output, time/current grading of earth-fault relays is not practicable.

Fortunately the grading of earth-fault relays, unlike overcurrent phase relays, is normally limited to one system voltage due to general use of delta/star step down transformer, as the earth-fault in one section does not draw ground current from other parts. This simply means that an earth-fault on one side of the transformer will not be seen by the earth-fault relays on the other side and hence the grading between the relays on the different voltage systems is not required.

Overcurrent earth-fault protection can be provided with only one overcurrent relay connected in the residual circuit or across the zero phase sequence filter. A current will flow through the relay winding only when a fault involving earth occurs. Figure (5.8) shows the location of the earth-fault relay along with the phase relays.

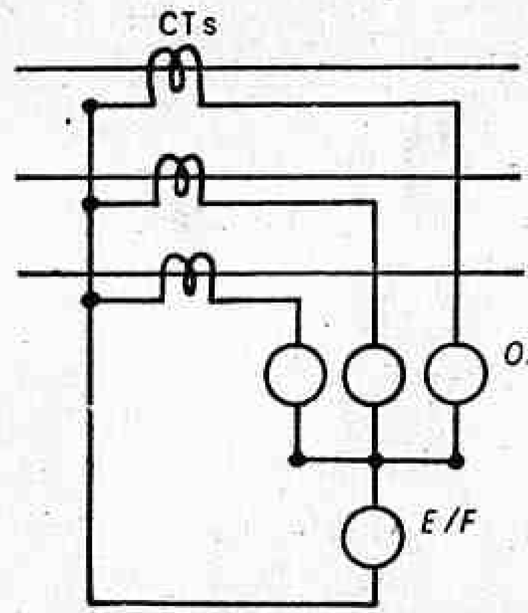


FIGURE 5.8 Location of phase relays and E/F relays. O/C—Overcurrent relays (phase relays); E/F—Earth-fault relay.

When both overcurrent and earth-fault protection are required using IDMT relays it is usual to provide two phase relays instead of three phase relays with one earth-fault relay from economic considerations (Fig. (5.9)).

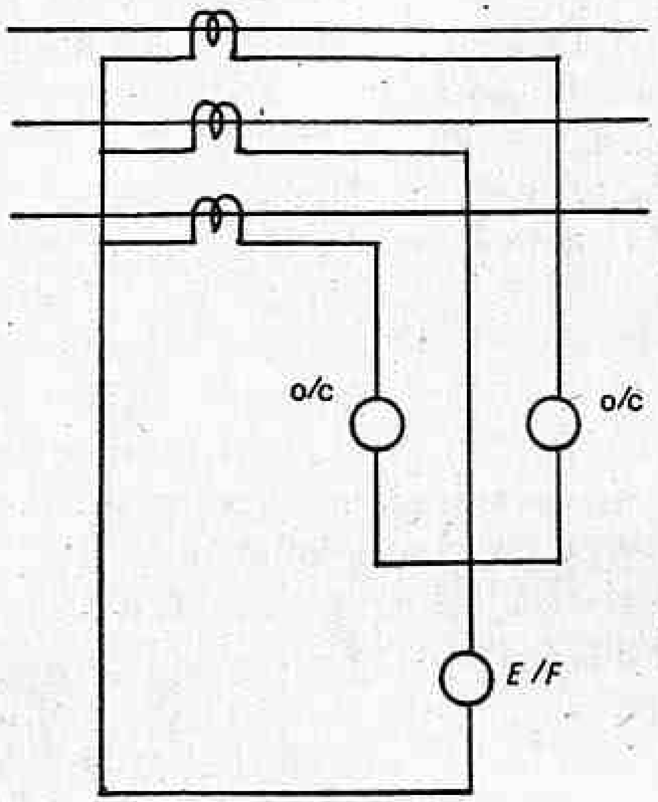


FIGURE 5.9 Two phase relays and one E/F relay.

If all the CTs were ideal, under normal operating conditions and interphase faults no current would flow through the earth-fault relay. However, when commercially identical CTs are used some current would flow through the relay. This is due to difference in errors and in amounts of residual magnetism. This current is called unbalance current or false residual current which is in the range of 0.01 to $0.1A$ at rated primary current and many times larger when heavy phase-fault currents flow.

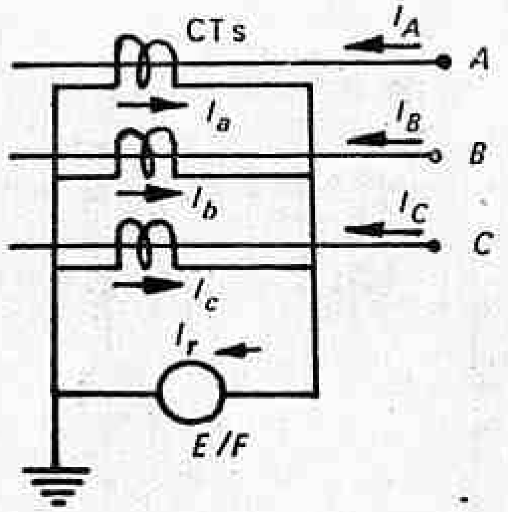


FIGURE 5.10 Principle scheme of E/F protection.

Figure (5.10) illustrates the principle of earth-fault protection. Obviously during normal operation and also for three-phase and line-to-line faults, the current passing through the relay is equal to zero:

$$I_r = I_a + I_b + I_c = I_a + aI_a + a^2 I_a = 0 \tag{5.1}$$

(three phase fault)

$$I_r = I_a + I_b = I_a - I_a = 0 \tag{5.2}$$

(line-to-line fault on phases A and B)

When a single or double earth-fault occurs, the zero sequence current flows through the relay. Now from the equivalent circuit of the CT we have

$$I_s = I_p' - I_e' = \frac{(I_p - I_e)}{n} \tag{5.3}$$

where

I_s=secondary current
I_p'=primary current referred to secondary
I_e'=exciting current referred to secondary
I_p=primary current
I_e=exciting current
n=secondary to primary turn ratio

Accordingly we can write

$$I_a = \frac{(I_A - I_{Ae})}{n},\ I_b = \frac{(I_B - I_{Be})}{n} \text{ and } I_c = \frac{(I_C - I_{Ce})}{n} \tag{5.4}$$

Therefore:

$$I_r = \frac{1}{n}(I_A + I_B + I_C) - \frac{1}{n}(I_{Ae} + I_{Be} + I_{Ce}) \tag{5.5}$$

Since $\qquad I_A + I_B + I_C = 3I_0$

and $\qquad \frac{1}{n}(I_{Ae} + I_{Be} + I_{Ce}) = I_{fr}$ = false residual current $\qquad$ (5.6)

Hence

$$I_r = \frac{1}{n}(3I_0) - I_{fr} \tag{5.7}$$

Equation (5.7) shows that earth-fault relay responds to zero sequence current and the value of the pickup of earth-fault relay has to be selected against the maximum value of false residual current only.

5.2.4 Directional Earth-Fault Relays

In the case of earth-fault directional relays the angular relationship of residual current and residual voltage is independent of the faulted phase and is governed only by the R/X ratio of the fault path. The current coil of the directional element is connected to detect current in the residual circuit of the CTs and the voltage coil is connected to a suitable voltage source to give sufficient torque. Thus for a residual current I_r and residual voltage V_r the torque will be proportional to $I_r V_r \cos(\phi - \theta)$ where θ is the maximum torque angle of the relay and ϕ is the angle between applied voltage and current.

The residual current as shown earlier is obtained with the help of three CTs. A common arrangement for obtaining residual voltage employs a five-limb voltage transformer or its equivalent with a star-connected primary, the star point being earthed, and an open delta secondary. The voltage across the open delta is applied to the voltage coil of the directional element of the relay. This is illustrated in Fig. (5.11a).

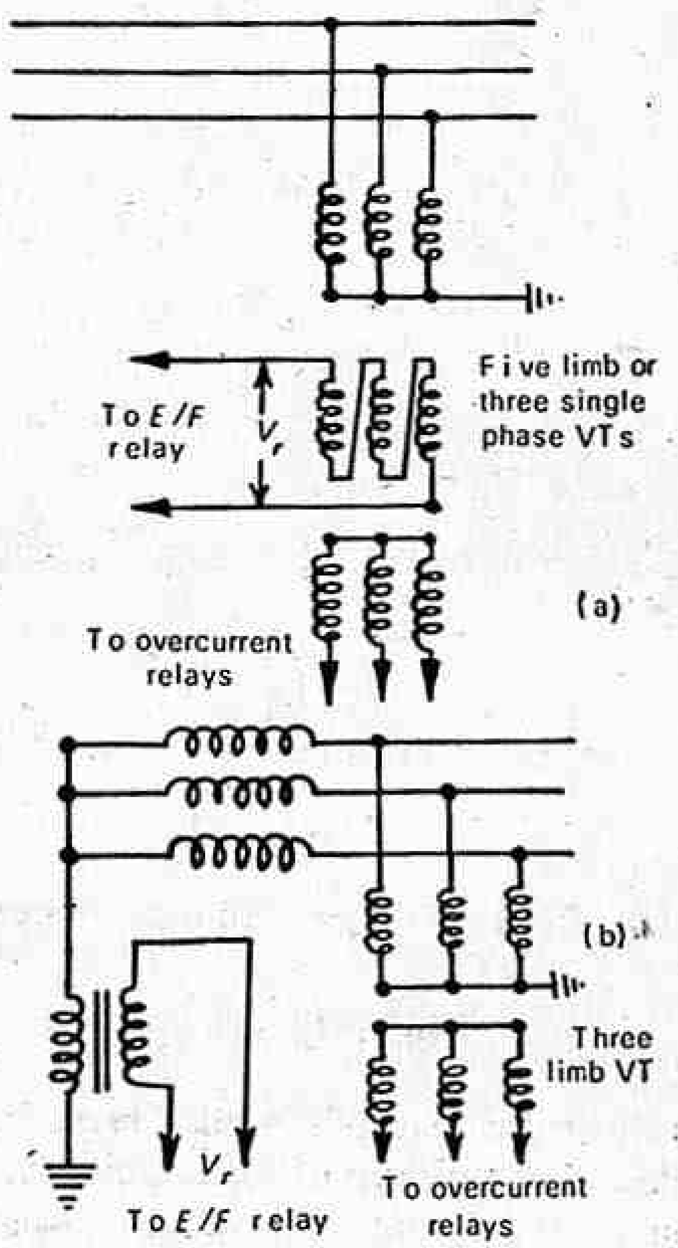


FIGURE 5.11 Methods of polarizing directional E/F relays.

Another method of obtaining residual voltage is shown in Fig. (5.11b) for systems earthed through arc-suppression coil. The voltage which appears across the arc-suppression coil is applied to earth-fault relay.

The magnitude of V_r when a fault occurs depends on the method of earthing the system neutral, and the fault resistance. An earth fault causes the system neutral to shift in case of systems earthed through some impedance. It can be shown that:

(a) The higher the earthing impedance, the higher is the residual voltage (tending to a value of three times phase voltage), and if this impedance is resistive the power factor is high. Fault resistance has negligible

effect on the residual voltage. (Although the current is low, which can be compensated for by using a sensitive relay, all other factors are favourable for high torque in the relay.)

(b) With low impedance or solidly earthed systems the residual voltage does not exceed nominal phase voltage. As the fault-loop impedance is mainly reactive, the power factor is very low. Fault-arc resistance obviously gives some improvement in power factor, but reduces the residual voltage further. (Fault current is high, but all other factors are contrary to the production of high torque in the relay.) .

A resistance earthed system provides the most satisfactory conditions for relay operation. It facilitates the tripping of the faulted circuit without undue delay (i.e. within a few seconds).

For low-impedance or solidly earthed systems the relays are designed to operate with low residual voltages. The production of full flux at very low voltage may give excessive saturation of the voltage-coil core at nominal voltage, leading to over loading of the *VT*. This is a major design consideration.

Another consideration with the solidly earthed system is the low fault power factor. For this some phase angle compensation can be applied. Two such phase angle compensation methods are shown in Fig. (5.12).

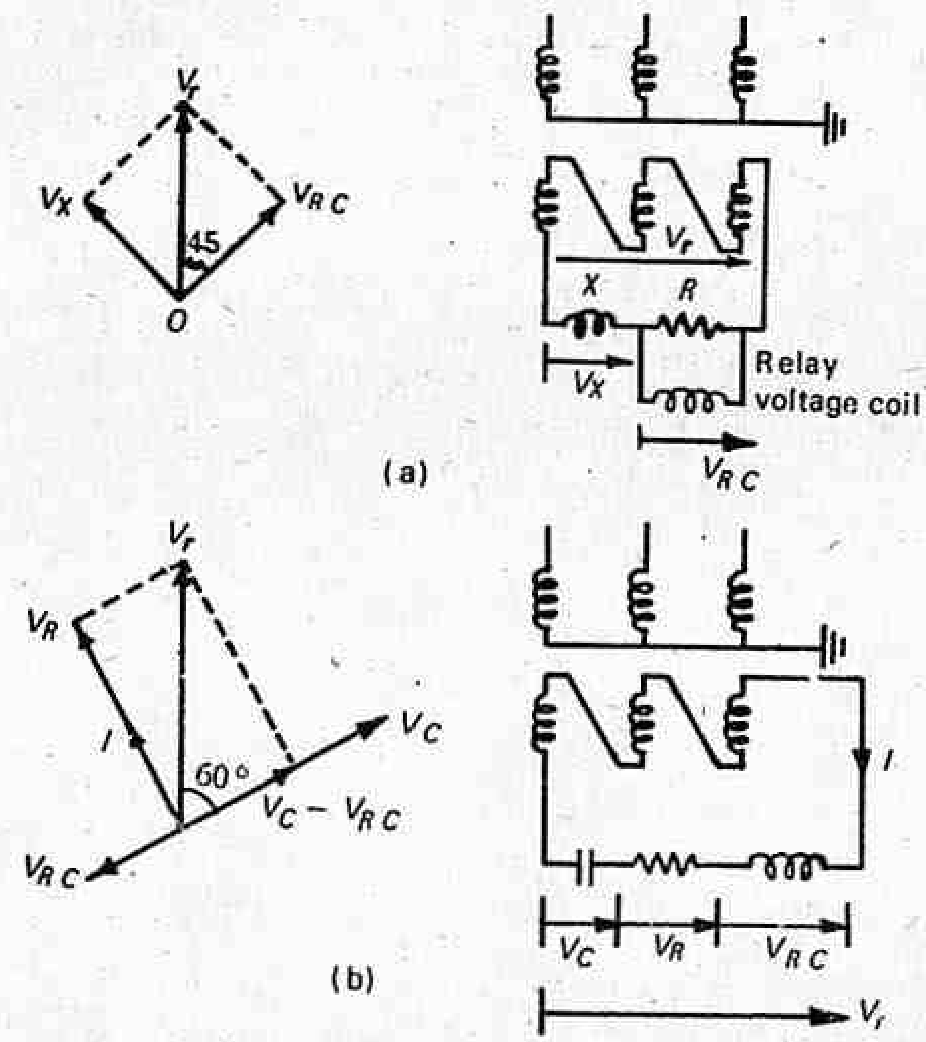


FIGURE 5.12 Phase angle compensation of directional E/F relays.

The first method is illustrated in Fig. (5.12a). The two equal impedances—one resistive and the other reactive—are connected across the residual voltage, whereas the voltage coil of the earth-fault relay is connected across the resistive impedance. Thus the voltage across the resistor and the relay coil in parallel (V_{RC}) lags the residual voltage V_r by approximately 45°. By doing this the torque increases even at low fault power factors. For example, with a fault power factor of unity, the fault current I_F leads the voltage across the relay coil V_{RC} by approximately 45°, and the expression for torque is approximately equal to $0.7\, I_F V_{RC}$. Now with a fault power factor of 0.7 lagging, I_F is in phase with V_{RC}, and the torque becomes $I_F V_{RC}$ or 1.4 times torque for a unity power factor fault. If the relay already has a 15° compensation angle the relay torque will be a maximum for a fault power factor of 0.5 lagging.

The second method is illustrated in Fig. (5.12b). It can be seen that the relay coil voltage can be arranged to lead the residual voltage by 120° and the required lag of 60° is obtained by reversing the coil connections.

Earth-Fault Detection in Systems Earthed through Arc Suppression Coil. In a system earthed through a continuously rated arc suppression coil, the earth-fault is detected by energizing a relay either from the secondary winding of the coil or from a low-ratio *CT* in the neutral-earth connection. Figure (5.13) represents a simple three-phase system earthed through an arc-suppression coil for a fault on phase *A*. The relay torque is proportional to $V_r I_r \sin \alpha$.

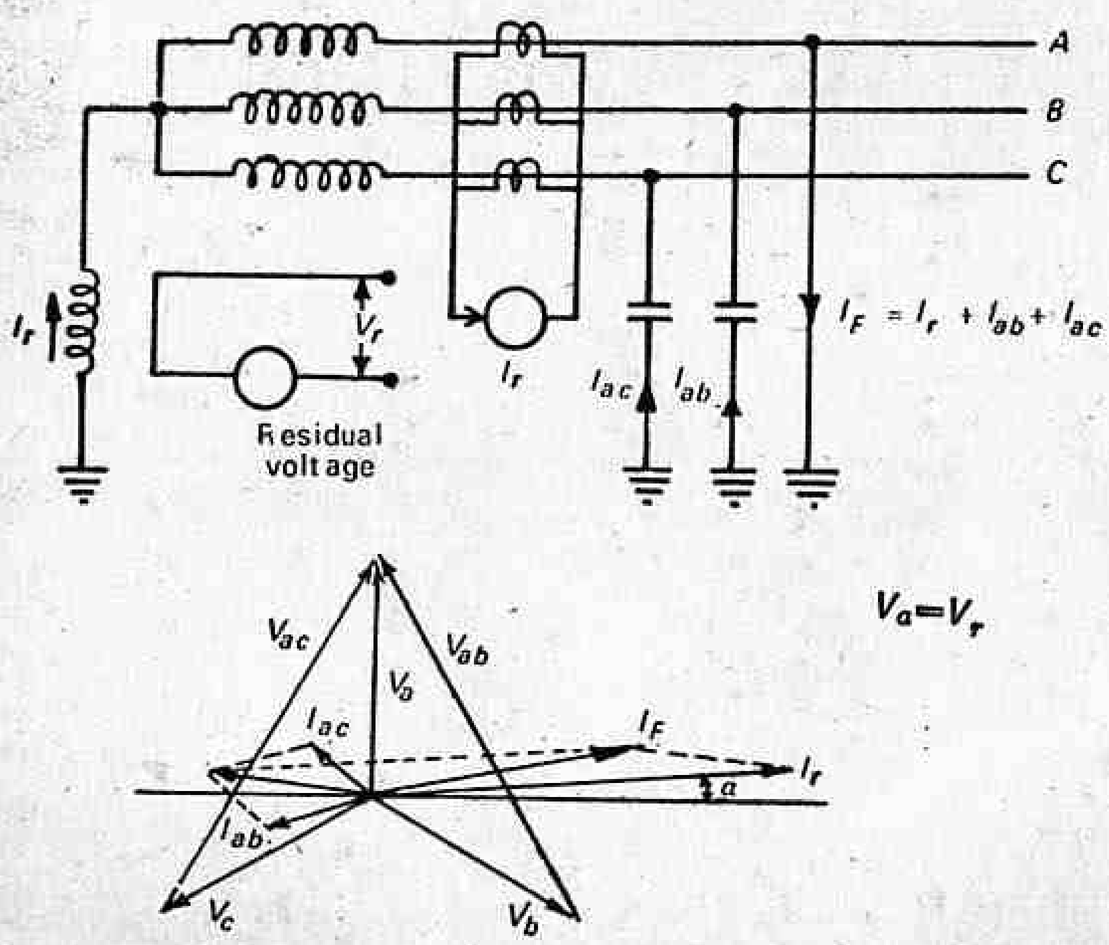


FIGURE 5.13 Simple three-phase system earthed through an arc suppression coil.

In case of multi-feeder system it is necessary to detect as to which circuit is faulted. A supersensitive directional relay is used on each feeder. Consider a case of *n* feeders each provided with a sensitive earth-fault relay of the type shown above. It can be seen that the relays on the healthy circuits restrain and the relay on the faulted circuit operates. No capacitive current flows in phase *A* of any healthy feeder since this phase is at earth potential. Figure (5.14) illustrates one such system. Assuming that the circuits have equal capacitances and resistances, the total capacitive current per feeder is

$$I_{cap} = I_{ab} + I_{ac}$$

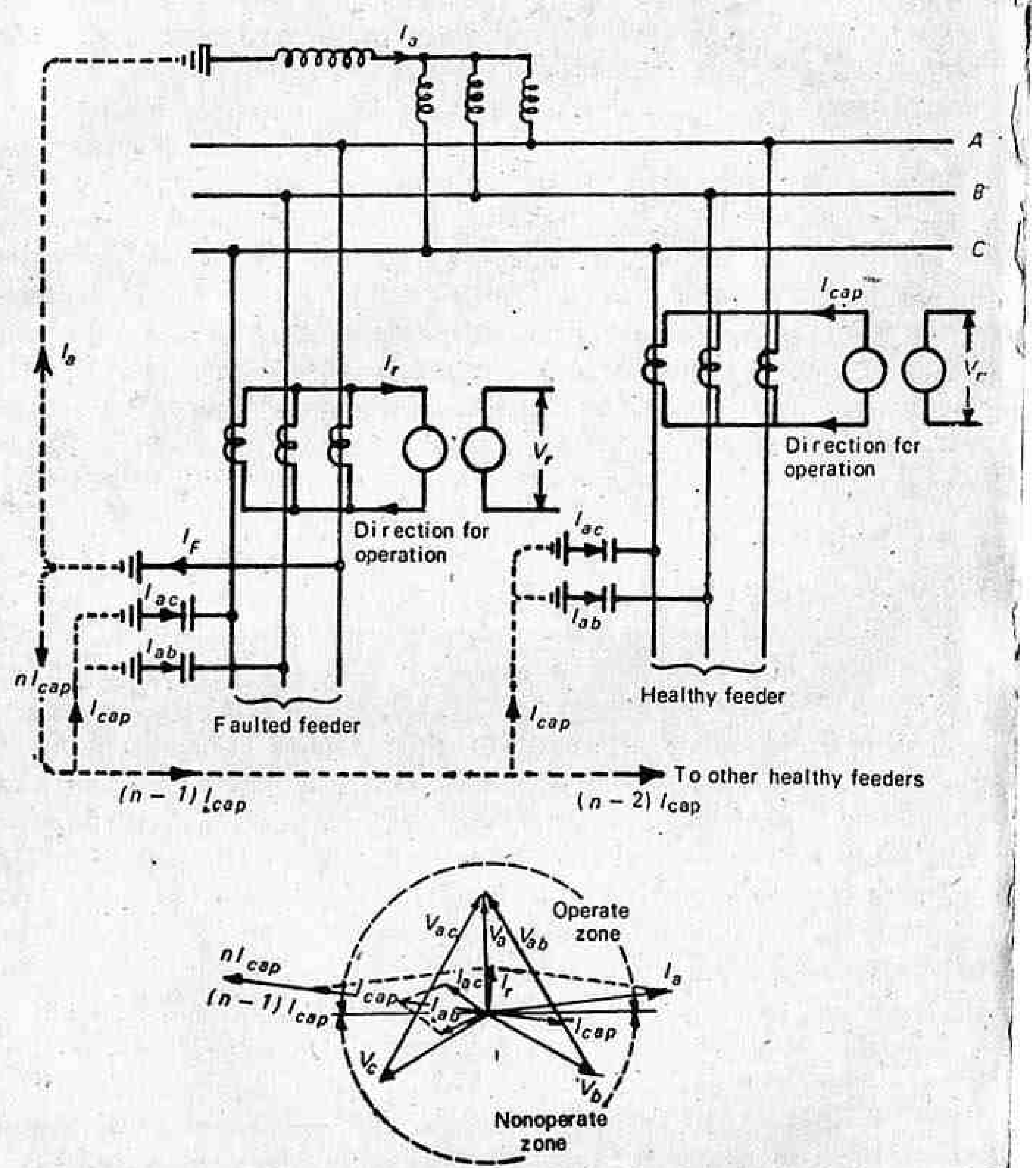


FIGURE 5.14 Feeder fault detection in '*n*' radial feeders system earthed through arc suppression coil.

CHAPTER 6

Apparatus Protection

6.1 Introduction

The two major items of equipment in a power system are the generators and the transformers. Faults occur less frequently on these apparatus than on lines, but the damage caused by the faults usually takes much more time and money to repair than are required to repair the damage done by faults on lines. Rapid reclosing of circuit breakers is feasible on lines and it helps in saving the amount of damage. A fault in a generator or transformer on the other hand, always needs some attention of the supervisory staff. Fast clearing of faults, however, helps in minimizing the damage to the apparatus and also reduces the interruption to power service resulting from reduced voltage and from instability.

6.2 Transformer Protection

6.2.1 Nature of Transformer Faults

Power transformers, being static, totally enclosed and oil immersed develop faults only rarely but the consequences of even a rare fault may be serious unless the transformer is quickly disconnected from the system. For the purpose of discussion, faults can be divided into three main classes:

(1) Faults in the auxiliary equipment which is part of the transformer.
(2) Faults in the transformer windings and connections.
(3) Overloads and external short circuits.

6.2.2 Faults in Auxiliary Equipment

The detection of faults in auxiliary equipment is necessary to prevent

In the event of generator being overloaded it will overheat the stator which can further damage the insulation and thus complicate matters.

Failure of prime mover may cause the generator to 'motor' by taking power from the system in case it is not a single generator system. The seriousness of this condition depends on the type of drive used for the generator.

A sudden loss of load may cause the machine to overspeed which is more likely to occur with hydraulic generators because the water flow cannot be stopped quickly for reasons of energy and mechanical and hydraulic inertia.

Overvoltages are likely to occur due to overspeeding or due to defective voltage regulator.

6.3.2 Stator Protection

The type of stator faults likely to occur have been discussed in the previous section. The earth-fault current is usually limited by resistance in the neutral of the generator. Depending upon the amount of resistance in the neutral circuit of the generator the fault current may be limited to a value between 200 A and 250 A or between 4 A and 10 A. Resistor earthing is employed to get the former value whereas distribution transformer earthing is employed for the latter. This latter method has the advantage of ensuring minimum damage to the stator core, but it is not practicable when the stator winding is directly connected to the delta winding of the main transformer.

When the stator neutral is earthed through a resistor a CT is mounted in the generator neutral and connected to either an inverse time relay or an instantaneous attracted armature relay as shown in Fig. (6.12) depending on whether the generator is directly connected to the station bus bars or via a delta/star transformer. In the former case the inverse time relay

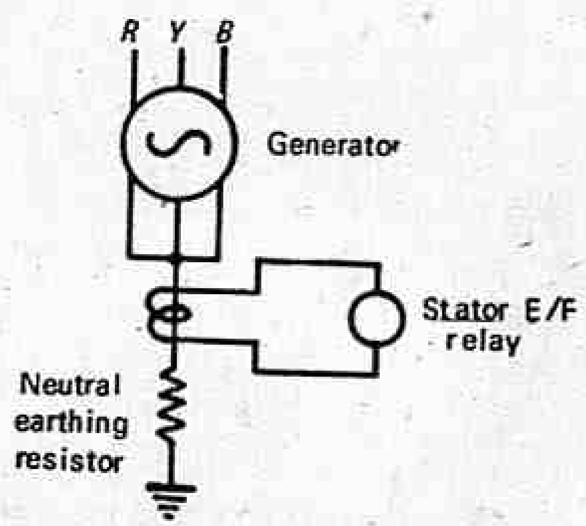


FIGURE 6.12 Location of E/F relay in a resistance earthed generator.

will require grading with other earth-fault relays in the system. But in the latter case, because the earth-fault loop is restricted to the stator and transformer primary winding, no discrimination with other earth-fault relays is necessary. With resistor earthing it is impossible to protect 100% of the stator winding, the percentage of winding protected being dependent on the value of the neutral earthing resistor and the relay setting. In this case high-speed relays and breakers will be required to prevent damage. However the distributed capacitance of the stator to ground fixes a limit to the value of resistance necessary in the neutral circuit of the generator to prevent overvoltage due to resonance which might result in another winding fault. The maximum value of the resistance is given by

$$R_n = \frac{10^6}{6\pi f C} \text{ ohms}$$

where C is the capacitance of the stator circuit to earth per phase in microfarad and f the system frequency.

If neutral is earthed through the primary winding of a distribution transformer, earth-fault protection is provided by connecting an over-voltage relay across its secondary, then the maximum value of resistance is equal to

$$R_n = \frac{10^6}{6\pi f N^2 C} \text{ ohms}$$

where N is the turn ratio of the transformer. In this case slow acting relays are sufficient to prevent damage.

