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Substations – Volume XI – Relaying

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Substation Design
Volume XI
Protective Relaying

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This series of courses are based on the "Design Guide for Rural Substations", published by the Rural Utilities Service of the United States Department of Agriculture, RUS Bulletin 1724E-300, June 2001.

Preface

This course is one of a series of thirteen courses on the design of electrical substations. The courses do not necessarily have to be taken in order and, for the most part, are stand-alone courses. The following is a brief description of each course.

Volume I, Design Parameters. Covers the general design considerations, documents and drawings related to designing a substation.

Volume II, Physical Layout. Covers the layout considerations, bus configurations, and electrical clearances.

Volume III, Conductors and Bus Design. Covers bare conductors, rigid and strain bus design.

Volume IV, Power Transformers. Covers the application and relevant specifications related to power transformers and mobile transformers.

Volume V, Circuit Interrupting Devices. Covers the specifications and application of power circuit breakers, metal-clad switchgear and electronic reclosers.

Volume VI, Voltage Regulators and Capacitors. Covers the general operation and specification of voltage regulators and capacitors.

Volume VII, Other Major Equipment. Covers switch, arrestor, and instrument transformer specification and application.

Volume VIII, Site and Foundation Design. Covers general issues related to site design, foundation design and control house design.

Volume IX, Substation Structures. Covers the design of bus support structures and connectors.

Volume X, Grounding. Covers the design of the ground grid for safety and proper operation.

Volume XI, Protective Relaying. Covers relay types, schemes, and instrumentation.

Volume XII, Auxiliary Systems. Covers AC & DC systems, automation, and communications.

Volume XIII, Insulated Cable and Raceways. Covers the specifications and application of electrical cable.

Chapter 1
Protective Relaying Overview

Protective relays are used to detect defective lines or apparatus and to initiate the operation of circuit-interrupting devices to isolate the defective equipment. Relays are also used to detect abnormal or undesirable operating conditions other than those caused by defective equipment and either operate an alarm or initiate operation of circuit-interrupting devices. Protective relays protect the electrical system by causing the defective apparatus or lines to be disconnected to minimize damage and maintain service continuity to the rest of the system.

The design objectives of a protective relaying are to minimize the effects of a system disturbance and to minimize the possible damage to power system equipment. A good protective relaying system will address dependability, security, speed, and simplicity.

Dependability is the certainty of correct operation in response to system troubles. Dependability includes the reliable operation of the relay system operating when it is supposed to and selectivity of the relay system operating to isolate the minimum amount of the system necessary to provide continuity of service. *Security* is the ability to avoid misoperations between faults. Every relay system has to be designed to either operate or not operate selectively with other systems. *Speed* means clearing all faults in the shortest possible time with all due regard to dependability and security. A relaying system should be no more complex than is required for any given application. Adding more equipment into a scheme than is necessary for good coverage adds to the possibility of equipment failure and misoperation.

A *short circuit* is an abnormal connection of relatively low resistance between two or more points of differing potential in a circuit. If one of these points is at ground potential, it is referred to as a *ground fault*. If ground potential is not involved, it is referred to as a *phase fault*. Phase faults cause excessive currents and low voltages. Ground faults may or may not cause excessive currents or abnormal voltages, depending on whether the system is normally ungrounded, high- or low-resistance grounded, or effectively grounded.

A few of the abnormal system conditions that occur in electrical substations include,

- Excessive Heating
- Overvoltage
- Undervoltage
- Unbalanced Phase Conditions
- Reverse Phase Rotation
- Abnormal Frequency
- Overspeed
- Abnormal Pressure
- Abnormal Impedance
- Out-of-Step Conditions
- Excessive System Phase Angles

Below is a brief discussion of each of these conditions.

Equipment is designed to deliver full-rated capacity with the temperature maintained below a value that will not be damaging to the equipment. If operating temperature becomes excessive, the life of the equipment (generator, motor, transformer, etc.,) will be reduced. Excessive heating may be caused by overloading, high ambient temperatures, improper cooling, or failure of cooling equipment.

Equipment is designed for normal operating voltages as stated on its nameplate with a slight allowance (usually about 5 percent) for normal overvoltage. *Abnormal overvoltage* may cause:

- Insulation failure
- Shortening of the equipment life
- Excessive heating as a result of greatly increased excitation currents where electromagnetic devices are used
- Excessive heating in resistors used in controls
- Failure of transistors and other electronic devices

Continued *under-voltage* will likely cause overheating of motors and dropping out of contactors, and lead to the failure of electrical equipment.

On balanced three-phase systems with balanced three-phase loads, a sudden unbalance in the current or the voltages usually indicates an open or a partially shorted phase. An unbalanced voltage condition is especially serious for three-phase motors because negative sequence currents can lead to considerable overheating within the motor. On balanced three-phase systems with single-phase loads, the loading on each phase may normally vary, depending on the magnitude of each single-phase load. However, it is desirable to keep this unbalance to a minimum to maintain balanced voltages for three-phase loads. Unbalanced conditions, which include single-phase and double-phase faults with or without ground, can be detected with the use of negative and zero sequence relay elements.

Reversed phase rotation can occur after circuit changes have been made or during an open phase condition. Reversed rotation of motors may cause considerable damage to the facility driven by the motors, such as a conveyor.

Abnormal frequencies can occur when the load does not equal the generation. The frequency may be above or below the system normal frequency. Many facilities such as electric clocks, synchronous motors, etc., are frequency sensitive.

Considerable mechanical damage can be done to generators and motors because of over-speed. Excessive over-speed may cause parts of the generator or motor to be thrown for considerable distances, which is dangerous to personnel as well as to other facilities. Generators or series-connected motors may reach dangerous over-speeds when loads are suddenly removed.

In electrical equipment, such as transformers, that use liquid as an insulating fluid, high internal pressures can be created during internal faults.

Electrical equipment has impedance associated with it that either has definite known values or values that may vary within a known range during known varying operating conditions. These values are normally determined during the manufacture and installation of equipment. Substantial deviations in the impedance of the equipment can indicate a failure of the equipment.

In the United States, all the generators and rotating equipment on the system rotate at an RPM to maintain a 60 hertz frequency. As such, each machine on the electrical system maintains a relative position, or phase angle, with respect to every other machine on the system. Once a machine exceeds a critical phase angle, it can no longer stay in phase with the system. It is said to have moved *out of step* with the system, and has to be removed from the system and resynchronized to the system in order to establish operation. Out of-step conditions are typically monitored through the use of impedance relays and set to trip or block the trip of breakers in order to segment the system at predetermined locations based on system stability studies.

The closing of a circuit breaker on a system connects the electrical systems on either side of the circuit breaker. The closing of the breaker will cause any difference of voltage and phase angle across the breaker to be reduced to zero, causing current flow from one system to the other to equalize the system voltages, currents, and phase angles. If the voltage and phase angle differences across the breaker are too much, excessive currents can flow, resulting in a disturbance to the system, possibly damaging the breaker or adjacent rotating equipment.

Typically, the voltage and phase angle across the breaker are compared to confirm the systems are within proper limits before the breaker is closed.

Fundamental Considerations

A *phasor* is a complex number used to represent electrical quantities. In protective relaying systems, phasors are used to aid in applying and connecting relays and for analysis of relay operations after faults. Phasor diagrams have to be accompanied by a circuit diagram. The phasor diagram shows the magnitude and relative phase angle of the currents and voltages, while the circuit diagram shows the location, direction, and polarity of the currents and voltages.

The relative *polarities* of a current transformer's primary and secondary terminals are identified either by painted polarity marks or by the symbols "H1" and "H2" for the primary terminals and "X1" and "X2" for the secondary terminals. The convention is that, when primary current enters the H1 terminal, secondary current leaves the X1 terminals. Or, when current enters the H2 terminal, it leaves the X2 terminal. When paint is used, the terminals corresponding to H1 and X1 are identified. Since AC current is continually reversing its direction, one might well ask what the significance of polarity marking is. Its significance is in showing the direction of current flow relative to another current or to a voltage, as well as to aid in making proper connections. The polarity marks for a potential transformer have the same significance as for a current transformer.

A *system fault* is a condition in which the electric current follows an abnormal path as a result of the failure or removal of the insulation that normally confines the electric current to the conductors. Insulation is usually either air or high-resistive material that may also be used as a mechanical support. Air insulation can be accidentally short-circuited by birds, rodents, snakes, kite strings, tree limbs, etc.; broken down by overvoltage due to lightning; or weakened by ionization due to a fire or smoke. Organic insulation can deteriorate because of heat or aging or can be broken down by overvoltage due to lightning, switching surges, or faults at other locations. Porcelain insulators can be bridged by moisture with dirt or salt, or can develop a crack as a result of mechanical forces.

Symmetrical components are the foundation for obtaining and understanding fault data on three-phase power systems. Knowledge of symmetrical components is important both in making a study and in understanding the data obtained from digital analysis from a computer. It is also extremely valuable in analyzing faults and relay operations. A number of protective relays are based on symmetrical components. Symmetrical components are one of the most powerful technical tools used by a relay engineer. The practical value lies in the ability to think and visualize in symmetrical components.

Instrument transformers provide relays with currents and voltages that are proportional to voltage and currents flowing in the primary circuit. Voltage signals are obtained from potential transformers (PTs) and current signals from current transformers (CTs).

Chapter 2
Basic Relay Types

Protective relays consist of three basic modules:

1. An input module
2. A decision module
3. An output module

See Figure 1. The modules are each constructed of components that will vary depending on the type of construction of the relay: electromechanical, static, or microprocessor.

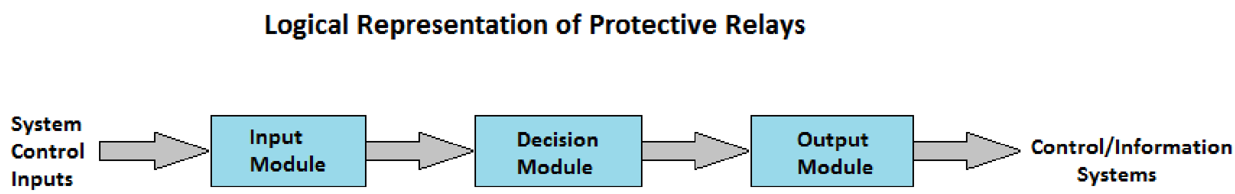

Figure 1

Relays are also classified according to the function they provide to the system. The five most common functions are:

1. Protection
2. Regulation
3. Reclosing and synchronization
4. Monitoring
5. Auxiliary

The primary emphasis of this discussion is protection. Other functions are included as applicable. Each of the basic relay modules operates to perform tasks as follows.

The principal *input module* task is to receive the inputs from the electrical system to the relay, generally in the form of currents, voltages, and status input contacts. It acts as the interface between the relay decision module and the electric power system, protecting the sensitive decision module from the harsh environment of the electric power system. The electrical system input section typically consists of transformers, transactors, zener diodes, electronics, and other equipment to provide a signal, proportional to the inputs, to the decision module. The input equipment will condition the input signals to be in a format required by the decision module. Conditioning may include converting the voltage, contact, or current inputs into voltages or currents suitable to electronic equipment. Conditioning may also include the conversion of the signals from analog values to digital values. The input section also will typically contain equipment that will provide protection for the relay to withstand the surges, transients, and oscillations that may be present in the substation environment. An additional task of the input section of the relay is to provide for the input and storage of the relay settings. For electromechanical and static relays, this is most often the setting of various taps, dials (which will normally preset tension on a spring), and selector switches on the face of the relay. For microprocessor relays, the input section often includes a series of push buttons that will allow the input of relay settings or the input of requests for the relay to display settings or data processed by the relay. The relay settings will be stored for use by the relay in providing its protective functions.

Microprocessor relays often include a number of additional inputs to the relay. Included in these inputs are the power supply; clock signals to provide sequence of events (SOE) timing; communication ports to provide direct computer, SCADA, or other data inputs; and front panel push buttons to set the relay or scroll through the metering functions. Microprocessor relays are often provided with multiple relay setting groups that will allow for changes in the electric power system configuration. The change from one settings group to another can usually be keyed locally by an external contact in the substation control scheme or remotely via SCADA. It should be noted that there is an inherent danger of inadvertently changing a relay setting or setting group with this type of microprocessor relay.

The relay engineer has to be aware of the electrical system inputs that are available for use in determining the failure of the electric power system or electric power system components. Knowledge of the electric power system and how the system responds to various failures is invaluable in making decisions as to the types of relays that are used to protect the electric power system.

The *Decision Module* monitors the input data included in the relay settings input to the relay and the system data, including currents, voltages, status contacts, and control signals that were input to the relay. The module will evaluate the system data in comparison to the relay settings. When the system data exceed the threshold determined by the relay settings, this module will signal the output module to function and record the results. The quantities to which the relay responds usually designate the relay type.

For electromechanical relays, the decision module often consists of disks that work by induction, plungers, or solenoids; levers that will work on a balance beam principle; units that work on the basis of thermal characteristics; or D’Arsonval units that consist of a combination of fixed magnetic and electromagnetic elements. Each of the units is configured with a contact that either makes (closes) or breaks (opens) upon the operation of the device. The recording of the action is usually accomplished by the dropping of a target to indicate the relay operation. The module compares the input relay settings to the input signals through the inherent magnetic or thermal action of the relay to overcome the spring tensions and inertia associated with the relay settings. Relays may operate,

1. Instantaneously,
2. With some definite time delay, or
3. With a time delay that varies with the magnitude of the quantities to which the detecting element responds.

Static relays replace the electromechanical components with solid-state components and make the comparisons by electronic means. Static or solid-state detecting elements generally convert the current, voltage, or power inputs to proportional DC millivolt signals that are then applied to adjustable transistor amplifiers. These amplifiers have a "go–no go" characteristic that causes an input signal up to the set level to produce no output and input signals beyond that level to produce full output. The output may be another DC millivolt signal applied to further transistor logic or to a contact closure. Indication of the operation of the relay is usually accomplished by the dropping of a target to indicate the relay operation.

Microprocessor relays replace the decision module with a small digital computing unit that utilizes sampled input data and digitized setting parameters. Comparisons are made digitally by the computer performing a calculation or series of calculations, comparing the relay setting information to the periodic samples obtained from the electric power system. When the threshold values are exceeded, the module activates the output module. Most relays will also store a number of metering values, the status of input devices, intermediate logic elements, and other information available to the relay in output storage registers. The information is then available for retrieval by the engineer at his convenience, either locally at the substation or remotely through communications that are often provided to the relay.

Microprocessor relays usually include internal self-checking functions for the majority of their functions. Should a failure occur within the logic of the relay, an alarm will be given to the relay output module that the relay is in an alarm condition. The relay engineer also needs to be aware of the functions and features that may not be covered by an alarm, such as the capability of the output relays to function.

The *Output Module* provides an output from the decision module to the control system in order to operate electric power system equipment and isolate faulty system components. For electromechanical relays, this system typically consists of output contacts or auxiliary relays with multiple contacts. The contacts act as the interface between the relay and the electric power control system. These contacts are then used to trip circuit breakers, provide alarms, trip other relays such as lockout relays and send signals via communications to remote equipment or personnel, or other functions. The contacts will carry specific ratings for the voltages and currents they will successfully carry or break.

Static relays provide the option for outputs to be either auxiliary reed (magnetically activated) relays and their associated contacts or solid-state-controlled thyristors. Electronically controlled thyristors are usually faster than their relay counterparts. Triggering circuitry may include opto-isolators to provide isolation between the relay and the harsh environment of the electric control system.

Microprocessor relays will use either reed relays or solid-state-controlled thyristors for output elements. Usage will vary between manufacturers and may be optional to the user. In addition to the standard relay outputs, microprocessor relays may include a number of additional output contacts that may be programmed for the user's requirements. One of the output contacts is normally designated as the relay alarm contact. Most relays include a number of output storage registers where the relay stores a number of metering values, the status of input devices, intermediate logic elements, and other information available to the relay. The information is then available for retrieval by the engineer at his convenience, either locally at the substation or remotely through communications that are often provided to the relay. Most microprocessor relays include communication capabilities that allow the relay to transmit data in digital format to computers, SCADA systems, or local control systems. The image shown below is a Schweitzer microprocessor realy.

Many microprocessor relays also include a display unit as a part of the output module. This display unit is typically used to display metering values of the inputs that are brought to the relay or metering information that is calculated in the relay. The display may also show other functions of the relay, such as the display of internal variables, flags, and input parameters. The display typically provides a means of getting information out of the relay without the requirement to connect a computer to one of the output ports.

Relay Selection

The type of relay selected by the relay engineer for an application is of primary importance. The engineer has to determine, with existing system knowledge or with additional studies, the types of failure that each component of the electric power system can experience and the characteristics of the failure. The electrical system inputs that will be available to the relay and the speed with which the relay has to operate to maintain electrical system stability has to be known. With this information, the engineer can apply relays that will measure the identified characteristics of the electric power system component with the previously established relay settings and operate dependably and securely in protecting the electrical system. The relay engineer should consider some of the following factors.

Electromechanical relays are the oldest and have the most history associated with them. They provide discrete protection functions within each case. Relay settings are usually straightforward and well documented in most instruction books. The relay engineer has to have a relatively good idea of the magnitudes of electrical signals that will be applied to the relay in order to obtain the proper range of settings for each application.

Static relays generally provide discrete functions similar to electromechanical relays. Since the operation of the relays depends only on threshold values being met, these relays are generally faster than their electromechanical counterparts. Static relays often come in cases similar to their electromechanical counterparts, making replacement relatively simple. Static relays are also available in “packages” that include all the protective functions for the line in a single rack.

