Naval Facilities Engineering Command
200 Stovall Street
Alexandria, Virginia 22332-2300

Electric Power Distribution Systems Operations

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FOREWORD

This manual on electric power distribution systems is one of a series developed to aid utility supervisory personnel at shore establishments in the performance of their duties. It includes information obtained from extensive research of current literature on the subject and preferred practices based on practical experience. The principles and procedures described are in accordance with national professional society, association, and institute codes.

Additional information concerning procedures, suggestions, recommendations or modifications that will improve this manual are invited and should be submitted through appropriate channels to the Commander, Naval Facilities Engineering Command, (Attention: Code 165), 200 Stovall Street, Alexandria, VA 22332-2300.

This publication has been reviewed and approved in accordance with the Secretary of the Navy Instruction 5600.16A and is certified as an official publication of the Naval Facilities Engineering Command. It cancels and supersedes Operation of Electric Power Distribution Systems, NAVFAC MO-201, November 1963, in its entirety.

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Assistant Commander for
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ABSTRACT

Application principles and procedures for the operation of electric power distribution systems and associated major apparatus are presented. The contents include principles of power systems, cabling systems, electrical equipment, power system protection and coordination, instruments and meters, operational procedures, and electrical utilization systems.

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CHAPTER 1. PRINCIPLES OF POWER SYSTEMS.

1.1 TYPICAL POWER NETWORK. An understanding of basic design principles is essential in the operation of electric power systems. This chapter briefly describes and defines electric power generation, transmission, and distribution systems (primary and secondary). A discussion of emergency and standby power systems is also presented. Figure 1-1 shows a one-line diagram of a typical electrical power generation, transmission, and distribution system.

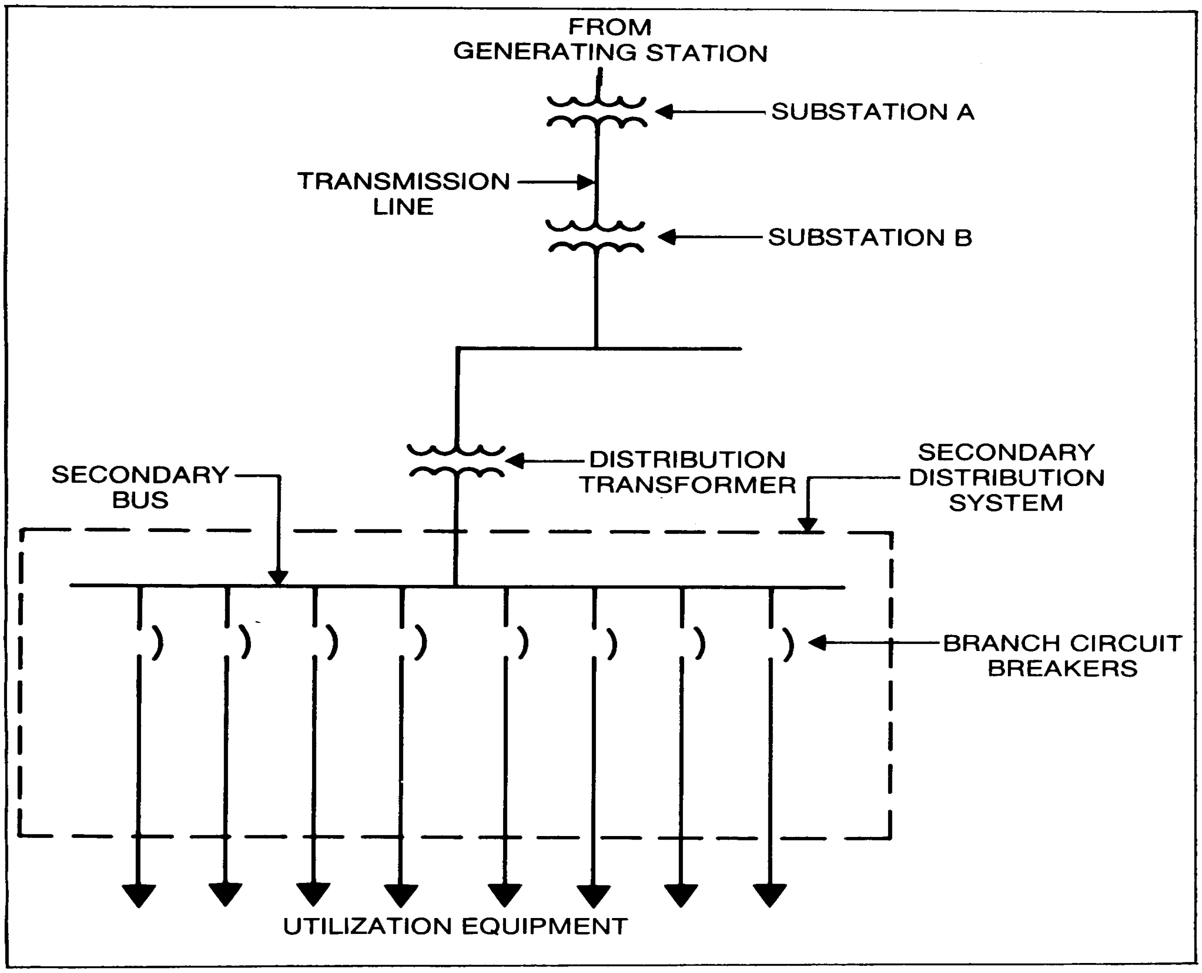

FIGURE 1-1
Typical Electric Power Generation,
Transmission, and Distribution System

1.2 ELECTRIC POWER GENERATION. A generator is a machine that transforms mechanical energy into electric power. Prime movers such as engines and turbines convert thermal or hydraulic energy into mechanical power. Thermal energy is derived from the fission of nuclear fuel or the burning of common fuels such as oil, gas, or coal. The alternating current generating units of electric power utilities generally consist of steam turbine generators, gas combustion turbine generators, hydro (water) generators, and internal-combustion engine generators.

1.2.1 Prime Movers. The prime movers used for utility power generation are predominantly steam turbines and internal-combustion machines. High-pressure/high-temperature and high-speed (1800 to 3600 rotational speed (rpm)) steam turbines are used primarily in large industrial and utility power generating stations. Internal-combustion machines are normally of the reciprocating-engine type. The diesel engine is the most commonly used internal-combustion machine, although some gasoline engines are also used.

1.2.2 Generators.

1.2.2.1 Generator Capacity. Turbine units can be built for almost any desired capacity. The capacity of steam turbine driven generators in utility plants range from 5 MW to 1000 MW. Most of the installed steam turbine generators are rated less than 500 MW. Gas turbine generators for electric power generation generally have capacities ranging from 100 kW to 20 MW (but are used in multiple installations). The applications of gas turbine generators include both continuous and peak load service. Diesel engine generator sets have capacities ranging from 500 kW to 6500 kW. These units are widely used in auxiliary or standby service in portable or stationary installations, but they may be used as the primary power source in some locations. Smaller units (steam turbine, gasoline, or diesel engine) are also available for special applications or industrial plants. See NAVFAC MO-322 for testing procedures.

1.2.2.2 Generator Voltage. Large generators used by commercial utilities are usually designed with output voltages rated between 11 and 18 kV. Industrial plant generators are normally rated 2.4 kV to 13.8 kV, coinciding with standard distribution voltages. The generated voltage is stepped up to higher levels for long distance power transmission.

1.2.2.3 Generator Frequency. Power generation in the United States is standardized at 60 Hz. The standard frequency is 50 Hz in most foreign countries. Generators operating at higher frequencies are available for special applications.

1.2.3 Voltage and Frequency Controls.

1.2.3.1 Voltage Control. The terminal voltage of a generator operating in isolation is a function of the excitation on the rotor field winding. The generator output terminal voltage is normally maintained at the correct level by an automatic voltage regulator that adjusts the field current.

