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Exam Preview:

1. Actual faults, especially line-to-ground faults, usually involve arcing. Ground-fault currents, particularly in low-voltage systems, are often less than normal load currents. These currents, however, can be extremely destructive because they may build up voltage 3 to _ times more than normal.
    a. 5
    b. 6
    c. 8
    d. 10
2. Low-voltage fuses are those rated 600 V and below and are generally classified as either plug type or cartridge type. They are used primarily on indoor circuits, or devices, and are enclosed in a metal cabinet.
    a. True
    b. False
3. According to the reference material, low-voltage power circuit breakers are rated to carry 100 percent of their continuous current rating inside enclosures at __°C ambient temperature.
    a. 15
    b. 20
    c. 30
    d. 40
4. Meters reading up to 25 A or less may have the shunt within the meter case. External shunts are available in ratings up to many thousands of amperes.
    a. True
    b. False

5. Distance relays comprise a family of relays that respond to voltage and current in terms of impedance. Which of the following distance relays matches the description: provide phase-fault relaying for long lines and generator or large synchronous motor loss-of-field relaying?
    a. Impedance-type
    b. Mho-type
    c. Reactance-type
    d. None of the above
6. According to the refence material, studies indicate that 90 percent of the disturbances are less than one second in duration and 80 to 85 percent involve only one phase of a three-phase system.
    a. True
    b. False
7. Using the Instruments section of the reference material, which of the following instruments is used to measure the magnitude of the electric power being delivered to a load or group of loads?
    a. Voltmeter
    b. Ammeter
    c. Wattmeter
    d. Power Factor Meter
8. According to the refence material, live-front switchboards have the breakers and switches mounted on the rear of the panels and are generally limited to a maximum of 600 VDC and 2,500 VAC.
    a. True
    b. False
9. Most utilization equipment (except motors) carries a nameplate rating which is the same as the voltage system on which it is to be used. According to the reference material, single-phase motors for use on 120 V systems have been rated ___ V for many years.
    a. 115 V
    b. 110 V
    c. 105 V
    d. 100 V
10. An oscillograph is an instrument for observing and recording rapidly changing values of short duration, such as the waveform of alternating voltage, current, or power. Frequencies of up to approximately _______ Hz can be measured.
    a. 1,000
    b. 5,000
    c. 10,000
    d. 25,000

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CHAPTER 4. POWER SYSTEM PROTECTION AND COORDINATION.

4.1 SYSTEM PROTECTION METHODS. This chapter briefly presents system protection methods. These methods include application and coordination of components required to protect power systems against abnormalities which are reasonably expected to occur during normal system operation. This chapter deals almost exclusively with the quick isolation of the affected portion of the system.

4.1.1 <u>System Protection and Coordination</u>. Electrical system protection should not only be safe under all service conditions, but should also be selective to insure continuity of service. A selective system is a system that isolates only the faulted circuit without disturbing any other part of the system. Overcurrent devices should provide short-circuit, as well as low overcurrent, protection for system components (bus, wire, motor controllers, etc.).

4.1.1.1 Definition. System protection should guard electrical equipment against thermal damage and electromechanical stress, while providing the highest possible degree of coordination among protective devices. Coordination (or selectivity) of electrical protective devices is achieved when the devices react, under fault conditions, to isolate faulty equipment, while maintaining service to the remainder of the system.

4.1.1.2 Objectives. Protection for power systems allows for the following objectives:

(a) Personnel injury prevention.

(b) Prevention of damage to equipment.

(c) Interruption of power minimization.

(d) Minimization of the effect of faults on the system, both in extent and duration.

(e) Minimization of the effect of disturbances on the utility system.

4.1.1.3 Methods. There are several methods to minimize the effects of faults on the system and load. The basic features that are incorporated in the design of power systems will perform the following:

(a) Quickly isolate the affected portion of the system, while maintaining normal service to as much of the system as possible, and minimizing damage to the affected portion.

(b) Minimize the magnitude of the available short circuit current to minimize potential system damage to the system, components, and load.

(c) Provide alternate circuits, automatic switching, and automatic reclosing devices, where applicable, to minimize the duration and extent of outages.

4.1.2 Abnormalities.

4.1.2.1 Short Circuits. Short circuits may be phase-to-ground, phase-to-phase, phase-to-phase-to-ground, three-phase, or three-phase-to-ground. Short circuits may range in magnitude from extremely low current faults, having high impedance paths, to extremely high current faults, having very low impedance paths. All short circuits produce abnormal current flow in one or more phase conductors or in the neutral or grounding circuit. Such disturbances can be detected and safely isolated.

4.1.2.2 Other Disturbances. Other sources of disturbances such as lightning, load surges, and loss of synchronism, usually have little overall effect on system coordination and can be handled on an individual basis for the specific equipment to be protected.

4.1.3 Protective Equipment. The isolation of short circuits requires the application of protective equipment which senses abnormal current flow and removes the affected portion from the system. The sensing device and interrupting device may be completely separate, interconnected through external control wiring, mechanically coupled, or a single device.

4.1.3.1 Overcurrent Relays. Overcurrent relays are sensing devices only and must be used in conjunction with an interrupting device to isolate the affected portion of the system. Action of overcurrent relays may be either directional or nondirectional, while response may be instantaneous or time delay.

4.1.3.2 Fuses. Fuses are the oldest and simplest of all protective devices. The fuse is both the sensing and the interrupting device. Fuses are installed in series with the circuit and operate when a fusible link melts in response to overcurrent. Fuses are one-shot devices, because their fusible elements are destroyed in the protective process.

4.1.3.3 Circuit Breakers. Circuit breakers are interrupting devices only. They must be used in conjunction with sensing devices to fulfill the detection function. The sensing devices are usually separate protective relays or combinations of relays for circuit breakers rated to operate at 1000 V or more. Low-voltage circuit breakers usually use direct-acting sensing and tripping devices that sense the actual load current.

4.1.3.4 Fused Interrupter Switches. Fused interrupter switches are a hybrid form of circuit protection which function exactly the same as fuses under short-circuit conditions. Under certain circumstances, however, they may function as circuit interrupters. These switches will be treated and coordinated as fuses and no attempt will be made to incorporate the interrupter in the coordination scheme.

4.2 SHORT-CIRCUIT CURRENTS. This section provides a general discussion of short-circuit currents, focusing on circuit impedances, fault currents, and the analysis of short-circuit currents and interrupting ratings to coordinate protective devices.

4.2.1 Circuit Impedances. The determination of short-circuit current is dependent principally upon the reactance (X) of the elements from the source (or sources) to the fault point. This holds true for all elements except cable, open-wire lines, and buses. When the ratio of reactance to resistance (X/R ratio) of the entire system from the sources to the fault is greater than 4, negligible error will result from neglecting resistance. Neglecting R introduces an error that always makes the calculated short-circuit current slightly larger than the actual short-circuit current. It is common practice to refer to reactances (X), even when they represent impedances (Z).

4.2.2 Fault Currents. Certain simplifying assumptions are customarily made when calculating fault current. An important assumption is that the fault is bolted; that is, it has zero impedance and is sustained (not intermittent). This assumption not only simplifies calculation, but also applies a safety factor, since the calculated values are a maximum and equipment selected on this basis is rarely stressed beyond its full rating. Three-phase and single-phase fault currents are customarily assumed for the purpose of calculation because one of these two currents will define the maximum short-circuit current available in a circuit, and because these current values will be needed to properly coordinate phase and ground overcurrent protective devices.

4.2.2.1 Actual Fault Currents. Actual fault currents are usually less than the calculated values. Bolted line-to-line currents are about 87 percent of the three-phase value, while bolted line-to-ground currents can range from a few percent to possibly 125 percent of the three-phase value, depending on system parameters. Line-to-ground currents of more than the three-phase value are rare but may occur in industrial systems. Actual faults, especially line-to-ground faults, usually involve arcing. Ground-fault currents, particularly in low-voltage systems, are often less than normal load currents. These currents, however, can be extremely destructive because they may build up voltage 3 to 8 times more than normal.

4.2.2.2 Sources of Fault Current. Basic sources of fault current are: the utility supply system, local generators, synchronous motors, induction motors, and capacitors.

(a) A typical modern electric utility supply system represents a large and complex interconnection of generating plants. The individual generators in a typical system are not affected by a maximum short circuit in an industrial plant. Transmission and distribution lines and transformers introduce impedance between the utility generators and the industrial customer. Were it not for this impedance, the utility system would be an infinite source of fault current.

(b) In-plant generators react to system short circuits in a predictable way. Fault current from a generator decreases exponentially from a relatively high initial value to a lower steady-state value some time after the initiation of the fault. Since a generator continues to be driven by its prime mover, and has its field energized from its separate exciter, the steady-state value of fault current will persist unless interrupted by some circuit interrupter. Most properly applied fault protective devices, such as circuit breakers or fuses, operate before steady-state conditions are reached.

(c) Synchronous motors supply current to a fault in much the same manner as do synchronous.generators. The drop in system voltage due to a fault causes the synchronous motor to receive less power from the system for driving its load. The inertia of the motor and its load acts as a prime mover, and with field excitation maintained, the motor acts as a generator to supply fault current. This fault current diminishes because the motor will slow down as the kinetic energy is dissipated, reducing the voltage generated, and because of the decay of motor field excitation.

(d) The fault-current contribution of an induction motor results from generator action produced by inertia driving the motor after the fault occurs. In contrast to the synchronous motor, the field flux of the induction motor is produced by induction from the stator rather than from a direct current field winding. Since this flux decays on removal of source voltage resulting from a fault, the contribution of an induction motor drops off rapidly, ultimately disappearing completely upon loss of voltage. As field excitation is not maintained, there is no steady-state value of fault current as with synchronous machines.

(e) Capacitor discharge current, because of its very short time constant of less than one cycle, can be neglected in most cases. However, there are applications in industrial and commercial power systems in which very high transitory short-circuit currents can be developed when a short circuit occurs close to a bank of energized capacitors. These transitory currents, generally of much higher frequency, may exceed in magnitude, the power-frequency short-circuit currents and persist long enough to impose severe duty on the circuit parts carrying this current.

4.2.2.3 Short-Circuit Current Behavior. When a short circuit occurs, a new circuit is established with lower impedance and the current consequently increases. In the case of a bolted short circuit, the impedance is drastically reduced and the current increases to a very high value in a fraction of a cycle. Figure 4-1 represents a symmetrical short-circuit current wave; that is, a short-circuit current that has the same axis as the normal current which flowed before the fault occurred. To produce a symmetrical short-circuit current (under the usual condition that the short-circuit power factor be essentially zero) the fault must occur exactly when the normal voltage is maximum. In Figure 4-1 the system voltage is assumed to remain constant, although the current changes.

(a) The total short-circuit current consists of components from any source connected to the circuit (Figure 4-2). The contributions from rotating machinery decrease at various rates. This causes the symmetrical current to decrease until a steady-state value is reached. This decrease is known as the alternating current decrement of the short-circuit current. Figure 4-2 shows a decreasing symmetrical short-circuit current.

(b) Most short-circuit currents are not symmetrical, but are offset from the normal-current axis for several cycles. If the power factor is essentially zero until a steady-state value is reached and the short circuit occurs at the zero point on the voltage wave, the current starts to build up from zero, but cannot follow the normal-current axis because the current must lag behind the voltage by 90°. Although the current is symmetrical with respect to a new axis, it is asymmetrical with respect to the original axis.

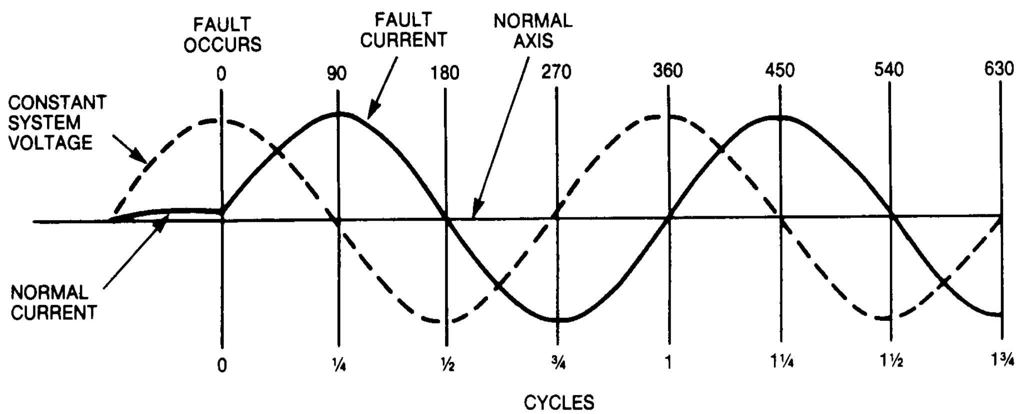

FIGURE 4-1
Symmetrical Short-Circuit Current Wave

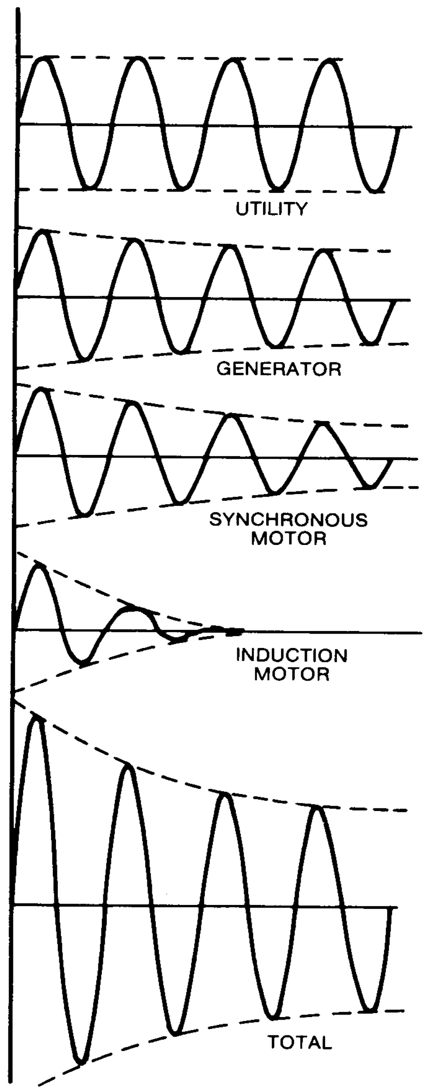

FIGURE 4-2
Decreasing Symmetrical Short-Circuit Current

Figure 4-3 shows an asymmetrical short-circuit wave with the maximum possible asymmetry. The magnitude of current offset for a typical fault will be between the two extremes of complete symmetry and complete asymmetry, because the odds are against the fault occurring at either peak or zero voltage. The offset of the asymmetrical current wave from a symmetrical wave, having equal peak-to-peak displacement, is a positive value of current that may be considered as a direct current.

The asymmetrical current, therefore, may be thought of as the sum of an alternating current component b and a direct current component a. The direct current component decreases eventually to zero, as the stored energy it represents is expended in the form of I^2R losses in the resistance of the system. The initial rate of decay of the direct current component is inversely proportional to the X/R ratio of the system from the source to the fault. The decay becomes more rapid as the X/R ratio is decreased. This decay is called the direct current decrement. The total short-circuit current is thus affected by both an alternating current and a direct current decrement before reaching its steady-state value.

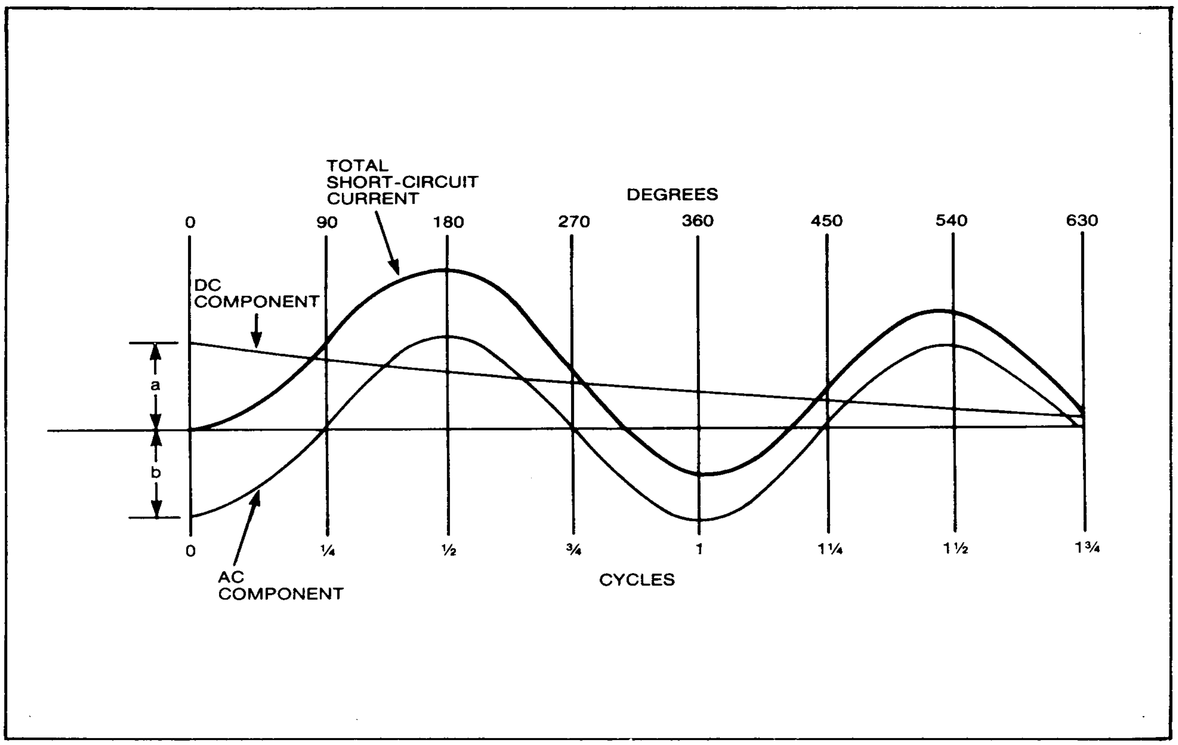

FIGURE 4-3
Asymmetrical Short-Circuit Current Wave

4.2.2.4 Short-Circuit Current Concepts. From the foregoing, it can be seen that the short-circuit current behaves differently in the first few cycles than it does later (if allowed to persist). Former practice was to determine an asymmetrical value of short-circuit current by applying simple multipliers to the calculated symmetrical value of short-circuit current. The trend in recent years is to rate protective equipment on a basic symmetrical value. Asymmetry is then accounted for by various application formulas depending on the class of equipment. Recently, the concept of I^2t has been introduced to supplement the symmetrical current concept, because it represents the actual thermal and magnetic stresses imposed on equipment carrying short-circuit current in the first few cycles. The quantity I^2t represents the time integral of the current squared for the time under consideration. An I^2t rating is being applied increasingly to electrical apparatus. Conceivably, all future protective equipment may be coordinated on an I^2t basis rather than a maximum current basis.

4.2.3 Analysis. The maximum magnitude of short-circuit current, as well as adequate interrupting ratings, must be known in order to coordinate protective devices. For coordination, minimum as well as maximum values may be required. Furthermore, it is often necessary to know the maximum let-through current to verify the withstand capability of circuit elements in series with the fault.

4.2.3.1 Withstand Capability. The fault current varies with time after the fault. A protector, that does not interrupt until several cycles after initiation of the fault, usually allows the fault current to decay from its maximum asymmetrical value. The protector and all series devices, however, must withstand the maximum current as well as the total dissipated energy. A protective device which interrupts in a fraction of a cycle (before maximum fault current is attained) reduces the withstand requirements of series devices.

4.2.3.2 Calculations. Short-circuit currents may be calculated at the following recommended times:

(a) First-cycle maximum symmetrical values are always required. They are often the only values needed for low-voltage breakers with instantaneous trip devices and for fuses in general.

(b) Maximum values (1.5 to 4 cycles) are required for medium-and high-voltage circuit breaker application.

(c) Reduced fault current values (about 30 cycles) are needed for estimating the performance of time-delay relays and fuses and for low-voltage power circuit breakers without instantaneous trip devices. They must often be calculated after the fault has initiated so that the proper current is known for setting time delayed protective relays. Often, minimum values must also be calculated to determine whether sufficient current is available to open the protective device within a satisfactory time.

4.3 RELAYS. This section provides a general discussion of protective relay systems and describes the various types of relays used for short-circuit protection.

4.3.1 Protective Relay Systems. Protective relay systems are intended to detect abnormal conditions and to isolate them by initiating the operation of circuit breakers or other devices. Normally, relays operate power circuit breakers rated above 600 V. The most common condition for which protection is required is the short circuit. There are many other conditions, however, which also require protection. These conditions include undervoltage, overvoltage, open-phase, overcurrent, unbalanced phase currents, reverse power flow, underfrequency, overfrequency, and overtemperature.

The basic relay types most commonly used in power systems are: overcurrent, directional, differential, current phase-balance, ground-fault, synchronism check and synchronizing, pilot-wire, voltage, distance, phase-sequence or reverse-phase, frequency, temperature, pressure, and auxiliary relays. Following is a brief description of the characteristics and applications of the various relay types.

4.3.2 Overcurrent Relays. The most common relay for short-circuit protection of the industrial power system is the overcurrent relay. Overcurrent relays used in the industry are mostly of the electromagnetic attraction, induction, and solid-state types.

4.3.2.1 Electromagnetic Attraction. The simplest overcurrent relay using the electromagnetic attraction principle is the solenoid type. The basic elements of this relay are a solenoid wound around an iron core and steel plunger or armature which moves inside the solenoid and supports the moving contacts.

4.3.2.2 Induction. The induction overcurrent relay is similar to a watt-hour meter since it consists of an electromagnet and a movable armature which is usually a metal disk on a vertical shaft restrained by a coiled spring. The relay contacts are operated by the movable armature.

4.3.2.3 Operating Current. The pickup or operating current for all overcurrent relays is adjustable. When the current through the relay coil exceeds a given setting, the relay contacts close and initiate the circuit breaker tripping operation. The relay operates as a burden to a current transformer.

4.3.2.4 Operating Time. If the current operates the relay without intentional time delay, the protection is called instantaneous overcurrent protection. When the overcurrent is of a transient nature, such as caused by the starting of a motor or some sudden overload of brief duration, the circuit breaker should not open. For this reason most overcurrent relays are equipped with a time delay which permits a current several times the relay setting to persist for a limited period of time without closing the contacts. If a relay operates faster as current increases, it is said to have an inverse-time characteristic. Overcurrent relays are available with inverse-, very inverse-, and extremely inverse-time characteristics to fit the requirements of the particular application. There are also definite minimum-time overcurrent relays having an operating time that is practically independent of the magnitude of current after a certain current value is reached. Induction overcurrent relays have a provision for variation of the time adjustment and permit change of operating time for a given current. This adjustment is called the time lever or time dial setting of the relay. It is possible to adjust the operating time of relays to selectively trip circuit breakers which operate in series on the same circuit.

4.3.2.5 Overcurrent Relays with Voltage Restraint or Voltage Control. A short circuit on an electric system is always accompanied by a corresponding large voltage dip, whereas an overload will cause only a moderate voltage drop. A voltage-restrained overcurrent relay is designed to operate at lower current values when the system voltage drops below its nominal value. A voltage-controlled relay will not operate until the system voltage drops below a predetermined setting, as would occur during a short circuit.

4.3.3 Directional Relays.

4.3.3.1 Directional Overcurrent Relays. Directional overcurrent relays consist of a typical overcurrent unit and a directional unit combined to operate together for a predetermined phase-angle and magnitude of current. The current in one coil is compared in phase-angle position with a voltage or current in another coil of that unit. The reference current or voltage is called the polarization. The relay operates only for current flow in one direction and will be insensitive to current flow in the opposite direction.

4.3.3.2 Directional Ground Relays. The grounded-neutral industrial power system may use directional ground relays, constructed much the same as the directional overcurrent relays. In order to properly sense the direction of fault current flow, directional ground relays require a polarizing source which may be either potential or current, as the situation requires.

