GER-3199

Distance Relays Application Guide

"APPLICATION GUIDE FOR THE USE OF DISTANCE RELAYS"

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The natural growth of power systems today has resulted in a greater need for high speed distance type protection against all kinds of faults on transmission lines. While for economic reasons, the greatest demand in the past has been for those distance type relays that protect against multi-phase faults, modern power systems have indicated a sharp increase in the use of ground as well as phase distance relays. The many ramifications in system design and special user requirements have resulted in a significant increase in the available types of distance relays. It is the purpose of the following sections of this paper to assist the Application Engineer in his endeavor to select the proper relay for the job at hand.

In general the points discussed in this paper apply to phase distance relays. However, to complete the picture, the different models of ground distance relay are tabulated at the end of the paper along with typical application information. Basic material on the theory of operation of the simple (or directional) mho units, offset mho units, and reactance (or ohm) units form the background. From there, the paper proceeds to discuss the significance of such terms normally associated with distance relays as memory action, offset, angle of maximum torque, transient overreach, blinders, and arc resistance and to relate these terms to the desired relay characteristics for the various different protective functions. Finally each of the different popular models will be described and standard recommended packages will be grouped for such schemes of protection as straight distance directional comparison and transferred tripping. Special applications such as out-of-step blocking and out-of-step tripping will also be discussed.

PHASE DISTANCE RELAY TORQUE EQUATIONS

In order to establish a sound basis for applying mho and reactance type relays, it is important to have some understanding of the torque equations that define the characteristics of these relays. Since the mho and reactance units are basically single-phase units that are used to protect against faults between pairs of phases, three units are required for the protection of all three phases. An AB unit is required for faults involving phases A and B. For phase B to phase C faults, a phase BC unit is required and for phase C to phase A faults, a phase CA unit is needed. For three-phase faults all three units will operate.

By virtue of their construction, the reactance and mho units have the same ohmic reach on phase-to-phase faults as they have on three-phase faults. The following equations describe the reactance, mho and offset mho units of any one pair of phases. The voltages and currents designated as E and I with subscripts are actually dual quantities. For example, in the case of the mho unit, I_O - the operating coil current - for, say the phase BC unit is actually the vector difference between I_B and I_C. The restraint voltage E_R is the phase B to C voltage. The same applies to the polarizing voltage E_P.

MHO UNIT

Operating Torque	**Restraining Torque**
$KI_OE_P \cos(\theta - \phi)$	$TE_RE_P + K_S$

where:
- K — Design Constant (100 times the minimum reach)
- T — Relay Tap Setting in Percent
- K_S — Control Spring Torque Constant
- I_O — Operating Coil Current
- E_R — Restraint Circuit Voltage (These are actually the same voltage fed to two separate circuits.)
- E_P — Polarizing Circuit Voltage
- θ — Angle by which I_O lags E_P (Transmission Line Impedance Angle)
- ϕ — Maximum Torque Angle (Design Constant)

By equating the operating and restraining torque, cancelling E_p from both sides of the equation recognizing that $E_R/I_o = Z$ and assuming K_S to be negligible, the mho unit characteristic in the R-X plane is obtained. See Figure 1 below.

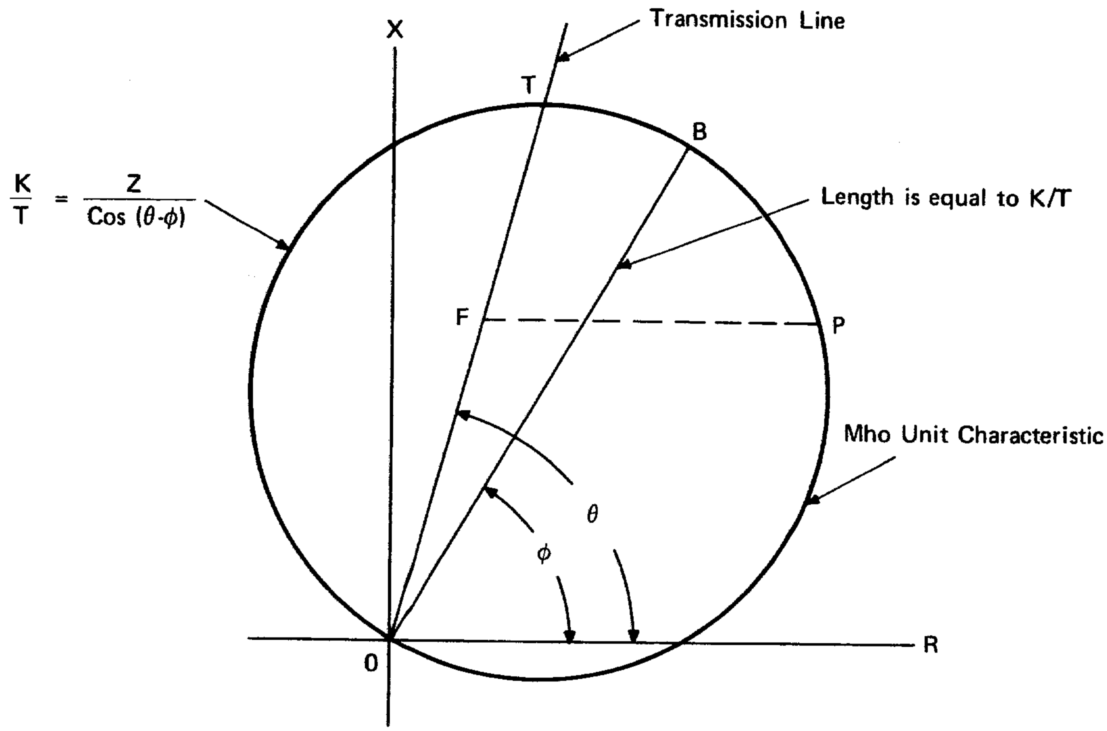


FIGURE 1

It is important to note that the mho unit is inherently directional because its characteristic always passes through the origin in the R-X diagram. This unit will operate for faults that plot anywhere inside the circular characteristic. The amount of arc resistance that this type of unit can accommodate for a fault on the transmission line is represented, on the R-X diagram, by the horizontal distance from the fault to the relay characteristic. For example, for a fault at point F on the protected line in Figure 1 this unit will accommodate an arc resistance equal to $\overline{FP}$.

The operating torque of the mho unit is proportional to the product of the operating current and the polarizing voltage. For first zone faults that are close to the relay terminals, the polarizing voltage can get quite small and in some instances actually approach zero. In order to insure positive high-speed operation for these conditions, the polarizing circuit is designed with memory action so that a substantial torque persists for several cycles after the fault occurs, even if the polarizing voltage actually goes to zero. This is based on having normal voltage prior to the fault. As the fault moves away from the relay location, the voltage at the relay increases until sufficient voltage is available to insure operation on a steady-state basis. This is what permits the mho unit to be used in conjunction with time delay for second and third zone faults. The mho unit should not be used in conjunction with time delay if it is desired to detect *zero voltage* faults.