1.2.3.2 Frequency Control. Electrical frequency is directly proportional to the rpm of the rotor which is driven by the prime mover. Because of this relationship, prime movers are controlled by governors that respond to variation in speed or frequency. The governor is connected to the throttle control mechanism to regulate speed, accomplishing frequency control automatically.

1.2.4 Parallel Operation of Generators. Large power plants normally have more than one generator in operation at the same time. When generators are to be paralleled, it is necessary to synchronize the units before closing the paralleling circuit breaker. This means that the generators must be brought to approximately the same speed, the same phase rotation and position, and the same voltage. Proper synchronization is accomplished with the aid of a synchroscope, an instrument which indicates the difference in phase position and in frequency of two sources. Paralleling of generators is accomplished either manually or automatically with one incoming unit at a time.

1.2.5 DC Generation. The requirement for direct current power is limited largely to special loads; for example, electrochemical processes, railway electrification, cranes, automotive equipment, and elevators. Direct current power may be generated directly as such, but is more commonly obtained by conversion or rectification of AC power near the load.

1.3 ALTERNATING CURRENT POWER TRANSMISSION SYSTEM. The transmission system is the bulk power transfer system between the power generation station and the distribution center from which power is carried to customer delivery points. The transmission system includes step-up and step-down transformers at the generating and distribution stations, respectively. The transmission system is usually part of the electric utility's network. Power transmission systems may include subtransmission stages to supply intermediate voltage levels. Subtransmission stages are used to enable a more practical or economical transition between transmission and distribution systems.

1.3.1 Transmission Voltage. Usually, generated power is transformed in a substation, located at the generating station, to 46 kV or more for transmission. Standard nominal transmission system voltages are: 69 kV, 115 kV, 138 kV, 161 kV and 230 kV. Some transmission voltages, however, may be at 23 kV to 69 kV, levels normally categorized as primary distribution system voltages. There are also a few transmission networks operating in the extra-high-voltage class (345 kV to 765 kV).

1.3.2 Transmission Lines. Transmission lines supply distribution substations equipped with transformers which step the high voltages down to lower levels. The transmission of large quantities of power over long distances is more economical at higher voltages. Power transmission at high voltage can be accomplished with lower currents which lower the I^2R (Power) losses and reduce the voltage drop. The consequent use of smaller conductors requires a lower investment. Standard power transmission systems are 3-phase, 3-conductor, overhead lines with or without a ground conductor. Transmission lines are classed as unregulated because the voltage at the generating station is controlled only to keep the lines operating within normal voltage limits and to facilitate power flow.

1.4 PRIMARY DISTRIBUTION SYSTEMS. The transmission system voltage is stepped-down to lower levels by distribution substation transformers. The primary distribution system is that portion of the power network between the distribution substation and the utilization transformers. The primary distribution system consists of circuits, referred to as primary or distribution feeders, that originate at the secondary bus of the distribution substation. The distribution substation is usually the delivery point of electric power in large industrial or commercial applications.

1.4.1 Nominal System Voltages. Primary distribution system voltages range from 2,400 V to 69,000 V. Some of the standard nominal system voltages are:

Volts	Phase	Wire
4,160Y/2,400	Three	Four
4,160	Three	Three
6,900	Three	Three
12,470Y/7,200	Three	Four
12,470	Three	Three
13,200Y/7,620	Three	Four
13,200	Three	Three
13,800Y/7,970	Three	Four
13,800	Three	Three
24,940Y/14,400	Three	Four
34,500	Three	Three
69,000	Three	Three

The primary distribution voltages in widest use are 12,470 V and 13,200 V, both three wire and four wire. Major expansion of distribution systems below the 15 kV nominal level (12 kV - 14.4

kV) is not recommended due to the increased line energy costs inherent with lower voltage systems.

1.4.2 Distribution Substations. A substation consists of one or more power transformer banks together with the necessary voltage regulating equipment, buses, and switchgear.

1.4.2.1 Substation Arrangements. A simple substation arrangement consists of one incoming line and one transformer. More complicated substation arrangements result when there are two or more incoming lines, two or more power transformers, or a complex bus network.

Some typical distribution substation arrangements are shown in Figure 1-2. Specific sections are identified as follows:

(a) A primary section provides for the connection of one or more incoming high-voltage circuits. Each circuit is provided with a switching device or a combination switching and interrupting device.

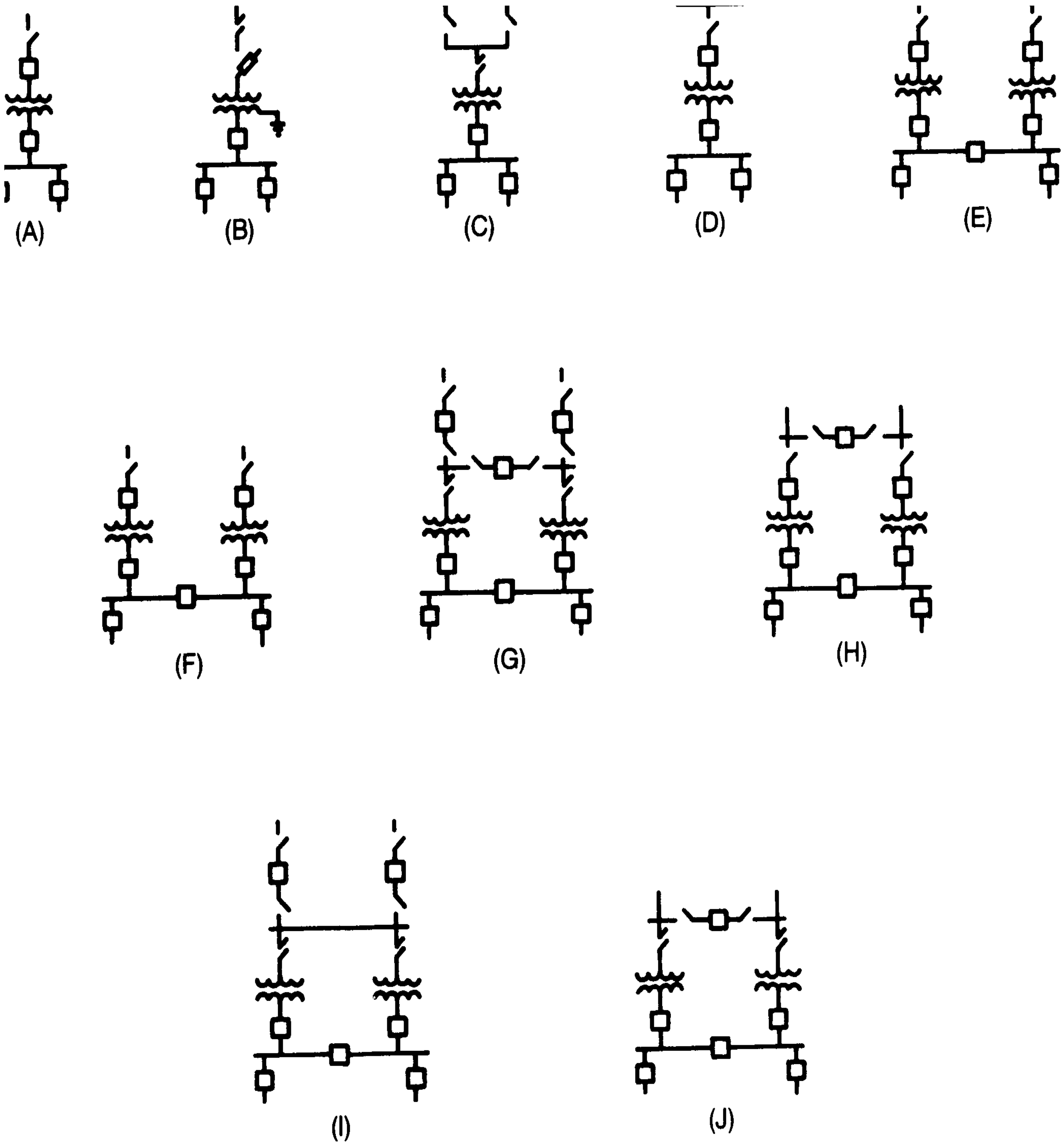

FIGURE 1-2
Typical Distribution Substation Arrangements

(b) A transformer section includes one or more transformers with or without automatic load-tap-changing (voltage regulating) capability.