4.3.3.3 Directional Power Relays. The directional power relay is, in principle, a single-phase or three-phase contact-making wattmeter and operates at a predetermined value of power. It is often used as a directional overpower relay set to operate if excess energy flows out of an industrial power system into the utility power system. Under certain conditions it may also be useful as an underpower relay to separate the two systems if the power flow drops below a predetermined value. It is also used to disconnect a generator operating in parallel with a larger generator or a utility, should the prime mover's fuel supply be interrupted.

4.3.4 Differential Relays. All the previously described relays have the common characteristic of adjustable settings to operate at a given value of some electrical quantity such as current, voltage, or power. There are other fault-protection relays which function by virtue of continually comparing two or more currents. Certain fault conditions will cause a difference in these compared values and the resulting differential current can be used to operate the relay. Current transformers, however, have a small error in ratio and phase angle between the primary and secondary currents, depending upon variations in manufacture, the magnitude of current, and the connected secondary burden. These errors will cause a differential current to flow even when the primary currents are balanced. The error current may become proportionately larger during fault conditions, especially when there is a direct current component present in the fault current. The differential relays, of course, must not operate for the maximum error current which can flow for a fault condition external to the protected zone. To provide this feature, the percentage differential relay has special restraint windings to prevent improper operation due to the error current on heavy through-fault conditions while providing very sensitive detection of low-magnitude faults inside the differentials protected zone.

4.3.5 Current Phase-Balance Relays. In some cases phase-balance current relays can provide an acceptable substitute for differential protection. A negative-sequence current relay is a more sensitive device that also detects unbalanced phase currents. In applying these relays it is assumed that under normal conditions the phase currents in the three-phase supply to the equipment and the corresponding output signals from each phase current transformer are balanced. Should the fault occur in the motor or generator involving one or two phases or should an open circuit develop in any of the phases, the currents will become unbalanced and the relay will operate. In addition to protecting against winding faults, the phase-balance current relay affords protection against damage to the motor or generator due to single-phase operation.

4.3.6 Ground-Fault Relays. Ground-fault relays may be used to provide improved protection when the power system is intentionally grounded and ground-fault current can flow through the conductors. This is often an overcurrent relay connected to sense the resultant current (vector summation of currents through all conductors of a feeder) or the current flow through the grounded conductor. The ground relay can be set to pick up at a much lower current value than the phase relays, because the vector summation of the currents flowing through the conductors of a feeder is normally zero. Overcurrent relays used for ground-fault protection are generally the same as those used for phase-fault protection, except that a more sensitive range of minimum operating current values is possible since they see only fault currents and not load currents. Relays with inverse-, very inverse-, and extremely inverse-time characteristics, as well as instantaneous relays, are all applicable as ground-fault relays.

4.3.7 Synchronism-Check and Synchronizing Relays.

4.3.7.1 Synchronism-Check Relays. The synchronism-check relay is used to verify that two alternating current sources are within the desired limits of frequency, voltage, and phase angle to operate in parallel. Synchronism-check relays should be employed for switching applications on systems known to be normally paralleled at some other location. When used for these applications, synchronous relays ensure the two sources have not become electrically separated or displaced by an unacceptable phase angle.

4.3.7.2 Synchronizing Relays. The synchronizing relay monitors two separate systems that are to be paralleled. It automatically initiates switching when the phase-angle displacement, frequency difference, voltage deviation, and the operating time of the switching equipment (to accomplish interconnection) are acceptable.

4.3.8 Pilot-Wire Relays. The relaying of tie lines, either between the industrial system and the utility system or between major load centers within the industrial system, often present a special problem. Such lines must be capable of carrying maximum emergency load currents for any length of time and they must be easily and quickly removed from service when a fault occurs. A type of differential relaying called pilot-wire relaying responds very quickly to faults in the protected line. It clears the fault promptly and minimizes line damage and disturbance to the system, yet is normally unresponsive to load currents and to currents flowing to faults in other lines and equipment. The various types of pilot-wire relaying schemes all operate on the principle of comparing the conditions at the terminals of the protected line. The relays are connected to operate if the comparison indicates a fault in the line. The information necessary for this comparison is transmitted between terminals over a pilot-wire circuit.

4.3.9 Voltage Relays. Voltage relays actuate at predetermined values of voltage, which may be.overvoltage, undervoltage, a combination of both, voltage unbalance (comparing two sources of voltage), reverse phase voltage, and excess negative-sequence voltage (single phasing of a three-phase system). Adjustments for pickup or dropout voltage and operation timing are usually provided in these relays. Time-delay is often required to preclude nuisance relay operation by transient voltage disturbances.

4.3.10 Distance Relays. Distance relays comprise a family of relays that respond to voltage and current in terms of impedance. This impedance represents an electrical measure of the distance along a transmission line from the relay location to a fault. The impedance can also represent the equivalent impedance of a generator or large synchronous motor when a distance relay is used for loss-of-field protection. Three main types of distance relay and their usual applications are as follows:

4.3.10.1 Impedance-Type. Impedance-type relays provide phase-fault relaying for moderate-length lines.

4.3.10.2 Mho-Type. Mho-type relays provide phase-fault relaying for long lines and generator or large synchronous motor loss-of-field relaying.

4.3.10.3 Reactance-Type. Reactance-type relays provide ground-fault relaying and phase-fault relaying on very short lines.

4.3.11 Phase-Sequence or Reverse-Phase Relays. Reversal of the phase rotation of a motor may result in costly damage to machines, periods of lengthy shutdown, and production loss.

Critical motors are frequently equipped with phase-sequence or reverse-phase relay protection. When connected to a suitable potential source, phase-sequence and reverse-phase relays close their contacts on reversal of phase rotation. These relays also can be used to sense unbalanced voltage or undervoltage conditions.

4.3.12 Frequency Relays. Frequency relays sense underfrequency or overfrequency conditions during system disturbances. Most frequency relays have provision for adjustment of operating frequency and voltage. The speed of operation depends on the deviation of the actual frequency from the relay setting. Some frequency relays operate instantaneously if the frequency deviates from the set value. Others are actuated by the rate at which the frequency is changing. The usual application of this type of relay is to selectively drop system load based on the frequency decrement in order to restore normal system stability.

4.3.13 Temperature Relays. Temperature relays usually operate in conjunction with temperature detecting devices such as resistance temperature detectors or thermocouples located in the equipment to be protected and are used for protection against overheating of large motors (above 1500 hp), generator stator windings, and large transformer windings.

4.3.14 Pressure Relays. Pressure relays used in power systems respond either to the rate of rise of gas pressure (sudden pressure relay) or to a slow accumulation of gas (gas-detector relay), or a combination of both. Such relays are valuable supplements to differential or other forms of relaying on power, regulating, and rectifier transformers.

4.3.15 Auxiliary Relays. Auxiliary relays are used in protection schemes whenever a single protective device alone cannot provide all the functions necessary for satisfactory protection. Auxiliary relays are available with a wide range of coil ratings, contact arrangements, and tripping functions, each suited for a particular application. Some of the most common applications of auxiliary relays are circuit breaker lockout, circuit breaker latching, targeting, multiplication of contacts, timing, circuit supervision, and alarming.

4.3.16 Relay Device Numbers and Functions. The standard device numbers assigned to the more commonly used relays and the associated functions are listed below. The numbers are frequently used in connection diagrams, in instruction books, and in specifications.

Device No.	Definition and Function
21	Distance relay functions when the circuit admittance, impedance, or reactance increases or decreases beyond predetermined limits.
25	Synchronizing or synchronism-check relay functions when two alternating current sources become electrically separated or displaced by an unacceptable phase angle.
27	Undervoltage relay functions on a given value of undervoltage.
32	Directional power relay functions on a desired value of power flow in a given direction, or upon reverse power resulting from arc back in the anode or cathode circuits of a power rectifier.
37	Undercurrent or underpower relay functions when the current or power flow decreases below a predetermined value.
40	Field relay functions on a given, or abnormally 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 low field excitation.
46	Reverse-phase or phase-balance current relay functions when the polyphase currents are of reverse-phase sequence, or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.
47	Phase-sequence voltage relay functions upon a predetermined value of polyphase voltage in the desired phase sequence.
48	Incomplete sequence relay generally returns equipment to the normal (off) position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (alarm).
49	Machine or transformer thermal relay functions when the temperature of a machine armature, or other load carrying winding or element of a machine, or the temperature of a power rectifier or power transformer (including a power rectifier transformer) exceeds a predetermined value.
50	Instantaneous overcurrent or rate-of-rise relay functions instantaneously on an excessive value of current, or on an excessive rate of current rise. This indicates a fault in the apparatus or circuit being protected.

Device No.	Definition and Function
51	AC time overcurrent relay has either a definite or inverse time characteristic that functions when the current in an AC circuit exceeds a predetermined value.
55	Power factor relay operates when the power factor in an AC circuit rises above or below a predetermined value.
56	Field application relay automatically controls the application of the field excitation to an AC motor at some predetermined point in the slip cycle.
59	Overvoltage relay functions on a given value of overvoltage.
60	Voltage or current balance relay operates on a given difference in voltage, or current input, or output of two circuits.
63	Liquid, gas pressure, or vacuum relay operates on given values or on a given rate of change of pressure.
64	Ground protective relay functions on failure of the insulation of a machine, transformer or of other apparatus to ground, or on flashover of a DC machine to ground. NOTE: This function is assigned only to a relay that detects the flow of current from the frame of a machine or enclosing case or structure of a piece of apparatus to ground, or detects a ground on a normally ungrounded winding or circuit. It is not applied to a device connected in the secondary circuit or secondary neutral of a current transformer, or in the secondary neutral of current transformers connected in the power circuit of a normally grounded system.
67	AC directional overcurrent relay functions on a desired value of AC overcurrent flowing in a predetermined direction.
81	Frequency relay functions on a predetermined value of frequency. Either under, over, or on normal system frequency (or rate of change of frequency).
85	Carrier or pilot-wire receiver relay is operated or restrained by a signal used in connection with carrier-current or DC pilot-wire fault directional relaying.
86	Locking-out relay shuts down, or withholds from service, certain equipment, if abnormal conditions persist. It can be reset electronically (remote) or manually.
87	Differential protective relay functions on a percentage, phase angle, or other quantitative difference of two currents or other electrical quantities.

4.4 APPLIED PROTECTIVE RELAYING. This section provides a general discussion of applied protective relaying and describes the functional zones of protection of a typical power system.

4.4.1 Zones of Protection. The general scheme of protective relaying divides the power system into functional zones that can be protected from damage and isolated when faulted to minimize any service interruption. The power system is divided into protective zones for:

(a) Generators.
(b) Transformers.
(c) Buses.
(d) Transmission and Distribution Circuits.
(e) Motors.

A typical power system and its zones of protection are shown in Figure 4-4. Each zone is associated with a relay or group of protective relays that sense operating conditions within the zone. When conditions (voltage, current, frequency, temperature, etc.) deviate from the protective set points, indicating a fault or potential damage to the equipment in the zone, the relays actuate circuit breakers to isolate only the faulted or endangered zone (most loads continue to receive electrical power). Protection in adjacent zones may be overlapped to avoid the possibility of unprotected areas.

4.4.2 Generator Protection. Abnormal conditions that may occur with rotating equipment include the following:

(a) Faults in the Windings.
(b) Overload.
(c) Overspeed.
(d) Loss of Excitation.
(e) Motoring.

4.4.2.1 Faults in the Windings. Internal faults generally develop as a ground fault in one of the phase windings and may occasionally involve more than one phase. Differential protection is the most effective scheme against multiple-phase faults. The currents in each phase, on each side of a generator phase winding, are compared in a differential circuit. Any difference in current indicates an unintentional current path to ground and is used to operate a relay.

4.4.2.2 Overload. Most large generators are equipped with resistance temperature detectors that are connected to thermal relays. The relays operate when the temperature of the machine exceeds an established value. Generator feeder overcurrent relays may serve as backup protection for machine overloads.

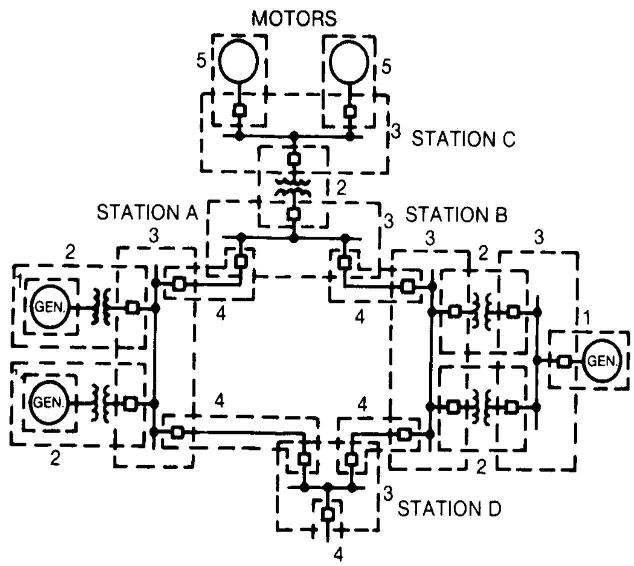

FIGURE 4-4
A Typical Power System and Its Zones
of Protection

4.4.2.3 Overspeed. A prime mover accelerates when the generator it drives becomes separated from its load. The acceleration depends on the inertia, the rate and amount of load loss, and the governor response. A generator overfrequency relay can be used to supplement the prime mover electromechanical overspeed equipment.

4.4.2.4 Loss of Excitation. Field relays protect against varying degrees of abnormally low excitation. The relay operates on an abnormally low value or failure of machine field current to keep the generator from falling out of synchronism with the rest of the system.

4.4.2.5 Motoring. Generator motoring protection is designed to protect the prime mover or system. The anti-motoring relay functions when prime mover torque is lost causing power to flow from the system into the generator. Time delay is normally included to prevent operation during system transients.

4.4.3 Transformer Protection. Differential relays are the principal form of fault protection for transformers rated at 10 MVA and above. These relays, however, cannot be as sensitive as the differential relays used for generator protection. Overcurrent relays can also be used as protection against external or internal faults. Directional distance relaying can be used for transformer backup protection when the setting or coordination of the overcurrent relays is a problem. Smaller transformers may be protected, entirely by primary and secondary overcurrent devices. Transformer protection must provide the following:

4.4.3.1 Protection of the transformer from harmful conditions occurring on the connected system.

4.4.3.2 Protection of the power system from the effects of transformer failure.

4.4.3.3 Detection and indication of conditions occurring within the transformer which might cause damage or failure.

4.4.4 Bus Protection. Differential protection is the most sensitive and reliable method for protecting buses. Differential protection provides quick action and permits complete overlapping with the other power system relaying. Differential protection methods generally used, in decreasing order of effectiveness, are as follows:

(a) Voltage responsive and linear coupler methods.
(b) Percentage differential.
(c) Current responsive.
(d) Partial differential.

4.4.4.1 Auxiliary Relay. Since the differential relay must trip all circuit breakers connected to the bus, a multi-contact auxiliary relay is needed.

4.4.4.2 Backup Protection. Remote backup protection is inherently provided by the primary relaying at the remote ends of the supply lines.

4.4.5 Power Cable Protection. Most faults in a power system occur on the transmission and distribution lines. A cable must be protected from overheating due to excessive short-circuit current flowing in its conductor. The fault point may be on a section of the protected cable or on any other part of the power system. Devices to protect cables against short-circuit damage should have high reliability and fast tripping.

4.4.5.1 Protective Techniques. Seven protective techniques are commonly used for isolating faults on power lines:

(a) Instantaneous overcurrent.
(b) Time overcurrent.
(c) Directional instantaneous and/or time overcurrent.
(d) Step-time overcurrent.
(e) Inverse-time distance.
(f) Zone distance.
(g) Pilot relaying.

All seven relay systems are used both for phase-fault and ground-fault protection.

4.4.6 Motor Protection. Motors must be protected against one or more of the following hazards:

(a) Faults in the windings or associated circuits.
(b) Excessive overloads.
(c) Reduction or loss of supply voltage.
(d) Phase reversal.
(e) Phase unbalance.
(f) Out-of-step operation (synchronous motors).
(g) Loss of excitation (synchronous motors).

While protective relays may be applied to a motor of any size and rating, in practice, they are usually applied only to the larger or higher voltage motors. The relays generally used for motor protection are indicated in Table 4-1.

TABLE 4-1
Relays Generally Used For Motor Protection

Type of Protection	Type of Relays
Phase-Fault Protection.	Instantaneous overcurrent and differential relays.
Ground-Fault Protection.	Instantaneous or time overcurrent relay.
Locked-Rotor Protection.	Time overcurrent relay or a distance relay/timer combination.
Overload Protection.	Thermal and time overcurrent relays.
Low-Voltage Protection.	Instantaneous or time delay undervoltage relay.
Phase-Rotation Protection.	Undervoltage and phase-sequence voltage relays.
Phase-Unbalance Protection.	Reverse-phase or phase-balance current relay.
Out-of-Step Protection.	Directional overcurrent and power factor relays.
Loss-of-Excitation.	Field and power factor relays.

4.5 FUSES. A fuse is a thermal overcurrent protective device with a circuit-opening fusible member that is directly heated and severed by the passage of an excessive overcurrent through it.

4.5.1 Purpose. Fuses provide overload and short-circuit protection for electrical apparatus, cables, and wire. They interrupt abnormal current with minimum system disturbance and equipment damage. Under overload or fault conditions, a properly applied fuse will open, extinguish the arc established in the opening process, and maintain open-circuit conditions with rated-voltage applied across its terminals. To restore service after a fuse has operated, it is necessary to replace the fusible member or to replace the complete fuse consisting of the fusible member and fuse holder.

4.5.2 Rating. Fuses are rated in terms of continuous-current-carrying capability, current-interrupting capability, and voltage.

4.5.2.1 Continuous-Current Rating. The continuous current rating of a fuse is the designated limit in rms alternating current, or direct current, that it can carry continuously without deteriorating or exceeding the limit of permissible temperature rise. The continuous current rating of a fuse is normally selected as equal to or slightly greater than the current-carrying capacity of the circuit that it protects. One major disadvantage of fuses is that considerably more current, than the system continuous-current rating, is required to melt the fusible element.

4.5.2.2 Interrupting Rating. The interrupting rating denotes the maximum symmetrical fault current permitted at the fuse location. Generally, both symmetrical and asymmetrical rms ratings are given.

4.5.2.3 Voltage Rating. The voltage rating of a fuse is the nominal system voltage application. Associated with the voltage rating is the maximum design voltage, marked on the nameplate, which is the highest system voltage for which the fuse is designed to operate.

4.5.3 Low-Voltage Fuses. Low-voltage fuses are those rated 600 V and below and are generally classified as either plug type or cartridge type. Low-voltage fuses are used primarily on indoor circuits, or devices, and are enclosed in a metal cabinet.

4.5.3.1 Cartridge-Type Fuses. Most cartridge-type fuses consist of a fusible link enclosed in a cylindrical cartridge with contact ferrules or knife blades at each end. End contacts slip into fuse clips or pressure contacts. Cartridge fuses are made for two voltages: (1) 250 V and lower, and (2) 600 V maximum. Class G, H, J, or K fuses have ferrule-type contacts up to 60 A and Class H, J, K, or L have knife blade-type contacts from 70 to 600 A with Class L fuses available to 6000 A. Cartridge fuses may be of the one time type or renewable. The one time fuse is a unit assembly and must be completely replaced after an interrupting operation. Renewable fuses have provisions for the replacement of the fusible member. There are several types of cartridge fuses available for use on a power system; such as, dual element, current-limiting, and high-interrupting capacity. Selection depends upon the type of circuit or equipment to be protected. Fuses with very little time delay, short time delay, and long time delay are available in standard cartridge type. In addition, special fuses having current limiting ability may be used where short-circuit currents are 10,000 A or greater. Class H fuses are rated at 10,000 A interrupting capacity (A.I.C.). Class G, J, K and L are rated from 50,000-200,000 A.I.C. These fuses have a long time delay in the overcurrent range and very fast operation in the range of short circuit or fault current. Such a fuse provides protection for the equipment and the circuit while withstanding starting inrush current of motors.

4.5.3.2 Plug-Type Fuses. Plug-type fuses have a standard screw base and are rated at 125 V with current ratings not exceeding 30 A.

4.5.4 High-Voltage Fuses. High-voltage fuses are rated above 600 V and are divided into three classifications: (1) power fuses, (2) distribution fuses, and (3) oil fuses.

4.5.4.1 Power Fuses. A power fuse is a fuse consisting of a fuse support and a fuse unit or a fuse holder that includes the refill unit or fuse link. Power fuses are divided into two main categories, expulsion and current-limiting.

(a) There are two main types of expulsion power fuses in common usage, the fiber-tube fuses and the solid material fuses. The fiber-tube fuse usually has a renewable-type link in a vented tube holder. Gases and pressure produced by the arc and the fiber lining of the tube, sometimes aided by a spring, extinguish the arc. These fuses are limited to outdoor use in a location away from personnel.

Solid member fuses have a solid fusible member located in the center of a hollow cylinder. The hollow cylinder generally consists of dry compressed boric acid and is under spring tension prior to the operation of the fuse. When the fusible member opens the spring withdraws one end of the member upward through the boric acid chamber lengthening the arc path. The intense heat produced by the arc decomposes some of the compressed boric acid, resulting in the formation of water vapor and inert boric oxide. The interruption of the arc is achieved by the deionizing action of the steam and the high particle turbulence of boric oxide. This causes the rate of deionization to exceed the rate of ionization of the arc. The boric acid fuse is inherently fast and will interrupt currents of short circuit magnitude in approximately one-half cycle; measured from the instant of fault occurrence. Because the expelled gases are nontoxic, these fuses can be used indoors within an enclosure provided a discharge filter or snuffer is used to contain the explosion.

(b) Used alone or in combination with interrupter switches or circuit breakers, current-limiting fuses provide high interrupting capability at relatively low cost. These fuses are designed to limit the flow of fault current by opening the circuit within one-fourth cycle provided the threshold magnitude is exceeded. A current-limiting fuse, however, will react to a low magnitude fault current like any other fuse. Current-limiting fuses use silver-sand construction. The current-limiting action is achieved through the melting of the sand by the fault current into a high resistance glass-like compound which in turn chokes off the fault current before peak value is reached. The fast operation limits the fault experienced by series system components. Because the applied voltage is critical, a current-limiting fuse must not be used for voltage other than design voltage. A current-limiting fuse with a rating of 200,000 A.I.C. can be used for applications with available fault current of 200,000 A, but the fuse will not withstand a current of 200,000 A. Because the current-limiting fuse interrupts the fault current so rapidly, a voltage surge is often generated which may damage upstream lightning arresters.

4.5.4.2 Distribution Fuses. A distribution cutout consists of a fuse support, fuse holder, and a fuse link. There are two types of expulsion fuses used in distribution cutouts, the fiber-tube and the open-link fuse. The fiber-tube fuse consists of a replaceable fuse link inside a tubular fuse holder that is lined with a commercial grade of hard fiber material. This type of fuse is used in both the open and enclosed cutouts. In the open fuse cutout shown in Figure 4-5, the fiber-type tube fuse is mounted between the ends of a single porcelain insulator having a centrally located mounting bracket. In another design it may be mounted between two post-type insulators attached to a channel base. The electrical connections at both ends of the fuse holder are exposed. In the enclosed fuse cutout the fuse clips, fuse link, fuse holder, and all electrical contacts are completely enclosed within a porcelain housing. The fuse tube is mounted on the inside of the cutout door. In the open-link cutout shown in Figure 4-6, the open-link fuse consists of a fusible element enclosed in a relatively small fiber tube with cable extensions of the fusible element extending from both ends of the tube. These cable extensions are connected to the spring-loaded,contacts of the fuse supports. The spring action insures separation of the open ends of the fusible member upon operation of the fuse and it is used because of the relatively limited interrupting capability of the small fiber tube. When an open-link fuse operates, it is necessary to replace the fusible element and the holder. The open fiber-tube cutout and the open-link cutout are either single-element cutouts or two- or three-element repeater-type cutouts. Following the operation of the first fusible element of a three-element cutout, the second fusible element is automatically put in series with the circuit. If the fault still persists, the third element operates and isolates the fault. If the fault clears from the circuit in the time interval between the operation of the first element and prior to the operation of the third element, however, the repeater cutout will prevent an extended outage. The open fiber-tube fuse cutout and the open-link cutout are dropout type and give visual indication that they have been operated. The enclosed fiber-tube cutout may either be a dropout or nondropout device.