The mho unit is available in several different ohmic ranges and angles of maximum torque. Since the restraint circuits are essentially the same for all ranges, the difference in range is obtained by changing the design constant K in the operating circuit. Actually, the minimum reach of a mho unit is directly proportional to K. For this reason, the higher range mho units operate at a higher torque level per unit of fault current than do the lower range units.

REACTANCE (OHM) UNIT

Operating Torque	Restraining Torque
KI_oI_P	$TE_RI_P \sin\theta + K_S$

where:

- K – Design Constant (100 times minimum reach)
- T – Relay Tap Setting in Percent
- K_S – Control Spring Torque Constant
- I_o – Operating Coil Current (These are actually the same current fed to two separate circuits.)
- I_P – Polarizing Coil Current
- E_R – Restraint Circuit Voltage
- θ – Angle by which I_P lags E_R (Transmission Line Impedance Angle)

Be equating the operating and restraining torques, cancelling I_P from both sides of the equation, recognizing that

$$\frac{E_R}{I_o} \sin\theta = X$$

and assuming K_S to be negligible, the reactance or ohm unit characteristic in the R-X plane is obtained. See Figure 2.

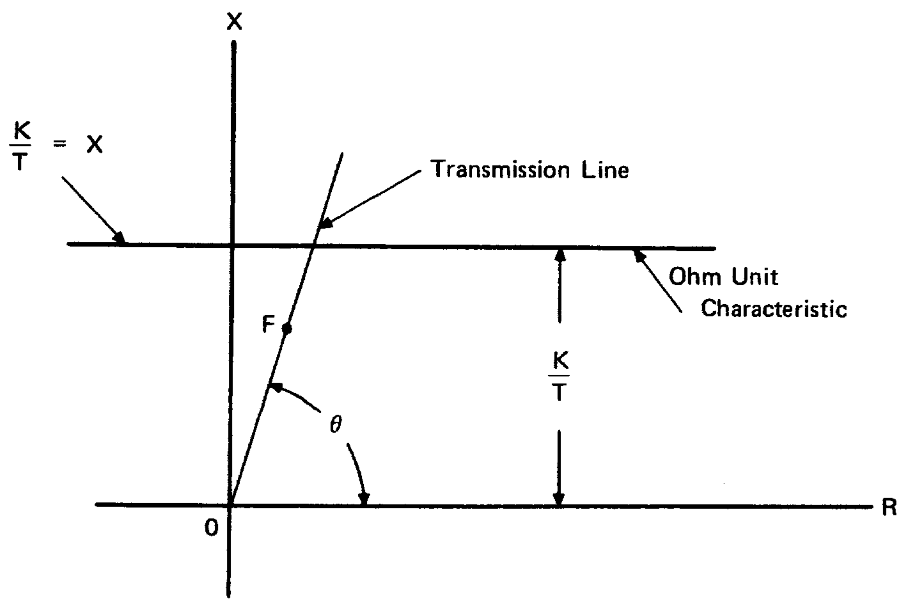


FIGURE 2

It is important to note that the ohm unit will operate for faults that plot anywhere below its characteristic line on the R-X diagram. Thus, the unit is not directional in itself and therefore is always used in conjunction with a (directional) mho unit. Its horizontal characteristic makes this unit insensitive to resistance and so it measures only the reactive portion of the impedance from the relay location to the fault. It operates to trip if this reactance is less than the relay setting. The measurement of this unit is unaffected by arc resistance in the fault.

While the operating torque is given as the product of two currents, I_O and I_P, these are actually the same current supplied to two different poles in the magnetic circuit of the relay. Thus, the operating torque of the ohm unit is proportional to the fault current squared. Since no voltage term appears in the operating torque equation for this unit, it will operate on zero voltage faults without memory action.

The ohm unit is available in several different ohmic ranges. However, regardless of the range, the restraint circuits are essentially the same for all relays. The difference in range is obtained in the operating circuit by changing the design constant K. The minimum reach of an ohm unit is directly proportional to K. For this reason, the higher range reactance units operate at a higher torque level, per unit of fault current, than do the lower range units.

OFFSET MHO UNIT

Operating Torque	**Restraining Torque**
$KI_O(E + I_OZ_T) \cos(\delta - \phi)$	$T(E + I_OZ_T)(E + I_OZ_T) + K_s$

where:

- K — Design Constant (100 times the minimum reach)
- T — Relay Tap Setting in Percent
- K_s — Control Spring Torque Constant
- I_O — Operating Coil and Transactor Primary Current
- Z_T — Transactor (offset) Impedance
- E — Voltage supplied to relay (PT secondary voltage)
- ϕ — Maximum Torque Angle (Design Constant)
- δ — Angle by which I_O lags $(E + I_OZ_T)$

It will be noted that the equations for the operating and restraining torques of the offset mho unit are the same as those for the simple mho unit except that I_OZ_T is now a part of the polarizing and restraining voltages.

By equating the operating and restraining torques and assuming K_s to be negligible, the offset mho unit characteristic in the R-X plane is obtained. Figure 3 is a plot of this characteristic illustrating that the diameter of the circular characteristic is still K/T as in the case of the simple mho unit but the entire circle is offset by an amount equal to the transactor impedance Z_T in the direction of the impedance angle of the transactor. Note that in Figure 3, the mho unit characteristic is offset along the maximum torque angle ϕ. Some offset mho units are offset vertically along the X axis.

From Figure 3 it is apparent that the offset mho unit is not directional inasmuch as its characteristic does not pass through the origin of the R-X diagram. This unit will operate for faults that plot anywhere inside the circular characteristic. The amount of arc resistance that this type of unit can accommodate for a fault on the transmission line is represented on the R-X diagram by the horizontal distance from the fault to the relay characteristic. For example, for a fault at point F on the line (in Figure 3) this unit will accommodate an arc resistance equal to $\overline{FP}$.

The operating torque of the offset mho unit is proportional to the product of the operating current (I_O) and the polarizing voltage $(E + I_OZ_T)$. In this case, the voltage is composed of two components, the system voltage (E) and the transactor voltage (I_OZ_T). For faults at the relay location where the voltage E can go to zero, I_OZ_T still exists. Thus, a polarizing voltage is present even for zero voltage faults and for this condition, the operating torque is proportional to I_O^2. Because of this, the offset mho unit will operate on a steady-state basis for zero voltage faults and therefore may be used in conjunction with time delay to operate for these faults.