(c) A secondary section provides for the connection of one or more secondary feeders. Each feeder is provided with a switching and interrupting device.

1.4.2.2 Substation Bus Arrangements. A bus is a junction of two or more incoming and outgoing circuits. The most common bus arrangement consists of one source or supply circuit and one or more feeder circuits. The numerous other arrangements and variations are mainly intended to improve the service reliability through the bus to all or part of the load during scheduled maintenance or unexpected power outages. Typical bus arrangements are shown in Figure 1-3.

The arrangements are normally referred to as:

(a) Double-bus.
(b) Two-source sectionalizing bus.
(c) Three-source sectionalizing bus.
(d) Star or synchronizing bus.

When two sources are used simultaneously, but must not be operated in parallel, a normally open bus-tie circuit breaker is interlocked with the source circuit breakers. This permits serving both bus sections from one of the sources when the other is not available. For normally parallel sources, a single straight bus may be used. It is preferable, however, to use a normally closed bus-tie circuit breaker to split the system so that service continuity can be retained on either section when the other section is out of service.

1.4.2.3 Substation Operation. Substations may be attended by operators or designed for automatic or remote control of the switching and voltage regulating equipment. Most large new substations are either automatic or remotely controlled.

(a) In an automatic substation, switching operations are controlled by a separately installed control system. Major apparatus, such as transformers and converting equipment, may be placed in or taken out of service automatically. Feeder circuit breakers, after being opened, can be reclosed by protective relays or by the control system.

(b) Remote control substations are often within a suitable distance from attended stations. In such cases pilot-wire cables provide the communication link to receive indications of circuit breaker or switch positions and to transmit control adjustments, as required. Microwave radio, telephone lines, and carrier current are often used for remote-control links at distances beyond the economic reach of pilot wire systems.

1.4.3 Types of Systems. There are two fundamental types of primary distribution systems; radial and network. Simply defined, a radial system has a single simultaneous path of power flow to the load. A network has more than one simultaneous path. Each of the two types of systems has a number of variations. Figure 1-4 illustrates four primary feeder arrangements showing tie, loop, radial and parallel feeders. There are other more complex systems, such as the primary network (interconnected substations with feeders forming a grid) and dual-service network (alternate feeder to each load). These systems, however, are simply variations of the two basic feeder arrangements.

The following paragraphs discuss the functions and characteristics of the simpler feeder arrangements.

1.4.3.1 Tie Feeder. The main function of a tie feeder is to connect two sources. It may connect two substation buses in parallel to provide service continuity for the load supplied from each bus.

1.4.3.2 Loop Feeder. A loop feeder has its ends connected to a source (usually a single source), but its main function is to supply two or more load points in between. Each load point can be supplied from either direction; so it is possible to remove any section of the loop from service without causing an outage at other load points. The loop can be operated normally closed or normally open. Most loop systems are, however, operated normally open at some point by means of a switch. The operation is very similar to that of two radial feeders.

1.4.3.3 Radial Feeder. A radial feeder connects between a source and a load point, and it may supply one or more additional load points between the two. Each load point can be supplied from one direction only. Radial feeders are most widely used by the Navy because the circuits are simple, easy to protect, and low in cost.

1.4.3.4 Parallel Feeder. Parallel feeders connect the source and a load or load center and provide the capability of supplying power to the load through one or any number of the parallel feeders. Parallel feeders provide for maintenance of feeders (without interrupting service to loads) and quick restoration of service when one of the feeders fails.