Generator Differential Protection. The best form of stator protectiom from phase-to-phase and phase-to-ground (iron lamination of the stator core) is provided by the longitudinal differential relay. The relay recommended for this application is an instantaneous attracted armature type setting 10

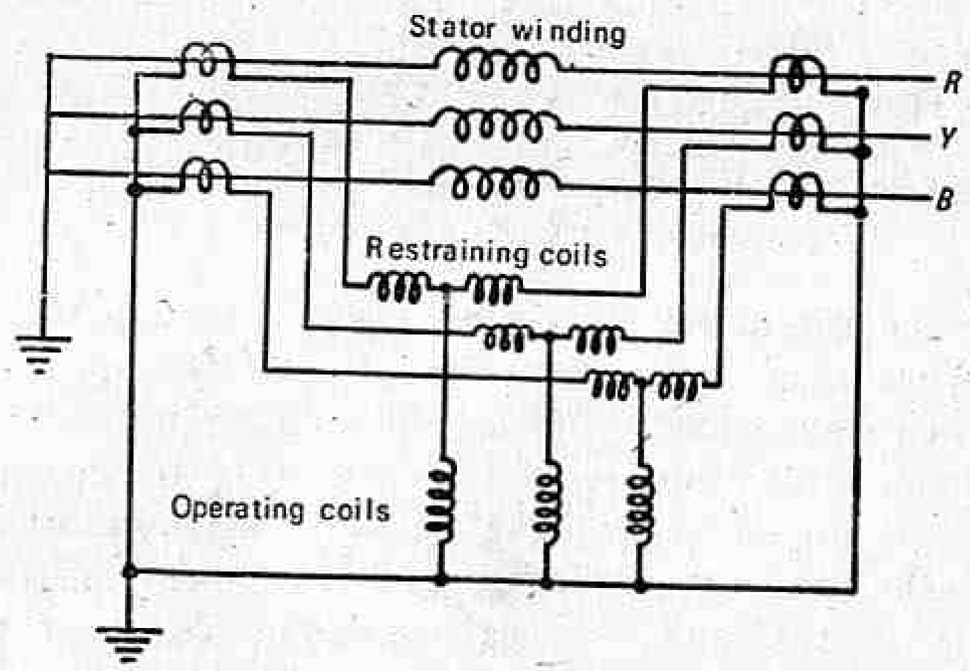


FIGURE 6.13 Percentage biased differential relay.

to 40% which is immune to a.c. transients and has the high speed feature is suitable if the CTs are reasonably matched. As is well known that if the CTs on the line side have dissimilar characteristics from those mounted at the neutral end of the winding, a relatively large spill current will flow through the relay operating coil, a percentage bias differential relay should be used under such circumstances. Longitudinal percentage biased differential protection for generator stator is shown in Fig. (6.13).

Stator Inter-turn Fault Protection. Inter-turn fault on the same phase of the stator winding does not disturb the balance between the currents in the neutral and the high voltage CTs; with the result that such a fault cannot be detected by longitudinal differential protection. Transverse differential protection can detect the unbalance between normally identical windings caused by an inter-turn fault when the generator has two windings per phase. Bias is used because the sharing will never be exact. Biased transverse differential protection to protect against inter-turn faults is shown in Fig. (6.14).

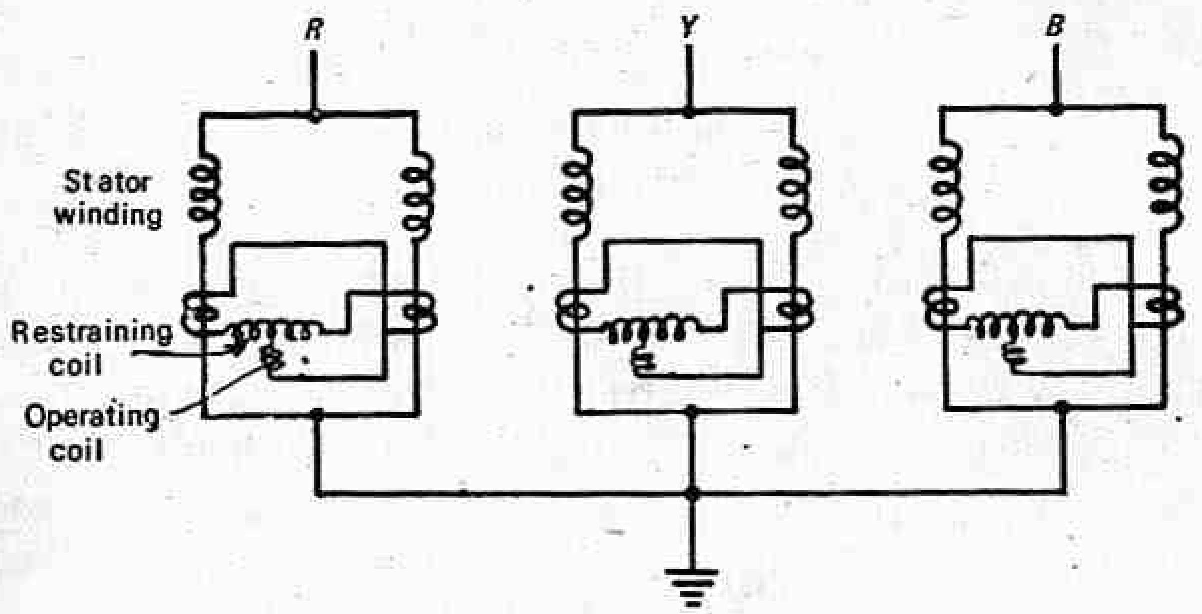


FIGURE 6.14 Biased transverse differential protection for inter-turn fault protection for parallel wound stator.

Generators having single winding per phase or those generators whose parallel windings are not accessible can be protected by using zero sequence component of voltage caused by the reduction of emf in the faulted phase. One such circuit is shown in Fig. (6.15) where the zero sequence voltage appears across the tertiary winding of the voltage-transformer which is connected to the operating winding of the three element directional relay. The winding in quadrature to this operating winding of the relay is energized by the secondary of the voltage-transformer.

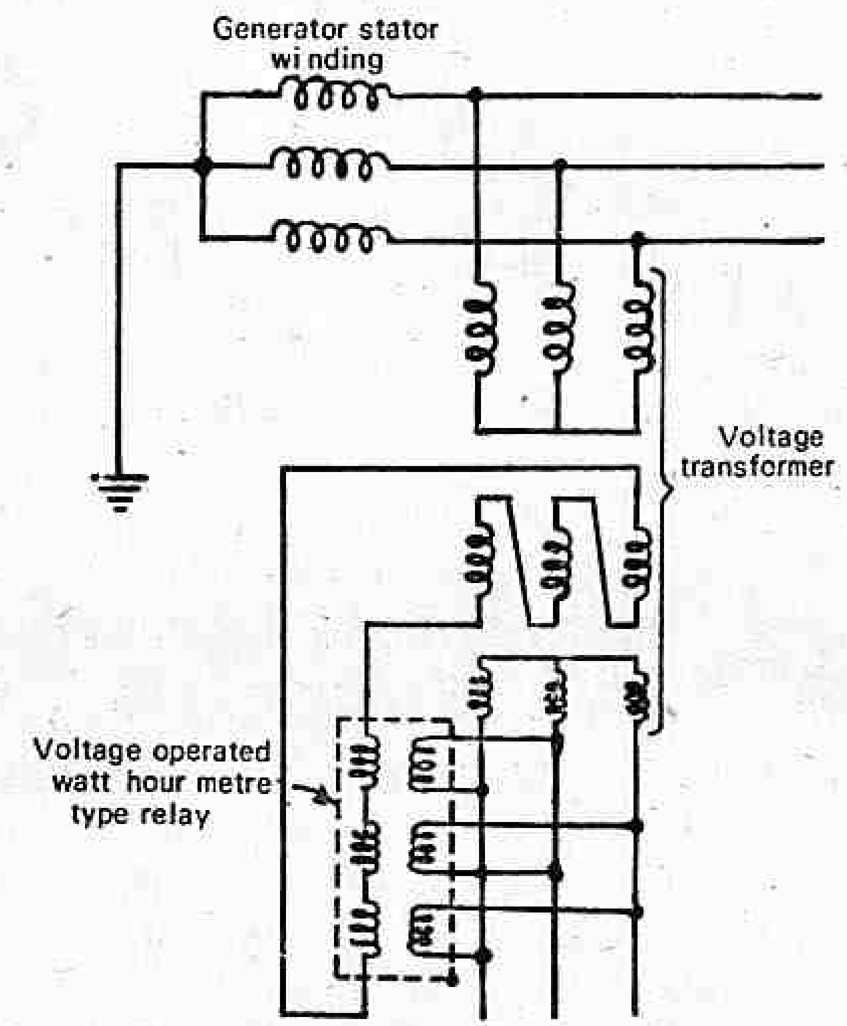


FIGURE 6.15 Interturn fault detection.

6.3.3 Rotor Protection

As pointed earlier rotor windings may be damaged by earth faults or open circuits. Figure (6.16) shows a modern method of rotor earth-fault detection. The field is biased by a d.c. voltage which causes current to flow through the relay *R* for an earth fault anywhere on the field system.

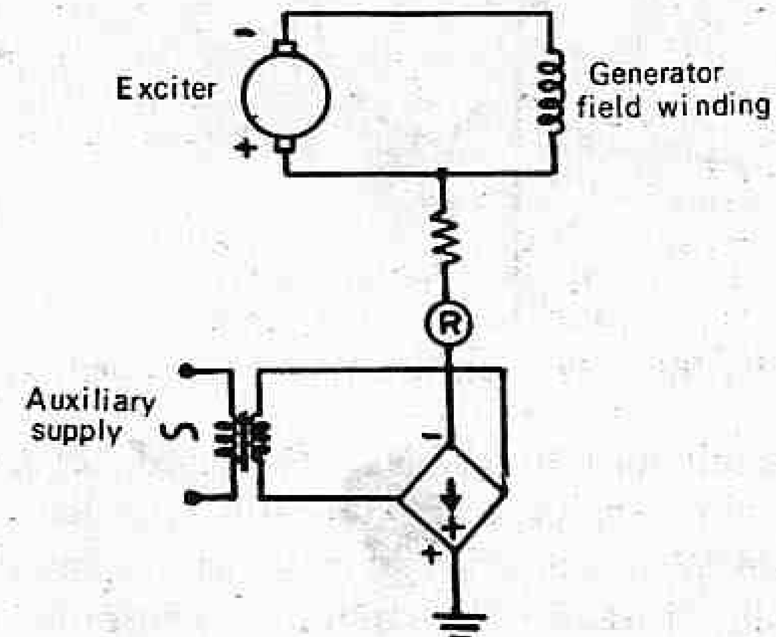


FIGURE 6.16 Rotor earth-fault detection.

Detection of rotor open circuits is the same as that used for detecting loss of excitation described in the next section.

6.3.4 Loss of Excitation (Field Failure) Protection

Two distinct effects of loss of excitation are that the machine starts drawing magnetizing current of large magnitude from the system, and the slip frequency emfs induced in the rotor circuit; both of them cause overheating of the rotor.

Loss of excitation can be detected by measuring the reactive component of stator current; an excessive value of VAR import indicates either actual or prospective loss of synchronism. To allow for system transients which may cause a momentary reversal of VAR component it is usual to incorporate a fixed time delay of between one and five seconds in the tripping sequence of the relay.

It can also be detected by an undercurrent moving coil relay in the field circuit, but some large generators operate over a very wide range of field excitation and such a relay may be an embarrassment. Furthermore, field failure due to exciter failure may not be detected because the undercurrent relay may be held in by a.c. induced from the stator. An undercurrent relay fast enough to drop out on a.c. cannot be used because it would be affected by a.c. induced during synchronizing and during external faults.

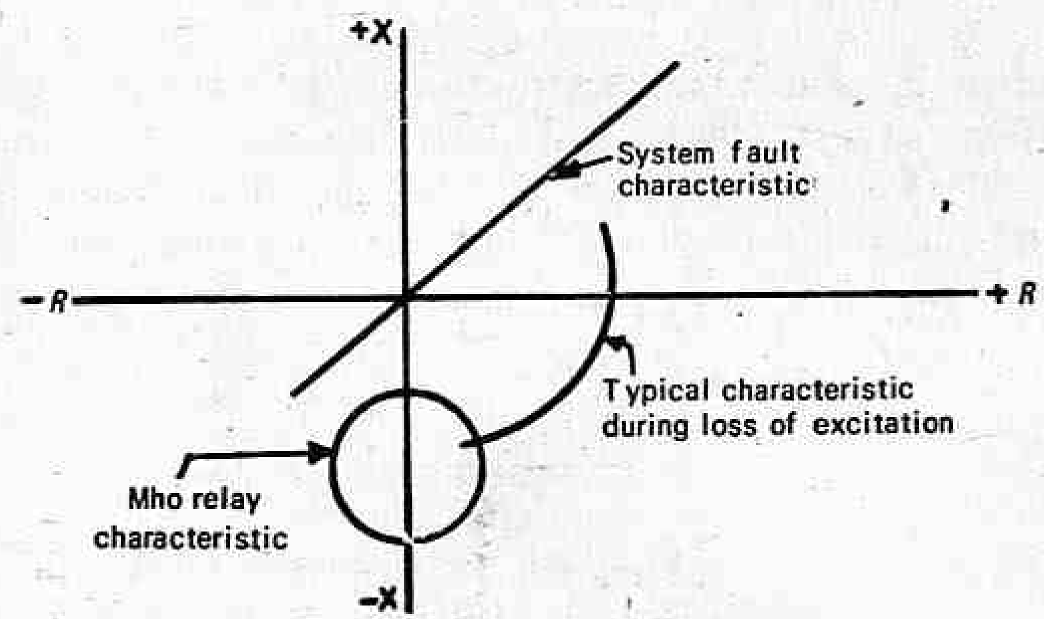


FIGURE 6.17 Loss of excitation characteristic.

An alternative solution is to apply an offset impedance or mho measuring relay at the generator terminals. Its operating characteristic is arranged as shown in Fig. (6.17) so that during conditions of extremely low excitation or complete loss of excitation the equivalent generator impedance falls within the tripping zone.

6.3.5 Unbalanced Loading Protection

Whatever be the cause of the unbalance it is obvious that the negative phase sequence current will result in heating of the stator. In case of high-speed turbo-generators, the continuous current which can be carried is usually between 10 and 15% of the positive sequence continuous rating. The negative sequence heating follows a normal resistance law and hence is proportional to the square of the current. The heating time constant of the machine is largely a function of the cooling system employed. This is expressed by a rating equation:

$$I_2^2 t = K$$

where I_2 is the negative sequence current expressed on a per unit basis of *continuous maximum rating* (CMR), t is the *current duration* in seconds, and K is a constant which for turbo type machines will usually have a value between 3 and 20.

The problem of protecting against this condition lies in obtaining a relay characteristic which will accurately match this heating characteristic. The usual arrangement is an inverse with definite minimum time delay relay connected to a network which segregates the negative sequence current from the positive and zero sequence current Fig. (6.18). The relay has a long operating time and has a range of settings to allow its characteristic to be accurately matched to those of the machine.

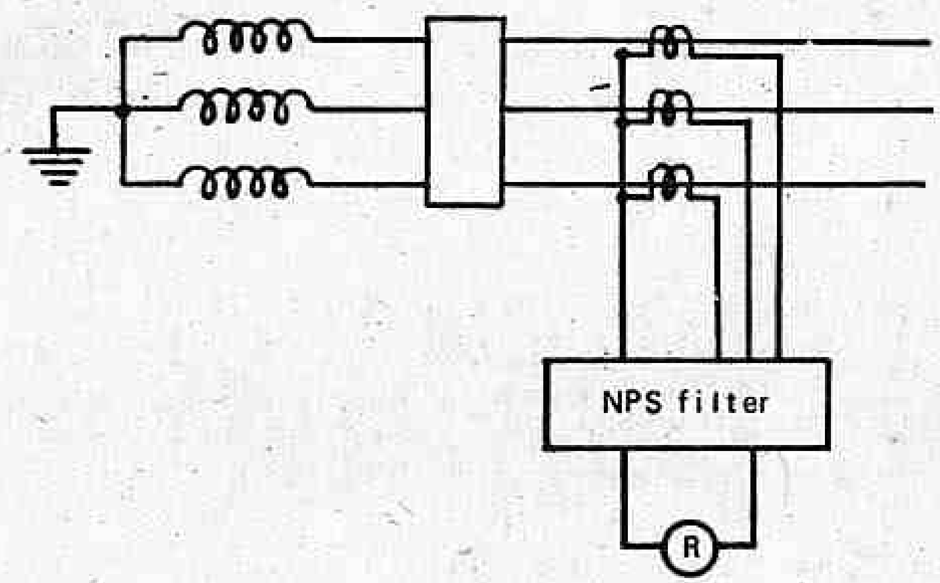


FIGURE 6.18 Protection against unbalanced load using negative sequence filter. NPS—negative phase sequence; R—overcurrent IDMT relay.

6.3.6 Overload Protection

Continuous balanced overloading of a machine causes overheating in the stator winding. An obvious solution to this is the application of overcurrent relays; but this is not usually provided because this discriminates by time, it must be arranged to discriminate with the slowest relay on the system which the generator is feeding, moreover in any event such a protection cannot detect a fault in the cooling system of the generator.

The most reliable method of detecting such a condition is by means of temperature detector coils embedded at various points in the stator winding arranged to provide an indication of the temperature conditions which exist over the stator winding. Temperature detectors may be either thermocouples, thermistors, or resistance temperature detectors. The temperature detector coil forms one arm of the Wheatstone bridge circuit as shown in Fig (6.19).

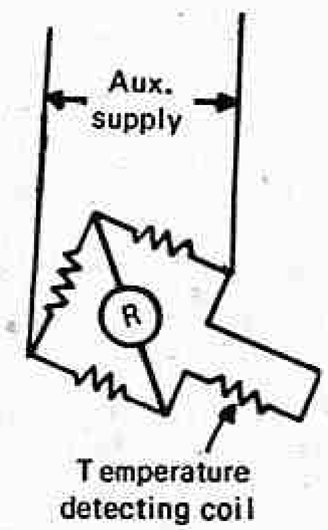


FIGURE 6.19 Stator overheating protection using temperature detector coils.

Sets below 30 MW rating are not normally provided with embedded temperature detectors but are usually provided with thermal relays. This type of relay has a bimetallic strip heated by secondary current from the stator, the housing of the bimetallic strip is designed to have a heating and cooling characteristic similar to that of the machine. Such a relay will however provide no protection against overheating due to the failure of the cooling system.

6.3.7 Prime-Mover Protection

In the event of prime-mover failure the machine starts motoring meaning thereby that it draws electrical power from the system and drives the prime-mover. This condition imposes a balanced load on the system, which can be detected by a power relay with a directional characteristic, as illustrated in Fig. (6.20). It would detect this condition over the full power factor range. An auxiliary time-lag must be provided to prevent operation by synchronizing surges and power oscillations following system disturbances.

The load coming on the machine under such conditions are very low of the order of 1% of the machine rating in case of steam sets and 25% in case of engine driven sets. However, in some cases such

a condition could be very harmful as in the case of steam turbine sets where steam acts as coolant, maintaining the turbine blades at a constant temperature and the failure of steam results in overheating due to

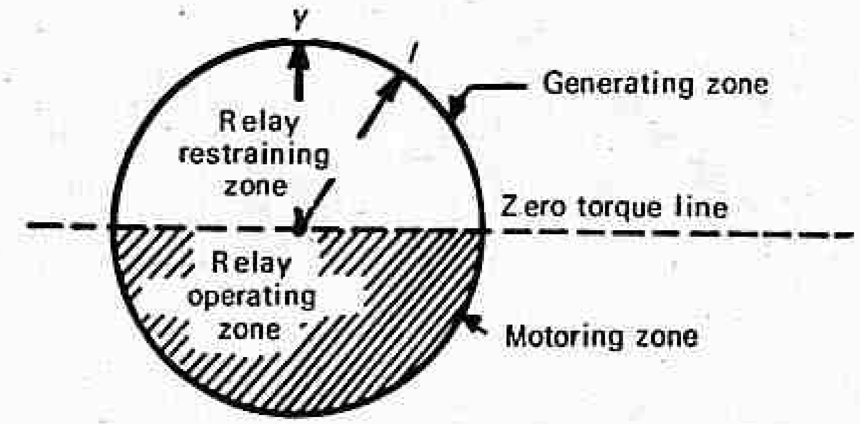


FIGURE 6.20 Reverse power relay operating characteristic.

friction with subsequent distortion of the turbine blades. Back pressure turbine sets and engine driven sets must be provided with reverse power protection. Whereas in condensing turbines the rate of temperature rise is low and such a protection is not necessary. Hydroelectric generators are generally fitted with mechanical devices to disconnect the generator from the system should the water flow drop to a value likely to cause cavitation.

Backup reverse-power protection may be provided in unattended stations by sensitive directional relays with low settings of about 2% of rated power in conjunction with timing relay.

6.3.8 Overspeed Protection

Steam sets which are controlled by fast acting gevernor gear respond rapidly to the initial speed rise in the event of load being suddenly lost, unlike hydraulic sets. Hence overspeed protection is more necessary in case of hydraulic sets, which is a reverse or underpower interlock relay to prevent the main generator circuit breaker being tripped under nonemergency conditions until the set output has dropped to a value low enough to prevent overspeed on loss of load. This is supplementary to the mechanical overspeed device which is usually in the form of centrifugally operated rings, mounted on the rotor shaft, which fly out and close the stop valves if the speed of the set increases more than 10%.

6.3.9 Overvoltage Protection

Overvoltage protection is provided on machines which are subjected to everspeed on loss of load. The protection is provided with an over-voltage relay. The relay is energized from a single-phase voltage transformer, and is usually of the induction pattern with an IDMT characteristics. The relay opens the main circuit breaker and the field switch if the over voltage persists.

6.3.10 Protective Scheme for a Direct Connected Generator

Direct connected generators are normally of smaller ratings and a typical scheme of protection for a 30 MW generator is shown in Fig. (6.21). It consists of the following protections:

(i) Unbiased differential protection.
(ii) Backup overcurrent protection.
(iii) Negative phase sequence protection.
(iv) Standby earth fault.

In addition to these protections the following may also be provided:

(i) Field failure protection.
(ii) Rotor earth-fault protection.
(iii) Reverse power protection (to be provided on back pressure turbine sets and engine driven sets).

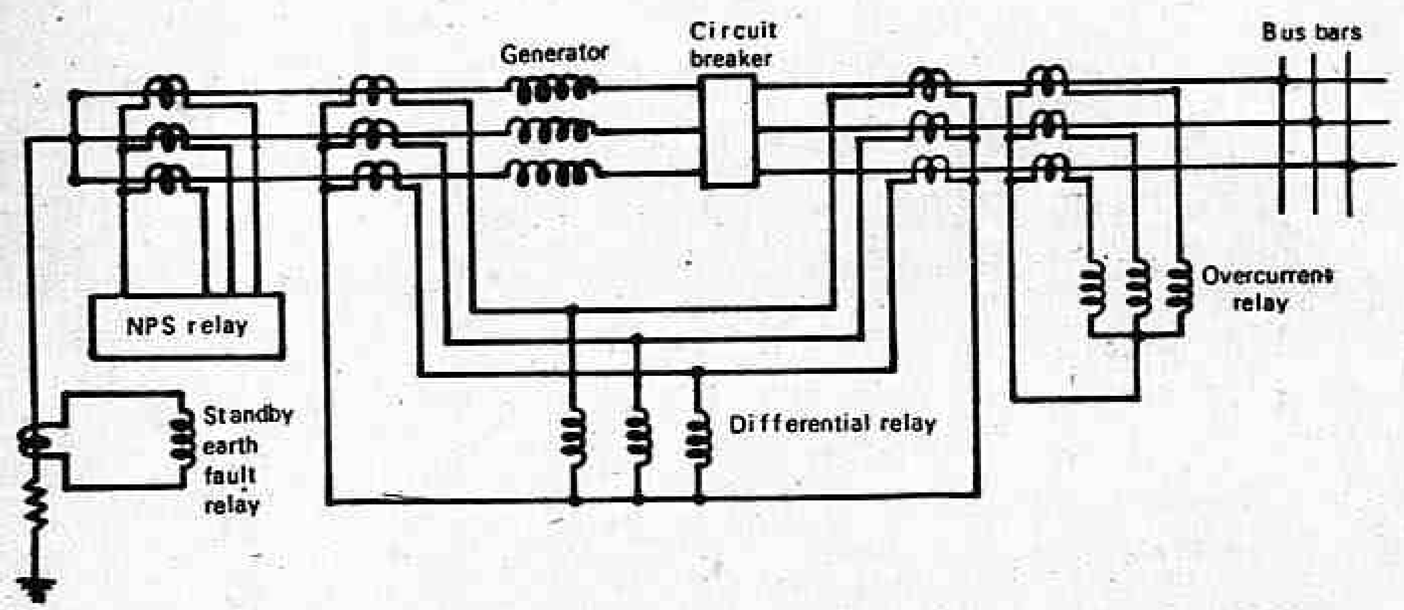


FIGURE 6.21 Typical protective scheme for a 30 MW direct connected generator.

6.3.11 Protection of Generator Transformer Units

In large high voltage systems generators are connected through step-up power transformers to the main transmission circuit. For supplying the generator auxiliaries a unit transformer is connected at the generator terminals.

It is usual to provide a common differential protection for both the generator and the step-up transformer and the intervening connections. This differential protection which covers a zone from generator neutral to the HV circuit breaker must take into account the phase shift and current transformation in the step-up transformer. Magnetizing inrush surges due to restoration of voltage on fault clearance, may cause unwanted operation of the protection scheme unless precautions are taken. Also the effective setting will differ depending on the position and type of fault, i.e. HV or LV phase or earth.

A typical overall differential protective scheme is shown in Fig. (6.22). A biased differential relay with a setting of 20% and a bias of 20% is generally satisfactory. This overall differential protection does not include the unit transmformer which has a separate differential protection.

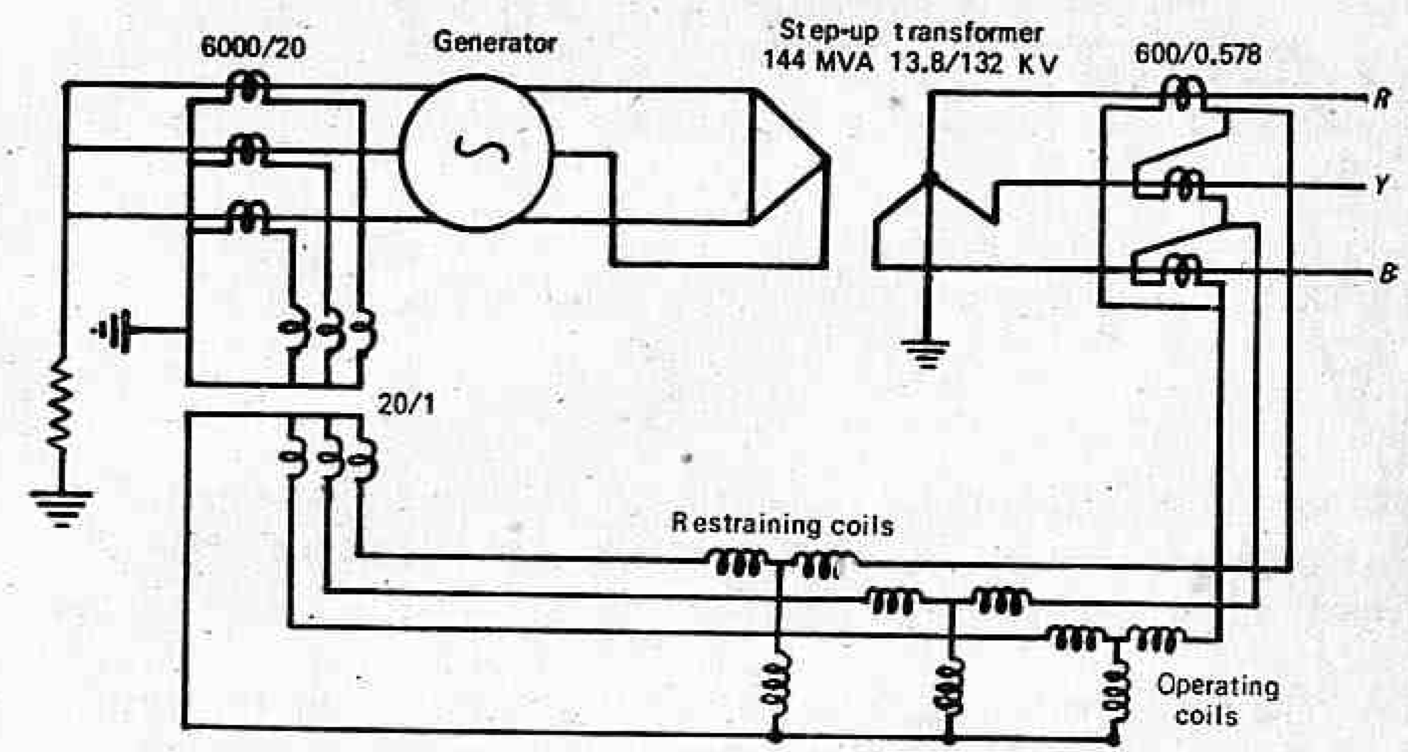


FIGURE 6.22 Generator-transformer overall biased differential protection.

For protection against earth-faults an earth-fault relay can be put in the generator neutral or in the secondary winding of the step-up transformer. The differential protection is ineffective against earth-faults in case the HV star side of the generator-transformer is resistance earthed and thus restricted earth-fault protection is provided. In case it is solidly earthed the differential protection is quite adequate, but still a separate restricted earth-fault protection of the instantaneous type is preferred and the differential protection under such a case acts as a backup protection to the restricted earth-fault protection. A scheme of restricted *E/F* protection along with the differential protection for a resistance earthed transformer on the HV side is shown in Fig. (6.23).