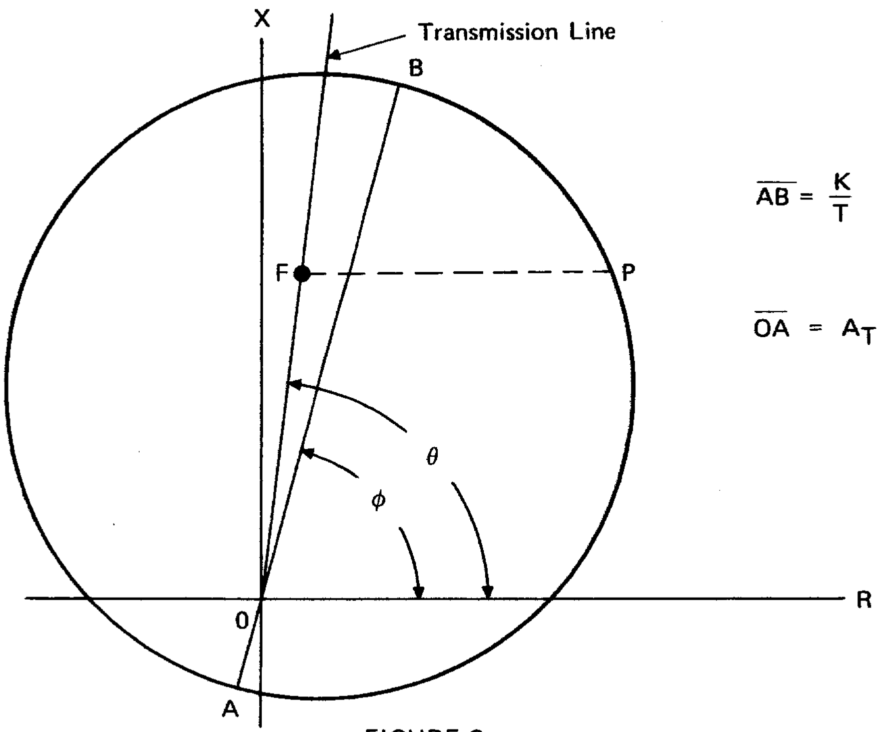


FIGURE 3

The offset mho unit is available in several different ohmic ranges, offset ranges and angles of maximum torque. Since the restraint circuits are essentially the same for all ohmic ranges, the difference in range is obtained by changing the design constant K in the operating circuit. Actually, the minimum diameter of an offset mho unit is directly proportional to K. For this reason, the higher range units operate at a higher torque level then do the lower range units.

ANGLE OF MAXIMUM TORQUE

The angle of maximum torque of a simple mho unit is the angle at which it has its maximum reach. Referring to Figure 1, the angle of maximum torque (ϕ) is the angle between the diameter ($\overline{OB}$) of the characteristic and the R axis.

This angle is significant in two respects. First, it determines the amount of arc resistance that can be accommodated by the unit. This is illustrated in Figure 4 below where two mho units, one having a maximum torque angle of 60 degrees and the other 75 degrees, are both set to reach the same distance ($\overline{OD}$) along an 80 degree transmission circuit. It is apparent from this sketch that the characteristic with the smaller angle of maximum torque will accommodate a larger amount of arc resistance.

For example, for a fault at Point F on the transmission lines, the 60 degree characteristic will accommodate an arc resistance that is greater by an amount AB than that which the 75 degree characteristic will accommodate. Note that the magnitude of this difference varies with the fault location along the protected line.

The performance of the mho unit under heavy load conditions and system swings is also related to the angle of maximum torque. Referring back to Figure 4, let point L represent the apparent load impedance on the R-X diagram. As the reach of the mho unit is increased, the characteristic will expand and approach the apparent impedance of the load. Thus, increasing the reach setting of the mho unit makes it more susceptable to operation on system swings which cause the apparent load impedance to move in the direction of the dashed

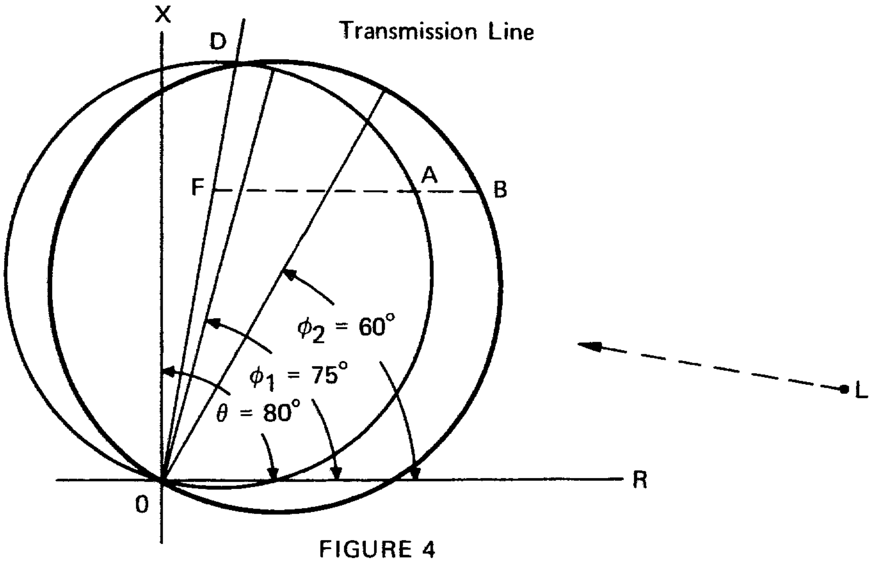


FIGURE 4

arrow of Figure 4. It is interesting to note, that on a secondary basis, a load current of 5 amperes at rated volts (66.3) represents an apparent load impedance of 66.3/5 or 13.3 secondary phase-to-neutral ohms. The angle of this impedance is, of course, determined by the power factor of the load.

In a protective relaying scheme that utilizes mho units for three zones of protection, the first zone unit is set for the shortest reach (generally not longer than 90 percent of the protected line length) while the third zone unit is set with the longest reach and the second zone is set somewhere in between. With such an arrangement, the first zone will accommodate the least amount arc resistance and will be least subject to operate on system swings. The third zone unit will accommodate the most arc resistance and will be most susceptable to operation on system swings. Thus, where these factors are important, it may be desirable to use a first zone mho unit with a relatively small angle of maximum torque while the second and third zone units have a larger maximum torque angle. This will permit the first zone unit to accommodate more arc resistance but, because of its short reach setting, its susceptability to system swings will be minimized. On the other hand, the second and third zone units, because of their longer reach settings, will accommodate considerable arc resistance but their larger angles of maximum torque will minimize their susceptability to system swings.

When a mho unit is used to protect a short line, it is especially desirable to use a unit with a small angle of maximum torque in order to insure maximum arc resistance accommodation. For this reason, the very short reach mho units are available with 45 degree maximum torque angles.