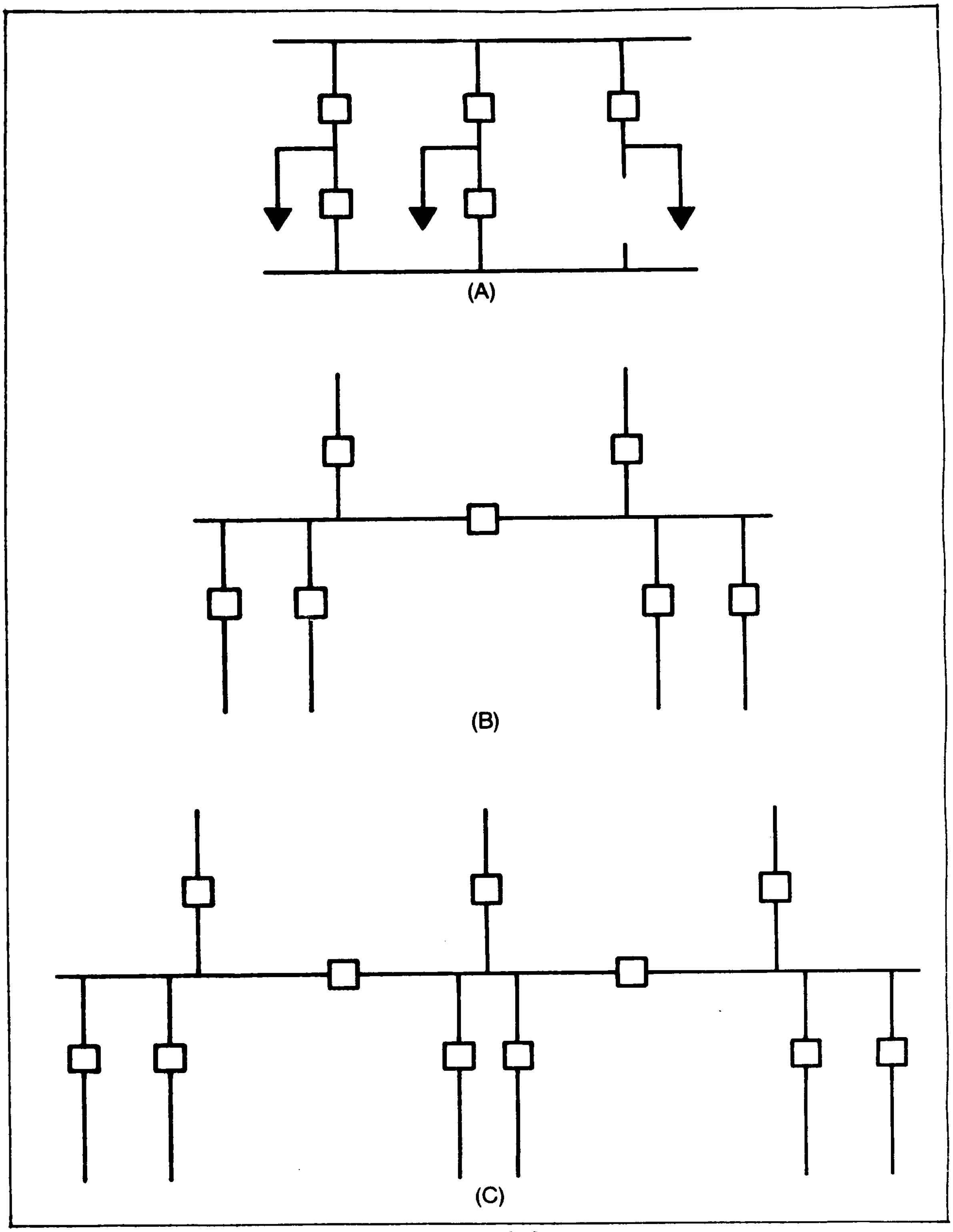

FIGURE 1-3
Typical Bus Arrangements

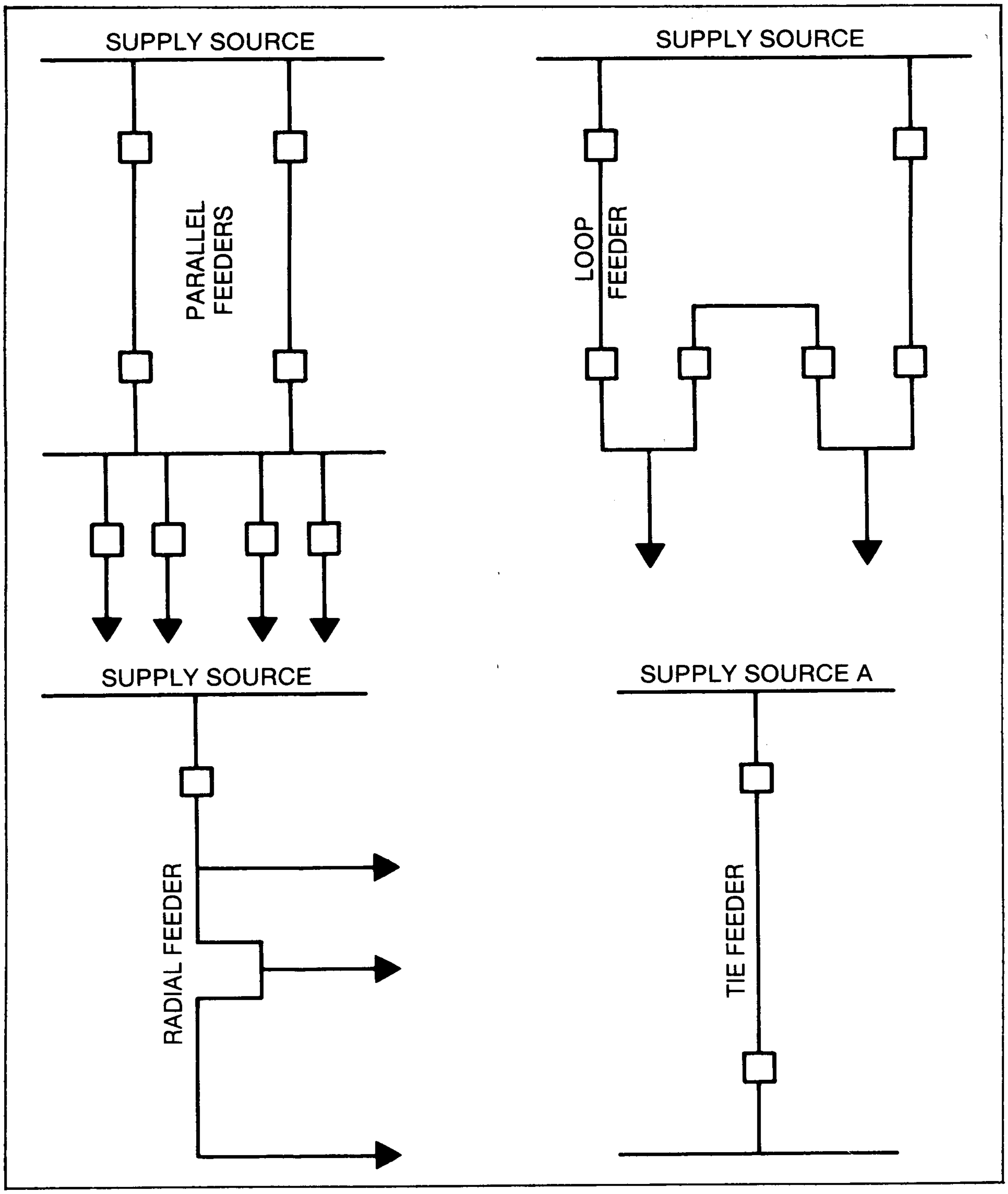

FIGURE 1-4
Four Primary Feeder Arrangements

1.5 SECONDARY DISTRIBUTION SYSTEMS. The secondary distribution system is that portion of the network between the primary feeders and utilization equipment. The secondary system consists of step-down transformers and secondary circuits at utilization voltage levels. Residential secondary systems are predominantly single-phase, but commercial and industrial systems generally use three-phase power.

1.5.1 Secondary Voltage Levels. The voltage levels for a particular secondary system are determined by the loads to be served. The utilization voltages are generally in the range of 120 to 600 V. Standard nominal system voltages are:

Volts	Phase	Wire
120	Single	2
120/240	Single	3
208Y/120	Three	4
240	Three	3
480Y/277	Three	4
480	Three	3
600	Three	3

In residential and rural areas the nominal supply is a 120/240 V, single-phase, three-wire grounded system. If three-phase power is required in these areas, the systems are normally 208Y/120 V or less commonly 240/120 V. In commercial or industrial areas, where motor loads are predominant, the common three-phase system voltages are 208Y/120 V and 480Y/277 V. The preferred utilization voltage for industrial plants, however, is 480Y/277 V. Three-phase power and other 480 V loads are connected directly to the system at 480 V and fluorescent lighting is connected phase to neutral at 277 V. Small dry-type transformers, rated 480-208Y/120 or 480-120/240 V, are used to provide 120 V single-phase for convenience outlets and to provide 208 V single- and three-phase for small tools and other machinery.

1.5.2 Types of Systems. Various circuit arrangements are available for secondary power distribution. The basic circuits are: simple radial system, expanded radial system, primary selective system, primary loop system, secondary selective system, and secondary spot network.

1.5.2.1 Conventional Simple-Radial Distribution System. In the simple-radial system

(Figure 1-5), distribution is at the utilization voltage. A single primary service and distribution transformer supply all the feeders. There is no duplication of equipment. System investment is the lowest of all circuit arrangements. Operation and expansion are simple. Reliability is high if quality components are used, however, loss of a cable, primary supply, or transformer will cut off service. Further, electrical service is interrupted when any piece of service equipment must be deenergized to perform routine maintenance and servicing.

1.5.2.2 Expanded Radial Distribution System. The advantages of the radial system may be applied to larger loads by using a radial primary distribution system to supply a number of unit substations located near the load centers with radial secondary systems (Figure 1-6). The advantages and disadvantages are similar to those described for the simple radial system.

1.5.2.3 Primary Selective Distribution System. Protection against loss of a primary supply can be gained through use of a primary selective system (Figure 1-7). Each unit substation is connected to two separate primary feeders through switching equipment to provide a normal and an alternate source. When the normal source feeder is out of service for maintenance or a fault, the distribution transformer is switched, either manually or automatically, to the alternate source. An interruption will occur until the load is transferred to the alternate source. Cost is somewhat higher than for a radial system because primary cable and switchgear are duplicated.

1.5.2.4 Loop Primary-Radial Distribution System. The loop primary system (Figure 1-8) offers nearly the same advantages and disadvantages as the primary selective system. The failure of the normal source of a primary cable fault can be isolated and service restored by sectionalizing. Finding a cable fault in the loop, however, may be difficult and dangerous. The quickest way to find a fault is to sectionalize the loop and reclose, possibly involving several reclosings at the fault. A section may also be energized at both ends, thus, effecting another potential danger. The cost of the primary loop system may be somewhat less than that of the primary selective system. The savings may not be justified, however, in view of the disadvantages.