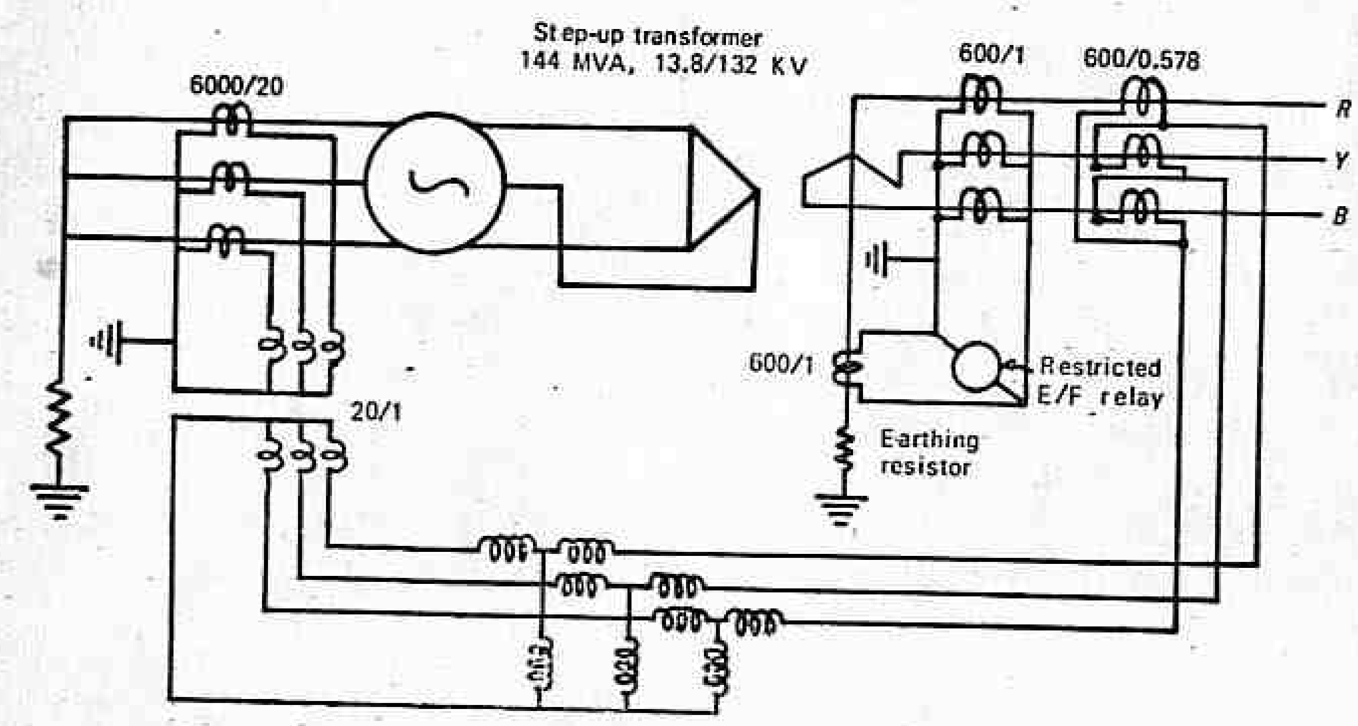


FIGURE 6.23 HV restricted earth-fault protection on generator-transformer units

The complete scheme of protection is shown in Fig. (6.24).

6.3.12 Relay Tripping Functions

The various systems have been described simply as means of operating the protective relays whose function is to energize a multicontact tripping relay, which in turn operates the following:

(a) The main circuit breaker to isolate the generator from the system.
(b) The neutral earthing switch, if any, to interrupt earth-fault current.
(c) The field switch to begin the decay of the generated voltage feeding the fault, in some cases by switching in a suppression resistor.
(d) An alarm relay.

Relays on the unit transformer LV side trip only the unit transformer, leaving the generator in service. The auxiliary protections energize the alarm relay.

6.4 Motor Protection

There is a wide range of motors in existence for various purposes. However, the fundamental problems affecting the choice of protection are independent of the type of motor and the type of load to which it is connected. The motors under discussion here are a.c. motors which include synchronous motors and induction motors.

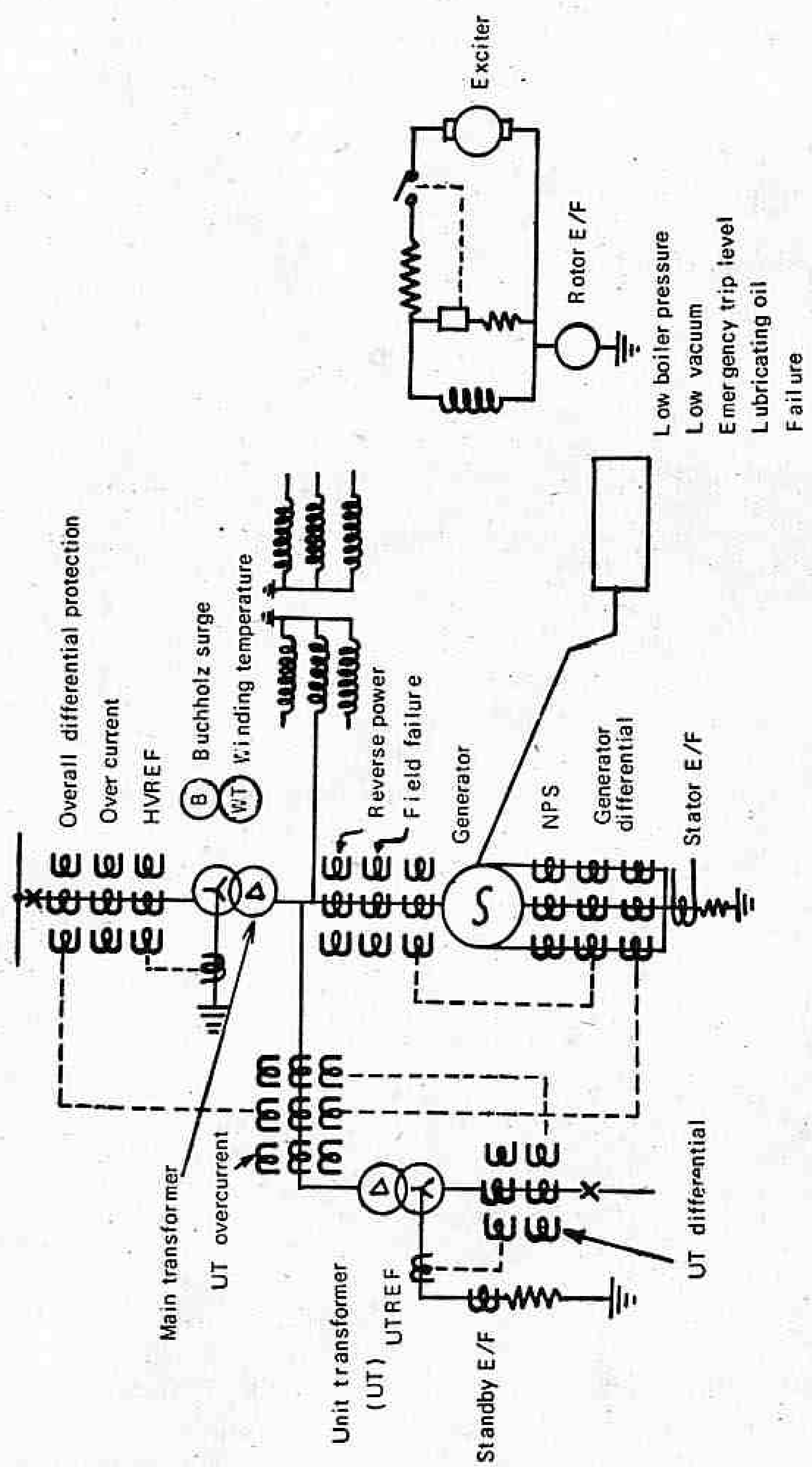


FIGURE 6.24 Protection of generator-transformer unit.

6.4.1 Types of Faults

Types of electrical faults in motors are similar to those of generators. Motors therefore in general are protected against the following faults:

(a) Stator faults.
(b) Rotor faults.
(c) Overloads.
(d) Unbalanced supply voltages including single phasing.
(e) Undervoltage.
(f) Reverse or open-phase starting.
(g) Loss of synchronism (in the case of synchronous motors only).

6.4.2 Stator Protection

The stator short circuits can be either to earth or between phases. The protection from these faults is provided with the help of thermal or dash, pot type overcurrent tripping devices giving an inverse time-current characteristic and usually providing instantaneous tripping at high current. Instantaneous overcurrent relays supplied from CTs are provided for motors of larger rating (usually more than 50 HP).

Phase-fault protection is provided by two high-set instantaneous relay elements; the setting is so chosen that it is well above the maximum starting current.

Earth-fault protection for a motor operating on an earthed neutral system is provided by means of a simple instantaneous relay having a setting of approximately 30% of the motor full load current in the residual circuit of three CTs. Operation of relay due to CT saturation during initial high starting current should be avoided. This is usually achieved by

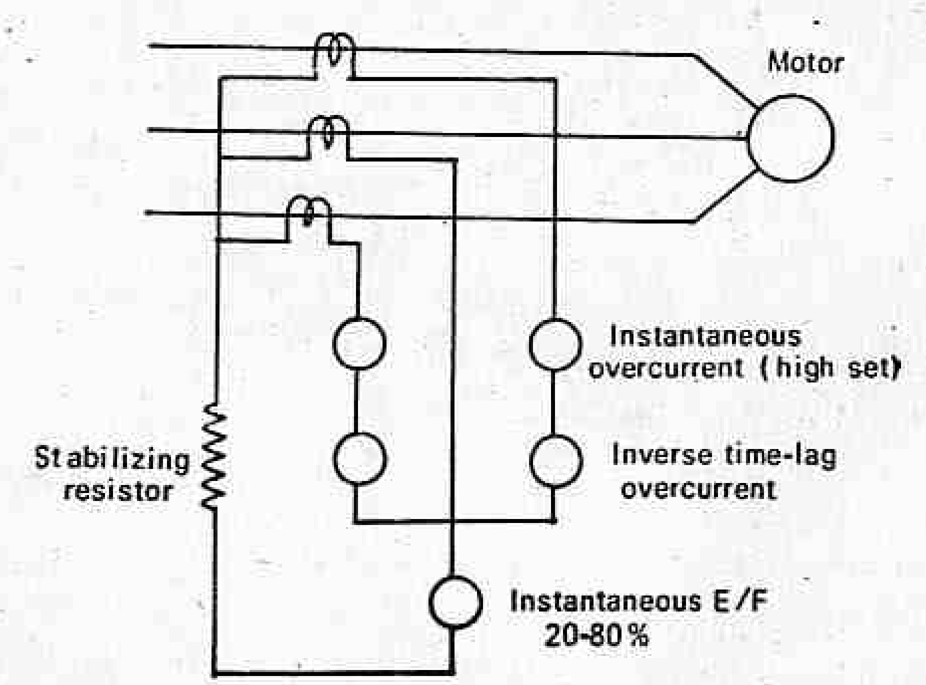


FIGURE 6.25 Induction motor-protection relay.

increasing the voltage setting of the relay by inserting a stabilizing resistance in series with it. Details of one such scheme applied to an induction motor is shown in Fig. (6.25). When a motor operates on an unearthed neutral system E/F relay as shown in Fig. (6.25) is of no use and a neutral displacement equipment has to be applied.

Differential protection is sometimes provided on very large and important motors in case of unearthed neutral systems.

6.4.3 Rotor Protection

Any form of unbalance either in the supply voltage or in the loading pattern will cause negative sequence currents to flow in the stator which will induce high frequency currents in the rotor. The frequency of these currents in the rotor is $(2-S)$ times the nominal frequency of supply. The rotor heating due to the positive sequence component of the stator current is proportional to d.c. resistance value while the heating effect on the rotor windings of the negative sequence component is proportional to $(2-S)f$ (approximately 100 Hz) a.c. resistance value. Obviously the heating effect of negative phase sequence current is greater than that of the positive phase sequence current. Motor protection therefore must take this into account if it is to decide correctly what load the motor can stand for a given degree of voltage unbalance without overheating. Types of protections provided for unbalanced voltages will be discussed subsequently. On wound rotor machines some degree of protection against faults in the rotor winding can be obtained by an instantaneous overcurrent relay measuring the stator current.

6.4.4 Overload Protection

The wide diversity of motor duties and motor designs makes it very difficult to cover all types and ratings of motor with a given characteristic curve. The overload protection is so designed that it matches as closely as possible the heating curve of majority of motors. The protection characteristic should lie just below the heating curve of the motor protected. The protection should preferably have adjustable characteristics so that it may be adopted to different designs of motors and different duties. The protection should not allow the motor to be restarted after tripping while the winding temperature is still high as this may have dangerous consequences. In order to be an effective safeguard an ideal protection should therefore not only match the heating characteristic of the motor but also its cooling characteristic. It must also be ensured that the relay must not operate under heavy starting currents up to say 6 times full load current which can last for a few seconds, half a minute or even longer in exceptional cases. The thermal time constant of most types of motors is of the order of 15 to 20 minutes, hence for protection from overloads the relay should have a time constant slightly lower than this.

When a motor stalls, a current equal to the starting current flows and serious damage results if it persists for a time longer than the starting time. Hence, the closer the characteristic of the overload relay matches the starting current curve the better is the motor protected against such damage.

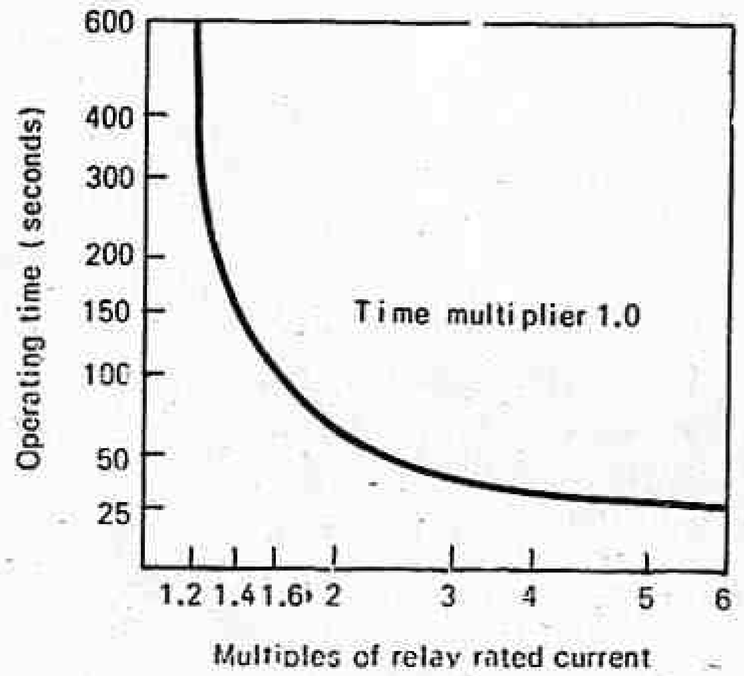


FIGURE 6.26 Operating time characteristic of IDMT relay induction type.

Induction overcurrent relays having characteristic of the type shown in Fig. (6.26) are best suited for such purposes. A typical setting required for overload protection is 120% of full load current. It can be seen from Fig. (6.26) that the current setting is 120% of full load, but a starting current of 6 times full load current for 30 seconds will not cause tripping. With the help of the time multiplier setting the operating time at high values of overcurrent can be adjusted to match the motor starting characteristic without changing the current setting.

One phase-connected relay element is sufficient for overload protection, but two provide single phasing protection as well.

6.4.5 Unbalance and Single Phasing Protection

The unbalanced three-phase supply causes negative sequence current to flow in the motor which is likely to cause overheating of the machine windings. Unbalanced loads or accidental opening of one phase of the supply (single phasing) depending on the load still keeps the motor running, although such a condition also causes the negative sequence current to flow in the motor.

As pointed out earlier for star connected motors, complete overload and single phasing protection can be provided by fitting two overload

elements (Fig. (6.25)). The characteristics of the overload elements are such that the motor is permitted to run with supply on two phases only until such time as there is a risk of thermal damage. For delta connected motors such an arrangement gives satisfactory protection when the motor is running with more than 70% of full load. For detecting the condition of single phasing a better scheme is to provide a phase-balance relay or bimetal relays as explained below.

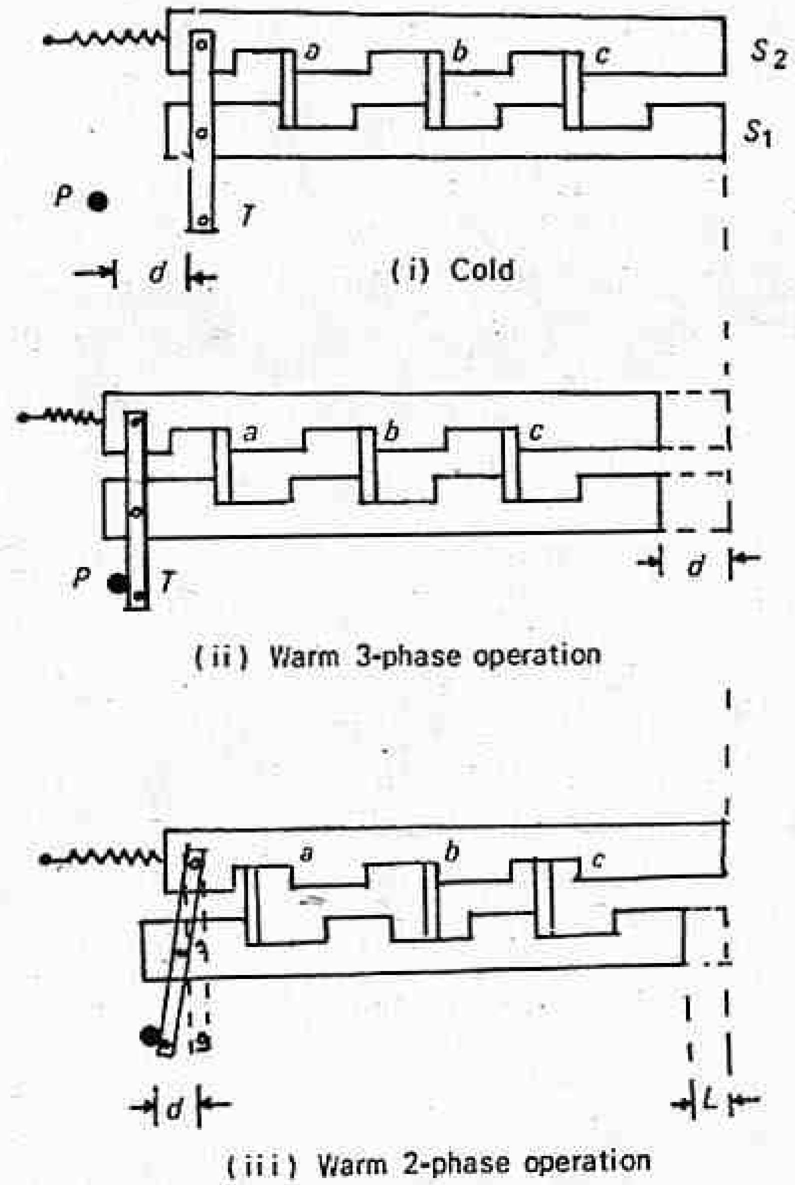


FIGURE 6.27 Bimetal relay with single phasing trip feature.

Figure (6.27) shows the bimetal relay having two slides S_1 and S_2 such that the slider S_1 is moved by the deflection of the bimetal strips, whereas the slider S_2 is kept in position due to nonbending of the bimetal strips. On symmetrical loading all the three bimetal strips *a*, *b* and *c* bend equally and both the sliders S_1 and S_2 move in the same direction by a distance *d* thereby initiating tripping (Fig. (6.27ii)). On single phasing only the two bimetal strips, say *a* and *c* bend whereas the third strip *b* remains cold. The slider S_1 is accordingly moved by the heated bimetal strips *a* and *c* whereas slider S_2 is kept in position by the cold strip *b*. Thus, this differential motion of the two sliders causes the tripping lever *T* to move the distance *d* required for initiating tripping. This operation is shown in

Fig. (6.27iii). It may be noted that although the movement of the slider S_1 is to the extent l which is less than d tripping is initiated. Thus, the bimetal relay accordingly responds earlier and protects the motor, also in the critical range of 40–60% when single phasing, which would have remained unprotected by a conventional overload relay.

Sometimes with more important and large motors thermal protection with thermistors is provided. When excessive heating occurs due to overloading or single phasing, the thermistors embedded in the stator causes the tripping as a result of change in the resistance.

Thermistors are small enough to be embedded inside and in direct contact with the motor and windings and they have good thermal response. Their use as temperature sensors, therefore eliminates the delay in transferring heat to actual sensing elements.

Figure (6.28) illustrates the block diagram of an overtemperature protective scheme for a three-phase direct-on-line start type squirrel cage

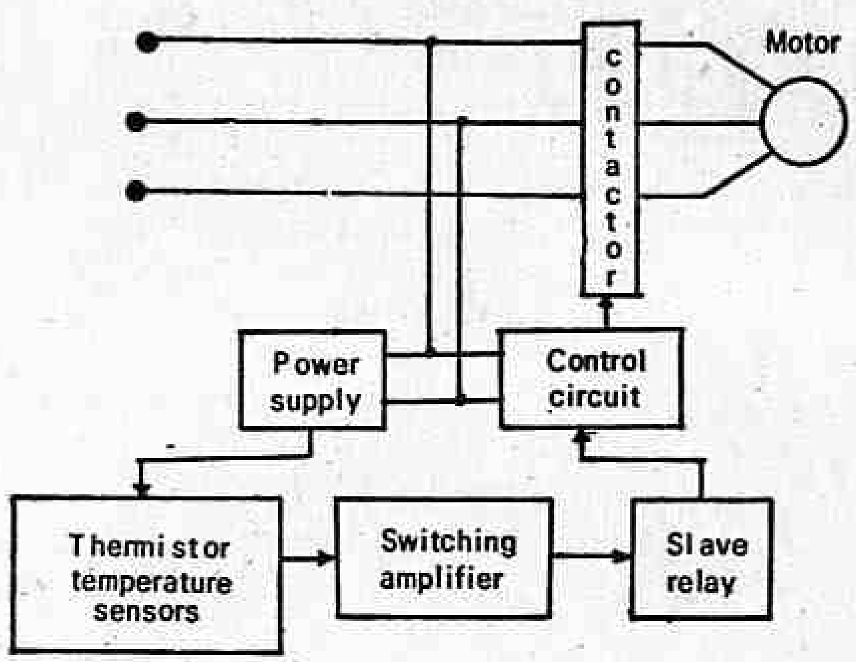


FIGURE 6.28 Temperature operated scheme.

induction motor. Three negative thermal coefficient (NTC) thermistors are located at the hot spots at the surfaces of the three stator winding phases (one on each phase) and are electrically connected into the temperature sensing circuit. The signal from the temperature sensing circuit is fed to a switching amplifier which causes a relay to operate when this signal equals or exceeds a preset level. A normally closed (*N/C*) contact of this relay is connected in the control circuit. During normal loads the signal from the temperature sensors is below the preset value and the relay is nonoperative. Its *N/C* contact keeps the control circuit energized and the contactor closed. When the temperature reaches the upper limit the signal from the temperature sensing circuit causes an output in the amplifier and the relay operates to open its contact. The control

circuit gets deenergized and the contactor opens to disconnect the motor from supply.

The scheme described above has many advantages such as:

(i) It can be used for motors of different ratings but of the same class of insulation.
(ii) The temperature at which the relay operates is adjustable.
(iii) An advance warning about the rising of temperature can be given if three additional thermistors, set to operate at a slightly lower temperature, are installed.
(iv) Protection is provided even if one or two of the three thermistors get overheated. Thus the scheme has an inherent capability of protection against single phasing.
(v) When the temperature of the motor winding and in consequence that of the thermistor has dropped to a low value the relay automatically resets and it is possible to restart it.

6.4.6 Under Voltage Protection

Operation of motor on undervoltage will generally cause overcurrent and thus can be protected by overload devices or temperature sensitive devices. However, a separate single-element undervoltage relay energized with phase-earth or phase-phase voltage can be provided to protect against a three-phase drop in voltage or an attempt to start with low voltage on all phases. A time delay is usually incorporated to prevent tripping by a transient voltage drop.

6.4.7 Reverse Phase Protection

The direction of rotation of the motor changes if the phase sequence is changed. In some motor applications this type of protection may become an essential feature of motor protection. An induction disc, polyphase voltage relay is used to protect motors from starting with one phase open or with reversed phase sequence. The connections of such a relay are shown in Fig. (6.29), its torque is proportional to the sine product of the two line-to-line voltages. The relay will not close its contacts and hence the motor will not start unless all the three phases are present and in the correct sequence.

6.4.8 Loss of Synchronism

A synchronous motor may pull out of step due to severe overload or due to reduction in supply voltage. Such a condition may be detected by a relay which responds to the change in power factor that occurs when there

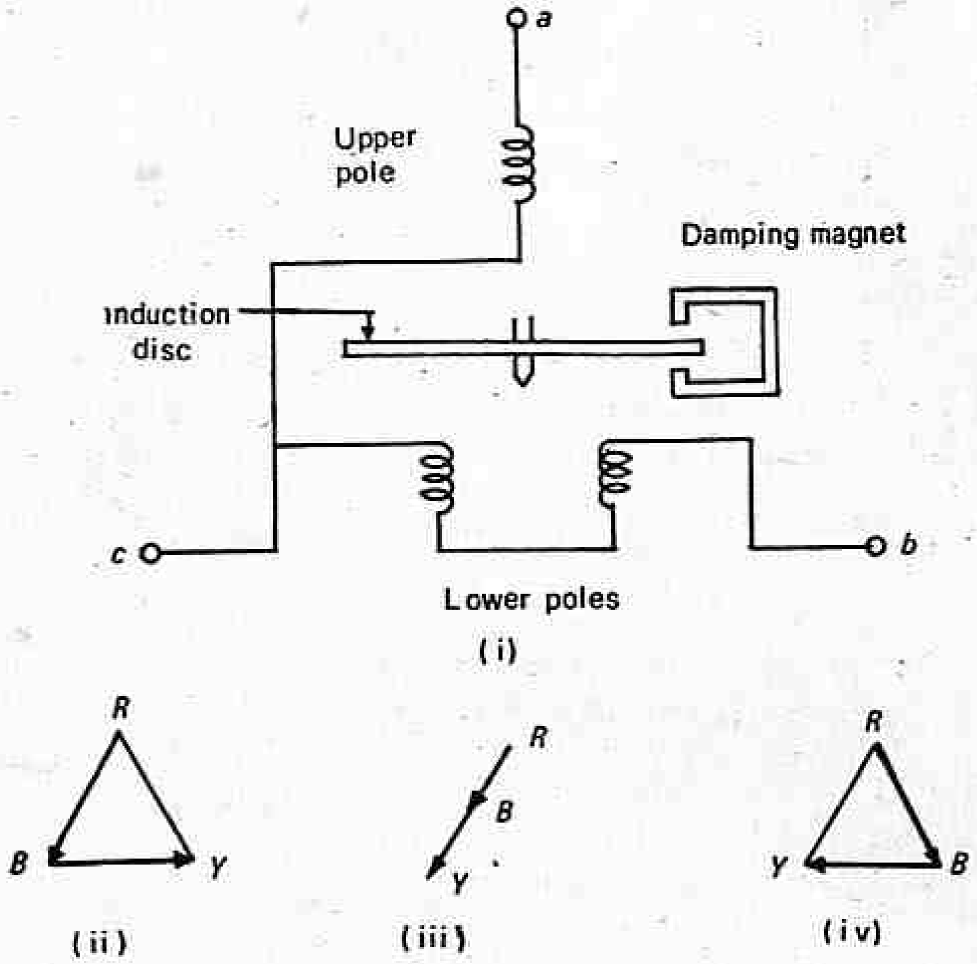


FIGURE 6.29 Open and reversed phase relay.

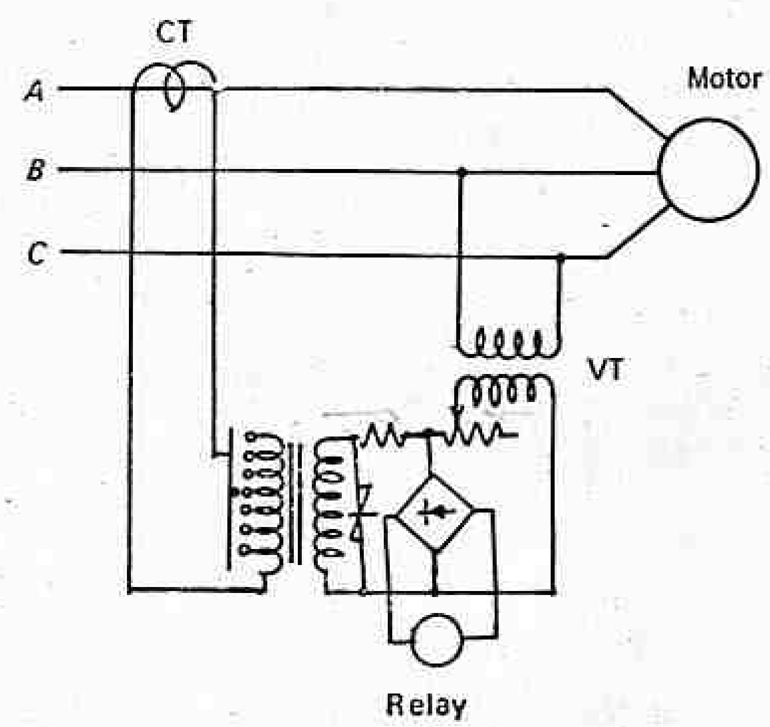


FIGURE 6.30 Out-of-step protection relay.

is pole slipping. One such typical circuit is shown in Fig. (6.30). The voltage between two phases is compared with the current in the third phase; an attracted armature relay energized from a full-wave rectifier bridge is differentially connected and is in the operated state so long as the motor is in synchronism (step). A nonlinear resistor protects the rectifiers and extends the operating range of the relay.

6.5 Bus Zone Protection

Bus zone protection includes, besides the bus itself the apparatus such as circuit breakers, disconnecting switches, instrument transformers and bus sectionalizing reactors, etc. Although bus zone faults are rare, experience shows that bus zone protection is highly desirable in large and important stations. Bus zone is more vulnerable to the effects of faults once it occurs for the folllowing reasons:

(i) Concentration of fault MVA increases risk of considerable damage.
(ii) Loss of bus zone would result in widespread supply interruption.