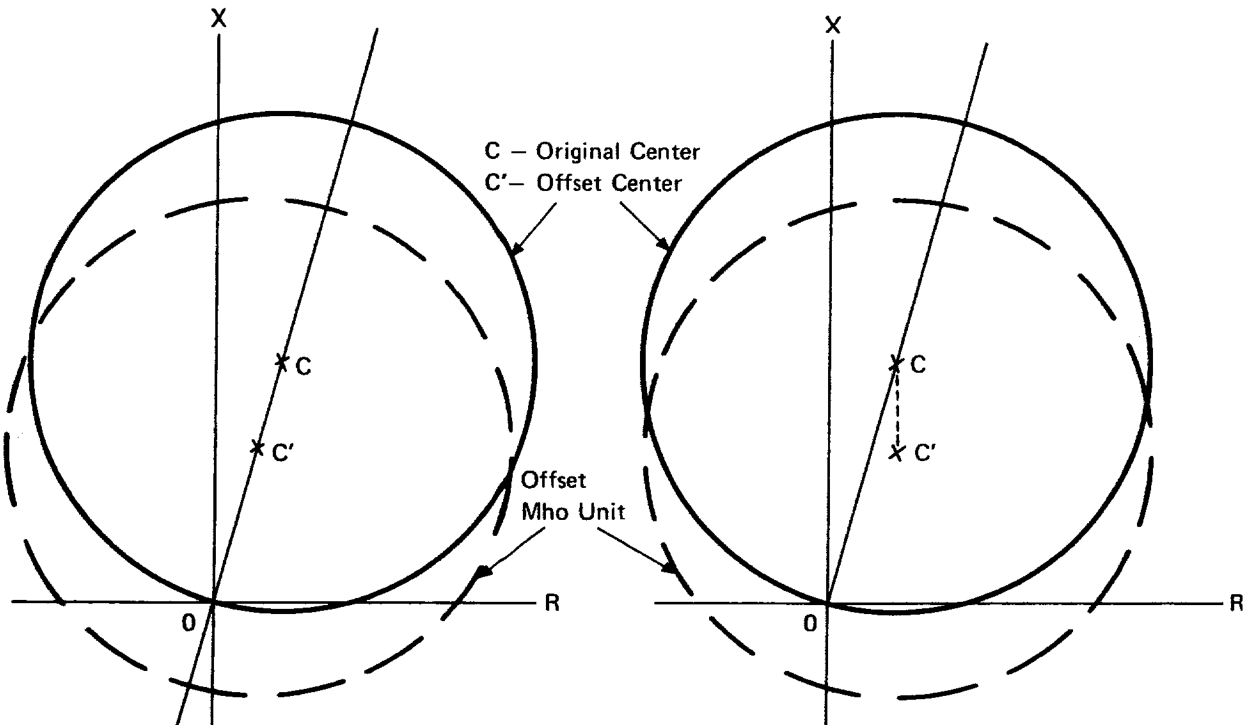
The angle of maximum torque of the offset mho unit is defined as its angle of maximum torque when set with zero offset. In other words, the angle of maximum torque of the offset mho unit is obtained by assuming that the unit is set with zero offset and the angle of maximum torque is then the angle at which it has its maximum reach. In general, an offset mho unit is a second or third zone unit. A first zone unit never has offset because high-speed first zone tripping units must have directional characteristics except on radial, or essentially radial circuits. The same comments relating to arc resistance and system swings apply to the offset mho unit as do to the simple mho unit.

The maximum torque angle of the ohm unit characteristic illustrated in Figure 2 is 90 degrees. This is the standard ohm unit that is used in the type GCX relays for transmission line protection. It is obvious that this type of characteristic will accommodate considerably more arc resistance than a first-zone mho unit with the same reach setting along the transmission line.

Ohm units are also available with other angles of maximum torque. These are discussed under the headings "Out-of-Step Tripping" and "Blinders".

OFFSET

Offset, as used with transmission line relays, is that feature which is incorporated into certain mho units that permits the simple directional mho characteristic to be displaced from its position of passing through the origin in order to make it include the origin in an offset position on the R-X diagram. While the offset can theoretically take any direction, there are only two offset directions generally employed. The first, and probably the most common is to offset the characteristic in the direction of the angle of maximum torque of the unit. The second is to offset the characteristic along the X axis in the R-X plane. These are illustrated in Figures 5a and 5b below.



Offset Along Maximum Torque Angle

FIGURE 5a

Offset Along X-Axis

FIGURE 5b

It is apparent from Fig. 5 that offsetting a simple mho unit converts it from a true directional unit to a non-directional unit. In standard relaying schemes, for the protection of transmission lines, this offset is provided for one single purpose. This is to embody the unit with the ability to pick up and stay picked up, on a steady-state basis, for as long as a zero voltage fault persists. Thus, the difference between the two types of offset is insignificant.

In directional comparison schemes using carrier current or microwave channels for the protection of transmission lines, it is essential for the unit that keys the transmitter and sends a blocking signal on external faults to have an offset characteristic. The reason for this may be derived from Figure 6 by assuming that the line section between breakers 1 and 2 is protected by a directional comparison carrier relaying scheme. If a fault were to occur at F1, immediately adjacent to circuit breaker 3, the carrier starting relays at circuit breaker 1 must operate to start carrier and send a blocking signal to circuit breaker 2 in order to prevent a false trip at circuit breaker 2. This blocking signal must be continued until the fault is cleared by circuit breaker 3. Since this fault can result in very low voltage (and conceivably zero voltage) to the relays associated with circuit breaker 1, the carrier starting units at circuit breaker 1 must have an offset characteristic so that after they pick up fast due to the memory action, they stay picked up due to their offset characteristics until circuit breaker 3 clears the fault.

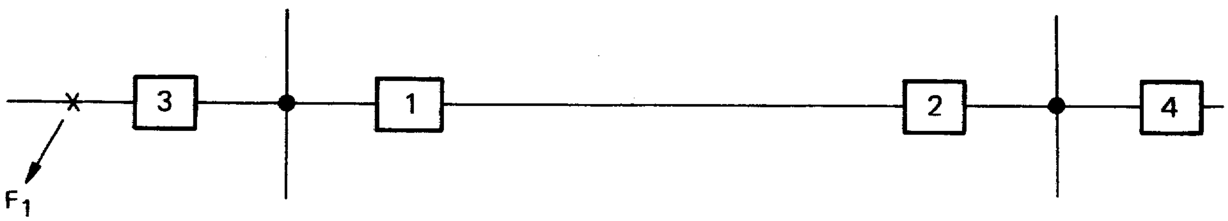


FIGURE 6

The amount of fault current that is required to pick up or maintain pick up of an offset mho unit with zero voltage applied decreases as the offset is increased just as long as the offset does not exceed one half of the diameter of the characteristic. Thus, a mho unit set for a three-ohm diameter will operate for zero voltage faults at a lower fault current when it has a 1.0 ohm offset than when it has a 0.5 ohm offset.

In general, there is no reason to offset a mho unit more than necessary to insure positive steady-state operation for zero voltage faults.

MEMORY ACTION

Memory action is that feature which is designed into the potential polarizing circuit of the simple and offset mho units in order to prolong the polarizing flux at a high level for some short time after the voltage disappears. This memory action is required in the simple mho unit to insure positive high-speed operation on close-in faults that result in very low or even zero voltage being supplied to the relay polarizing circuit. This is explained for the Mho Unit under the section on Relay Torque Equations. Since memory action persists for only several cycles, it serves no practical purpose in a mho unit when that unit is used in conjunction with a time delay auxiliary relay. Thus, memory action is required only on mho units that are used for high-speed first zone tripping and on mho units that are used for high-speed functions in directional comparison and transferred tripping schemes.