Microprocessor relays often can accommodate more complex system operation because of the inputs provided to the relay and the programming features included with the relay. In many cases, numerous functions are provided in the relay so that the number of discrete relays required for protection may be reduced substantially. In many cases, additional functions may be provided to protect a system from abnormal conditions that might not otherwise be considered based on the low occurrence of such conditions or because of other considerations.

Microprocessor relays often provide many more options for providing protection than either their electromechanical or static relay counterparts. Once the inputs to the relay are obtained, the decision module can then be programmed to provide many protective functions with these inputs. This information can also be used to implement the transmittal of data remotely through SCADA or other data retrieval means. In terms of the number of functions, the microprocessor relay will often provide more protective functions for the dollar spent. This type of relay may be slightly slower to operate than some of the electromechanical or static relays that are available. The operating speeds of microprocessor relays are typically in the range of 1.5 to 2 cycles. Some static relays may operate in less than 1 cycle. Microprocessor relays usually include internal self-checking functions for the majority of their functions. As noted, the relay engineer also needs to be aware of the functions and features that may not be covered by an alarm, such as the capability of the output relays to function.

In new installations, the use of microprocessor relays may result in reduced cost since fewer relays are required. Generally, less floor space is needed so smaller control buildings are needed for the equipment. This may result in reduced auxiliary power system requirements. The interconnection wiring in a panel is also reduced since many of the protective functions are included in one relay enclosure.

For simple systems, control system design may be equally simple with electromechanical, static, and microprocessor relays. If the complexity of the power system requires many specific functions of protection, the microprocessor relays may provide a simpler installation.

Consider the effects of the protective relay system on the personnel who will operate and maintain the equipment. If new devices are being proposed, special training may be required for them to operate and maintain the equipment. Additional equipment may be necessary for relay testing, such as computers to connect locally to the microprocessor relays.

Be aware that the complexity of the relay will increase the complexity of the relay settings. A simple electromechanical overcurrent relay has basically two settings: a *tap setting* for the pickup of the relay and the *time dial* to determine the time delay until trip, if any. A feeder with four overcurrent relays will thus have eight settings, with a set of common phase settings and ground settings. By comparison, a microprocessor relay may have up to 10 or more pages of relay settings. A small part of these settings will actually involve the protective functions of the relay; however, the relay engineer will need to study the applicability of the functions and determine whether or not to use them. In general, if the relay engineer does not need the function, the function should be disabled in the relay to avoid over-complicating the protection scheme.

Design and application of protective relaying schemes is an art that uses science to make it work. In most cases, many relays and protective schemes can be used to protect a line or piece of equipment. What is used depends largely on the skill of the relay engineer and preferences of the people who will be operating and maintaining it.

Substation automation combines many functions, such as relaying, metering, and data acquisition. The relay engineer should be aware of the benefits and traps included in implementing relays in a substation automation project. There are some cases where firms use programmable logic controllers to perform protective relay functions. These cases are usually either very simple, such as providing a timing function, or very complex, providing logic to control switching or testing of a three-terminal line. In the majority of cases, the relay engineer should use relays to provide the relay functions and not introduce automation equipment into the relay functions. It is recommended the relays be used to do what they are designed to do, provide system functions, and use automation equipment to provide additional operating features or metering functions.

To communicate relaying functions being used on a system, device function numbers and contact designations have been developed to identify devices in protective relay schemes. See Table 1, below for a list device numbers.

Table 1
Standard Device Function Numbers

Reprinted from IEEE Std. 37.2-1996, "IEEE Standard Electrical Power System Device Numbers and Contact Designations," Copyright © 1996 by the Institute of Electrical and Electronics Engineers, Inc. The IEEE disclaims any responsibility or liability resulting from the placement and use in the described manner.

Device Number	Description
1	**Master Element** is a device, such as a control switch, etc., that serves, either directly or through such permissive devices as protective and time-delay relays, to place equipment in or out of operation. NOTE-This number is normally used for a hand-operated device, although it may also be used for an electrical or mechanical device for which no other function number is suitable.
2	**Time-delay starting or closing relay** is a device that functions to give a desired amount of time delay before or after any point of operations in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62, 79, and 82.
3	**Checking or interlocking relay** is a device that operates in response to the position of one or more other devices or predetermined conditions in a piece of equipment or circuit, to allow an operating sequence to proceed, or to stop, or to provide a check of the position of these devices or conditions for any purpose.
4	**Master contactor** is a device, generally controlled by device function 1 or the equivalent and the required permissive and protective devices that serves to make and break the necessary control circuits to place equipment into operation under the desired conditions and to take it out of operation under abnormal conditions.
5	**Stopping device** is a control device used primarily to shut down equipment and hold it out of operation. (This device may be manually or electrically actuated, but it excludes the function of electrical lockout [see device function 86] on abnormal conditions.)
6	**Starting circuit breaker** is a device whose principal function is to connect a machine to its source of starting voltage.
7	**Rate-of-change relay** is a device that operates when the rate-of-change of the measured quantity exceeds a threshold value except as defined by device 63.

8	**Control power disconnecting device** is a device, such as a knife switch, circuit breaker, or pull-out fuse block, used for the purpose of connecting and disconnecting the source of control power to and from the control bus or equipment. NOTE-Control power is considered to include auxiliary power that supplies such apparatus as small motors and heaters.
9	**Reversing device** is a device that is used for the purpose of reversing a machine field or for performing any other reversing function.
10	**Unit sequence switch** is a device that is used to change the sequence in which units may be placed in and out of service in multiple-unit equipment.
11	**Multifunction device** is a device that performs three or more comparatively important functions that could only be designated by combining several device function numbers. All of the functions performed by device 11 shall be defined in the drawing legend, device function definition list or relay setting record. See Annex B for further discussion and examples.
12	**Over-speed device** is a device, usually direct connected, that operates on machine over-speed.
13	**Synchronous-speed device** is a device such as a centrifugal-speed switch, a slip frequency relay, a voltage relay, an undercurrent relay, or any other type of device that operates at approximately the synchronous speed of a machine.
14	**Underspeed device** is a device that functions when the speed of a machine falls below a predetermined value.
15	**Speed or frequency matching device** is a device that functions to match and hold the speed or frequency of a machine or a system equal to, or approximately equal to, that of another machine, source, or system.
16	Reserved for future application.
17	**Shunting or discharge switch** is a device that serves to open or close a shunting circuit around any piece of apparatus (except a resistor), such as a machine field, a machine armature, a capacitor, or a reactor. NOTE-This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42 (or their equivalent) and also excludes device function 73 that serves for the switching of resistors.
18	**Accelerating or decelerating device** is a device that is used to close or cause the closing of circuits that are used to increase or decrease the speed of a machine.

19	**Starting-to-running transition contactor** is a device that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.
20	**Electrically operated valve** is an electrically operated, controlled, or monitored device used in a fluid, air, gas, or vacuum line.
21	**Distance relay** is a device that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.
22	**Equalizer circuit breaker** is a device that serves to control or make and break the equalizer or the current-balancing connections for a machine field, or for regulating equipment, in a multiple-unit installation.
23	**Temperature control device** is a device that functions to control the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above a predetermined value. NOTE-An example is a thermostat that switches on a space heater in a switchgear assembly when the temperature falls to a desired value. This should be distinguished from a device that is used to provide automatic temperature regulation between close limits and would be designated as device function 90T.
24	**Volts per hertz relay** is a device that operates when the ratio of voltage to frequency is above a preset value. The relay may have any combination of instantaneous or time delayed characteristics.
25	**Synchronizing or synchronism-check relay** is a synchronizing device that produces an output that causes closure at zero-phase angle difference between two circuits. It may or may not include voltage and speed control. A synchronism-check relay permits the paralleling of two circuits that are within prescribed limits of voltage magnitude, phase angle, and frequency.
26	**Apparatus thermal device** is a device that functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.
27	**Under-voltage relay** is a device that operates when its input voltage is less than a predetermined value.
28	**Flame detector** is a device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.
29	**Isolating contactor** or switch is a device that is used expressly for disconnecting one circuit from another for the purposes of emergency operation, maintenance, or test.

30	**Annunciator relay** is a non-automatically reset device that gives a number of separate visual indications upon the functioning of protective devices and that may also be arranged to perform a lockout function.
31	**Separate excitation device** is a device that connects a circuit, such as the shunt field of a synchronous converter, to a source of separate excitation during the starting sequence.
32	**Directional power relay** is a device that operates on a predetermined value of power flow in a given direction such as reverse power flow resulting from the motoring of a generator upon loss of its prime mover.
33	**Position switch** is a device that makes or breaks contact when the main device or piece of apparatus that has no device function number reaches a given position.
34	Master sequence device is a device such as a motor-operated multi-contact switch, or the equivalent, or a programmable device, that establishes or determines the operating sequence of the major devices in equipment during starting and stopping or during sequential switching operations.
35	**Brush-operating or slip-ring short-circuiting device** is a device for raising, lowering, or shifting the brushes of a machine; short-circuiting its slip rings; or engaging or disengaging the contacts of a mechanical rectifier.
36	**Polarity or polarizing voltage device** is a device that operates, or permits the operation of, another device on a predetermined polarity only or that verifies the presence of a polarizing voltage in equipment.
37	**Under-current or under-power relay** is a device that functions when the current or power flow decreases below a predetermined value.
38	**Bearing protective device is a device** that functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.
39	**Mechanical condition monitor is a device** that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.
40	**Field relay** is a device that functions on a given or abnormally high or low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an AC machine indicating abnormally high or low field excitation.

41	**Field circuit breaker** is a device that functions to apply or remove the field excitation of a machine.
42	**Running circuit breaker** is a device whose function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor that is used in series with a circuit breaker or other fault-protecting means, primarily for frequent opening and closing of the circuit.
43	**Manual transfer** or selector device is a manually operated device that transfers control or potential circuits in order to modify the plan of operation of the associated equipment or of some of the associated devices.
44	**Unit sequence starting relay** is a device that functions to start the next available unit in multiple-unit equipment upon the failure or non-availability of the normally preceding unit.
45	**Atmospheric condition monitor** is a device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.
46	**Reverse-phase or phase-balance current relay** is a device in a polyphase circuit that operates when the polyphase currents are of reverse-phase sequence or when the polyphase currents are unbalanced or when the negative phase-sequence current exceeds a preset value.
47	**Phase-sequence or phase-balance voltage relay** is a device in a polyphase circuit that functions upon a predetermined value of polyphase voltage in the desired phase sequence, when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a preset value.
48	**Incomplete sequence relay** is a device that generally returns the equipment to the normal or off position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time.
49	**Machine or transformer thermal relay** is a device that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.
50	**Instantaneous overcurrent relay** is a device that operates with no intentional time delay when the current exceeds a preset value.
51	**AC time overcurrent relay** is a device that functions when the AC input current exceeds a predetermined value, and in which the input current and operating time are inversely related through a substantial portion of the performance range.

52	**AC circuit breaker** is a device that is used to close and interrupt an AC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.
53	**Exciter or DC generator relay** is a device that forces the DC machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.
54	**Turning gear engaging device** is a device either electrically operated, controlled, or monitored that functions to cause the turning gear to engage (or disengage) the machine shaft
55	**Power factor relay** is a device that operates when the power factor in an AC circuit rises above or falls below a predetermined value.
56	**Field application relay** is a device that automatically controls the application of the field excitation to an AC motor at some predetermined point in the slip cycle.
57	**Short-circuiting or grounding device** is a device that functions to short-circuit or ground a circuit in response to automatic or manual means.
58	**Rectification failure relay** is a device that functions if a power rectifier fails to conduct or block properly.
59	**Overvoltage relay** is a device that operates when its input voltage exceeds a predetermined value.
60	**Voltage or current balance relay** is a device that operates on a given difference in voltage, or current input or output, of two circuits.
61	**Density switch** or sensor is a device that operates at a given density value or at a given rate of change of density.
62	**Time-delay stopping** or opening relay is a device that imposes a time delay in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.
63	Pressure switch is a device that operates at a given pressure value or at a given rate of change of pressure.

64	**Ground detector relay** is a device that operates upon failure of machine or other apparatus insulation to ground. NOTE-This function is not applied to a device connected in the secondary circuit of current transformers in a normally grounded power system where other overcurrent device numbers with the suffix G or N should be used; for example, 51N for an AC time overcurrent relay connected in the secondary neutral of the current transformers.
65	**Governor** is a device consisting of an assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other media to the prime mover for such purposes as starting, holding speed or load, or stopping.
66	**Notching or jogging device** is a device that functions to allow only a specified number of operations of a given device or piece or equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.
67	**AC directional overcurrent relay** is a device that functions at a desired value of AC overcurrent flowing in a predetermined direction.
68	**Blocking or "out-of-step" relay** is a device that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or cooperates with other devices to block tripping or reclosing on an out-of-step condition or on power swings.
69	**Permissive control device** is a device with two positions that in one position permits the closing of a circuit breaker, or the placing of a piece of equipment into operation, and in the other position, prevents the circuit breaker or the equipment from being operated.
70	**Rheostat** is a device used to vary the resistance in an electric circuit when the device is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.
71	**Level switch** is a device that operates at a given level value, or on a given rate of change of level.
72	**DC circuit breaker** is a device that is used to close and interrupt a DC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.
73	**Load-resistor contactor** is a device that is used to shunt or insert a step of load limiting, shifting, or indicating resistance in a power circuit; to switch a space heater in circuit; or to switch a light or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74	**Alarm relay** is a device other than an annunciator, as covered under device function 30, that is used to operate, or that operates in connection with, a visual or audible alarm.
75	**Position changing mechanism** is a device that is used for moving a main device from one position to another in equipment; for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.
76	**DC overcurrent relay** is a device that functions when the current in a DC circuit exceeds a given value.
77	**Telemetering device** is a transmitting device used to generate and transmit to a remote location an electrical signal representing a measured quantity; or a receiver used to receive the electrical signal from a remote transmitter and convert the signal to represent the original measured quantity.
78	**Phase-angle measuring relay** is a device that functions at a predetermined phase angle between two voltages, between two currents, or between voltage and current.
79	**Reclosing relay** is a device that controls the automatic reclosing and locking out of an AC circuit interrupter.
80	**Flow switch** is a device that operates at a given flow value, or at a given rate of change of flow.
81	**Frequency relay** is a device that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds or is less than a predetermined value.
82	**DC load-measuring reclosing relay** is a device that controls the automatic closing and reclosing of a DC circuit interrupter, generally in response to load circuit conditions.
83	**Automatic selective control** or transfer relay is a device that operates to select automatically between certain sources or conditions in equipment or that performs a transfer operation automatically.
84	**Operating mechanism** is a device consisting of the complete electrical mechanism or servomechanism, including the operating motor, solenoids, position switches, etc., for a tap changer, induction regulator, or any similar piece of apparatus that otherwise has no device function number.
85	**Carrier or pilot-wire relay** is a device that is operated or restrained by a signal transmitted or received via any communications media used for relaying.

86	**Lockout relay** is a device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.
87	**Differential protective relay** is a device that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electrical quantities.
88	**Auxiliary motor** or motor generator is a device used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.
89	**Line switch** is a device used as a disconnecting, load-interrupter, or isolating switch in an AC or DC power circuit. (This device function number is normally not necessary unless the switch is electrically operated or has electrical accessories, such as an auxiliary switch, a magnetic lock, etc.)
90	**Regulating device** is a device that functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.
91	**Voltage directional relay** is a device that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.
92	**Voltage and power directional relay** is a device that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.
93	**Field-changing contactor** is a device that functions to increase or decrease, in one step, the value of none of the functions assigned to the field excitation on a machine.
94	**Tripping or trip-free relay** is a device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.
95-99	These device numbers are used in individual specific installations if numbers 1 through 94 are suitable.

Types of Relays

Overcurrent Relay

The *overcurrent relay* responds to a magnitude of current above a specified value. There are four basic types of construction:

1. Plunger,
2. Rotating disc,
3. Static, and
4. Microprocessor.

In the *plunger type*, a plunger is moved by magnetic attraction when the current exceeds a specified value. In *the rotating induction-disc type*, which is a motor, the disc rotates by electromagnetic induction when the current exceeds a specified value. The photo on the right shows a typical rotary induction disk-type electro-mechanical realy. *Static types* convert the current to a proportional DC millivolt signal and apply it to a level detector with voltage or contact output. Such relays can be designed to have various current-versus-time operating characteristics. In a special type of rotating induction-disc relay, called the voltage restrained overcurrent relay, the magnitude of voltage restrains the operation of the disc until the magnitude of the voltage drops below a threshold value. Static overcurrent relays are equipped with multiple curve characteristics and can duplicate almost any shape of electromechanical relay curve. *Microprocessor relays* convert the current to a digital signal. The digital signal can then be compared to the setting values input into the relay. With the microprocessor relay, various curves or multiple time-delay settings can be input to set the relay operation. Some relays allow the user to define the curve with points or calculations to determine the output characteristics.

The protective characteristic of the overcurrent relay, in terms of the impedance diagram, is a circle, assuming a constant voltage, with the relay located at the origin of the R-X coordinate diagram (see Figure 2). The relay operates on the simple magnitude of current passing through it according to the settings applied to the relay.