It is of utmost importance therefore that bus zone protection should be fast, stable and most reliable. Periodic testing is necessary to check the pickup of the relay on internal faults. It is the opinion of some experts that local bus protection should not be provided and the bus faults cleared by the backup relays at the neighbouring stations, as the provision of local bus protection would certainly increase the risk of inadvertent tripping.

Where local bus protection is provided care is taken by providing two independent protective circuits, both of which must be satisfied before tripping can occur.

6.5.1 Bus Zone Faults

Bus zone faults can generally be classified under one of the following headings.

(i) Failure of circuit breakers to interrupt fault current or failure to clear under through fault conditions.
(ii) Insulation failure due to material deterioration.
(iii) Flashover caused by prolonged and excessive overvoltages.
(iv) Errors in the operation and maintenance of switchgear.
(v) Foreign objects accidentally falling across bus bars.

The clearing of a bus fault requires the opening of all the circuits ultimate failure of the main transformer windings. The following can be considered as auxiliary equipment.

(i) *Transformer Oil.* Low oil is a dangerous condition in a transformer because live parts and the leads to bushings, etc. which have to be under oil, get exposed if the oil drops below the specified level. Oil level indicators with alarm contacts are available to give indication for immediate attention.

(ii) *Gas Cushion.* Deterioration of transformer oil and insulation is minimized if oxygen and moisture are excluded from the gas space. As the normal operating pressure within the tank varies rather widely, so sealing of the tank is not always recommended. A pressure vacuum gauge can be used on a sealed tank to provide a visual indication of pressure in the tank. Conservator tank is mounted on the main tank to take the expansion and contractions of the oil whereas silica gel is placed in the breathing vent to prevent moisture from entering. Sometimes a nitrogen cylinder is connected to the gas space, with regulating devices, to maintain the pressure between 0.5 and 0.8 atmosphere. This scheme maintains an inert atmosphere in spite of small leaks and provides some indication of presence of leaks by the rate of exhaustion of nitrogen in the cylinder. Alarm contacts can be provided in the system to indicate pressure inside the tank, above, or below predetermined limits.

(iii) *Oil Pumps and Forced Air Fans.* The top oil temperature normally gives indication of the load on the transformer. Increased oil temperature might be an indication of an overload or it might be due to a fault in the cooling system, such as failure of the oil pump or the blocking of a radiator valve, or nonoperation of fans. A thermometer with alarm contacts will indicate rise in the oil temperature due to any of these faults. An oil flow indicator is commonly used to indicate proper operation of oil pumps.

(iv) *Core and Winding Insulations.* Incipient faults may occur initially which may develop into major faults if not taken care of at the initial stages. Insulation failure may develop because of the following:

(a) The insulation of the laminations and core bolts may be of poor quality or has been damaged accidently during erection.
(b) The insulation between the windings, between winding and the core, and the conductor insulation may be of poor quality; may have been damaged mechanically; may be brittle because of ageing or overloading.
(c) Badly made joints or connections.

These incipient faults need not be attended to immediately and as such do not cause any interruption to the supply service, but must be taken care of as soon as possible. Gas actuated relays described later in this chapter provide indication alarms for incipient faults.

6.2.3 Winding Faults

Electrical faults which cause immediate serious damage and are detected by unbalance current or voltage may be divided into the following classes:

(i) Faults between adjacent turns or parts of coils such as phase-to-phase faults on the HV and LV external terminals or on the windings itself or shortcircuits between turns of HV and LV windings.
(ii) Faults to ground or across complete windings such as phase-to-earth faults on the HV and LV external terminals or on the windings.

A short circuit between turns can start with a point contact resulting from mechanical forces or insulation deterioration due to excessive overload or a loose connection, breakdown of transformer insulation by an impulse voltage. The puncture of the turn insulation by an impulse is supposed to cause a path of destruction, through which the normal frequency voltage can maintain an arc. However, if the turn voltage is insufficient to maintain the arc it will be quenched by the oil at the first current zero.

Faults to ground, or across a large part of the winding will result in large values of fault currents as well as the emitting of large amounts of gas due to the decomposition of oil. This type of fault is not difficult to detect, but rapid clearance of fault is essential to avoid excessive damage and to maintain system stability.

6.2.4 Overloads and External Short Circuits

Overloads can be sustained for long periods, being limited only by the permitted temperature rise in the windings and cooling medium. Excessive overloading will result in deterioration of insulation and subsequent failure. It is usual to monitor the winding and oil temperature conditions and an alarm is initiated when the permitted temperature limits are exceeded. External short circuits may only be limited by the transformer reactance and where this is low fault currents may be excessive.

6.2.5 Differential Protection of Transformers

Differential protection is the most important type of protection used for branching from the faulted bus or bus section (except circuits having no backfeed).

6.5.2 Bus Backup Protection

When no separate bus protection is provided but distance protection i provided for the feeders connected to the bus, it is possible to cover th bus bars within zone 2 reach of the distance relays. It may however b noted that for small switchgear installations such a scheme may be quit satisfactory, whereas for large and important installations a separate bu zone protection may be provided.

Bus backup protection may also mean that in case the breaker fails to operate for a fault on the feeder then it must be regarded as a bus fault It should then open all other breakers on that bus. Such a backup can be provided with appropriate time delay through a timer.

6.5.3 Differential Schemes of Bus Bar Protection

It is based on simple circulating current principle that during normal load conditions or external fault conditions the sum of currents entering a bus equals the sum of those leaving. If the sum of these currents (for a given conductor) is not zero, it must be due to a short circuit either a ground fault or a phase-to-phase fault. Hence differential schemes can be applied for both these type of faults, the essential difference in the schemes being the method of connecting the CTs.

A simple differential protection of a bus section is shown in Fig. (6.31). A current in the relay indicates a fault within the protected region and initiates opening of the generator breaker and each of the line breakers.

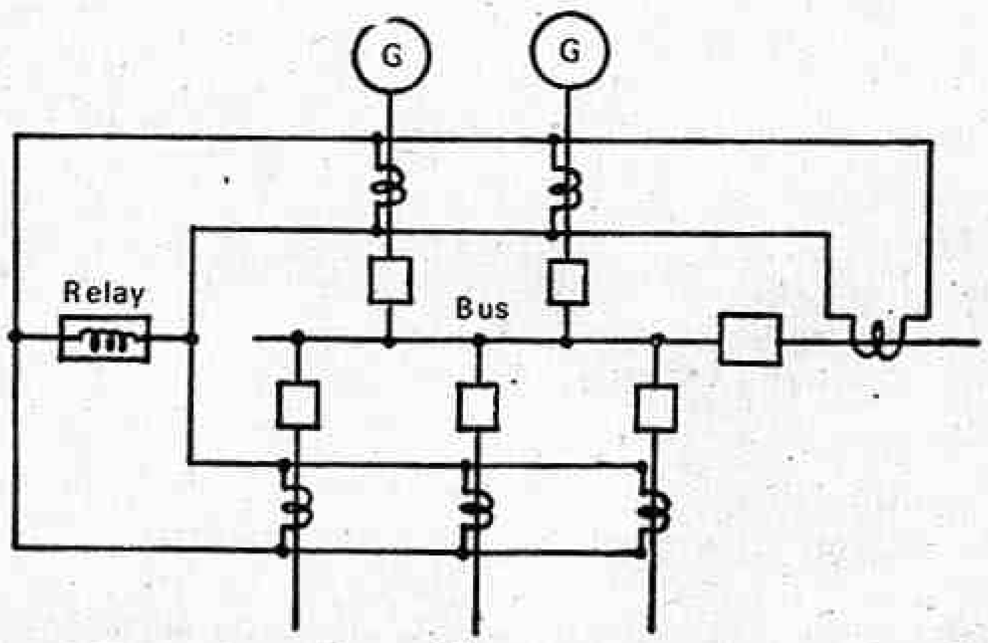


FIGURE 6.31 Differential protection of a bus section.

The main drawback with this type of differential protection is the difference in the magnetic conditions of the iron cored CTs which may result in false operation of the relay at the time of an external fault. Even with identical CTs having large iron cores to avoid the saturation with maximum fault currents the d.c. transient component presents difficulty because of its slow decay. Biasing of differential relays improves the stability considerably but is not a complete solution.

It can be seen that a high impedance bus differential relay can iscriminate between internal and external faults better than the usual low-mpedance relay. In other words, the ratio of the relay current during an nternal fault to relay current during an external fault is greater if the npedance of the relay is higher.

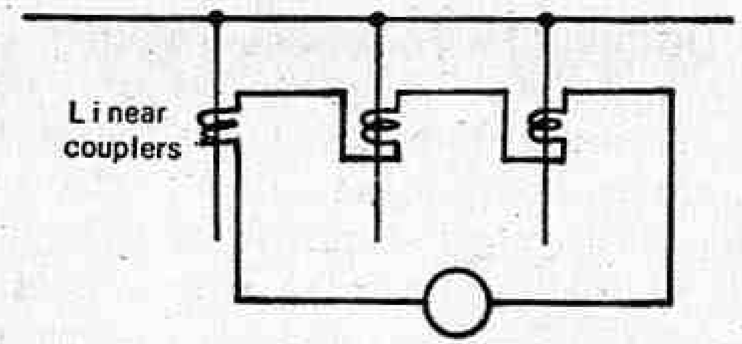


FIGURE 6.32 Linear coupler scheme.

A special type of CT having no iron core also known as the linear oupler is sometimes employed to overcome the difficulties of an iron cored T. In the case of a linear coupler the secondary voltage is proportional the primary current, and the secondary windings of all couplers on the me bus section are connected in series to the relay as shown in Fig. (6.32). he sum of their voltage outputs is equal to the vector sum of the voltages the circuits connected to the bus bars. Under normal and external ult conditions the voltages add up to zero, whereas for an internal fault ere is a resultant voltage in the secondary circuit and the relay operates.

6.5.4 Frame Leakage Protection

It is possible to design a station so that the faults which develop are mostly earth faults, by providing earthed metal barrier surrounding each conductor in the bus structure. With this arrangement every fault that might occur must involve a connection between a conductor and an earthed metal part. A somewhat less certain arrangement may be obtained in open construction by making spacing between adjacent conductors great compared to spacing over insulators to earth. Again faults that occur will almost certainly be from a conductor to supporting structure.

In each of the preceding cases the metal supporting structure also

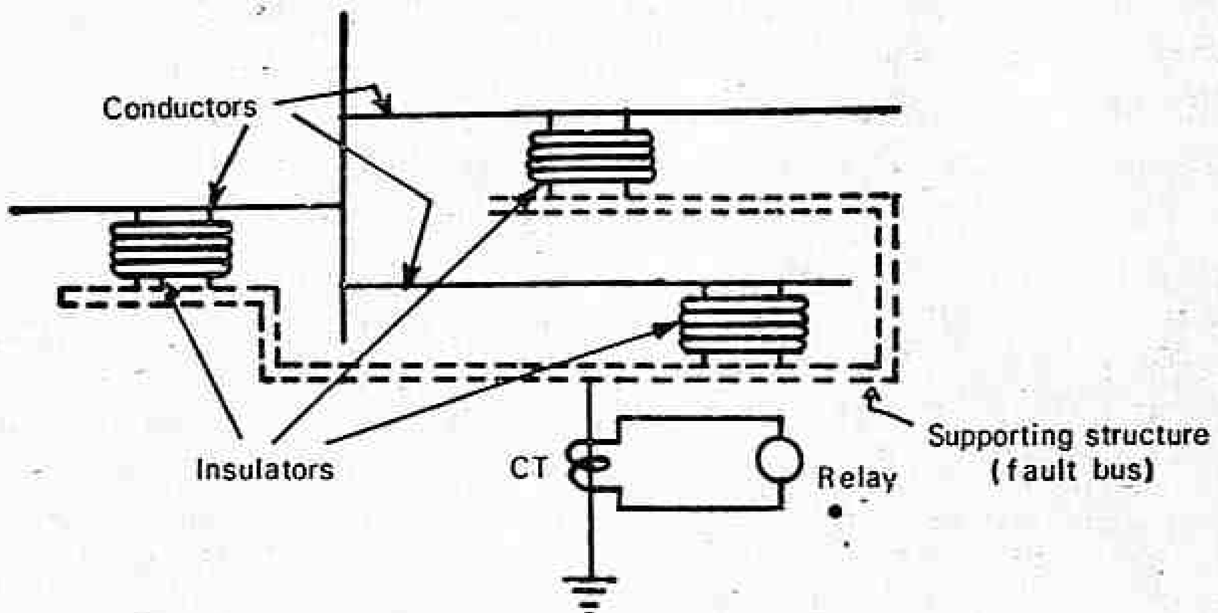


FIGURE 6.33 Frame leakage protection.

known as fault bus is earthed through a CT as shown in Fig. (6.33). A fault involving a connection between a conductor and the earth, i.e. supporting structure, will result in current flow through this CT and actuation of the relay connected to its secondary. Operation of this relay will result in tripping all breakers connecting equipment to the bus. Sometimes an impedance Z is connected in the earthing connection to limit the value of the short circuit current during line to earth fault.

The value of the neutral earthing resistor and the amount of winding to be protected determines the relay fault setting. The usual practice is to protect 80-85% of alternator or transformer winding against earth fault. The remaining 15-20% from neutral end is left unprotected. It can be seen in Fig. (6.34) for phase-to earth-fault that the setting required

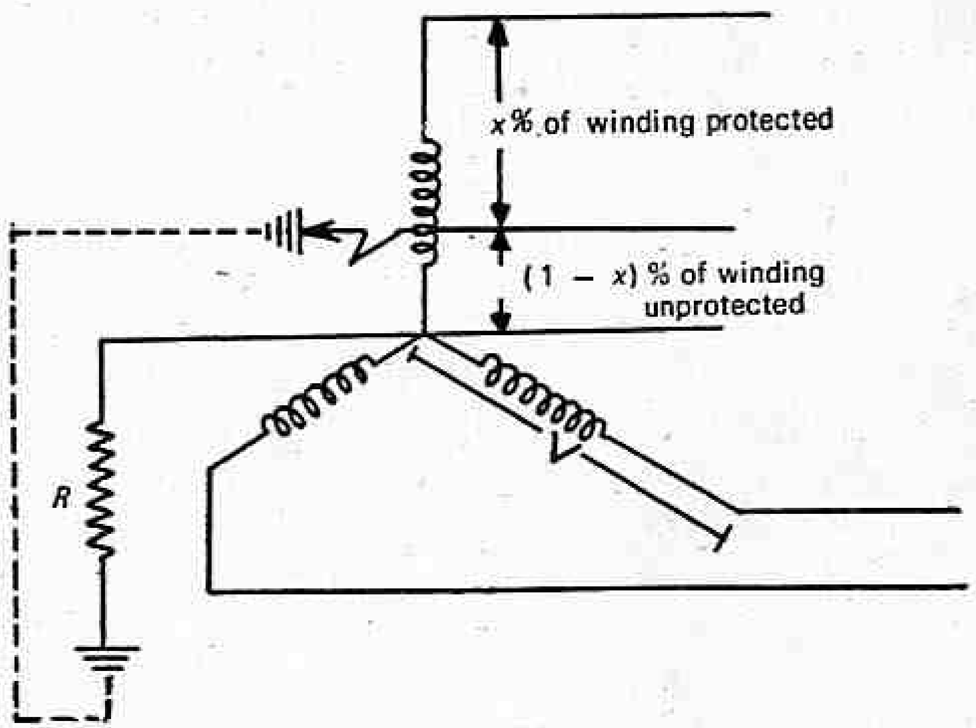


FIGURE 6.34 Percentage of unprotected winding against phase to earth-fault.

from the differential protection is determined by the value of the neutral earthing resistor and also by the amount of winding to be protected. The earth-fault current I_F is given by

$$I_F=(1-x)\frac{V}{R}$$

This must be equal to the primary fault setting of the differential protection I_S for minimum operating current.

Thus $$I_S=(1-x)\frac{V}{R} \text{ and } I_R=\frac{V}{R}$$

Hence $$x=\left(1-\frac{I_S}{I_R}\right)$$

where I_S=Primary fault setting current.
I_R=Earthing resistor current setting.
R=Earthing resistance.

or % of winding unprotected $(1-x)=\frac{I_S}{I_R}\times 100$

$$=\frac{I_S\cdot R}{V}\times 100$$

EXAMPLE 6.1

A star connected three-phase 15 MVA 6.6 KV alternator is protected by circulating current equipment, the star point being earthed via a resistor R. Plot a curve to a base of current up to 150% of full-load current through R showing the percentage of winding protected for an earth-fault setting of 20%. Find the value of earthing resistor if 85% of the winding is to be protected.

Solution. A fault setting of 20% means that, if a terminal fault has its current limited to the full load rating then 20% of the winding from the neutral end will be unprotected. Now for different values of currents through R under terminal fault conditions by simple proportion it is possible to find the percentages of winding protected. This is shown in a tabular form in Table 6.2 for a 20% setting. Thus the curve can also be drawn as shown in Fig. (6.35).

Table 6.2 *Effect of earthing resistance on the winding protected*

% of full load current through R for a terminal fault	*% of winding unprotected*	*% of winding protected*
20	100	0
40	50	50
60	33.33	66.66
80	25	75
100	20	80
120	16.66	83.33
150	13.33	86.66

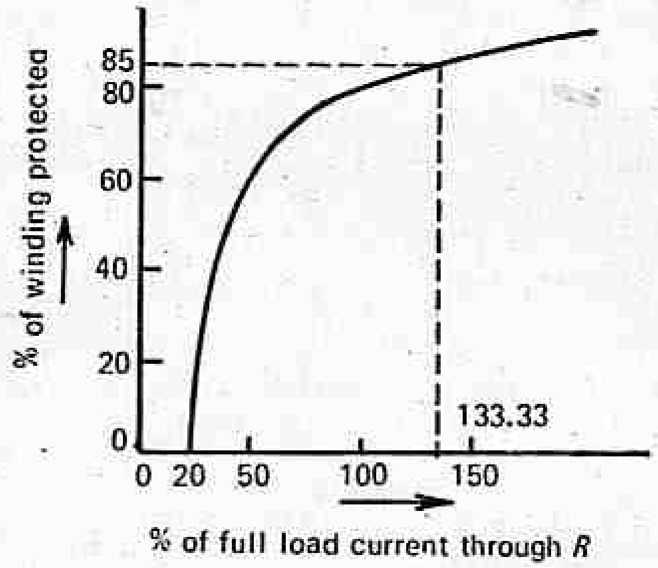


FIGURE 6.35 Earth-fault setting characteristics.

For protecting 85% of the winding the current through R comes out to be 133.33%.

$$\text{Full-load current} = \frac{15\times10^6}{\sqrt{3}\times6.6\times10^3} = 1310\text{ A}$$

Now $$1-x = \frac{I_S\cdot R}{V}\times100$$

or $$15 = \frac{0.2\times1310\times R}{6600/\sqrt{3}}\times100$$

or $$R = \frac{15\times6600}{\sqrt{3}\times0.2\times1310\times100} = 2.2\text{ ohms}$$

EXAMPLE 6.2

The neutral point of a three-phase 20 MVA, 11 KV alternator is earthed through a resistance of 5 ohms, the relay is set to operate when there is an out of balance current of 1.5 A. The CTs have a ratio of 1000/5.

What percentage of winding is protected against an earth fault and what should be the minimum value of earthing resistance to protect 90% of the winding.

Solution. The primary CT current for relay operation $=1.5\times\frac{1000}{5}=300\text{A}$

Hence $$I_S = 300\text{ A}$$

$\therefore$ % of winding unprotected $$= \frac{I_S\cdot R}{V}\times100 = \frac{300\times5\times\sqrt{3}}{11000}\times100 = 23.6\%$$

$\therefore$ % of winding protected $= 100-23.6 = 76.4\%$

Resistance required for protecting 90% of the winding is given by

$$10 = \frac{I_S R\times100}{V}$$

or $$R = \frac{10\times11000}{\sqrt{3}\times300\times100} = 2.12\text{ ohms}$$

EXAMPLE 6.3

A three-phase transformer having a line voltage ratio of 400 V/33,000 V is connected in star-delta. The CTs on the 400 V side have a current ratio of 1000/5. What must be the ratio of CTs on the 33,000 V side.

Solution. Figure (6.36) shows the connections of CTs. Suppose that the line current on the primary side of the transformer I_{L1} is 1000 A, then the line current on the secondary side I_{L2} can be found by the equation.

$$\sqrt{3}\times400\times1000 = \sqrt{3}\times33{,}000\times I_{L2}$$

or $$I_{L2} = \frac{400\times1000}{33000} = \frac{400}{33}\text{ A}$$

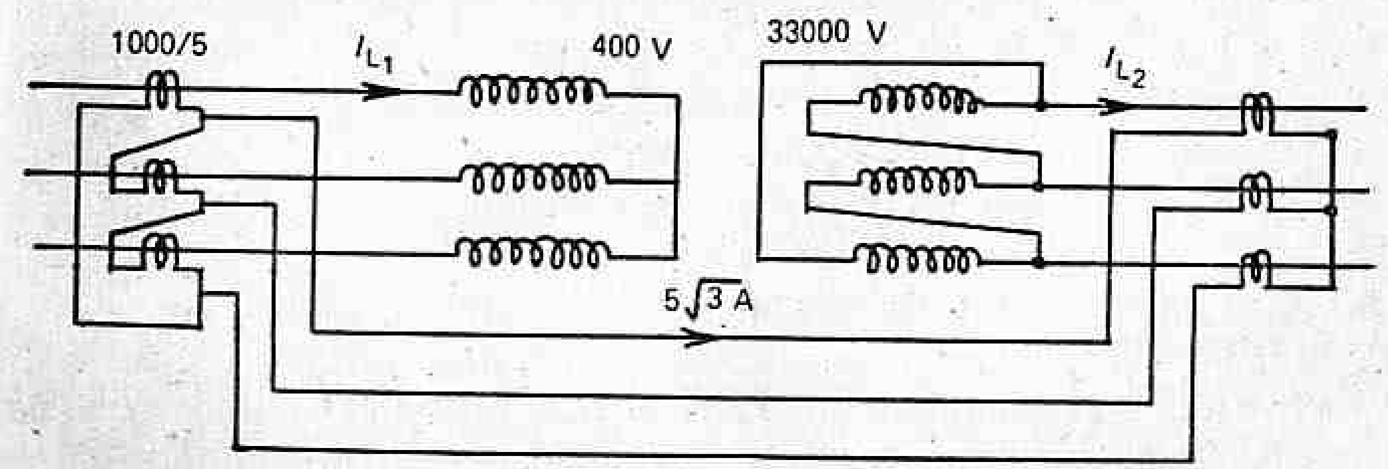


FIGURE 6.36

The current through the secondary of the CT on the primary side will be 5 A. The CTs on the primary side being delta connected, the current through its pilot wire will be $5\sqrt{3}$ A. The CTs on the secondary side being star connected will have a current of $5\sqrt{3}$ A in the secondary therefore.

$$\text{Hence CT ratio on the 33000 V side} = \frac{400}{33\times 5\sqrt{3}}$$
$$=7/5$$

QUESTIONS

1. Describe the principle of Merz Price System of protection applied to a power transformer. What are the shortcomings of this scheme and how are they overcome?
2. Describe the protection scheme for internal faults in a three-phase delta/star connected power transformer. Draw a neat sketch and explain clearly why the CTs are to be connected in a particular fashion only.
3. Explain the effect of inrush magnetizing current on the protective system of transformers. Why does desensitizing of relay not provide satisfactory protection to the transformer? What is the principle of harmonic restraint?
4. (a) Describe a Buchholz relay and discuss its merits and drawbacks.
   (b) Discuss what special factors are to be taken into account while designing the protection of a large star/delta transformer.
5. What are the abnormal conditions in a large synchronous generator against which protection is necessary?
   Draw neatly the differential protection scheme of an alternator. Discuss its limitations and suggest remedies to overcome them.
6. Why restricted earth-fault protection is provided to alternators though it does not provide protection against earth-fault to the complete winding. What is the justification of providing this protection?
7. (a) Explain how the inclusion of a resistance in the neutral earthing circuit of an alternator affects the performance of the differential protection of the three-phase stator.
   (b) Describe how protection is provided in large turbo-alternators against earth-fault in the rotor.
8. What is restricted earth-fault protection for generators?
   A 500 KVA, 6.6 KV star connected alternator has a synchronous reactance of 2.0 ohms per phase and negligible resistance. The differential relay operates if the out-of-balance current through it exceeds 30% of the normal full-load current of the alternator. If the star point of the alternator is earthed through a resistance of 6.5 ohms what per cent of the stator winding is left unprotected? Show that the effect of the alternator reactance can be neglected. (2.24%)

9. Calculate the required value of neutral resistance for a three-phase 11 KV alternator, so as to protect 70% of the winding against earth-fault by a relay with pickup current of 1A. The neutral CT has a ratio of 250/5. (38 ohms)
10. Describe the protection of the stator windings of a three-phase alternator against turn-to-turn faults.
11. What are the types of faults that are likely to occur in a three-phase induction motor?
    If a motor is not fully loaded, is it necessary to provide protection against single phasing? Explain why.
12. Distinguish between overload protection and short circuit protection of a motor.
13. Give a scheme of protection for a large three-phase induction motor.
14. Discuss the considerations which determine the need for bus bar protection.
15. Describe the method of protecting bus bars by differential relaying. What are the limitations of this method and to what extent these can be overcome?
16. Describe a simple method of bus bar earth-fault protection applicable to metal-clad switchboards on a distribution system.

internal phase-to-phase and phase-to-earth faults and is generally applied to transformers having ratings of 5 MVA and above. The principle of a differential relay is well understood and discussed in an earlier chapter. Any deviation from the normal ratio of the current intensities, at the input and output ends, must of necessity be caused by a fault in the protected part, so that the unbalance current can be employed directly for tripping and indicating the fault. For this reason current differential protection combines highest selectivity with the lowest tripping time.

The differential protection of transformer is also known as *Merz-Price protection* for the transformer. Figure (6.1) shows an ordinary differential protection for a three-phase star-delta power transformer. In a star-delta transformer, the load currents in the two windings are not in direct phase opposition, but are displaced by 30° and to allow for this the CT secondaries are connected in delta on the star side and in star on the delta side.

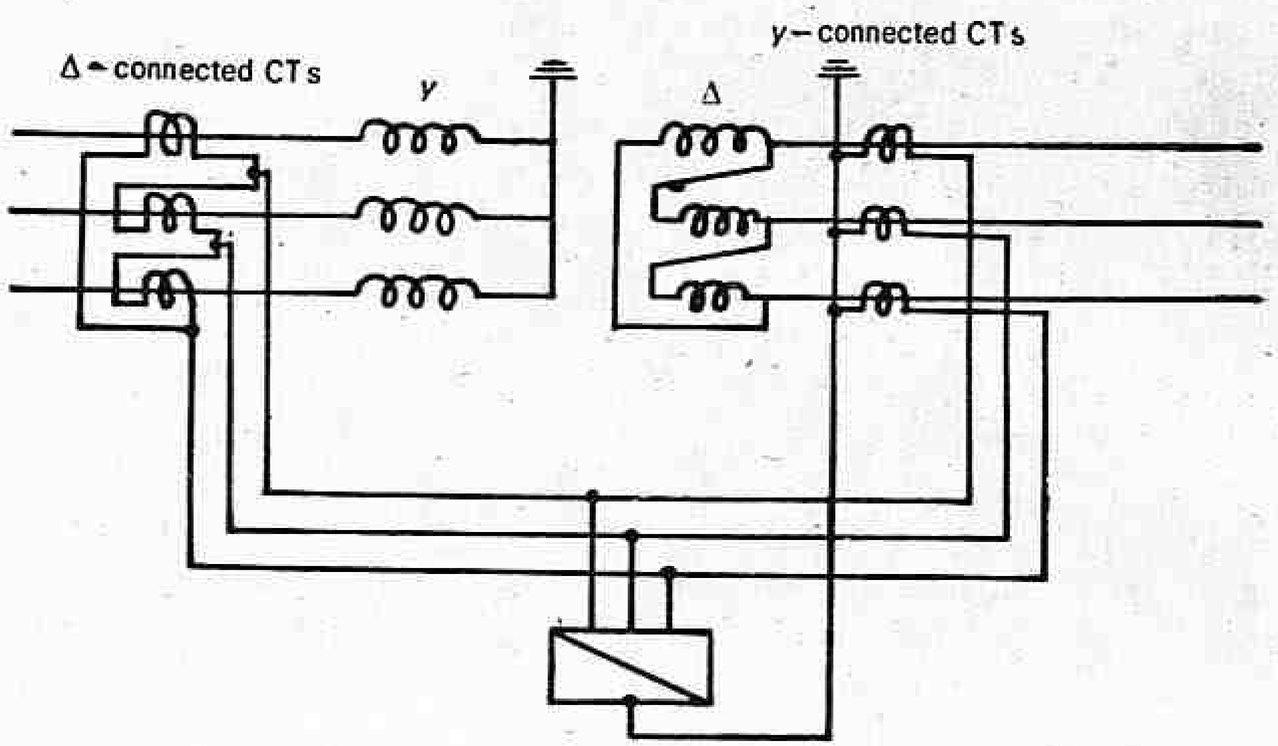


FIGURE 6.1 Differential protection for a Y-Δ power transformer.

6.2.6 Problems Encountered in Differential Protection of Transformer

The differential scheme described suffers from the following drawbacks:

(i) Unmatched characteristics of CTs.
(ii) Ratio change as a result of tapping.
(iii) Magnetizing inrush current.

CT Characteristics. Unless saturation is avoided, the difference in CT characteristics due to different ratios being required in circuits of different voltages may cause appreciable difference in the respective secondary currents

whenever through-faults occur. This trouble is aggravated in the case of transformers due to unequal ratio CTs being employed on either side of the protected transformer. A source of ratio error which results in circulating currents under through-fault condition is the unequal burden imposed on the CTs due to unequal lead lengths.