As discussed in the sections under "Relay Torque Equations", memory action is not required for the reactance unit because this type of unit operates on current alone. The offset mho unit will also operate on current alone even for zero voltage faults. However, the memory action is desirable in the offset mho unit to provide for maximum speed when the unit is used as a transmitter keying (carrier starting) unit in directional comparison relaying schemes. In such schemes, it is important that the transmitter be keyed-on as quickly as possible to provide a blocking signal on external faults. Once the unit picks up, it will continue to stay picked up, as long as the fault persists, even for zero voltage faults.

SELECTION OF RANGE

When selecting the ranges of a terminal of distance relays, the major consideration is that the ranges should encompass the desired settings. Another consideration is that future tapping or splitting of the line should, if practical, still permit the use of the same relays. However, still another more subtle consideration should be evaluated. This deals with the torque level of operation of the relays.

For any desired ohmic reach setting, the unit having the highest minimum reach that can accommodate the desired setting will provide the highest torque level of operation. For example, if a 4-ohm reach setting is desired, a 3-30 ohm mho unit with a 4-ohm setting will operate at a higher torque level than a 2-20 ohm mho unit with a 4-ohm reach setting. If a 0.75 ohm reach setting is necessary, a 0.5-5.0 ohm reactance unit will operate at a higher torque level than a 0.25-2.5 ohm reactance unit.

Thus, all other things being equal, there is some advantage in selecting the highest range units that can accommodate the desired settings.

TRANSIENT OVERREACH

In general, distance relays are calibrated and set in terms of applied sinusoidal voltages and currents. When these same relays are installed on the Power System they are often called on to operate for conditions that are considerably different from those used in setting their reach. When a fault occurs on a transmission circuit, the resulting fault current generally contains a d-c offset in addition to the a-c power frequency component. The ratio of this d-c offset to the a-c component of current depends on the instant in the cycle at which the fault occurred while the rate of decay of the offset is a function of the impedance angle (or L/R ratio) of the system. This offset condition exists only for several cycles after the inception of the fault.

The effect of the offset is to cause the relays to "see" an impedance that is somewhat smaller than the actual impedance to the fault. This can result in the relay overreaching its setting. Since the offset decays rapidly, the overreach is transient in nature and so is termed Transient Overreach. When a distance relay is used in conjunction with time delay (RPM relay) for second and for third zone protection, the transient overreach characteristics on the measuring units so used are of no significance because the d-c offset transient will have disappeared long before second or third zone time expires.

On the other hand, the first zone distance measuring units operate at high speeds without any intentional time delay. These units are usually set so that they do not reach beyond the remote terminal(s) of the protected line section and so they are designed with limited transient overreach characteristics.

Summing up, all first zone relays, or units of relays, have limited transient overreach characteristics while second and third zone relays, or units of relays, do not. Conversely, when selecting a relay for a first zone application it should have limited transient overreach characteristics. For second and third zone applications limited transient overreach is not required.

ARC RESISTANCE

It is well known that arc or fault resistance will affect the reach of a mho unit but not that of a reactance unit. From Figure 1 it is evident that for the fault at F on the transmission line, the mho unit will operate for arc resistances up to a magnitude equal to $\overline{FP}$. However, for a fault at T even the smallest amount of arc resistance will cause the fault to appear outside the mho characteristic. Thus, the magnitude of the arc resistance and the location of the fault as well as the actual setting will determine whether or not the mho unit "sees" the fault.

From Figure 2 it is apparent that the reach of the ohm unit itself is not affected by arc resistance just as long as the fault is within the reactance reach setting of the unit. This is true because for a fault on the line (at point F for example) the arc resistance will plot horizontally-parallel to the relay characteristic. The amount of arc resistance that the ohm unit can accommodate is actually only limited by the setting of the directional mho unit (not shown in Figure 2) that is used in conjunction with the ohm unit. Since this mho unit generally takes a third zone setting, the combination can accommodate considerably more arc resistance than a mho unit set for the same first zone reach as the reactance unit.

Since arc or fault resistance is not related to the length of the protected line section, it is quite possible for the magnitude of the arc resistance on a short line to approach or actually exceed the impedance of the line. Such applications demand a first zone reactance unit rather than a mho unit for optimum protection. In the case of longer lines, the arc resistance tends to be smaller relative to the line impedance and for such cases the mho unit may be satisfactorily used.

Arc resistance in faults is difficult to evaluate. However, it is known that the resistance of an arc increases with the length of the arc and has an inverse relationship to the current in the arc. As a rough approximation, assuming fault currents in excess of 1,000 primary amperes, the arc voltage may be assumed relatively constant at about 500 volts per foot of arc. If it is further assumed that the arc length per phase is essentially equal to one half the spacing between adjacent phases for all types of multi-phase faults, then the arc voltage at the inception of the fault can be roughly approximately by the following equation

$$V_{arc} = \frac{d \times 500}{2} \text{ primary volts per phase}$$

where d is the spacing between adjacent conductors.

If we assume further that line conductor spacing is roughly one foot per 10KV then the above equation becomes

$$V_{arc} = \frac{50}{2} (\overline{KV}) = 25(\overline{KV}) \text{ primary volts per phase}$$

where $\overline{KV}$ is the rated voltage of the line in kilovolts.

Since the potential transformers have a ratio of $(\overline{KV})(1000)/115$ volts, the secondary arc voltage is

$$V_{arc} = 25(\overline{KV}) \frac{115}{1000(\overline{KV})}$$

2.9 secondary volts per phase.

Thus it appears, for fault currents in excess of 1,000 primary amperes, roughly 3 secondary volts per phase of arc voltage can be present. This voltage divided by the secondary fault current will yield an arc resistance that may be plotted on the R-X diagram along with the protected line to provide a rough estimate as to the adequacy of the protective relay settings.

It is important to note that for a second or third zone time delay trip the fault arc may elongate with time so that the fault resistance at the time the relay is called on to operate is larger than that value calculated above.

BLINDERS

The term blinders as it applies to phase distance relays has the same significance as when it is applied to a horse. In the case of the horse, blinders limit his vision to a narrow beam in the direction in which he is facing. In the case of a distance relay, blinders limit the operation of the distance relays to a narrow beam that parallels and encompasses the protected line. In general, relay blinders are required with mho units only where long lines are involved and the resulting mho unit settings are large enough to pick up on maximum full load currents or minor system swings. (Figure 7 on following page.)

The blinder and mho unit contacts are interlocked in the trip circuit in such a way that tripping can only occur in the fault impedance plots inside the mho characteristics and between blinders A and B. Actually the blinders are nothing more than reactance units similar to those of Figure 2 that have been rotated by modifying the power factor angle of the restraint circuit of the units. The A blinder operates for faults that plot to its right. The B blinder operates for faults that plot to its left. The overall effect of the blinders is to restrict the operating zone to an area on the R-X diagram that parallels the protected line and thus makes the combination relatively insensitive to system swings and immune to operation on full load.