4.5.4.3 Oil Fuses. In an oil fuse (sometimes called oil-filled) cutout the fusible element is immersed in oil in a sealed tank, and there is no external indication that the fuse has or has not operated. The sealed tank permits the use of this fuse where damp, corrosive, or explosive atmospheric conditions exist, where the fuse cutout may be subject to periodic submersion, or where exposure of live electrical parts might be hazardous. Oil fuse cutouts are designed for underground vault, pothead, cubicle, or pole-top installation and may be used for both indoor and outdoor applications. The use of oil as the dielectric makes it possible to interrupt relatively high fault currents as compared to the fault capability of a distribution cutout using a fiber-tube fuse. Oil fuse cutouts can also be combined with current-limiting fuses in double compartment enclosures. These oil fuse interrupter switches provide medium loadbreak and high fault current interrupting capability.

4.5.5 Operation. A fuse protects electric circuits and equipment from damage within the limits of their ratings. Successful protection depends not only upon the manufacturing quality and correct application, but also on the regular monitoring of fuses. Failure to properly monitor fuses may result in damage to costly equipment. It cannot be stressed too strongly that prescribed safety rules should be adhered to at all times when operating fuses near energized equipment or conductors. The following are suggestions for the operation of fuses, which will aid in obtaining satisfactory performance:

(a) Verify that fuses are disconnected from all power sources before servicing equipment.

(b) A blown fuse indicates an overload or a short circuit. Do not replace fuses until faults are located and corrected.

(c) Always replace a fuse with a fuse of the same type and rating. Never replace a K-type fuse with an H-type fuse. Similarly, if a sign calls for a certain manufacturer's fuse, do not substitute this for another. Although it may be the same class, the interrupting capacity may be lower.

(d) Special care should be taken to see that the fuses are securely locked or latched in the closed position.

(e) Replace all fuses of a group when one or more have blown, such as both fuses on a single-phase transformer or all three fuses on a three-phase transformer bank. Although a fuse did not blow, it may have been damaged by the fault.

(f) Spare fuse units should be stored in such a manner that they will not be damaged and will be readily available when needed.

(g) Fuses used on static capacitors should not be removed or replaced without first discharging capacitors. Capacitors used in power applications have a discharge resistor to reduce the voltage to a specified value in a specified time after being disconnected. Sole reliance on this feature for safety is not advisable.

4.6 LOW-VOLTAGE CIRCUIT BREAKERS. Low-voltage circuit breakers fall into two basic classifications and are defined in the following paragraphs.

4.6.1 Molded-Case Circuit Breakers. A molded-case circuit breaker is assembled as an integral unit in a supporting and enclosed housing of insulating material.

4.6.2 Low-Voltage Power Circuit Breakers. A low-voltage power circuit breaker has a metal frame and is used on circuits rated at 600 VAC and below.

4.6.3 Air Circuit Breaker. The term air circuit breaker is often used when describing low-voltage power circuit breakers. Since the arc interruption takes place in the air in both molded-case circuit breakers and low-voltage power circuit breakers, this term really applies to both types.

4.6.4 Ratings. The ratings which apply to circuit breakers are:

(a) Voltage.
(b) Frequency.
(c) Continuous current.
(d) Interrupting current.
(e) Short-time current.

4.6.5 Trip Device Characteristics. The overcurrent trip devices considered here are integral parts of their respective types of circuit breakers. By continually monitoring the current flowing through the circuit breaker, they sense any abnormal current conditions, and in accordance with their time current characteristics permit the circuit breaker operating mechanism to open its contacts and interrupt the circuit.

4.6.5.1 Basic Characteristics. The basic overcurrent trip device characteristics used on molded-case circuit breakers and low-voltage power circuit breakers are longtime delay and instantaneous. The combination of these characteristics provides time delay to override transient overloads, delayed tripping for those low-level short circuits or overloads that persist, and instantaneous tripping for higher level short circuits.

4.6.5.2 Alternate Characteristics. Trip devices of low-voltage power circuit breakers, and certain new molded-case circuit breakers, may provide a short-time-delay characteristic and ground current sensing. In addition, these trip devices are equipped with long time-delay and instantaneous characteristics. The resulting combination of long-time-delay and short-time-delay characteristics provides delayed tripping for all levels of current up to the maximum allowable available short-circuit current limit of the circuit breaker without instantaneous trip elements.

4.6.5.3 Trip Device Design. The basic trip device design has been of the electromechanical type, using a displacement dashpot for the low-voltage power circuit breaker. The thermal electromechanical type has been used for molded-case circuit breakers. In recent years, however, the direct-acting solid-state trip device has been developed and is available for use on both types of circuit breakers.

4.6.6 Application. The proper application of a circuit breaker, either molded-case circuit breaker or low-voltage power circuit breaker, involves considerations that go beyond voltage, current, and interrupting ratings. There are differences between molded-case circuit breakers and the low-voltage power circuit breakers which affect their application.

(a) Low-voltage power circuit breakers are rated to carry 100 percent of their continuous current rating inside enclosures at 40°C ambient temperature. Molded-case circuit breakers are rated to carry 100 percent of their rated continuous current when tested in the open at 25°C ambient temperature. Generally, molded-case circuit breakers must be derated for continuous current when used in an unventilated enclosure, and they must also have special 40°C ambient temperature calibration compensation for thermal trip elements. Certain molded-case circuit breakers, particularly those of, larger frame sizes, are rated for use in enclosures.

(b) Low-voltage power circuit breakers have short-time current ratings. Short-time current ratings allow for selectivity between circuit breakers in series during short-circuit conditions, consequently, only the one nearest the fault opens. This short-time rating is based on a 30-cycle duration test for low-voltage power circuit breakers. Molded-case circuit breakers sometimes have limited short-time ratings for time durations of approximately 18 cycles. The solid state trip devices, available to both low voltage power circuit breakers and the larger three-pole molded case circuit breakers, can include ground fault current sensing and tripping that is adjusted independently of the phase overcurrent trip devices.

(c) Low-voltage power circuit breakers are designed to permit routine maintenance to increase long life. In contrast, most molded-case circuit breakers are sealed and maintenance of the internal mechanism is not possible. Both types allow field adjustment of the tripping boundaries to some degree, although some varieties of molded-case circuit breakers are preset and sealed at the factory and are not field adjustable.

4.6.7 Protection. There are two types of overcurrent protection generally emphasized, phase overcurrent and ground fault. Circuit breakers can be made to provide ground-fault protection that is generally more sensitive than phase-overcurrent protection. Several low-voltage power circuit breakers also offer ground fault protection.

(a) Historically, the only means of providing protection against ground-overcurrent damage has been the use of separately mounted overcurrent relays and current transformers. The characteristics of the elements, such as high relay burdens and current transformer saturation, have limited the effectiveness of these schemes. Electronic technology has provided a basis for design of a ground-fault tripping function that is sensitive enough to detect very low ground overcurrents, yet is immune to nuisance tripping under numerous system conditions; including motor starting and phase-to-phase faults. These faults must be detected by the instantaneous or delay elements to ensure coordination in a selective system. To allow the greatest flexibility of application in a selective system, there must also be enough adjustment in pickup and time delay to allow at least two levels of coordination. Two level devices are used extensively to provide ground-fault protection in air circuit breakers. Three-level coordination is also available, but careful analysis of system operation is necessary to use more than three levels, as nuisance tripping must be prevented.

(b) An important aspect of good protection is the simultaneous disconnection of all phases of a polyphase circuit under short-circuit conditions. This prevents a short circuit from being backfed from other energized phases. Circuit breakers can provide simultaneous disconnection of polyphase circuits. The long-time-delay characteristic of low-voltage power circuit breakers should be selected to be no higher than necessary to override transient overcurrents associated with the energizing of load equipment. They should also coordinate with downstream protective devices. The adjustable instantaneous trip elements of trip devices on molded-case circuit breakers and low-voltage power circuit breakers should be set no higher than necessary to avoid nuisance tripping.

4.6.8 Coordination. Circuit breaker performance must be coordinated with upstream and downstream circuit breakers and protective devices. The objective in coordinating protective devices is to make them selective in operation with respect to each other. Coordinating device operation reduces the effects of short circuits by disconnecting only the affected part of the system (i.e., the zone of protection containing the faulted equipment). Normally, coordination is demonstrated by plotting the time-current curves of the circuit breakers showing that no overlapping occurs between the curves of series circuit breakers and fuses. Often selectivity is possible only when circuit breakers with delayed trip devices are used in all circuit positions except the one closest to the load. System coordination is discussed in the next section.

4.7 SYSTEM COORDINATION STUDY. The coordination study of an electric power system consists of an organized time-current study of all protective devices in series from the utilization device to the source. This study compares the time it takes the individual devices to operate when certain levels of normal or abnormal current are sensed.

4.7.1 Objective. The objective of a coordination study is to generate a comprehensive one-line-diagram of the distribution system. Additionally, the study will determine the characteristics, ratings, and settings of overcurrent protective devices. This will ensure that protective devices will isolate a fault or overload anywhere in the system with the least possible effect on unfaulted sections of the system. At the same time, the devices and settings selected must provide satisfactory protection against overloads on the equipment and must interrupt short circuits as rapidly as possible.

The coordination study provides data useful for the selection of instrument transformer ratios, protective relay characteristics and settings, fuse ratings, low-voltage circuit breaker ratings, characteristics, and settings. The coordination study also provides information regarding relative protection and selectivity, coordination of devices, and the most desirable arrangement of these devices.

4.7.2 Short-Circuit Currents. To obtain complete coordination of the protective equipment applied, it may be necessary to obtain some or all of the following information regarding short-circuit currents for each local bus.

4.7.2.1 Momentary Duty. The maximum and minimum 0 to 1 cycle momentary duty currents are used to determine the maximum and minimum currents to which instantaneous and direct-acting trip devices respond. They also verify the capability of the applied apparatus, such as circuit breakers, fuses, switches, and reactor and bus brislings, to withstand the maximum electromechanical stresses to which they could be subjected.

4.7.2.2 Interrupting Duty. The maximum 3-8 cycle interrupting duty current, at maximum generation, will verify the ratings of circuit breakers, fuses, and cables. This is also the value of current at which the circuit protection coordination interval is established. The maximum 3-8 cycle interrupting duty current, at minimum generation, is needed to determine whether the circuit protection is sensitive enough to protect against damage that could result from low level faults.

4.7.2.3 Ground Fault Currents. The most common faults in electrical systems are ground faults. The magnitudes of ground fault currents are calculated using the method of symmetrical components, using the impedance values for both the momentary duty and interrupting duty as outlined above. The ground fault current for a solidly grounded system can range from 25 - 125 percent of the bolted three-phase fault current values, but for most systems does not exceed the calculated three-phase fault current value. For low and high resistance grounded systems, the ground fault current is limited by the impedance of the grounding device and is substantially less than the three-phase fault current. The maximum and minimum generation cases need to be determined, just as for three-phase faults, to determine whether the circuit protection is sensitive enough to protect against damage that could result from low level faults. Separate ground fault relays are generally applied to the system with separate coordination studies performed for the ground fault protection system.

4.7.3 Coordination Time Intervals. When plotting coordination curves, certain time intervals must be maintained between the curves of various protective devices in order to ensure correct sequential operation of the devices. These intervals are required because relays have overtravel; fuses have damage and tolerance characteristics; and circuit breakers have certain speeds of operation. Sometimes these intervals are called margins.

4.7.3.1 Overcurrent Relays. When coordinating inverse time overcurrent relays, the time interval or margin is usually 0.3-0.4 second. Time margin is measured between relay curves either at the instantaneous setting of the load side feeder circuit breaker relay or the maximum short-circuit current (which can flow through both devices simultaneously) whichever is the lower value of current. The interval consists of the following components:

Circuit breaker opening time (5 cycles)	0.08 second
Overtravel	0.10 second
Safety factor	0.12-0.22 second

(a) The 0.3-0.4 second margin may be decreased if field tests of relays and circuit breakers indicate the system still coordinates with the decreased margins. The overtravel of very inverse and extremely inverse time overcurrent relays is somewhat less than that for inverse relays. This allows a decrease in time interval to 0.3 second for carefully tested systems. When solid-state relays are used, overtravel is eliminated and the time may be reduced by the amount normally included for overtravel. For systems using induction disk relays, a decrease of the time interval may be made by using an overcurrent relay with a special high-dropout instantaneous element. This is set at approximately the same pickup as the time element, with its contact wired in series with the main relay contact. This eliminates overtravel in the relay. The time interval often used on carefully calibrated systems with high-dropout instantaneous relays is 0.25 second. The minimum time interval using a high-dropout instantaneous relay could be 0.15 second (that is, 0.03 second instantaneous reset, plus 0.05 second vacuum circuit breaker opening time, plus 0.07 second safety factor).

4.7.3.2 Relays and Fuses. When coordinating relays with downstream fuses, the relay overtravel and circuit breaker opening time do not exist for the fuse. The margin for overtravel is plotted beneath the relay curve, and since a safety factor is desirable above the total clearing time of the fuse, the same time margin is needed for relay-to-relay coordination. Reduction of the margin is acceptable, however, when below 1 second. The same margin is used between a downstream relayed circuit breaker and the damage curve of the fuse.

4.7.3.3 Direct-Acting Trip Circuit Breakers and Fuses. When coordinating direct-acting trip low-voltage power circuit breakers with source-side fuses at the same voltage level, a 10 percent current margin is sometimes used. This allows for possible fuse damage below the average melting time characteristics. The published minimum melting time-current curve should be corrected for ambient temperature or preloading if the fuse manufacturer provides the data necessary to perform this correction. If the fuse is preloaded to less than 100 percent of its current rating, however, and the ambient temperature is lower than about 50°C, the correction to the minimum melting time-current curve of the fuse is usually less than 20 percent in time. Since the characteristic curves are relatively steep at the point where the margin is measured, the normal current margin applied probably is sufficient to allow coordination without making a fuse characteristic correction also.

4.7.3.4 Direct-Acting Trip and Relayed Circuit Breakers. When low-voltage circuit breakers equipped with direct-acting trip units are coordinated with relayed circuit breakers, the coordination time interval usually used is 0.4 second. This interval may be decreased to a shorter time as explained previously for relay-to-relay coordination. The time margin between the fuse total clearing curve and the upstream relay curve could be as low as 0.1 second where clearing times below 1 second are involved.

4.7.3.5 Direct-Acting Trip Circuit Breakers. When coordinating circuit breakers equipped with direct-acting trip units, the characteristic curves should not overlap. In general, only a slight separation is planned between the different characteristic curves. This lack of a specified time margin is explained by the incorporation of all the variables plus the circuit breaker operating times for these devices within the band of the device characteristic curve.

4.7.4 Pickup Current. The term pickup has acquired several meanings. For many devices, pickup is defined as that minimum current which starts an action. It is accurately used when describing a relay characteristic. It is also used in describing the performance of a low-voltage power circuit breaker. The term does not apply accurately to the thermal trip of a molded-case circuit breaker, which operates as a function of stored heat.

4.7.4.1 Overcurrent Relay. The pickup current of an over current protective relay is the minimum value of current which will cause the relay to close its contacts. For an induction disk time-overcurrent relay, pickup is the minimum current which will cause the disk to start to move and ultimately close its contacts. For solenoid-actuated devices with time-delay mechanisms, this same definition applies. For solenoid-actuated devices without time-delay mechanisms, the time to close the contacts is extremely short. Taps or current settings of these relays usually correspond to pickup current.

4.7.4.2 Low-Voltage Circuit Breakers. For low-voltage power circuit breakers, pickup is defined as that calibrated value of minimum current, subject to certain tolerances, which will cause a trip device to ultimately close its armature. This occurs when either unlatching the circuit breaker or closing an alarm contact. A trip device with a longtime delay, short-time delay, and an instantaneous characteristic will have three pickups. All these pickups are given in terms of multiples or percentages of trip-device rating or settings.

4.7.4.3 Molded-Case Circuit Breakers. For molded-case circuit breakers with thermal trip elements, tripping times, not pickups, are discussed. This is because a properly calibrated molded-case circuit breaker carries 100 percent of its rating at 25°C in open air. The instantaneous magnetic setting could be called a pickup in the same way as that for low-voltage power circuit breakers.

4.7.5 Current Transformer Saturation. A current transformer produces a current applicable to standard protective relays and in a specific proportional and phase relationship to the primary current. This current is used by current meters, power meters, and protective relays. Current transformer saturation can slow induction disk relay operation. When the current transformer becomes saturated, due to a high burden or many times full-load current, the actual secondary relay current is less than it should be. This causes the relay to operate more slowly than it should, or not at all. Instantaneous elements should be set below the current transformer saturation point so they will not be affected by a saturation condition. In most industrial systems, current transformer saturation is a problem only on circuits with relatively low-ratio current transformers.

4.7.6 Coordination Curves. On a coordination curve, time 0 is considered as the time at which the fault occurs, and all times shown on the curve are the elapsed time from that point. For a radial system, all the devices between the fault and a fault current source experience the same current until one of the protective devices interrupts the circuit. After interruption, relay overtravel, and circuit breaker and relay reset times, are examined. This determines whether any device other than the one nearest the fault will continue to operate under reduced current and trip a backup protective device. The series devices are considered coordinated if the source side protective device nearest the fault is the only device to operate.

4.7.6.1 Representation. A coordination curve is arranged so the region below and to the left of the curve represents an area of no operation. The curves represent a locus of a family of paired coordinates (current and time) which indicate the period of time required for device operation at a selected current value. Protective relay curves are usually represented by a single line only. Circuit breaker tripping curves, which include the circuit breaker operating time and the trip device time, are represented as bands. The bands represent the limits of maximum and minimum times at selected currents during which circuit interruption is expected. The region above and to the right of the curve or band represents an area of operation. Fuse characteristics are represented by a tolerance band bounded by minimum melting time and total fault current interrupting time curves. A specific fault current is expected to blow the fuse at some value between these times.

4.7.6.2 Time-Current Curve. Figure 4-7 shows a time-current curve represented as a band. Time t_2 is the maximum time from the initiation of the current flow I within which operation of the device and circuit breaker is assured. Time t_1 is the time from initiation of the current flow I within which the current must be returned to normal to prevent the device under consideration from operating due to the thermal or mechanical momentum of the protective device. Reading current along the abscissa of the time-current curve, the time or range of times in which any device is expected to operate corresponds to the ordinate or ordinates of the curve plotted. Usually circuit breaker curves begin at a point of low current close to the trip device rating or setting and an operating time of 1000 seconds. Relay curves begin at a point close to 1-1/2 times pickup and the corresponding time for this point. Curves usually end at the maximum short-circuit current to which the device under consideration can be subjected. A single curve can be drawn for any device under any specified condition, although most devices (except relays) plot an envelope within which operation takes place. This envelope takes into consideration most of the variables which affect operation. Some of these variables are ambient temperature, manufacturing tolerances, and resettable time delay.

4.7.7 Coordination Study. There are four steps involved in a coordination study.

4.7.7.1 One-Line Diagram. The first requisite for a coordination study is a one-line diagram'of the system or portion of the system involved. This one-line diagram should show the following data:

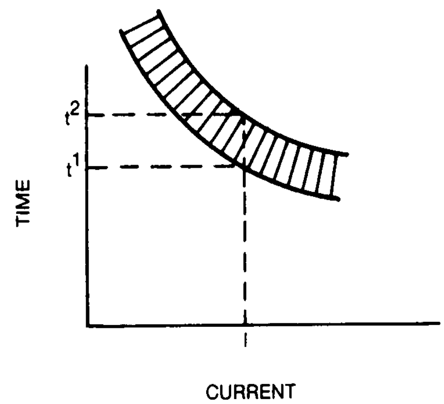

FIGURE 4-7
Time-Current Curve Band

(a) Apparent power and voltage ratings, as well as the impedance and connections of all transformers.

(b) Normal and emergency switching conditions.

(c) Nameplate ratings and subtransient reactance of all major motors and generators, as well as transient reactances of synchronous motors and generators, plus synchronous reactances of generators.

(d) Conductor sizes, types, and configurations, and type of insulating material.

(e) Current transformer ratios.

(f) Relay, direct-acting trip, and fuse ratings, characteristics, and ranges of adjustment.

(g) Cable lengths, particularly if an impedance diagram is not included.

4.7.7.2 Short-Circuit Currents. The second requirement for a coordination study is a complete short-circuit current detail, as described earlier. The short-circuit current study should include maximum and minimum expected three-phase and ground fault duties, as well as available short-circuit current data from all sources.

4.7.7.3 Time-Current Characteristics. The third requirement for a coordination study is the determination of time-current characteristics of all the devices under consideration.

4.7.7.4 Maximum Loading. The fourth requirement for a coordination study is the determination of expected maximum loading on any circuit considered. Any limiting devices such as utility settings on relays must be noted.

4.7.8 Plotting Procedures. The practice of using overlays for making coordination curves removes much of the tedious work necessary in making coordination studies. Once a specific current scale has been selected, the proper multipliers for the various voltage levels considered in the study are calculated. Protective device curves for the various devices are then plotted on graph paper. Preferably, the curves are plotted progressively as each circuit is studied, starting with the device furthest from the source. This procedure will show whether or not the proposed time-current characteristic of each successive device coordinates with the one on its load side. Short circuit calculations can now be accomplished using computers. Use of computers provides increased accuracy, shorter computation time, and accurate plotting. Several sophisticated software programs are now available for personal computers (PCs), as well as for mini and mainframe computers. With the inception of computers and associated software programs, short circuit studies can be performed in conjunction with voltage drop calculations. The main advantages realized in using this approach are system protection and system accommodation for future load growth, and the sizing of down line devices, accordingly.

CHAPTER 5. POWER SYSTEM INSTRUMENTS AND METERS.

5.1 INSTRUMENTATION AND METERING. This chapter discusses instruments and meters used in power distribution systems. Metering and instrumentation are essential for satisfactory power system operation. Instruments and meters are needed for monitoring system operating conditions and for allocating the costs of electrical energy purchase, generation, and distribution.

5.1.1 Basic Objectives. Instrumentation and metering assists operators in the operation of the power systems. Information relative to the magnitude of loads, energy consumption, load characteristics, load factor, power factor, voltage, and other parameters are required for proper operation. Certain checks are required on electric equipment, prior to placing it in service, to ensure that the insulation is adequate for application of voltage and that the connections have been properly made. After equipment is in service, certain periodic checks are necessary to ensure that the equipment remains in proper operating condition. Instruments and meters are used to perform these and many other important functions.

5.1.2 Definitions. The following two paragraphs broadly define power system instruments and meters.

5.1.2.1 Instruments. An instrument is defined as a device for measuring the value of the quantity under observation. Instruments may be either of the indicating or recording type.

5.1.2.2 Meters. An electric meter is generally thought of as a device that measures and records watts with respect to time or watt-hours. The term meter is also commonly used in a general sense, as a suffix, or as part of a compound word (such as voltmeter, frequency meter) even though these devices are, more correctly classified as instruments.

5.1.3 Alternating Current Measurements. Alternating current instruments and meters are designed to measure the root mean square values at the frequency specified and are calibrated for a pure sine wave. Any deviation in frequency or wave shape will result in a decrease in the accuracy of the instrument or meter. A large variety of instruments and meters are available to measure alternating current system parameters. In most cases their current coils are rated 5 A and their potential coils are rated 120 V. Instrument current and potential transformers are used when the current and voltage of the circuit exceed the rating of the instruments.

5.1.3.1 Current Transformers. Current transformers isolate instrument circuits from the primary circuits and reduce current through instruments to values within individual instrument measuring element ratings. The current transformer ratio selected should be minimized, without exceeding rated current in the secondary winding. A ratio that will give a normal current reading at about one-half to three-quarter scale on the instrument should be used if possible.

On three-phase three-wire circuits, two transformers are sufficient for metering, although a third transformer is sometimes used for checking the ratio of the others. On a three-phase four-wire grounded system, three transformers are required. Usually the turns ratio of a current transformer is such that dangerously high potentials result when the secondary circuit is opened. A test switch or current jack, therefore, is normally provided to short-circuit the transformer secondary while testing the instrument, or for using plug-in portable meters. The secondary circuits of current transformers are always grounded.

