# *Terms Used by Power System Protection Engineers*

*A Special Publication of the*

***IEEE***
***Power System Relaying Committee***

*Prepared by the*

***Terms Used by Power System Engineers Working Group***

*of the*

***Relay Standards Subcommittee***

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## Terms Used by Power System Protection Engineers

This special report was prepared for and approved by the "Power System Relaying Committee" of the "IEEE Power Engineering Society". It was prepared by the "Terms Used by Power System Engineers Working Group" of the "Relaying Standards Subcommittee".

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# Foreword

Members of the “Power System Relaying Committee” have expressed concern from time to time that recently graduated engineers, technologists and engineers from other disciplines usually experience difficulty with properly interpreting the terminology used in the area of Power System Protection. The consequence is that they experience difficulty in communicating effectively with their colleagues.

To overcome this difficulty, the “Power System Relaying Committee” of the IEEE formed, in January 1991, the “Terms Used by Power System Protection Engineers Working Group”. This working group was assigned the task of preparing a special publication which should describe in a straight forward manner the terms commonly used by power system protection engineers.

Almost all the terms, discussed in this report, are defined in the IEEE Std 100-1992 “The New IEEE Dictionary of Electrical and Electronics Terms”, the “International Electrotechnical Commission’s” publication, “IEC Multilingual Dictionary of Electricity” and standards published by various organizations. The objective of the report was not to redefine the terms but provide brief explanations to assist the recent graduate engineers, technologists and new entrants in the area of power system protection in understanding them properly.

To keep the explanations from conflicting with the definitions of terms provided in the standards, the Working Group maintained liaison with the “Terminology Usage Review Working Group” (of the “Relay Standards Subcommittee” of the “Power System Relaying Committee” of the IEEE “Power Engineering Society”) that recommends adoption of new definitions for inclusion in the IEEE dictionary and IEEE/ANSI standards.

The explanations of the terms were written and then revised several times to avoid conflict with the official definitions and to make the explanations suitable for achieving the intended objectives of this report. The Working Group hopes that this document will be found useful by recent engineering graduates, technologists, and engineers who do not have formal training in Power System Protection but have to interact with protection engineers.

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# 1. INTRODUCTION

There is considerable concern among power system engineers in general, and power system protection engineers in particular, that recent graduates and engineers from other disciplines usually experience difficulty with properly interpreting the terminology used in applying relays, analyzing their performance and designing protection systems.

This makes it difficult for relay engineers to communicate effectively with their colleagues and convey their interpretations of relaying issues and questions effectively. To overcome this difficulty, the "Power System Relaying Committee" of the IEEE "Power Engineering Society" decided to prepare a special publication that would provide, in simple and straightforward language, interpretations of the terms used in the area of power system protection. The "Terms Used by Power System Protection Engineers Working Group" was formed in January 1991 and was assigned the task of preparing a special publication describing the terms commonly used by power system protection engineers.

The Working Group appreciated at the outset that definitions of almost all the terms used by power system protection engineers are included in the IEEE Std 100-1992 "The New IEEE Dictionary of Electrical and Electronics Terms" [2], the "International Electrotechnical Commission's" publication, "IEC Multilingual Dictionary of Electricity" [9] and standards published by various organizations.

The Working Group discussed and decided

- neither to redefine the terms already included in the dictionaries and standards,
- nor to reproduce the established definitions from standards, and also
- not to provide historical development of terms.

The Working Group decided to provide, in its special report, explanations of the terms in a straight forward manner so that recent graduate engineers, technologists and new entrants in the area of power system protection can understand them properly and become useful participants in their work without unnecessary frustration.

# 2. GENERAL TERMS

The terms concerning the quality of measurements and philosophy of protection are described in this section. The specific terms included in this section are

- accuracy,
- accuracy class,
- reliability,
- security,
- dependability,
- sensitivity,
- relay stability,
- primary protection,
- backup protection,
- dual protection, and
- device number.

## 2.1 Accuracy

This term is used for at least two different purposes, one to describe the accuracy of a device and the other to specify the accuracy of a measurement.

In the first context, accuracy is the degree to which a device (relay, instrument or meter) conforms to an accepted standard. The statement of an accuracy is only as good as the methods used to express it for individual components and the manner in which they affect the overall accuracy of the device.

In the second case, the accuracy of a measurement specifies the difference between the measured and true values of a quantity. The deviation from the true value is the indication of how accurately a reading has been taken or a setting has been made.

**Example:** If a relay is specified to have ±5% accuracy, it means that the relay should operate when its exciting quantity (current or voltage) is between -5% and +5% of its setting.

Let us consider the case of Figure 1 and assume that the ct provides secondary current which is an accurate representation of the primary current. When the fault current is12,000 A, the current in the relay will be 100 A. If the relay accuracy is ±5%, it could interpret the current to be of any level from 95 A to 105 A. In case the relay is set to operate at 100 A, it may or may not operate depending on its interpretation of the level of current in the circuit.

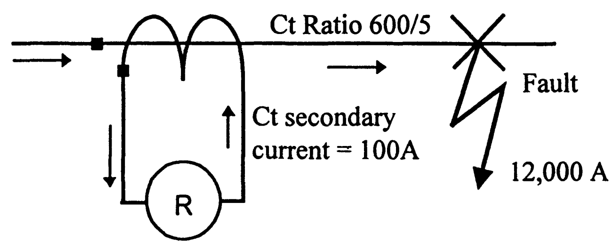



**Figure 1. A line protected by a current relay.**

## 2.2 Accuracy Class

This term is used to define the quality of the steady state performance of a current transformer. The accuracy class of a current transformer (ct) used for protection functions is described by a letter which indicates whether the accuracy can be calculated (class C) or it must be obtained from physical tests (class T). This letter is followed by a number which is equal to the maximum secondary terminal voltage that the ct will produce at 20 times the rated secondary current with no more than 10% error.

Examples of accuracy classes for 10% error class C cts are C100, C200, C400 and C800. At this time, there is no accuracy class higher than C800. Examples of accuracy classes for 10% error class T cts are T105, T250, T375 and T750.

## 2.3 Reliability

Reliability is an index that expresses the attribute of a protective relay or a system to operate correctly for situations in which it is designed to operate. This also includes the attribute of not operating (incorrectly) for all other situations. Reliability is expressed in terms of two competing fundamental attributes, dependability and security.

### 2.3.1 Dependability

Dependability is the aspect of reliability that expresses the degree of certainty that a relay will operate correctly. For relay systems, dependability is assured by using redundant protection systems and backup relays.

**Example:** The primary protection for a transmission line may be provided by using a phase comparison protection scheme. The degree of certainty that this scheme will operate for all faults on the transmission line is the dependability index of the scheme. To increase this index for the transmission line protection system, distance relays can be included to act as backup relays.

### 2.3.2 Security

Security is the aspect of reliability that expresses the degree of certainty that a relay will not operate incorrectly irrespective of the nature of the operating state of the power system.

**Example:** If a differential relay is designed to operate for faults in a transformer it is protecting, the degree of certainty that the relay will not operate for faults outside the transformer zone is the security index of the relay.

## 2.4 Sensitivity

This term is used to express different attributes of devices. One definition expresses it as a ratio of the response of the device to the change of the input. In the power system protection field, sensitivity is the minimum value of an input (or change of an input) that would cause a relay to operate.

**Example:** An instantaneous ground fault directional relay designed to operate at a minimum current of 0.5A would be classified as having a sensitivity of 0.5 A.

## 2.5 Relay Stability

A relay is considered to be stable if, starting from a steady state, it returns to the same steady state following the introduction and removal of inputs representing a disturbance in the system to which it is connected.

**Example:** A solid-state timing relay, whose timing accuracy is not affected by the changes in the dc voltage supply used to operate it, is considered to be stable.

**Example:** Consider that a relay system experiences a momentary loss of dc supply used for performing logic and/or tripping functions. If the relay system returns to a normal steady state mode on restoration of the dc supply, the relay is considered to be stable.

Stability differs from security. A stable but insecure pilot relay system may trip incorrectly due to a weakness in the tripping logic or design. A secure but unstable pilot relay system may experience wide variations in the input and output levels but will not trip incorrectly.

## 2.6 Primary Protection

The protection system that is designed to operate before other devices respond to a disturbance due to its sensitivity and speed, is said to provide primary protection.

**Example:** A differential relay protecting a transformer is expected to operate when a fault is experienced in its protection zone. Other devices used to protect the transformer, such as overcurrent relays, are expected to operate if the differential relay fails to detect the fault. In this case, the differential relay provides primary protection for faults in its zone of protection.

## 2.7 Backup Protection

Relays used to provide second line of defense are said to provide backup protection. The operating time of these relays is longer than the operating time of primary relays, and, therefore, they operate but trip appropriate circuit breakers only if the primary relays fail to detect the presence of the disturbance or fail to open the circuit breakers. These relays could be physically in the substation in which the primary relays are located or may be located in a remote substation.

**Example:** A phase comparison system can be used to provide primary protection of a transmission line. Distance relays may be used, without permissive overreach or transfer trip, to provide backup protection of the line.

## 2.8 Dual Protection

Power system equipment of bulk transmission systems is often protected with dual primary relays. Both primary protection systems are kept independent of each other as far as possible. Depending on the protection philosophy adopted, each protection system may be connected to its own cts, vts, relays, trip coils of circuit breakers and batteries. These systems are sometimes referred to as "Protection system A" and "Protection system B".

**Example:** A transmission line may be protected by a differential protection system, which is expected to operate in 10 to 15 ms, and a distance protection system with transfer trip, which is also expected to operate in comparable time. The differential protection in this case could be classified as "Protection system A" or "Protection system 1" and the distance protection system could be classified as "Protection system B" or "Protection system 2."

## 2.9 Device Number

The circuit diagrams used in power systems use nomenclatures and device numbers as specified in the ANSI/IEEE Standard C37.2. A device number is assigned for each type of relay and instrument. The phases are identified as A, B, C or a, b, c. The numerals 1, 2 and 3 are not used because 1 is used to identify positive sequence quantities and 2 is used to identify negative sequence quantities.

**Examples:** Some of the device numbers specified in the Standard are listed in the following table.

| Device | Assigned Number |
|---|---|
| Distance relay | 21 |
| Undervoltage relay | 27 |
| Instantaneous overcurrent relay | 50 |
| Ac time overcurrent relay | 51 |
| Overvoltage relay | 59 |
| Ac directional overcurrent relay | 67 |
| Frequency relay | 81 |
| Differential relay | 87 |

# 3. RELAY TYPES

This section briefly describes the following terms used for describing different types of relays.