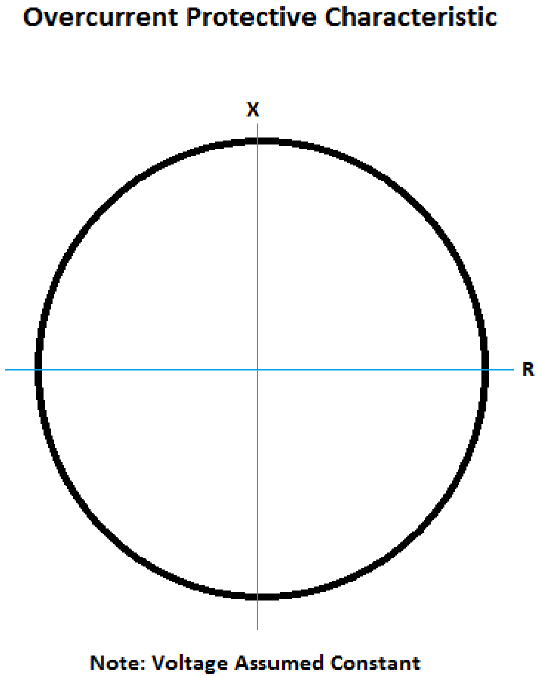

Figure 2

The overcurrent relay may be the simplest relay in concept to use. When the current exceeds the setting value, it causes a trip. Complications in applying the relay may occur when the system does not provide adequate differentiation between current values, such as between short lines on a system with high fault current duties. When a number of overcurrent relays are used sequentially in a circuit, the trip delay times may become excessive.

Distance Relay

The *distance relay* responds to a combination of both voltage and current. The voltage restrains operation, and the fault current causes operation that has the overall effect of measuring impedance. The relay operates instantaneously (within a few cycles) on a 60-cycle basis for values of impedance below the set value. When time delay is required, the relay energizes a separate time-delay relay or function with the contacts or output of this time-delay relay or function performing the desired output functions.

The protective characteristic of the distance relay, in terms of the impedance diagram, is a circle with the relay located at the origin of the R-X coordinate diagram (see Figure 3). The relay operates on the magnitude of impedance measured by the combination of restraint voltage and the operating current passing through it according to the settings applied to the relay. When the impedance is such that the impedance point is within the impedance characteristic circle, the relay will trip. The relay is inherently directional. The line impedance typically corresponds to the diameter of the circle with the reach of the relay being the diameter of the circle.

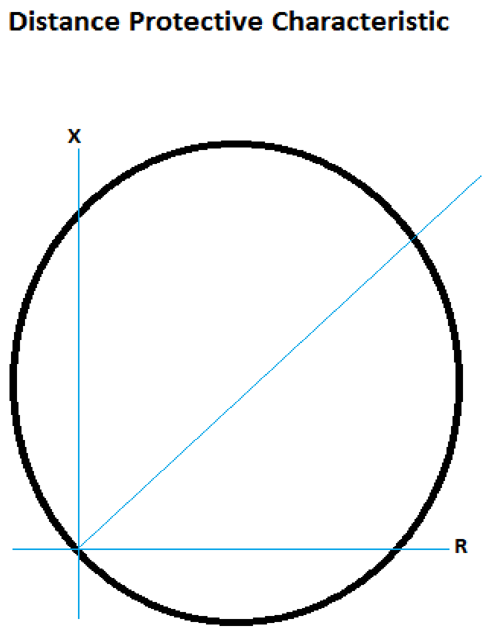

Figure 3

Since the relay responds directly to the value of impedance represented by the fault current and voltage applied to the relay, it will discriminate more correctly between the location of faults since the electric power system also may be represented by its impedance. The distance relay may be used more successfully on an electric power system when the magnitudes of fault current do not provide adequate location differentiation to be able to accurately trip specific breakers and isolate a fault.

The distance element in a relay may be used when a component of the electric power system, such as a transmission line, has defined impedance characteristics. Several distance elements are often used, with the circles passing through the origin of the R-X diagram, to provide several zones of protection for the system component. Additional zones of protection will be used with timers to provide direct protection, or without timers and used in pilot protection schemes requiring communications from all remote terminals of the transmission line. Distance elements may be used for out-of-step protection with the first zone impedance characteristic passing through the R-X impedance coordinate diagram origin and the remaining zones concentric around the first zone.

Differential Relay

The *differential relay* is a current-operated relay that responds to the difference between two or more currents above a set value. The relay works on the basis of the differential principle that what goes into the device has to come out (see Figure 4). If the current does not add to zero, the "error" (fault) current flows to cause the relay to operate and trip the protected device. Note: For simplicity of illustration, the CTs are indicated with a 1:1 ratio and equal currents in the primary and secondary of the CTs.

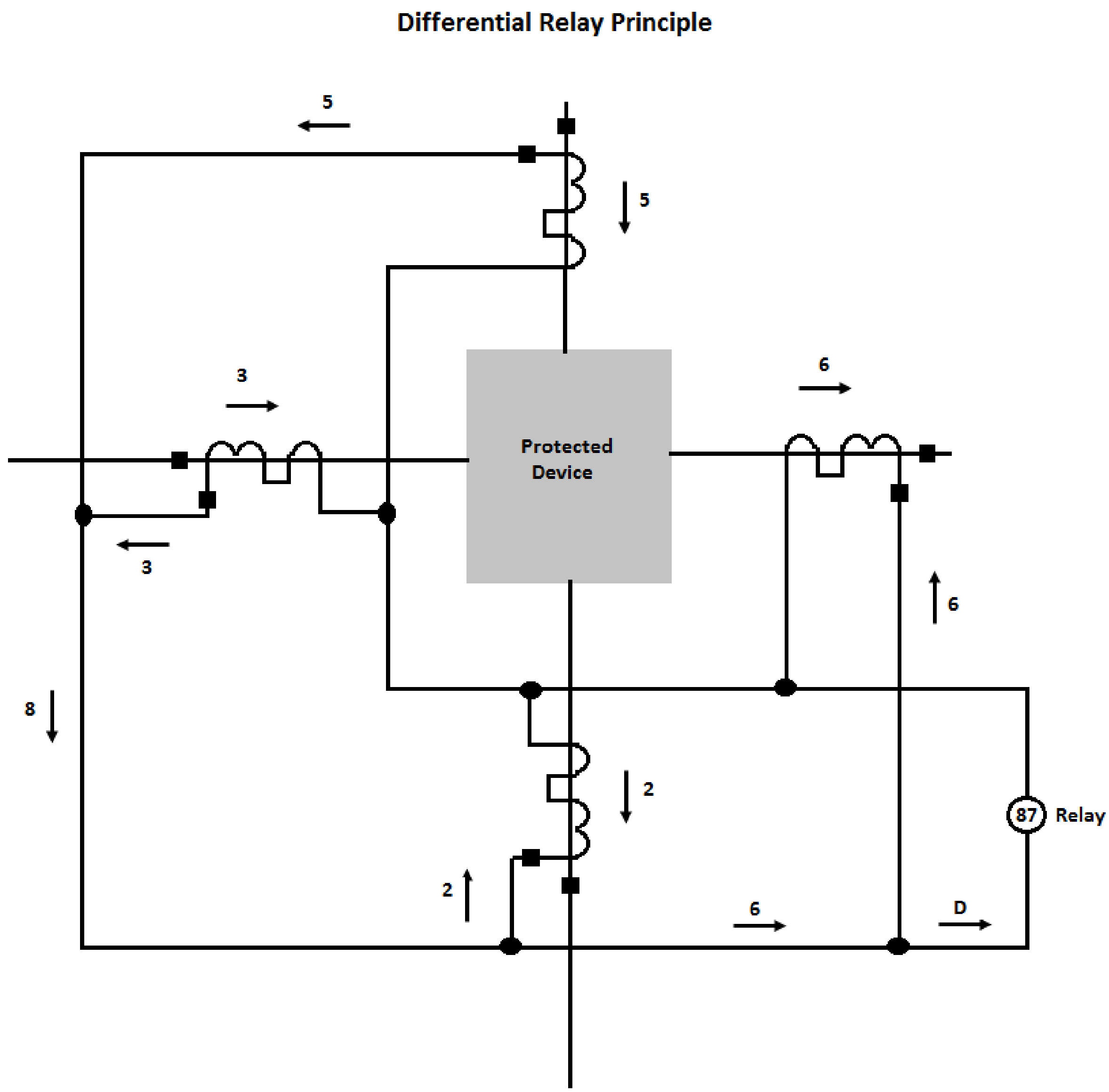

Figure 4

The differential relay is used to provide internal fault protection to equipment such as transformers, generators, and buses. Relays are designed to permit differences in the input currents as a result of current transformer mismatch and applications where the input currents come from different system voltages, such as transformers. A current differential relay provides restraint coils on the incoming current circuits. The *restraint coils* in combination with the *operating coil* provide an operation curve, above which the relay will operate. Some of the relays for specific equipment, such as transformers, use additional restraint proportional to the harmonics sensed in the incoming currents. Setting levels are based on the characteristics of the protected equipment.

Differential relays are often used with a lockout relay to trip all power sources to the device and prevent the device from being automatically or remotely re-energized. The relays are very sensitive. The operation of the device usually means major problems with the protected equipment and the likely failure in re-energizing the equipment.

Overvoltage Relay

The *overvoltage relay* responds to a magnitude of voltage above a specified value. As noted, the basic types of construction include plunger, rotating induction-disc, static, and microprocessor relays.

Under-voltage Relay

The *under-voltage* relay responds to a magnitude of voltage below a specified value and has the same basic construction as the overvoltage relay.

Power Relay

A *power relay* responds to the product of the magnitude of voltage, current, and the cosine of the phase angle between the voltage and current, and is set to operate above a specified value. The basic construction includes the rotating induction-disc, static, or microprocessor relay. The relay is inherently directional since the normally open contacts close for power flow in one direction above a set value but remain open for power flow of any amount in the opposite direction.

Directional Overcurrent Relay

A *directional overcurrent relay* operates only for excessive current flow in a given direction. Directional overcurrent relays are available in electromechanical, static, and microprocessor constructions. An electromechanical overcurrent relay is made directional by adding a directional unit that prevents the overcurrent relay from operating until the directional unit has operated. The directional unit responds to the product of the magnitude of current, voltage, and the phase angle between them, or to the product of two currents and the phase angle between them. The value of this product necessary to provide operation of the directional unit is small, so that it will not limit the sensitivity of the relay (such as an overcurrent relay that it controls). In most cases, the directional element is mounted inside the same case as the relay it controls. For example, an overcurrent relay and a directional element are mounted in the same case, and the combination is called a directional overcurrent relay. Microprocessor relays often provide a choice as to the polarizing method that can be used in providing the direction of fault, such as applying residual current or voltage or negative sequence current or voltage polarizing functions to the relay.

Frequency Relay

A *frequency relay* responds to frequencies above or below a specified value. The basic types are electromechanical relays with a vibrating reed or rotating induction-disc with a frequency-sensitive circuit, static relays, and microprocessor relays.

Thermal Relay

The *thermal relay* responds to a temperature above a specified value. There are two basic types: direct and replica. In the *direct type* of thermal relay, a device such as a thermocouple is embedded in the equipment. This device converts temperature to an electrical quantity such as voltage, current, or resistance. The electrical quantity then causes a detecting element to operate. In the *replica type* of thermal relay, a current proportional to the current supplied to the equipment flows through an element, such as a bimetallic strip, that has a thermal characteristic similar to the equipment. When this element is heated by the flow of current, one of the metallic strips expands more than the other, causing the bimetallic strip to bend and close a set of contacts.

Pressure Relay

The *pressure relay* responds to sudden changes of either fluid or gas pressure. It consists of a pressure-sensitive element and a bypass orifice located between the equipment to which the relay is connected and a chamber that is part of the relay. During slow pressure changes, the bypass orifice maintains the pressure in the chamber to the same value as in the equipment. During sudden pressure changes, the orifice is not capable of maintaining the pressure in the chamber at the same value as in the equipment, and the pressure-sensitive element mechanically operates a set of contacts.

Auxiliary Relay

Auxiliary relays perform such functions as time delay, counting, and providing additional contacts upon receiving a signal from the initiating relay. These relays are necessary to provide the broad variety of schemes required by a power system.

Chapter 3
Relay Schemes

Protective relays are most often applied with other protective and auxiliary relays as a system rather than individually. The following basic scheme descriptions apply to electromechanical, static, and microprocessor relay systems.

The static and microprocessor relay systems generally have more elaborate logic involved in the tripping decision, particularly in the area of transient blocking during external fault clearing. Static systems require more careful treatment of input circuits, i.e., CT and PT leads are often shielded. Static systems are slightly faster, require less maintenance, and are considerably more costly than the electromechanical systems.

Microprocessor relays are very versatile and often can perform many functions at a lower cost than other methods. In addition to basic relaying they may do fault locating, fault data recording, self testing, and metering. Since microprocessor relays tend to have more protective functions available in a relay case, it often allows the relay engineer to provide additional protection the relay engineer would not have previously considered. Microprocessor relay systems tend to have fewer devices since they contain more functions in one case. This will tend to reduce the cost of initial installation.

Transmission Line Protection

Transmission lines provide the links between the various points of the power system and deliver power from the point of generation to the ultimate user. The lines operate at the differing voltages included in the power system. The significance of a line to the electric power system varies according to the voltage level, the location of the line in the system, the loads carried by the line, and other factors specific to the utility. Schemes for the relay protection of the line vary according to the significance of the line in the system, the characteristics of faults on the line, the speed at which a line fault has to be cleared, and the preferences of the relay engineer and the utility's practices. The protection schemes available for transmission line relay protection include:

- Overcurrent, instantaneous, non-directional
- Overcurrent, timed with either inverse curves or discrete times, non-directional
- Overcurrent, instantaneous, directional
- Overcurrent, timed with either inverse curves or discrete times, directional
- Current differential using overcurrent
- Distance, instantaneous and timed

- Pilot with a communication channel between all terminals

Depending on the fault characteristics of the line in question, the relay engineer may use any of the above relay protection schemes for the protection of phase and ground faults on a transmission line. Protection schemes may include the use of the schemes individually or in combinations to protect lines with primary and secondary protection schemes.

The relay engineer has to know the following in determining the relay protection to be used for a transmission line:

- The configuration of the transmission line
- The number of line terminals
- Whether the line is radial or looped in the system
- How many taps, if any, are on the line
- How the line will be loaded
- Fault levels associated with the line
- Any other transmission line-specific data peculiar to the system
- Load-specific information such as specified outage times, temporary power levels, etc.
- System constraints such as out-of-step relay requirements
- Coordination requirements with relay systems of the remote line terminals

Higher voltage transmission lines tend to have more sophisticated relay protection systems often using piloted schemes (the use of communications channels providing information from the remote end of the line) to provide more security. Transmission lines at 345 kV normally utilize two primary relay schemes with pilot protection. However, the voltage of the line is not the primary factor in determining the types of relay protection that may be used. Rather, it is the significance of the line in the power system and the effect of faults on the line that will determine the speed in which the line has to be removed from the system when a fault occurs. Some lower voltage systems are in operation where extremely sophisticated relay schemes are in place, and some 345 kV systems operate with simplistic schemes because of the characteristics of the system at the location of the line. With the above information about the system, the relay engineer can make a decision as to the types of relay schemes that may be used. The following are schemes used for transmission line protection.

Non-piloted schemes involve the use of relays to provide protection without the use of communications channels providing information from the remote end of the line. The relay measures the input quantities, makes the action decision based on those quantities, and provides an output to the circuit breakers or circuit logic at the site of application based on the input and the relay logic. All the inputs and outputs are local to the site of application.

Overcurrent relay protection is the simplest form of protection usually applied on lower voltage lines or on radially supplied feeders. It is used occasionally as backup relay protection for some transmission lines. In its most basic form, non-directional inverse time overcurrent relays are applied on radial feeders with two phase devices and one ground device. The fault current is reduced by increased line impedance the further out on the line the fault occurs, resulting in a longer time for the relay to trip the feeder. When a back-feed from another power source is possible on the feeder, directional overcurrent relays may be used to provide selectivity between faults “in front” of or in the tripping direction of the relay versus those behind the relay. An instantaneous overcurrent element is often used to protect the transmission line or feeder for high-current, close-in faults near the terminal where the relay is located. While this type of protection can be used on a network system with varying contributions from both directions on the lines, it is extremely difficult to coordinate such a system and it should be avoided where possible.

A *Current Differential with Overcurrent Relay* circuit uses the differential principle in connecting the CT circuits and an overcurrent relay instead of a differential relay. The scheme has limited use since the CTs from all terminals of the line, line segment, or bus has to be connected by the hardwire circuits back to the overcurrent relay. This connection is more secure and can be set more sensitively than a simple overcurrent relay application. It also can keep one more overcurrent relay from being in a string of overcurrent relays that have to be set with increasing time delay. The circuit is typically used within a substation or generation plant facility where short line segments or buses require protection that does not need the speed of a differential relay. In applying the circuit, the relay engineer has to be aware of the CT error and mismatch that may occur in the differential circuit to the relay and set the relay over any mismatch that may occur. The circuit is often applied in a variation as an open-differential circuit. This circuit has a number of lines connected to it with CTs connected in N-1 lines (see Figure 5). The overcurrent relay is then set for the load of the line without the CT. This circuit is often applied as a backup circuit to a transformer differential circuit at a substation with an in-and-out transmission line. The relay engineer has to be aware of through faults in the lines with CTs that do not involve the line without the CT. CT mismatch will result in an error current as a result of the through-fault current that will flow to the relay.