5.1.3.2 Potential Transformers. Potential transformers reduce voltages to values within the rating of instrument potential coils. Single-phase transformers are usually employed with two transformers connected in open delta for three-phase three-wire circuits. For three-phase four-wire systems, three transformers are required. Switches are provided in the potential transformer secondary circuit to disconnect the instrument for testing. Potential transformer secondaries are also grounded.

5.1.4 Direct Current Measurements. Direct current measurements employ either shunts or DC transformers to carry the main current to be measured.

5.1.4.1 Shunts. A shunt is made of metal with a low-temperature coefficient of resistance and low thermoelectric effect with respect to copper. Strips of resistance metal are brazed into heavy copper blocks which become both the terminals for the line and the leads to the instrument. Ordinarily, the shunt must be calibrated with the leads attached. The direct current ammeter actually measures the millivolt drop across its shunt and is calibrated in terms of the current rating of its associated shunt. Meters reading up to 50 A or less may have the shunt within the meter case. External shunts are available in ratings up to many thousands of amperes.

5.1.4.2 Direct Current Transformers. A direct current transformer is a form of magnetic amplifier or saturable core reactor. Two double-circuit transformers are used, with one winding of each connected in the direct current circuit and the secondary windings excited by an alternating voltage. As the direct current varies, it induces varying degrees of core saturation. As the transformer core saturation changes, so does the magnetic flux linkage of the AC secondary circuit. An alternating current instrument senses the changes in the flux linkages of the secondary circuit and is calibrated to read direct current amperes. This method has two definite advantages over the shunt method. The secondary circuit is isolated from the measured source and the user may add one or more instruments, relays, or other current-operated devices to the secondary of the transformer. The lower cost and greater reliability of the direct current transformer provide a definite advantage over the shunt, for very high current values. Direct current transformers are especially useful where remote metering of large direct currents is involved, because calibrated leads are not required.

5.1.5 Transducers. Electrical quantities of alternating current systems can be measured by using a transducer, that is referred to as a Hall generator and based on the Hall effect. The Hall generator acts as a multiplying device, putting out a direct current millivolt signal proportional to the product of the current and a magnetic field input. The magnetic field input may be developed from a current or a voltage source. The output signal may be used to operate a direct current voltmeter calibrated to the product units or as an input to telemetering or recording devices. The Hall generator principle has been applied to devices for the measurement of voltage, current, power, reactive power, power factor, and frequency. One advantage of the Hall generator type of transducer is its small all-solid-state construction. Other advantages include its relatively high output signal level, a high operating speed, and the output the transducer inputs.

5.2 INSTRUMENTS. This section provides descriptions of the various instruments used to monitor power system operating conditions.

5.2.1 Ammeters. Ammeters measure the current flowing in a circuit. An ammeter or its associated current transformer primary is connected in series with the circuit being measured.

5.2.2 Voltmeters. Voltmeters measure the potential difference between conductors or terminals. A voltmeter is connected directly, or through a potential transformer, across the points to be measured. For voltmeters operating on direct current circuits above 300 V, external series resistors are commonly required.

5.2.3 Wattmeters. A wattmeter measures the magnitude of the electric power being delivered to a load or group of loads. To indicate the product of voltage and in-phase current, the wattmeter has both potential coils and current coils.

5.2.4 Varmeters. A varmeter measures reactive power. A varmeter operates as a wattmeter with the current coils connected in series with the circuit and the voltage phase shifted 90 electrical degrees from the voltage across the circuit. Varmeters usually have the zero point at the center of the scale, since reactive power may be leading or lagging. The varmeter has an advantage over a power factor meter in that the scale is linear, and small variations in reactive power can be read. A power factor meter may be difficult to read near unity power factor.

5.2.5 Power Factor Meters. A power factor meter indicates the power factor of the load. It is a direct-reading instrument that will indicate the power factor of a three-phase load only if the voltage and load are balanced on the three phases. The meter consists of both current and voltage elements, utilizing instrument transformers where necessary. The meter indicates unity power factor on scale center and lead or lag for any power factor other than unity. It is possible to obtain the average power factor over a definite period, like a day, week, or month, by use of the readings of an integrating kilowatt-hour meter and a kilovar-hour meter.

5.2.6 Frequency Meters. The frequency of an alternating current power supply can be measured directly by frequency meters. The most commonly used type is the pointer-indicating type.

The pointer-indicating type frequency meter is connected directly across the line or the secondary of one phase of a potential transformer. A frequency meter may have a scale range such as 55 to 65 Hz or 58 to 62 Hz for use on a 60 Hz system, and the moving pointer indicates the exact value.

5.2.7 Portable Instruments. Most instruments are permanently mounted on switchboards, but many can be obtained in portable forms. Portable instruments are useful for special tests or for augmenting permanent instruments. Provisions are sometimes made on the secondaries of instrument transformers for connecting portable instruments into the circuit. Portable current and potential transformers are available when the self-contained range of the portable instrument is not sufficient for the values to be measured.

Examples of typical portable instruments are portable ammeters, voltmeters, and wattmeters. These may be of the indicating or recording type depending on the type of test or data required. A versatile alternating current portable instrument, sometimes called a circuit analyzer, is available to read current, voltage, and resistance. The circuit analyzer may operate on either alternating or direct current, therefore, providing flexible instrumentation for various conditions.

5.2.8 Recording Instruments. Most instruments available as direct-reading indicating instruments are also available as recording or curve-drawing instruments. A continuous record of current, voltage, power, and frequency may be required for economic, statistical, and engineering studies, as well as for checking operator and machine performance. The record is traced automatically on either a strip or a circular chart by a pen fastened to the end of the pointer of the instrument. The chart is moved at a constant speed by a clock mechanism. Some recording instruments have adjustable speeds for movement of the chart. Normal records are obtained at a speed consistent with chart-changing schedules, types, and load characteristics. Special tests may require a more rapid chart speed in order to obtain proper data. These special tests may require more sophisticated equipment, such as magnetic tape recorders.

5.2.9 Miscellaneous Instruments

5.2.9.1 Temperature Indicator. Temperature indicating and temperature control devices include liquid, gas, or saturated-vapor thermometers, resistance thermometers, bimetal thermometers, radiation pyrometers, and thermoelectric pyrometers. These devices may be obtained as indicating instruments or as recorders. They are used for measuring temperatures of electric windings, bearings, oil, air, and conductors. Some of them can be obtained with electric contacts for use on an alarm device or relay circuit. Pyrometers are generally used for indication and control of furnace temperatures.

5.2.9.2 Megohmmeter. A megohmmeter is an instrument for measuring the insulation resistance of electric cables, insulators, buses, motors, and other electric equipment. The megohmmeter consists of either a hand- or motor-driven direct current generator and resistance indicator. It has a maximum indication of 50,000 megohms to infinity and is available in different voltage ratings, usually 500, 1000, or 2500 V. Performance of an insulation resistance test on electrical insulation (prior to placing equipment in service or during routine maintenance) will provide a good indication as to the condition of the insulation. Wet insulation can be detected very readily. A high reading, however, does not necessarily mean that equipment can withstand the rated potential since the instrument does not apply rated potential. A high-potential test, in addition to the resistance test, may be desirable but not practicable. In lieu of a high-potential test, a dielectric-absorption test, using a megohmmeter, may be performed. Recording and plotting periodic resistance readings will show trends and may often predict insulation failure.

5.2.9.3 Ground Ohmmeter. A ground ohmmeter measures the resistance to earth of ground electrodes. Calibration is usually zero to 500 ohms. Some types of ground ohmmeters also include provision for measurement of soil resistance.

5.2.9.4 Low-Resistance Ohmmeter. Low-resistance ohmmeters are available for small resistance measurements such as electric conductors, joints, contact surfaces, and electric windings. The low-resistance ohmmeter is not considered a high-precision device, but it is useful in field testing. Low-resistance ohmmeters contain a source of direct current and a meter to read the resistance in microhms.

5.2.9.5 Ground Detector. A ground detector indicates a ground path on an ungrounded system. Direct-reading types are available. An incandescent lamp ground detector connected either directly to low-voltage systems or to potential transformers on medium-voltage systems is sometimes used. The voltage rating of the lamp is selected so that the lamp glows on the normal system. Whenever a ground fault occurs on one phase of the system, the lamp connected from that phase to ground will go out or dim and the other two lamps will glow brightly. With a fault of sufficiently low resistance on one phase, the lamp glow difference can be detected visually. A voltage relay and an alarm device could be installed to sound whenever a ground fault occurs.

5.2.9.6 Oscillograph. An oscillograph is an instrument for observing and recording rapidly changing values of short duration, such as the waveform of alternating voltage, current, or power. The oscillograph has many uses, such as determining transient characteristics of voltage, current, and other phenomena which occur too rapidly for measurement, by indicating meters. Frequencies of up to approximately 10,000 Hz can be measured.

(a) Most magnetic-type oscillographs consist of a galvanometer (which gives deflections closely proportional to the instantaneous value of current or voltage), an optical system (using a light beam from a mirror rather than usual pointers), and the recording device (film or light-sensitive material which can be moved rapidly). Multi-element oscillographs are available for recording several different values simultaneously, such as, three-phase current, voltage, and power.

(b) Direct-writing oscillographs record the phenomena or transients directly on a paper chart using an inking pen. Due to the pen inertia, this type of instrument has a limited frequency range in the order of 0.5-100 Hz.

5.2.10 Accuracy. The accuracy of an instrument is based on standard conditions at 25°C in a normal mounting position with no stray field (other than the earth's) and no DC ripple. The AC power source should have a pure sine wave and normal frequency. Accuracy class is now stated as the limit expressed in percent of fiducial value (usually full scale value) at which errors will not be exceeded under standard conditions.

Switchboard instruments are usually 1.0 percent class. Panel instruments (2-1/2 to 5-1/2 inch sizes) are usually 2.0 percent class, however, in special cases panel instruments may be 1.0 percent. Smaller panel instruments may be as much as 5.0 percent; although some of the cheaper, but larger types, also fall into this category. Portable instruments have recognized accuracy classes of 0.25 percent, 0.5 percent, and 1.0 percent. These are the most common and practical classes for general maintenance work. Manufacturers mark instrument dials with a number (0.5 or 1.0) to denote their accuracy classification.

5.3 METERS.

This section provides descriptions of the various meters used to monitor power system operation conditions.

5.3.1 Watt-hour Meters. Watt-hour meters measure the amount of electric energy used by a load. Alternating current watt-hour meters employ the induction-disk type of mechanism; the disk revolves at a speed proportional to the rate at which energy is passing through the meter. The number of revolutions, through a gear train, is recorded on a dial in kilowatt-hours. The watt-hour meter may be used to calculate the power used by a load. Count the number of revolutions of the disk for any number of seconds and use this formula:

$$\text{power (kilowatts)} = \frac{3600 \times R \times Kh}{1000 \times S}$$

Where:

Kh = the meter constant (marked on the meter disk or nameplate)
R = the number of revolutions
S = the number of seconds

If the power is being measured through instrument transformers external to the meter, the meter constant must be multiplied by the instrument transformers ratios (Kh x PT ratio x CT ratio).

5.3.1.1 Instrument Transformers. Current and potential instrument transformers may be used with watt-hour meters. On three-phase three-wire circuits, two current-element meters are used. On four-wire circuits, three current-element meters are necessary.

5.3.1.2 Ratings. Watt-hour meters are rated according to voltage, current, and frequency. Transformer-rated meters are suitable for service at all voltage and current ratings when used with appropriate instrument transformers.

(a) The voltage rating for a particular application depends upon the feeder connection. For self-contained meters, applied on a three-phase three-wire system, the meter is rated at line-to-line voltage. For metering a load, served from a three-phase four-wire wye system, the meter is rated at line-to-neutral voltage. The standard voltage ratings are 120, 240, and 480 V.

(b) The following two standard curlent ratings are applicable to each meter:

- The class designation (CL) of a watt-hour meter denotes the maximum load range in amperes. The standard class ratings are 10 (for transformer-rated meters), 100, and 200.
- The test current rating (TA) of a meter corresponds to the value of current at which the watt-hour meter is calibrated. Standard test currents and their relations to meter class are: CLIO - TA 2.5 A, CL100 - 15 A, and CL200 - 30 A.

(c) The standard frequency rating is 60 Hz.

5.3.2 Demand Meters. The maximum power demand during a specified period of time is measured by a demand meter. Both indicating and recording meters are available for this purpose.

5.3.2.1 Curve-Drawing Wattmeters. Curve-drawing wattmeters, which record the load-time curve of the system, can be used to determine the maximum demand by averaging the load over the selected demand interval of time.

5.3.2.2 Integrating Demand Meters. Integrating demand meters totalize the energy used over the demand interval and either record the average demand for each interval or, by means of a maximum indicating pointer, indicate the maximum demand that has occurred since the meter was last read and reset. The most common demand intervals used in commercial metering are 15 minutes and 30 minutes.

5.3.2.3 Lagged Demand Meters. Lagged demand meters usually obtain their demand interval by thermal time lag. Lagged demand usually indicates 90 percent of the maximum value of a suddenly applied steady load by the end of the selected demand interval, and 99 percent at the end of the succeeding interval.

5.3.2.4 Contact-Operated Demand Meters. Contactors can be attached to watt-hour meters to transmit impulses at a rate proportional to the load. These impulses operate the demand meter to drive a pointer or pen. The indicator is reset at the end of the demand interval by a synchronous or mechanical clock. Contact-operated demand meters have the advantage of easier servicing than combined watt-hour meters and demand meters. Additionally, the demands of several lines or loads can be combined through a totalizing relay to operate one demand meter, giving total demand. Phase-shifting transformers and scale plates are available to make the meters read the demand in kVA. The demand in kVA may be more useful in determining the actual load in terms of equipment rating.

5.3.2.5 Printing Demand Meter. Another type of contact-operated demand meter is the printing demand meter which records the demand for each interval by printing it on a tape together with the time of day.

5.3.2.6 Magnetic Media Recording Meter. A variation of the printing demand meter is the magnetic media recording meter. Kilowatt-hour (kWH) pulses and time pulses are recorded on magnetic media. The data can later be recovered directly by computer. The major advantage of this magnetic storage is the elimination of manual chart or tape reading and manual computations.

5.3.3 <u>Metering outfits</u>. Instrument transformers for outdoor primary metering installations are available as packaged units. The packaged units are available for single-phase and three-phase applications.

CHAPTER 6. POWER SYSTEM OPERATION.

6.1 POWER SYSTEM STRUCTURE. This chapter will discuss the structure, the procedures, and the various switchboards generally applicable to Power System Operating Centers.

6.1.1 Bulk Power System. A bulk power system consists of the generating sources, the transmission system, and the distribution system. A broad description of each subsystem is provided in the following subparagraphs.

6.1.1.1 Generating Sources. Generating sources consist mostly of synchronous generators driven by steam, gas, or hydro turbines. Energy is delivered to the transmission system through a step-up transformer.

6.1.1.2 Transmission System. The transmission system consists of separate successive networks servicing the same geographical area. These networks operate at different voltages and are tied together at substations. The transmission network also serves to integrate neighboring power systems with the underlying system through interconnections.

6.1.1.3 Distribution System. The distribution system is similar in structure to the transmission system, however, each network covers a much smaller geographical area. The distribution system also provides service to individual customers, rather than providing service to other systems.

6.1.2 Power System Objectives. All power systems (utility, industrial, commercial, and residential) have in common the function of providing electric energy safely, reliably, and as economically as possible. Correct voltage and frequency wave shape must be continuously maintained within permissible limits. A complex, but coordinated, control network is required to provide proper system operation.

6.1.3 Power Systems Control Network. The combination of multiple generating sources and several layers of transmission and distribution networks provide a high degree of system redundancy. Superimposed on this physical structure is a control and automation system that is highly distributed and is designed to provide redundancy in a manner similar to that provided by the power system.

6.1.3.1 Control Centers. The hierarchy of control centers in the United States, in descending order from the national level to the local distribution areas, is as follows:

(a) The National Council coordinates regional centers.
(b) The Regional Coordination Center coordinates power pools.

(c) The Power Pool Operating Center is the interconnection of power systems.

(d) The Power System Operating Center monitors the transmission and distribution centers and power plant operations.

6.2 CONTROL CENTER PROCEDURES. Complex power systems provide reliable electric service at low cost with the aid of automatic control. These systems simultaneously track the randomly varying system load, optimize generation to minimize cost, and coordinate the action of many independent control centers. The primary functions of the control center are to manage resources, monitor performance and reliability, and adjust control parameters to maintain the desired quantity and quality of electrical supply.

6.2.1 Power System Parameters. Considerable information regarding the power system is needed to logically perform the control objectives previously described. The following is a general listing of the conditions and facts that must be identified.

(a) Position (open or closed) of circuit breakers and switches in the power system.

(b) Power flow, active and reactive, from each generating station, in each tie-line interconnecting the system with neighboring systems, and at key points in important transmission circuits.

(c) Energy (kWH) from generating stations and tie-lines.

(d) Bus voltage at each generating station and essential substations.

(e) System frequency.

(f) System time error, in seconds, based on a particular standard of reference.

(g) Tap position of load-ratio-control transformers or step-voltage regulators at key points in the transmission system.

(h) Current load on cables and transformers at critical locations in the transmission system.

The transmission of information between locations is generally accomplished by telemetering. The transmission mediums are wire circuits, carrier (current) equipment, and radio or microwave.

6.2.2 Control Functions. Centralized equipment, both central (master) and remote, enables operators to supervise and operate remotely located power system elements (supervisory control equipment). Examples of the functions or apparatus controlled from central locations by means of the supervisory control equipment are:

(a) Start-stop.
(b) Change levels.
(c) Switching.
(d) Lines.
(e) Capacitors.
(f) Reactors.
(g) Synchronous condensers.
(h) Power plants.
(i) Transformer LTC tap.
(j) Voltage regulator position.

Supervisory control equipment is often combined in quantities at remote locations such as substations or switchyards. Circuits and equipment are energized by operating circuit breakers and switches. For decision making, the operator also receives information concerning equipment state and electrical loading. The remote supervisory equipment combines the capability of receiving and executing commands and transmitting associated information to the central supervisory equipment. The centrally located supervisory equipment conversely incorporates the capability of receiving information and sending the operator's commands to a number of remote supervisory equipment. Operators, therefore, may observe and control remotely located elements of the power system using both remote and centrally located supervisory equipment.

6.2.3 Basic System Control Operations. The control objectives of a power system are related to the conditional state at which the system is operating. As the conditional state decreases below an acceptable threshold, restorative measures are initiated. The control system continuously maintains a balance between load and generation or demand and supply through basic operations.

6.2.3.1 Load and Frequency Control. The load and frequency control, of interconnected generators, introduces relatively simple problems to systems having one or two generating stations. The problems caused by load and frequency control become more difficult in large interconnected systems having many stations scattered over a wide area.

(a) In small single-station systems, the operator can readily adjust the governors of the prime movers to divide the load most economically between them. Guided by an accurate frequency meter and an electric clock (rather than a standard clock), the operator is able to accurately maintain the station frequency and time.

(b) In large systems, a central load dispatcher is necessary to assign loads to various stations and units in accordance with a predetermined schedule. This schedule is modified occasionally as the actual load differs from the predicted load or as emergencies arise owing to loss of generating units or tie lines. The load dispatching may be by telephone, remote telemetering and signaling, or both. Load assignment to a particular station varies with the type and function of the station and its relation to the system. Frequency control is sometimes assigned to one of the largest generating stations. Very large systems are sometimes divided into load districts, each with its own load dispatcher, often with a central load-dispatching agency for general supervision over the districts.

(c) Automatic load-frequency control is necessary for maintenance of good overall system operations, proper sharing of load between generating stations, suitable regulation of tie-feeder loading between systems, and maintenance of proper frequency and time control. The problem of control resolves itself into:

- o The measurement of a quantity.
- o Interpretation of the measurement in terms of deviation from a control point.
- o The application of corrections to restore the measured quantity to its normal value. In some cases more than one measurement is required for proper operation of the control equipment.

Generator, station, and system loads are measured through the summation of various thermal-converter millivolt outputs. Frequency is measured by a frequency-bridge type instrument. As this data is fed into a master controller, it is able to detect the need for more or less generation and to send impulses to the different stations calling for load increase or reduction. By the use of area requirement (proportional load control), the equipment is able to call for changes at the several generating stations. In effect, they supply the load of their respective areas, thereby causing a minimum of power flow over tie feeders from one station to another.

6.2.3.2 Reactive Power and Voltage Control. A generator basically controls two of the key parameters in a power system: the amount of power being generated to meet frequency specifications and the amount of reactive power being supplied to meet voltage specifications. The amount of field current supplied to the generator's rotor winding controls the amount of reactive power generated. Normally, a monitoring system senses the voltage and automatically adjusts the field current to the generator to maintain that voltage at some prescribed value. If the supply for a generator's field current fails, or if a short circuit develops within the field winding, the generator's ability to control the voltage within a power system is lost. Its ability to continue supplying electric power, therefore, is greatly reduced. When a generator in this condition is allowed to remain connected to the system, it will cause a severe local voltage depression. This forces the system to supply a flow of reactive power to the generator from other sources in order to maintain generator excitation. In many cases, however, the generator will continue to supply electric power, even after it loses its excitation supply, by operating as an induction machine. It is then functioning at a slightly higher speed than that corresponding to system frequency. Consequently, the iron in its rotor's solid forging may overheat. A loss-of-field or loss-of-excitation relay usually disconnects the generator when it begins accepting excessive reactive power from the outside.

6.2.3.3 Automatic Load Shedding. System frequency is a sensitive measure of discrepancy between load and generation. In the normal operating state, the generation is adequate to supply the existing load and no equipment will be overloaded. If the system becomes overloaded and additional generation is not available, the frequency falls below 60 Hz. Control centers normally have equipment that will automatically disconnect blocks of load when the system frequency reaches prescribed values below 60 Hz.

6.2.4 Computer Control. Today most generation and load control systems are computer based. The computer can be programmed to provide format changes, to make comparisons between desired and actual data measurements, and to correct system operation. These processes are performed faster using a computer than they are performed by human or hard-wired logic controllers. The computer can also provide efficient entry, formatting, and storage of data. Computer control of generating and transmission stations can also greatly improve the security of the power systems. For example, the computer can:

(a) Improve the monitoring and display of information.
(b) Be programmed to evaluate contingencies and to develop corrective procedures.

6.3 SWITCHBOARDS. This section provides a general discussion of power and control switchboards, supervisory control equipment, and the automatic control of devices in generating stations and substations.

6.3.1 Power Switchboards. For small stations or substations, the main switching equipment and buses may be mounted directly on or adjacent to the board. For larger stations, the switching equipment and buses are always remotely located in separate buildings or enclosures, or outdoors. In these cases, the main switching equipment and buses are generally identified as bus structures. Power switchboards are also identified as:

(a) Direct control.
(b) Remote mechanical control.
(c) Electrically operated.

This section describes the various types of switchboards available to provide different functions.

6.3.1.1 Direct Control. Direct control panel-type switchboards are generally used for small and medium-capacity installations where a complete installation of only a few panels is required. They are designed for control of incoming lines, generators, motor-generator sets, induction and synchronous motors, feeders, light and power supply, control-power supply, and battery-charging equipment.

6.3.1.2 Live-Front. Live-front switchboards have the circuit breakers and switches mounted directly on the front of the panels and are generally limited to 250 VDC and 600 VAC. These are seldom used in modern designs.

6.3.1.3 Dead-Front. Dead-front switchboards have the breakers and switches mounted on the rear of the panels and are generally limited to a maximum of 600 VDC and 2,500 VAC. All designs are operated from the front, providing safety to the operator. Some types are also equipped with interlocking features that prevent access to live parts.

6.3.1.4 Control-Power. Control-power switchboards are used in generating stations and substations to provide a separate source of energy for the control of electrically operated apparatus. The voltages ordinarily used are 125 and 250 VDC. The switchboards generally include control for a storage battery, one or two motor-generators, and the required number of feeder panels.