- Relay
- Electromagnetic relay
- Electromechanical relay
- Solid-state and static relays
- Microprocessor-based relay

## 3.1 Relay

A relay is a device which operates when the input provided to it exceeds (or decreases below) a specified level and other specified conditions are met. The relay may open or close an electrical contact directly, or indirectly by operating another relay. Electromagnetic, electromechanical, analog electronic, digital electronic, or a combination of these technologies, are used in manufacturing them.

The operation of any protection relay is based on comparisons of perceived values, calculated from the inputs, with pre-specified limits for operation. The following table illustrates the characteristic values compared in different technologies.

| Technology | Comparison of |
|---|---|
| Electromechanical | Electromagnetic forces |
| Solid-state | Electrical signals |
| Digital | Numerically processed quantized samples |

**Example:** Overcurrent relay, directional relay, differential relay, distance relay, frequency relay and undervoltage relay are a few examples of relays used in electric power systems.

**Example:** An overcurrent relay may be designed to operate when the current applied to it exceeds a specified level and remains above that level for a prespecified time.

## 3.2 Electromagnetic Relay

An electromagnetic relay is a device which uses electromagnetic energy, directly or indirectly, to operate. The operation of the relay may close some of its contacts while opening the remaining contacts. These contacts are used in external circuits energizing or de-energizing those circuits.

Most electromagnetic relays use one of the following phenomena.

- Electromagnetic attraction (or repulsion)
- Electromagnetic induction
- Magnetic amplification

The phenomena of electromagnetic attraction (or repulsion) and electromagnetic induction are used to cause physical movement of parts of a relay causing the relay contacts to open or close.

A magnetic amplifier relay usually has an ac and a dc coil (or two ac coils) on a magnetic core. Interaction between the fields generated by the two coils can be used to compare either the levels of two inputs or the relative phase angle between the inputs. These devices can also be designed to amplify input signals of small levels.

## 3.3 Electromechanical Relay

An electromechanical relay is a device which has one or more mechanical parts that move when current flow in its electrical circuit exceeds a specified level. Typical electromechanical relays used for power system protection are based on the principle of electromagnetic attraction (or repulsion) or electromagnetic induction.

A typical electromagnetic attraction relay is shown in Figure 2. When the electromagnetic force generated by the flow of current (ac or dc) in its electrical circuit exceeds the force of the restraining spring and the gravitational force on the plunger, the plunger moves. The shorting bar mounted on the plunger bridges the output contacts causing current to flow in that circuit. Several variations of such relays are used in power system protection applications.

In an electromagnetic induction relay, ac current flowing in the relay produces a flux which generates eddy currents in its rotor which can either be a disc or a cup. The interaction between the magnetic flux and the eddy currents generates a force which tries to rotate the disk. The disk is free to rotate but is restrained by a spring. When the force generated by induction exceeds the restraining force of the spring, electrical contacts attached to the rotor move to bridge stationary contacts. For more details, see overcurrent relays, and time-dial / time-lever / time-multiplier sections.

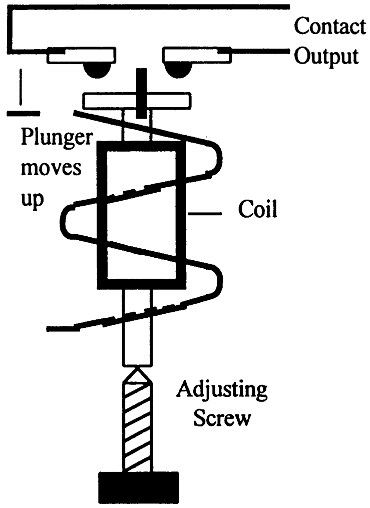



**Figure 2. An Electromagnetic (current operated) plunger relay.**

## 3.4 Solid-state and Static Relay

A solid-state or static relay uses semi-conductor technology to perform its intended functions. It may also use magnetic or optical elements.

Sometimes a distinction is made between solid-state relays and static relays. Relays with solid-state output circuits are classified as solid-state relays. A static relay may have an electromechanical relay to energize the trip circuit.

Microprocessor relays, which utilize semi-conductor components, have a special definition reserved for them; they are not referred to as solid-state relays. For more details of those relays refer to the sections on microprocessor relays, digital relays and numerical relays.

## 3.5 Microprocessor-based Relay

Early relays for power system protection used electromechanical technology which was later supplemented by solid-state electronics. A large number of electromechanical and solid-state relays are in operation at this time. With the advent of digital processing technology, designers started to use microprocessors in relay designs. These relays are now marketed by several manufacturers.

Figure 3 shows an example of the block diagram of a microprocessor-based relay. This relay monitors voltages and currents, which, at the power system level, are in the range of hundreds of kilo volts and kilo amperes respectively. The levels of these signals are reduced by vts and cts typically to 67 V and 5 A nominal values.

The outputs of the vts and cts are applied to the analog input subsystem of the relay. This subsystem provides galvanic isolation for the relay from the power system, reduces the level of the input voltages, converts currents to equivalent voltages and removes high frequency components from the signals using analog filters. Other relays could be monitoring temperature, pressure, flow and other parameters. The outputs of the analog input subsystem are applied to the analog interface, which includes amplifiers, multiplexers and analog-to-digital (A/D) converters. These components sample the reduced level signals and convert their analog levels to equivalent digital numbers which are stored in memory. The status of switches and circuit breakers in the power system is provided to the relay via the digital input subsystem and are read into the microcomputer memory.

The acquired information is processed by a relaying algorithm, which is a part of the software. The algorithm uses signal processing techniques to measure magnitudes and phase angles of voltages and currents. In some cases, the frequency of the system is also measured. These measurements are used to calculate other quantities, such as impedances. The computed quantities are compared with pre-specified thresholds (settings) to decide whether the power system is experiencing a fault or not. If it is, the relay sends a command to open one or more circuit breakers for isolating the faulted zone of the power system. The trip output is transmitted to the power system through the digital output subsystem.

The software, relay settings and other vital information are stored in non-volatile memory of the relay. Random-access memory (RAM) is used for storing data temporarily. The power supply to a relaying microcomputer must be available even when the system supply is interrupted. Arrangements are, therefore, made to provide energy to the relay during normal and abnormal operating conditions of the power system.

Sometimes, these relays are called numerical relays specifically if they calculate the algorithm numerically. The signal and data flows in these relays are shown in Figure 4. The relay is isolated from the power system by using auxiliary transformers which receive analog signals and reduce their levels to make them suitable for use in the microprocessor- based relay. Since the analog to digital converters can handle voltages only, the currents are passed through shunts to convert them to voltages proportional to the currents.

During digital processing, high frequency components can appear to belong to the fundamental frequency class. This phenomenon is referred to as aliasing. To prevent aliasing from affecting the relaying functions, anti-aliasing filters are used along with the analog input isolation block.

After being quantized by the A/D converter, analog electrical signals are described by discrete values of the samples taken at specified instants of time. These discrete numbers are processed by using numerical methods. For example, quantized values of current and voltage samples may be used to estimate the magnitudes and phase angles of their pha-sors. Voltage and current phasors may be further used to calculate impedances as seen from a relay location.

The digital signals are applied to the relay via optic isolators which insure physical disconnection of the relay from the power system.

### 3.5.1 Multi-function relay

Microprocessor relays were initially developed to replace the existing single-function relays. For example, separate relays were used to perform differential, loss of field, over-current and unbalanced loading protections of generators. During the past few years, relays that perform more than two protective functions have been developed. These are classified as multi-function relays.