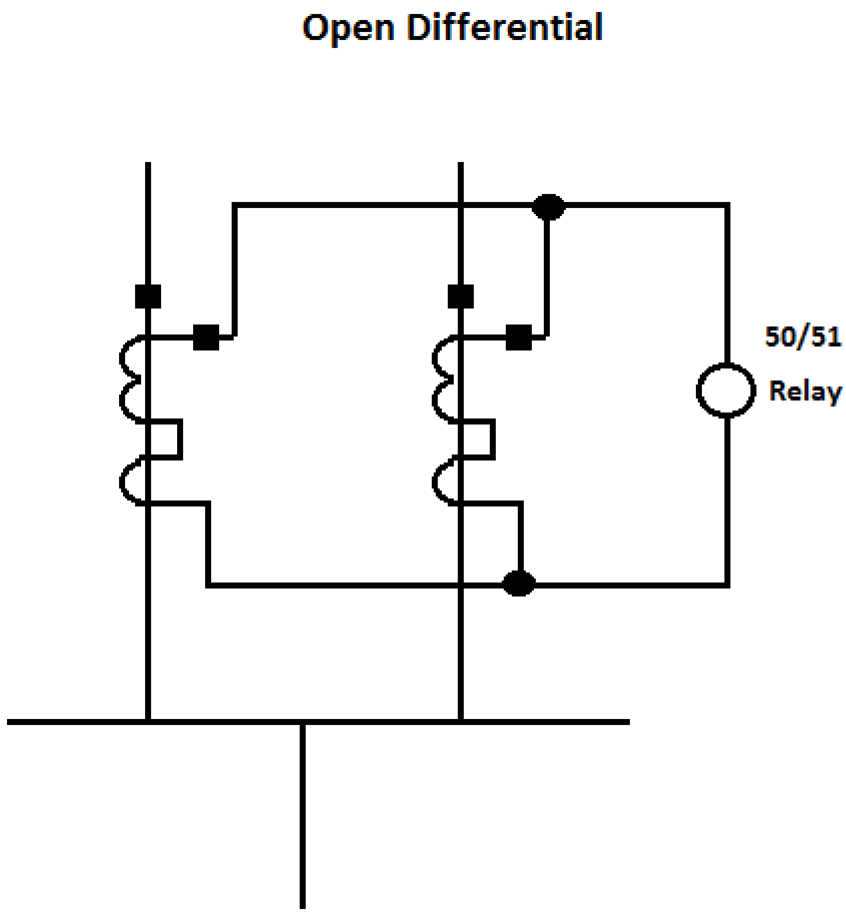

Figure 5

Another concept is *Step Distance Relaying*. Since the distance relay responds to the impedance of the device it is protecting, it can more easily be coordinated and used when the coordination of overcurrent relays does not work. The distance relay is more costly than the overcurrent relay and requires the addition of line potential sources, adding cost to the scheme. Advantages of distance relays include a fixed reach based on the impedance of the protected device, regardless of the system voltage and current changes; the ability to operate at fault currents less than load current; and little transient overreach.

Two relays are used to protect the total length of the line, providing protection referred to as zones (see Figure 6). Zone 1 relay is typically set for 85 to 95 percent of the line impedance. Zone 1 tripping time is set for instantaneous tripping, that is, with no intentional time delay. Zone 2 is typically set to 120 to 150 percent of the line impedance. Zone 2 needs to extend past the line being protected into the adjacent lines, not reaching past the far end terminal of the adjacent lines, yet ensuring the line in question is covered. Zone 2 tripping time is typically set with 18 to 30 cycles of trip delay.

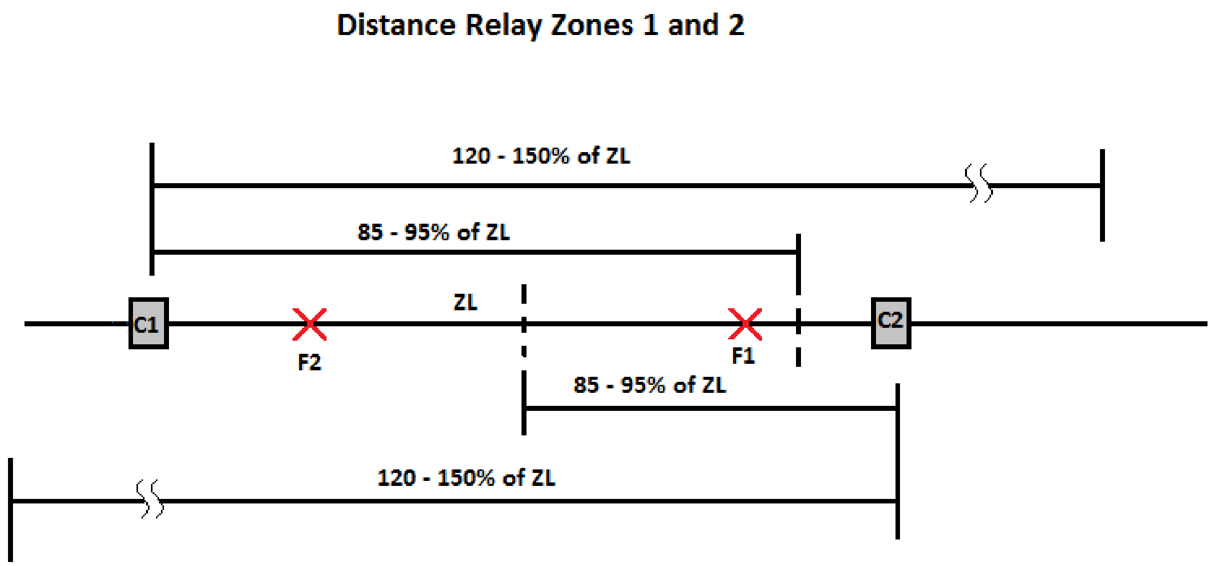

Figure 6

This scheme provides instantaneous tripping for 70 to 90 percent of the transmission line for a fault (F1, Figure 6) located within Zone 1 reach for both ends of the line. For the remainder of the line, a fault (F2, Figure 6) near each line terminal is cleared in the time delay used for Zone 2. A fault located near a line terminal will be sequentially cleared by the near breaker tripping first and the remote terminal breaker tripping after the Zone 2 trip time delay.

A third zone of protection, Zone 3, is often used in step distance relaying. Zone 3 is usually set to reach through the next line to cover breaker failures. The reach for the Zone 3 relay is usually in the range of 200 to 225 percent of the line impedance. Zone 3 tripping time is typically set with 60 to 120 cycles. The impedance setting will vary depending on the length of the adjacent lines. Because of the reach of the Zone 3 characteristic, it often encroaches on the load impedance and is susceptible to power system swings. Use caution when incorporating Zone 3 relays since long settings can result in tripping on load.

Zone 3 may be reversed to look in the opposite direction of the line to which step distance relays are being applied. This is the case when carrier schemes are applied. Occasionally, a reverse-set Zone 3 relay is used as a local breaker failure relay, indicating failure of adjacent circuit breakers.

Step distance relaying may be difficult to apply when the transmission lines are short, with little impedance. The settings for the distance relays may be very small, near the limits of the design for the relay reach, resulting in the possibility of the relay's overreaching and tripping for adjacent line faults. Three terminal lines will often use distance relays as fault detectors, but will normally require the implementation of a pilot scheme to ensure tripping for all fault conditions.

Pilot schemes simultaneously measure and monitor system parameters at all terminals of a transmission line, local and remote, and then respond according to their predetermined functions. These schemes require the use of a communications channel that may be provided through pilot wires, microwave, fiber, or power line carrier. If the measured parameters exceed threshold values, appropriate actions are initiated. Pilot schemes can generally be broken into two primary categories. Those categories are directional comparison and phase comparison. Directional schemes use directional distance relays for phase fault detection and either directional distance relays or directional overcurrent relays for ground fault detection. The decision to trip is based on relay setting thresholds being exceeded and the faults being located in the predetermined direction for trip.

Phase comparison schemes are an extension of the differential protection principal. Currents from all line terminals are converted into a composite signal, transmitted to the remote terminals, and compared to the local terminal composite signal. The result of the comparison will result in a trip if the relay setting threshold is exceeded. Phase comparison schemes are inherently directional and secure, not tripping for faults outside the protected zone of protection.

Directional comparison schemes are divided into four categories:

1. Blocking Schemes
2. Unblocking
3. Permissive Overreach Transfer Trip
4. Under-reaching Transfer Trip

<u>1. Blocking Schemes.</u> *Directional comparison blocking* uses distance relays as directional indicators and block initiation for phase faults. Either distance or directional overcurrent relays may be used for ground fault indicators and block initiation. Each terminal has trip and start relays. The trip relay reaches toward the remote terminal and a little beyond. The start relay reaches backwards, away from the protected section. The trip relay attempts tripping when it operates unless it is stopped by receipt of a blocking signal (carrier, audio tone, or microwave) from the remote end. The start relays at each end initiate the blocking signal. Thus, if only the trip relays see the fault, it is within the protected section and both ends trip. If the fault is just outside one end, the start relays at that end operate and send a block signal to the remote end, which would otherwise trip. The ground relays operate similarly.

A tripping delay is necessary to allow for the receipt of the blocking signal. A typical delay time of 6 to 16 msec is used to coordinate for the channel delay in communications. The communication channel is not required for tripping the breakers since the breakers will trip in the absence of the blocking signal. Failure of the channel could result in over-tripping of the breakers for adjacent line faults within the reach setting of the distance relays. Blocking directional comparison is commonly used with on/off type carrier facilities. Since it is not necessary to drive a signal through a fault to operate this scheme, it is the most popular carrier relaying system. See Figure 7.

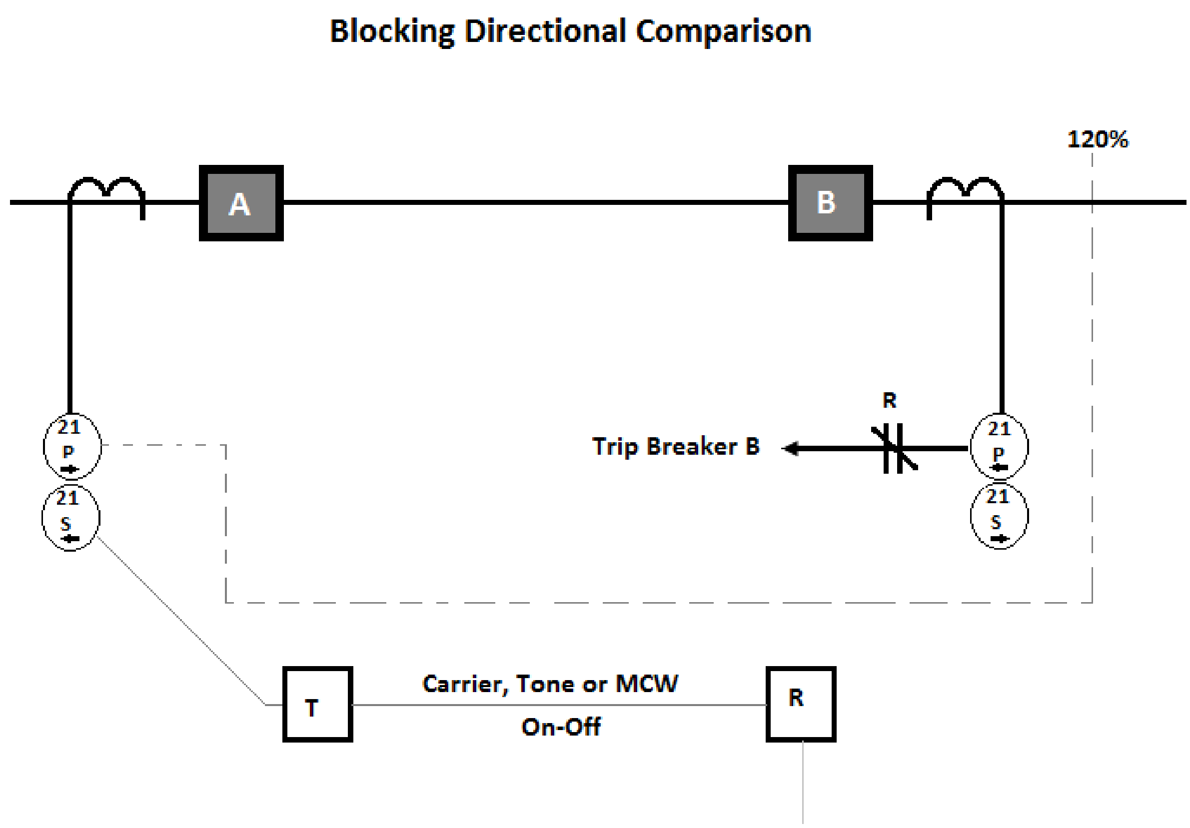

Figure 7

<u>2. Unblocking Schemes.</u> *Directional comparison unblocking* is similar to the blocking scheme except that the start relays are deleted and the blocking, "guard" signal is sent continuously. See Figure 8. The communication signal for an unblocking scheme uses a *frequency shift keying* (FSK) channel. For an internal fault, the frequency is shifted to the unblock, "trip" frequency. The receivers receive the trip frequency and close the output contact, which in series with the 21P relay output contact will trip the breaker. For an external fault, within the reach of one of the 21P relays, the distant 21P relay will see the fault while the local 21P relay will not see the fault since it is behind the relay. The distant 21P relay will shift its transmitter frequency to trip. The local 21P relay will not send the trip frequency or close the 21P output contacts. The line thus stays in service. Should the receivers fail to receive a guard signal and a trip signal, the receivers

will allow typically 150 msec of receiver contact closure to permit the 21P relay contact to trip the line. After this time limit, the communication channel will lock out.

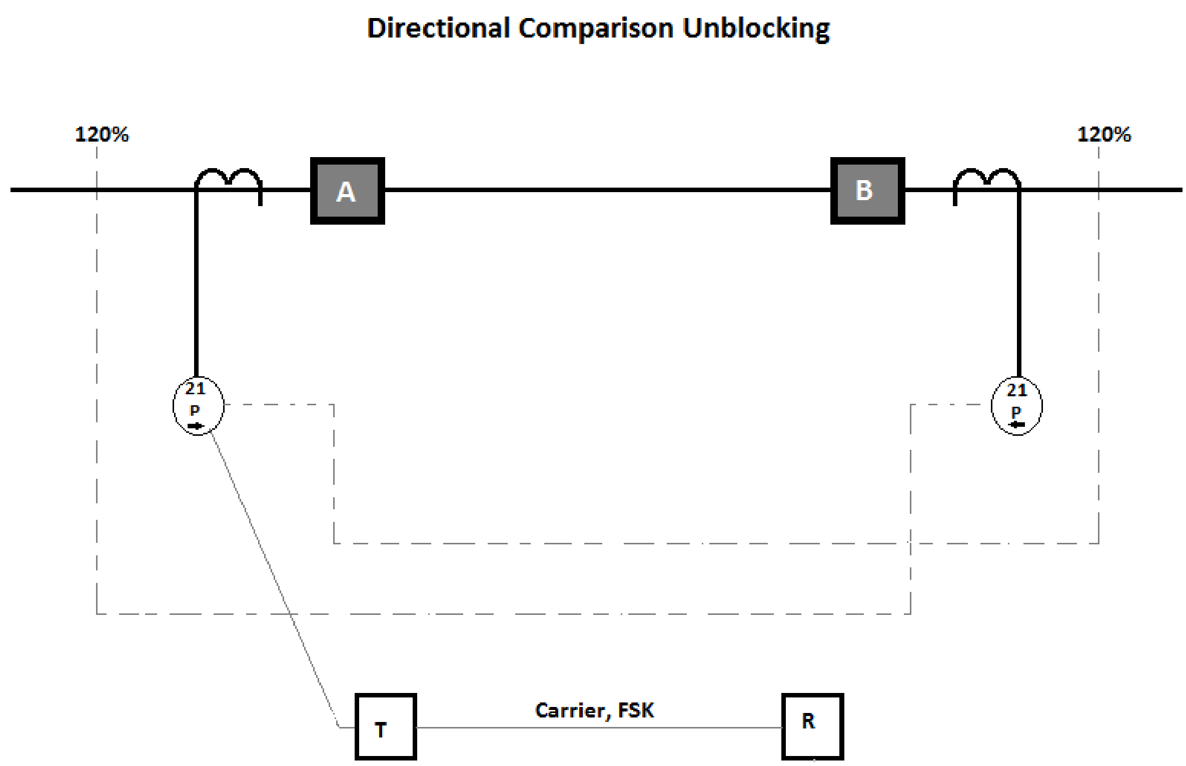

Figure 8

This scheme is more secure since over-tripping is avoided at all times with the exception of the 150-msec interval during the loss of signal. Reliability is improved since the communication channel operates continuously and can be monitored, providing an alarm in the case of failure. The scheme is applicable for two-terminal and multi-terminal lines. Separate channels are required between each pair of line terminals.

3. Overreaching Transfer Trip Schemes. *Permissive overreach* is also a simple scheme, requiring only one overreaching fault detector at each terminal. This fault detector sends both a trip signal and attempts local tripping through a contact on the receiver. If both relays see a fault, both ends trip simultaneously.

The scheme appears similar to the directional comparison unblocking scheme of Figure 8. A trip signal is required for this scheme to trip. Power line carrier channels therefore are not recommended for these schemes since a fault could short out the carrier signal. These channels are normally used with audio tones with frequency shift keying over microwave, leased line, or fiber-optic communications.

The overreaching transfer trip scheme provides highly secure transmission line protection since a trip signal is required from both ends of the line for tripping to occur. The dependability of the scheme may be less than the blocking schemes since the trip signal has to be received before the tripping is initiated. The scheme is often used when an existing non-piloted scheme has communications added for piloting.