1.5.2.5 Secondary Selective-Radial Distribution System. When a pair of unit substations are connected through a normally open secondary tie circuit breaker, the result is a secondary selective-radial distribution system (Figure 1-9). If the primary feeder or a transformer fails, the main secondary circuit breaker on the affected transformer is opened and the tie circuit breaker is closed. Operation may be manual or automatic. Normally, the stations operate as radial systems. Maintenance of primary feeders, transformer, and main secondary circuit breakers is possible with only momentary power interruption, or no interruption, if the stations may be operated in parallel during switching. With the loss of one primary circuit or transformer, the total substation load may be supplied by one transformer. In this situation, however, if load shedding is to be avoided, both transformers and each feeder must be oversized to carry the total load. A distributed secondary selective system has pairs of unit substations in different locations connected by tie cables and normally open tie circuit breakers. The secondary selective system may be combined with the primary selective system to provide a high degree of reliability.

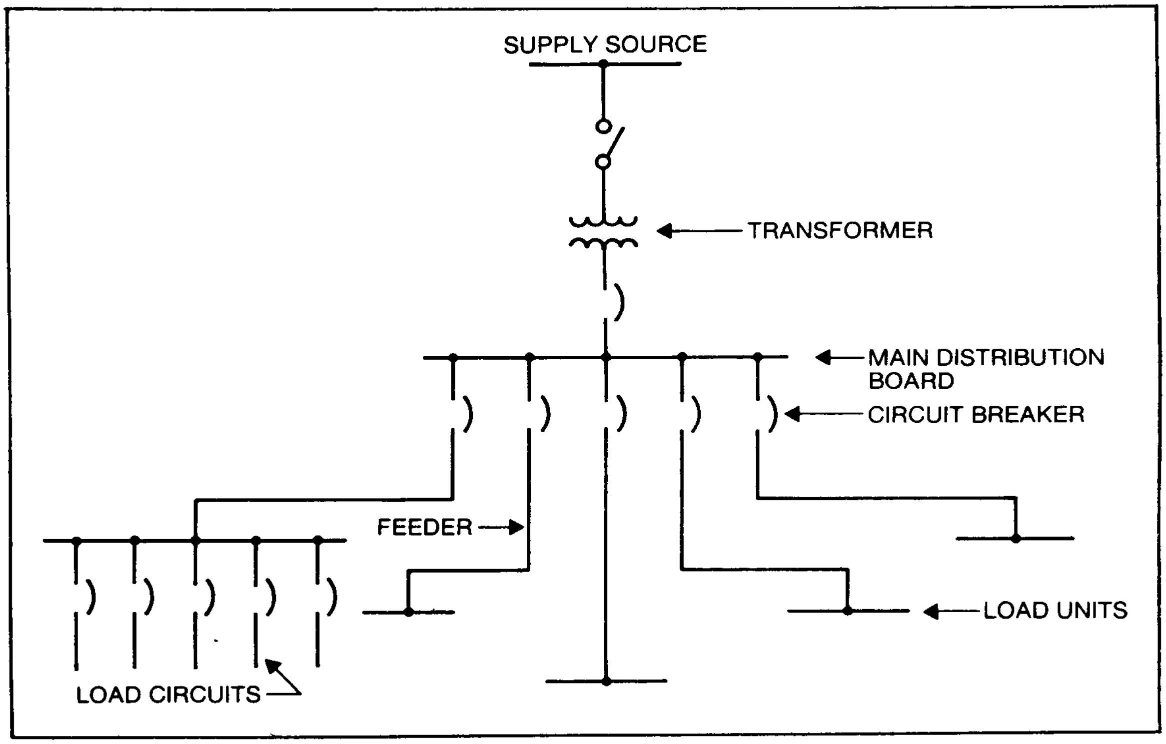

FIGURE 1-5
Conventional Simple-Radial Distribution System

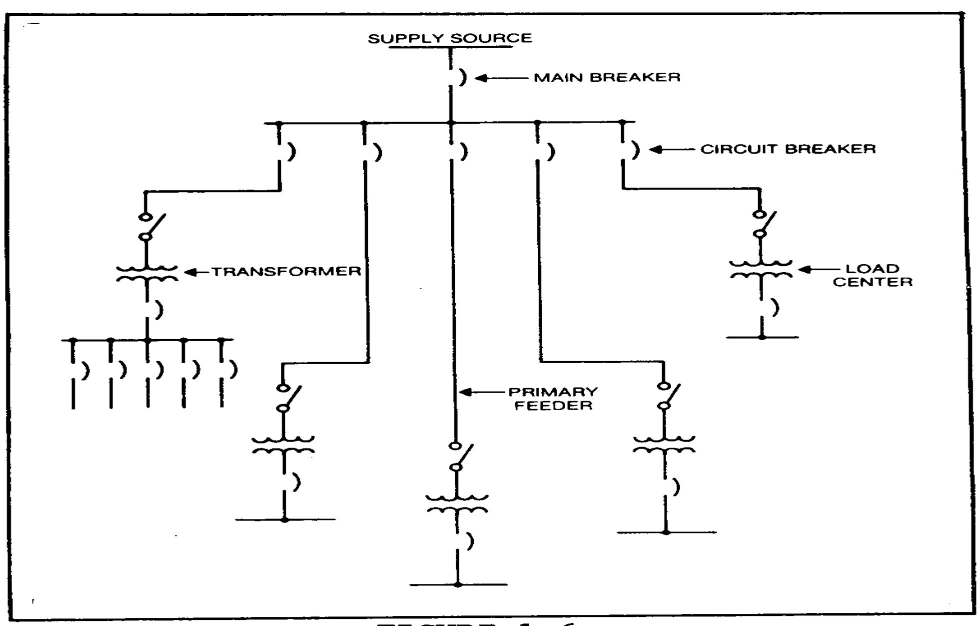

FIGURE 1-6
Expanded Radial Distribution System

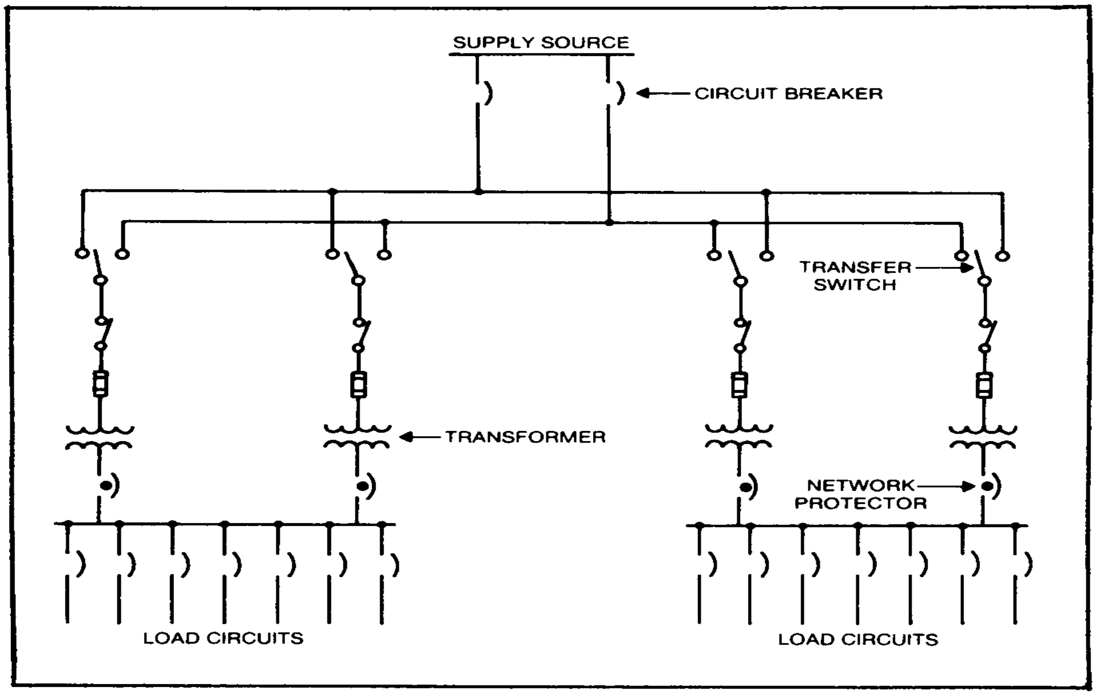

FIGURE 1-7
Primary Selective Distribution System

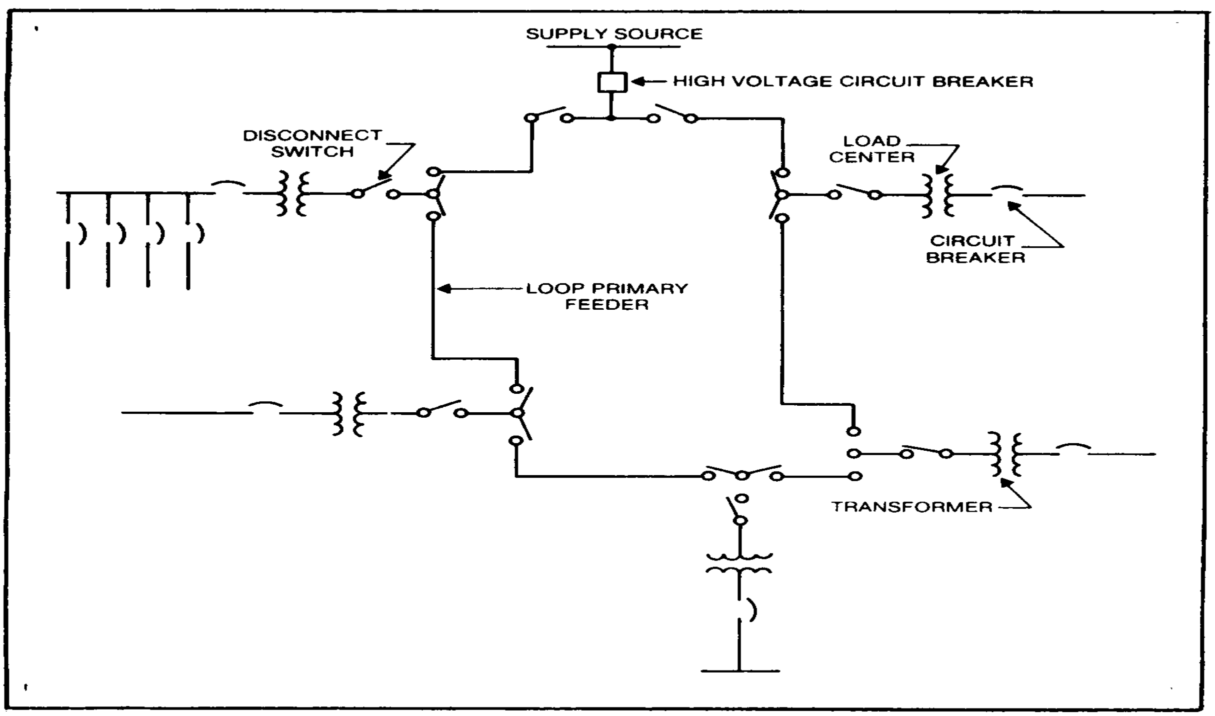

FIGURE 1-8
Loop Primary-Radial Distribution System

1.5.2.6 Secondary Network Distribution System. In a secondary network distribution system, two or more distribution transformers are each supplied from a separate primary distribution feeder (Figure 1-10).

The secondaries of the transformers are connected in parallel through a special type of circuit breaker, called a network protector, to a secondary bus. Radial secondary feeders are tapped from the secondary bus to supply loads. A more complex network is a system in which the low-voltage circuits are interconnected in the form of a grid or mesh.