6.3.1.5 Medium-Voltage. Medium-voltage metal-clad switchboards for 15,000 V or less, consist of equipment housed in steel compartments completely assembled by the manufacturer. This type of switchboard design is generally used for light, power, and station auxiliary power supply in large generating stations and industrial plants. It is also used extensively for AC substation switching. As all medium-voltage parts are enclosed, the equipment is interlocked to prevent mistakes in operation. All parts of the steel enclosure are grounded providing maximum safety to the operator for this class of switchboard. The secondary wiring is shielded, and barriers are provided between phases and between adjacent circuit breakers.

6.3.1.6 Electrically Operated. Electrically operated switchboards employ solenoid- or motor-operated mechanisms, some with stored-energy-type designs for circuit breaker operation. These are, in general, controlled from a central point or control board. This arrangement allows for the location of the control board to be independent of the location of the power board. Complete isolation of the high-tension equipment has been made possible.

6.3.2 Control Boards. The control of large power circuits by electrically operated breakers has effected the replacement of the switchboard by the control board. Several types of control boards are in general use. On these are mounted the necessary control switches, lights to indicate the positions of the breakers, indicating and recording instruments, and relays. The arrangements of devices on the boards are simple and distinctive to aid the operator in avoiding confusion and mistakes under normal and emergency conditions. The control and indicating devices of each main power circuit are clearly set off from those of other circuits. The assembly of the panels and the selection of the type of panel depend entirely upon the size and type of station and on local conditions.

6.3.2.1 Indicating Lamps. Indicating lamps are used to indicate breaker position; green lights indicating open breakers and red lights indicating closed breakers. White lights are sometimes included to be energized from potential transformers to indicate live circuits. Some stations include orange or another distinctive color to indicate that the circuit has tripped automatically. Red and green lights are commonly wired so that they are energized through the tripping coil and circuit of the breaker to supervise the trip circuit. An opening in the trip-coil circuit is then indicated by a dark lamp.

6.3.2.2 Mimic Bus. Mimic buses are frequently installed on the faces of control boards to aid operation, showing in miniature the bus and the circuit connections controlled by each control switch.

6.3.2.3 Auxiliary Circuits. Auxiliary circuits used on switchboards provide the following:

(a) The use of one instrument for several machines or circuits is made possible by the voltmeter bus and switches on plugs.

(b) Current supply for instruments and relays.

(c) Control power supply for operation of circuit breakers and switches.

(d) Annunciator or alarm circuits.

(e) Potential supply for relays.

(f) Synchronizing circuits.

(g) Test supply.

6.3.2.4 Ground Detector. Ground detectors are desirable on ungrounded systems so that immediate steps may be taken to clear a ground before a second ground occurs. The occurrence of a second ground, before the first has been cleared, could create a phase-to-phase short circuit.

6.3.3 <u>Supervisory Control Equipment</u>. Supervisory control equipment is often used to remotely control a number of devices from a distant location, using a minimum number of communication channels. The basic approach is to select, at one time, a single operating point and connect the control for that device to the communication channel to permit remote operation. Generally, only one device can be controlled at one time.

6.3.3.1 Functions. The functions normally performed by supervisory control include the following:

(a) Opening and closing circuit breakers and disconnect switches from the master station.

(b) Operating transformer tap changers and phase-angle regulator tap changers.
(c) The control of valves.
(d) Transmission of set points.

The supervisory equipment not only provides control from the master station, but is used to transmit position indications and metering from the remote to the master station. Another common function is the transmission of alarm conditions from the remote to the master station.

6.3.3.2 Old Systems. Until recently, most supervisory systems consisted of relay chains at the master and remote stations that were operated by pulse codes to select the proper operating point and then perform the control action. These systems use various pulse codes on either DC or audio-tone communication channels. Generally, the transmission speed is rather slow and is suitable for telegraph-grade channels.

6.3.3.3 New Systems. The latest supervisory system uses solid-state components rather than relays to generate and receive selection and operation codes. They usually operate over audio-tone channels using frequency-shift-type equipment and are capable of very high operating speeds. These systems can be operated over any high-speed communications channel including microwave, telephone, or power-line carrier. Bit rates of 1,000 bits per second or higher are common. This type of equipment often continuously scans the alarm and indication points. Telemetering is usually accomplished by converting from analog to digital form at the remote station and transmitting in digital form, a code similar to that for control being employed. Many modern installations display the telemetered quantities in digital form at the master station. Various control sequences and code-checking techniques are used to assure operation of the correct device and prevent false operation. By using modern equipment, a very high degree of security is possible.

6.3.4 Automatic Control. Automatic control is a combination of various devices, including relay operational amplifiers, magnetic amplifiers, and solid-state switches, which are used to automatically operate devices in generating stations and substations without operator intervention. Unattended substations are usually designed to operate automatically. The automatic controls normally provided in unattended stations include automatic circuit breaker reclosers, transformer tap changers or voltage regulators (to control voltage), and capacitor switches.

6.4 SAFETY AND ENVIRONMENTAL REQUIREMENTS. This section provides a discussion of the safety practices, environmental regulations, and occupational safety and health requirements that apply to the operation and maintenance of electric power distribution systems. Safety and health standards are prescribed by OSHA (29 CFR 1910) and the National Electric Code (ANSI/NFPA 70). OPNAVINST 5100.23B specifies program requirements and establishes standards for the safety and health of Navy employees. Activity Safety Offices maintain copies of these publications. Do not hesitate to ask for their assistance. Make sure that proper protective equipment and devices are used, hazardous work is preplanned, safety and rescue equipment is readily available, tools and equipment are properly maintained, employees are trained in CPR and rescue techniques, and alcohol is not consumed during the duty day or 8 hours prior to the shift.

6.4.1 Safety Practices. Safety related work practices should be used to protect personnel from injury while they are working on or near electric circuits and equipment. Personnel should be trained in the safety related work practices, safety procedures, and other personnel safety requirements that pertain to their respective job assignments. Personnel should not be permitted to work in an area where they are likely to encounter electrical hazards unless they have been trained to recognize and avoid the electrical hazards to which they will be exposed. An electrical hazard is identified as a dangerous electrical condition. Examples of electrical hazards are exposed energized parts and unguarded electrical equipment which may become energized unexpectedly. Specific work practices are required for work under three separate conditions, as outlined in the following subparagraphs.

6.4.1.1 Work On or Near Deenergized Circuits and Equipment. When work to be performed requires personnel to work on or near exposed circuit parts or equipment, when danger of electrical shock; unexpected movement of equipment, or other electrical hazards, the circuit parts and equipment that endanger the personnel should be deenergized, locked out, tagged out and tried out. This shall in accordance with established Lockout-Tagout-Tryout procedures. These Lockout-Tagout-Tryout procedures should include procedures for implementation responsibility, training, and coordination with other procedures. They should also contain detailed requirements for administration, deenergization of circuits and equipment, application of locks and tags, verification of deenergized condition, tryout, coordination during shift changes, restoration of electric service, testing, and temporary operation. The Lockout-Tagout procedures should be appropriate for the voltage rating and complexity of the electric circuits and equipment in the workplace. The procedure should also be appropriate for the various personnel involved, and other conditions in the workplace that are likely to endanger personnel who work on or near deenergized circuits and equipment.

6.4.1.2 Work Near Exposed Circuit Parts (Energized or may Become Energized). Where it is not feasible to deenergize and lock out or tag out electric circuits and equipment, personnel should be permitted to work near exposed electric conductors and circuit parts provided that the appropriate work practices and safeguards are implemented to protect personnel from injury. Personnel should be instructed to consider all exposed conductors and circuit parts to be energized and dangerous. Safety related work practices shall be used to prevent electric shock or other electrically induced injuries when work is performed in the proximity of exposed electric conductors or circuit parts that have not been deenergized and locked out or tagged out in accordance with subparagraph 6.4.1.1. Such work practices should include the use of safeguards to prevent personnel from contacting energized circuit parts directly with any part of their body and indirectly with the use of conductive wearing apparel, conductive materials or equipment, conductive tools, or some other conductive object. These work practices should include considerations such as employee alertness, illumination of the work space, wearing of conductive apparel, likelihood of contact with conductive materials and equipment, use of insulated tools, use of protective shields, use of proper portable ladders, work in confined spaces (such as manholes and vaults), work on overhead lines, and performance of housekeeping or janitorial duties.

6.4.1.3 Work on Electric Circuit Parts or Equipment (Has Not Been Deenergized and Locked or Tagged Out). Personnel should not be permitted to work on electric circuit parts or equipment that has not been deenergized, locked out and tagged out, unless they are qualified and trained to use safe work practices on such circuit parts or equipment. Safety related work practices should be used to prevent electric shock or other electrically induced injuries when personnel work on electric conductors or equipment that has not been deenergized. Only qualified personnel, who have been trained to work safely on energized circuits, should be permitted to work on conductors or circuit parts that have not been deenergized and locked out or tagged out in accordance with the procedures in subparagraph 6.4.1.1. The personnel, when appropriate, must also be trained to use proper protective equipment (i.e., insulating shielding materials and insulated tools). Only qualified personnel trained to work safely with test instruments and equipment on energized circuits should be permitted to perform test work on electric circuits or equipment where there is danger of injury due to accidental contact with energized parts or improper use of the test instruments and equipment.

6.4.1.3.1 Qualified personnel are those individuals that the Utilities Superintendent and Electrical Foreman judge to have sufficient experience for an assigned task.

6.4.2 Environmental Regulations. The major environmental regulations in force in the U.S.A. are those enforced by the Environmental Protection Agency (EPA). The materials used in electrical materials and equipment are very similar to those used in various other industries and in commercial products. The exception to this is Askarel, which is a polychlorinated biphenyl (PCB) that is strictly regulated under the Toxic Substances Control Act (TSCA). Askarel is a generic term (also a trademark of the Monsanto Co.) for a group of synthetic, fire resistant, chlorinated aromatic hydrocarbons used as electrical insulating liquids. Askarels are now prohibited for use in new electrical equipment, however, their use continues in existing equipment. Askarels were most often used as the insulating liquid in capacitors, as well as in indoor liquid-immersed transformers. The TSCA classifies capacitors and transformers into three categories and regulates them accordingly: (1) Non-PCB equipment, containing less than 50 parts per million (ppm) PCB, is not regulated by the TSCA; (2) PCB contaminated equipment, containing from 50 to 500 ppm PCB, is regulated by the TSCA; and (3) PCB equipment, containing 500 ppm or more PCB, is regulated by the TSCA. The TSCA has prohibited the use of askarels in existing electrical equipment in a few industries, such as in the food processing and handling industry and in the livestock feed industry. Disposal of askarels is also strictly regulated. Special disposal procedures must be followed in the cleanup of askarel spills or leaks and disposal can only be done at specific hazardous waste treatment sites or dumps. Disposal of the PCB equipment is regulated similarly. PCB equipment must be clearly identified with EPA approved labels and records must be kept for all PCB equipment. PCB contaminated equipment does not have the record keeping requirements of PCB equipment. Spills of 50 ppm (or greater than 50 ppm) PCB contaminated liquids, however, still require the special cleanup procedures.

6.4.3 Occupational Safety and Health Requirements.

6.4.3.1 Safety Requirements. The existing portions of the act generally govern the installation of electrical systems and do not attempt to cover the operation and maintenance of the electrical systems. This latter area is at the present time the subject of hearings and testimony pursuant to an OSHA rule making proposal on electrical safety related work practices, which was published in the November 30, 1987 Federal Register. This proposal would:

(a) Add a new standard on electrical safety related work practices for general industry.

(b) Revise references to the OSHA electrical standards.

(c) Remove existing work practice requirements from other parts of the OSHA general industry standards. This will ensure that all general electrical safety related work practices would be covered by the electrical safety standards proposed and remove an existing provision relating to construction from the general industry standards.

The OSHA standards, both existing and proposed, are based on consensus industry standards such as the National Electrical Code (ANSI/NFPA 70) and Electrical Safety Requirements for Employee Workplaces (NFPA 70E). As such, they should certainly serve as a guideline for NAVFAC to use in its operations. In accordance with ANSI C2 National Electrical Safety Code specifically for Distribution System installation, maintenance and operation.

6.4.3.2 Health Requirements. Health requirements have received renewed attention due to the May 23, 1988 effective date of the OSHA Hazardous Material Communication Standard. This OSHA standard requires all industries to advise their employees of the presence of hazardous materials in the workplace. Warnings are required to be posted and Hazardous Material Safety Data Sheets (MSDS) must be maintained and posted. Examples of materials used in electrical systems include mineral oil (used for insulating liquids), various cleaning fluids, cable pulling compounds, greases used for lubricating motors, protective coatings, and paints, etc.

CHAPTER 7. ELECTRICAL UTILIZATION SYSTEMS.

7.1 SYSTEM VOLTAGES. The most common utilization voltage in United States industrial facilities is 480 V. Other voltage levels depend upon motor size, utility voltage available, total load served, potential expansion requirements, voltage regulation, and cost. The system must be capable of providing power to all equipment within published voltage limits under all normal operating conditions.

The preferred utilization voltage for industrial plants is 480Y/277 V. Small dry-type transformers are utilized to provide 480-208Y/120 V or 480-120/240 V service.

Some loads, particularly large motors above 200 horsepower (hp), can often be served more economically at voltages above 600 V. When the plant primary voltage is suitable, these large loads may be served directly at primary voltage. For example, motors over about 200 hp may be served directly from 2400 V primary systems, motors over 250 hp from 4160 V systems, motors over 1000 hp from 6900 V systems, and motors over 2000 hp from 13.8 kV systems. Large motors, or a group of scattered motors, may be served directly from the medium-voltage primary feeders or through a transformer.

7.2 EQUIPMENT NAMEPLATE RATINGS AND NOMINAL SYSTEM VOLTAGES. This section provides a discussion on the requirements and usage of equipment nameplate ratings and the effect of deviations in the nominal system voltage from these ratings.

7.2.1 Nameplate Ratings. Utilization equipment is defined as electric equipment which uses electric power by converting it into some other form of energy. Light, heat, or mechanical motion are a few examples of converted energy. Each component of the utilization equipment requires a nameplate. The nameplate must list the nominal supply voltage for which the equipment is designed. Most utilization equipment (except motors) carries a nameplate rating which is the same as the voltage system on which it is to be used (e.g., equipment to be used on 120 V systems is rated 120 V; equipment to be used on 208 V systems is rated 208 V, etc.).

7.2.1.1 Single-Phase Motors. Single-phase motors for use on 120 V systems have been rated 115 V for many years. Single-phase motors for use on 208 V single-phase systems are rated 200 V, and for 240 V single-phase systems they are rated 230 V.

7.2.1.2 Three-Phase Motors. Prior to the late 1960s, low-voltage three-phase motors were rated 220 V for use on both 208 and 240 V systems; 440 V for use on 480 V systems; and 550 V for use on 600 V systems. Nameplate ratings for new motors are 200 V, 230 V, 460 V and 575 V; for use on 208 V, 240 V, 480 V and 600 V systems, respectively.

7.2.2 Effect of Voltage Variations. When the voltage at the terminals of utilization equipment deviates from the value listed on the nameplate of the equipment, the performance and the operating life of the equipment is affected. The effect may be minor or serious depending on the characteristics of the equipment and the amount of the voltage deviation from the nameplate rating. Generally, performance conforms to the utilization voltage limits, but it may vary for specific components of voltage-sensitive equipment. In addition, closer voltage control may be required for precise operations.

7.2.2.1 Induction Motors. Motor voltages below the nameplate ratings result in reduced starting torque, increased full-load temperature rise, and increased load current. Motor voltages above nameplate ratings result in increased torque, increased starting current, and decreased power factor. The increased starting torque will increase the accelerating forces on couplings and driven equipment. Increased starting current causes greater voltage drop in the supply circuit and increases the voltage dip on lamps and other equipment. In general, voltages slightly above nameplate ratings have less detrimental effect on motor performance than voltages slightly below nameplate ratings.

7.2.2.2 Synchronous Motors. Synchronous motors are affected by variations in voltage in the same manner as induction motors, except that their speed remains constant (unless the frequency changes). Additionally, their maximum or pullout torque varies directly with their voltage, if the field voltage remains constant. If the field voltage varies with the line voltage, as in the case of a static rectifier source, then the maximum or pullout torque varies as the square of the voltage.

7.2.2.3 Incandescent Lamps. The light output and life of incandescent filament lamps is critically affected by voltage. The light output decreases with lower voltages but the life of the lamp increases. The reverse is true for higher voltages.

7.2.2.4 Fluorescent Lamps. Fluorescent lamps, unlike incandescent lamps, operate satisfactorily over a range of +/- 10 percent of the ballast nameplate voltage rating. Light output varies approximately in direct proportion to the applied voltage. Thus a one percent increase in applied voltage will increase the light output by one percent and, conversely, a decrease of one percent in the applied voltage will reduce the light output by one percent. The life of fluorescent lamps is affected less by voltage variation than that of incandescent lamps. The voltage-sensitive component of the fluorescent fixture is the ballast, a small reactor or transformer which supplies the starting and operating voltages to the lamp and limits the lamp current to design values. These ballasts may overheat when subjected to above normal voltage and operating temperature.

7.2.2.5 High-Intensity-Discharge Lamps (Mercury, Sodium, and Metal Halide). Mercury lamps using the conventional unregulated ballast will have a 30 percent decrease in light output for a 10 percent decrease in terminal voltage. If a constant wattage ballast is used, the decrease in light output for a 10 percent decrease in terminal voltage will be about 2 percent. The mercury arc will be extinguished at about 20 percent undervoltage. The lamp life is related inversely to the number of starts. If low-voltage conditions require repeated starting, the lamp life will, therefore, be reduced. Excessively high voltage raises the arc temperature which could damage the glass enclosure if the temperature approaches the glass softening point. Sodium and metal halide lamps have similar characteristics to mercury lamps, although the starting and operating voltages may be different.

7.2.2.6 Capacitors. The reactive power output of capacitors varies with the square of the impressed voltage. A drop of 10 percent in the supply voltage, therefore, reduces the reactive power output by 19 percent.

7.2.2.7 Solenoid-Operated Devices. The pull of alternating current solenoids varies approximately as the square of the voltage. In general, solenoids are designed to operate satisfactorily on 10 percent overvoltage and 15 percent undervoltage.

7.2.2.8 Solid-State Equipment. All solid-state devices are very sensitive to change in voltage and temperatures with respect to time. All solid-state circuits, therefore, incorporate adequate regulation circuitry which then makes the devices very stable.

7.3 STREET LIGHTING SYSTEMS. For many years lighting service was powered by special circuits that could be energized only during periods when lighting was required. These special circuits usually had many lights connected in series. They, therefore, operated at a fairly high voltage and low current and were operated manually or by time-clock-controlled switches. Modern circuits use photoelectric controls which have a high order of reliability at reasonable cost. Photoelectric controls make it feasible and economical to connect streetlight luminaires directly to area distribution. This eliminates the separate circuits and control systems.

7.3.1 Multiple-Circuits. Multiple lighting is used extensively today and is usually connected directly to local low-voltage (120, 208, 240, or 277 V) distribution. The lights ordinarily are controlled by photocells. For special applications they may be operated continuously or may be switched by time clocks, pilot wires, carrier-current signals, or other means.

Lamp units used for multiple street lighting originally were incandescent bulbs ranging in size from 100 to 1,000 watts (W). Today there is a much broader range, including fluorescent and high-intensity discharge lamps (mercury vapor, high pressure sodium, and metal halide). All lamps are available in a wide range of mountings designed to direct the light output in a variety of patterns to match requirements, as well as in a choice of designs to suit the environment.

7.3.2 Series Street Lighting. Series street lighting is still extensively employed. Unlike general distribution, it is powered by a variable-voltage constant-current system.

7.3.2.1 Constant-Current Transformers. Constant-current transformers are commonly used to supply current, usually 6.6 or 20 A to the many lamps connected in series. The moving-coil constant-current transformer is a single-phase device with inherently high leakage reactance. Movement of the coil varies this reactance automatically to maintain constant-current output. The transformer is capable of regulating current within 1 percent for all loads within its rating, at any supply voltage within 5 percent of normal, and with any ordinary variation in frequency and temperature. Full-load power factor is approximately 75 percent and three-fourths load power factor is about 56 percent. Input kVA is substantially constant over the entire range of loads. In certain designs, capacitors improve the low power factor to a value near unity for normal loads. The indoor or station type of constant-current transformer is supplied from the substation high-tension bus. Indoor ratings vary from 5 to 70 kW, with 30 kW and 60 kW being the most popular. The secondary winding of larger ratings is usually designed with two coils, and leads from each coil are cross-connected to supply two series circuits. The pole- and submersible-type constant-current transformers are built in sizes from 2 to 30 kW in oil-filled tanks, usually with capacitors. They are mounted in the immediate vicinity of the lamps they supply, thus realizing economy in circuit construction. Distribution primaries supply the constant-current transformers with single-phase power.

7.3.2.2 Series Circuits. Current in a series circuit passes directly, without transformation, through the lamps and circuit. Most circuits operate at 6.6 A. Circuits serving large lamps in the heart of a city often operate at 20 A. Series circuits are usually carried on the same crossarms with primary wires in overhead distribution and in separate ducts or pipes in underground distribution. In parkways, series-circuit cables are often buried. Individual lamps are provided with series cutouts which automatically close the circuit when lamps are removed. A film cutout designed to puncture at about 1,000 V is connected across terminals of each lamp; if the lamp filament breaks or burns out, the film cutout is punctured, the lamp is short-circuited, and the circuit remains closed.

(a) Series circuits may be laid out on the parallel- or the open-loop plan. In the parallel-loop, outgoing and incoming wires of the circuit are carried along the same route; in the open-loop plan, the circuit goes out along one street and returns by another. The parallel-loop requires greater mileage of wire to supply lamps in a given area than the open-loop method.

(b) Three disadvantages of the series circuit are:

- The necessity for insulating lamps, leads, fixtures, and circuits for full operating voltage to ground.
- The large exposure of circuit wire in which a break causes interruption to all lamps.
- The economic necessity of installing streetlighting wires on the same crossarm with primaries, causing wire congestion and exposing other distribution to possible faulting if a streetlighting wire breaks.

CHAPTER 8. MANAGING THE OPERATION OF ELECTRICAL DISTRIBUTION SYSTEMS.

8.1 OPERATIONS OVERVIEW. The electrical distribution system performs the function of transforming and distributing electric power throughout the facility of concern. The system includes the electrical equipment necessary to receive the electric power, transform the voltage to the different utilization levels, and to control and distribute the electric power to the various electrical loads. By inference from the title of this chapter, the discussion is limited to specifically exclude the operation of generation plants that may be on site.

This chapter is divided into three main sections. The first section discusses the day-to-day operation of the electrical distribution system, the second section discusses maintenance of the electrical distribution system, and the third section discusses system planning studies. These areas require more than just day-to-day personnel supervision. There must be attention directed to operations, maintenance, and planning for the various short term and long term needs of the electrical distribution system.

8.2 OPERATIONS MANAGEMENT. Every electrical distribution system is unique. This manual, therefore, does not contain operating procedures detailing specific functions for a particular distribution system. It is incumbent on the Operations Command Structure to have, in place, sufficient operating procedures that are specific to the site and the system of concern. This section will discuss procedures and considerations that are believed necessary and of importance for operating personnel to safely and efficiently operate electrical distribution systems. This section discusses the operation of an electrical system from the point of receipt of power at the source or receiving station(s) to the points of load utilization. Additionally, this section will discuss various areas of consideration in the operation of the electrical distribution system.

8.2.1 Operating Procedures. Each electrical distribution system should have an operating procedures manual. For small simple systems, fed from utility services and consisting of one main incoming service with a few radial feeders, this manual might consist of only a few pages of simple instructions on the sequence of switching the main and feeder switching devices. More complex systems, however, often require operating manuals consisting of hundreds of pages and describing the details of various portions of the system. The manual, regardless of the size, must contain up-to-date information of the equipment contained in the system. It should also reflect the operating modes used, rather than those that might have been envisioned years previously for a system whose configuration and capabilities has been extensively modified.