One pair of blinders is required per phase. Thus, three pairs are needed per terminal on a three-phase system.

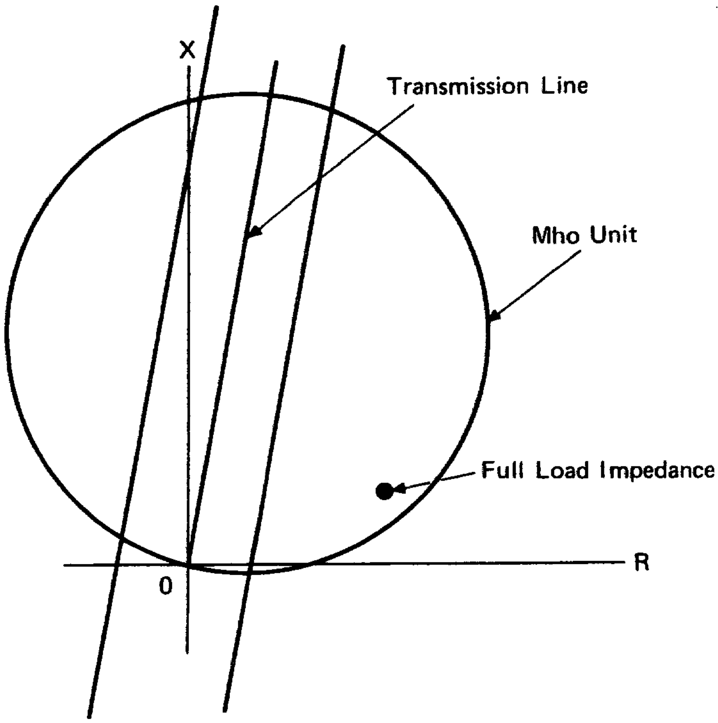


FIGURE 7

OUT-OF-STEP TRIPPING AND OUT-OF-STEP BLOCKING

Experience has indicated that for certain system operating conditions a severe system disturbance can cause system instability and result in a loss of synchronism between different generating units on an interconnected system. Such a condition is termed "Out of Step". Since a prolonged out-of-step condition can result in a partial, or in the extreme case, a complete system shut down, it is desirable to detect this condition as soon as possible and take the appropriate action.

There are two basic tools available to do this job. First, and probably the most common is the out-of-step-blocking relay. Out-of-step-blocking relays operate in conjunction with the mho-type tripping relays to prevent a terminal from tripping during severe system swings and out-of-step conditions. This prevents the system from separating in an indiscriminate manner. Next is the out-of-step-tripping relay. This device operates independently of the other protective devices to detect the out-of-step condition during the first pole slip and initiates tripping of the *desired* circuit breakers. It is important to recognize that the out-of-step-tripping relays must be installed on the system where they will be able to detect the out-of-step condition and that they should trip the proper local or remote circuit breakers. In this case, the proper breakers would be those that would separate the system in such a way as to balance the load with the available generation on any isolated portion of the system. Needless to say, the application of out-of-step-tripping relays must be coordinated with the out-of-step-blocking relays and both types of out-of-step protection should be based on the results of system studies.

Since an out-of-step condition is a balanced three-phase phenomenon, the out-of-step relays need be only single-phase devices. Figure 8 below illustrates the principles of operation on the R-X diagram.

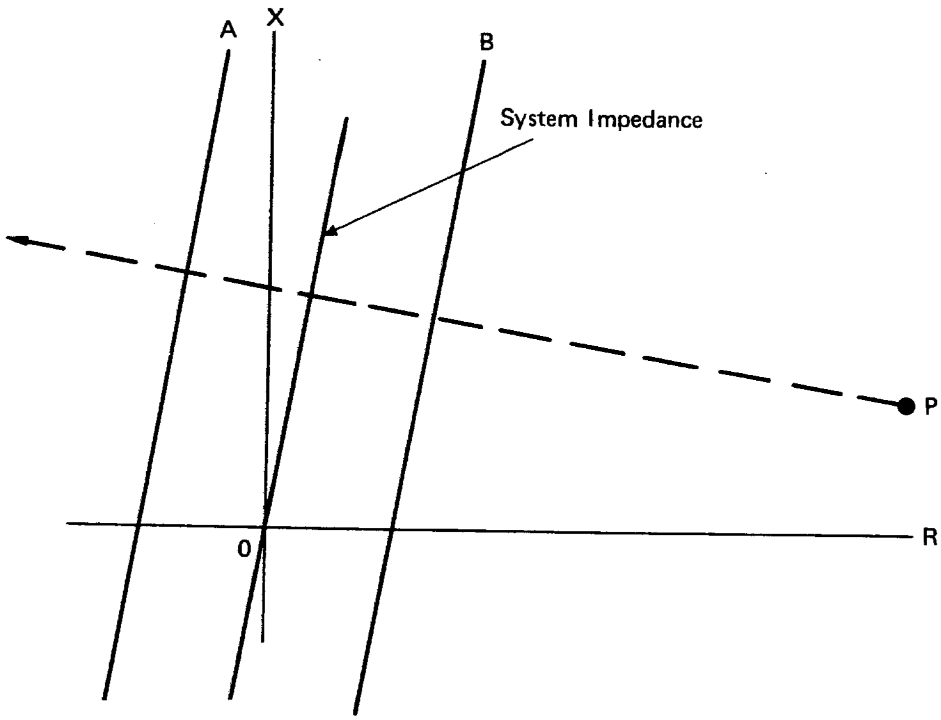


FIGURE 8

The out-of-step-tripping relay is made up of two rotated reactance type units the characteristics of which are labeled A and B in Figure 8. These units are essentially the same as those used as blinders with mho units. When an out-of-step condition occurs and the apparent impedance as viewed by these units moves from, say point P to the left along the dashed path, this impedance is first to the right of both characteristics. Next it is between the two characteristics and finally it emerges to the left of the characteristic A. This sequence of events is "evaluated" by an associated auxiliary relay to ascertain that an out-of-step condition exists and a trip signal is given either to local breakers or over some suitable communication channel to remote breakers. If the locus of the out-of-step impedance proceeded from left to right, the same result would be produced.

The out-of-step-blocking relay operates in a somewhat different manner. It is a single-phase distance type unit that operates in conjunction with the standard mho tripping units that are used in the various different protective schemes. Figure 9 on the following page illustrates how this is accomplished.

Assume that the apparent system impedance, as viewed by the relays prior to an out-of-step condition, plots at T on the R-X diagram. As this apparent impedance moves toward the relay characteristics, during or immediately after a system disturbance, it will first enter the out-of-step-blocking unit circle. Then, in continuing on its path, some short time later it will enter the tripping units characteristics. If the transit time of this locus between points A and B exceeds a few cycles, the out-of-step-blocking unit will operate an auxiliary device to block the tripping unit from tripping. It is because the out-of-step-blocking unit picks up some few cycles prior to the tripping unit that indicates a smooth change in impedance as viewed by these units.