(a) If a primary feeder fails, or a fault occurs on a primary feeder or distribution transformer, the other transformers start to feed back through the network protector on the faulted circuit. This reverse power causes the network protector to open and disconnect the faulty supply circuit from the secondary bus. The network protector operates so fast that there is minimal exposure of secondary equipment to the associated voltage drop.

(b) The secondary network is the most reliable for large loads. A power interruption can only occur when there is a simultaneous failure of all primary feeders or when a fault occurs on the secondary bus. There are no momentary interruptions as with transfer switches on primary selective, secondary selective, or loop systems. Voltage dips which could be caused by faults on the system, or large transient loads, are materially reduced.

(c) Networks are expensive because of the extra cost of the network protector and excess transformer capacity. In addition, each transformer connected in parallel increases the available short-circuit current and may increase the duty rating requirement of secondary equipment.

1.5.2.7 Secondary Banking. The term banking means to parallel, on the secondary side, a number of transformers. All of the transformers are connected to the same primary feeder. Banking is usually applied to the secondaries of single-phase transformers, and the entire bank must be supplied from the same phase of the primary circuit. All transformers in a bank are usually of the same size and should have the same nominal impedance.

(a) The advantages of banking include: reduction in lamp flicker caused by starting motors, less transformer capacity required because of greater load diversity, and better average voltage along the secondary.

(b) Solid banking, where the secondary conductors are connected without overcurrent protection, is usually not practiced because of the obvious risks. Three methods of protecting banked transformers are shown in Figure 1-11. In each arrangement the transformers are connected to the primary feeder through high-voltage protective links or fuses. Each method has different degrees of protection, depending on the location of the protective devices in the