Ratio Change as a Result of Tapping. Tap changing equipment is a common feature of a power transformer which effectively alters the turns ratio. Compensating for this effect by varying the tappings on differential-protection CTs is impracticable. Biased or percentage differential relays ensure stability with the amount of unbalance occurring at the extremities of the tap-change range. Biased relays are better suited to the overall protection of variable-ratio transformers.

Magnetizing Inrush Current. When the transformer is energized, the transient inrush of magnetizing current flowing into the transformer may be as great as ten times full-load current and it decays relatively slowly. This is bound to operate the differential protection of the transformer falsely. The magnitude of the magnetizing inrush current is a function of the permanent flux trapped in the transformer core and the instant on the voltage cycle when it is switched on.

There are a number of ways of ensuring immunity from operation by magnetizing surges. Firstly, the relay may be given a setting higher than the maximum inrush current; secondly, the time setting may be made long enough for the magnetizing current to fall to a value below the primary operating current before the relay operates. These simple remedies are incompatible with high speed and low primary operating current. In the third method the harmonic content of the current flowing in the operating circuit is filtered out and passed through a restraining coil.

6.2.7 Percentage or Biased Differential Relays

In order to avoid undesirable operation on heavy external faults due to CT errors and ratio change as a result of tap changing, a restraining winding is provided which is energized by the through current. In other words the operating winding is biased and operates by some percentage of the through current then the relay becomes more sensitive at low current without tripping for external fault. Under these conditions and if the restraining and operating magnets are similar with the ratio of turns as T, the criterion for operation for a static comparator is:

$$\left|\frac{I_1-I_2}{T}\right| > \left|\frac{I_1+I_2}{2}\right|$$

and for an electromagnetic comparator

$$\left|\frac{I_1-I_2}{T}\right|^2 > \left|\frac{I_1+I_2}{2}\right|^2$$

Value of T is usually 0.05 for generators and 0.1–0.4 for tansformers, the higher values being used if the transformer ratio is varied by a tap changer.

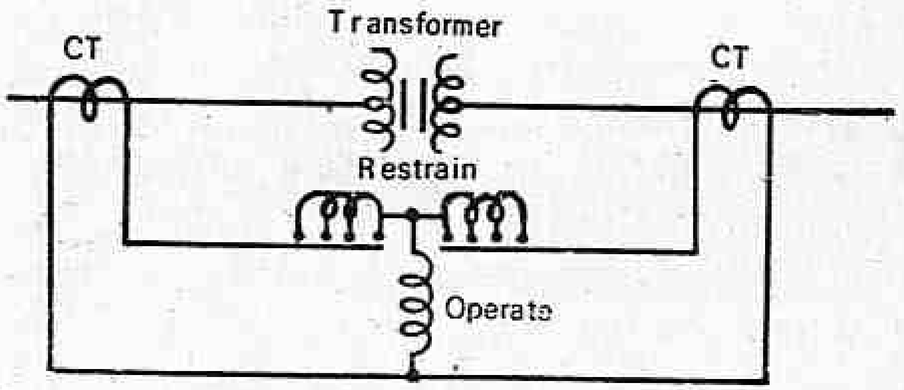


FIGURE 6.2 Biased differential protection for a transformer.

Figure (6.2) shows the single line diagram of the biased differential scheme for the transformer. Bias is adjustable by tappings on the restraining winding and setting by spring restraint typical values are 10 to 40% for bias and 50 to 100% for setting. The time characteristics of induction relays are such that magnetizing inrush currents do not cause operation. Figure (6.3) shows the bias characteristic for a typical relay.

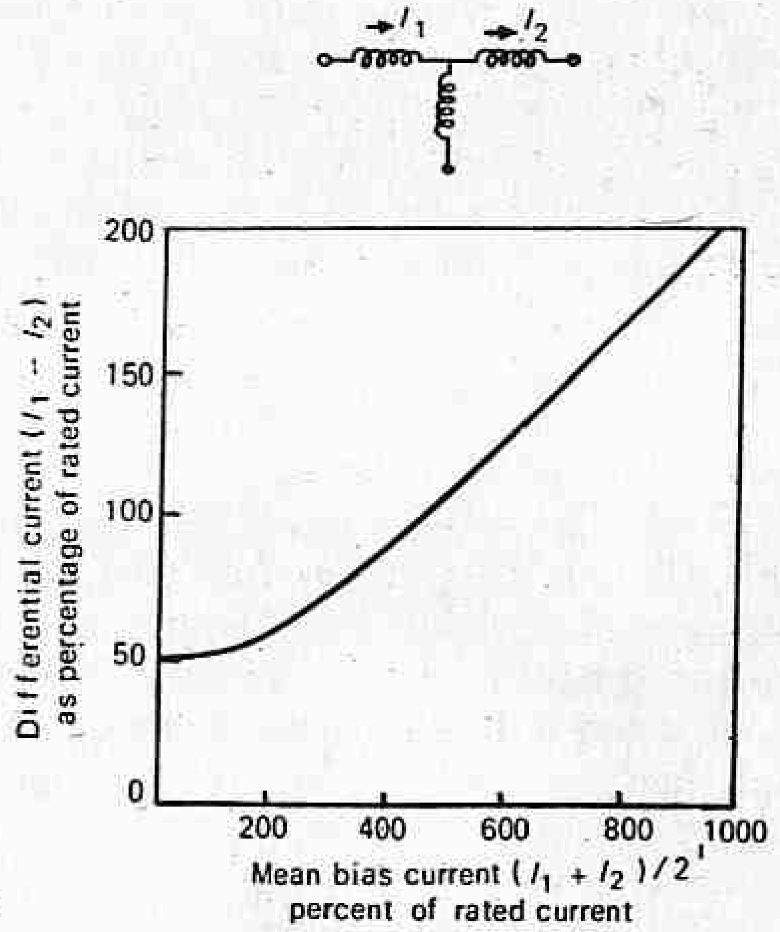


FIGURE 6.3 Bias characteristic of biased differential relay for transfomer protection. Setting 50% and bias 20%.

6.2.8 Methods for Preventing Operation on Inrush Currents

Magnetizing inrush currents contain pronounced harmonics but the current during internal fault conditions is sinusoidal. Advantage is taken of this fact in the design of the relay. It was pointed out earlier that for high speed and low primary operating current the harmonic content of the current is filtered and employed for restraint. Following are some of the methods.

(i) *Even Harmonic Cancellation.* For a typical waveform the harmonics as a percentage of the fundamental wave are given in Table 6.1.

Table 6.1 *Amplitudes of the harmonics in a typical wave shape of magnetizing inrush current*

Component	*Fundamental*	*D.C.*	*2nd*	*3rd*	*Harmonics* *4th*	*5th*	*6th*	*7th*
Typical value percent	100	55	63	26.8	5.1	4.1	3.5	2.5

In this method the 3rd harmonic and its multiples do not appear in the CT leads since these components circulate in the delta winding of the transformer and the delta connected CTs on the star side of the transformer. The d.c. components and the even harmonics can be cancelled out in the operating circuit of the rectifier bridge relay and employed for restraint. The 5th and 7th harmonics are small in magnitude and thus can be ignored.

(ii) *Harmonic Restraint.* This is a very popular method of making the differential relays immune to magnetizing inrush currents. Figure (6.4) shows the basic circuit of harmonic restraint relay. The restraint coil is energized by a d.c. proportional to bias winding current as well as the d.c. due to harmonics. Harmonic restraint is obtained from the tuned circuit $X_C X_L$ which permits only currents of fundamental frequency to enter the operating circuit. The d.c. and higher harmonics (mostly 2nd) are diverted into the rectifier bridge feeding the restraining coil. The relay is adjusted so that it will not operate when the harmonic current (restraining) exceeds 15% of the fundamental current (operating). Both the d.c. and higher harmonics are of large magnitude during magnetizing inrush.

The harmonic restraint feature may result in the failure of the relay to operate on an internal fault if considerable harmonics are present. These harmonics may be present in the fault current itself due to an arc, or the current transformer may saturate and produce harmonics. Also, if a fault exists at the time a transformer is energized, harmonics in the magnetizing current may prevent it from tripping. For this purpose it is customary to

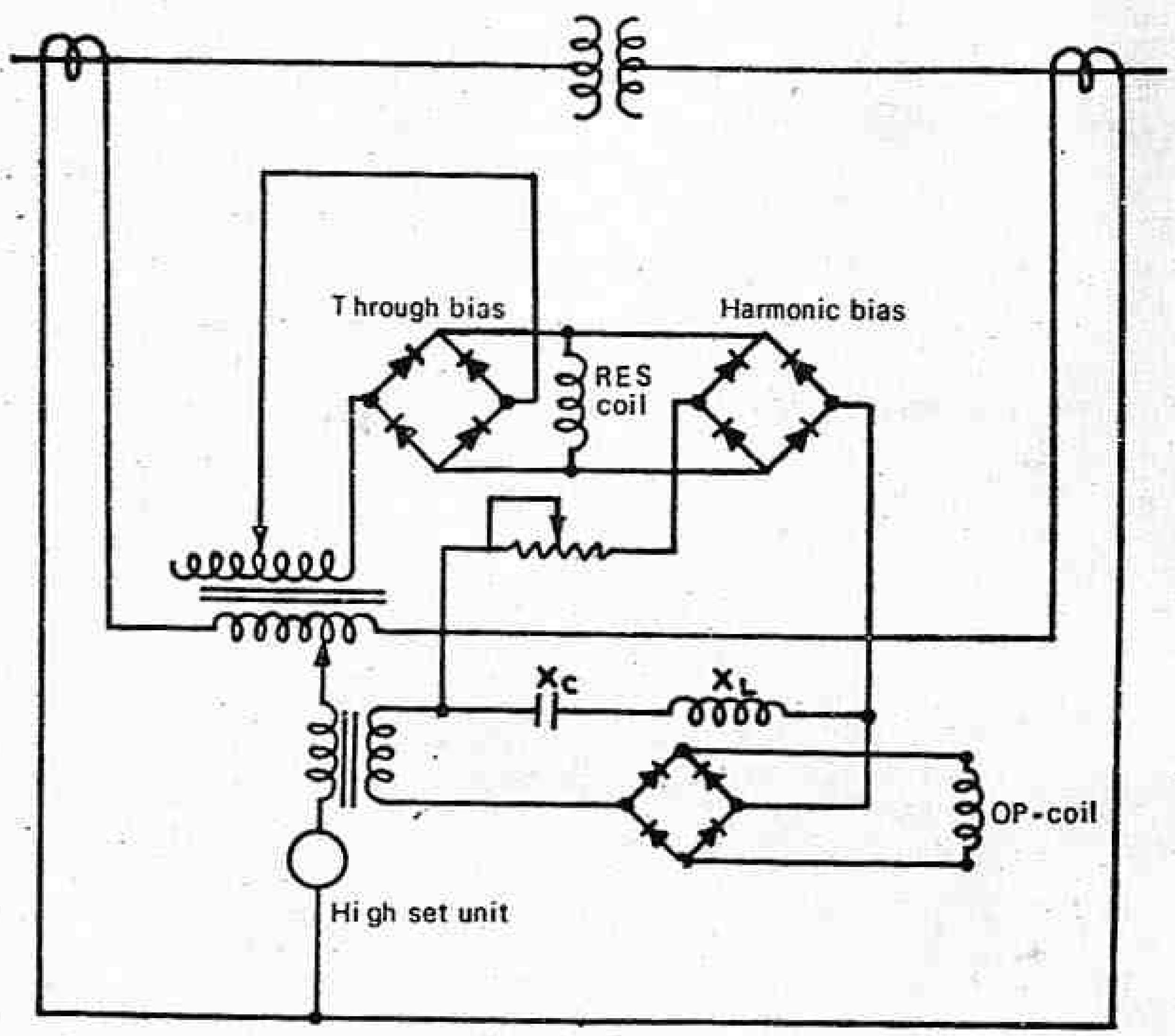


FIGURE 6.4 Basic circuit of harmonic restraint relay.

provide an instantaneous overcurrent relay in the differential circuit which is set above the maximum inrush current but will operate in less than one cycle on internal faults. In this way fast tripping is assured for all internal faults.

6.2.9 Influence of Winding Connections and Earthing on Earth Fault Current

The magnitude of earth-fault current for a given fault position within a winding depends upon the winding connections and the method of neutral earthing. The two conditions for earth-fault current to flow in the case of a winding fault to earth are:

(a) That a path exists for current to flow into and out of the winding.
(b) That ampere-turns balance is maintained between the windings.

From (a) above obviously it is not necessary for the winding itself to be earthed for fault current to flow, only that the system connected to the winding is earthed. The delta side of a transformer is usually earthed through an earthing transformer.

6.2.10 Star Winding with Resistance Earthed Neutral

The earth-fault current in this case depends on the value of earthing resistor and is proportional to the distance of the fault from the neutral end of the winding. Considering the case of a delta-star transformer, neutral earthed through a resistor on the secondary side; for a 1:1 voltage ratio the primary to secondary turn ratio is $\sqrt{3}$:1. For an earth fault (I_F) at 100% of the winding on the secondary side the corresponding value on the primary side is $1/\sqrt{3}$ times the fault current on the secondary $(1/\sqrt{3})\, I_F$. Now as the fault position on the secondary side varies, the effective ratio of transformation between the primary and the faulted portion of the secondary winding also varies. Hence for an earth fault at $x\%$ of the winding on the secondary side $[(x/100)\, I_F]$ the corresponding current on the primary side will be $(x/100)^2 I_F/\sqrt{3}$ as the effective turn ratio of primary to secondary now is $\sqrt{3} : x/100$. Thus the primary fault current is proportional to the square of the percentage of winding short-circuited. The variation of fault current both in the primary and the secondary windings is shown

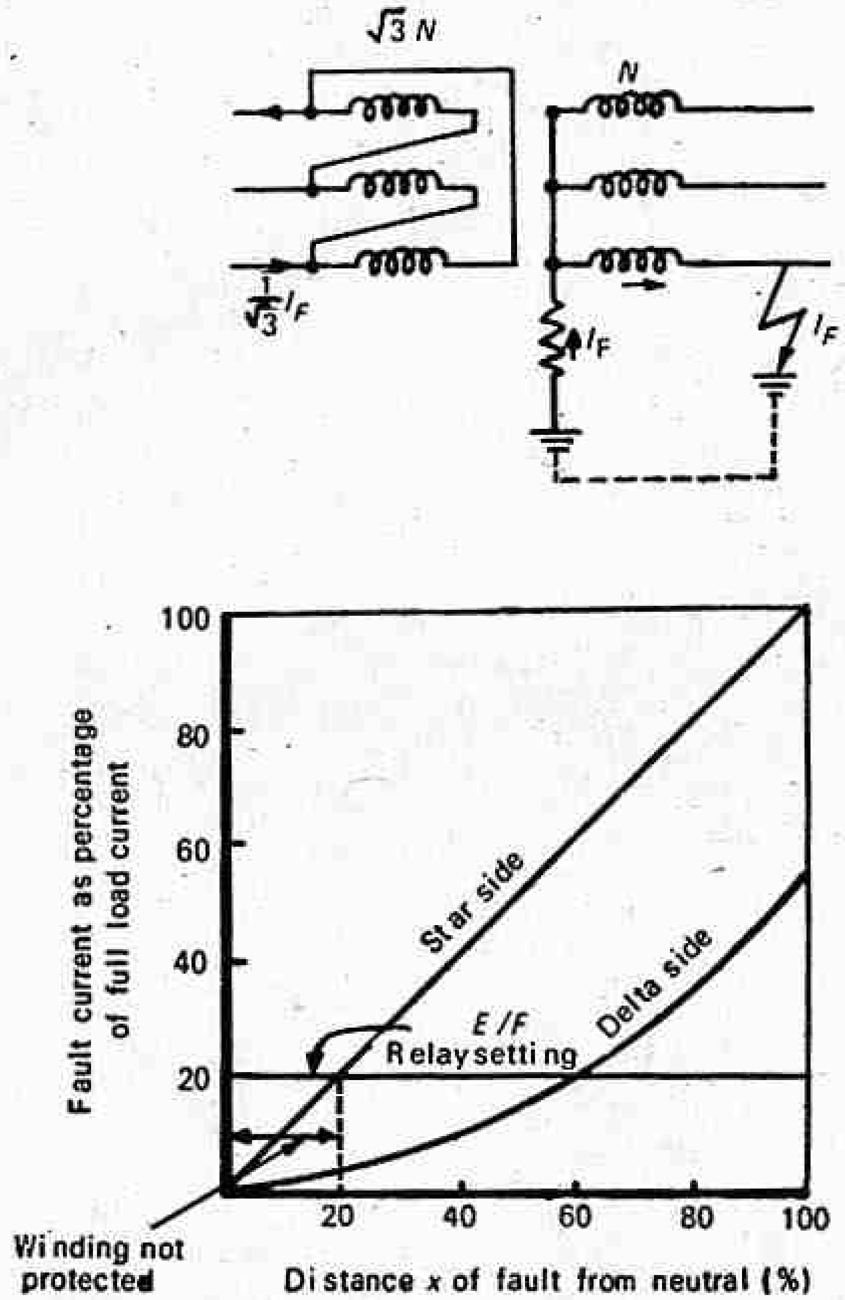


FIGURE 6.5 Transformer earth fault for resistance-earthed star winding.

in Fig. (6.5) for a 1:1 voltage ratio, the resistor is assumed to pass full-load current of the transformer with rated line-neutral voltage.

6.2.11 Star Winding with Neutral Solidly Earthed

The earth-fault current is limited solely by the winding impedance and the fault current is no longer proportional to the position of the fault. The leakage reactance of the faulted winding in terms of reactance per turn increases the nearer the fault is to the star point, but the reactance of the other winding is effectively reduced owing to the change in transformation ratio so that the fault current reaches a minimum at some point near the middle of the winding. Figure (6.6) shows the transformer earth-fault current on a solidly earthed star winding.

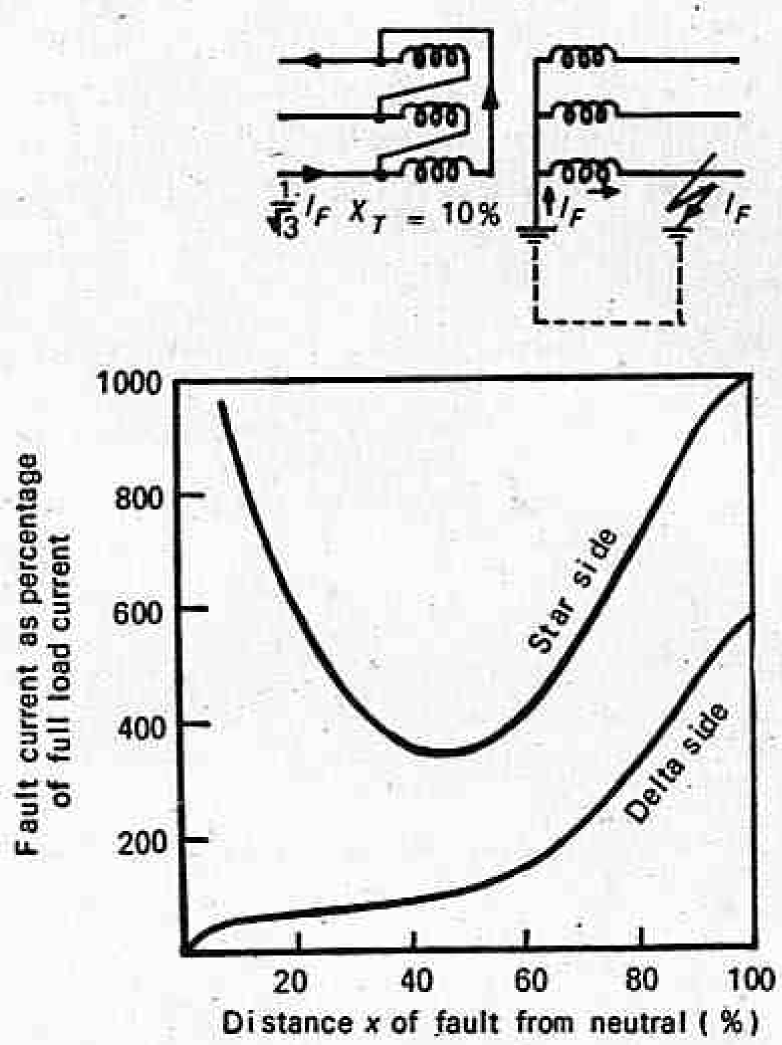


FIGURE 6.6 Transformer earth fault for solidly-earthed star winding.

6.2.12 Delta Winding

The minimum voltage on the delta winding is only half the phase-to-earth voltage and occurs on the midpoint of phase. The high leakage reactance 25 to 50% at midpoint gives fault currents with a solidly-earthed system of 100 to 200% of full load; this divides equally between two phases. If the system is resistance earthed the resistance R should be added vectorially to the high reactance in determining the minimum earth-fault

current. However, if the resistor is rated to pass currents of the order of the full-load current of the transformer at rated phase-neutral voltage V the minimum current can be expressed as $V/2R$ for all practical purposes.

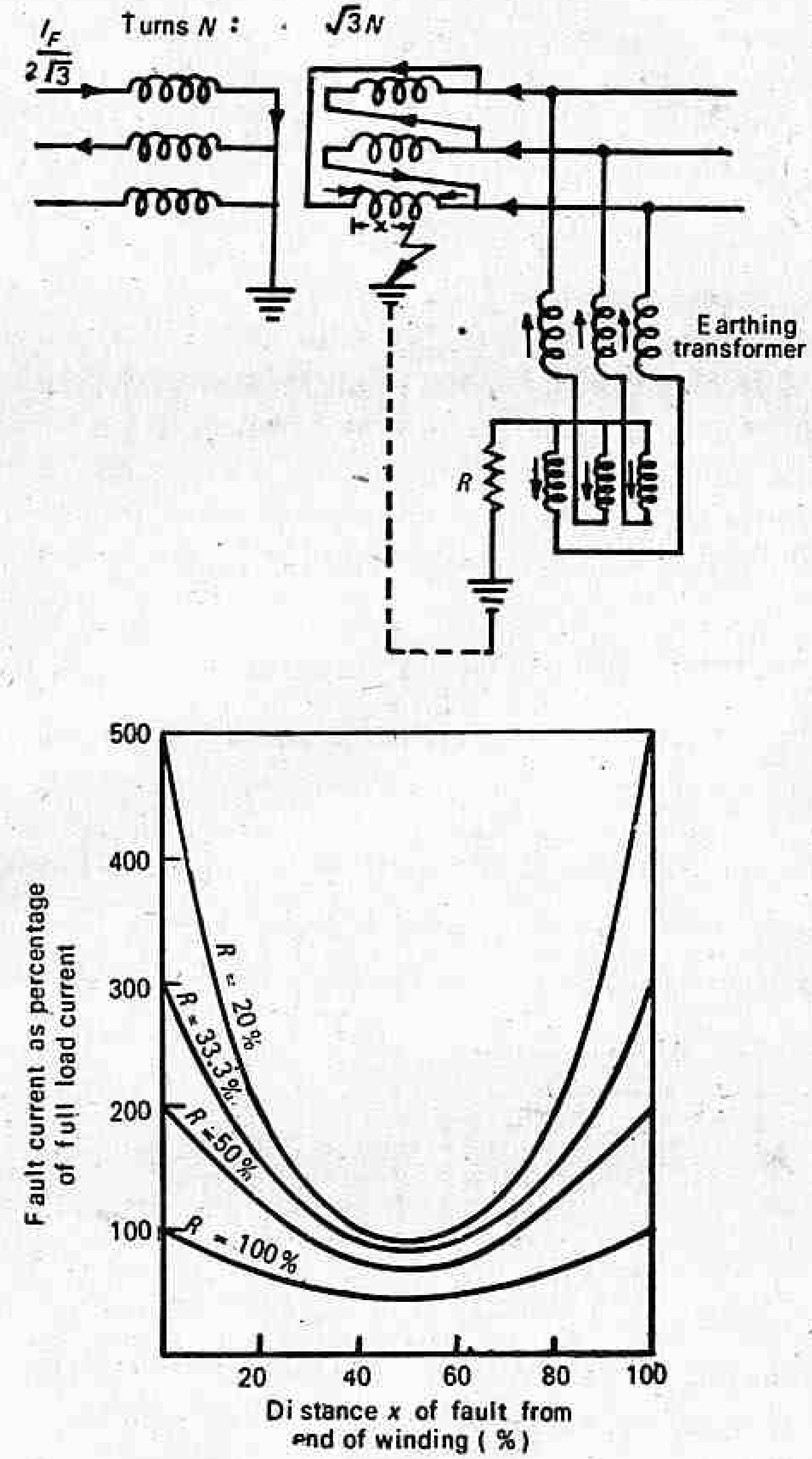


FIGURE 6.7 Transformer earth-fault for delta winding system, system resistance earthed.

6.2.13 Overcurrent and Earth-Fault (Unrestricted)

Overcurrent and earth-fault protection using IDMT relays is used mainly to protect the transformer against the effects of external short circuits and excess overloads. This protection however acts as a backup protection for the transformer with settings properly chosen. The current settings must be above the permitted sustained overload allowance and below the minimum short circuit current. Extremely inverse characteristic is the ideal as it closely resembles the thermal curve of transformer. Also the time setting may have to be high in order to grade with other overcurrent relays on the system. The protection is located on the supply side of the transformer and is arranged to trip both the HV and LV circuit breakers.

6.2.14 Tank Leakage Protection

If the transformer tank is lightly insulated from earth (an insulation resistance of 10 ohms) earth-fault protection can be achieved by connecting a relay to the secondary of a CT the primary of which is connected between the transformer tank and earth. Such an arrangement is usually necessary where banked transformers are provided with a single overall differential protection and it is difficult to find as to which transformer is faulty. This scheme is similar to the frame leakage bus bar protection scheme.

6.2.15 Restricted Earth-Fault Protection

This type of protection is provided to detect earth-faults within the protected

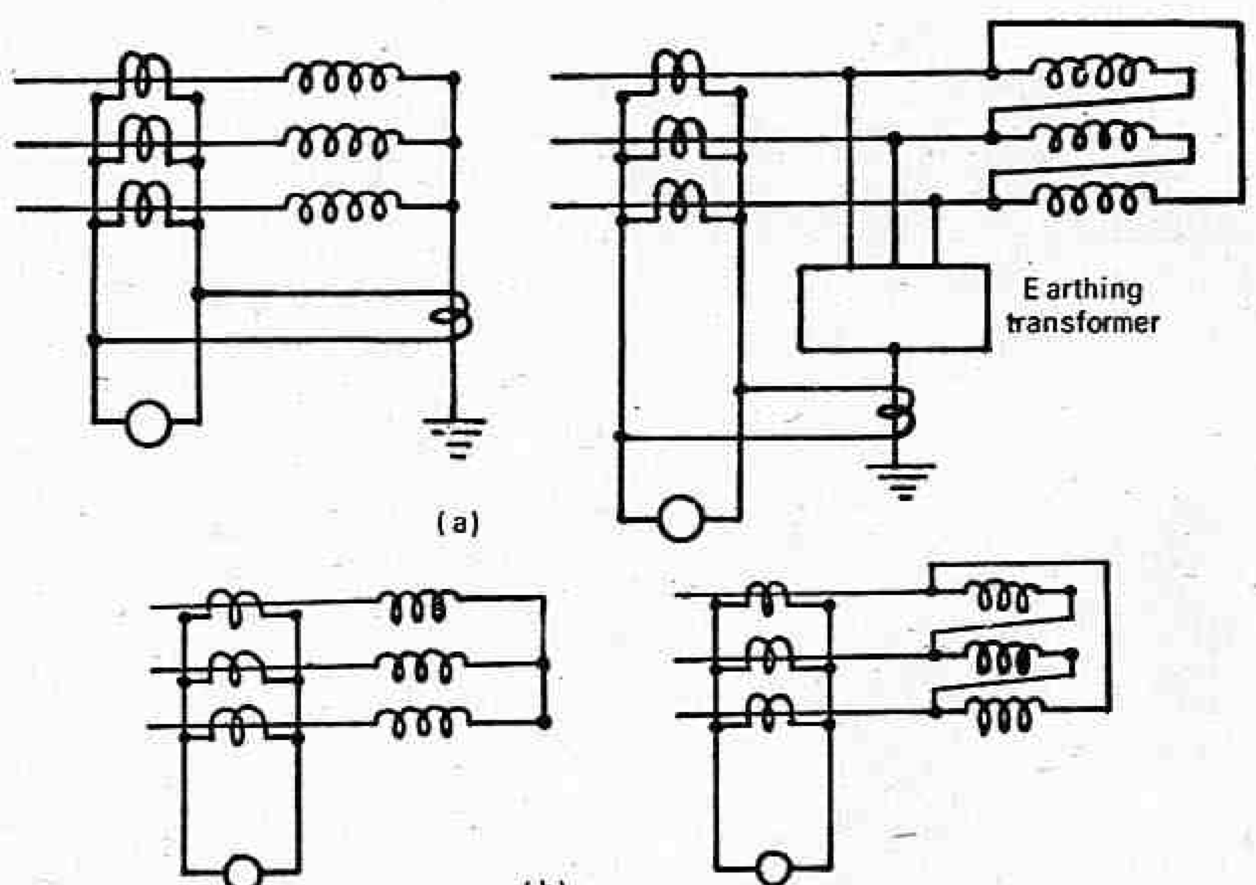


FIGURE 6.8 Restricted earth-fault protection: (a) neutral earthed within the protected zone; (b) neutral not earthed within the protected zone.

zone of the transformer. A CT is fitted in each connection to the protected winding, and the CT secondary windings are connected in parallel to a relay. Figure (6.8) illustrates the connections of restricted earth-fault protection for star and delta windings. Ideally, the output of the CTs is proportional to the sum of the zero sequence currents in the line and neutral earth connection if the latter is within the protected zone. For internal earth faults this sum is equal to two times the total fault current, but for external faults zero-sequence currents are either absent or sum to zero in the line and neutral-earth connection. A typical arrangement of differential and restricted earth-fault protection of a star/delta transformer is shown in Fig (6.9).