4. Under-reaching Transfer Trip Schemes

Under-reaching transfer trip schemes include two variations: direct under-reach and permissive under-reach. The communications for this type of relaying are generally the same as for the overreaching systems, using audio tones with frequency shift keying over microwave, leased line, or fiber-optic communications channels.

Direct Under-reach is a form of protection that requires only a single distance fault detector at each end. It has to be set short of the remote end and will simultaneously trip the local breaker and send a trip signal to the remote end, which then trips directly upon receipt of the signal. Note that local confirmation is not required upon receipt of a trip signal. Though this scheme is the least complex, it is seldom used because of the high risk of false outputs from the communication channel, which would result in false trips. This risk can be minimized by using a dual-channel transfer trip, which requires the receipt of two signals from the remote end to effect a trip. See Figure 9.

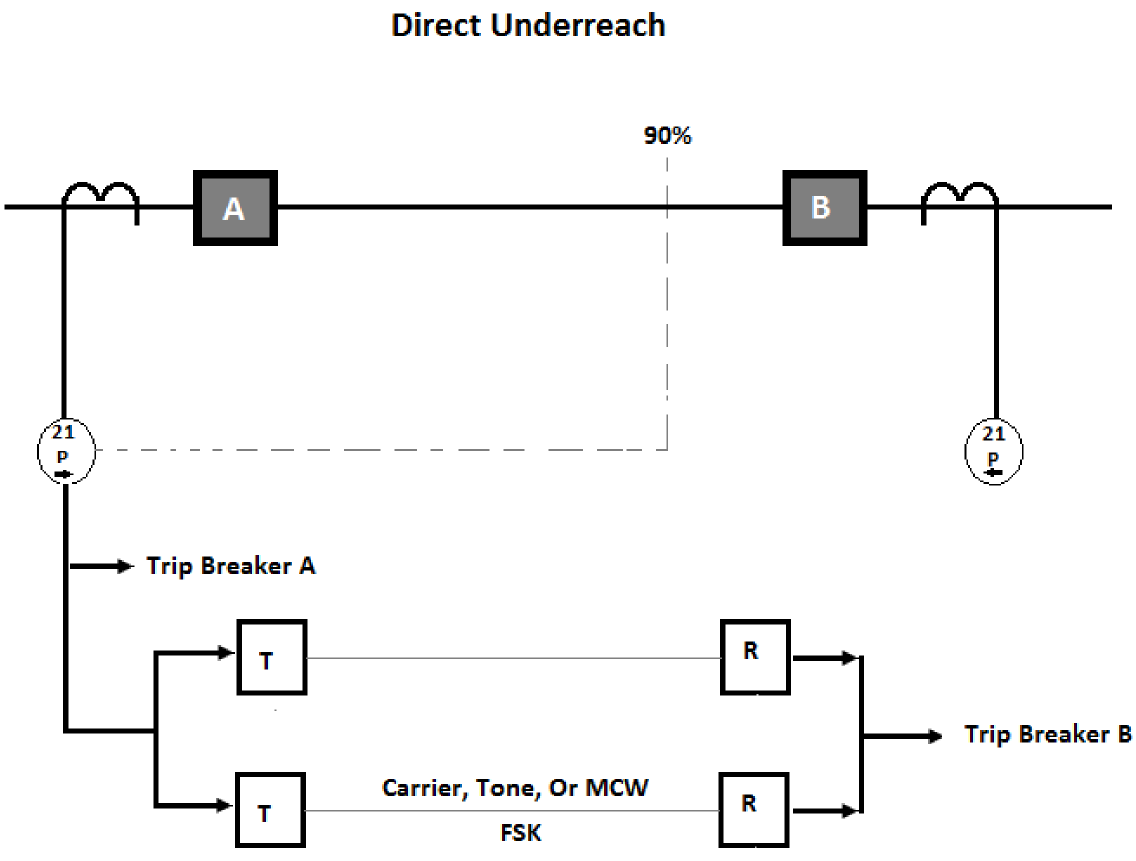

Figure 9

Permissive Under-reach is a scheme that is identical to the direct under-reach scheme with the addition of an overreaching fault detector. The transfer trip signal requires local confirmation by this fault detector before tripping can occur. This increases the security of the scheme and the consequent range of application. It is commonly selected when an existing step distance relay line is to have the pilot added. See Figure 10. Carrier is not normally used since a fault could short out the communication signal and prevent the signal from reaching the remote terminal.

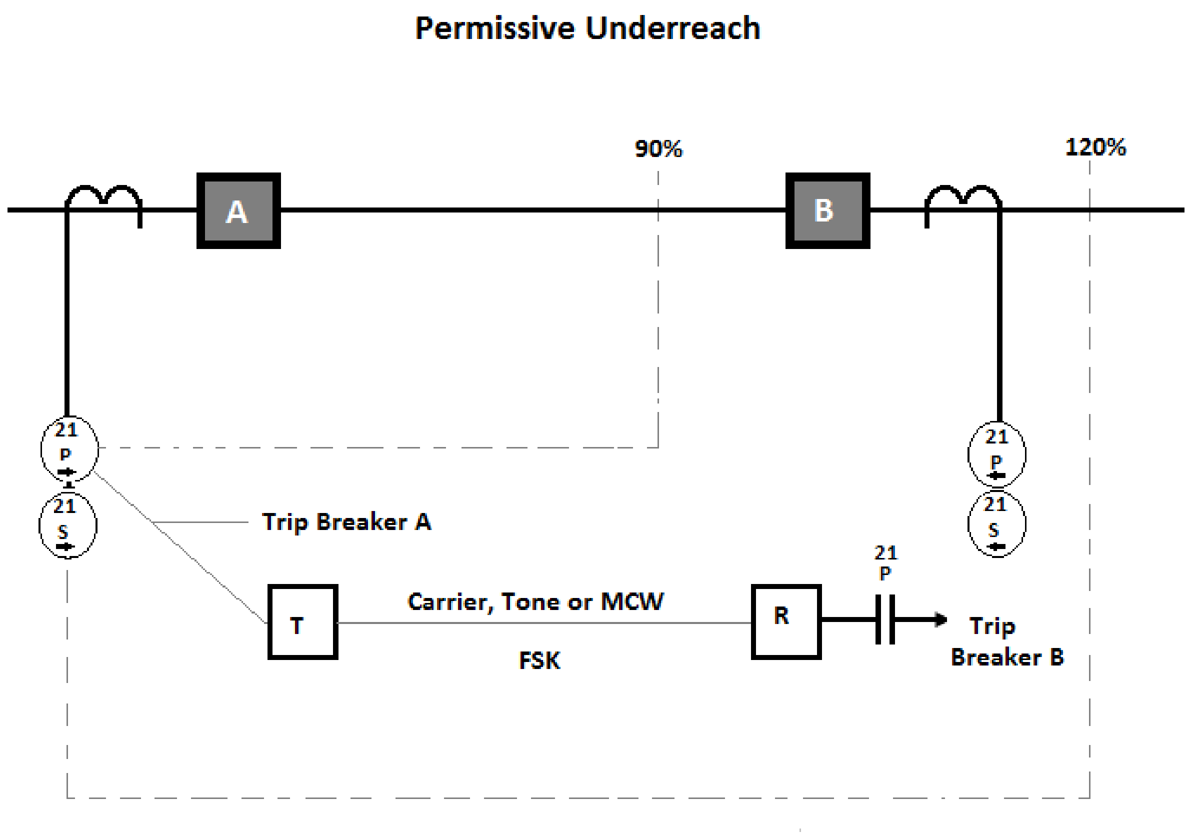

Figure 10

Phase comparison relay systems monitor the current direction at each line terminal of the protected line and transmit this information to the other terminal via a communication channel. Each line terminal compares local and remote current direction and trips if the current is into the line from both terminals. The communication channel is normally an on/off type of communications, transmitting only when the overcurrent detector's thresholds have been exceeded. This system is immune to tripping on overloads or system swings since it operates on current direction only. It needs no potential source unless it has to be supervised by distance relays because of low fault currents. Current or distance fault detectors are used to supervise tripping. These detectors have to be set above line charging current, which can appear to the relays as an internal fault at low loads. Internal timers have to be set to compensate for the transit time of the communication channel. One of the most popular applications of this system is on lines with series capacitors because it is less likely that such a current-operated scheme will operate incorrectly for faults near the capacitors.

A *pilot wire* scheme is a form of phase comparison since it compares current direction at each terminal. The difference between this scheme and others is that a pair of telephone wires is used as the communication channel. A special filter in the relay converts the three-phase currents to a single-phase voltage and applies this voltage to the wires. When current flows through the protected section, the voltages at each end oppose each other and no current flows in the operate coils. When current enters the line from each end, the voltage on the pilot wire reverses to allow current to circulate through the operate coils and consequently trip both ends.

Special monitor relays sound an alarm if the pilot wire pair becomes open or shorted. The wire line has to have adequate protection against induced voltages and a rise in station ground potential but may not use carbon block protectors because the line has to remain in service while the protection is operating. Neutralizing transformers and gas tubes with mutual drainage reactors, all with adequate voltage ratings, comprise the preferred pilot wire protection package. This relaying has the advantage of simplicity and does not require a potential source. It does not provide backup protection. Its application is limited to short lines a mile or so in length because of pilot wire cost and increased exposure. The system's dependability is based on the integrity of the pilot wires themselves. Many pilot wire systems have been replaced with other pilot schemes because of the failure of the pilot wire system to function reliably and securely. Recently, pilot wire systems have been replaced with fiber-optic systems providing the communications systems, using a module to convert the output voltage to a light signal. These modified systems have provided a more dependable and secure protection system.

A *single-phase comparison* scheme applies a sequencing network to the current inputs to the relay to produce a single-phase voltage output. This output is proportional to the positive, negative, and zero phase sequence components of the input currents. This signal is squared so that the positive portion of the signal provides the positive portion of the square wave. The negative portion of the signal provides the zero portion of the square wave. Two fault detectors are normally used to provide security, with the more sensitive detector used as the carrier start to transmit the signal to the remote end. The less sensitive detector is used to arm the comparison module for a trip upon the correct comparison of the local and remote signals. See Figure 11.

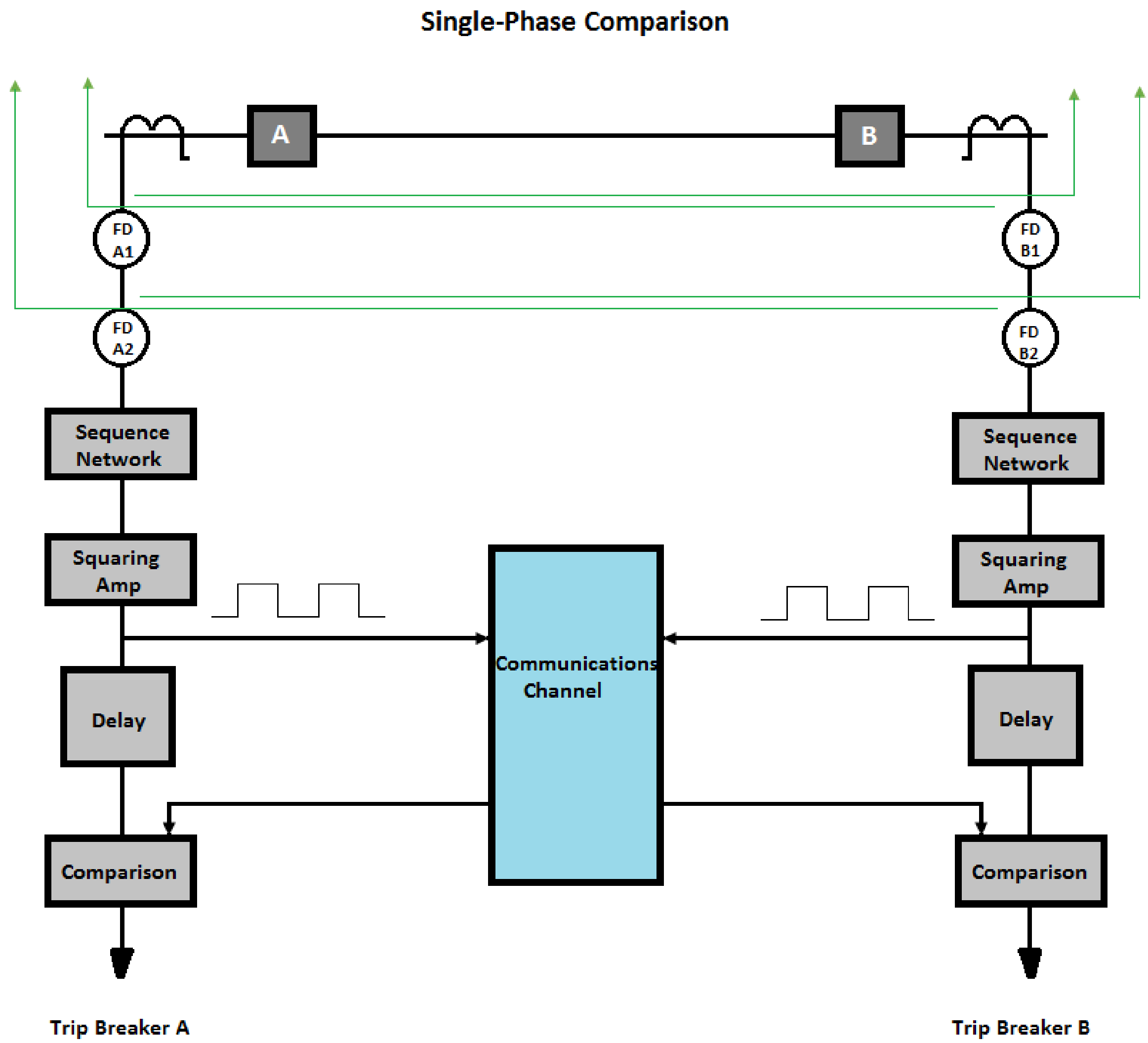

Figure 11

Normally current-operated units are used as the fault detectors. In a case where the fault current is less than the load current, impedance-operated units may be used for fault detection.
The use of impedance fault detectors will increase the cost of the system because of the necessity of having line potentials for the operation of the relay.

A *dual-phase comparison* scheme is similar to the single-phase comparison scheme except that square wave signals are developed for the positive and the negative portions of the single-phase voltage output of the sequencing network. Each signal requires a separate channel for the transmission of information to the remote site. This scheme can provide a slightly higher speed of detection since faults are detected on both the positive and the negative portions of the single-phase voltage output of the sequencing network. This scheme is normally used with a frequency-shift channel, which is continuously transmitted. On a power line carrier it is configured as an unblocking scheme.

A *segregated phase comparison* scheme is similar to the single-phase comparison scheme except that a square wave is developed for each phase of the transmission line. A communication channel is required for each phase to provide communications to the remote terminal. Comparisons are made on each of the three phases. The operation of the scheme is basically as described above in the previous phase comparison schemes.

Distribution Feeder

Distribution line switching and protection within the substation are provided by circuit breakers, reclosers, or fuses. The selection of the protective devices to be used on any particular feeder will depend on the load being fed by the feeder, the magnitude of loads being served, any special protective requirements necessitated by the load, and the utility's preferences in design and operating practices. In addition to the above-listed items, sectionalizers may be located on the distribution feeders for additional segmenting of the line during fault conditions.

Circuit Breakers

Circuit breakers will most commonly use overcurrent relays to provide fault protection at a substation. Historically, on a typical radial distribution feeder, two phase and one ground (if the system is grounded) non-directional inverse time overcurrent relays with instantaneous elements will be the minimum relays that are applied that will detect all phase and ground faults when properly coordinated. Often, a third overcurrent relay is applied to the phases. This will provide complete protection for faults if one of the relays should be disabled. This also permits the removal of one of the relays for testing outside the case, providing protection for the feeder without taking the feeder out of service. With today's microprocessor relays, three-phase relays and the neutral relay are applied to detect all faults when properly coordinated. The time–current characteristic chosen for coordination of protective devices will depend on what downstream devices are present on the feeder. See Figure 12.