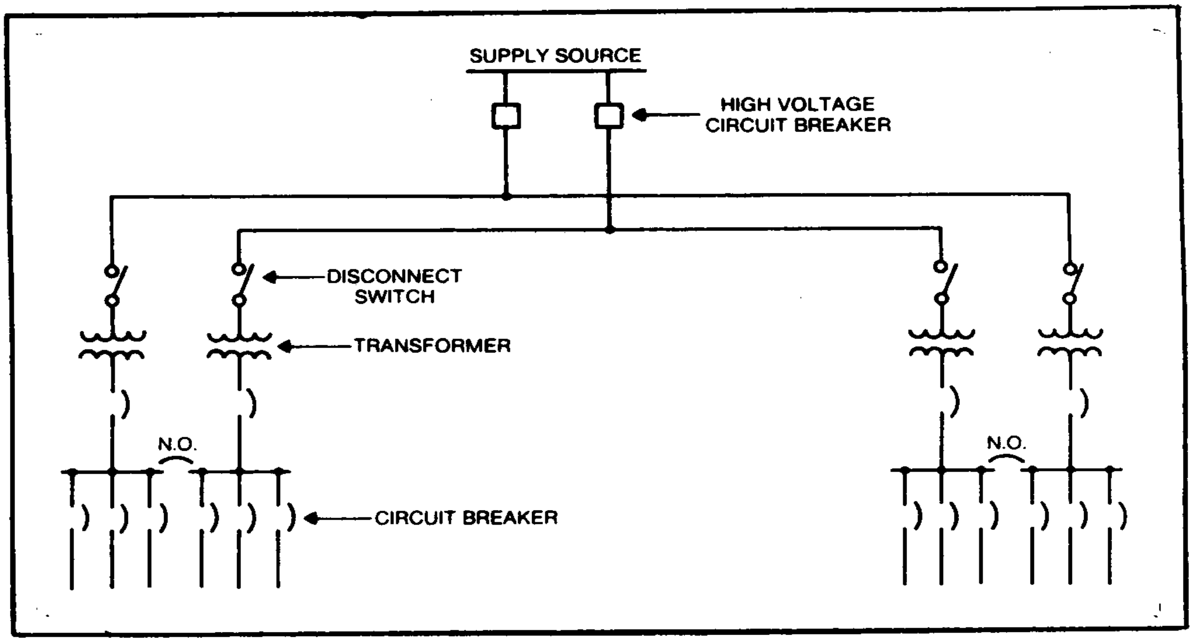

FIGURE 1-9
Secondary Selective-Radial Distribution System

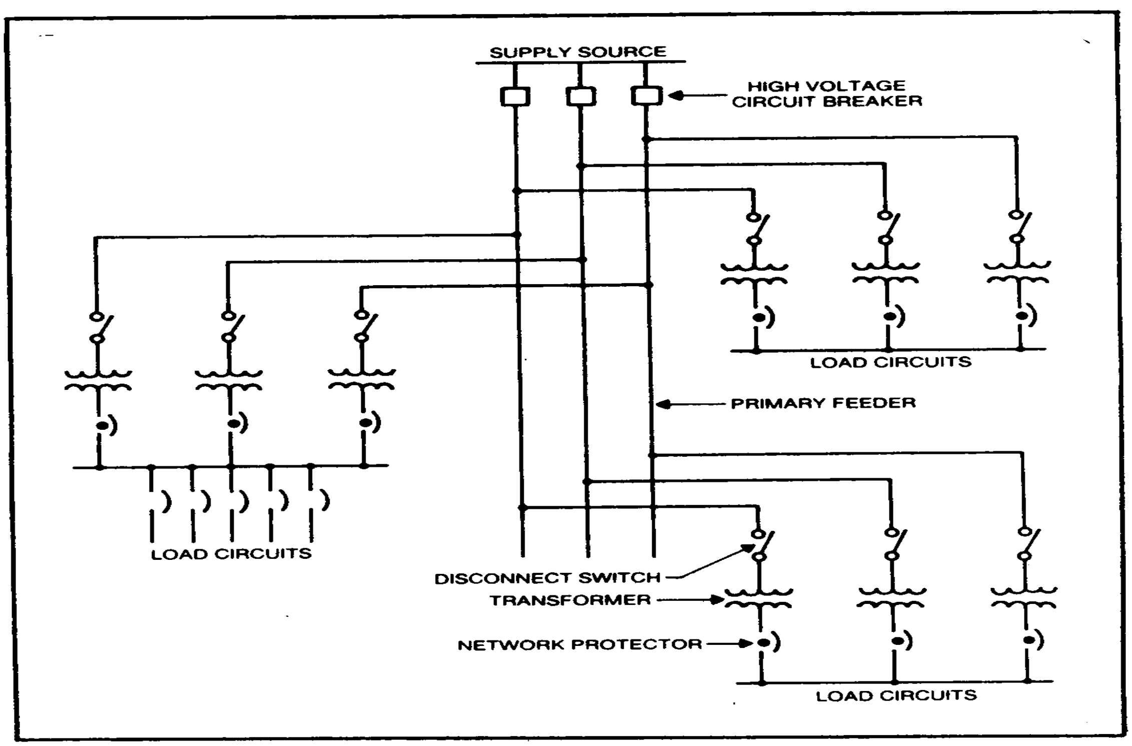

FIGURE 1-10
Secondary Network Distribution System

secondary. Figure 1-11(A) offers the least protection due to the slow acting fuses normally used in this configuration. In the arrangement of Figure 1-11(B), the secondary circuit is sectionalized and the faulted section can be isolated by the fuses.

The third scheme, shown in Figure 1-11(C), utilizes special transformers designed exclusively for banked secondary operation. These transformers, known as completely self-protecting transformers for banking (CSPB), contain in one integral unit the high-voltage protective link and the two secondary breakers. When excessive current flows in one of the breakers, it will trip independently of the other. Fault current protection and sectionalizing of secondary banks are more efficiently accomplished by this method.

1.6 EMERGENCY AND STANDBY POWER SYSTEMS. The principle and practices of emergency and standby power systems is presented in this section. Mobile equipment and uninterruptible power supply (UPS) systems are also discussed. Technical information is included on typical equipment and systems.

1.6.1 Definitions.

1.6.1.1 Emergency Power System. An emergency power system is an independent reserve source of electric energy. Upon failure or outage of the normal or primary power source, the system automatically provides reliable electric power within a specified time. The electric power is provided to critical devices and equipment whose failure to operate satisfactorily would jeopardize the health and safety of personnel or result in damage to property. The emergency power system is usually intended to operate for a period of several hours to a few days. See NAVFAC MO-322 for testing procedures.

1.6.1.2 Standby Power System. An independent reserve source of electric energy which, upon failure or outage of the normal source, provides electric power of acceptable quality and quantity so that the user's facilities may continue satisfactory operation. The standby system is usually intended to operate for periods of a few days to several months, and may augment the primary power source under mobilization conditions.

1.6.1.3 Uninterruptible Power Supply (UPS). UPS is designed to provide continuous power and to prevent the occurrence of transients on the power service to loads which cannot tolerate interruptions and/or transients due to sensitivity or critical operational requirements.

1.6.2 System Description.

1.6.2.1 Emergency Power Systems. Emergency power systems are of two basic types:

(a) An electric power source separate from the prime source of power, operating in parallel, which maintains power to the critical loads should the prime source fail.