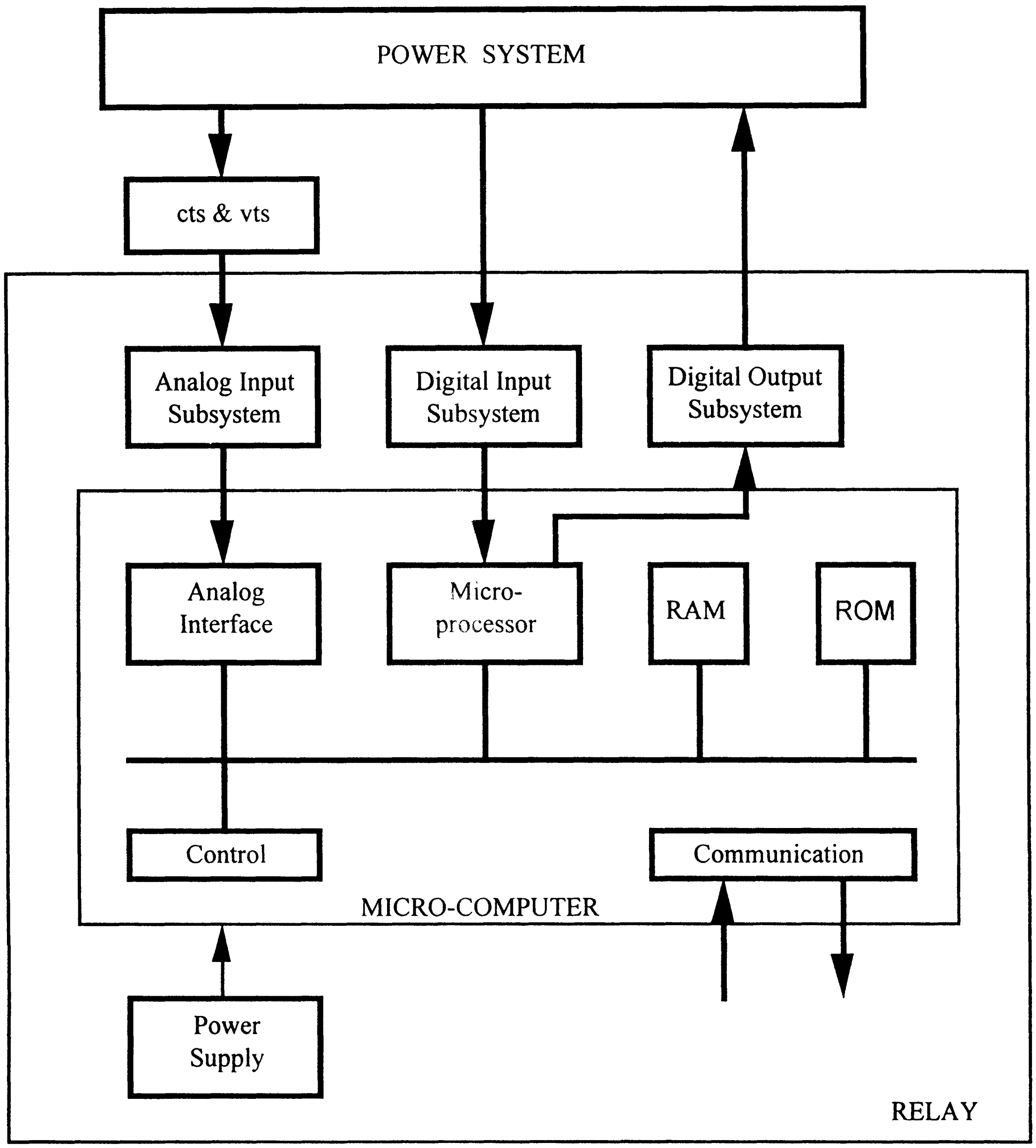



**Figure 3. Block diagram of a microprocessor-based relay.**

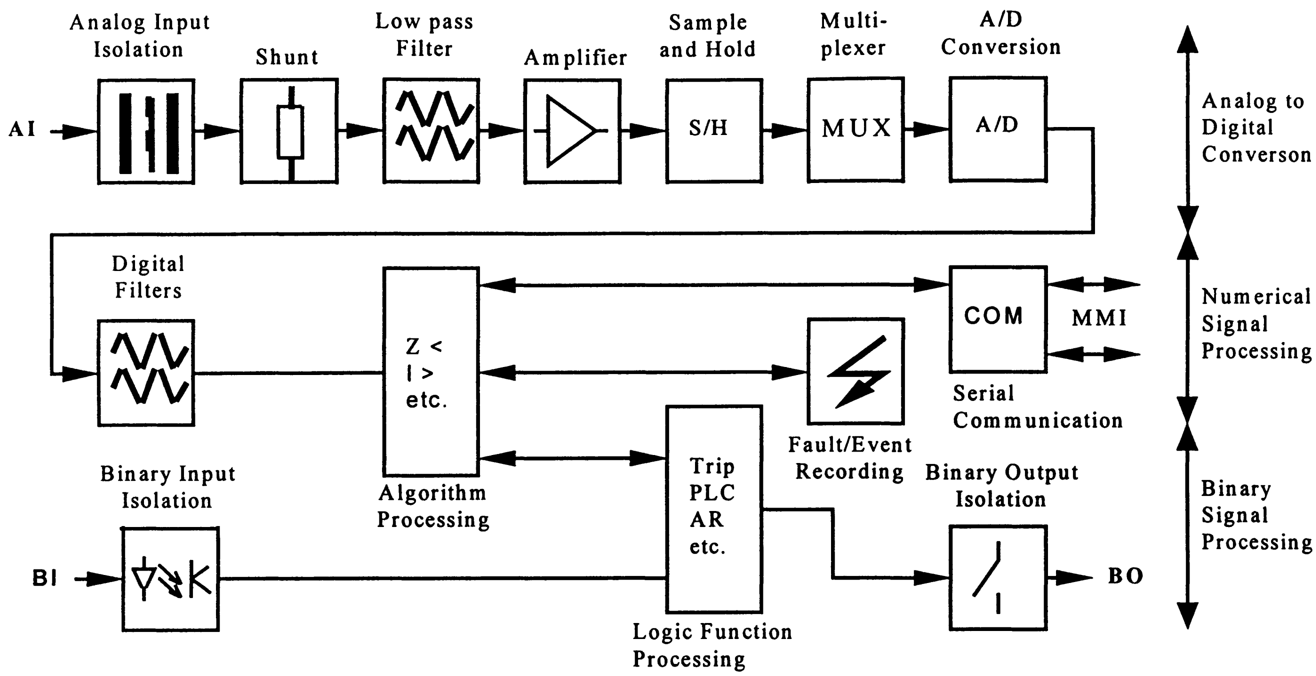



**Figure 4. Signal and data flow of a microprocessor-based relay.**

# 4. OVERCURRENT RELAY

The terms used in the area of overcurrent relay are described in this section. These include

- instantaneous overcurrent relay,
- inverse time overcurrent relay,
- directional overcurrent relay,
- time dial (time lever, time multiplier),
- connection angle, and
- polarizing quantity.

## 4.1 Instantaneous Overcurrent Relay

This type of relay has been assigned by ANSI the device number 50. The term instantaneous has at least two meanings and functions. The first concerns the operation of a relay or the tripping of a circuit breaker. It means that no intentional time delay is added to the trip function. The relay operates when it detects that the current level has exceeded the threshold setting. These relays operate typically in 4 to 16 ms on a 60 Hz system. The second function concerns the reclosing of circuit breakers. In this context, it means that reclosing of a circuit breaker is not intentionally delayed after it has been tripped. There is, however, an inherent albeit small time delay in performing these functions.

## 4.2 Overcurrent Relay Time-Current Characteristic

Inverse time overcurrent relays (device number 51), operate when the current in the relay exceeds a threshold. Inverse time delay means that the higher the relay current, the lower is the operating time. Some of the commonly used time delay characteristics are

- inverse time,
- very inverse time,
- extremely inverse time, and
- definite minimum time.

Sample current-time characteristics are shown in Figure 5. These curves represent the operating time of the relay within specified tolerance. Notice that the definite minimum time characteristic has approximately constant time delay for relay currents larger than three times the set value. Relay engineers use these curves, that are published by the manufacturers, to predict the time the relay would take to operate for different levels of relay current.

An induction disk inverse time overcurrent relay is shown in Figure 6. It has a non-magnetic disk, usually made of aluminum, mounted on a shaft. The disk is placed in the air gap of an electro-magnet which is excited by current flowing in its coil. The current in the coil produces flux in the air gap. Because the current in the coil is alternating in nature, the flux in the air gap is also time varying. The flux induces eddy currents in the disk. The air gap flux and the eddy currents interact with each other producing a torque that tries to rotate the disk. Since the disk is held back with a spring, it does not start to rotate until the torque exceeds a specified level.

A moving contact, which is attached to the shaft, as well as a stationary contact are provided in the relay. The coil of the electromagnet is provided with taps which allows the relay engineers to change the effective turns on the electromagnet. These settings are used to select the pickup current of the relay.

### 4.2.1 Time dial (Time lever, Time multiplier)

The time dial (also referred to as time lever or time multiplier) is the means for controlling the operating time of the relay. This is achieved by changing the angle through which the disk must rotate before its contacts are closed. Since the moving contact travels in an arc, it can be lengthened or shortened by selecting an appropriate time dial setting. The adjustment of the arc is calibrated in the form of an index which is known as the time dial.

Figure 7 shows how the operating time of a relay changes when the time dial setting is changed from 0.5 to 7.

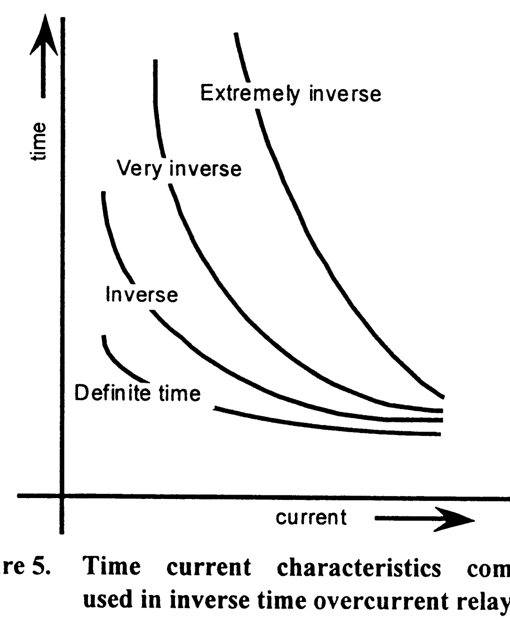



**Figure 5. Time current characteristics commonly used in inverse time overcurrent relays.**

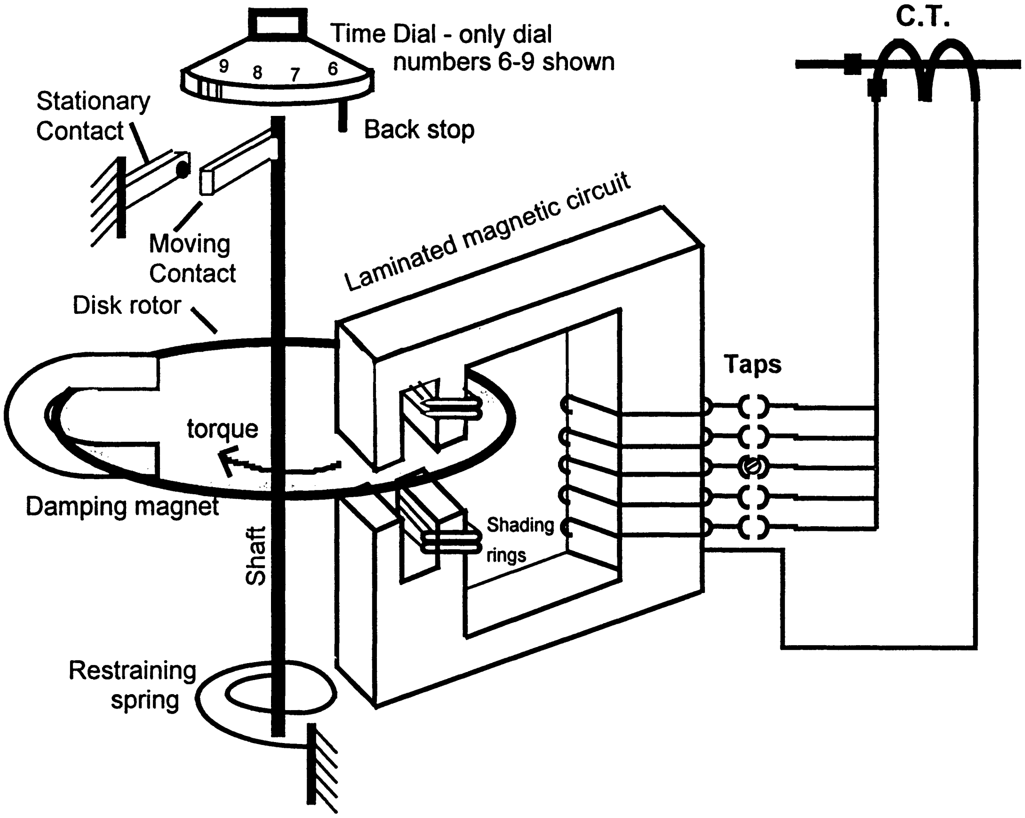



**Figure 6. Electrical and mechanical arrangement of a typical inverse time overcurrent relay.**

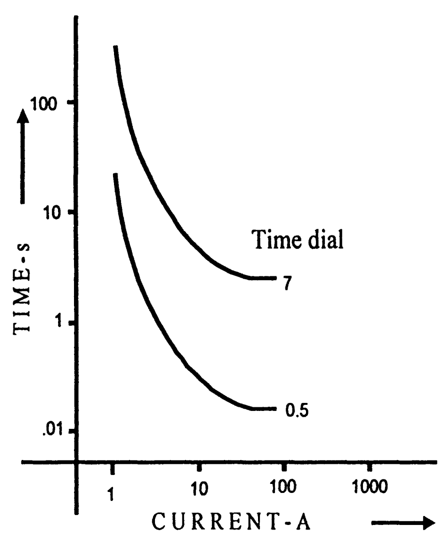



**Figure 7. Impact of time dial adjustment on the operating time of an overcurrent relay.**

## 4.3 Directional Overcurrent

Overcurrent relays respond to currents during faults experienced on the power system in either direction from the relay location. This is sometimes not desirable. For example, in a line of a network, fault currents at a relay location could be flowing for faults on the line side of the relay as well as for faults on the bus side of the relay. A line protection relay must be restrained from operating for faults on the bus side of the relay.