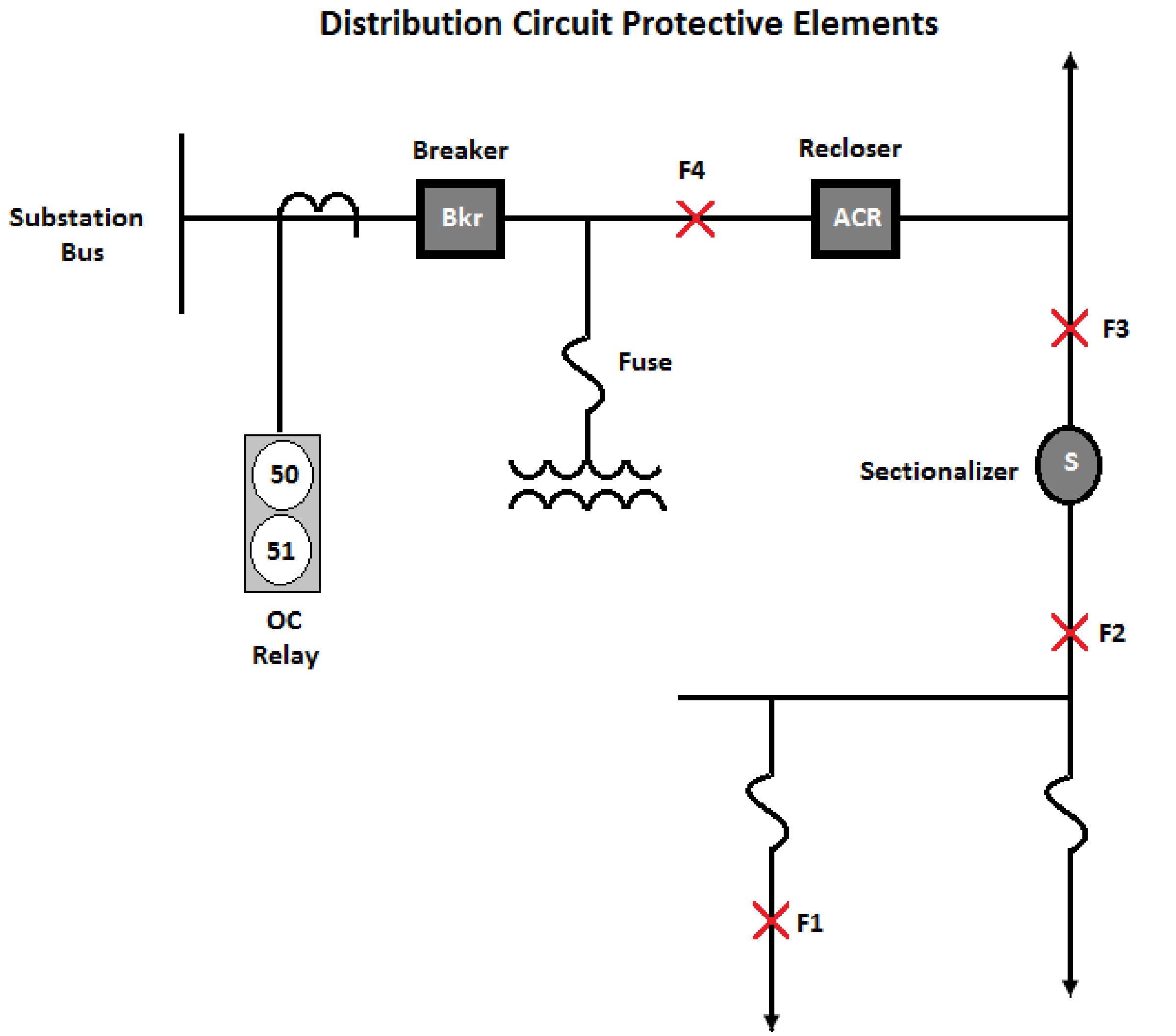

Figure 12

Other protection may be provided in addition to overcurrent relays, such as voltage-controlled overcurrent relays and negative sequence relays. Special circumstances on a feeder will allow specific relays to be applied to address those circumstances. Microprocessor relays will often have a number of protective functions available that may be used for special circumstances. Relay protection for circuit breakers may be more readily customized and applied to special situations. Many of the microprocessor relays available for distribution feeder protection also include multiple setting groups. This feature will allow a relay to be set for a particular configuration. Should the configuration change, the setting group can be changed, either automatically or manually, to provide for different settings to adjust the relay protection to the new configuration.

Automatic Circuit Reclosers

Reclosers are devices similar to circuit breakers but more compact and self-contained so that they may be used within the substation or mounted on poles out on the distribution feeder. The controls permit various combinations of instantaneous and time-delayed trips and automatic reclosures so that coordination may be accomplished with both upstream and downstream devices. Reclosers may be single- or three-phase interrupters. Single-phase reclosers are series trip devices, and three-phase reclosers may be either series trip or nonseries trip devices. Non-series trip reclosers usually employ a solid-state control and have a self-contained battery. Some single-phase reclosers are available with electronic controls.

Single-phase reclosers usually provide better service reliability to rural distribution circuits because a fault to ground on one phase will not trip the other phases. However, where loads are predominantly three phase, or where the load on the circuit is large, three-phase reclosers with ground trip settings are desirable to achieve the required sensitivity for ground faults.

Microprocessor controls are also available for reclosers. The microprocessor adds much flexibility to the controller and provides additional functions, similar to many of the microprocessor relays. Also, many additional protective characteristics (curves) are typically available in the microprocessor controls. There is normally a communications port available on the control that can then provide data to remote sites.

Sectionalizers are devices, located outside the substation on the distribution lines, are similar to reclosers, except that they do not interrupt fault current. Instead, the sectionalizer counts trips of an upstream recloser and opens its contacts during a de-energized period following a predetermined number of recloser interruptions. Sectionalizers can, however, interrupt load currents within their rating. See Figure 12 on the previous page.

Fuses

Fuses are used both to protect connected distribution transformers and to protect sections or branches of the distribution circuit. Occasionally, they are used within the substation for protection of a feeder or as backup protection for a bypass switch around a recloser or a breaker. They are most commonly supplied in outdoor holders that are combination fuseholders and disconnect switches. Fuses are usually applied as the farthest downstream device in a sectionalizing scheme because of their nonrepeating nature. An upstream recloser trips and recloses several times with the accumulated “on” time being sufficient to blow the fuse during a delayed trip. The recloser then resets before the trip occurs.

Coordinating these devices on a distribution circuit involves the progressive disconnecting of sections of the distribution circuit beginning at the end farthest from the station until the fault is removed. Since several different types of devices are involved, this process can be more complex than coordinating a transmission line.

Referring again to Figure 12, it may be seen that a fault at Fl should be interrupted by the fuse. This means that the relay, recloser, and sectionalizer has to be programmed so that they will let enough accumulated fault current through (integrated over several reclosures) that none of these devices locks out. Generally, the recloser will have one fast and three delayed trips in such a situation. Time curves will be selected so that the fuse will blow during the second delayed trip. The sectionalizer would be programmed to open following the second delayed trip to clear a fault at F2. A fault at F3 would then be cleared when the recloser locks out following the third (delayed) trip. The relay would be set to clear a fault at F4 but coordinated with the line recloser so as not to trip for a fault at F3, paying careful attention to over-travel and reset time of electromechanical reclosers following each successive interruption.

This is a simplified example of distribution coordination and ignores complications, such as long branches and improperly applied protective devices, both common occurrences on real distribution systems. In such cases, compromises have to be made and areas of nonselectivity accepted. The coordination process involves moving these areas of nonselectivity into positions where they do the least harm.

Major Equipment

Major equipment to protect in the substation includes transformers, reactors, bus-work, and circuit breakers.

Transformers are protected by fuses or circuit-interrupting devices such as breakers or circuit switchers with relays detecting faults and providing trip signals to the circuit-interrupting devices. Transformers 5 MVA and below are almost always protected by fuses. Relay protection of transformers is most often used for transformers rated 10 MVA and above although there are transformers up to 30 MVA that are protected by fuses.

Fuse protection has the merits of being economical and requiring little maintenance. Fuses require no circuit-interrupting devices such as circuit breakers or circuit switchers and no battery power systems for auxiliary power. Auxiliary equipment that would normally be located within a control building is minimized, resulting in the reduced need for and cost of a control building. Fuses will provide protection for primary and secondary external faults, but little protection for transformer internal faults. Fuses introduce the probability of creating a severely unbalanced (single-phasing) voltage condition for secondary loads should only one fuse blow. Proper coordination with secondary devices is essential to avoid this condition.

Relay protection for the larger size transformers usually includes sudden pressure relays, differential relays, overcurrent relays or directional phase distance relays, and ground overcurrent relays. See Figure 13. Sudden pressure relays are often considered by many to be the primary relay protection on a transformer. The sudden pressure relay is sensitive to the sudden changes in pressure in the transformer tank that occur during an internal fault.

Differential protection is a primary scheme of protection that is normally applied on a percentage differential basis to allow for differences in transformer ratios, magnetizing current, and current transformer mismatch. Overcurrent relays are often applied on the primary voltage winding to provide backup protection to the differential relay protection. If the overcurrent relays may not be coordinated with the secondary main and feeder relays, a directional phase distance relay may be applied. A ground overcurrent relay is normally applied to provide increased sensitivity to ground faults.

Figure 13 indicates the possibility of using local primary and secondary breakers. Because of economics, a primary breaker is sometimes not used. Tripping of the transformer is accomplished by sending a transfer trip signal to the remote substation using a communications signal or a high-speed ground switch. The time required to isolate the transformer is increased by the communication channel time or the time for the remote relay and breaker to clear the fault established by the high-speed ground switch. Secondary breakers are often not used. The engineer will have to decide whether or not to trip all the feeder breakers or to manually open the feeder breakers before re-energizing the transformer. Reactors may be protected by generator-type differential relays with phase and ground overcurrent backup relays. Occasionally, phase distance relays are used for backup.

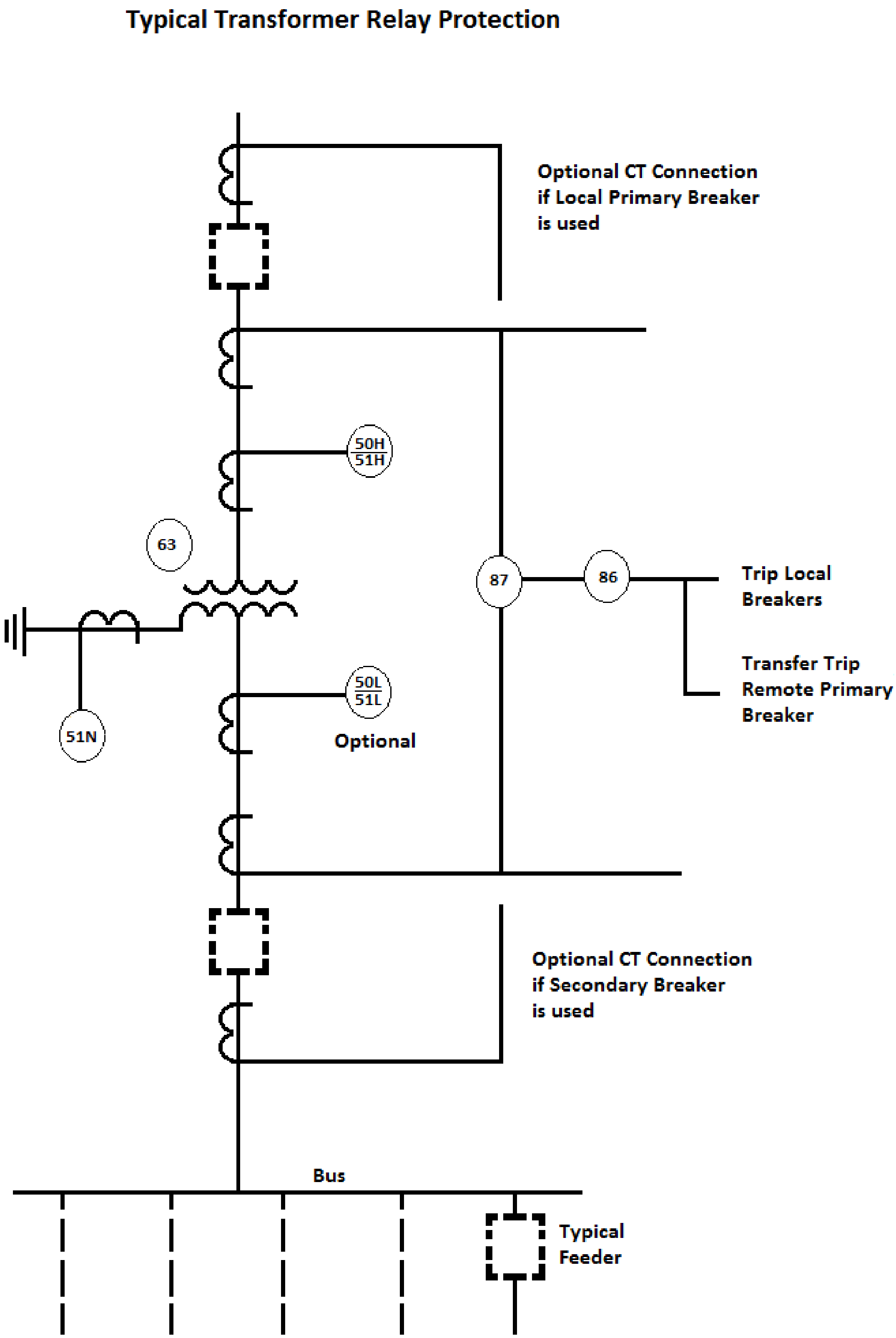
Typical Transformer Relay Protection
Optional CT Connection
if Local Primary Breaker
is used
50H
51H
63
87
86
Trip Local
Breakers
Transfer Trip
Remote Primary
Breaker
51N
50L
51L
Optional
Optional CT Connection
if Secondary Breaker
is used
Bus
Typical
Feeder

Figure 13

Additional means of protection applied to transformers and reactors include negative sequence relays, overvoltage relays, and thermal relays. Negative sequence relays can be set sensitively to back up differential relays since they do not respond to load current. Overvoltage relays will protect the transformer from excessive system voltage that will result in excessive transformer magnetizing current and heating of the transformer core. Thermal relays provide additional protection for the transformer against internal heating as a result of overloading the transformer.

Each transformer installation should be individually evaluated for the type of protection that is to be applied.

Bus Protection

Remote Tripping for Bus Fault

Short-circuit faults on buses can be isolated by allowing remote substation breakers on all lines that feed into the faulted bus to trip by Zone 2 or time-delay ground relay. This type of bus protection is simple and the most economical. It has the disadvantage that any loads fed by lines to the remote substations are also removed from service. Another disadvantage is that the time necessary to clear the fault may be intolerable.

Local Tripping for Bus Fault

In distribution substations, the bus protection is often provided by overcurrent relays, phase and neutral, located on either the low-voltage or high-voltage side of the transformer. See Figure 13 on the previous page. The phase relays have to be set to coordinate with the feeder relays and any additional downstream devices. This results in a slow trip time for the clearing of the bus. Each bus has to be evaluated to determine if the time delay that will be experienced by this type of protection will be excessive and if this type of protection will be adequate. This bus protection scheme is very simple and may also be able to act, in part, as backup protection to the feeder relays.

Short-circuit faults can be removed by a bus protective scheme in which all the substation breakers associated with a faulted bus are tripped. The two basic types of bus protective schemes are *current differential* and *voltage differential*. The current differential scheme connects all the current transformers on all the circuits connected to a bus in parallel, and the relays operate on the unbalanced current that exists during fault conditions. See Figure 14. During normal conditions, there should be no unbalanced current, since the current entering a bus has to equal the current leaving a bus. Restraint coils help to compensate for unequal current transformer performance during external faults, but the scheme still has to be applied carefully on buses with high short-circuit capabilities. Voltage differential schemes use the same parallel connection but connect a high-impedance voltage element across the parallel. It is possible to set this voltage element well above the worst case external fault voltage and still retain adequate sensitivity for internal faults. This type of relay performs well on buses with high short-circuit capability.

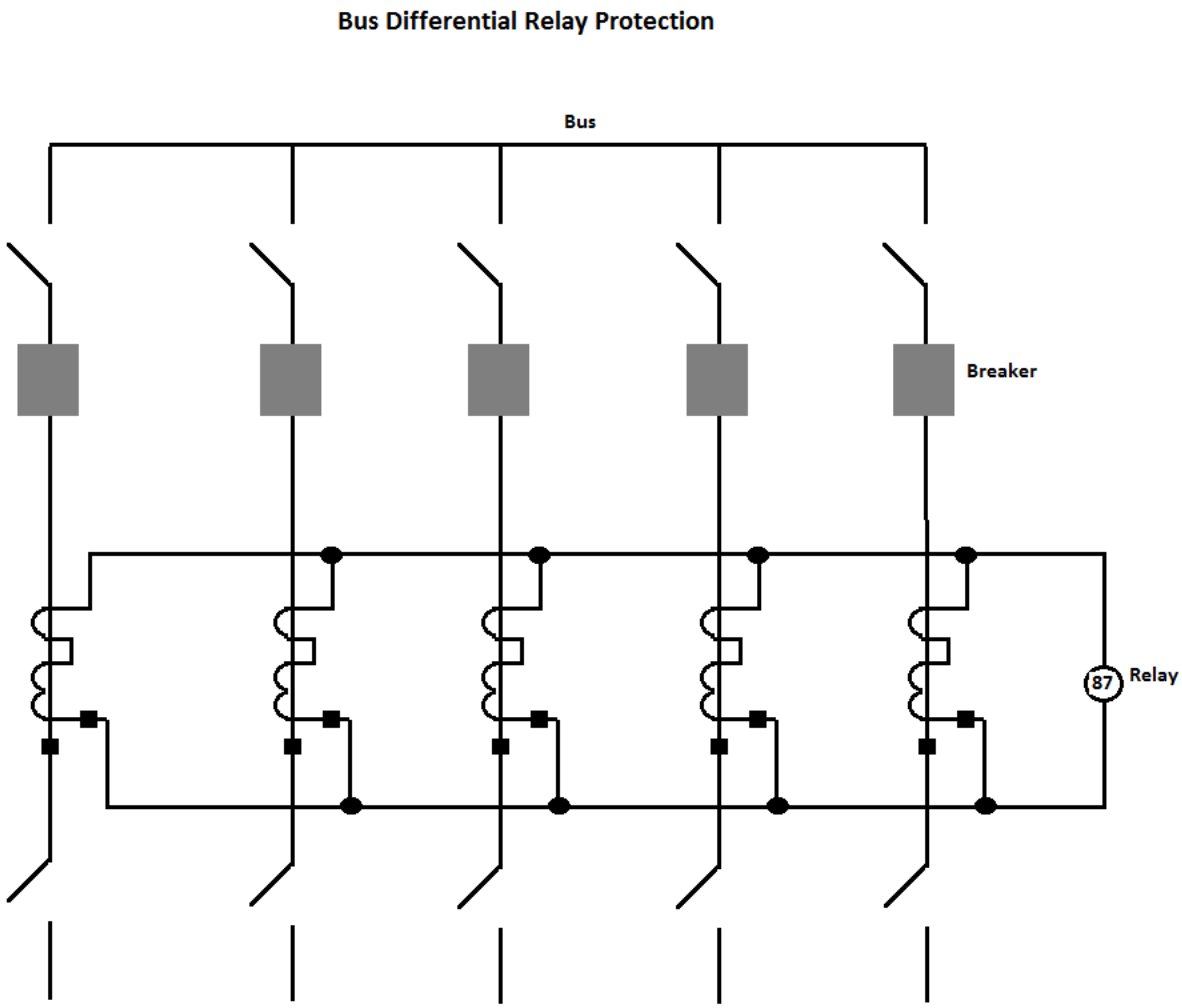

Figure 14

In some cases, overcurrent relays are applied to the differential circuit. This provides an inexpensive relay for use in the operation of the differential circuit. The disadvantage of the overcurrent relay is that there is no restraint in each of the relay circuits. Any mismatch in the CTs has to be taken into consideration in the settings of the relay by using a higher pickup amperage or a longer time delay. This will make the operation of the circuit slower than the times provided by differential relays. Many times this time delay is unacceptable for the coordination with the rest of the system relays.