The operating procedures manual should illustrate how to energize the entire system from the point of connection (to the power source) to the lowest utilization voltage level. It should have sufficient detail; including drawings, figures, and tables, so that reference to vendor manuals, equipment drawings, and other documents should not be necessary to operate the distribution system. The manual should also describe the functions of the electrical distribution system and the individual equipment providing the operating capabilities of the various components. This should include the continuous, short time, and emergency ratings of all transformers, switchgear, distribution panels, motor control centers, and feeder cables. It should relate the operating modes of the electrical distribution system under various system configurations and describe in detail the step-by-step procedures necessary to energize the entire system. It should detail the step-by-step procedures necessary to alter system configurations, describe the various alarm, trouble, fault detection and equipment shutdown systems provided. The operations manual should describe the analysis of various annunciator, alarm, protective relay, and equipment shutdown systems, including various checklists, as necessary, to indicate possible causes of the trouble indication. It should, additionally, contain suggested courses of action, indication of the effect of the trouble on system operation, and the means of restoration of service to the affected area. The operating manual should also contain, as a minimum, one-line diagrams of the entire electrical distribution system that are up-to-date and contain each equipment size and rating. For systems that can have multiple operating configurations, the one-line diagrams should indicate the normal operating position of the circuit switching devices that may be used to alter system operating configurations. This should include all bus tie breakers and switches, circuit sectionalizing devices, incoming breakers from multiple sources, if all sources are not energized simultaneously. This does not mean, however, that all radial feeder breakers must have their position shown, as it is understood that they must be closed for the system to function normally. When system equipment is replaced or modified, the drawings must be revised to reflect the changes made; the operating manual should be revised if the change could affect the operating modes of the system.

8.2.2 Routine Operation. The normal operation of a well designed electrical distribution system should not involve day to day operating changes. If a generating plant is on site, the operation of the distribution system is often integrated with the operation of the generating plant. The generating plant system operators, therefore, also serve as operating personnel for the electrical distribution system. If there is no generating plant on site, the maintenance personnel of the electrical distribution system provide both maintenance and operation of the system.

A system is normally operated automatically by installed equipment. Even though the distribution system can operate without intervention by personnel, collection of operating data by the personnel can be beneficial to the routine operation of the system. The data can provide information for other personnel involved in the maintenance, design, or analysis of system performance. Routine readings should be kept of major bus operating voltages, feeder operating currents, feeder kilowatt loads; including peak demands, feeder power factors, and energy consumption (kilowatt-hours) for major sub-portions of the distribution system. Energy consumption records may be required by accounting personnel to properly allocate costs of electric power to various subunits, however, this information is also useful for analysis of system operating factors. Use of modern electronic watt-hour meters, having advanced recording features on internal microcomputers, allows the data to be retrieved with personal computers by the usage of modems. The software allows detailed analysis of system operations and production of detailed reports showing almost all of the major parameters (voltage, current, power factor, demand load, kVAR load, and energy consumption) for individually configurable report formats. If such advanced recording devices are not installed, then the use of traditional chart recorders should be considered for key operating parameters. The recorders should be used at least for temporary periods to establish normal load cycles (time of daily, weekly, monthly, etc. peak loads), system voltages, power factors, and currents during these conditions. Recording the voltages, power factors, and currents during light load conditions is also important to determine the overall operating profile of the system.

Use of relatively inexpensive microcomputer load flow analysis programs, which have only become available in the last few years, can be very useful in determining the optimum operating configurations for the electrical distribution system. With the knowledge of peak and minimum load information and the use of the load flow analysis program, possible problems such as low voltage, overloaded conductors and equipment, and alternative operating configurations, during system forced and planned outages, can be analyzed and the appropriate corrective action planned easily and quickly. In the past, these tools were not available to the operating personnel. Many catastrophic failures occurred as a result, due to the lack of adequate and timely information.

8.2.3 System Disturbances or Outages. Even though the electrical distribution system normally operates for many days without any change in system configuration and without any disturbances or outages to utilization equipment, there is always the chance of a fault or overload that will result in an electrical disturbance or outage. The term outage, as used here, is the complete absence of power at the point of use. The term disturbance is used for the temporary departure from normal of one or more of the parameters of electric power at the point of use. This includes such terms as sag, dip, surge, spike, impulse, noise, and phase shift. The more usual disturbances involve line voltage impulses, noise, transients, steady-state voltage change, or a combination of these disturbances. Studies indicate that 90 percent of the disturbances are less than one second in duration and 80 to 85 percent involve only one phase of a three-phase system. Disturbances are usually classified by time duration, with disturbances lasting over one minute usually being classified as an outage. The ranges of classification involve an overlap of the categories to some extent, although their use is not mandatory.

8.2.3.1 One Second to One Minute. These disturbances are usually attributed to severe faults on one or more phases and are manifested by 50 to 100 percent voltage loss on one or more phases. Often caused by lockout relays on circuit protective devices, this type of disturbance results in an outage to the system on the cleared side of the fault, however, on the power source side of the fault it is a disturbance. The cleared side of the fault refers to the system downstream from the overcurrent or short-circuit protective device, which, when it operates, opens the circuit and thus de-energizes the downstream system and clears the fault. The power source side of the fault is the system upstream from the overcurrent or short-circuit protective device, and which, after device operation, is still connected to the remainder of the power system and remains energized.

8.2.3.2 10 to 40 Cycles. These disturbances are classed as sags or surges due to the operation of relatively slow speed switching devices, operation of tap changers on transformers and voltage regulators, and the starting of motors.

8.2.3.3 0 to 8 Cycles. These disturbances are classed as surges, or more commonly sags, due to the operation of fuses or high speed switching devices. Inrush currents result from energizing electrical equipment. A single-phase load on a multi-phase source may cause a surge on the unloaded phases while causing a sag on the loaded phase.

8.2.3.4 0.001 to 1 Cycles. These disturbances are usually caused by surge arrester operation, capacitor switching, and short duration faults.

8.2.3.5 Less Than 0.001 Cycle. These disturbances are generally classed as impulses; the most severe of these are caused by natural lightening, electrostatic discharge, and switching of nearby loads.

The above paragraphs illustrate that the electrical distribution system may ride through most disturbances without change. The utilization equipment, however, may be unable to tolerate a disturbance. It may operate improperly, fail to operate, or operate in a such a way, that if continued, may cause equipment failure or danger to personnel and operations. These factors must be taken into consideration at the time of the design and installation of the utilization equipment. Although this problem is most often encountered with various types of electronic equipment, it can also effect mundane equipment such as fluorescent and sodium vapor light fixtures. Since ideal power quality and continuity can seldom be obtained from the supplying utility, the effects of power supply disturbances can be reduced to acceptable levels using the following methods:

(a) Modify the design of the utilization equipment to be impervious to power disturbances and discontinuities.

(b) Modify the power distribution system to be compatible with the utilization equipment.

(c) Modify both systems and equipment to meet a criterion that is realistic for both.

(d) Interpose a continuous electric supply system between the prime source and the utilization equipment. This will, however, act as a buffer to external sources of disturbances, but could increase the magnitude of load induced disturbances.

Common solutions to the problem of electrical disturbances are filters, power conditioners, surge arresters, capacitors, solid-state motor starters, adjustable frequency motor drives, uninterruptible power supply systems, isolating transformers, and revisions to grounding systems. Since disturbances by their definition last less that one minute (most last less than one second) it is obvious that the distribution system must be designed and installed to operate automatically without operator intervention to overcome the affects of disturbances. When outages occur, an alarm or annunciator system should be used to provide operating or maintenance personnel an indication of the time of occurrence and location of the outage. This will allow prompt implementation of the restoration of electrical service to the affected area. The following procedures must be in place for the personnel to follow, so that a systematic method will be used:

(a) Report the problem and document the cause of the outage.
(b) Change the system configuration as required to restore service.
(c) Schedule repairs, if necessary.
(d) Make the appropriate repairs or equipment replacements.
(e) Restore the system to its normal operational configuration.

These personnel procedures should be performed in a timely and safe manner. When an outage occurs on the electrical distribution system, a thorough investigation should be made to determine the cause of the outage. The system configuration should be changed to remove damaged equipment from service. The system power should be restored after a check for safety has been made that determines that power can be restored. The safety considerations should include checking for possible damage to equipment, both upstream and downstream of the suspected fault location, and the changing of certain switching devices to the off position, so that the unexpected return of power to certain equipment may not cause injury to personnel or damage to equipment. These considerations should be a part of the operating procedures manual discussed in paragraph 8.2.1.

8.2.4 Power Quality. Power quality is usually measured by the amount of deviation from the nominal parameters that the steady-state power supply encounters. The usual parameters measured are the voltage and frequency, since the current is a function of the load level on the system. Measurements made on the system, or feeder voltage, usually include the magnitude. The phase angle might also be included when a significant unbalance is suspected due to large loading on single phases of a multi-phase system. The frequency magnitude is also measured. If harmonics are causing a problem, then the various harmonic frequencies can be measured, as well as the voltage of each harmonic. In order to perform the latter tests, sophisticated recording devices with fast response times and frequency spectrum analysis capabilities must be used. If the purchase of equipment is not deemed economical, then it can be rented from one of several sources. Additionally, if power disturbances are causing operating problems, then special transient recording devices must be used. These devices are used to record and monitor the system parameters over a set time period and provide sufficient data to determine the probable cause of the disturbances. This equipment is also costly; similar to harmonic analysis equipment, the optimum solution may be to rent the equipment, as necessary. Specialized training is usually required to operate this test equipment.

System voltages normally operate within a steady-state range of 5 percent plus to 10 percent minus the nominal system value. This range corresponds to Voltage Range A (referenced in ANSI C84.1, American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz)). The voltage range tolerance limits in ANSI C84.1 were established based on the voltage tolerance limits of ANSI/NEMA MG-1, which establishes the voltage tolerance limits of the standard induction motor. Since motors are the major component of utilization equipment load on distribution systems, they were given primary consideration in the establishment of the voltage standard. Use of the voltage range values in ANSI C84.1 can be determined for any system voltage because the numbers are established on a 120 V Base. The proper voltage range for higher voltage systems, therefore, can be taken by multiplying the transformation ratio of the system times the Base voltage range values. ANSI C84.1 specifies the voltage at the two important points in the system. The first, is the maximum and minimum at the point of receipt from the power source. The second, is the minimum at the point of utilization. It also provides recommended allocations for the voltage drop in the primary distribution system, in the final distribution transformer, and in the final utilization voltage wiring from the last transformer to the utilization device. Consideration in developing the recommended ranges included the effects of high and low voltage on motor and lighting equipment lifetime, output, and starting characteristics.

8.2.4.1 Voltage Regulation. Voltage regulation, by definition, is the percentage change in secondary voltage from no-load to full-load conditions. The regulation is customarily specified at a specific power factor, as the power factor of the load affects the voltage regulation of the device or circuit. Voltage regulation cannot be improved by the use of the conventional no-load tap changer on a transformer. The tap changer merely changes the transformer turns ratio, but does not significantly change the transformer impedance. The regulation (percent change from no-load to full-load) will, therefore, not change. The operating voltage range will, however, change and affect the performance of the utilization equipment. As mentioned previously, load flow studies should be performed and operating conditions (no-load, light-load, or full-load) examined to ensure that voltage tolerance ranges are not exceeded. If voltage tolerance ranges are exceeded, then one alternative is to adjust transformer taps to compensate for either high voltage, at no-load or light-load conditions, or low voltage, at full-load conditions.

Capacitors of either switched or fixed configurations can also be used to correct the voltage range profile of a distribution system. Often, for large complex systems, the use of switched capacitors is the only realistic solution for a voltage range that is too wide. In this instance, capacitors are switched off-line when the load is light, so that the voltage does not become too high. As the load increases, capacitors are switched on-line to prevent the voltage from becoming too low. For maximum benefit, capacitors should be located close to the load that is causing the problem, however, this is often not technically or economically feasible.

Synchronous motors can also be used to good advantage on large power systems if the 0.8 power factor design is purchased, rather than the less expensive unity power factor motor. The 0.8 power factor synchronous motor can be used to improve voltage levels on its utilization bus in the same manner as capacitors. Both devices act as a source of reactive power (VARs) to the system. Control of the operating voltage range can also be achieved by the use of transformers with on-load tap changers and line regulators. Both devices use multi-tap devices, in combination with voltage sensing and control apparatus, to adjust the transformer ratio or regulator ratio by actively switching taps as the steady-state load changes. These devices are usually used by utilities in the primary distribution system and provide the final distribution circuits with a voltage range within the Range A limits of ANSI C84.1. Unless the site distribution system is unusually large and complex, and the daily load fluctuations quite large, these devices are not applied to electrical distribution systems on facilities.

8.2.4.2 Power Factor Control. Power factor can be controlled using the same methods as those used for controlling the voltage. Capacitors and synchronous motors can be switched or adjusted (either manually or automatically) to achieve a desired power factor. A high power factor (one close to unity or 100 percent) is generally desirable. When the various feeder and utilization circuits are operated at a high power factor, voltage drops and losses are minimized throughout the system. This is one way to achieve more load handling capability. There is more equipment capacity available for real loads, if the reactive (kVAR) portion of the load is reduced, since most system devices are current sensitive. Often distribution systems are found operating at power factors in the 70 percent range. If the power factor can be increased to the 90 - 95 percent range, then the operating load on the equipment can be increased by 25 - 35 percent. It is, however, frequently undesirable to operate the distribution system in the leading power factor range. Operating the system with a leading power factor can possibly cause unstable transients. Since most loads are inductive in nature, it is usually difficult to get the distribution system power factor into the high 90 percent range. It is even more difficult to achieve unity power factor.

Improved power factor control can release equipment for surplus use or make available additional load capacity with no change in the system configuration. The cost is usually nominal, especially when compared to the cost of new transformation equipment, switchgear equipment, and larger sized cables.

8.2.4.3 Harmonics. Harmonics on the distribution system is an increasing problem resulting from the growing use of solid-state switching devices in equipment, such as adjustable frequency drives, rectifier power supplies, high frequency power supplies, uninterruptible power systems, and arc discharge lamps. ANSI/IEEE 519, Guide for Harmonic Control and Reactive Compensation of Static Power Converters, contains guidelines on input power sources for the maximum harmonic content total not to exceed 5 percent and the maximum for any one harmonic not to exceed 3 percent of the fundamental frequency. Harmonic distortion is calculated by using the square root of the sum of the squares of each of the harmonic amplitudes (expressed as a percentage of the fundamental). Various means, usually filters, inductors, or capacitors, are used to reduce the effect of harmonics caused by loads on the system and on other loads.

8.2.4.4 Frequency. The system frequency regulation is generally determined by the serving utility. Most utilization equipment will operate satisfactorily over a frequency range of +/- 5 percent, however, most electronic equipment requires a tighter range of +/- 0.5 to 1 percent. This degree of frequency regulation is easily achieved by the use of utility grids in the continental United States. Systems fed from isolated generation sources or those located in certain foreign countries may experience frequency variations outside the range required by electronic equipment. These conditions may then require special static power supplies for such sensitive electronic equipment.

8.2.4.5 Voltage Unbalance. Voltage unbalance on multi-phase systems is usually limited to a maximum of 3 percent. Unequal distribution of single-phase loads will increase the amount of voltage unbalance. Whenever possible, effort should be made to distribute the load evenly between the phases. Excessive phase voltage unbalance can cause excessive heating to three-phase devices such as motors. Additionally, high ripple may be observed in some three-phase AC/DC power supplies if the voltage unbalance is too high.

8.2.5 Operational Improvements. System configurations should be designed and installed with provisions for future expansion, or possible changes in the system configuration, and improvements to the system equipment. Operational improvements may be required resulting from increased load on the system or the addition of a different type of utilization equipment (which may require a different voltage or frequency to operate properly or a better quality supply than that available). In these situations, the system must carry more load than originally anticipated in the design. Increasing the distribution voltage(s) and increasing transformer capacity by the addition of cooling fans are two methods used on existing equipment to modify and successfully fulfill the new load requirements. The improvement in system power factor may release additional system capacity for utilization to serve new loads, rather than being wasted on the reactive power requirements of the existing system configuration.

8.2.5.1 Increasing System Distribution Voltage. This technique is often used on overhead pole line type distribution systems to increase system capacity. The system must have transformers that are capable of operating at the new voltage. This method, therefore, is usually limited to systems consisting of many single-phase transformers operating in three-phase banks which can be reconnected on their primary side from delta to wye without change to the transformer's operating voltage. The system voltage is generally increased by a factor of the square root of three (e.g., from 2400 V to 4160 V), the transformers are reconnected, and the new load is added onto the line at new transformer locations. of course, the existing transformers cannot carry additional load, but the individual distribution circuit's load capacity has increased by the square root of three, or 1.732. If excessive voltage drop is a problem, then the same solution can result in better voltage regulation at the end of heavily loaded circuits, as the load current of an existing load is reduced by the same factor. Load losses vary as the square of the voltage, so an increase.in the operating voltage in the example by a factor of 1.732 will result in reduced losses by a factor of three. This method cannot be used if the distribution equipment, such as the cable, switchgear, or transformers are not rated for the increased voltage. On more modern systems (consisting of three-phase transformers, underground cable, and metal-clad switchgear), the equipment is usually operated at or near its design voltage ratings. A simple increase of system voltage, therefore, cannot be used to increase system capacity. In these cases, the practical solution is often to superimpose a new higher voltage distribution system on top of the existing system, and to serve the old loads from transformer substations. These substations should convert the supply voltage from the new system distribution voltage to the old one. For example, a newer 13.8 kV distribution system might be superimposed over an older 4.16 kV system, with several 13.8 kV to 4.16 kV substations installed to serve the old portion of the distribution system. All new loads, however, would be fed by the 13.8 kV distribution system with direct transformation to the utilization voltage (e.g., 13.8 kV to 480 V).

8.2.5.2 Installation of Transformer Fans. When the load increases to, or above, the transformer capacity at an existing substation, fans are often used to increase the transformer load handling capacity by a factor of 15 to 25 percent (depending upon the size of the transformer). The transformer bushings, primary and secondary load cables, switchgear or fuses, and other factors must also be investigated to assure that there are no other weak links in the system that may prevent full capacity utilization of the transformer's inherent capability. This should be included as part of the design criteria of the initial installation of the transformer equipment. The primary and secondary cables, bushings, and primary and secondary switchgear should all be sized to provide greater load carrying capability than the transformer. Then, as the need arises, the transformer capacity can be increased relatively inexpensively by the addition of fans. The other devices, such as bushings, cables, and switchgear cannot be inexpensively changed to achieve the same capacity increase, therefore, this capability should be provided upon initial installation.

8.3 MAINTENANCE MANAGEMENT. Every distribution system is unique in its configuration, load, and types of installed equipment. This section provides general guidelines regarding the requirements of a proper Electrical Distribution System Maintenance Program. In both the long term and in the day-to-day operation of the system, maintenance must be performed in order to preserve a reliable source of electric power. Often, however, it appears that an electrical system requires no maintenance.

ANSI/NFPA 7OB-1987, Recommended Practice for Electrical Equipment Maintenance, is a premier source of information for all levels of personnel involved with the electrical distribution system. This document defines an Electrical Preventive Maintenance (EPM) program that is intended to reduce the hazard to life and property that can result from failure or malfunction of electrical systems and equipment. It explains the benefits that can be derived from a well administered EPM program and explains the function, requirements and, economic considerations that can be used to establish such a program. This section discusses these factors, but not in such detail as is provided in ANSI/NFPA 70B.

8.3.1 <u>Need for an EPM Program</u>. The need for an EPM Program, of electrical equipment, is not apparent. The deterioration of electrical equipment occurs at a normal rate, however, equipment failure is not inevitable. As soon as new equipment is installed the process of deterioration begins. Unchecked, the deterioration process can cause malfunction or an electrical failure. Deterioration can be accelerated by factors such as a hostile environment, overload, or severe duty cycle. An effective EPM Program identifies these factors and provides measures for coping with them. In addition to deterioration, there are other causes of equipment failure that may be detected and corrected through EPM. Included in these causes are load changes or additions, circuit alterations, improperly set or selected protective devices, and changing voltage conditions. Without an EPM program, management assumes a much greater risk of a serious electrical failure and its consequences. A well planned EPM program will reduce accidents, save lives, and minimize costly breakdowns and unplanned shutdowns. Impending troubles can be identified and solutions applied before they become major problems requiring more expensive and time consuming solutions.

8.3.2 <u>Benefits of an EPM Program</u>. An effective EPM program provides both direct and indirect benefits. Direct benefits are generally measurable economic benefits derived from the reduced cost of repairs and reduced equipment downtime. Indirect benefits are less measurable, but very real, benefits. Benefits that are difficult to measure include safety, improved personnel morale, better workmanship, improved productivity, reduced interruption of production, and improved insurance considerations. To understand how personnel and equipment safety are served by an EPM program, the mechanics of the program (i.e., the inspection, testing, and repair procedures) should be understood. Improved morale will come from personnel awareness of management effort to promote safety by reducing the likelihood of electrical injuries, fatalities, electrical explosions, and fires. While the benefits resulting from improved safety are often difficult to measure, direct and measurable economic benefits can be documented by equipment repair cost and equipment downtime records after an EPM program has been placed in operation.

In many cases, the investment in EPM is small compared to the cost of equipment repair and production losses associated with an unexpected equipment shutdown. Insurance statistics document the high cost of inadequate electrical maintenance. A study compiled by the Factory Mutual Insurance Group showed that in a two year study period one-half of the losses associated with electrical equipment failures could have been prevented with an effective EPM program. Several case histories have been documented relating preventable electrical equipment failure that resulted from the lack of a maintenance program. Among them included a transformer failure and fire that was caused by transformer insulating oil contamination. The transformer oil had not been tested in several years. The cost of the repairs alone would have paid for the

EPM program, not including the lost production value while the facility was without power. Another case documents a main service switchgear fire caused by fouling from dirt, gummy deposits, and iron filings. The switchgear damage alone was over $100,000, which would have paid for the EPM program for many years. Another case documents the failure of a large single motor; causing the entire plant to shutdown for 12 days, as the motor was vital to the plant process. The failure was caused by dust clogged cooling ducts. An EPM inspection would have detected the clogged ducts and prevented the failure and associated plant shutdown.

8.3.3 Ingredients of an Effective EPM Program. An effective EPM program is one that enhances safety and also reduces equipment failure to a minimum (consistent with good economic judgment). The basic requirements of the program include personnel qualified to carry out the program and regularly scheduled inspection, testing, and servicing of electrical equipment. Equally important to the success of the program is the application of sound judgement in the evaluating and interpreting of inspection and test results and the keeping of concise, but complete records. The following factors should be considered when planning the EPM program:

- Personnel Safety.
- Equipment Loss.
- Production Economics.

The essential ingredients of a successful EPM program are:

- Responsible and Qualified Personnel.
- Survey and Analysis of Electrical Equipment and Systems to Determine Maintenance Requirements and Priorities.
- Programmed Routine Inspections and Tests.
- Accurate Analysis of Inspection and Test Reports so that Proper Corrective Action Can Be Programmed.
- Performance of Necessary Work.
- Complete and Concise Records.

Additionally, the following must also be considered in establishing and maintaining an effective EPM program:

- Design of Equipment for Ease of Maintenance.
- Training Programs for Technical Skills and Safety.
- Use of Independent Companies for Specialized Services.
- Proper Tools and Instruments.

8.3.4 Planning and Developing the EPM Program. The purpose of an effective EPM program is to reduce the hazard to life and property that can result from failure or malfunction of the electrical system or equipment. There are four basic steps to implement the planning and development of an EPM program:

(a) Compilation of a listing of all plant equipment and systems (survey).

(b) Determination of the equipment and/or systems that are most critical and most important.

(c) Development of a scheduling system for maintaining the timeliness of the project.

(d) Development of methods and procedures for each phase of work, or contracting for specialized services required.

8.3.4.1 Maintenance Supervisor. The maintenance supervisor tasked with the planning and development of the EPM Program must be qualified both technically and administratively to effectively perform in this position. The maintenance supervisor should have open lines of communication to those personnel responsible for system and equipment design. Improper design, improper construction methods, and misapplication of hardware are a few of the problems traced to an unsafe installation, or one requiring excessive maintenance. The maintenance supervisor should be made aware of any deficiencies.