For the same initial load impedance, if a fault were to occur on the protected line, at say Point C, the impedance as viewed by these units would change abruptly from T to C. For this condition, both the trip units

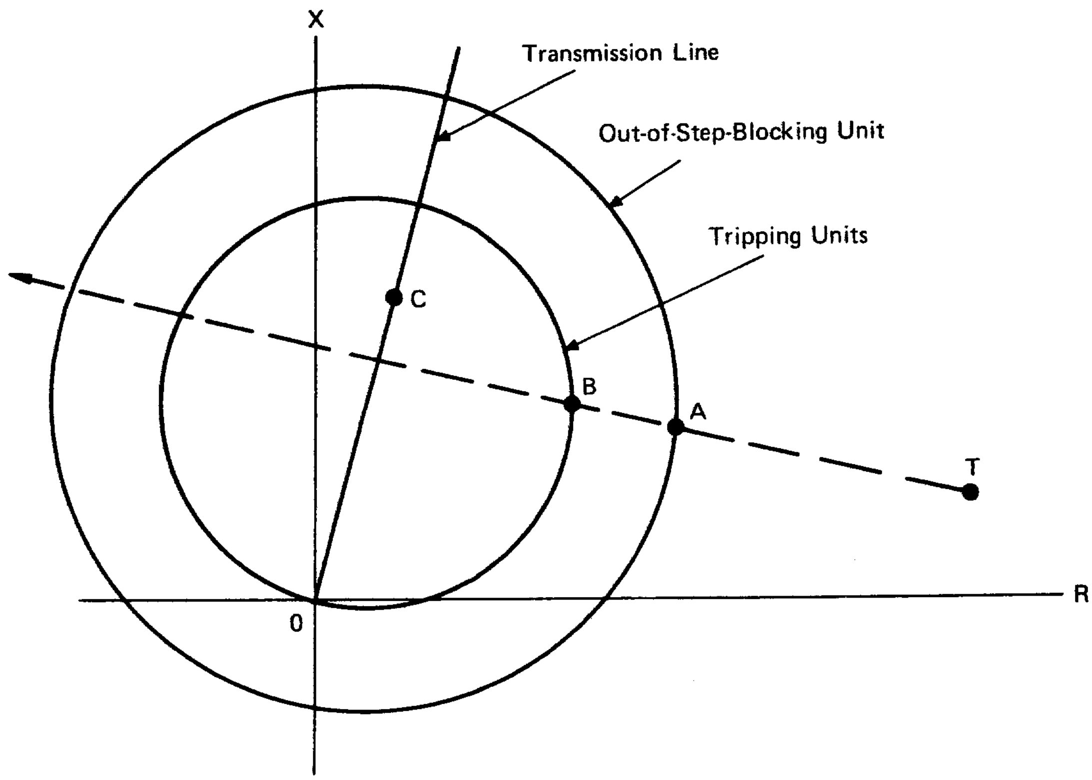


FIGURE 9

and the blocking unit would operate simultaneously. For this situation, the trip unit incapacitates the blocking auxiliary unit before it can set up blocking. Thus, tripping is permitted.

One out-of-step-blocking relay could be used at each line terminal that would be subject to undesired out-of-step tripping. In some instances users apply the out-of-step-blocking relays as in Figure 8 above but use it to block automatic reclosing after an out-of-step trip by the distance tripping units. In this scheme, the tripping units are not blocked but are permitted to trip on out-of-step and automatic reclosing is blocked.

AVAILABLE PHASE DISTANCE RELAYS

The phase distance relays for general application are roughly divided into two categories. The first being the well known Phase Packaged relays and the other being the newer Zone Packaged relays. The Phase Packaged relays, as the name implies, have two or three zones of protection for one pair of phases built into one relay case. Three such relays are required to protect all three pairs of phases. Phase Packaged relays have one phase target per relay and the associated timing relay (RPM11D) has three individual zone targets.

The Zone Packaged relays have only one zone of protection for all three phases built into one relay case. One such relay is required for each zone of protection. The zone packaged relays have only one target for all three phases. This target operates regardless of which pair of phases is faulted and is actually a zone target. The associated timing relay (RPM21D) has no zone targets since they are not required.

Table 1 lists the general purpose phase packaged distance relays that are used for phase fault protection. This table also describes the different relays and their basic applications. Table 2 provides the same information for the zone packaged relays.

Table 3 is a listing of the special function phase distance relays and their specific applications. This table also refers to relay groupings in Table 6 that give the complete packages.

Tables 4 and 5 provide the phase distance relay groupings for the various transmission line protective schemes using combined primary and backup relays and separate primary and backup relays respectively. Table 6 lists the relays in all the different groups.

TABLE 1
GENERAL PURPOSE-PHASE PACKAGED-DISTANCE RELAYS FOR PHASE FAULT PROTECTION

Relay	1st Zone Charac-teristic	2nd Zone Charac-teristic	3rd Zone Charac-teristic	Comments
GCX17A	Reactance	Reactance	Mho	For short lines and where arc resistance is a problem.
GCX17B	Reactance	Reactance	Mho	Same as GCX17A except with fault detector.
GCX17M	Reactance	Reactance	Mho	Same as GCX17A except for lower fault currents.
GCX17N	Reactance	Reactance	Mho	Same as GCX17M except with fault detector.
GCX17R	Reactance	Reactance	Mho	Same as GCX17A except with very short reach.
GCY12A	Mho	Mho	Offset Mho	For longer lines and where arc resistance is no problem.
GCY13A	Mho	Mho	None	Same as GCY12A except with no third zone.

TABLE 2
GENERAL PURPOSE-ZONE PACKAGED-DISTANCE RELAYS FOR PHASE FAULT PROTECTION

Relay	Characteristic	Zone of Protection	Comments
CEY15A	Mho	1st	These relays in combination are suitable for protection of medium and long lines.
CEY16A	Mho	2nd	
CEB16B	Offset Mho	2nd or 3rd	
CEB17A	Offset Mho	2nd or 3rd	

TABLE 3
SPECIAL FUNCTION PHASE DISTANCE RELAYS

Relay	Characteristic	Function	Equipment Group*
CEX17D	Two single phase modified reactance units.	Blinders	Group 18
CEX17E	Two single phase modified reactance units.	Out-of-step tripping	Group 19
CEB12B	Single phase offset mho	Out-of-step blocking	Group 7
CEB12C	Single phase offset mho	Generator back-up	Group 20
CEB13B	Three phase offset mho	Carrier starting in three terminal GCX directional comparison carrier schemes	See Group 8 in Table 4
CEB13C	Three phase offset mho	Generator back-up through a delta-wye bank	Group 21
CEB16A	Three phase offset mho	Single zone time delay back-up	Group 22
CFZ17A	Three phase impedance	Carrier starting and out-of-step blocking in GCX directional comparison carrier schemes for two terminal lines	See Group 6 in Table 4
CEYB12A	Single phase mho plus single phase offset mho	Carrier starting and carrier stopping in directional comparison carrier schemes	See Group 9 in Table 5
GYC51A GYC53A GYC77A	Single phase mho plus time overcurrent unit.	Two zone distance protection for sub transmission lines	Group 16

*See Table 6 for relay groups.