Directional overcurrent relays are used in such situations. These relays (classified as device number 67), when designed with electromechanical or analog electronic technologies, consist of an overcurrent element supervised by a directional element. The overcurrent element responds only if the fault is in the specified direction.

Some directional relay applications use single-phase directional relays; one relay is applied in each phase of the three-phase power system. Another application is for ground directional protection, which use ground (or residual current) and the sum of the three phase voltages (or current in the neutral connection of the source).

In the phase directional relays, the phase angle of the current with respect to the voltage is checked. In the ground directional relays, the phase angle of the ground or residual current is checked with respect to the phase angle of the sum of the three-phase voltages. Alternatively, the phase angle of the residual current is checked with respect to a neutral current of a source that provides a constant reference no matter where the fault is located.

### 4.3.1 Connection angle

In the phase directional relays, the phase angle between the current and voltage is used to decide if the fault is in the forward direction. Different combinations of currents and voltages can be used for this comparison. Consider that the three directional relays are applied currents from phases A, B and C. Two of the several options for selecting the voltages for use in these relays are listed in Table 1.

In Option 1, the voltage element of the relay, which receives phase A current, is applied voltage from phase C. As shown in Figure 8, unity power factor load current leads the applied voltage by 60°. This is also true for the relays which receive phase B and phase C currents using connections of Option 1. The relays which use this combination of currents and voltages are identified as having a connection angle of 60°.

Similarly, when connections of Option 2 are used, the relay, which receives phase A current, is applied the voltage from phase B minus the voltage from phase C. In this case, the unity power factor current leads the applied voltage by 90°. This is also true for the relays that receive phase B and phase C currents. The relays using this combination of currents and voltages are identified as having a connection angle of 90°. The phasor diagram for this situation is also shown in Figure 8. The polarizing voltage, $V_b$-$V_c$, and fault current for phase A to ground fault $I_a$, are also shown in this figure. Notice that the phase displacement between the fault current and the polarizing voltage is less than 30°.

The voltages, which are referred to as polarizing voltages, are selected in such a manner that they remain relatively unchanged during a fault. This ensures that during system faults, when the currents have substantial magnitudes, the polarizing voltages are as close to the nominal value as possible.

**Example:** Consider that directional relays using Option 2 for connecting the voltage elements have been applied at a relay location. Figure 9 (a) shows the phase voltages, $V_a$ , $V_b$ and $V_c$, and the currents $I_a$ , $I_b$ and $I_c$ when the system is operating normally. The polarizing voltages ($V_b$-$V_c$ , $V_c$-$V_a$ and $V_a$-$V_b$) and the currents during normal operation are also shown in this figure. Now consider that a phase A to phase B fault has occurred on the line side of the relay and the fault is very close to the relay location. The voltages and currents for this situation are shown in Figure 9 (b). Notice that the current $I_b$ leads the polarizing voltage ($V_c$-$V_a$) by a small angle, from 10° to 30°. Also, the current $I_c$ leads the polarizing voltage ($V_a$-$V_c$) by a small angle. This ensures that the relays sense that the fault is in the forward direction.

#### 4.3.2 Polarizing quantity

Many relays use a voltage or current as a reference for comparing their operating signal. This quantity has a predictable phasor relationship to the current flowing to a fault, irrespective of the location of the fault. The reference voltage or current is referred to as the polarizing signal.

**Example:** A healthy phase voltage, in addition to the faulted phase voltage, is sometimes used in a relay as a polarizing voltage to assist in accurately determining the direction of the fault. This helps in correctly identifying the direction of the fault especially when the magnitude of the faulted phase voltage is small. If a fault, between phase b and phase c is experienced very close to the relay location, the phase b to phase c voltage collapses. The phase voltages for this situation and the currents are shown in Figure 9 (b). The polarizing voltages and fault currents are also shown in this figure. It is obvious from this figure that even if the phase b and phase c voltages have collapsed to low values, the polarizing voltages are substantial to ensure relay operation.

**Table 1. Voltage and current combinations for 60° and 90° connections for directional relays.**

| | Relay 1 | Relay 2 | Relay 3 |
|---|---|---|---|
| **Current applied** | $I_a$ | $I_b$ | $I_c$ |
| **Voltage applied** Option 1 | $-V_c$ | $-V_a$ | $-V_b$ |
| **Voltage applied** Option 2 | $V_b$-$V_c$ | $V_c$-$V_a$ | $V_a$-$V_b$ |

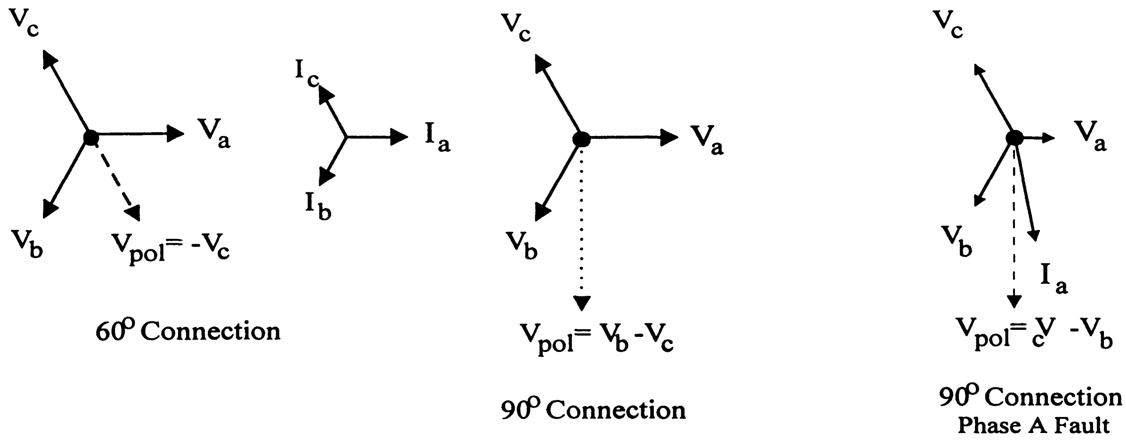



**Figure 8. Voltage phasors used in 60° and 90° connection angles.**

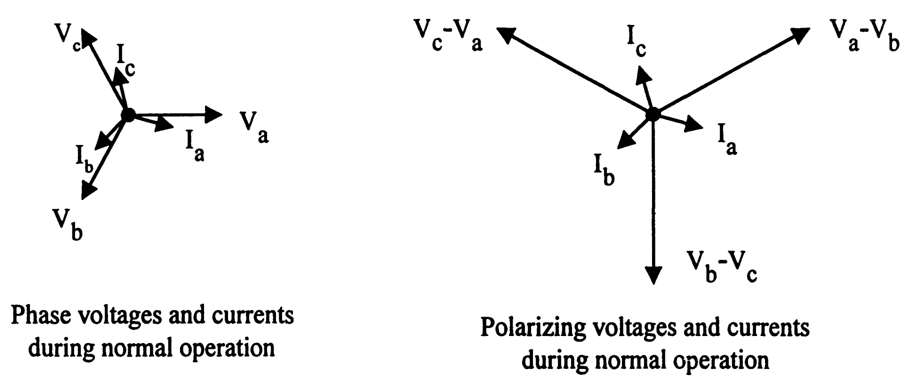



**Figure 9 (a). Phase and polarizing voltages, and phase currents during normal operation.**

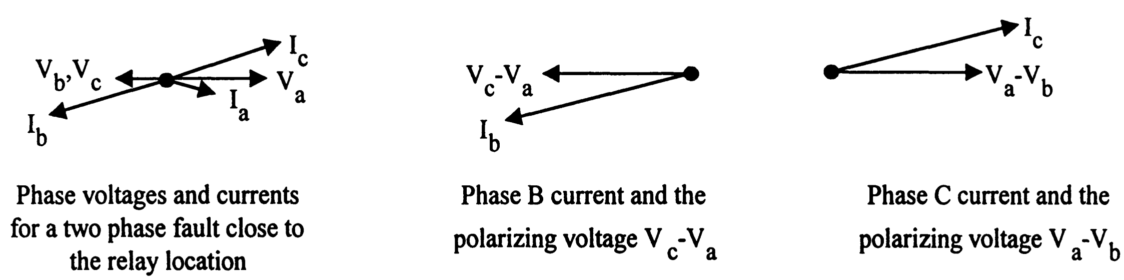



**Figure 9 (b). Phase currents and polarizing voltages for identifying the direction of a phase-b to phase-c fault.**

# 5. OHMIC RELAY APPLICATIONS

This class of relays was originally used to protect transmission lines and were believed to measure the distance from the relay location to a fault. Currently, several types are applied to power systems for protecting lines during faults, generators during loss of excitation, and the system during power swings. The terms most commonly used and described in this section are

- distance relay,
- impedance relay,
- mho relay, and
- Blinder.

## 5.1 Distance Relay

Faults on transmission lines are commonly detected by protective relays that measure and respond to one or another form of the ratio of voltage to current. This ratio is impedance or a component of impedance. These relays are termed distance relays because (ideally) the measured impedance is proportional to the distance along a homogeneous transmission line from the relay location to the fault. This class of relays is assigned device number 21.