Since the recent use of the microprocessor relay that normally provides additional functions at a relatively inexpensive cost, a pseudo bus differential scheme has been applied. This scheme uses a combination of instantaneous relay elements from the secondary main bus relay and the feeder relays to detect whether the fault is on the feeder or on the bus. See Figure 15. This scheme requires that there be no fault sources on the feeders since the operation of the feeder instantaneous elements for reverse feeder current would make the fault look like a feeder fault and cause the scheme to fail. If fault sources are located on the feeders, directional instantaneous overcurrent relays have to be used. An instantaneous element is used on the main breaker relay with a setting that is ensured to pick up any bus fault. The instantaneous elements of the feeder relays have to be set to reach out farther than the main breaker relay so that, for any close-in feeder fault that the main breaker relay will see, the feeder relay will also see and disable the circuit. For a bus fault, the feeders will not see the fault so the relay takes no action. The main breaker relay sees the fault, closes its contact, and, after the appropriate time delay, trips the breaker. This circuit will be slower than an actual differential relay circuit operating time, but will be faster than the overcurrent relay in protecting the bus from damage.

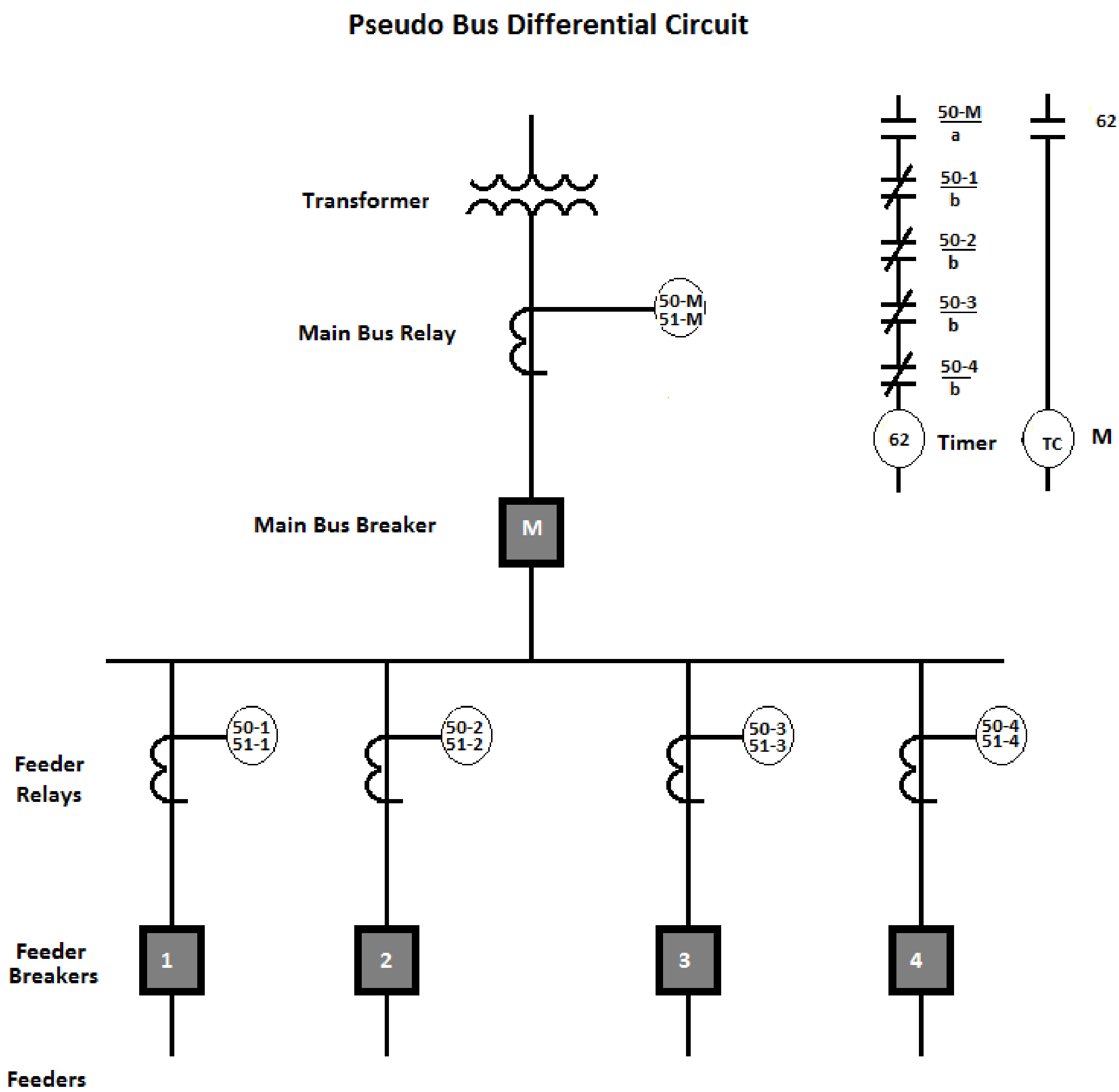

Figure 15

Local tripping for a bus fault may be accomplished by the use of a reverse-looking Zone 3 element from a distance relay. Zones 1 and 2 on a line are set to look out on the line, away from the bus. Often, the Zone 3 element is set to look in the reverse direction, which will see the bus behind it. Through a timer, the Zone 3 may be set to trip through-bus faults.

<u>Breaker Failure Protection</u>

Breaker failures can normally be separated into two classes: the failure of the breaker itself and the failure of the relaying associated with the breaker. Schemes developed to protect for the failure of breakers are based on providing either remote backup or local backup. Failure of the breaker results in the necessity to trip all the adjacent breakers in order to clear the fault and to isolate the failed breaker.

Remote backup normally consists of a Zone 3 distance relay and/or ground time overcurrent relay set to cover lines contiguous to the line being protected. This scheme will provide protection for breaker failure regardless of whether the failure is a result of relay failure or breaker failure. It will normally see faults on the protected line plus faults on the next bus and line adjacent to the protected line. This scheme has the advantage of simplicity.

Complications in using the scheme include that the relay has to be set above the maximum load current that is carried on the lines, yet it has to be set sensitively enough to see the faults that may occur on the lines. Faults occurring at the remote ends of the lines may not be detected because of insufficient current flow. When applied on a system where the adjacent bus has a number of lines with varying length, the settings for the relay may extend beyond the adjacent lines resulting in over-coverage and over-tripping. When adjacent lines are multi-terminal lines, a number of terminals may be unnecessarily tripped by remote backup. Longer reach Zone 3 relays are more susceptible to out-of-step system swings. Even with its shortcomings, in some situations with its inherent economics, this scheme may provide acceptable backup performance.

A simple means of providing *local backup* protection is to use the Zone 3 relay looking in the reverse direction. This provides a degree of protection for local equipment including all adjacent breakers, bus, lines, and remote terminals. Advantages and disadvantages in the use of this scheme are included in the discussion above on remote backup.

An additional means of providing breaker protection is to add timing to the primary relays. If the relays do not trip and the fault is still on the system within the set time of the timer, the timer will act to trip all adjacent breakers. This scheme depends on the proper action of the primary relays and provides no backup to the failure of those relays.

An additional scheme provides the use of a second set of relays to back up the primary relaying. Carried to the maximum limit, a second DC tripping system is provided including battery, panels, charger, relays, breaker trip coils, CTs, and potential devices. This degree of duplication is occasionally provided for EHV systems. Higher voltage systems including 69 kV and above will often provide dual trip coils in the circuit breakers, and primary and secondary relays with dual DC trip buses. The engineer has to decide if auxiliary DC power systems will be duplicated, including power panels and chargers; often both systems are fed from a common battery. The reduced cost of relaying afforded by the development of microprocessor relays makes this option a relatively economical option to provide backup protection for relays. This scheme does not provide for the tripping of adjacent breakers in the case of the failure of the breaker mechanical mechanism to trip the breaker and clear the fault.

Full breaker failure backup includes protection for the failure of relays and the failure of the breaker. A separate backup relay that acts to trip all adjacent breakers, including remote breakers by means of a transfer trip, provides this degree of backup. Figure 16 indicates a typical configuration for a local breaker failure relay. Indicated are primary and secondary relays, dual trip coils in the breaker, and the fault detector and timer associated with the breaker relay. Should either the primary or secondary relay call for a trip of the breaker, an auxiliary relay, 62X or 62Y, keys the timer. If the fault is not removed during the setting for the timer, the 86BF lockout relay is picked up to trip all adjacent breakers and transfer trip any remote breakers. The time setting for the timer is usually in the range of 10 to 20 cycles. If either the protective scheme resets or the current relay drops out within the set time, nothing happens.

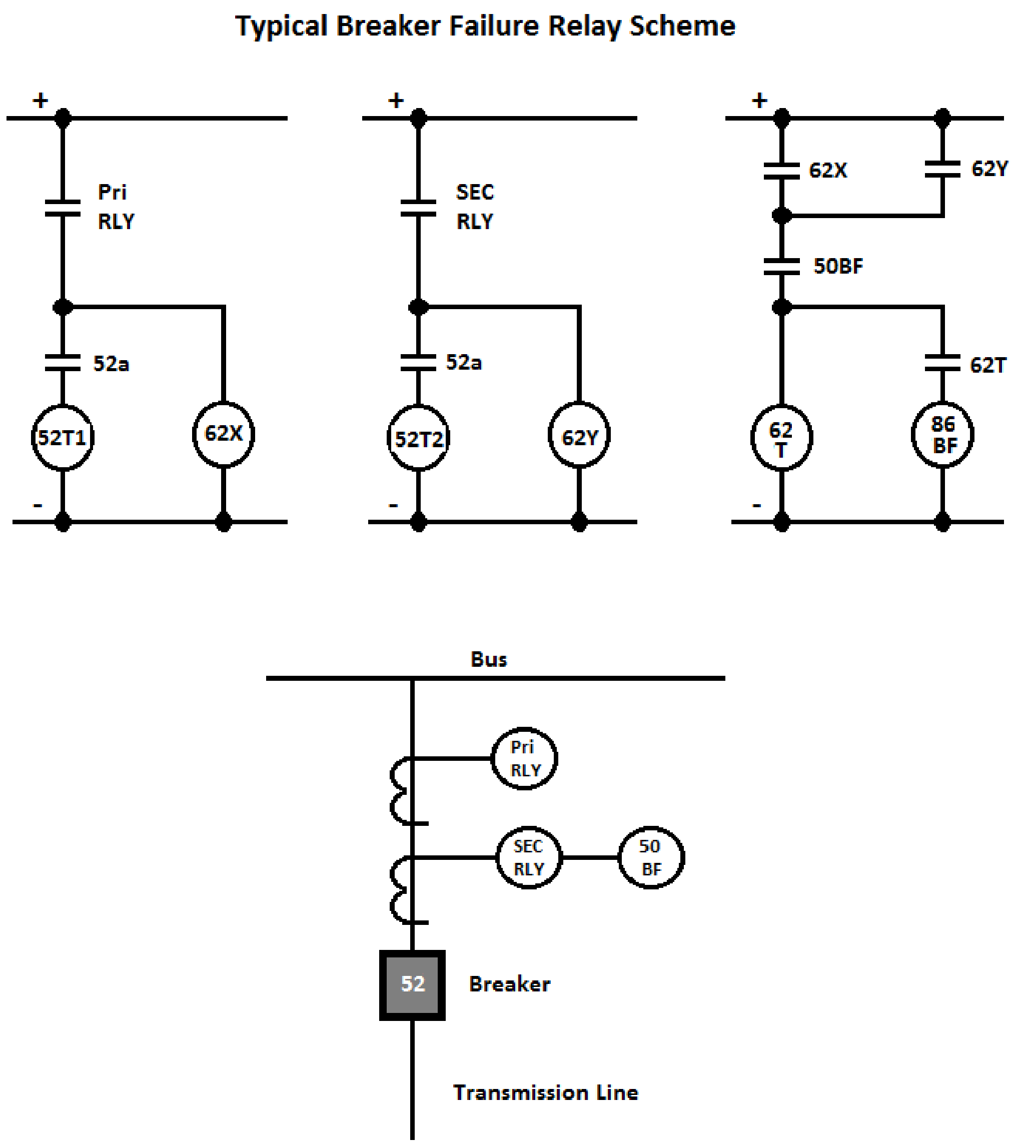

Figure 16

Reclosing

Protective relays detect faults or abnormal conditions. These faults or abnormal conditions can be transient or permanent. For open-wire overhead circuits, such as most of the distribution lines, most faults are transient faults, caused for example by lightning, that can be cleared by disconnecting the circuit from the power source. Service can be restored by reclosing the disconnecting device. Certain abnormal conditions, such as overheating of motors, can be relieved by reducing the load on the motor. The motor starters thus can be safely reclosed after the motor has cooled off. The disconnecting device can be reclosed either manually or automatically. Manual reclosing is performed by following the same procedures used in closing the device. Automatic reclosing is usually performed by automatic reclosing relays. Reclosing is generally not applied where permanent faults are more likely, such as on cables.

Automatic reclosing relays permit the circuit disconnecting device, usually a breaker, to close one or more times when the breaker has been tripped by protective relays. Relays that permit one reclosing operation are called *single-shot reclosing* relays, while relays that permit more than one reclosing operation are called multishot reclosing relays. Single-shot reclosing relays can be either the manual- or self-reset type. The *manual-reset* types have to be manually reset after each automatic reclosing operation to obtain succeeding automatic reclosing operations. The *self-reset types* automatically reset if the breaker remains closed for a predetermined time.

Multishot reclosing relays are of the self-reset type. Automatic reclosing can take place either instantaneously or with time delay, when the line is de-energized or energized, or when the voltages on both sides of the breaker are synchronized. On radial circuits, the first reclosure is usually instantaneous, with additional reclosures, when used, taking place after some time delay. On loop or multiterminal distribution lines, instantaneous reclosing is generally not used unless special forms of protective relaying are applied to ensure simultaneous operation of all line breakers for all line faults. After a specified number of unsuccessful automatic reclosure attempts, the breaker is usually locked open.

Coordination

When a circuit element such as a line, transformer, or bus becomes faulted, it has to be removed from service. This, as has been previously stated, is the function of the protective relay system.

Coordination is the process of ensuring that only those elements of the power system that has to be removed to clear the fault, and no more, are tripped in the shortest time possible.

As previously discussed, some schemes are inherently selective in tripping the protected equipment. Such protection schemes include differential schemes and transmission line phase protection that are differential in nature. No additional coordination is required for these schemes.

Coordination with distance relays is the easiest to accomplish. Since such a relay's reach is constant under all system conditions, the instantaneous zone is typically set short of the remote end of the line by 10 percent, and it will never trip for any condition but a fault on the protected section. With the remote end set the same, 80 percent of the line is thus covered by instantaneous protection. To cover the remaining 20 percent, the second zone can be relied on or a piloted scheme can be added. The second zone reaches beyond the protected section and so it has to have a time delay to allow the breaker at the remote station to clear a fault on another line. The third zone reaches beyond the remote second zones and so has to time coordinate in the same manner, thus the increasing time settings.

Coordinating with overcurrent relays can be more difficult and can also require a more detailed knowledge of system parameters. For the simple system shown in Figure 17, with a fault at "X", the near relays at "C" and "D" has to operate and their breakers have to be completely open before the remote or backup relays at "A" and "F" close their contacts. It is assumed that:

1. A faulted condition exists until the breakers isolating the fault are entirely open.

2. When a relay closes its tripping contacts, a *seal-in* auxiliary relay ensures that the switching operation will be completed even though the fault is cleared at the same instant the relay contacts close.

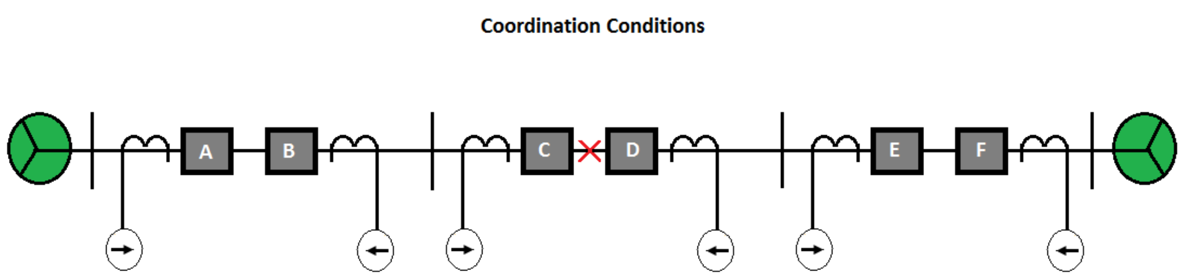

Figure 17

The time delay of the remote relay necessary for selectivity has to be equal to the operating time of the near relay plus the opening time of the breaker; plus a reasonable factor of safety, which can be taken at about 25 percent of the combined relay and breaker time with a minimum allowance of not less than six cycles if the relays are normally field calibrated at the calculated setting. If the relays are bench tested at typical setting values and only adjusted in the field with no further calibration, this margin has to be greater, typically 0.2 to 0.3 seconds.