TABLE 4
COMBINED PRIMARY AND BACK-UP RELAYS

Scheme of Protection	Basic Relays	Out-of-Step Blocking
Three Zone Straight Distance	Group 1 or 2 or 3	Group 7
Two Zone Straight Distance	Group 4 or 5 or 16* or 17	Group 7
Directional Comparison for Two Terminal Lines	Groups 1 and 6	No additional equipment required.
	Group 2 or 3	Group 7
Directional Comparison for Three Terminal Lines	Groups 1 and 8	Group 7
	Group 2 or 3	Group 7
Direct Underreaching Transferred Tripping	Group 1 or 2 or 3	Group 7
Permissive Underreaching Transferred Tripping	Group 1 or 2 or 3	Group 7
Permissive Overreaching Transferred Tripping	Group 1 or 2 or 3	Group 7

Note: The above groupings apply to three terminal lines as well as two terminal lines except where noted.

* Group 16 cannot be used withoout-of-step blocking.

See Table 6 for relay groups

TABLE 5
SEPARATE PRIMARY AND BACK-UP RELAYS

Scheme of Protection	Primary Relays	Back-up Relays	Out-of-Step Blocking*
Directional Comparison	Group 9 or 10	Group 1 or 2 or 3 or 4 or 5	Group 7
Direct Underreaching Transferred Tripping	Group 11 or 12▲	Group 1 or 2 or 3 or 4 or 5	Group 7
Permissive Underreaching Transferred Tripping	Group 12▲ or 13 or 14	Group 1 or 2 or 3 or 4 or 5	Group 7
Permissive Overreaching Transferred Tripping	Group 15	Group 1 or 2 or 3 or 4 or 5	Group 7

The above groupings apply to three as well as two terminal lines.

* One out-of-step blocking relay may be used for both the primary and back-up protection. However, if desired, it is also possible to use separate out-of-step blocking relays for the primary and back-up protection. In the latter case, two of Group 7 would be required.

▲ Group 12 provides three zones where only one or two zones are actually necessary. This is so because the reactance unit requires a mho unit for directional supervision and all reactance relays are three zone devices.

See Table 6 for relay groups.

TABLE 6
GROUPS OF PHASE RELAYS

Group 1
3 ea. – GCX17A or B or M or N or R
1 ea. – RPM11D

Group 2
3 ea. – GCY12A
1 ea. – RPM11D

Group 3
1 ea. – CEY15A
1 ea. – CEY16A
1 ea. – CEB17A
1 ea. – RPM21D

Group 4
1 ea. – CEY15A
1 ea. – CEY16A or CEB16B
1 ea. – RPM21D

Group 5
3 ea. – GCY13A
1 ea. – RPM11D

Group 6
1 ea. – CFZ17A

Group 7
1 ea. – CEB12B

Group 8
1 ea. – CEB13B

Group 9
3 ea. – CEYB12A

Group 10
1 ea. – CEY16A
1 ea. – CEB17A

Group 11
1 ea. – CEY15A

Group 12
3 ea. – GCX17A or B or M or N or R

TABLE 6 CONTINUED

Group 13
1 ea. – CEY15A
1 ea. – CEY16A

Group 14
3 ea. – GCY13A

Group 15
1 ea. – CEY16A

Group 16
3 ea. – GYC51A or 53A or 77A

Group 17
1 ea. – CEY15A
1 ea. – CEY16A
1 ea. – IAC60E or 80E or 90E

Group 18
3 ea. – CEX17D

Group 19
1 ea. – CEX17E
1 ea. – NAA19B or NAA19C

Group 20
3 ea. – CEB12C
1 ea. – RPM13A
1 ea. – HGA14AM or HGA14AL
1 ea. – HEA51

Group 21
1 ea. – CEB13C
1 ea. – RPM13A
1 ea. – HGA14AM or HGA14AL
1 ea. – HFA51

Group 22
1 ea. – CEB16A
1 ea. – RPM21D

AVAILABLE GROUND DISTANCE RELAYS

The ground distance relays provide protection against single phase to ground faults. Because these relays measure the faulted phase positive sequence impedance from the relay to the fault, one relay is required for each phase. The basic ground distance relay is the GCX17G. Like the phase GCX relays this device provides a first and second zone reactance characteristic plus a third zone mho characteristic. Basically the ground distance relay, GCX17G, is very similar to the phase distance relay, GCX17A. The reactance unit of this relay is also unaffected by arc resistance.

In addition to the GCX17G there are also available the CEB13G and the CEY16G relays. The CEB13G is made up of three single phase units, similar to the mho unit of the GCX17G, all in one case. The CEY16G is similar to, and the functional equivalent of, the CEB13G for all the *standard applications covered below.*

None of these relays require memory action or offset. This is true for the ground relay reactance units because the operating torque, as in the case of the phase relay reactance unit, is proportional to the current squared. The ground relay mho units do not require memory action or offset because they are polarized from quadrature potential. For example, the phase A mho unit is polarized from phase B-C potential. When a phase A to ground fault occurs on the system, even at the relay terminals, the phase B-C polarizing voltage is maintained at a substantial level and high torque is obtained even on a steady state basis.

Table 7 and 8 provide the ground distance relay groupings for the various transmission line protective schemes using combined primary and back-up relays as well as separate primary and back-up relays. Table 9 lists the ground relays in all the different groups.

COMPLETE RELAYING SCHEMES

It is important to note that the above information applies only to the distance relays. In many instances, additional auxiliary devices are necessary to complete the total list of equipment that is required. Typical elementary diagrams and other information is available for most if not all of the protective schemes covered in this paper.

TABLE 7
COMBINED PRIMARY AND BACK-UP RELAYS

Scheme of Protection	Relays
Three Zone Straight Distance	Group 23
Directional Comparison	Groups 23 and 24
Direct Underreaching Transferred Tripping	Group 23
Permissive Underreaching Transferred Tripping	Group 23
Permissive Overreaching Transferred Tripping	Group 23

TABLE 8
SEPARATE PRIMARY AND BACK-UP RELAYS

Scheme of Protection	Relays
Directional Comparison	Groups 23 and 25
Direct Underreaching Transferred Tripping	Group 26
Permissive Underreaching Transferred Tripping	Group 26
Permissive Overreaching Transferred Tripping	Groups 23 and 27

TABLE 9
GROUPS OF GROUND RELAYS

Group 23
3 ea. – GCX17G
1 ea. – RPM11D
1 ea. – NAA15C
1 ea. – Y1678 Aux. C.T.

Group 24
1 ea. – CEB13G or CEY16G

Group 25
2 ea. – CEB13G or CEY16G
1 ea. – PJC11AV

Group 26
6 ea. – GCX17G
1 ea. – RPM11D
2 ea. – NAA15C
2 ea. – Y1678 Aux. C.T.

Group 27
1 ea. – CEB13G or CEY16G
1 ea. – PJC11AV

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