The portion of line that is being protected by a distance relay is called the "zone of protection" or the "protected zone." Figure 10 shows that the zone of protection of Relay A, installed at bus 1, is from the relay location to a location close to bus 2. Similarly, the zone of protection of Relay B, installed at bus 2, is from the relay location to a location close to bus 1. If the line impedance is **Z**, the reach of each relay is n**Z**; n ranging from 0.75 to 0.90 in some applications, and more than 1.0 in some others.

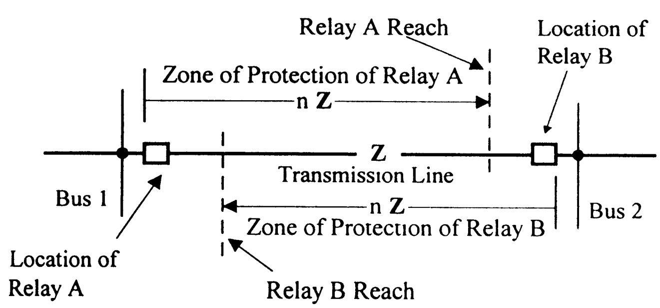



**Figure 10. Protection zones for relays protecting a transmission line.**

The impedance measured during normal operation of a line is the ratio of the voltage at the line terminal and the current flowing in the line; this value is usually high and is predominantly resistive. But, during faults, this impedance is lower and highly reactive in nature. A change in the detected impedance is used to determine if a fault has occurred, and also if the fault is in its zone of protection or is elsewhere on the system. This is accomplished by limiting the operation of the relay to a certain range of the observed impedance, commonly called, "reach." When a fault occurs within the protected zone of a distance relay protecting an end to end line, only the faulted transmission line is isolated.

The operating characteristics of these relays are expressed in terms of impedance or its components, resistance and reactance. Plotted on a rectangular coordinate system, (using resistance, R, as the abscissa and reactance, X, as the ordinate) the characteristics usually form simple geometric figures. Commonly used operating characteristics are shown in Figure 11. The point of measurement for a distance relay is located at the origin of the figures, and the relay is designed to generally operate when the measured impedance falls within the shaded area in the figures.

The major advantage of using a distance relay for multiphase faults, not involving ground, is that its zone of operation is a function of only the impedance of the protected line and the fault resistance (except for the situations when there is current in-feed from the remote terminal of the line or there is mutual coupling with lines on the same right of way). This is approximately a fixed constant, irrespective of the levels of fault current magnitudes. Therefore, a distance relay has a fixed reach, as opposed to an overcurrent relay whose reach varies as the system operating conditions change. Consequently, it is not necessary to change the settings of distance relays unless the line characteristics change. This makes distance relays ideally suited for primary and backup protection for faults on transmission lines.

### 5.2 Impedance Relay

Relays that respond to the magnitude of the measured impedance are classified as impedance relays. The measurement is taken by determining the ratio of the rms voltage of the line at the relay location to the rms current flowing in the line at the relay location. These relays are commonly applied to detect faults on transmission lines. A comparison of the measured impedance with the line impedance provides an indication whether the fault is in the protected zone of the relay or not. This type of relay is also assigned a device number of 21.

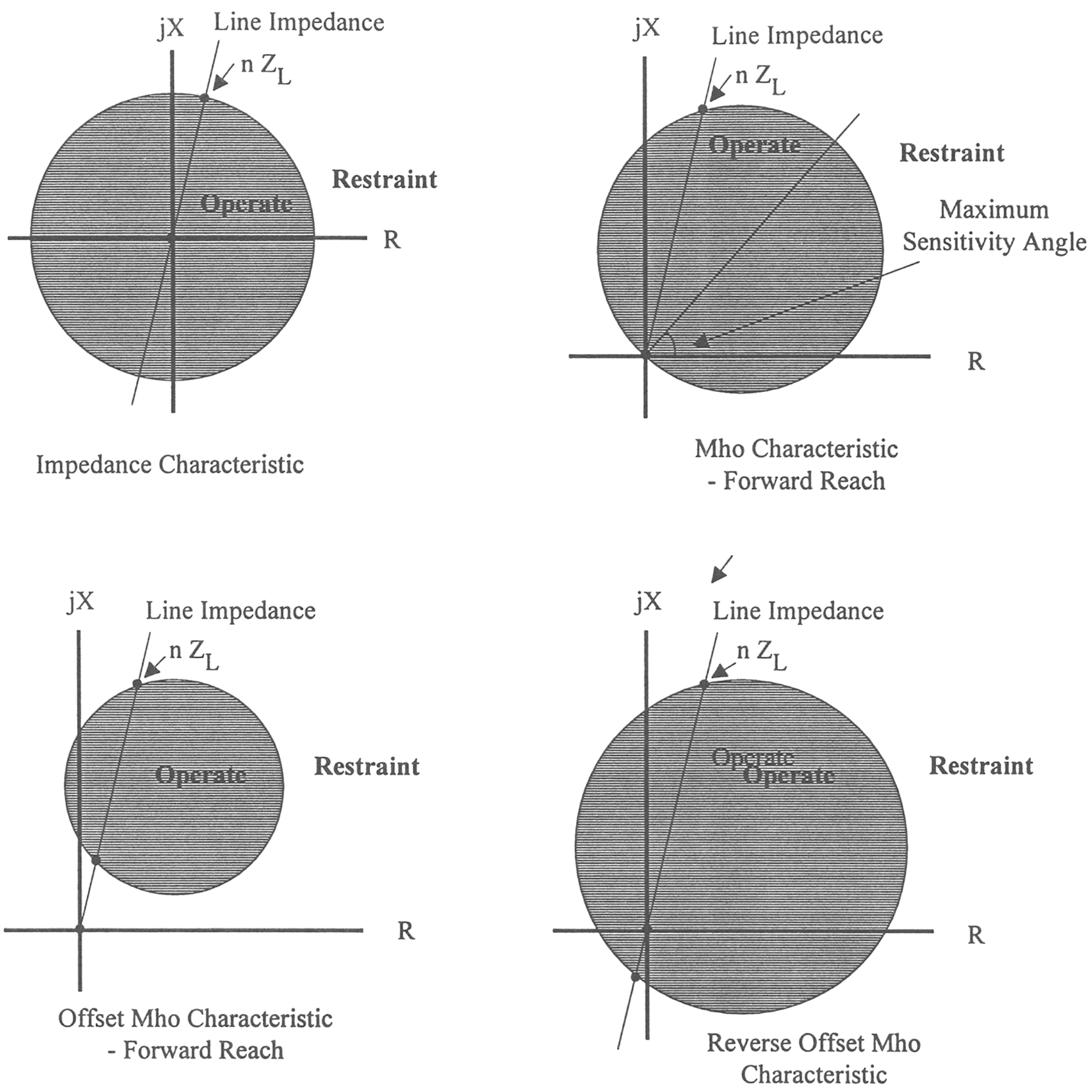



**Figure 11. Generally used characteristics of generic distance relays.**

The operating characteristics of the impedance relay, and the "reach," plotted on a rectangular coordinate system, is shown in Figure 12. Since an impedance relay responds to measurements in all quadrants, a directional unit is generally used to limit the reach to the line side of the relay, as is shown in this figure. With this combination, the impedance relay responds only to the measured impedances which are in the shaded portion of this diagram.

A variation of the impedance relays, called "offset impedance relays," whose characteristic is also shown in Figure 12, are used to start power line carrier protection. These relays look from the circuit breaker towards the line as well as the station bus. In addition, impedance relays can be used to protect generators and transmission lines from out-of-step conditions. On generators, this condition is due to power crossing the air gap being less than the load on the shaft, which is a function of the supply voltage and its phase displacement from the voltage of the receiving system.

### 5.3 Mho Relay

Distance relays can be designed to have circular operating characteristics, plotted on an impedance plane, that passes through the origin of the plane as shown in Figure 13. This type of relay is called a Mho relay or Admittance relay. A fraction n of the line impedance $Z_L$ is a measure of distance of the fault on the line from the relay location. The Mho relay is inherently directional; that is, it will "see" and, therefore, respond only to transmission line faults in one direction from the relay location. Maximum torque angle is the impedance angle at which the relay is most sensitive.

### 5.4 Blinder

Sometimes transmission lines are heavily loaded. The power being transmitted is such that the voltage to current ratio (apparent impedance) at the line terminal is less than the reach of the third zone setting of the line protection relays. A distance relay which has a straight-line non-directional characteristic is used to block the line relay from tripping during normal operation of the line. The characteristic takes advantage of the fact that the apparent impedance is predominantly resistive. The typical characteristic of a blinder is shown in Figure 13.

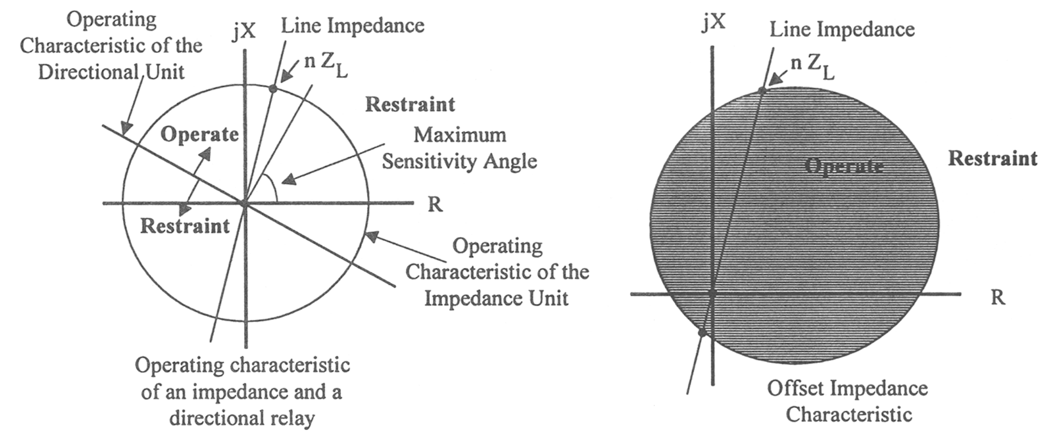



**Figure 12. Operating characteristics of impedance and offset impedance relays.**

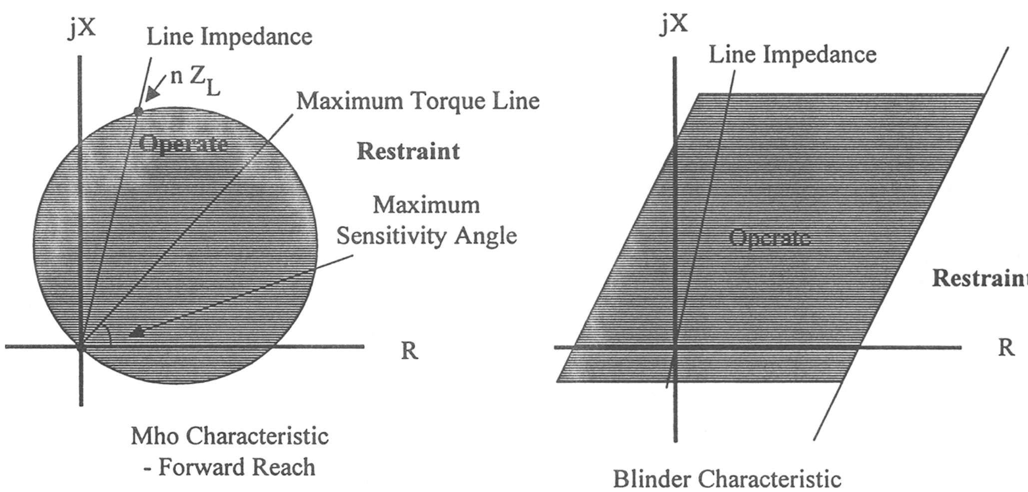



**Figure 13. Typical operating characteristic of a mho relay and a blinder.**

# 6. OTHER RELAYS

Several other relays are used in power systems. Terms used for the following relays are described in this section.