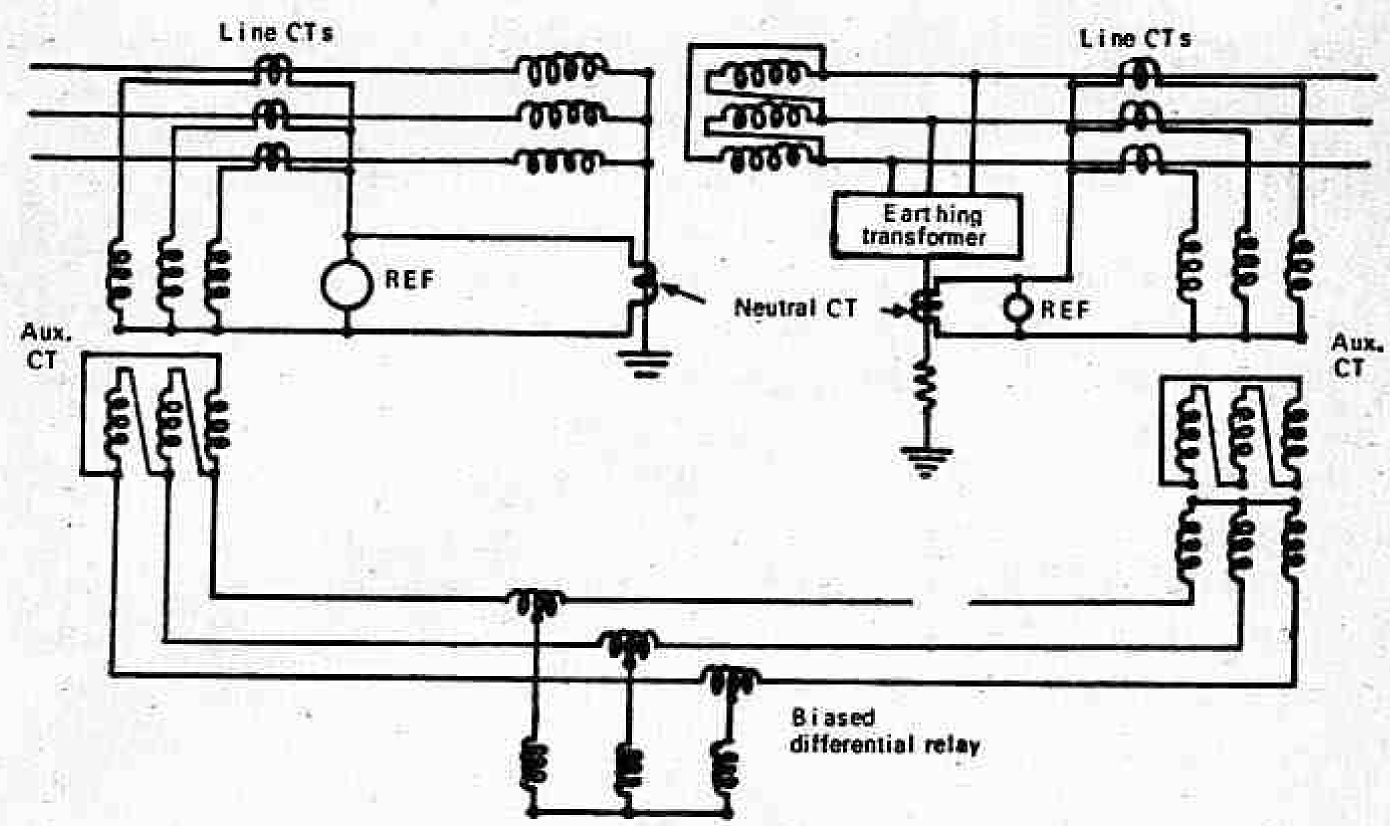


FIGURE 6.9 Differential and restricted earth-fault protection of a star/delta transformer.

The amount of winding protected against earth-fault is determined by the minimum primary current at which the earth-fault relay operates. When the neutral point of the star winding of a transformer is earthed through a resistor the amount of winding protected therefore varies according to the rating of the neutral earthing resistor and the relay setting.

6.2.16 Gas Actuated Relays

When a fault occurs inside the transformer tank gas is usually generated, slowly for an incipient fault and violently for heavy faults. Most short circuits developed either by impulse breakdown between adjacent turns at the end turns of the winding or as a very poor initial point contact which will immediately heat to arcing temperature. The heat produced by the high local current causes the transformer oil to decompose and produce a gas which can be made use of to detect the winding faults. Based on this the following relays are available:

(1) Gas accumulator relay, popularly known as Buchholz relay actuated by the gas formed.
(2) Rate of pressure rise relay which acts on the measurement of the rate of formation of the gas.
(3) Pressure relays and pressure relief devices which have for their actuation a measurement of the total accumulated pressure.
(4) Gas analyzers which act on the analysis of products of decomposition.

Buchholz relay is the simplest form of protection which is commonly used in all transformers provided with conservator. It consists of a chamber connected in the upper side of the pipe run between the oil conservator and the transformer tank, and containing two cylindrical floats, one near the top of the chamber and the other opposite the orifice of the pipe to the transformer (Fig. (6.10)). Under normal conditions the floats are up, but on the occurrence of, say a between-turns fault gas bubbles produced by the breakdown of the oil flow out of the transformer in the direction of the conservator. On reaching the Buchholz relay they are trapped and thereby reduce the oil level in the chamber and cause the upper float to fall. This is usually a slow fault and when the float has fallen through a predetermined distance a pair of contacts, which are controlled by the float, close and give an audible or visual warning.

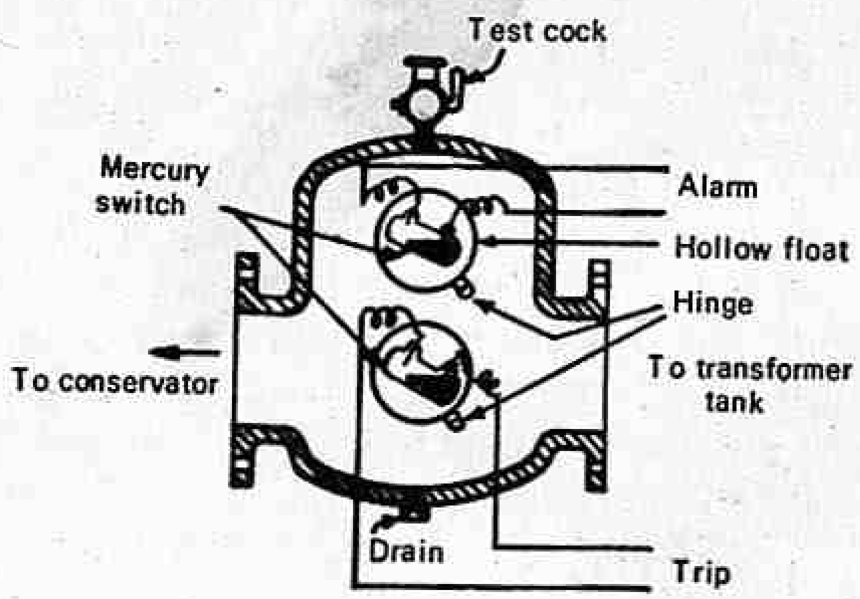


FIGURE 6.10 Buchholz relay.

However, if the fault is heavy, the surge of gas and oil up the pipe towards the conservator engages the lower float which is pushed over instantaneously and engages its associated contacts which in turn trip the circuit breaker. Leakage of oil causes the upper float to operate and if

persistent will also cause the lower float to operate. Care must be taken during oil changing to avoid spurious signals.

The main advantage of Buchholz relays are that they indicate incipient faults, for example, between turns faults or core heating and so may enable a transformer to be taken out of service before serious damage occurs. One important limitation, however, is that they do not protect the connecting cables which must therefore have a separate protection.

Hermetically sealed transformers are common in the United States. These transformers are sometimes fitted with hydraulic relays which respond to the rate of change of pressure in the gas cushion above the oil.

6.2.17 Transformer Feeder Protection

In order to supply bulk power from a major switching station, the transformer is sometimes connected directly to the feeder without an HV switchgear at the transformer. Although such a scheme provides considerable saving in the cost of switchgear but the problems of providing adequate protection are increased. In addition to the protection provided for transformer and feeder when considered separately, the need for some means of intertripping between the HV and LV circuit breakers becomes essential.

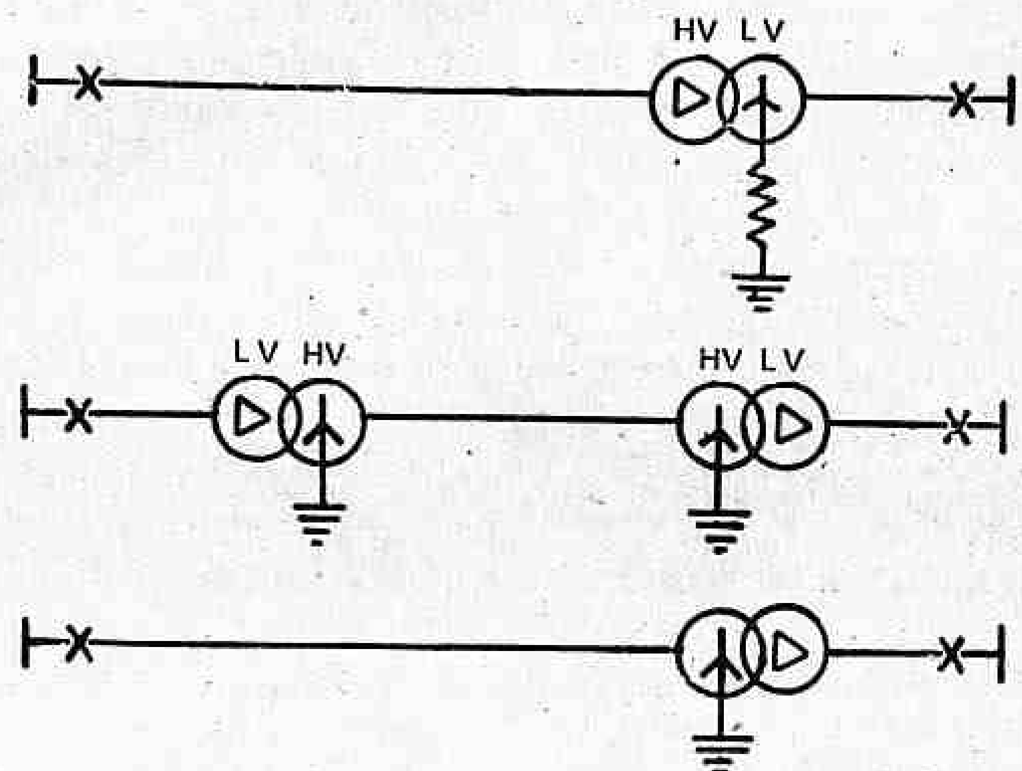


FIGURE 6.11 Typical transformer feeder circuits.

Figure (6.11) shows typical transformer feeder circuits. There are two basic systems of protection which can be used for the transformer feeder protection, viz. unit and nonunit systems. Unit systems employ differential schemes which may be applied either separately for the transformer and the feeder or as an overall unit protection, combined for both the transformer and the feeder. In both the cases a pilot wire channel is required. In the former to provide a means of intertripping and in the latter as an integral part of the scheme. Nonunit systems provide backup protection for faults outside the protected zone in addition to clearing the in-zone faults.

Overall unit protection offers the advantage that CTs on the HV side of the transformer are not required, but this is at the expense of a reduction in sensitivity and speed of operation in comparison to separate unit schemes unless additional relays are used. Separate unit schemes are definitely the best form of protection but usually a nonunit scheme for the feeder combined with a unit scheme for the transformer provides adequate protection at a reduced cost.

6.3 Generator Protection

The increased size of generators and even greater increase in their outputs by more efficient methods of cooling make it imperative to protect them against faults. The generator capacity has sharply risen is recent times from 30 MW to 500 MW with the result that the loss of even a single unit may cause overloading of associated machines and eventual system instability. The basic function of protection applied to generators is, therefore, to reduce the outage period to a minimum by rapid discriminative clearance of faults. Unlike other apparatus, opening a breaker to isolate the faulty generator is not sufficient to prevent further damage, since the generator will continue to supply power to a stator winding fault until its field excitation is suppressed. It is therefore necessary to open the field, stop the fuel supply to the prime mover and in some cases apply braking.

All large modern generator units are invariably transformer connected owing to interconnections. Before considering the types of protection fitted to generators it is desirable to consider the origin and effects of faults.

6.3.1 Generator Faults

Generator faults can be considered under the following heads.

(a) *Stator Faults*. These include the following:

(i) Phase-to-earth faults.
(ii) Phase-to-phase faults.
(iii) Inter-turn faults.

Most faults occur in the stator windings and their connections and majority of these are earth faults. Phase faults and inter-turn faults are less common, these usually develop into an earth fault. The effect of earth faults in the stator is twofold:

1. Arcing to core, which welds laminations together, causing eddy current hot spots on subsequent use. Repairs to this condition involve considerable expenditure of time and money.
2. Severe heating in the conductors damaging them and the insulation, with possible fire risks.

(b) *Rotor Faults*. Faults in the rotor circuit may be either earth faults or between turns, which result from severe mechanical and thermal stresses acting on the winding insulation. Modern practice is to operate a generator with its field winding isolated from earth and therefore a single fault between field winding and rotor body due to insulation breakdown can be tolerated. It is important, however, to know the existence of such a fault so that the generator may be taken out of service at leisure, since the incidence of a second fault will short circuit some part of the field winding, resulting in asymmetry of the air-gap fluxes. This can cause severe vibration of the rotor with possible damage to the bearings.

Rotor open circuits though rare can cause arcing and thus result in serious conditions.

(c) *Abnormal Running Conditions*. The abnormal running conditions which are likely to occur in a generator are: (i) loss of excitation, (ii) unbalanced loading, (iii) overloading, (iv) failure of prime mover, (v) overspeeding, and (vi) over-voltage.

Field failure may occur due to a faulty field breaker or failure of the exciter. When a generator loses its field excitation it speeds up slightly and acts as an induction generator deriving excitation from the system and supplying power at a leading power factor. A fall in voltage will also occur owing to loss of excitation which may result in loss of synchronism and system instability. There is also the possibility of overheating of the rotor due to induced currents in the rotor and damper windings.

Unbalance may occur due to single phase faults, unbalanced loading, open circuits due to broken lines, or due to the failure of one pole of a circuit breaker to close. Although short circuits will normally be cleared by circuit protection, uncleared faults and cases of unbalanced loading arising from one of the foregoing, occasionally cause the unbalanced current condition to be maintained on the generator. The unbalance gives rise to negative sequence currents which produce an armature reaction field which rotates in a direction opposite to that of the rotor and hence produces a flux which sweeps through the rotor with twice the rotational speed. Hence spurious currents of twice the machine frequency are induced in the rotor body, in the field windings and the damper windings. These currents cause overheating if the degree of unbalance is appreciable. The amount of negative sequence current which can be carried by a generator is usually well below its rated current.

CHAPTER 7

Auto-Reclosing

7.1 Introduction

It is well realized that the transient faults which are most frequent in occurrence do no permanent damage to the system as they are transitory in nature. These faults disappear if the line is disconnected from the system momentarily in order to allow the arc to extinguish. After the arc path has become sufficiently deionized, the line can be reclosed to restore normal service. The type of fault could be a flashover across an insulator. Reclosing could also achieve the same thing with semi-permanent faults but with a delayed action, e.g. a small tree branch falling on the line, in which case the cause of the fault would not be removed by the immediate tripping of the circuit breaker but could be burnt away during a time delayed trip and thus the line reclosed to restore normal service. Now should the fault be permanent, reclosing is of no use, as the fault still remains on reclosing and the fault has to be attended personally. It simply means that if the fault does not disappear after the first trip and closure, double or triple-shot reclosing is used in some cases before pulling the line out of service. Experience shows that nearly 80% of the faults are cleared after the first trip, 10% stay in for the second reclosure which is made after a time delay, 3% require the third reclosure and about 7% are permanent faults which are not cleared and result in lockout of the reclosing relay. When a line is fed from both ends, the breakers at the two ends trip simultaneously on occurrence of the fault, the generators at the two ends of the line drift apart in phase, the breakers must be reclosed before the generators drift too far apart for synchronism to be maintained, such a reclosure increases the stability limit considerably.

In presentday power systems, automatic reclosing finds wide application. It therefore follows that to effect fault clearance and subsequent reclosure, it is often necessary to operate sequentially several items of switchgear

Recently logical design principles have been applied for the control of auto-reclose switching sequences in large substations.

7.2 Definitions and Available Features

(a) *Operating Time of Protective Relay.* Time from the inception of the fault to the closing of the tripping contacts.

(b) *Operating Time of Circuit Breaker.* Time from the energizing of the trip coil until the fault arc is extinguished.

(c) *Dead Time of Circuit Breaker or System.* Time between the fault arc being extinguished and the circuit breaker contacts remaking.

(d) *Dead Time of Auto-Reclose Relay.* The time between the auto-reclose scheme being energized and the completion of the circuit to the circuit breaker closing contactor. On all but instantaneous or very high speed reclosing schemes this time which is normally adjustable and marked on the calibrated dial is virtually the same as the circuit breaker dead time. In multi-shot schemes the individual dead times may be the same or separately adjusted.

(e) *Closing Impulse Time of Auto-Reclose Relay.* The time during which the closing contacts on the auto-reclose relay are made.

(f) *Reclaim time of Auto-Reclose Relay.* The time from the making of the closing contacts on the auto-reclose relay to the completion of another circuit within the auto-reclose scheme which will reset the scheme or lock out the scheme or circuit breaker as required. This time may be fixed or variable or dependent on the dead time setting. In the multi-shot scheme the individual reclaim time may be the same or independently adjustable.

(g) *Reclosing Time.* This is the time taken by the circuit breaker to open and reclose the line and is measured from the instant of energization of the trip circuit to the instant when the breaker contacts remake the circuit. This period is made up of the circuit breaker time plus the system electrical dead time.

(h) *Lockout of Circuit Breakers.* A feature in the auto-reclose scheme to prevent further automatic closing of the circuit breaker after the chosen sequence of reclosures has been unsuccessful. From this position the circuit breaker must be reclosed manually.

(i) *Lockout of Auto-Reclose Relay.* A feature in the auto-reclose scheme to prevent further automatic closing after the chosen sequence, regardless of whether the reclosure was successful or not.

(j) *Anti-Pumping*. A feature incorporated in the circuit breaker or the reclose scheme whereby, in the event of a permanent fault, repeated operation of the circuit breaker are prevented when the closing impluse is longer than the sum of the protective relay and circuit breaker operating times.

(k) *Number of Shots*. The number of attempts at reclosing which an auto-reclose scheme will make before locking out on a permanent fault. The number of shots may be fixed or adjustable.

(l) *Spring Winding Time*. On motor wound spring closed circuit breakers this is the time required for the motor to fully charge the spring after a closing operation.

(m) *Operation Counter*. Usually an electromagnetically operated cyclometer type dial which is stepped round one digit each time the coil is energized. These are often incorporated in auto-reclose schemes to record the number of operations of the circuit breaker. This is necessary for maintenance purposes for in unattended substations the operations might not be logged in the usual manner.

(n) *Counting Relay*. A relay usually of the electromagnetic type incorporating a ratchet arrangement which is driven forward one step each time the coil is energized. A contact is operated after a chosen number of steps and the mechanism may be manually or electrically reset.

Figure (7.1) illustrates auto-reclose cycle for a circuit breaker fitted with single shot auto-reclose scheme.

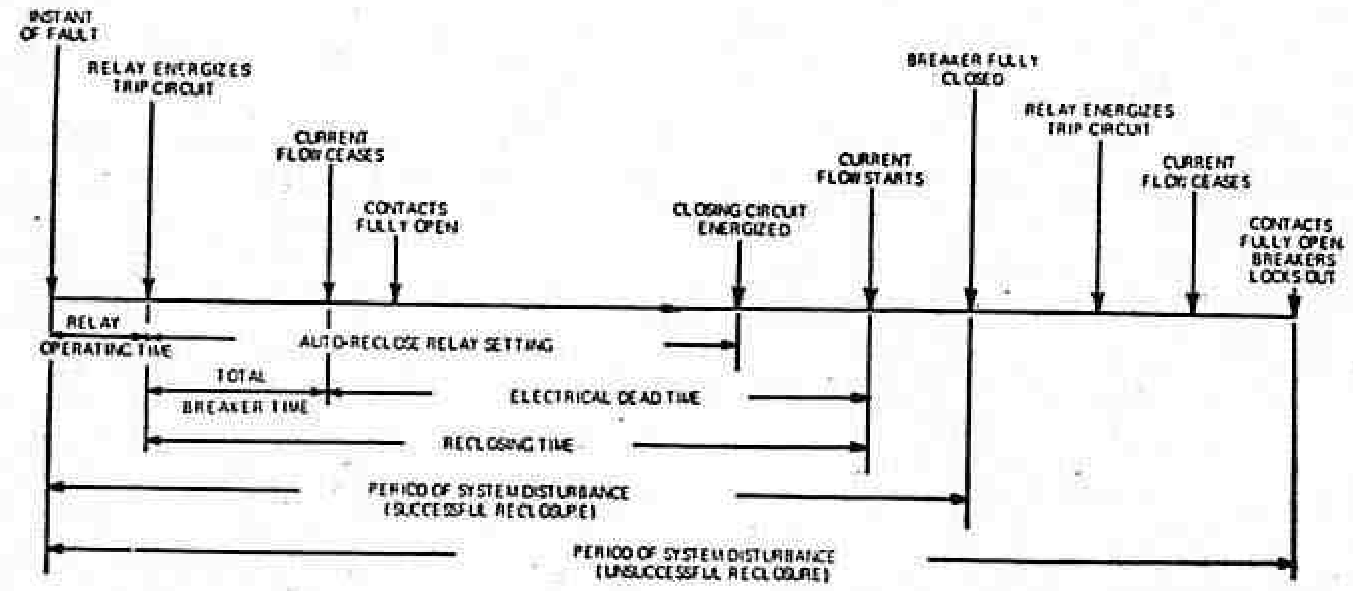


FIGURE 7.1 Auto-reclose cycle for a circuit breaker with a single shot auto-reclose scheme.

7.3 Auto-Reclosing

The purpose of auto-reclosing has been discussed in section 7.1. The auto-reclosing can be broadly classified in two categories:

(a) *Medium voltage auto-reclose* where continuity of supply is the principal aim.

(b) *High voltage auto-reclose* where the main considerations are of stability and synchronizing.

These will now be discussed.

7.3.1 MEDIUM VOLTAGE AUTO-RECLOSE

The obvious advantages are continuous supply except for short duration when tripping and reclosure operations are being performed, this renders the substation unattended. The success of rapid reclosure to a large extent depends on the speed of operation of the protections. This is so because high speed protection decreases the amount of damage incurred and thus increases the probability of successful operation of reclosing, consequently it renders the system less vulnerable to any fault which may occur later. In some cases application of automatic reclosing enables us to use very simple but high speed protections of the lines. With instantaneous protection being applied indiscriminate tripping of several circuit breakers is possible but the provision of auto-reclose makes it a selective operation. The principles of acceleration of the overcurrent protections by means of automatic reclosing is discussed below.

(i) *Overcurrent Protection with Acceleration Prior to Automatic Reclosure.* In this case the provision of single shot auto-reclosure in a nonselective overcurrent high speed protection makes the protection selective. Consider the system shown in Fig. (7.2). Overcurrent protection with time delays located at breakers 1, 2 and 3 are provided so that $t_1<t_2<t_3$. The

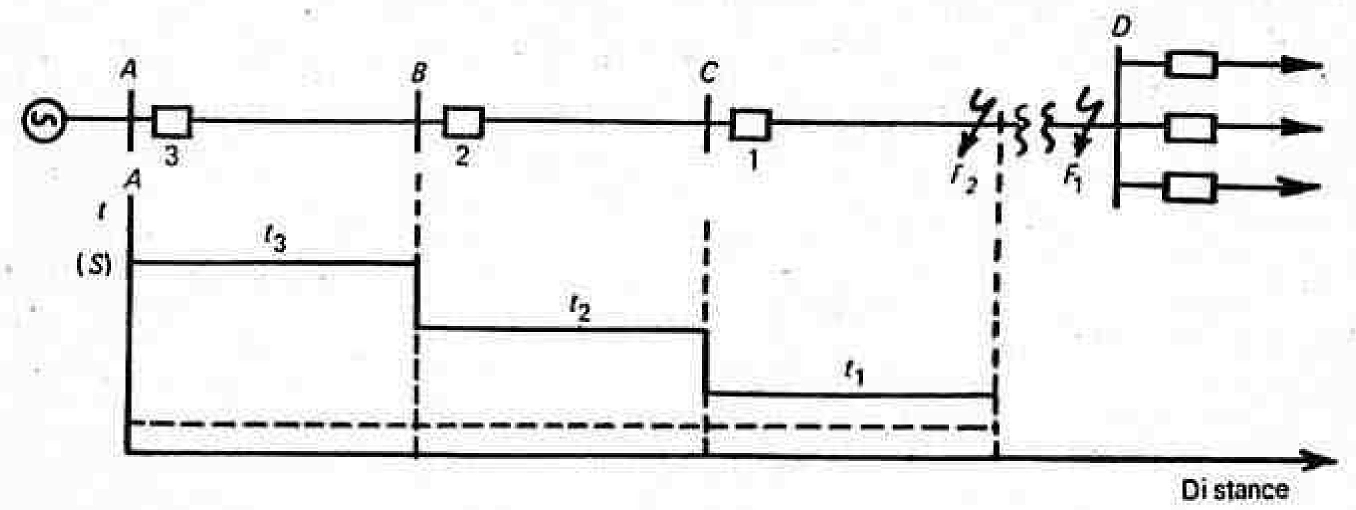


FIGURE 7.2 Time vs distance characteristic of overcurrent protection with acceleration prior to automatic reclosure.

nonselective high speed overcurrent protection and automatic reclosure is located at breaker 3 only. The pickup current of this high speed protection is selected so that it only responds for faults occurring on the line sections *AB, BC* and on that part of section *CD* before the transformer bank. Therefore, for faults within the protected zone the high speed overcurrent protection trips breaker 3. After this the automatic reclosure immediately returns the line to service and at the same time the high speed overcurrent protection is removed for a time a little more than the operating time of overcurrent time delay relay (t_3) located at breaker 3, i.e. $t_{out} > t_3$. This is necessary because if the fault persists after the reclosure, it should be cleared by overcurrent protections at 1, 2 or 3. The advantage is that only one automatic reclosing system on the head section of the line is required. Simplicity of the scheme for short distribution systems where the intermediate substations are not suited for automatic reclosing is an attractive feature of this scheme.

(ii) *Overcurrent Protection with Acceleration after the Automatic Reclosure.* In this case the fault is first cleared by overcurrent protection with stepped time delays. After this, automatic reclosure returns the line to service and if the fault is permanent, the high speed overcurrent protection operates and removes the line from service.

(iii) *Overcurrent Protection with Inturn Automatic Reclosure.* It enables us to realize high-speed protection of every section against transient as well as permanent faults. This is achieved by installing high speed nonselective overcurrent protections at all head parts of the sections. The pickup value for all such protections is selected for faults inside the full length of the given section and not for faults beyond the stepdown transformers if one such exists. Different zones of protection are shown in Fig. (7.3). Any nonselective operation of faults outside the given section is corrected by automatic reclosing. When the line is protected by composite overcurrent protection, the first stage of the protection can be employed as high speed nonselective overcurrent protection.

Consider a permanent fault at F_1 of system shown in Fig. (7.3). The

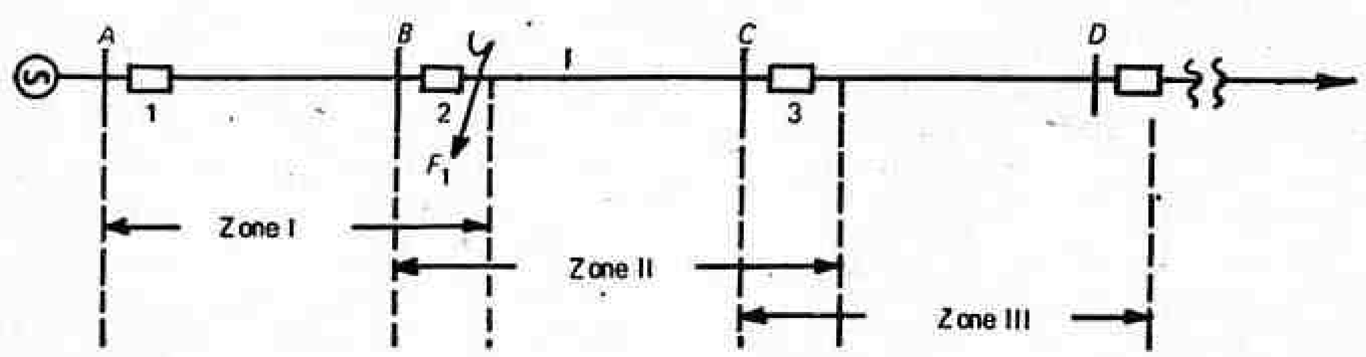


FIGURE 7.3 Overcurrent protection with 'inturn' automatic reclosure.

high speed relays of breakers 1 and 2 will operate. Practically immediately the automatic recloser located at breaker 1 restores the section 1 to service. As the fault F_1 is located outside section 1 and breaker 2 is still open the high speed overcurrent protection of section 1 will not operate, although it was automatically removed from service for a little while. Now after a time delay t_{AR_2} the automatic recloser at breaker 2 closes.

$$t_{AR_2} = t_{AR_1} + \Delta t_{AR}$$

where t_{AR_2} = time delay of the automatic recloser at breaker 2.

t_{AR_1} = inherent time delay of the automatic recloser at breaker 1.