8.3.4.2 Maintenance Work Center. The maintenance work center must be properly equipped and conveniently located. It should contain the inspection and testing procedures for that area, copies of previous reports, single-line diagrams, schematic,diagrams, records of complete nameplate data, vendors' catalogs, plants stores catalogs, and supplies of report forms. There should be adequate storage facilities for tools and test equipment required by the maintenance group.

8.3.4.3 Survey of Electrical System. This survey may be defined as the collection and evaluation of accurate data regarding the plant electrical system to be utilized as an informational tool necessary for the development of an EPM program. The data collection step consists of three segments:

- Organizing the survey.
- Setting priorities for each segment of the survey.
- Assembly of all documentation.

The availability of up-to-date, accurate, and complete diagrams is the foundation of a successful EPM program. An EPM program cannot operate without this data and its importance cannot be overemphasized. The following documents are most often required:

(a) Single-line diagrams, showing circuitry down to the major utilization equipment.

(b) Short-circuit and coordination studies, which should be updated to reflect changes in: supply capacity, transformer size or impedance, conductor size, operating conditions and additions of motors, and most importantly, changes to any protective devices or settings.

(c) Circuit routing diagrams or raceway layouts.

(d) Plot plans or equipment location plans.

(e) Schematic diagrams or elementary wiring diagrams.

(f) Connection wiring diagrams.

System diagrams are generally needed to complete the data being assembled.   For a large building complex, system diagrams for the lighting, ventilation, heating and air conditioning, and control and monitoring systems are examples of system diagrams that may be required. Section 4, System Planning Studies, provides a more thorough discussion of the collection and evaluation of electrical system data.

8.3.4.4 Emergency Procedures. The survey process also includes the acquisition or preparation of emergency procedures. Emergency procedures should list, step by step, the action to be taken in the event of an emergency. These should include procedures for the safe shutdown or start-up of equipment and systems. Optimum use of these procedures is made when they are bound for quick reference and located in the area of the equipment or systems. Also included in the survey process, are the acquisition and maintenance procedures for proper test and maintenance of equipment. The use of well maintained safety equipment is essential and should be mandatory when working on or near live electrical equipment. Portable lighting is often necessary, particularly in emergency situations involving the plant electrical supply. Portable meters and instruments are necessary for testing and troubleshooting, especially on circuits of 600 V or less. The size of the plant, the nature of its operations, and the extent of the maintenance and repair program are all factors that determine the frequency and use of test and maintenance equipment. Specialized equipment may often be rented or shared between nearby facilities.

8.3.4.5 Identification of Critical Equipment. Equipment is considered critical if its failure to operate normally and under complete control will cause a serious threat to personnel, property, or the product.   Electrical power (i.e., process steam, air, water, etc.) may be essential to the operation of a machine, however, unless the loss of one or more of these supplies causes the machine to become hazardous to personnel, property, or product, the machine may not be considered critical. The combined knowledge and experience of several people may be needed to determine the criticality of a machine. An entire system may be critical by its very nature. Examples of critical systems are:

(a) Emergency lighting.
(b) Emergency power.
(c) Fire alarm systems.
(d) Fire pumps.
(e) Certain communication systems.

There are also parts of a system that are critical because of the function of the utilization equipment and its associated hardware. An example of this is the safety combustion controls on a large boiler, whose failure may cause a serious explosion. Parts of the electrical system, such as overcurrent devices or automatic transfer switches, are critical, because they reduce the widespread effect of a fault in the electrical equipment. Alarm and shutdown systems are often critical, because they monitor the process and automatically take action to prevent a catastrophe and alert operating personnel to dangerous or out-of-control conditions.

8.3.4.6 Scheduling. The proper scheduling of routine inspections and tests is the core of an effective EPM program. They will determine the condition of electrical equipment, allow determination of what maintenance is required, and verify that equipment will continue to function until the next scheduled maintenance period. Factors that need consideration in the preparation of a proper schedule are:

(a) Atmosphere or environment that the electrical equipment is located in (i.e., air contaminant content, moisture, dust, hazardous vapors, chemicals, exposure to high ambient temperatures and humidity.

(b) Load conditions (i.e., continuous-, intermittent-, periodic-, varying-, or short-time duty cycles, running time, number of starts, operating overloaded.

(c) History of equipment, which is used to develop repair cost trends, items replaced, design changes or modifications, significant trouble or failure patterns, and the stocking of replacements.

(d) Inspection frequency, as determined by equipment criticality, manufacturers' servicing recommendations, operating duty, environmental severity, history or lack of prior trouble.

8.3.4.7 Methods and Procedures. Methods and procedures for an effective EPM program must include not only the individual components of the electrical system, but the connections between those components. Neglecting the system's interconnections and operation together can cause unanticipated problems to occur. Although the manufacturer may have provided testing and calibrating procedures documentation for individual components, the application is often unique; therefore system peculiar inspection and testing procedures should be developed. The system procedures should contain:

(a) Various required forms for use in the plant and in the field.

(b) A procedure for each piece of equipment; detailing the special tools, materials and equipment necessary; an estimate of the time to perform the work, references to appropriate technical manuals, record of previous work performed, items of special attention, precautions, unusual incidents, etc.

(c) Safety procedures to be followed, special test equipment required, protective equipment and barriers to be used, lockout/tagout/tryout procedure to be used.

(d) Implementation of actual plant inspection schedule, based on equipment scheduled inspection frequencies, personnel availability, availability of spare equipment, shutdowns permitted by operating personnel, anticipated time to perform inspections and tests, availability of replacement parts and special test equipment.

(e) Maintenance of records to evaluate results (i.e., inspection schedules, work order logs, unusual event logs, cost reports, and analysis of test results).

(f) Emergency procedures, including training in the emergency situations most likely to occur, and periodic drills.

8.4 SYSTEM PLANNING STUDIES. This section discusses six system planning studies that should be conducted periodically. Performed regularly, the studies provide an organized way to track key system characteristics, such as, power factor, annual usage, peak demand, energy losses, voltage and current profiles, and load factor. Tracking these characteristics helps the system engineer to improve system performance, minimize downtime, and manage system expansion. The studies should be performed simultaneously to ensure data consistency.

Each study is prepared on a load projection basis using an econometric forecasting method that utilizes acquired electrical system historical data. The following studies will be discussed:

(a) Power Requirement Study.
(b) Long Range System Planning.
(c) Short Range System Planning.
(d) Coordination Study.
(e) Economic Conductor Analysis.
(f) Power Factor Correction.

8.4.1 Objectives. The objectives of these studies are to improve system performance and reduce operating costs. The performance of the studies will provide information to ensure an adequate supply of power and continuous service. Preparation of the studies is discussed in the following paragraphs.

8.4.2 Power Requirement Study. Data from the power requirement study provides information to forecast load growth. The following historical data is collected:

(a) Total peak demand.
(b) Total annual demand.
(c) Total annual energy used.
(d) Purchases for a given period of time (at least five years).

Projecting these values on a graph gives an indication of future demand. The power requirement study will also show the annual losses and load factors for both past and future years.

8.4.3 Long Range System Planning. Long range planning studies provide an outline for system growth and information for short term planning of system improvements. It is essential to provide the economical development of a system, assuring adequate service at the lowest cost. Long range planning is best provided using a map of the system that indicates the existing facilities (with their associated loads) and future construction. A study of the map will help the system engineer ensure that changes to lines or substations will not effect the overall plan of development.

8.4.3.1 Summary of Long Range System Planning. Long range system planning must be continuous, due to changing conditions. The planning procedure must, consequently, make provisions for updating the plan. It must also provide a viable approach for implementing the plan into action. Maintaining the plan (map) is a continual process consisting of the following steps:

(a) Review the Base Master Plan annually. The Base Master Plan is a comprehensive study of the many planning factors (i.e.; electrical requirements, local industry, geology, rail routes, population growth, etc.) involved in the facility construction or modification of a naval activity. The Shore Station Development Map, based on this study, is a graphical representation of the current and planned facilities. The map should be reviewed annually and prior to the design of new facilities. The map should also be updated, as necessary.

(b) Review the data on the existing system for accuracy and completeness. An analysis of the existing system is made to furnish the engineer with a foundation upon which to base the long range plan. This analysis should include a review of the condition of the existing system.

(c) Prepare contingency plans for possible, but uncertain, future expansion. This requires research of load levels with the capacity to support future expansion of the system.

(d) Select the most logical of the contingency plans when system changes are required. An examination of the contingency plans serves to determine the most sensible and economical method for transition from the existing system to the long range system.

(e) Review the contingency plans annually, in light of changing conditions. Update the plan (map), as necessary.

(f) Prepare construction work plans, providing a construction program for the installation of needed facilities, two years in advance. This program will be used for the preparation of detailed construction plans and specifications.

8.4.3.2 Details of Long Range System Planning. The following is required for detailed planning:

(a) Up-to-date system map.

(b) Location of all major concentration loads.

(c) Results of voltage and current investigations.

(d) All pertinent data relative to existing and future loads.

(e) Power requirements study.

(f) Latest outage summary.

(g) Present transmission facilities.

(h) Availability of future power.

The first step is to analyze the existing system for system capacity relative to existing load and system performance. This includes voltage levels, current balance, service reliability, energy losses, and operating expenses. The analysis will be useful in identifying the weaknesses and strengths of the existing system.

The second step is to project the long range load levels using an econometric forecasting method (graphing load versus time) with at least five years of historical data. The forecasting will help establish the growth pattern for the entire system and also the various segments of the system.

Having established and identified the growth areas, the third step is to impose the projected load growths on the existing system to see if it will accommodate the growth. This step will indicate any required changes. The possible changes, that may be required, are listed below.

(a) Increase existing substation capacity.

(b) Add new substations to the system and analyze the existing transmission grid.

(c) Increase distribution line capacity.

(d) Add more distribution feeders from the existing substation.

(e) Analyze the system at different distribution voltage levels, thereby, adding fewer substations at higher voltage and more at lower voltages.

To achieve orderly growth over the next twenty years, and after establishing a long range load design, the next feasible step is to develop the load levels for the intermediate periods (i.e., load levels between present and long range load levels). Perform the steps of long range planning for each transition load level as described above.

Substation requirements for each service area are analyzed for the various voltage levels (e.g., 24/4.16 kV, 7.2/12.5 kV, and 14.4/24.9 kV). A system model, discussed in subparagraph 8.4.3.3, is useful in determining load density, the construction cost for the substation, and the number of feeders from each substation. The system model will also help to establish the number of substations and number of feeders required for the system to accommodate the loads of the present service area.

8.4.3.3 System Model. A system model is represented in Figure 8-1. The figure illustrates a substation with four primary feeders, eight laterals, and a rectangular service area. The general model can represent any number of primary feeders and any polygon shaped service area. For this particular study, the number of primary feeders is varied from three to six. It is believed that this is a representative number of the possible distribution feeders for this study.

The number of laterals in the model is dependent upon the allowable spacing between the laterals, i.e., the area served by each lateral. Lateral spacing of four miles would mean that no customer would be more than two miles away from a three-phase lateral.

The factors that can be varied as part of the model are:

- System voltage.
- Number of primary feeders.
- Primary feeder conductor size.
- Lateral feeder conductor size.
- Area served by lateral feeders.
- Load density in kW per square mile.
- Cost per mile of primary and lateral feeders.
- Cost of distribution substation facilities.
- Cost of energy losses.

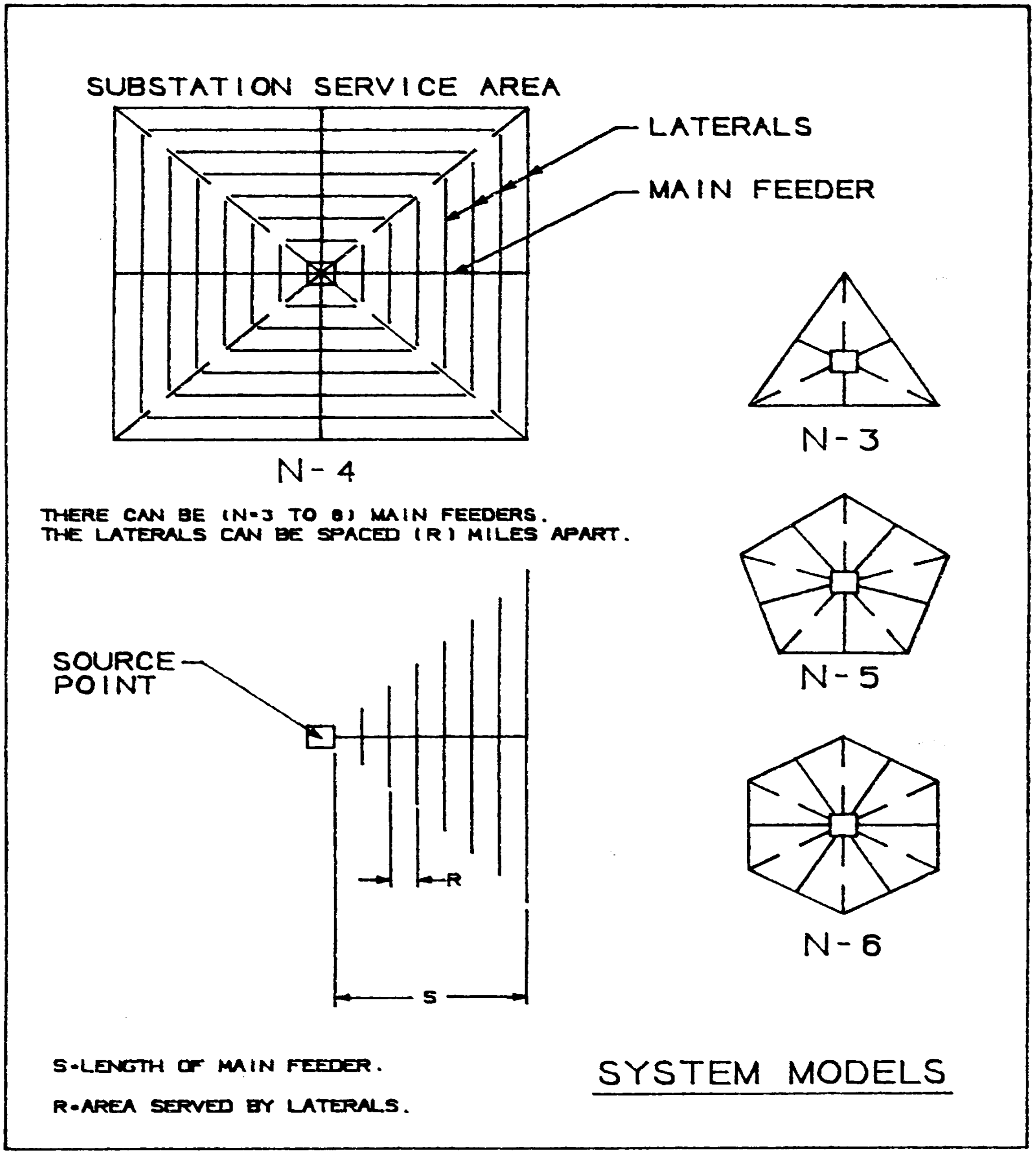

FIGURE 8-1
System Model

As these factors are varied, the model will determine:

(a) The maximum area that can be served without exceeding a 7 percent voltage drop at any point in the area.

(b) The total cost for constructing all substation facilities and primary and lateral feeder circuits; the costs are represented on a per sq mile basis and assume an 8 percent annual cost.

(c) The total losses in the system and their associated costs. Losses are based on the planning load levels.

(d) The total cost for the plan, including the annual cost on a per sq mile basis for the substation and distribution feeders, as well as the cost of losses.

The model represents all main and lateral circuits as three-phase lines. Voltage drop factors for the lines and the resistance data for loss calculation are taken from the Electrical Distribution Handbook. The model assumes uniform load densities for representation of system loading conditions. For long range planning purposes, this allows a satisfactory representation of system loading. If, for a particular system, an unusually large concentrated load did exist, then this would be considered separately. Extensive studies of a variety of distribution feeder circuit patterns have indicated that the assumption of uniform load density, as represented in the model, allows a meaningful analysis of the system.

The model is intended to represent actual system conditions, including voltage drop and system losses. The service area is initially set at one square mile and the voltage drop is computed. The service area is then expanded and the voltage drop is recomputed for each increase in service area. When a maximum voltage drop of 7 percent is detected at the end of the last lateral, the area expansion is stopped. The model is then used to determine the total number of primary and lateral feeder circuit miles required for the expanded service area. This is possible because as the service area is expanded, the model automatically adds the required primary feeder circuits and lateral feeder circuits necessary to serve the increased area. The model is then used to determine the total energy losses on the system. Finally, the model provides computation of the substation size required, given the maximum possible service area and the load density within that area. Using cost data for constructing primary and lateral circuits as well as substation costs and evaluation of energy losses, the model is used to determine the total cost on a square mile basis for the particular planning alternative. The model then provides computation of the number of substations that will be required to provide service for the area being considered.

Using this approach, the model represents an actual operating system. The flexibility of the model, however, allows a number of different system configurations to be investigated and evaluated. In this way, many alternatives can be evaluated before deciding on the final system configuration. A report is then compiled for various alternatives and cost data is assembled indicating the economic approach for system development.

8.4.4 Short Range System Planning. For every electrical distribution plant, short range system planning is imperative to achieve the orderly expansion of the system to accommodate the load growth.

8.4.4.1 Voltage Drop Study. Short range system planning is achieved by performing a voltage drop study. The voltage drop study reveals the strong and weak points of the system by measuring the load at various points on the system. An example of a voltage drop study is represented below.

Voltage drop calculations are referred to as a 120 V Base.

$$\text{Voltage Drop (120 V Base)} = \frac{\text{Actual Voltage Drop} \times 120}{\text{System Nominal Voltage}}$$

For Example:

Nominal System Voltage	=	12.47 grounded wye/7.2 kV
Actual Voltage Drop	=	360 V
Voltage Drop (120 V Base)	=	$\frac{360 \times 120}{7200} = 6\text{V}$

8.4.4.2 Voltage Drop Factors. The study analyzes voltage drop factors for the different conductor sizes on the system. The development of voltage drop factors is illustrated below.

The voltage drop for known source-end and lagging power factor conditions may be calculated from the following equation.

$$\text{Voltage Drop} = I\,(r \cos A + x \sin A)$$

Where:
- I = Line current in amperes
- A = Phase angle between voltage and current
- r = Resistance of line in ohms
- x = Reactance of line in ohms

This equation provides an estimate of the voltage drop resulting from normal system designs.

Line current may be expressed in terms of kilowatts and voltage as follows:

$$I = \frac{kW}{(kV)\ (COS\ A)\ (P)}$$

Where: kW = Circuit load in kilowatts
kV = System nominal phase-to-ground voltage in kilovolts
P = Number of phases

Voltage drop referred to at a 120 V Base (VD) is expressed as follows:

$$VD = \frac{\text{Actual Voltage Drop (120)}}{\text{System Nominal Voltage}}$$

Using the preceding equations for line current and voltage drop referred to at a 120 V Base (VD), the equation for voltage drop becomes:

$$VD = \frac{(kW)\ (r \cos A + x \sin A)\ (120)}{(kV)^2\ (\cos A)\ (P)\ (1000)}$$

The equation for (VD) expressed in per mile units is written as follows:

$$VD = \frac{(kW)\ (R \cos A + X \sin A)\ (s)\ (120)}{(kV)^2\ (\cos A)\ (P)\ (1000)}$$

Where: R = Resistance in ohms per phase mile of line
X = Reactance in ohms per phase per mile of line
S = Line distance in miles

Letting the following factor be designated the voltage drop factor (VDF):

$$VDF = \frac{(R \cos A + X \sin A)\ (120)}{(kV)^2\ (\cos A)\ (P)}$$

The equation for (VD) becomes:

$$VD = \frac{(kW)\,(S)\,(VDF)}{1000}$$

8.4.5 Coordination Study. The coordination study, commonly referred to as the sectionalizing study, is an analysis of all or part of a distribution system. This analysis is performed to determine the adequacy of sectionalizing device placement and selection based on the fault current calculations. This study can be performed in conjunction with the voltage drop study to incorporate the major system changes in terms of loads or a change in system configuration.

The distribution system coordination objectives may be to minimize outages per consumer per year, to minimize expense for service restoration after outages, to minimize damage to primary lines and apparatus during faults, or to minimize the probability of hazardous voltage at ground level or on grounded objects interconnected with the system neutral.

These objectives are accomplished by the use of sectionalizing devices appropriately selected and located on the distribution system. The outages, equipment damage restoration expenses, and hazardous voltage (caused by live fault and overload conditions) can never be completely eliminated. These dangerous and undesirable line operating conditions, however, can be reduced to an acceptable level by the use of proper sectionalizing devices.

The performance of coordination studies has been greatly simplified since the introduction of computer modeling techniques for calculation of load and fault currents. These techniques have been applied in the performance of voltage drop, load flow, and fault current studies. Sectionalizing electric systems requires application of three-phase OCRs and breakers with ground fault sensing capability, however, the computer applications addressed will be limited to analysis of single-phase and three-phase sectionalizing devices not requiring ground fault sensing capabilities. Single- and three-phase sectionalizing devices are used frequently on rural electric systems and require less engineering judgement than larger devices equipped with ground fault sensing. The purpose of using computer applications is to reduce hand calculations and measurements.

A coordination study requires the performance of the following four procedures:

(a) Accumulate and process data.
(b) Check sectionalizing for coordination and correct ratings.
(c) Change sectionalizing to correct inadequacies.
(d) Document findings as required.

Procedures (b) and (c) are repeated as often as required. Procedures (a) and (b) are the most beneficially adapted to computer methods. These procedures are repetitive tasks that do not require engineering judgement. While many decisions made in procedure (c) could be determined using computer software, it would be difficult to duplicate sectionalizing situations. Computer generated data derived from procedures (a) to (c) will be beneficial to the performance.of procedure (d). Final documentation, however, requires the communication skills of an engineer.

The data required to accomplish a coordination study is:

(a) A representation or model of the system including the type of device and its location at each sectionalizing point.

(b) Peak load current at each sectionalizing point.

(c) Maximum and minimum fault current at each end point.

(d) Time current characteristic curves and ratings for each device used.

For the engineer performing a coordination study, a system map showing system configuration, location of consumers, and existing sectionalizing points serves as an acceptable model of the system. To calculate load and fault currents the model must also in some way give line section loading, distance, conductor, and phasing information. It is recommended that line current and fault current values be added to the sectionalizing study map to aid sectionalizing point evaluations.

Final documentation will require a system map for communication of sectionalizing point locations, in order to monitor and check computer results. A system's circuit diagram, modified to include sectionalizing device locations, will often be adequate for a computer aided study.

Load current, maximum available fault current, and minimum available fault current is required for each sectionalizing point. Sectionalizing software can be programmed to calculate these current values. A more efficient method, however, is to modify existing voltage drop and fault current software to store this information for later use by the sectionalizing software. This will make use of the existing software already programmed to calculate these values and greatly reduce sectionalizing software requirements.

The voltage rating, continuous current rating, interrupting current rating, minimum pickup rating, and time current characteristic curves for each device used on the system are required for the study. This data should be stored on a permanent computer data file since it remains constant from one study to the next except for the addition of devices.

Considerable time and expense can be saved if a coordination study is performed in conjunction with the construction work plan (see subparagraph 8.4.3.1 (e)). Much of the data required for a coordinating study can be accumulated while performing studies required for the construction work plan.

To determine if system sectionalizing is adequate, the device at each sectionalizing point should be tested for:

(a) Correct voltage rating.
(b) Adequate load current.
(c) Adequate interrupting current rating.
(d) Adequate continuous current rating.
(e) Correct pickup current rating.
(f) Coordination with adjacent devices.