- Differential relays
- Inrush phenomenon
- Combustible gas relay
- Gas accumulation relay
- Static pressure relay
- Sudden pressure relay
- Thermal relay
- Replica or replica temperature relay
- RTD relay
- Phase disagreement
- Breaker failure
- Pole flash-over
- Single phase tripping

## 6.1 Differential Relays

Differential relays, which are assigned the device number 87 by ANSI, are used for protecting lines, transformers, generators, buses and other components of power systems. They function on the principal of comparing two or more electrical quantities (usually currents) and operating if the difference between the values of any signal, observed at the input and output terminals of the protected component of the power system, exceeds a specified threshold.

Current differential relays are based on Kirchhoff's current law which states that the sum of currents entering a node in a network must be zero. Cts are used to provide the currents entering and leaving a zone to a current differential relay. The currents entering a zone are compared with those leaving the zone. The operating current is the phasor difference between these currents.

When there is a fault in the protected zone, the currents entering and leaving the protected zone do not add to zero and, therefore, the differential relay operates. On the other hand, when there is a fault outside the protected zone, the currents entering and leaving the zone add to approximately zero and the differential relay does not operate. Figure 14 shows one phase of a differential relay circuit. The cts are connected to each other and to the operating coil of the differential relay. The current in the operating coil is the difference between $I_{in}$ and $I_{out}$.

In low impedance current differential relays, the difference current flows in the operating coil and the relay operates like an overcurrent relay. When a high impedance current differential relay is used and an internal fault occurs, the total ct secondary current flows through the high impedance overvoltage coil, producing operation.

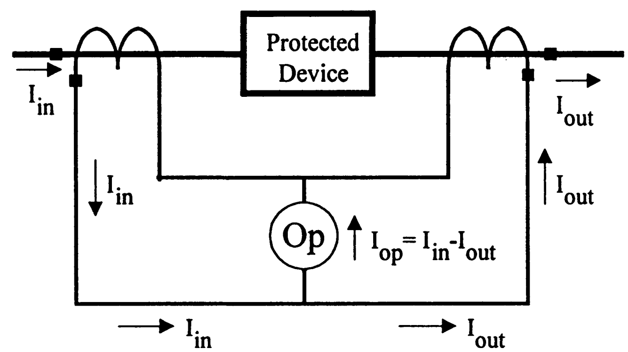



**Figure 14. A typical current differential relay.**

Since the fault currents are large and the cts are not perfect, there is always a relay operating current when a fault occurs outside the differential relay zone. This current could cause an undesired operation of the relay. One of the measures used to keep the differential relays from operating during external faults is the use of the percentage differential principle. Figure 15 shows one phase of a typical percentage current differential relay. Two restraining coils, $R_1$ and $R_2$, are included to provide the restraint. The operating coil is excited by the difference between the currents $I_{in}$ and $I_{out}$, but the relay operates only when the operating current, $I_{in}$-$I_{out}$, is more than a specified percentage of the restraint currents.

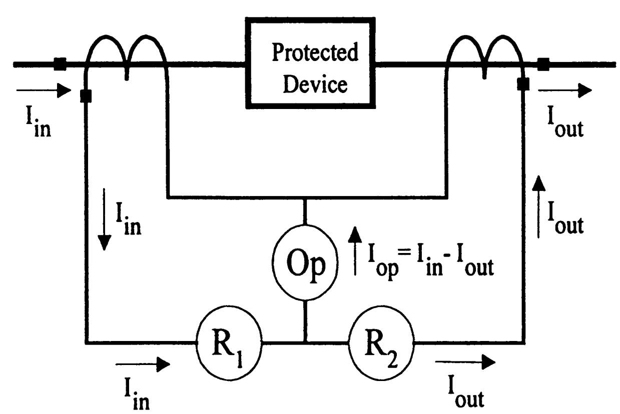



**Figure 15. A typical percentage differential relay.**

### 6.1.1 Transformer differential protection

The ratio of the cts provided at the two terminals of the protected zone and the differences in their characteristics are always of concern in most applications. When differential relays are used to protect transformers, the issues that are given special consideration include

- matching of ct ratios and performance,
- phase shift due to transformer winding interconnections,
- elimination of zero sequence currents, and
- transformer inrush.

The volt-amperes at the primary and secondary terminals of a two-winding transformer are equal if the magnetizing currents are negligible. If a transformer steps up the primary voltage to a higher level, the current at the high voltage terminal is proportionately reduced. Selection of appropriate ct ratios is used to match the magnitudes of the currents entering and leaving the protected zone as applied to the relay.

The connections of the windings of the protected transformer may introduce a phase shift. For example, a transformer with the high-side winding connected in delta and the low-side winding connected in wye, would shift the phase angle of the low-side current by 30°. To compensate for this phase shift, the cts of the wye side are connected in delta and cts outside the delta winding are connected in wye.

**Example:** Consider a three-phase 100 MVA delta-wye 13.8/230 kV transformer. The nominal currents on the 13.8 kV and 230 kV sides are

$$100 * 1000 \div \left(13.8 * \sqrt{3}\right) = \quad 4{,}184 \text{ A}$$

$$100 * 1000 \div \left(230 * \sqrt{3}\right) = \quad 251 \text{ A}$$

If the primary cts are of 5,000/5 ratio and the secondary cts are of 400/5 ratio, the outputs of the primary and secondary cts will be 4.18 A and 3.14 A respectively, when the transformer is supplying rated current.

Since cts on the wye-side of the transformer are connected in delta, the outputs applied to the relay by the secondary cts will be $3.14*\sqrt{3} = 5.43$ A. The difference between the 4.18 A current from the primary cts and 5.43 A current from the secondary cts is eliminated by using ratio matching cts provided in the relays (or installed outside the relay) or taps provided on the relay. In some microprocessor relays, this is achieved by including a multiplier in the relay software.

The phase shift matching can also be achieved (incorrectly) by connecting the wye-side cts in wye and delta-side cts in delta. This arrangement would not compensate for the zero-sequence currents that would flow in the wye-connected winding and not in the delta-connected winding. In the arrangement of Figure 16, zero-sequence currents flow in the wye-connected winding but circulate in the delta winding when a single phase to ground fault on the system connected to the wye winding of the transformer is experienced. The outputs of the cts provided on the delta side do not contain the zero-sequence currents. The solution is to eliminate the zero-sequence currents from the outputs of the cts connected to the wye connected winding. This can be done by using a zero-sequence shunt (or trap) or by connecting the ct secondaries in delta, which also solves the phase shift problem described above.

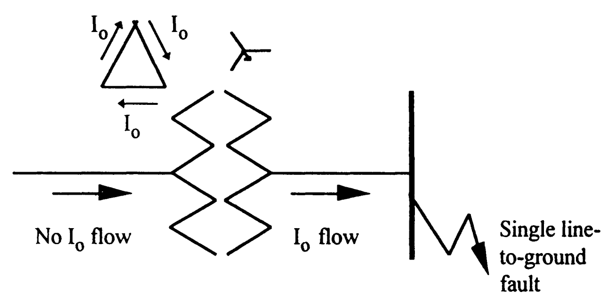



**Figure 16. Zero-sequence currents in a delta-wye transformer.**

### 6.1.2 Magnetizing inrush currents

When a transformer is disconnected from the system and the flow of current is interrupted, the transformer core retains a residual flux. The next time the transformer is energized, the core may saturate and, therefore, draw large magnetizing currents from the source even if no load is connected to the transformer. Since the magnetizing current is supplied by the source and is not reflected on the output side of the transformer, it shows up as operating current in the differential relay circuit. Therefore, the relay must be restrained from operating for this current.

The waveforms of magnetizing inrush currents are not sinusoids of a single frequency; they contain substantial amounts of harmonics. Figure 17 shows two examples of the magnetizing inrush currents flowing into a delta winding of a delta-wye transformer. These currents decay over a period of time, which depends on the size and type of the transformer and the nature of the system.

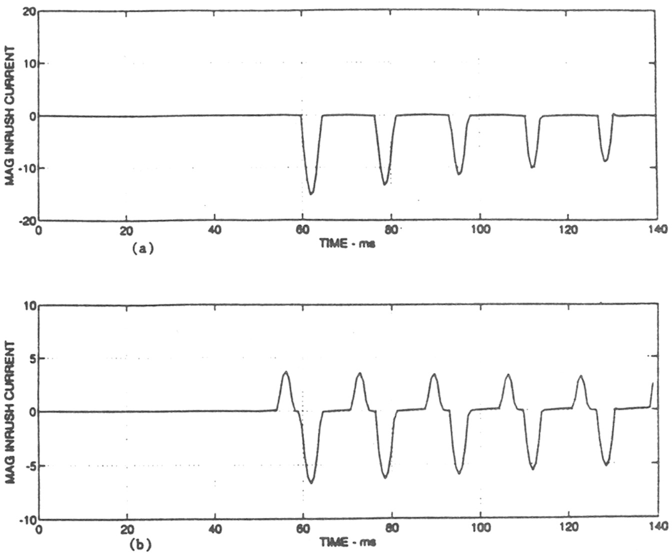



**Figure 17. Typical magnetizing inrush currents in a delta-wye transformer.**

## 6.2 Other Relays for Transformer Protection

Other relays generally used for transformer protection include

- combustible gas relay,
- gas accumulation relay,
- static pressure relay,
- sudden pressure relay,
- thermal replica relay,
- RTD relay,
- loss-of-field (excitation) relay, and
- out-of-step relay.