Δt_{AR} = time step $\simeq 0.5$ second.

As the fault of F_1 is permanent, the high speed overcurrent protection of section 2 opens breaker 2 once more and removes section 2 from service. This scheme has increasing clearing times as we proceed towards the far end of the line.

7.3.2 High Voltage Auto-Reclose

In the high voltage circuits where the fault levels associated are extremely high, it is essential that the system dead time be kept to a few cycles so that the generators do not drift apart. High speed protection such as pilot wire carrier or distance must be used to obtain operating times of one or two cycles. It is therefore desired that the reclosure be of the single shot type. High speed reclosure in high voltage circuits improves the stability to a considerable extent on single-circuit ties. On double circuit ties subjected to single circuit faults the continuity through the healthy circuit prevents the generators from drifting apart so fast and increase in the stability limit is thus moderate. Nevertheless, it is sometimes important. However, when the faults occur simultaneously on both the circuits the stability limit increases again considerably.

The successful application of high speed auto-reclose to high voltage systems interlinking a number of sources depends on the following factors.

(i) The maximum time available for opening and closing the circuit breakers at each end of the faulty line, without loss of synchronism.

(ii) The time required to deionize the arc at the fault, so that it will not restrike when the breakers are reclosed.

(iii) The speed of operation on opening and closing of the circuit breakers.

(iv) The probability of transient faults, that will allow high speed reclosure of the faulty lines.

It will be seen that some of these conditions are conflicting, e.g. the faster the breakers are reclosed the greater the power that can be transmitted without loss of synchronism, provided that the arc does not restrike. But here the likelihood of arc restriking is greater. An unsuccessful reclosure is more detrimental to stability than no reclosure at all. For this reason the time allowed to deionize the line must not be less than the critical time for which the arc hardly ever restrikes. The reduction of reclosing time obtained by high speed relaying is however preferred as it reduces the duration of arc. Indeed, the increase in power limit due to reclosing is much greater with very rapid fault clearing than with slower fault clearing. For best results the circuit breakers at both ends of the faulty line must be opened simultaneously. Any time during which one circuit breaker is open in advance of the other represents an effective reduction of the breaker electrical dead time and may well jeopardize the chances of a successful reclosure.

To determine the electrical dead time for a circuit breaker used in a high speed auto-reclose scheme it is essential to know the time interval during which the line must be kept deenergized in order to allow for the complete deionization of the arc and ensure that it will not restrike when the line is reconnected to the system. The deionization time of an arc in open atmosphere depends on a number of factors such as: circuit voltage, conductor spacing or gap length, fault current, fault duration, wind velocity, etc.

Line voltage is the most important of all the factors affecting the arc deionization time. Typical values of deionization times for an arc in free air are:

Line voltage (KV)	*Minimum deionizing time* (seconds)
66	0.1
110	0.15
132	0.17
220	0.28
275	0.3

7.4 Three-Phase versus Single-Phase Auto-Reclose

Three-phase auto-reclosure is one in which the three phases of the transmission line are opened after fault incidence, independent of the fault type, and are reclosed after a predetermined time period following the initial circuit breaker opening. For a single circuit interconnectors between two power systems, the opening of all the three phases of the circuit breaker makes the generators in each group start to drift apart in relation to each other, since no interchange of synchronizing power can take place.

On the other hand single-phase auto-reclosure is one in which only the

faulted phase is opened in the presence of a single-phase fault and reclosed after a controlled delay period. For multiphase faults, all three phases are opened and reclosure is not attempted. In case of single-phase faults which are in majority, synchronizing power can still be interchanged through the healthy phases.

In the case of single-phase auto-reclosing each phase of the circuit breaker has to be segregated and provided with its own closing and tripping mechanism. Also it is necessary to fit phase selecting relays that will detect and select the faulty phase. Thus single-phase auto-reclosing is more complex and expensive as compared to three-phase auto-reclosing. When single-phase auto-reclose is used the faulty phase must be deenergized for a longer interval of time, than in the case of three-phase auto-reclose, owing to the capacitive coupling between the faulty phase and the healthy conductors which tends to increase the duration of the arc. The advantage claimed for single-phase reclosing is that on a system with transformer neutrals grounded solidly at each substation, the interruption of one phase to clear a ground fault causes negligible interference with the load because the interrupted phase current now flows in the ground through neutral points until the fault current is cleared and the faulted phase reclosed. The main drawback is its longer deionizing time which can cause interference with communication circuits and, in certain cases maloperation of earth relays in double circuit lines owing to the flow of zero sequence currents.

QUESTIONS

1. What is the purpose of providing auto-reclosing? Discuss the main considerations for designing the auto-reclose scheme with particular reference to high-voltage system.
2. Distinguish between single-phase and three-phase auto-reclose. In which case is the duration of arc more, single-phase auto-reclose or three-phase auto-reclose and why? Clearly bring out their relative merits and drawbacks.
3. Define the following terms:
   (i) Dead time of circuit breaker.
   (ii) Reclosing time.
   (iii) Lockout of circuit breakers.
   (iv) Number of shots.

CHAPTER 8

Testing and Maintenance of Protective Gear

8.1 Introduction

Protective gear differs from other types of electrical equipment in that for most of its useful life it is inoperative, as it operates only under fault conditions. Testing of protective gear thus poses a problem because it is solely concerned with fault conditions and therefore testing under normal operating conditions does not always give realistic results. Moreover the service conditions imposed on the protective gear are particularly onerous as the apparatus is normally static and must operate without warning. Consequently defects may easily pass undetected until revealed by incorrect operation on the occurrence of a system fault, and regular maintenance testing is essential in order to forestall failure. Ideal protective gear combines high performance with simplicity but where economic considerations compel, some sacrifice of simplicity with more intensive maintenance is necessary.

The importance of reliable operation of protective gear is, however, so great that all possible means should be employed to ensure that the protective gear and its associated equipment, always operate correctly on the occurrence of a fault. Testing and maintenance is therefore of immense importance for protective gear. The standard of service required varies so widely for different protective gears that it is beyond the scope of this book to deal with it in detail. However, some guiding principles are described which can be applied with suitable modifications to any particular equipment.

8.2 Classification of Relay Testing

Tests are usually conducted to demonstrate that:

(a) the relay will operate correctly to clear a fault; and

(b) the relay will remain inoperative on faults outside its specified zone.

To ensure correct operation of relay, it is advisable to set up a relay testing programme to suit the system needs. The system conditions should be simulated before testing a particular relay.

Broadly speaking the tests to be performed fall under the following heads: (i) factory tests, (ii) installation or commissioning tests, and (iii) periodic maintenance tests.

8.2.1 Factory Tests

It is the responsibility of the manufacturer to ensure that the gear conforms to standard specifications and, therefore, before it is accepted and commissioned it is to be tested. For a protection scheme or relay to be tested the operational conditions which arise in transmission and distribution systems during faults must be faithfully reproduced. For this purpose the plant for supplying the current for these tests particularly in the case of high speed types of protection must be of considerable capacity and special design. Separate light and heavy current tests are carried out and the results correlated. Relay test benches are used for light current tests, and the heavy current tests are carried out with the relays and current transformers connected operationally.

The development in the factory will also include many other tests and trials ranging from material investigations and control, to effects of impact and vibration, resistance to atmospheric corrosion, effects of temperature and dust tightness of relay cases. Sometimes the development of a new relay design is also proved in the testing laboratory of the factory.

8.2.2 Installation or Commissioning Tests

As the behaviour of the equipment under fault conditions has been proved at the factory tests, the main object of commissioning tests is to prove that protective gear has been properly installed and wired and that it functions correctly and is ready for service. Also the presence of many other elements associated with the protective relays, which may have been supplied by different manufacturers, the comprehensive tests at the site of installation are of great importance. Further these tests provide a check over the components which have passed factory tests and have been transported undamaged for erection at the site.

The commissioning tests carried out on an installation can be summarized as follows:

(a) Check the wiring diagrams used by the erectors. (Schematic diagrams showing all the reference numbers of the interconnecting wiring greatly assist in this work.)

(b) Make a general inspection of the equipment, checking all the connections, wires on relays terminals, labels on terminal boards, etc.
(c) Measure the insulation resistance of all circuits.
(d) Test main current transformers for ratio and polarity, and check points on the magnetization curves.
(e) Test main voltage transformers for ratio, polarity and phasing.
(f) Inspect and test the relays by secondary injection.
(g) Check the equipment by primary injection to prove stability for external faults and to determine the effective current setting for internal faults.
(h) Check the tripping and alarm circuits for the equipment.

These tests will be described in the sections that follow later in this chapter.

8.2.3 Periodic Maintenance Tests

Periodic maintenance after the installation and commissioning of protective gear is of utmost importance. Moisture and dust are generally present as potential sources of trouble, and tend to produce deterioration in insulation, corrosion of conductors, high resistance between relay contacts, and stickiness of relay bearings and pivots. Owing to the infrequent operation of the gear in service these troubles often develop unchecked. Further connections may get loose in time and this, coupled with high contact resistance due to corrosion may lead to open circuits.

It is, therefore, essential to inspect and test protective gear at suitably chosen intervals. The frequency of maintenance inspections and tests depends on the quality of the equipment, importance of the supply and upon the conditions at the site where the relays are installed.

The protective equipment includes in addition to relays many ancillary pieces of equipment which may affect the efficacy of the protection if not tested and inspected regularly. Typical of the items, failure of which may prevent or delay fault clearance, are the small wiring connections, batteries, fuses, links and the auxiliary switches on circuit breakers.

A general inspection of the physical condition of all equipment, a check of accessible connections including fuses and links, secondary injection tests of relays and functioning tests of logic and trip circuits are included in maintenance tests. The operation of indicating and alarm circuits should also be proved. Maintenance programmes also provide for the occasional tripping of circuit breakers which otherwise are very rarely operated under normal circumstances, in order to check the tripping mechanism of the circuit breakers.

The programming and recording of maintenance tests is of great importance, and the various tests should be so scheduled in order to fit the system needs. The test sheets employed should specify exactly every test and inspection required.

A typical maintenance schedule is given below.

(a) *Continuous Observation.* The items mentioned below need continuous supervision and a trained person is needed for this purpose:

(i) Pilot supervision.
(ii) Trip circuit supervision.
(iii) Relay voltage supervision.
(iv) Battery earth-fault supervision.
(v) Bus-bar protection CT circuit supervision.

(b) *Daily Inspection.* Relay flags and indicators are to be inspected in every shift.

(c) *Once a Week.* Carrier current protection testing.

(d) *Monthly Tests.* Inter-tripping channel tests without tripping any switches.

(e) *Six Monthly.* Inspections, tripping tests, insulation resistance tests, and battery biasing equipment check.

(f) *Yearly.* Check tripping angle of phase comparison method, secondary injection tests, Buchholz relay tests, and tests on earthing resistors.

(g) *Two Yearly.* Secondary injection tests.

8.3 Test Benches

Test benches are used for proving the design characteristics of relays. These are provided with accurate timing apparatus and calibrated current and voltage supplies.

The basic circuit for testing overcurrent relays is shown in Fig. (8.1). The harmonic content in the current wave form is kept to within 2% of the fundamental by adjusting the current through a choke which has an impedance at least six times that of the relays under test. Interchangeable matching transformers are used for differently rated relays, so that the same burden is imposed on the control circuit for all current ratings.

The test current is adjusted to the desired level with the relay short circuited by a normally closed cantact on the starting contactor. By energizing the starting contactor the short circuit across the relay is

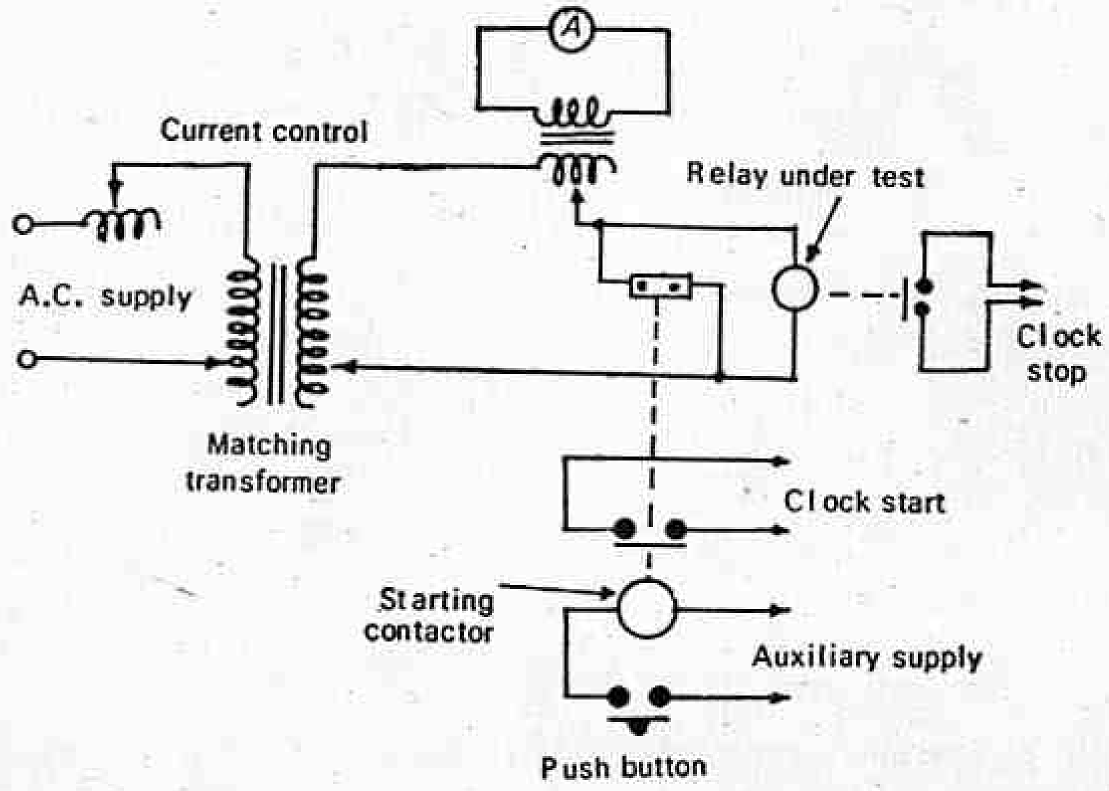


FIGURE 8.1 Test circuit for overcurrent relays.

released and the timer starts. Finally the timer stops when the relay operates. The method adopted for load adjustment allows sufficient time for the current to be accurately set without overloading the relay, and also gives a steady ammeter reading immediately on transference of the current to the relay since the pointer does not have to rise from zero.

8.4 Heavy Current Test Plant

Simulating the exact fault conditions as would occur in practice is a difficult and a tedious job. The plant for providing the current for these tests as pointed out earlier ought to be of considerable capacity and special design. To ensure that the behaviour of the protection under transient conditions is fully proved, it is often necessary to assemble the complete protective equipment comprising relays, CTs, auxiliary equipment and simulated pilot circuits having appropriate constants. Moreover the gear should remain stable under through fault conditions, i.e. when there is no disparity in the current entering and leaving a protected zone. Under these conditions the CTs will be subjected to a sudden growth of primary current, with consequent asymmetrical waveform, giving rise to transient d.c. component and may cause saturation in some of the CT cores and ultimately cause maloperation of the protective gear.

Heavy current test plant should therefore be capable of supplying and controlling very heavy currents of pure sinusoidal waveforms in circuits having reactances. In addition to this a point-on-wave control so that

the fault could be applied at any point of the voltage wave, and observation and recording arrangement are essential features of a heavy current plant.

The English Electric heavy current test plant, schematic diagram shown in Fig. (8.2) comprises a 7.5 MVA, 6.6 KV alternator, driven by a

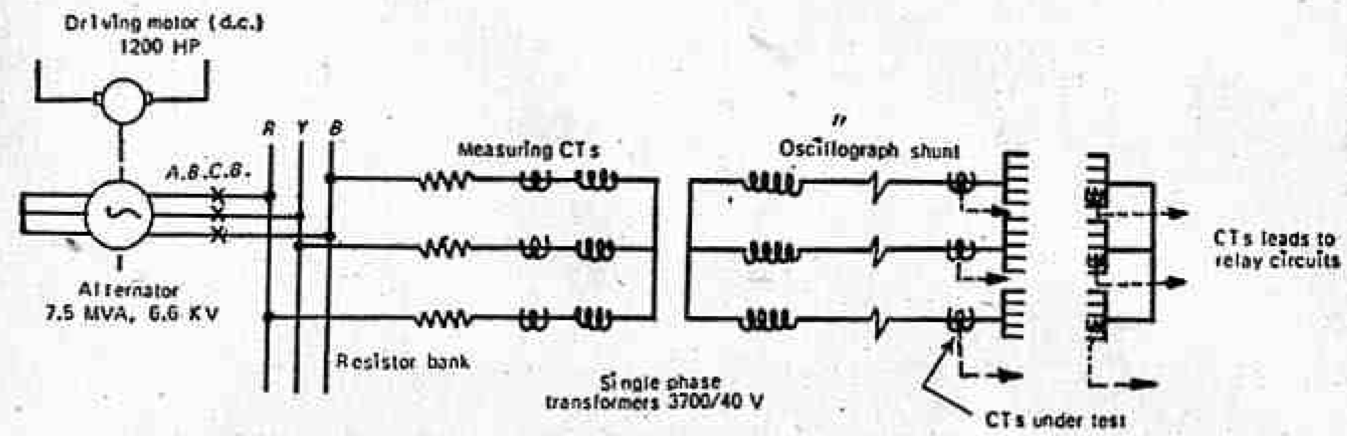


FIGURE 8.2 Schematic diagram of heavy current test plant.

1200 HP d.c. motor feeding heavy current test tables via three single-phase 3700 V/40 V transformers. Provision is made on each of the three test tables for accommodating five pairs of CTs. In addition accommodation is provided on the high voltage side of the heavy CTs for bushing CTs with bar primaries. The plant provides a maximum current of 50,000 amperes. The X/R ratio has a maximum value of 15 (i.e. a time constant of 48 ms). By means of resistor banks in the high voltage circuit, this can be varied down to an X/R ratio of unity. To keep the a.c. decrement as small as possible, field forcing of the alternator is provided; thus the only variation occurring in the a.c. symmetrical peak value is that due to the change from sub-transient to transient impedance in the alternator. The test duration and the point-on-wave at which the air blast circuit breaker operates can be controlled, and a complete oscillograph record of each test is printed out automatically.

8.5 General Methods of Testing Protective Gear

8.5.1 Primary Injection

These tests are limited by the manner in which current can be passed through the primary winding of the current transformers of the protective gear under test. Generally it is possible to obtain access to the primary connections to enable current at low voltage to be injected, but in certain cases, such as when CTs are fitted in the bushings of power transformers, other means of injection have to be used. Primarily these tests are performed for checking the polarity and correctness of the primary and secondary wiring. When carrying out this test the entire circuit comprising

CT secondaries, relay coils, trip and alarm circuits, and all intervening wiring is checked. Figure (8.3) shows a simple scheme of primary injection.

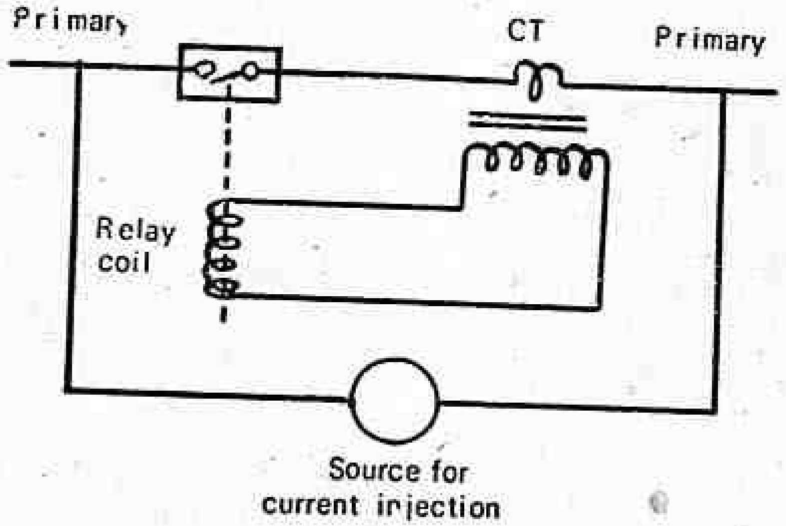


FIGURE 8.3 Simple scheme of primary injection.

The heavy test current required for injection is either obtained by running a generator on short circuit or by means of a portable injection transformer arranged to operate from the local mains supply and having several low voltage heavy current windings. The secondary low voltage windings can be connected in series or parallel depending on the current required and resistance of the primary circuit. The output can be controlled by a tapped reactor or an auto-transformer.

A typical primary-injection transformer is shown in Fig. (8.4), which is usually of about 10 KVA rating with a ratio of 250/10+10+10+10 volts. A current up to 1000 A can be obtained by connecting all the four secondary windings in parallel. If the main CTs are fitted with test windings these can be used for primary injection instead of the primary winding (Fig. (8.5)). The current required for primary injection is then greatly reduced, but these test windings are not always provided because of space limitations in the main CT housings.

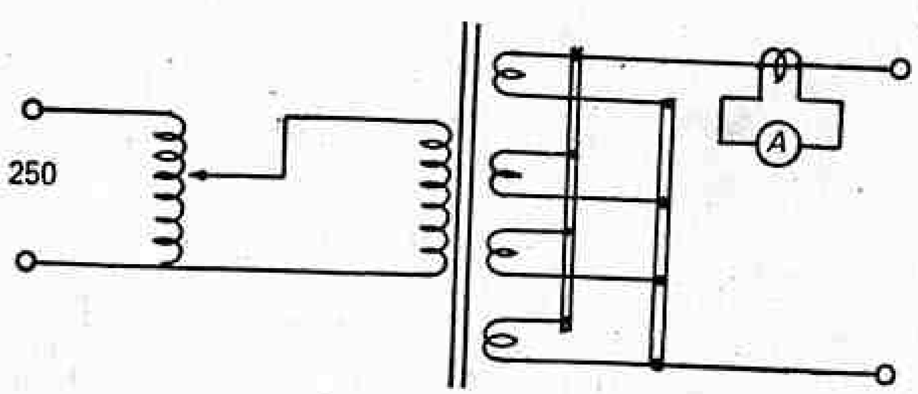


FIGURE 8.4 Primary injection test set.

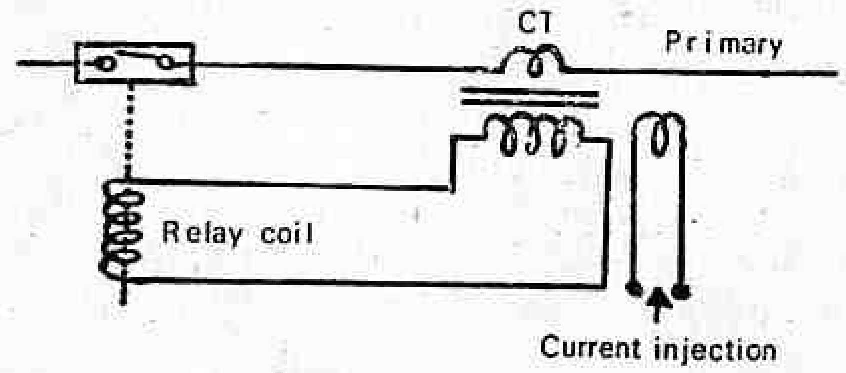


FIGURE 8.5 Current injection in the test winding.

8.5.2 Secondary Injection

In this case the testing current is injected into the secondary circuits of the protective gear as shown in Fig. (8.6). One of the advantages of these tests is that fault conditions are simulated with relatively small currents and the amount of power consumed by such tests is small.

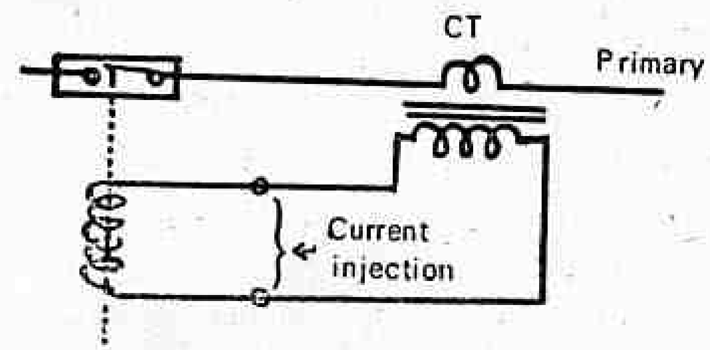


FIGURE 8.6 Secondary injection.

A limitation of testing by this means is that the ratio and phase-angle errors of the instrument transformers and the phasing of their secondary connections are not taken into account.

8.5.3 Measurement of Time

It is often necessary to make measurements of time to determine the speed of fault clearance and the factor of safety available for discrimination. Timing devices for protective equipments operating in not less than 0.1s are wellknown, and normally comprise a cycle counter, Warren clock or stop-watch controlled either manually or electrically. On account of the errors introduced in starting and stopping most of these devices are not sufficiently accurate for checking the time of operation when this is less than 0.1s. Special apparatus has to be used which can measure time duration of the order of a few milliseconds with fair accuracy. The requirements of such apparatus are accuracy, direct reading, robustness and portability. The apparatus is, however, necessary in making detailed investigations into the causes of maloperation of high speed protective equipment, particularly when their functioning depends upon the sequential operation of a number of relays.

8.6 Current Transformer Tests

Current transformers are generally mounted in the switchgear when it is delivered to site and may not be easily accessible. The normal tests which are carried out can easily be performed with the CTs mounted in the switchgear. These tests are: (i) polarity check, (ii) ratio check and (iii) magnetization curve.

8.6.1 Polarity Check

This check is necessary to see the relative polarity of the primary and secondary terminals when terminals are not marked or to establish the correctness of the marking if already marked. A simple test circuit for this purpose is shown in Fig. (8.7). The primary is connected across a low voltage battery through a push button switch. The secondary of the CT is short circuited through a moving coil permanent magnet centre zero type ammeter. On closing the push-button the d.c. ammeter A should indicate a positive flick and on opening a negative flick.

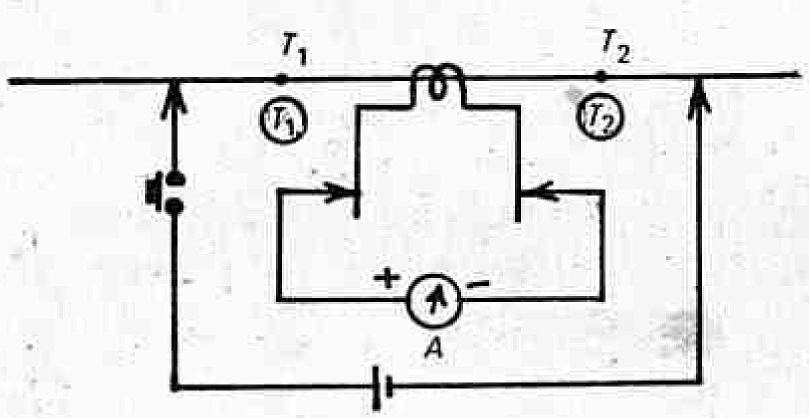


FIGURE 8.7 CT polarity check.

8.6.2 Ratio Check

This check is usually carried out during the primary injection tests described in 8.5.1. The ratio of the readings of the ammeters in the primary and secondary circuit of the CT under test is taken which should approximate to the ratio marked on the CT.

8.6.3 Magnetization Curve

CTs intended for different purposes will have different magnetization characteristics. On a single bushing there may be several CTs of the same

ratio but having different characteristics to perform different duties such as protection, metering or operation of ammeters only. A magnetization test is a convenient method for the identification of the different CTs which will have differing knee points. The knee point as already defined is the secondary voltage at which an increase of 10% in voltage will result in an increase of 50% in the magnetizing current.

A simple method of checking the magnetization characteristics of a CT is to apply a gradually increasing sinusoidal voltage of standard frequency to the secondary winding leaving the primary open circuited. The magnetization current and the voltage applied are measured with the help of an ammeter and voltmeter. The shape of this curve indicates as to when the saturation occurs in the CT core.

8.7 Potential Transformer Tests

The three checks which are made in the case of a PT are: (i) polarity check, (ii) ratio check and (iii) phasing check.

8.7.1 Polarity Check

Polarity check is performed in the same way as that for a CT. If the PT is of the capacitor type then the polarity of the transformer at the bottom of the capacitor stack should be checked.

8.7.2 Ratio Check

A simple test for ratio can be made by connecting voltmeters to the primary and secondary, one of the voltmeters sometimes being used in conjunction with a potential divider to read high primary voltages.