These tests are performed by comparing system parameters to device ratings or characteristics and can be easily accomplished by the use of computer applications. Tests for correct voltage, load current, and interrupting current ratings require only that, for each sectionalizing point, the device at that point and its ratings are on file storage. They can be compared to system parameters of voltage level, load current, and maximum fault current, also on file storage. If the system voltage level does not fit within the acceptable device voltage level range, then the voltage level test has failed. Load current must be less than the continuous current rating and maximum fault must be less than the device interrupting current rating to pass load current and interrupting current tests. It is often beneficial to apply a constant multiplier to all load currents, before the load current test, to adjust for load growth or imbalance conditions on multi-phase lines.

The minimum pickup current rating test must search the system controlling the device under evaluation to find the minimum fault current available through that device (as defined by some given fault impedance - usually 40 ohms for Rural Electrification Administration studies). The value must be greater than the requirements for minimum and maximum fault current available through the device being evaluated and must fall within the range of coordination as defined for the device with the source side device that it is protecting. The range of coordination, with adjacent devices, can be defined for each test using methodical representations of the device TCC curves. The coordination test need only be performed on the source side device if all devices on a circuit are evaluated. Coordination with load side devices will be tested when the load side device is evaluated.

8.4.6 Economic Conductor Analysis. An economic conductor analysis is performed to reduce electric system energy losses to the lowest possible level. Although cost minimization is important, the first consideration in the design of primary lines for an electric distribution system is assurance that the conductor size specified is adequate from a voltage drop standpoint. When voltage drop studies reveal that the resultant voltage level will be satisfactory using a certain conductor size, it is then necessary, or desirable, to consider the cost of energy losses and determine if the designed line is the most economical. A simplified method of economic comparison has been developed using data and methods which result in a graphic representation of the total cost to own and operate various types of line at various load levels.

The example contained herein is for a typical electric system operating at 7.2/12.5 kV. If the system, or parts of the system, operates at a different voltage, the calculations must be modified accordingly. The required data to perform the economic analysis is as follows:

(a) Construction cost of new three phase lines with various conductor sizes.

(b) Fixed costs of the electrical system, including operation and maintenance expenses which are represented as a percent of plant value.

(c) System load factor.

(d) Demand and energy rate for the system.

Based on this information, the Cost of Energy Losses is determined by using the following formula.

First, the Loss Factor is calculated:

$$\text{Loss Factor} = .16(LF) + .84(LF)^2$$

Where: LF = Load Factor

Then, the Cost of Energy Losses is calculated:

$$\text{Cost of Energy Losses} = L + \frac{12MN}{(8760) \times \text{Loss Factor}}$$

Where: L = energy rate
M = demand rate
N = ratchet (if any)

The cost of energy losses for various conductors and their savings (in energy losses) are computed at different load levels. A graph for the conductors is drawn as a comparison, indicating the most economical conductor size required for each particular load level.

8.4.7 Power Factor Correction. Power factor is defined as the rate of useful working current to total current in the line. Since power is the product of current and voltage, power factor can also be defined as the ratio of real power to apparent power. This ratio is expressed as:

$$\text{Power Factor} = \frac{\text{kW}}{\text{kVA}}$$

Where: kW = real power
kVA = apparent power

It is advantageous to have the power factor near unity. If the power factor is below 90 percent, a penalty is imposed by most utilities or power suppliers. Under these circumstances, the energy losses are too high. In order to correct the situation, capacitors are installed on-line at strategic locations.

The advantages of installing capacitors are:

(a) Improvement in power factor.

(b) Reduction of energy losses.

(c) Rise in voltage.

(d) Service reliability.

(e) Avoidance of expensive line conversion cost.

The power factor correction study can be best performed in conjunction with the voltage drop study. The capacitor placements can be performed by checking the power factor value or the kVAR losses on the circuit resulting from the load it is carrying. Installing the capacitors and improving the power factor to near unity will reduce the kVAR losses and raise the voltage, thereby reducing the voltage drop on the circuit.

CHAPTER 9. NEW AND EMERGING TECHNOLOGY.

9.1 SUPERVISORY CONTROL AND DATA ACQUISITION. Supervisory Control and Data Acquisition (SCADA) systems have been in use for approximately twenty years in various industries, since the inception of general purpose computer use for applications other than data processing in offices. The advent of microprocessor technology has expanded the application of SCADA technology through the more advanced concept of the Distributed Control System (DCS). This section will briefly discuss the history of such systems; concentrating on the applications of a SCADA or DCS system for electrical distribution systems.

9.1.1 SCADA Systems History. SCADA systems originated with the concept of computer control of plant processing equipment, such as used in the paper and petroleum refining industry. A need was recognized to improve the accuracy and timeliness of the outdated pneumatic and hydraulic based control systems of the 1940s and 1950s. The development of the main frame digital computer gave promise that such improvements could be made. Original control systems consisted of a mainframe computer located at a centralized location. Communications lines had to-be built from the centralized location to the locations of the equipment to be controlled and monitored. Generally, the master communications unit (MCU) was the only unit capable of communicating directly with the central Computer. The MCU was also used to poll the remote terminal units (RTUs) on a predetermined schedule to gather system status information. Should an RTU detect a change in status which required attention, however, it could signal the MCU and request a status query. The early RTU units had very limited capabilities. Basically, RTUs could pass information concerning the change in state of contact closures. The ability to manipulate analog information was very limited, with analog/digital (A/D) converters able to manage only limited data ranges. System capabilities were limited by the: relatively large size of the equipment, small number of data points per RTU, slow communications speed, and the need for the central computer to manage all information. All components were discrete components (i.e., individual transistors, diodes, capacitors, etc.) assembled on printed circuit boards. The communications network of the old systems managed all of the information traffic, there ' fore, the chances of individual data items having errors (due to possible random noise bursts and interruptions in the communications channel) was much higher. Additionally, the conventional communications path of the older systems were made of copper telephone wire.

With the advent of integrated circuits and microprocessors, the great reduction in size and the vast improvement in both computing and communications speed has resulted in the evolution of the DCS. The DCS has microprocessors located remotely at locations close to the controlled equipment, as well as at a central processing unit. Local control actions and status monitoring are performed by the local microprocessors, enabling the central computer to be an information manager for the system. Such a system is inherently more reliable than the old style system, in which all information was required to flow from the remote points to the central computer and back to the remote point for final execution. Modern microprocessors are able to manipulate large amounts of digital and analog data routinely. This provides data processing capabilities that were only dreamed about less than twenty years ago. Advances such as fiber optic cables, satellite transmissions, microwave transmissions, and high frequency radio transmissions have enhanced the reliability of the communications path. The advent of Local Area Networks (LANs) has provided the development of systems which allow each of the RTUs to communicate with other units; outdating the old system that allowed only the MCU to communicate with individual remotes.

9.1.2 SCADA Applications for Electric Utilities. Electric utilities have used SCADA systems mainly to control generation plant output and to monitor and remotely control their high voltage transmission systems. In recent years, SCADA systems have become more economical for monitoring and controlling electrical distribution systems of voltages no less than the 15 kV class. Most utilities have few, if any, distribution systems in the 5 kV class, as load growth has forced the upgrade or elimination of these systems. Utilities monitor the load on various distribution circuits, monitor the status of circuit breakers, monitor the voltage and power and VAR flows on transmission circuits, and monitor and control the power and VAR flows from power generating stations. The concentration of data points to be monitored at typical utility substations makes installation of SCADA systems easily justifiable. The standardization of most utility substation designs allows utilities to more readily design and install SCADA equipment than the typical commercial or industrial user, whose distribution system is unique in configuration, and generally has a lower concentration of data points at any one substation.

9.1.2.1 SCADA System for Electrical Distribution. Since the typical NAVFAC electrical distribution system is similar to the typical industrial electrical distribution system, the economic justification for a dedicated SCADA system is often difficult, as the concentration of data points is usually relatively low and the configuration at any one site is unique. This does not preclude the use of a SCADA system, it means that the SCADA system used will have to serve other applications, just as in most industrial plants, where the SCADA system is installed to control the plant process, monitoring the electrical system is one of the side benefits.

Unless an electrical distribution system is quite large and complex, the use of a SCADA system alone, for monitoring and controlling the electrical distribution system, cannot be economically justified. In most plants, the SCADA system is used to control the plant process. The SCADA system, as used on an electrical distribution system, should monitor and control the same conditions as those discussed for an electric utility (i.e., the monitoring of power flows, voltage, and current for major circuits, the monitoring and control of circuit breakers, and the monitoring and control of generation units). The electrical system configuration can, therefore, be changed remotely by closing or opening various circuit breakers and switches. Trouble can then be detected immediately, as alarm conditions and automatic protective device operations are reported to a central location. The SCADA system can also accumulate the information necessary for utility load shedding and energy conservation. Historical data, for use by management and engineering personnel, is readily available. Automatic alarm and trouble reporting can ease maintenance and,troubleshooting diagnosis, as well as support emergency planning.

9.1.2.2 Energy Management Systems. For large building complexes, a slightly different version of the traditional SCADA system has emerged; that of the Energy Management System (EMS). This equipment has been used extensively for large high rise office buildings and hotels, as well as multi-building complexes typical of most Naval Facilities. The EMS generally has an integrated central control and display panel that incorporates the building fire alarm system and controls for the building's heating, ventilating, and air conditioning (HVAC) systems, and controls for the building lighting system. As these are the major controllable building loads, and are usually interruptible for short periods of time, the EMS monitors the building's main utility meter and minimizes demand charges by shedding controllable loads for short time periods. The time period is coordinated with the demand billing period of the electric utility (typically 5, 15, or 30 minutes). When the current demand period expires, the interrupted load is reenergized, with the hope that in the intervening period the overall load has declined to a point that a new demand peak will not occur. The EMS system is programmed to shed various loads by either fixed or variable load priorities that are determined by the building management.

9.1.3 Typical SCADA System Configuration. The modern SCADA system generally consists of a central station and three to over one hundred remote stations. The central station generally consists of one or more computer consoles, with two or more central computers in a redundant operating configuration. The computer consoles contain the computers, communications equipment, power supplies, integral or separate data and alarm printers, and depending upon configuration, the terminal strips that are necessary for connection to remote equipment. The computer consoles have one or more Cathode Ray Tube (CRT) display devices, with the means of operator communication: a touch-type keyboard, a touch screen, or a light wand. The actual CRT displays, generated by specially written computer software, consist of schematic multi-color representations of the various operating systems.

Electrical systems are usually represented in one-line diagram format with some geographical or physical orientation of the various equipment rather than the top down style of a conventional one-line diagram. Various system operating buses might be displayed in different colors to reflect the different operating voltages. Circuit breaker status is indicated by red or green lights to indicate closed or open status respectively. Bus power flows, voltages, and currents would be displayed alongside the bus identification information. Transformers, circuit breakers, disconnect switches, major circuits, and major utilization equipment are generally shown on the display. The display may be broken down into more detailed screens to illustrate the details of a complex system. All of the control conditions for generating units should be displayed; frequency, load, voltage, watt or VAR control settings, power factor, and other information such as unit alarm status. For a large boiler and steam turbine generator, this could involve several subsystem displays (i.e., steam system, air system, fuel system, lubrication system, cooling system, etc.). The remote units generally consist of one cabinet, each of which contains one or more local microprocessors, as well as the communications equipment, power supplies, and terminal strips necessary to connect the equipment being monitored and controlled. There may be a local CRT display and keyboard interface with the microprocessors and even a small data printer and an,alarm printer. These, however, are usually used for troubleshooting and varying the system configuration, rather than for daily operational use. The various RTUs and central computers are connected by a variety of methods; a simple twisted pair cable, multi-pair cables, fiber optic cables, by carrier communications over the power conductors, by radio transmissions, and even by satellite transmissions. The selection of the transmission medium depends on the needs of the user, the location of the central station and RTUs, the volume of data, the need for data security, system reliability goals, and the cost.

9.2 CONTROL CIRCUITS AND DEVICES. Control circuits for electrical distribution systems traditionally consisted of discrete electromechanical relays that were hard wired to produce the desired end result, based on a predetermined set of input conditions. There are now two major types of control circuits; the Programmable Logic Controller (PLC) and the integrated microprocessor control. The following two subparagraphs briefly describe the major features of both types of control devices.

9.2.1 Programmable Logic Controllers. PLC systems have been in use for about fifteen years; their development paralleling the ongoing development of integrated circuits. These systems consist of many logic circuits that may be configured by the user to any number of configurations to accommodate the size of the equipment purchased and the complexity of the task to be performed. PLC systems were first used in the automotive industry and developed to replace the large electromechanical relay systems that were used to control large automated factory processes. The automotive industry faced the yearly task of either rewiring or replacing relay control panels used to control various parts of the auto assembly lines. PLCs, as the name implies, are programmable. The logic is, therefore, not hard-wired and can be changed by the end user as often as desired without changing any physical connection.

With the achievement of new communications technology, it is sometimes difficult to differentiate between a SCADA system and a system of PLCs communicating via a LAN. Some manufacturers offer a hierarchy of products utilizing PLC to control the final end devices. The PLCs are generally connected to the SCADA system via RTUs, which have limited control capability. other manufacturers, without strong PLC product lines, have developed SCADA systems with stronger local control capability built into the RTUs. In the electrical distribution system, PLCs are most often used for motor control logic, load shedding schemes, motor reacceleration schemes, and for other utilization device control systems.

Originally, PLCs were developed for complex systems involving hundreds or even thousands of discrete relays. They are available today, however, for systems that require as few as four to six traditional relays. PLCs are available with time-delay relay and analog capabilities, although they have not found much utilization to perform actual control of the electrical system. Large PLCs were historically developed for hundreds of points at one location, which did not fit the need for the typical electrical distribution system. Modern PLCs can handle less points, however, the more recent development of integrated microprocessor controls by switchgear and circuit breaker manufacturers provided the same capability and were designed specifically to meet the need of the typical electrical distribution system. PLCs and integrated microprocessor controls are essentially the same product, both consisting of the same subcomponent.

9.2.2 Microprocessor Controls. Microprocessor controls are one of the newest technologies to be applied to the electrical distribution system.

Microprocessors are now being used for such applications as: protective relaying and tripping functions in circuit breakers and fuse-like switching devices; electronic meters that provide all of the voltage; current, power, energy consumption, demand, power factor, frequency, and for gathering other information that previously required up to eight separate metering devices; dedicated controls for complex machinery, gas turbines, diesel engines, compressors, generators, adjustable speed drives; desk top computer control and monitoring systems; and automated protective device testing. Microprocessor based protection modules are now being installed in molded case circuit breakers and low voltage power circuit breakers to control the operation of the direct acting trip units. These trip units are used to provide long time, short time, instantaneous, and ground fault overcurrent protection, as well as undervoltage protection. Additionally, microprocessor based protective relays are also being used to replace traditional electro-mechanical protective relays that have traditionally been used for low and medium voltage switchgear installations. The new devices offer improved protection of equipment by allowing more accurate protection settings paralleling equipment needs. The new devices also offer better troubleshooting diagnostics, on-line test features, and communication capabilities to allow remote trouble reporting. The new protective devices are being equipped with metering capabilities, which may allow elimination of separate voltmeters, ammeters, and wattmeters; often used on feeder and utilization circuits to provide operating load information.

Electronic metering devices are now available in one package to replace kilowatt-hour meters, demand attachments, power meters, power factor meters, and kilovar-hour meters. The new devices have bidirectional power flow monitoring capabilities; allowing one device to replace four conventional billing meters when a site has two way power flow with a power factor adjustment clause. The new devices have multiple rate and time of day usage meters with built-in communication capabilities to allow remote meter reading by SCADA or other systems, such as a personal computer with a modem and software (i.e., spreadsheet program) for analysis of the data. These new metering devices will display power factor, voltage, current, and power flows (both real and reactive); providing the possibility of elimination of even more of the old indicating meters. Use of modern metering equipment allows significant size reduction in certain applications where many discrete meter devices were used on a lineup of feeder switchgear equipment. A typical metering unit consists of a discrete kilowatt demand meter, a discrete power factor meter, a discrete kilowatt-hour meter, a discrete ammeter with associated ammeter switch, and a discrete voltmeter with associated voltmeter switch. All of these separate meters can now be replaced by one device, which is no larger than one of the five meters mentioned above.

Use of microprocessor based controls has also made improvements in controls of complex packages, such as boilers, gas turbines, compressors and generators. The new control packages are: smaller, can be readily reprogrammed for changing conditions, and can be a significant engineering and design cost savings over the old style discrete relay systems used in the past. Previous control systems were uniquely configured for the requirements of each customer, allowing no standardization of manufacturing and testing. The new microprocessor based controls allow the same control system to be supplied for each customer, with only the software requiring adjustment. The customer benefits because changing site condition problems are remedied by simply changing the software, rather than making numerous wiring connection changes that are usually not documented. The microprocessor system can display the new software configuration on demand, thus eliminating the documentation problem. The low cost of personal computers and the proliferation of software (for use in almost any application) has allowed operating and engineering personnel to monitor and control certain operations from their own office. Laboratories can now run automated tests and have the personal computers monitor various test parameters and produce automated test reports.

Relatively simple processes can be controlled by a personal computer and modem connected to a remote location via telephone lines. A simple RTU, located at the other end, can accumulate the remote data signals and transmit any commands to be executed. Such systems are quite inexpensive, but must be recognized as less reliable than SCADA or DCS systems due to the generally non-redundant designs used and the lower cost commercial grade design of personal computers, which are not specifically designed for 24 hour continuous operation over long time periods (many months or years). The development of microprocessor based test equipment has allowed testing to be performed by less skilled personnel, as the knowledge that would have been required to run the test and interpret results is now programmed into the microprocessor for certain dedicated testing equipment.

9.3 COGENERATION. Cogeneration is not a new technology. It has received new emphasis, however, resulting from the increased awareness of the need for energy conservation and from the regulatory impetus resulting from the 1978 Public Utility Regulatory Policies Act (PURPA). PURPA requires public utility companies to accept electric power generated by their customers, if certain basic energy conservation parameters are met. Cogeneration is the useful production of more than one form of energy in the same plant (e.g., the simultaneous production of process steam and electricity, the use of waste heat recovery devices to produce electricity from a diesel engine driving a pump load, or using waste heat from a diesel engine generator for heating water for domestic use). Prior to PURPA, even if it were economical for the customer to install electrical generation equipment, the utility's rate tariffs would often prohibit this arrangement; based on perceived possible safety and reliability problems. With PURPA, if the energy conservation parameters are met, the customer must be allowed to connect the equipment to the system. The only provision is that the costs and rates paid for power are subject to local utility rate regulations.

Modern cogeneration systems consist of two basic types. The first type generally involves a large industrial plant that has a need for process steam. Many refineries, chemical plants, paper mills, and similar facilities typify this application. Prior to PURPA, many of these plants had boilers for steam production and purchased all of their electric power from electric utilities. In some parts of the country, these large facilities had large electric power production plants that also produced part of the electric power required to operate the plants. This reduced the need for the plants to purchase additional power elsewhere. The plants were in fact already "Cogeneration" plants. The amount of electric power purchased from the utility depended on the size of the plant load, the reliability of the local electric utility, the cost of utility power and the incremental cost of the plant's electric power. During the 1950s and 1960s, fuel costs and electric utility costs were such that many industrial plants shut down internal electric generation systems, as the cost of utility power made in plant "cogeneration" uneconomical. With the large electric power rate increases of the 1970s and 1980s, not all attributable to increased fuel costs, many large users suddenly rediscovered "cogeneration". These users discovered that they could use internally produced fuels, such as waste gases in refineries, and wood chips in lumber and paper plants, to fire boilers to produce the needed process steam and produce electricity cheaper than the local utility's increased rates. Use of such waste products also partially solved environmental disposal problems that had arisen from the advent of the Environmental Protection Agency (EPA). Many large industrial cogeneration projects now involve the use of gas turbine driven electric generators with a waste heat recovery device on the gas turbine exhaust that is used to make process steam. These plants are often called "combined cycle" plants if a portion of the steam produced is then also used to drive a steam turbine electric generator. The relatively low cost and ready availability of natural gas has made these systems quite popular and economical to operate.

A second type of cogeneration system evolved from a change in traditional electric utility rates from one in which increasing usage resulted in lower incremental rates to one of increasing usage resulting in increasing incremental rates. Smaller customers, such as office complexes, hotels, hospitals, and shopping malls found that they could economically use cogeneration systems for peak load shaving (a strategy to reduce the connected demand during each billing demand period to less than that used by the utility for billing purposes). Peak load shaving was implemented as the incremental cost of internal generation during peak daily use was now on a higher time of day utility rate, and the load increased regularly to put the last portion into a higher demand charge category. Often these sites already had a standby or emergency generator system which was required by local building codes. This invested capital was standing idle, waiting for a power failure that hardly ever occurred. In addition, the engine's waste heat could be used to heat water or make steam, that could be used and meet the PURPA requirements for a Cogeneration system. It then made simple economic sense to install these Cogeneration systems to reduce overall operating costs. In all of these systems, overall energy conversion efficiencies often are in the 60-70 percent range, whereas the standard fossil fuel fired electric utility plant rarely exceeds 35 percent energy conversion efficiency.

9.4 VARIABLE SPEED ELECTRIC DRIVE SYSTEMS. Variable speed electric drive systems are an emerging technology that has its roots in several areas, among these are: energy conservation; microprocessor controls; SCADA or DCS systems; improved process control needs; and reductions in operating costs. Many process systems do not operate at constant rates, and as a result the process does not operate as efficiently as theoretically possible. This is primarily due to the limitations of the mechanical equipment used in the process, such as pumps, compressors, blowers, fans, control valves, skimmers, agitators, mixers, etc. Improvements in power semiconductor technology have allowed steadily increasing currents and voltages to be used on transistors, thyristors, and silicon controlled rectifiers. In most industrial operations, the induction motor,is the preferred driver, due to its low initial cost, high reliability, and relatively smaller size compared to other motor and engine drives. The disadvantage of the electric motor has always been the difficulty of speed control; for alternating current motors, the speed is directly proportional to the power supply frequency, which could not usually be varied. Thus other means had to be used to vary the process output of the driven equipment, since the speed of the equipment usually was fixed. Control valves were used in fluid control applications, and the results worked well, but were not energy efficient. In air flow application, dampers had to be used, which were often unreliable. In some applications, a bypass flow stream resulted in fluid constantly being recycled through the same pump, resulting in higher fluid operating temperatures than was desirable. Many times, operating controls could not be properly adjusted for changing operating conditions, possibly due to the operating range being wider than that of the control equipment's capability, or in some cases, due to lack of automation of the control process. All of these problems are solvable with a variable speed drive system. The installation of variable speed drive systems is usually economically justified based on energy cost savings over the installation of a fixed speed drive, however, the other factors mentioned above also can be used as the justification for their use.

A modern variable speed drive system will consist of a synchronous or induction motor driven by a solid-state adjustable frequency power supply package. The system will be controlled by an integral microprocessor based control system that usually interfaces to a remote DCS. The heart of the system is the adjustable frequency power supply. This subsystem consists of: appropriate input power conditioning, filtering and transformation equipment; a rectification section to convert the AC supply power to DC; an inverter section to convert the DC to an adjustable AC output; output power conditioning, filtering and transformation equipment; and a control system to monitor and produce the continuously variable AC output, based on the required load characteristics and any external control signals from the process. The rectification section usually consists of silicon controlled rectifiers. The inverter section for small systems consists of power transistors, while larger systems use thyristors or silicon controlled rectifiers. The output is usually formed from a six or twelve pulse generating bridge, with the pulse widths being controlled by the microprocessor to simulate a sinusoidal wave shape. The frequency is adjusted by the control system based on the changing process conditions. Use of microprocessor based controls allows very stable frequencies to be produced, as well as allowing very small changes to occur as required by the process. Suitable output inductors, capacitors and filters are used to smooth the wave shape as necessary for the output motor device to utilize. Harmonic filtering may be required on the input side, so that higher order harmonics are not transmitted to the rest of the electrical system. Variable speed drive systems of the above types are now available in sizes ranging from fractional horsepower to over 10,000 horsepower, and in speed ranges from as low as a few rpm to over 6,000 rpm. Of course, the entire speed range is not available in any one drive system, as usually drive systems, especially the motors are designed for a smaller speed range, e.g., a large drive might be designed for from 3,600 to 5,400 rpm at 10,000 horsepower, or a small drive might be designed for from 30 to 1200 rpm at 2 horsepower.