These relays are briefly described in this section.

### 6.2.1 Combustible gas relay

The combustible gas relay is applied to transformers which are equipped with positive pressure inert gas-oil preservation systems. This device measures the presence of combustible gas in the transformer in the inert gas blanket. The presence of the combustible gas indicates the decomposition of insulating materials due to faults or corona. Since these faults are not accompanied with large fault currents, they are usually not detected by other relays until they develop into major short circuits which usually cause substantial damage. The combustible gas relay is expensive and is not normally applied on substation transformers.

### 6.2.2 Gas accumulation relay

Commonly known as a Buchholz relay, the gas accumulation relay is constructed so that it accumulates all or a fixed portion of the gas released by the protected equipment. It operates when the volume of gas reaches a certain level. The accumulator relay can only be applied to transformers with conservator tanks. Another name for this device is a gas detection relay.

### 6.2.3 Static pressure relay

This relay (assigned the device number 71) can be used on all types of oil-immersed transformers. It is mounted below the oil level on the transformer tank wall and is activated by the pressure in the tank. Because of the many incorrect operations of the static pressure relays over the years, most have been superseded by sudden pressure relays.

### 6.2.4 Sudden pressure relay

Two types of sudden pressure relays (assigned device number 63) generally used to protect transformers are the sudden gas pressure and sudden oil pressure relays.

Sudden gas pressure relays operate if the rate of rise of pressure in the transformer exceeds a specified level. These relays can be applied on all gas cushioned oil-immersed transformers and are mounted in the gas space above the oil.

Sudden oil pressure relays measure the rate of rise of oil pressure and operate if it exceeds a specified value. These relays can be applied on all oil-immersed transformers and are usually mounted near the bottom of the transformer tank wall.

These relays are commonly used to protect transformers and are generally connected to trip circuit breakers to disconnect the transformer from the rest of the power system. Because the micro-switch contacts used in sudden pressure relays are sensitive to control circuit disturbances, an auxiliary relay is often included in the sudden pressure circuit.

## 6.3 Thermal Relay

A thermal relay, (assigned device number 49) operates if the heat developed within the relay as a result of external and internal conditions exceeds a specified level. The relay uses input(s) from ct(s) to monitor the $I^2R$ heating in the protected equipment. This relay is different from a temperature relay which uses a temperature sensing device, either in or on the equipment being monitored. The circuit of a typical thermal relay is shown in Figure 19.

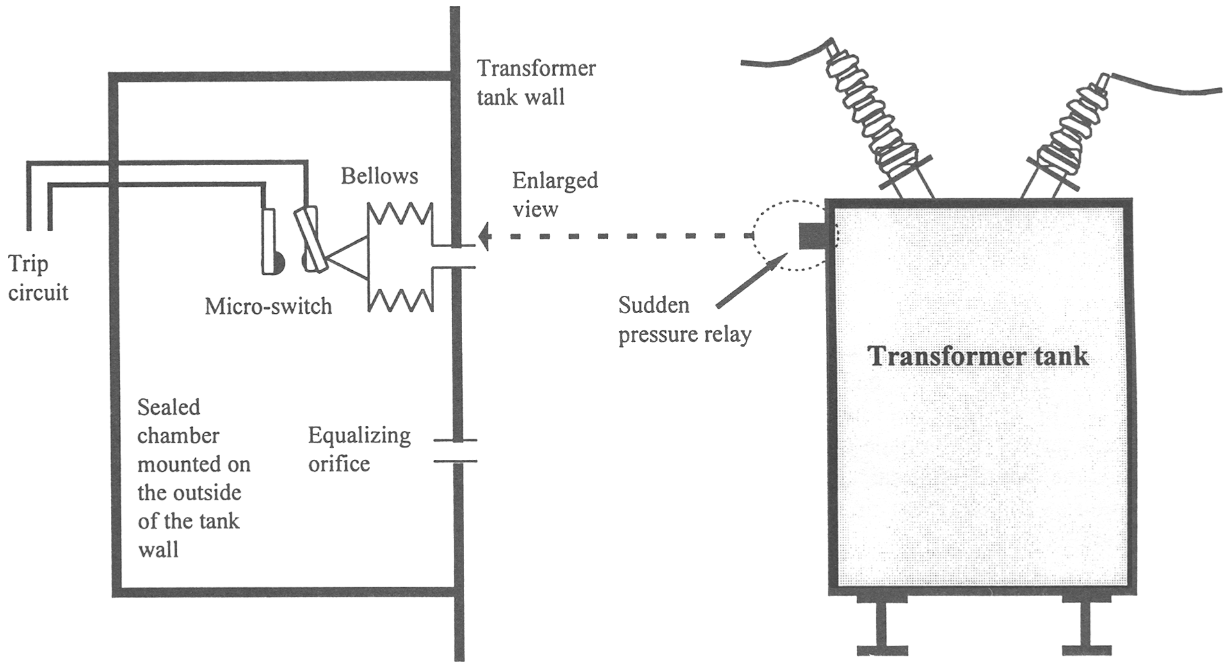
## 6.4 Temperature Relay

A temperature relay (assigned device number 49) measures the external temperature of the protected equipment.

Monitoring of the temperature is accomplished by using an RTD, gas bulb, thermocouple or another temperature sensing device located at the point to be monitored. The mounting of a typical temperature relay is shown in Figure 20.

### 6.4.1 Replica relay or replica temperature relay

These relays (assigned device number 49) are designed to achieve an internal temperature rise proportional to the temperature rise of the protected apparatus, or conductor, over a range of values. A current proportional to the current in the protected equipment is passed through a heating element in the relay. The relay is designed to simulate the heating and cooling of the protected apparatus. The modeling of the cooling of the equipment is essential to protect the equipment from being returned to service too soon after a thermal overload. A typical circuit for a replica relay is shown in Figure 21.




Simplified scheme for a sudden gas pressure relay

Sudden gas pressure relay mounting on the side of a transformer above the oil level

**Figure 18. Mounting and schematic arrangement of a sudden gas pressure relay.**

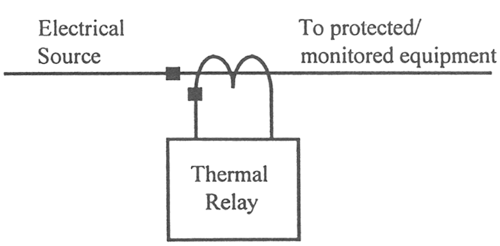



**Figure 19. Thermal relay monitors $I^2R$ losses in the protected equipment.**

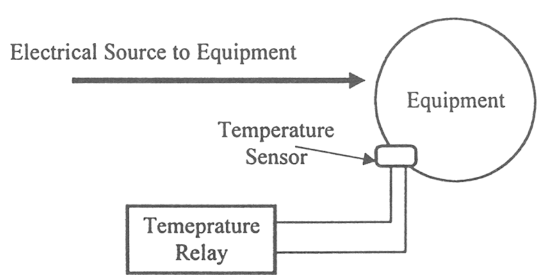



**Figure 20. The mounting of a typical temperature relay.**

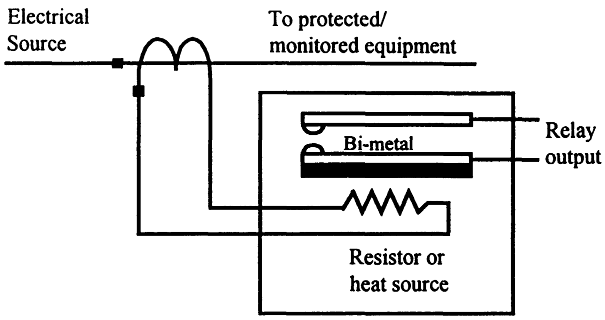



**Figure 21. The circuit diagram of a replica relay.**

## 6.4.2 RTD relay

A temperature relay, assigned device number 49, uses a resistance temperature detector (RTD) to monitor the temperature of the protected equipment. An RTD is a resistor made of a material whose resistance changes in a predetermined manner when the temperature changes. Electromechanical RTD relays normally use a Wheatstone bridge (or an equivalent circuit) to sense the temperature changes and respond with a predetermined output. One form of microprocessor RTD relay applies a low level of current to the resistor and measures the voltage drop across the resistor. From this measurement, it calculates the resistance and the temperature. The electrical circuit of a RTD relay is shown in Figure 22.

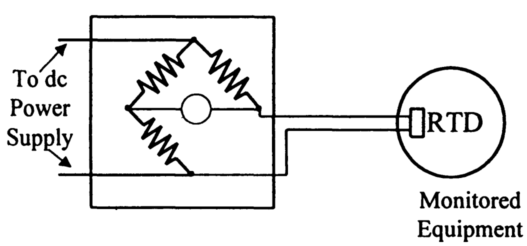



**Figure 22. Circuit of a typical RTD relay.**

## 6.5 Loss-of-field (excitation) Relay

The magnetic field is set up in a generator by providing dc currents to the field winding of the generator. In the event of the system experiencing a disturbance, the magnetic field must be changed to maintain the system voltage (at or near the generator terminals) at the nominal value.

The excitation system can be supplied current from an auxiliary generator mounted on the shaft of the main turbine-generator unit, or from the plant auxiliary bus, or the main generator. Several circumstances can result in loss-of-field; these include

- accidental tripping of the field circuit breaker,
- poor brush contact in the slip rings of the rotor, and
- loss of ac supply to the excitation system.

Reduced levels of excitation, or complete loss of field can result in loss of synchronism, instability and, possibly, damage to the generator. When a disturbance is experienced, the generator output oscillates (accompanied with rotor oscillations) in an attempt to stay in synchronous operation with the system. If the disturbance is accompanied by a substantial decrease in the terminal voltage, system stability is threatened. For these reasons, a loss-of-field relay is applied to protect the generator and the system to which it is connected. The relay is usually designed to trip the generator when the relationship between the alternating voltages and currents, measured at the generator terminals, indicates that a loss-of-field condition has occurred. ANSI has assigned device number 40 to loss-of-field relays.