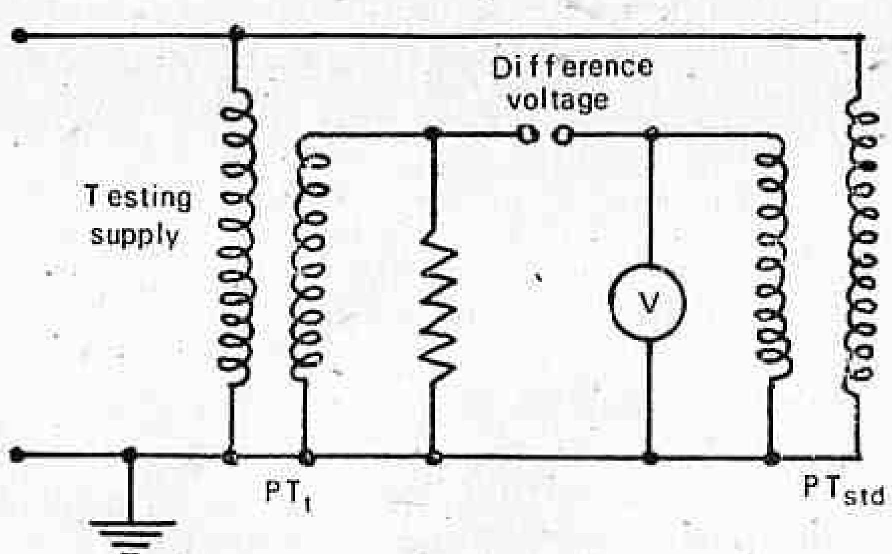


FIGURE 8.8 PT ratio check.

Another method is the comparative method. If a second PT of standard accuracy and the same ratio as the test PT is substituted for the potential divider then a fixed fraction of the primary voltage is delivered from its secondary. When this is applied in opposition to the secondary voltage of the test transformer, a difference voltage is obtained which is a measure of the difference in errors of the two transformers. This is shown in Fig. (8.8).

8.7.3 PHASING CHECK

The incoming secondary connections for a three-phase PT or bank of three single-phase PTs must be carefully checked for phasing. With the main circuit alive the secondary voltages between phases and neutral must be measured to verify that the phase relationship is correct. The phase rotation should then be checked with a phase rotation meter connected across the three phases as shown in Fig. (8.9). If the three-phase PT has

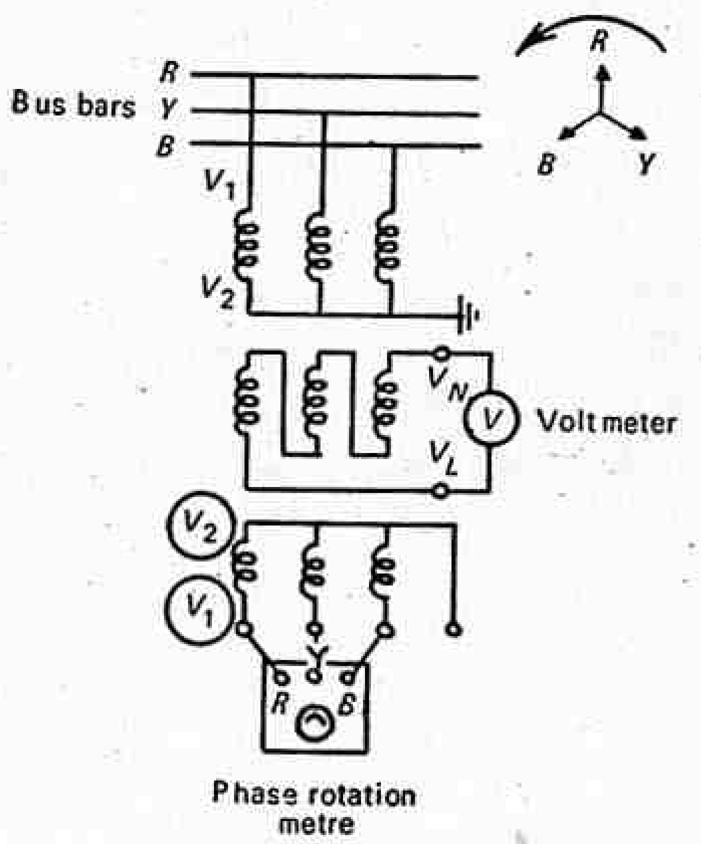


FIGURE 8.9 PT phasing check.

a broken delta tertiary winding then a check should be made of the voltage across the two connections from the broken delta V_N and V_L as shown in Fig. (8.9). With the rated balanced three-phase supply voltage applied to the PT primary windings, the broken delta voltage should be below 5 volts with rated burden connected.

8.8 Features of Design which Assist Maintenance

If the following principles are adhered to, the danger of backfeeds is reduced and fault investigation is made easier.

(a) The drawout type of relay case construction for which the test plug can be used. A defective unit can be replaced quickly without interrupting service.
(b) Circuits should be kept as electrically separate as possible, and the use of common wires should be avoided except where these are essential to the correct functioning of the circuits.
(c) Each group of circuits which is electrically separate from other circuits should be earthed through an independent earth link.
(d) Where a common PT or d.c. supply is used for feeding several circuits, one of which is associated with protective gear, each circuit should be fed through separate links or fuses. When these are withdrawn the circuits should be completely isolated.
(e) Fuses should, where possible, be graded so that a fault on a circuit not used for protection does not interrupt supplies to the protective gear circuits.
(f) A single auxiliary switch should not be used for interrupting or closing more than one circuit.
(g) In relay panel construction some consideration should be given to the accessibility of connections as these may have to be altered when extensions are made to the gear. Modern panels are provided with special test facilities, so that no connections need be disturbed during routine testing.
(h) Junction boxes should be of adequate size. In case they are to be located outdoors the boxes must be made water proof.
(i) All wiring should be ferruled for identification.
(j) In relay design itself provision of high armature torque and contact pressure, jewel bearings shrouded to exclude dust, avoidance of very thin wire, use of dust tight cases, etc., reduces maintenance and increases life.

QUESTIONS

1. Explain the importance of testing of relays.
2. Describe briefly the following tests on relays:
   (a) Factory tests.
   (b) Installation tests.
   (c) Maintenance tests.
3. Write technical notes on the following:

(a) Primary and secondary injection.
(b) Relay test benches.
(c) CT tests.
(d) PT tests.

4. What are the causes of relay deterioration? Describe a typical maintenance schedule of a relay.

CHAPTER 9

Static Relays

A static protective relay refers to a relay in which the measurement or comparison of electrical quantities is done in a static network which is designed to give an output signal in the tripping direction when a threshold condition is passed. The output signal operates a tripping device which may be electronic, semiconductor or electromagnetic.

9.1 Basis for Static Relay Development

As a result of the great expansion of electrical transmission and distribution systems during the last thirty years and with the advent of much larger power stations and more highly interconnected systems, the duty imposed upon protective gear has become more and more severe. Since relays now have to perform much more complicated functions many types tend to become very complex mechanically and hence costly and difficult to test and to maintain.

The basis of the so-called static relaying is the use of circuits and components to achieve a variety of functions and operating characteristics which for protection purposes have traditionally been obtained using electromechanical devices. Reliability, always important has been emphasized as short-circuit levels, circuit ratings and complexity of interconnection have increased. Shorter operating times have become more essential to preserve dynamic stability as the character and loading of systems approach design limits. The satisfaction of these requirements has left little potential for further improvements in conventional electromechanical relays. Until fifteen years ago, relay design was dominated by the use of electromechanical elements. Such an element of whatever basic characteristics, e.g. square law induction element has a dynamic behaviour special to that element and design freedom is consequently restricted by factors such as the conflicting requirements of sensitivity and mechanical robustness. Experience shows that these more exacting requirements can readily be met using new static relays.

9.2 Classification of Static Relays

Static relays are classified according to the type of the measuring unit or the comparator as follows:

(i) Electronic relays.
(ii) Transductor relays.
(iii) Rectifier bridge relays.
(iv) Trnasistor relays.
(v) Hall effect relays.
(vi) Gauss effect relays.

9.2.1 Electronic Relays

These were the first to be developed in the series of static relays. They date back to early 1928 when Fitzgerald presented a carrier current pilot relaying which constituted unit protection of the transmission line. Subsequently a series of electronic circuits for most of the common types of protective gear relays were developed. The components used were electronic valves for measuring unit.

The two basic arrangements one as an amplitude comparator and another as a phase comparator are shown in Fig. (9.1). In the former case two a.c. quantities to be compared are rectified and applied in opposition in the control grid circuit of an electronic tube, so that operation occurs when one quantity exceeds the other by an amount depending on the bias. In the latter case one a.c. quantity can be connected to the control grid of an electronic tube and the other a.c. quantity to the screen grid of the tube, operation occurs when the two quantities are in phase.

Electronic relays offer the following advantages:

(a) Low burden on CTs and PTs, since the operating power is from an auxiliary d.c. supply.
(b) Absence of mechanical inertia and bouncing contacts.
(c) Fast operation.
(d) Low maintenance, owing to the absence of moving parts.

In spite of all these however electronic relays have not met with general success except for carrier current relaying which has attained widespread use. The major reason is that carrier relaying has accomplished a highly desirable result not economically feasible by any other method. This

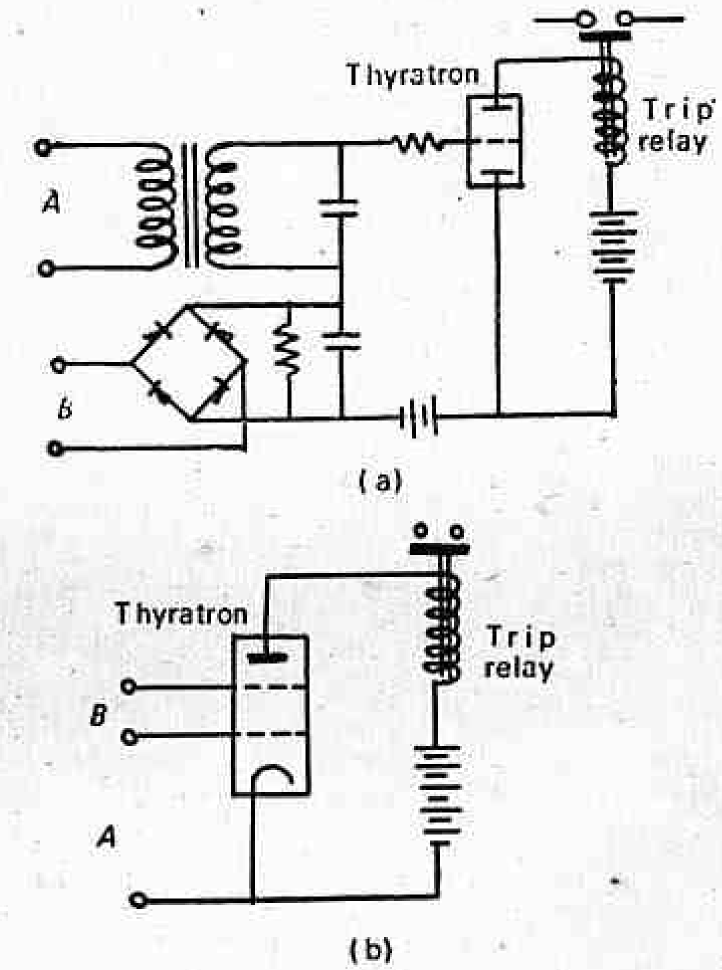


FIGURE 9.1 (a) Electronic amplitude comparator;
(b) electronic phase comparator.

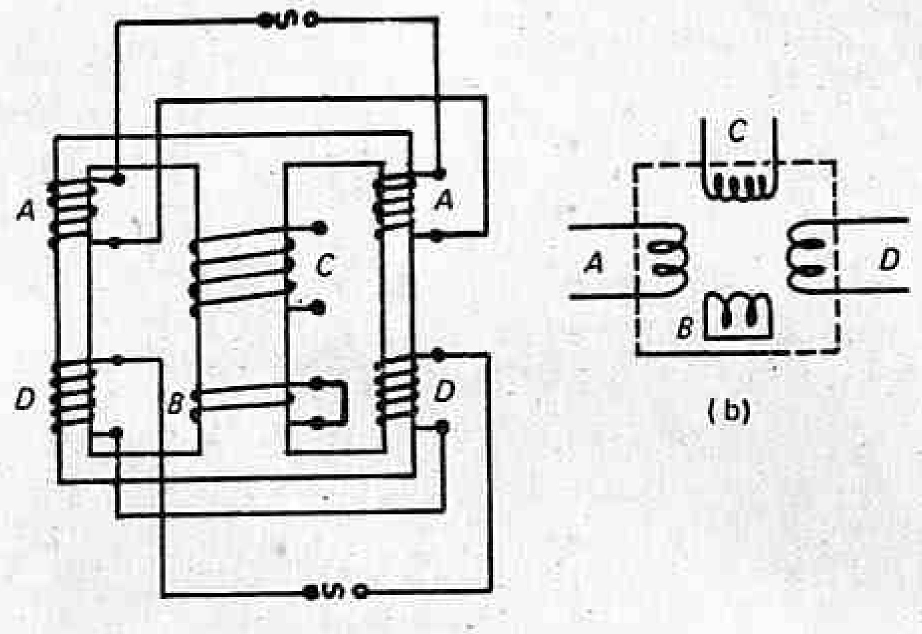
popularity is in spite of the following limitations of the electronic circuits.

(a) Presence of incandescent filament and necessary low-voltage power supply to heat them.
(b) Short life of the electronic valves.
(c) High power consumption.
(d) Requirement of high-tension supply.
(e) High cost for simple relays such as overcurrent relay.

9.2.2 Transductor (Magnetic Amplifier) Relays

Since relays now have to perform much more complicated functions, many types tend to become very complex mechanically, and hence costly to make and difficult to test and to maintain. The transductor controlling a simple slave relay, makes it possible to reduce a complex electromechanical device which operates in accordance with the interaction of fluxes and currents in a fully predictable way.

A transductor comprises essentially a magnetic core on which there are two groups of windings, usually known respectively as the operating windings and control windings. Each group may comprise only one winding but if there is more than one winding in a group all those windings are magnetically linked. On the other hand the windings of the different groups are not magnetically linked. The operating windings are energized with a.c. and control windings are energized with d.c. A transductor operates so as to present a variable impedance to currents flowing in the operating windings the magnitude of this impedance being varied by the current in the control winding. Figure (9.2) shows a single core transductor.



(a) (b)

FIGURE 9.2 (a) Single core transductor; (b) diagramatic representation of transductor. A—operating winding; B—coupling winding; C—control winding; D—output winding.

If used as an amplitude comparator it is limited in its sensitivity by the sensitivity of the slave relay in its output circuit; if used as a phase comparator to obtain greater sensitivity it is dependent upon an external a c. supply which is sometimes difficult to arrange.

Figure (9.3) shows a transductor relay where the restraining voltage is applied to the control winding through an impedance Z_R and a rectifier. The restraining current thus obtained is rectified and partially smoothed by the short-circuit effect of the rectifier on control winding and also due to the short circuited coupling winding. The effect of this is to drive both the limbs on which the operating winding is wound into saturation.

Now the operating winding is wound in such a way that the operating ampere-turns oppose the restraining ampere-turns in one limb and reinforce them in the other. Neglecting the finiteness of permeability and assuming equality of restraining and operating turns, the operating current would drive out of saturation, the limb in which operating current is against the restraining ampere-turns, when the peak value of the operating current

exceed the magnitude of restraining current. When this happens a voltage is induced in the output winding and the relay is energized. The same operation is repeated on the other limb during the next half cycle.

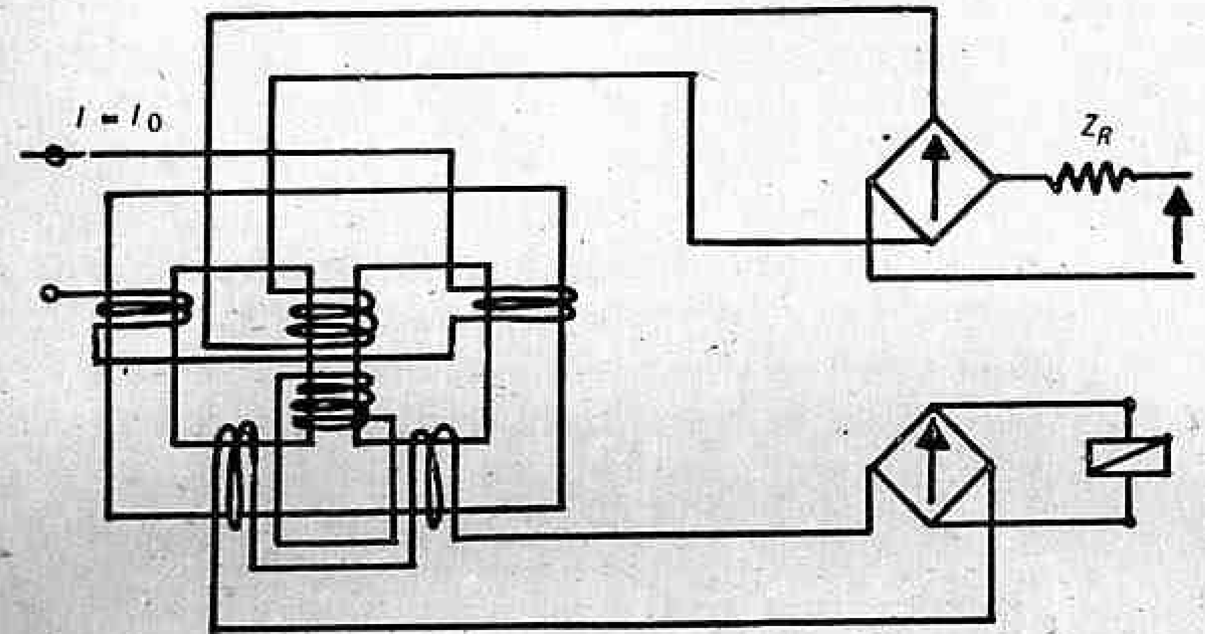


FIGURE 9.3 Transductor relay.

The slave relay current is very low until the above mentioned condition exists. Then it suddenly increases and becomes very large for a small value of operating current. For this reason a heavy duty of telephone type of relay is used with large setting. Due to smoothing and rectifying a signal, a delay is introduced because of the time constant of the smoothing circuit and hence the operating speed is slow.

Transductor relays are mechanically very simple and although some of them may appear to be a little complicated electrically, this does not affect their reliability adversely, since their operation is mainly dependent on static components whose characteristics are easily predetermined and checked. As a result they are easier to construct and test than electromechanical relays and their maintenance is practically negligible.

9.2.3 Rectifier Bridge Relays

With the development in semiconductor diodes this type has gained popularity and basically consists of two rectifier bridges and a moving coil or polarized moving iron relay. The most common are relay comparators based on rectifier bridges, which can be arranged as either phase or amplitude comparators. These will be discussed later in the next chapter.

9.2.4 Transistor Relays

These are the most widely accepted type of static relays, so much so that when we say static relays, we can safely infer transistor relays only. The transistor which acts like an electronic valve can overcome most of the limitations posed by the electronic valves and thus has made posssible to develop the *electronic relays* more commonly known as *static relays*.

The characteristics of modern transistors are such that they can replace the functional elements which are used in electromechanical relay to give necessary characteristics. The techanical features particularly suited to the design of functional units include amplifying and switching characteristics, sensitivity and high speed. Experience has shown that transistor circuits can not only perform the essential functions of a relay such as summation, comparison of inputs and integrating them, but they also provide necessary flexibility to suit the various relay requirements.

Two basic arrangements of relays based on transistor comparators are shown in Fig. (9.4). In either of these circuits, current of constant magnitude

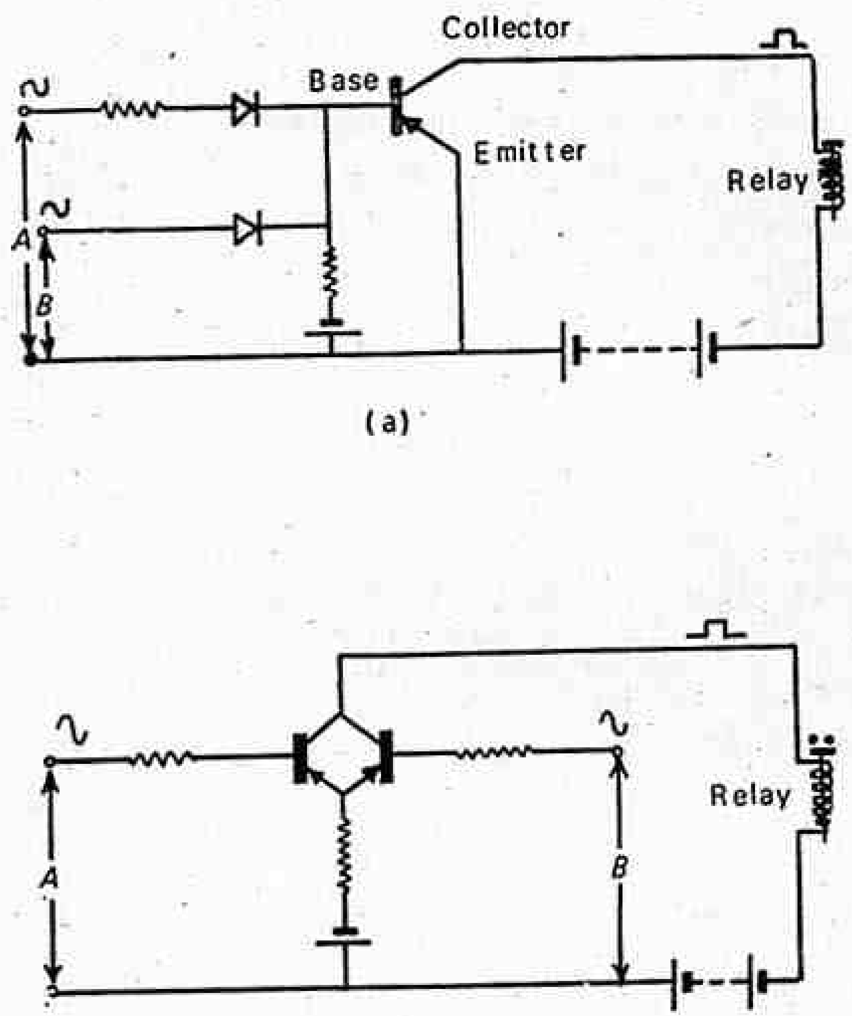


FIGURE 9.4 Static comparators: (a) multiple inputs to transistor base; (b) two back-to-back transistors.

flows in the collector circuit only when the input a.c. quantities are simultaneously negative; a relay in the collector circuit will pick up when the overlap angle exceeds a certain value, i.e. when the mean d.c. level in the collector circuit exceeds the relay pickup as a result of phase coincidence.

The advantages of transistorized relays may be enumerated as follows:

(a) Quick response, long life, high resistance to shock and vibration.

(b) Quick reset action—a high reset value and absence of overshoot is easily achieved because of the absence of mechanical inertia and thermal storage.

(c) No bearing friction or contact troubles (no corrosion, bouncing or wear), so minimum maintenance required.

(d) Ease of providing amplification enables greater sensitivity to be obtained.

(e) The basic building blocks of semiconductor circuitry permit a greater degree of sophistication in the shaping of operating characteristics, enabling the practical realization of relays with threshold characteristics more closely approaching the ideal requirements.

(f) The low energy levels required in the measuring circuits permit miniaturization and minimize current transformer inaccuracies.

(g) Use of printed (or integrated circuits) to avoid wiring errors and to facilitate rationalization of batch production.

Static relays employing transistors have their limitations which are:

(a) Variation of characteristics with temperature and age.

(b) Dependence of reliability on a large number of small components and their electrical connections.

(c) Low short time overload capacity compared with electromagnetic relays.

It has now become possible to compensate for all these factors. For example, the use of thermistors eliminate temperature error, whilst ageing may be minimized by presoaking for several hours at a relatively high temperature. Factors (b) and (c) above are the design features of the circuit and careful design can compensate for these limitations.

9.2.5 Hall Effect Relays

Hall effect is utilized to give a phase comparator. The effect is very predominant in certain semiconductors such as indium arsenide, indium antimonide, indium phosphate, etc. Figure (9.5) illustrates the basic Hall generator where the Hall crystal in the form of a slab carries current in the *X*-direction and is placed in a magnetic field in the *Y*-direction, a voltage

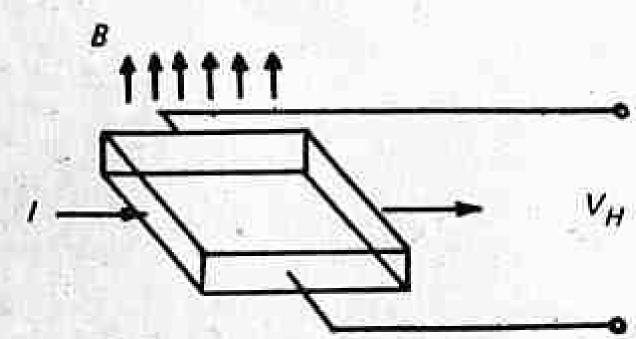


FIGURE 9.5 Basic Hall generator.

known as Hall voltage is induced in the Z-direction across the edges of the crystal.

Let $\phi=\phi_m \sin wt$

and $i=I_m \sin(wt-\alpha)$

then the Hall voltage V_H is given by

$$V_H \propto \phi i \tag{9.1}$$

$$\propto \phi_m \sin wt \times I_m \sin(wt-\alpha)$$

$$\propto \phi_m I_m [\cos\alpha - \cos(2wt-\alpha)] \tag{9.2}$$

In the above expression while the first term on the right-hand side is a d.c. voltage proportional to the vectorial product of the two inputs—flux and current—the second term is an a.c. voltage of double frequency.

The double frequency term can be eliminated by cross connecting two Hall generators as shown in Fig. (9.6) where the two input signals are the sinsusoidal a.c. currents I_1 and I_2.

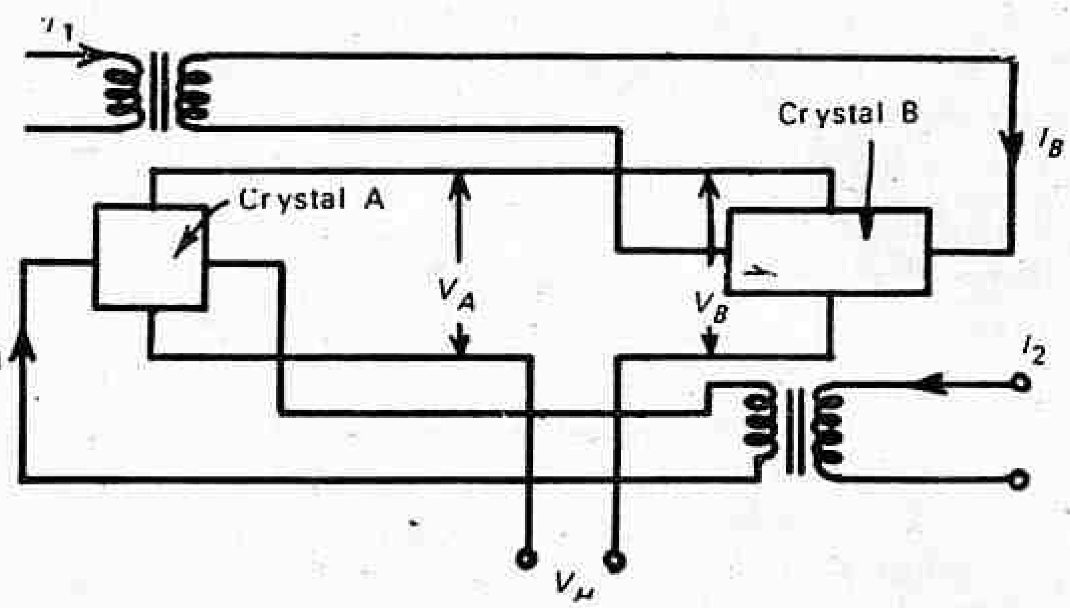


FIGURE 9.6 Cross-connection of two Hall generators.

Assuming

$$\left.\begin{aligned} I_1 &= I_{m_1} \sin wt \\ \text{and} \quad I_2 &= I_{m_2} \sin(wt+\alpha) \end{aligned}\right\} \tag{9.3}$$

fluxes through the crystals A and B are

$$\phi_A \propto I_1$$

$$\phi_B \propto I_2$$

and current through the crystals are

$$\left.\begin{aligned} I_A &\propto \frac{dI_2}{dt} \\ \text{and} \quad I_B &\propto \frac{dI_1}{dt} \end{aligned}\right\} \tag{9.4}$$

The two crystals are connected such that their output voltages oppose each other, and the resultant output of the combination is, therefore

$$V_H \propto V_A - V_B \tag{9.5}$$

$$\propto I_1 \frac{dI_2}{dt} - I_2 \frac{dI_1}{dt} \tag{9.6}$$

$$\propto Im_1 \sin wt \times Im_2\, w \cos(wt+\alpha)$$

$$- Im_2 \sin(wt+\alpha) w\, Im_1 \cos wt$$

or

$$V_H \propto Im_1 Im_2 \sin\alpha \tag{9.7}$$

The device therefore now acts as a pure phase comparator. A telephone type relay can be directly operated from the Hall voltage. The Hall effect device does not require an auxiliary d.c. source while the transistorized circuits need about 10 V d.c. supply. The total volt-ampere consumption of the Hall device will be higher than transistor circuits. Its construction will be much simpler. Because of the high cost of the Hall crystal, large temperature error and low output, they have not yet been used in practical relays except in the U.S.S.R.

9.2.6 Gauss Effect Relays

Some semiconductors have the property where resistance varies when magnetic field is applied. This effect is known as *magneto resistivity* or *Gauss effect*. If one a. c. voltage V_1 produces the magnetic field through the crystal, which for the best results should be in the form of a disc having a large diameter and another voltage V_2 sends a current radially through the disc, then the current will be proportional to $V_1 V_2 \cos\theta$, where θ is the angle between the two voltages. This can thus act as a phase comparator and used as a static relay. This is however better than Hall effect devices because polarizing current is not required, the crystal is simpler and the output is higher. The cost of the crystal has limited its use in static relays.

QUESTIONS

1. What is a static relay and what is the basis for its development? In what way has it been successful in replacing the conventional electromagnetic relays?
2. Name different types of static relays. Discuss the use of transistors and Hall crystals as static relays.
3. Discuss the advantages and disadvantages of static relays as protective devices.