Additional requirements for adequate relay coordination include the following:

1. The relays have to be capable of carrying a reasonable emergency overload without tripping incorrectly on load current.

2. The relays have to be able to operate under minimum system generating conditions for faults at the far ends of the sections that they protect. Maximum system generating conditions include a sufficient number of generators in service to supply the maximum demand load of the system. Similarly, the minimum system generating conditions include only the generators in service necessary to supply the minimum system load. Such minimum conditions would probably exist early Sunday mornings, for example. In addition to the above generation, there are usually some emergency generators in service called "spinning reserve" that can immediately pick up load if a generator fails. Both maximum and minimum conditions have to be checked, since maximum generation usually results in faster operation of induction-type relays with more critical selectivity, and the minimum condition determines whether the relays will receive sufficient current to operate.

The output of a synchronous generator under fault conditions is variable, depending on the characteristics of the machine and the duration of the fault. The initial output, which is maintained for three cycles or less, may be four to ten times the normal machine rating and is determined by the sub-transient reactance. The generator output rapidly decreases to the value determined by transient reactance, the average value of which may be assumed to exist for about 30 cycles on turbine generators and up to 120 cycles on condensers and slow-speed generators. The transient reactance may be taken roughly as 125 percent to 150 percent of the subtransient reactance. If the fault is not cleared, the generator output approaches the synchronous value, which is equal to or slightly less than the normal rating. It is the common practice, therefore, to use generator subtransient reactance values when calculating maximum fault kVA and to use transient values for minimum generating conditions. Synchronous values of short-circuit kVA are not usually calculated, but the decrease in generator output should be considered for slow operating relays.

For ground current calculations and determination of selectivity for ground relays, it is customary to show only the maximum fault conditions on transmission systems. On transmission systems where the relative distribution of ground fault current is changed for minimum generation because grounded transformers have been removed from service, it may be necessary to calculate and check the relay settings for both maximum and minimum ground faults. It may also be necessary to show minimum ground faults for some special conditions with certain lines or transformer banks out of service.

Briefly summarized, the job of the relay engineer is to assume various types of faults at numerous points on a system. The magnitude and distribution of fault currents are then calculated for these fault points with maximum and minimum generating conditions. Faults are assumed for normal system operating conditions and for various special conditions with certain lines, generators, or transformers out of service.

The operating time of all breakers involved have to be checked and tabulated and, for high burdens or low ratios, the true or effective ratios of bushing-type current transformers have to be determined. Having obtained these data, the next step is to determine suitable settings or adjustments for the relays that will provide selective operation for each fault condition. The tentative relay settings, the calculated current values, and the operating times of the near and remote relays for each fault condition are worked up and recorded as “Details of Selectivity” or on “Selectivity Curves.” After the most satisfactory settings are determined, “Summary Sheets” are made up for all the relays at each station. The Summary Sheets have the instructions or calibration data to enable the relay personnel in the field to set or adjust the relays to obtain the desired operating characteristics.

CHAPTER 4
Instrumentation

Substations employ many different systems to monitor operations. Depending on equipment types and configurations, a large variety of instruments, transducers, and meters may be used to perform this function.

Instruments and Transducers

An *instrument* is a device for sensing the magnitude of a physical quantity. It is calibrated or programmed to indicate or record this magnitude based on a known standard. The instrument may be indicating or recording. A *transducer* is a device that converts a physical quantity to a proportional low-level DC signal. Electrical transducers typically change amperes, watts, volts, and VARs to millivolt or milliampere signals. Transducer outputs can be used to operate local instruments or can be employed in data acquisition systems.

An *indicating instrument* depicts the present value of the quantity measured by the position of a pointer relative to a scale or as a digital display. It is used to give an observer information regarding the present operation of equipment or circuits.

A *recording or graphic instrument* makes graphic records of the value of a quantity as a function of time. This type of instrument is used when a permanent record of how the measured quantity varies with time is needed.

Instruments (indicating and recording) and transducers may be grouped according to the quantity they measure. The specific quantity is generally used with the suffix "meter" to identify the instrument. Thus, an ammeter is an instrument that measures amperes; a voltmeter is an instrument that measures voltages, etc. The most commonly used instruments for measurements of electrical quantities are ammeter, voltmeter, wattmeter, varmeter, frequency meter, and ohmmeter.

Switchboard instruments are intended for fixed installation on switchboards, panels, or consoles. Since they are constructed for fixed installations, they require careful handling in transport. *Panel instruments* are similar to switchboard instruments, but are used where smaller scale instruments are satisfactory.

Components of Instruments and Transducers

The components of *analog indicating instruments* are mechanism, scale, base, and cover. The mechanism is an arrangement of parts for producing and controlling the motion of the indicating hand or pointer. The mechanism for electromagnetic instruments includes the moving element, magnetic structure, control spring, and instrument hand or pointer. The components of thermal instruments are the same as those for electromagnetic instruments except the mechanism consists of the moving element, bimetallic strip, heater, adjusting spring, and instrument hand or pointer.

Digital Indicating Instruments are completely solid state and either contain a transducer or require inputs in the form of DC millivolt signals from transducers. The instruments then condition the signals to eliminate noise bursts and surges, feed the conditioned signals to analog to digital converters followed by binary-to-decimal encoders, and display the quantities on gaseous discharge or light-emitting diode displays. Internal "clocks" (usually 1 kHz oscillators) update the displays every millisecond. In addition to the digital display, these instruments may also have communications circuitry to permit remote monitoring of the measured quantities.

Recording Instruments are similar to digital indicating instruments but have the additional capability of data storage. Recording instruments employ electronic memory to store measured values recorded over a specified period. The stored data may be retrieved at a later date for further review and study. Various forms of communication including telephone circuit, microwave radio, and fiber-optic network may be used to retrieve data stored by the recording instrument. In some cases, the recording instrument may be connected to a local printer. The local printer is used to produce a paper copy of the stored data in table or graphical form.

Analog Instrument Scales

The instrument scale depicts the numerical value of the quantity being measured as indicated by the position of the hand or pointer with respect to scale markings. Convenient scales will give more accurate information and lessen observer eye strain. See the photo on the right for an example of an analog meter. There are two basic types of instrument scales: linear scale and nonlinear scale.

A *Linear Scale* is divided into a number of equally spaced segments, each segment representing the same unit of measurement. This type of scale is used when there are wide variations in the magnitude of the measured quantity.

A *Nonlinear Scale* is divided into a number of unequally spaced segments. Each segment may or may not represent the same unit of measurement. Usually the segments are expanded at one end of the scale and compressed at the other end of the scale. This type of scale is used when variations of the measured quantity are small and usually fall in the expanded area of the scale, thus permitting more accurate readings.

Operating Procedures

Instruments furnish valuable and indispensable information on the performance of an electric system or device. Without this information, the operator would be almost completely uninformed and would have to depend upon some crude or often inaccurate observations. Any abnormal indication should be immediately investigated.

The best instrument will serve no purpose unless properly read and correctly interpreted. Good lighting is essential to accurate reading; glare as a result of reflection of concentrated light should be avoided. Newer instruments have special covers to reduce glare. Some instruments are direct reading in that the scales directly furnish the values of the measured quantities, whereas other instruments require the use of instrument constants called scale factors. In this latter case the actual measured quantity is obtained by multiplying the instrument indication as shown on the scale by the scale factor. The scale factor may be shown on the instrument or may be associated with the position of an instrument switch. In the latter case, each position of the instrument switch will represent a different scale factor. For example, an AC ammeter with 0 to 5 ampere scale and 50 divisions has its indicating pointer located on the 35 division point. The scale factor is 20 as shown on the ammeter switch. The measured value is:

$$\frac{\textbf{Instrument Reading} * \textbf{Scale}}{\textbf{Total Divisions}} * \textbf{Scale Factor}$$

$$\frac{35 * 5}{50} * 20 = 70 \text{ Amps}$$

Instruments can withstand a certain amount of abuse such as occasionally going off scale for momentary periods, but sustained overloads to the meter will damage the mechanism or pointer. Instrument covers should be tightly fastened to the case to prevent entrance of dust or fumes. Instruments should not be left for extended periods without covers.

These instruments are rather rugged devices, but should be protected from excessive vibration and shock. The instruments should be kept clean to facilitate reading of the measured quantity.

Recording instruments require additional care if they contain printers or floppy disk drives. The instrument should be located in a dry place and kept clean. Printers should be checked periodically to ensure they have a sufficient paper supply and are printing legibly. Disks placed in disk drives should be monitored for sufficient storage space. It may be necessary to replace the disk periodically, depending on the amount of information being stored.

Meters

An *electric meter* is a device that measures and registers the integral of an electrical quantity with respect to time. The term *meter* is also used in a general sense to designate any type of measuring device including all types of electrical measuring instruments. Use of "meter" as a suffix to a compound word (e.g., voltmeter, ammeter, frequency meter) is universally accepted. However, in this chapter the narrow meaning of "electric meter" is used.

The most common types of electric meters are watt-hour meter, VAR-hour meter, and ampere-hour meter.

- The *watt-hour meter* is an electric meter that measures and registers electric energy in watthours or kilowatt-hours (1,000 watt-hours). For example, if the active electric power of a circuit is 15 kW and is consumed at a uniform rate for 3 hours, the watt-hour meter will register 3 x 15 = 45 kWh.

- A *VAR-hour meter* is an electric meter that measures and registers reactive power in reactive volt-ampere-hours (or reactive kilovolt-ampere-hours).

- An *ampere-hour meter* is an electric meter that registers the quantity of electricity in ampere-hours.

A *demand meter* is a device that indicates or records the maximum average load over any specified time interval (usually one hour or less) or the average load over a number of equal time intervals. It is a special form of electric meter indicating or recording the measured load for a given time interval and then resetting.

Combination Watt-Hour and Demand Meters measure and register load and also indicate or record maximum demand.

For example, if the active electric power in a circuit at the beginning of the measuring period is 20 kW and is uniformly decreasing until it reaches 10 kW at the end of 1 hour and then continues at the same uniform rate of 10 kW for 2 more hours, the watt-hour meter will read 35 kWh at the end of the third hour, and the demand meter will read a maximum 1-hour demand of 15 kW.

<u>Types of Meter Indicating and Recording Devices</u>
Each meter has a device that records the measured quantity. An electric meter usually has a register, which registers the integrating load. The demand meter has an indicating, graphic (recording), printing, or digital device. Digital device meters may also have communications circuitry to permit remote monitoring of the measured quantities.

Electric meter registers and register constants are the prime concern of the operators since the registers furnish the magnitude of electrical energy consumed by the load.

The *meter register* may be dial (pointer) type or cyclometric (digital) type. In the dial-type register, four or five dials are used to show the quantity measured. The register reads from left to right with the highest reading on the four-dial register 9999 and on the five-dial register 99999. The cyclometric register usually consists of four numbered rotating discs with the applicable number on each disc visible through a slot on a plate in front of the register.

The register or *dial constant* of a meter is the multiplier used to convert the register reading to the actual measured value. Its value may be 1, 10, or any multiple of 10. Another constant, used with watt-hour meters, is the watt-hour constant, which is the registration of one revolution of the meter disc expressed in watt-hours. This constant is used only when calibrating watt-hour meters, but can be used to calculate the register constant. The register constant is usually marked on the meter register, and the watt-hour constant is shown on the meter nameplate. Most modern electric meters have electronic registers. The electronic register displays the quantity measured on a liquid crystal display (LCD) or other electronic screen. Typically the units of the measured quantity are also displayed. No multiplier is required to convert the displayed value to the actual measured value.

An *Indicating Demand Meter* has a sweep hand to indicate the maximum demand for any given period. This period might be 15, 30, or 60 minutes. The maximum demand indicating hand is generally reset every month when the watt-hour meter reading is obtained.

A *Recording Demand Meter* may be found in existing installations but is generally not specified for new construction. The recording meter records the demand for each given demand period on either a round or strip chart. This chart, therefore, indicates all the demands over a given period. The maximum demand is determined by inspection of the meter chart.

A *Contact Device* was originally a pair of contacts on a cam geared to the rotating disc shaft of the watt-hour meter to produce a series of pulses. The pulse rate was directly proportional to the speed at which the meter disc rotated. On more recent analog types, a second slotted disc geared to the meter shaft passes between a photocell and a light source. The resultant voltage pulse train produced is amplified and applied to a reed relay to produce a contact pulse output.

A *Totalizer* is a solid-state device that receives pulse trains from several watt-hour meters and produces a single output pulse train proportional to the sum of the inputs. Inputs may be additive or subtractive.

The constant of a demand meter is the multiplier used to convert the indicated or recorded demand reading on the meter to actual measured values. This constant may be 1, 10, or a multiple of 10. The demand meter constant and the register constant on the watt-hour meter do not necessarily have the same value.

Electronic meters typically have digital memory that will retain measured values for a defined period. The values may be stored in random access memory (RAM) or on a magnetic medium such as a tape drive, hard drive, or floppy disk. The values stored in digital memory can be read by a computer connected to the digital memory device via local connection or through a communications link.

Connection of Watt-Hour and VAR-Hour Meters

Watt-hour and VAR-hour meters have to have both current and potential connections to measure the active and reactive energy. Watt-hour and VAR-hour meters are classified with respect to circuit connections and the type of load being measured.

The current and potential coils of self-contained meters are connected directly to the circuit. These meters are normally used where the circuit voltage does not exceed 240 volts and the continuous load does not exceed 30 amperes. Self-contained watt-hour meters for 200- and even 400-ampere continuous load currents and 480 volts circuit voltage are available but are usually only used in special cases.

The current and potential coils of transformer-type meters are connected to the circuit by means of current and potential transformers. These meters are normally used when the circuit voltage exceeds 240 volts and/or the current is above 200 amperes. Current transformers are used to reduce the current to the meter to 5 amperes at rated load. Potential transformers are used to reduce the voltage to the meter to 120 volts.

Both self-contained and transformer-type meters may be used for single-phase systems. These meters have only one current and one potential coil. The transformer-type meter is usually equipped with a small indicating lamp to show when the potential coil is energized. This is important where the secondary of the potential transformer is fused.

Three-Phase, Two-Element Watt-Hour meters have two current and two potential coils and are used on three-phase, three-wire systems. Transformer-type meters require two current transformers and two potential transformers. The meters often have two small indicating lamps to show when the two potential coils of the watt-hour meter are energized.

Three-Phase, Two and a Half-Element Watt-Hour meters have three current coils and two potential coils and are used on three-phase, four-wire systems where the error due to voltage unbalances on the three-phase system can be neglected. Transformer-type meters require three current transformers and two potential transformers. There are two potential indicating lamps to show when the two potential coils are energized.

Three-Phase, Three-Element Watt-Hour meters have three current coils and three potential coils and are used on three-phase, four-wire systems where both current and voltage unbalances can be expected. Transformer-type meters require three potential transformers and three current transformers. There are three potential indicating lamps to show when the three potential coils are energized.

Multi-Function Meters

A *multi-function meter* is a combination device that performs the functions of instruments, transducers, and meters. It is flexible, allowing the user to monitor many quantities simultaneously. It contains a central processing unit (CPU) for the calculation and digital display of desired quantities. Most multifunction meters can be user configured to normally display a few quantities simultaneously while all quantities can be read using push buttons on the front of the device or via remote monitoring. Many multi-function meters also have digital memory for storing measured quantities recorded over a defined period. Stored quantities can be downloaded to a laptop computer or other digital device.

Multi-function meters require three voltage and three current inputs to monitor three-phase power circuits. Because the multi-function meter is a microprocessor-based device, it can be set to calculate primary voltage and primary current values based on inputs from potential and current transformers with a wide range of primary-to-secondary ratios. The instrument transformer ratios are set at the factory but may be changed in the field. Once the instrument transformer ratios are set, the meter will calculate and display primary values with correct units. No scale factors are required to accurately read the meter display.

Multi-function meters can measure and calculate many electrical quantities including instantaneous volts, amps, watts, VARs, volt-amperes, power factor, and hertz. The meter may also record the instantaneous maximum and minimum for each of these values over a pre-defined period. Accumulating quantities that can be calculated include watt-hours and VAR-hours. The latest versions of multifunction meters are incorporating programmable alarm levels and various power quality measurements. The meter can also initiate communications to a remote master or PC when certain events or levels are measured.

Multi-function meters may communicate with remote terminal units (RTUs), programmable logic controllers (PLCs), human–machine interfaces (HMIs), and other digital devices via local communications network, common telephone lines, radio, or carrier signals coupled to power circuits. Local network hardware typically conforms to either RS-232 or RS-485 standards. Additional hardware and software requirements are defined by the communications protocol specified for the local communications network. Telephone lines, radio, and carrier signals are often used by utilities for remote meter reading.

Summary

This course has covered electrical protection relays used to detect defective lines or apparatus and to initiate the operation of circuit-interrupting devices to isolate the defective equipment.

The various types of relays used in substations were discussed as well as the relay schemes commonly used in substations.