## 6.6 Out-of-step Relay

When two or more interconnected synchronous generators or systems have lost synchronism with respect to one another and are operating at different frequencies, they are said to be operating under an out-of-step condition. This condition can be caused by a mismatch between the electrical output of the generator and the mechanical input to the generator. Distance relays (in conjunction with blinders) are applied to detect and trip the generators when this is suspected to have happened. Generally, the protection is designed either to trip the generator breaker or to open the line interconnecting the two systems. The disconnected generator, or the interconnecting line are brought back in service after the condition has stabilized. The out-of-step relays are assigned the device number 78.

# 7. CIRCUIT BREAKER APPLICATIONS

A few terms concerning circuit breakers often used by protection engineers are

- breaker failure,
- phase disagreement,
- pole flashover, or
- single-phase tripping.

These terms are briefly described in this section.

## 7.1 Breaker Failure

The failure of a circuit breaker to interrupt fault current following the attempt to energize its trip coil by a protective relay is described as breaker failure. The reason for such failures include

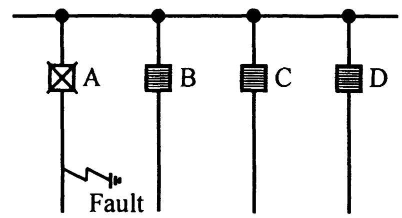
- inadequate or damaged interrupter,
- mechanically damaged mechanism, and
- lack of electrical continuity of the trip circuit.

A breaker failure relay (assigned device number 50BF) recognizes the condition of current continuing to flow in the circuit breaker after a reasonable period of time has elapsed since a relay made an attempt to energize the trip coil of the circuit breaker. On recognizing such a condition, the breaker failure relay initiates the clearing of all the circuits that can feed current to the fault via the failed breaker.

The following three examples show the circuit breakers that are tripped by a breaker failure relay.

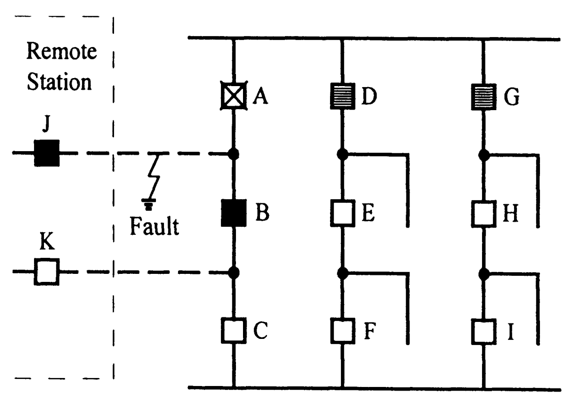
**Example:** Circuit breaker A of a single bus switching station, shown in Figure 23, has failed to interrupt current flowing to a fault on the line it controls. The condition is identified by the breaker failure relay which issues commands to trip circuit breakers B, C and D. The relay also issues a trip command to trip circuit breaker A.

**Example:** Circuit breaker A of the switching station, shown in Figure 24, has failed to interrupt current flowing to a fault on line to circuit breaker J at the remote station. Circuit breakers B and J have successfully interrupted the flow of current through them. On detecting circuit breaker failure, the breaker failure relays issues trip commands to circuit breakers D and G, as well as A and B. If communication facilities are available, the trip command is also sent to circuit breaker J.




Circuit breaker A fails to interrupt the fault current

**Figure 23. Single bus switching arrangement; circuit breaker A fails to interrupt current.**




Circuit breaker A fails to interrupt current to the fault on the line to the remote station.

**Figure 24. A breaker-and-a-half switching arrangement; circuit breaker A fails to interrupt current to fault on the line to circuit breaker J.**

**Example:** Circuit breaker A of the switching station, shown in Figure 25, has failed to interrupt current flowing to a fault on the line to circuit breaker H at the remote station Y. Circuit breakers D and H have successfully interrupted the flow of current through them. On detecting circuit breaker failure, the breaker failure relay issues trip commands to circuit breakers B and J, as well as A, D and H.

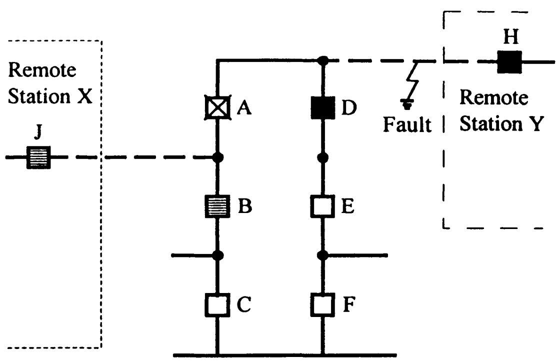



**Figure 25. Circuit breaker failure in a ring bus switching station.**

The three examples, one for a single bus switching station, one for a breaker-and-a-half switching arrangement and the third for a ring bus switching station show the local, as well as, remote circuit breakers that could supply fault current through the failed circuit breaker. The breaker failure relay issues trip commands to these circuit breakers as well as the circuit breakers that have successfully interrupted the flow of fault current.

## 7.2 Pole Disagreement

This is the condition in which one pole of a three-phase circuit breaker is open while the remaining poles are closed. It also includes the condition in which two poles of a three-phase circuit breaker are open while the remaining pole is closed. Such conditions cause negative-sequence currents to flow in the equipment controlled by the circuit breaker. Since the flow of negative-sequence currents can damage equipment, especially the rotating machines, these conditions must be recognized and the circuit breaker opened. This condition also causes zero-sequence currents to flow in the system which can result in ground fault relays to operate. This condition is sometimes called "pole disagreement".

**Example:** Figure 26 shows the contact arrangement of a three-phase breaker which has two breaks per pole. The condition in which

- the contacts of an interrupter, or interrupters in one phase are open, and
- the contacts of interrupters in the other two phases are closed

is identified as pole disagreement. If the contacts of interrupter A, or A and B, are open and the contacts of interrupters C, D, E and F are closed, pole disagreement has occurred.

Pole disagreement is supervised by auxiliary contact arrays ("a" and "b" switches) or by comparing phase currents in the three phases. On identifying a pole disagreement, the pole disagreement relay starts a timer and, if the disagreement continues for a specified time, either all three poles of the circuit breaker are tripped or backup clearing of the condition is initiated.

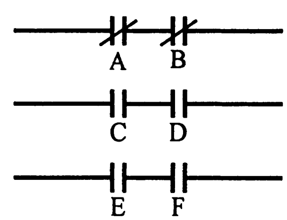



**Figure 26. Contact arrangement of a three phase circuit breaker which has two interrupters per phase. The contacts of interrupters "A" and "B" are closed whereas the interrupters "C", "D", "E" and "F" are open.**

## 7.3 Pole Flashover

A flashover across an open or partially open pole of a three-phase circuit beaker can occur due to lightning, switching surges or loss of dielectric in a pressurized interrupter. This phenomenon is called pole flashover. Flashover can occur on circuit breakers which have one operating mechanism for all three poles and also on circuit breakers which have independent operating mechanisms for each pole.

## 7.4 Single-Pole Tripping

When a single-phase fault is experienced on a system, fault current flows in one phase only. In many situations, only one pole of the circuit breaker controlling a line is opened during these faults. Most power system protection engineers call this practice "single-pole tripping" but sometimes it is called single phase tripping".

Faults other than single phase to ground faults are usually isolated by tripping all three poles.

# 8. SYSTEM DISTURBANCES

The importance of protection from system disturbances has increased with the development of interconnections between power systems. Load generation unbalance may be caused in a system by loss of generators or interconnections with the neighboring utilities. If the load of a system exceeds the available generation, the frequency decreases. Severe overloads produce rapid frequency decay. Rotating machinery, especially steam turbines, cannot operate safely at frequencies less than a few percent below the rated frequency. Frequency relays are, therefore, used to shed load to restore generation-load balance.

## 8.1 Underfrequency Relay

Underfrequency relays (assigned device number 81) are applied to automatically shed load when the system operating frequency decreases to a specified level below the nominal frequency or if its rate of decay (df/dt) exceeds a specified level. They trip selected loads to prevent a system from collapsing, or experiencing a major blackout, by restoring the balance between load and generation.

Underfrequency relays are usually installed at distribution substations and industrial installations, and are generally set between 59.7 and 58.5 Hz. Time delays are usually applied to provide system security. In addition, particularly for solid-state underfrequency relays, an undervoltage inhibit function is included to further improve security. Relays may have multiple settings to ensure that loads are tripped in small increments as the frequency decreases.

# 9. DISTURBANCE ANALYSIS

Fault analysis has become an important activity because it provides a better insight in the operation of the system as well as its equipment. Power system engineers, especially protection engineers had been recording waveforms of voltages and currents during faults for many year.

Before the use of the digital electronics technology became wide spread in power systems, light beam oscilloscopes were being used. As the manufacturers developed digital relays, they found that some capabilities for recording waveforms of power system signals could be include in the relays. Consequently, several devices were made available that could record voltages and currents during systems disturbances. However, many stand-alone devices have been developed and used in power systems to record voltages and currents during system disturbances. The difference between the capabilities of the commercial relays and dedicated recording devices is that the resolution of the recording made by the relays are usually not as good as the recordings made by the dedicated devices.

Out of the several terms used in this area, the following terms are briefly described in this section.

- Sequential events recorder
- Transient fault recorder
- Pre-fault, fault and post-fault periods

## 9.1 Sequential Events Recorder

A sequential events recorder is a system that monitors and records the state of discrete events, such as, "on" or "off" status of a circuit breaker, "closing" or "opening" of a circuit breaker, activation of an alarm or its deactivation. In addition to this binary information, the sequential event recorders note the absolute or relative time of the occurrence of the observed events. Other names used for a sequential event recorder include sequence of events recorder, SER and data logger.

## 9.2 Transient Fault Recorder

A transient fault recorder is a device that records the magnitudes of system quantities (typically currents, voltages, etc.) along with the time when those magnitudes were observed. Each recorder has a frequency response and a dynamic range that dictates the quality of the observations. Depending on the design of the recorder, the signals can be recorded for monitoring transient system changes, including the high frequency components in them, or for observing long term changes, such as monitoring power system swings. Often, a transient recorder includes the ability to record binary changes of states as described for the sequential events recorder.

## 9.3 Pre-fault, Fault and Post-Fault Periods

Pre-fault period is the time before the inception of a fault. Fault period is the time during which the system continues to experience a fault. The post-fault period is the time that starts from the instant a fault has been cleared.

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