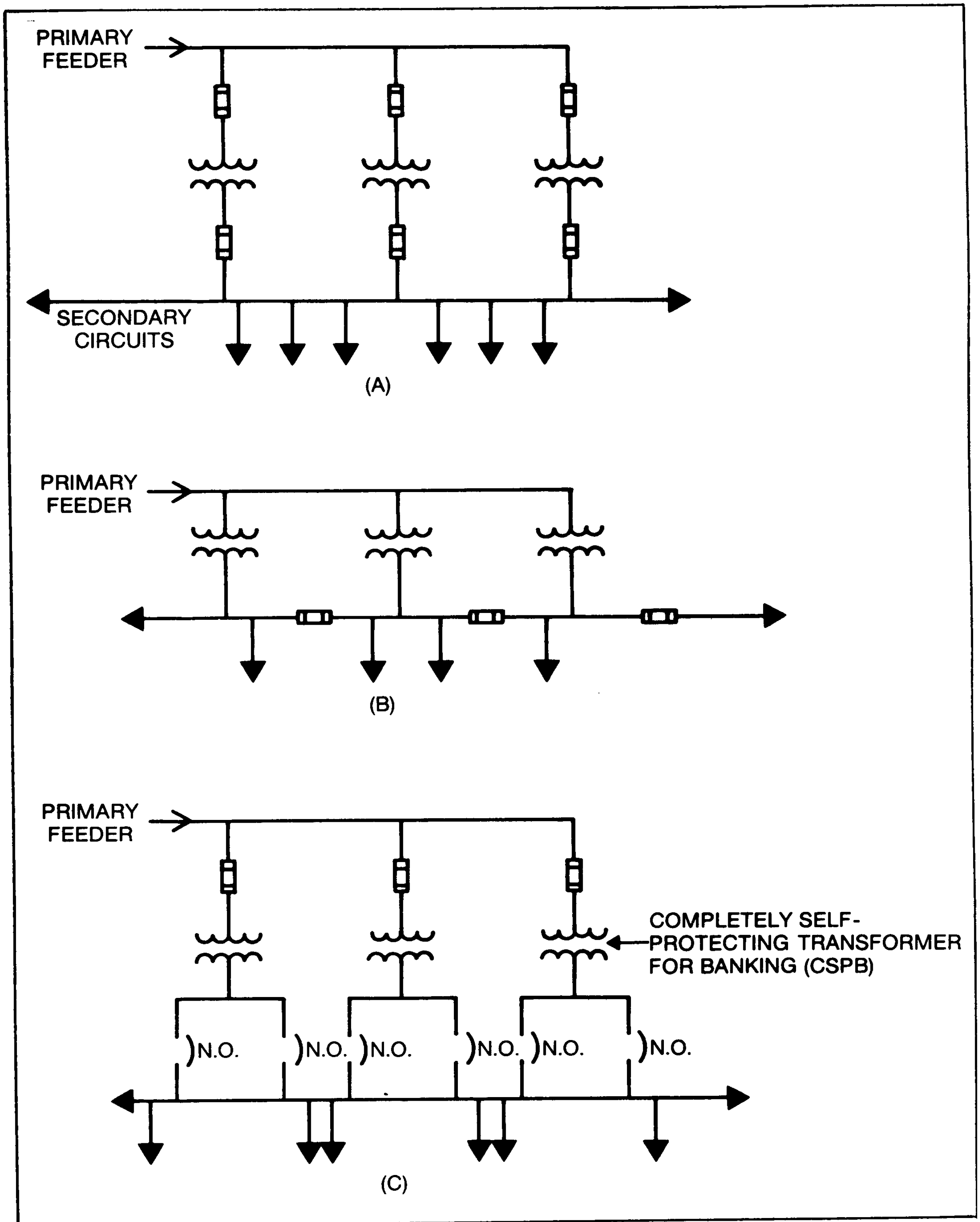

FIGURE 1-11
Secondary Banking Distribution System

(b) An available reliable power source to which critical loads are rapidly switched automatically when the prime source of power fails.

Emergency systems are frequently characterized by a continuous or rapid availability of electric power. This electric power operates for a limited time and is supplied by a separate wiring system. The emergency power system may in turn be backed by a standby power system if interruptions of longer duration are expected.

1.6.2.2 Standby Power Systems. Standby power systems are made up of the following main components:

(a) An alternate reliable source of electric power separate from the prime source.

(b) Starting and regulating controls when on-site standby generation is selected as the source.

(c) Controls which transfer loads from the prime or emergency power source to the standby source.

1.6.3 Engine-Driven Generators. These units are work horses which fulfill the need for emergency and standby power. They are available from fractional kW units to units of several thousand kW. When properly maintained and kept warm, the engine driven generators reliably come on line within 8 to 15 seconds. In addition to providing emergency power, engine-driven generators are also used for handling peak loads and are sometimes used as the preferred source of power. They fill the need of backup power for uninterruptible power systems.

1.6.3.1 Generator Voltage. The output of engine-driven generators used for emergency or standby power service is normally at distribution or utilization voltages. Generators rated at 500 kW or less operate at utilization voltages of 480Y/277 V, 208Y/120 V, or 240Y/120 V. Higher rated generators usually operate at nominal distribution system voltages of 2400 V, 4160 V, or 13,800 V.

1.6.3.2 Diesel Engine Generators. The ratings of diesel engine generators vary from about 2.5 kW to 6500 kW. Typical ratings for emergency or standby power service are 100 kW, 200 kW, 500 kW, 750 kW, 1000 kW, 1500 kW, 2000 kW, and 2500 kW. Two typical operating speeds of diesel engine generators in emergency and standby service are 1800 rpm and 1200 rpm. Lower speed units are heavier and costlier, but are more suitable for continuous power while nearly all higher speed (1800 rpm) sets are smaller.

1.6.3.3 Gasoline Engine Generators. Gasoline engines are satisfactory for installations up to approximately 100 kW output. They start rapidly and are low in initial cost as compared to diesel engines. Disadvantages include: higher operating costs, a great hazard due to the storing and handling of gasoline, and a generally lower mean time between overhaul.

1.6.3.4 Gas Engine Generators. Natural gas and liquid propane (LP) gas engines rank with gasoline engines in cost and are available up to about 600 kW. They provide quick starting after long shutdown periods because of the fresh fuel supply. Engine life is longer with reduced maintenance because of the clean burning of natural gas.

1.6.3.5 Gas Turbine Generators. Gas combustion turbine generators usually range in size from 100 kW to 20 MW, but may be as large as 100 MW in utility power plants. The gas turbines operate at high speeds (2000 to 5000 rpm) and drive the generators at 900 to 3600 rpm through reduction gearing. Gas turbine generator voltages range from 208 V to 22,000 V. The gas turbine generator system has a higher ratio of kW to weight or to volume than other prime mover systems and operates with less vibration than the other internal combustion engines, but with lower fuel efficiency.

1.6.4 Typical Engine Generator Systems. The basic electrical components are the engine generator set and associated meters, controls, and switchgear. Most installations include a single generator set designed to serve either all the normal electrical needs of a building or a limited emergency circuit. Sometimes the system includes two or more generators of different types and sizes, serving different types of loads. Also, two or more generators may be operating in parallel to serve the same load. Automatic starting of multiple units and automatic synchronizing controls are available and practical for multiple-unit installations.

1.6.4.1 Automatic Systems. In order for engine-driven generators to provide automatic emergency power, the system must also include automatic engine starting controls, batteries, an automatic battery charger, and an automatic transfer device. In most applications, the utility source is the normal source and the engine generator set provides emergency power when utility power fails. The utility power supply is monitored and engine starting is automatically initiated once there is a failure or severe voltage or frequency reduction in the normal supply. Load is automatically transferred as soon as the standby generator stabilizes at rated voltage and speed. Upon restoration of normal supply, the load is transferred back to the normal source and the engine is shut down.

(a) Automatic transfer devices (ATD) for use with engine-driven generator sets are similar to those used with multiple-utility systems, except for the addition of auxiliary contacts that close when the normal source fails. These auxiliary contacts initiate the starting and stopping of the engine-driven generator. The auxiliary contacts include a paralleling contactor (PC) and a load-dumping contactor (LDC), both electrically operated and mechanically held.

1.6.4.2 Engine Generators (Parallel operation). Figure 1-12 shows a standby power system where failure of the normal source would cause both engines to automatically start. The first generator to reach operating voltage and frequency will actuate load dumping control circuits and provide power to the remaining load. When the second generator is in synchronism, it will be paralleled automatically with the first. After the generators are paralleled, power is restored to all or part of the dumped loads. This system is the ultimate in automatic systems requiring more complexity and cost than would be appropriate in most activity requirements.

(a) If one generator fails, it is immediately disconnected. A proportionate share of the load is dumped to reduce the remaining load to within the capacity of the remaining generator. When the failed generator is returned to operation, the dumped load is reconnected.

(b) When the normal source is restored, the load is transferred back to it and the generators are automatically disconnected and shut down.

1.6.4.3 Peak Load Control System. With the peak load control system shown in Figure 1-13, idle standby generator sets can perform a secondary function by helping to supply power for peak loads. Depending on the load requirements, this system starts one or more units to feed peak loads while the utility service feeds the base loads.

1.6.4.4 Combined Utility-Generator Operation. The system shown in Figure 1-14 provides switching and control of utility and on-site power. Two on-site buses are provided, (1) supply bus (primary) supplies continuous power for computer or other essential loads, and (2) an emergency bus (secondary) supplies on-site generator power to emergency loads through an automatic transfer device if the utility service fails.

In normal operation, one of the generators is selected to supply continuous power to the primary bus (EG1 in Figure 1-14). Simplified semiautomatic synchronizing and paralleling controls permit any of the idle generators to be started and paralleled with the running generator to alternate generators without load interruption. Anticipatory failure circuits permit load transfer to a new generator without load interruption. If the generator enters a critical failure mode, however, transfer to a new generator is made automatically with load interruption.

1.6.5 <u>Engine Generator Operation</u>.

1.6.5.1 Governors and Regulation. Governors can operate in two modes, droop and isochronous. With droop operation, the engine's speed is slightly higher at light loads than at heavy loads, while an isochronous governor maintains the same steady speed at any load up to full load:

$$\text{speed regulation} = \frac{(\text{no-load rpm}) - (\text{full-load rpm})}{(\text{full-load rpm})} \times 100\%$$

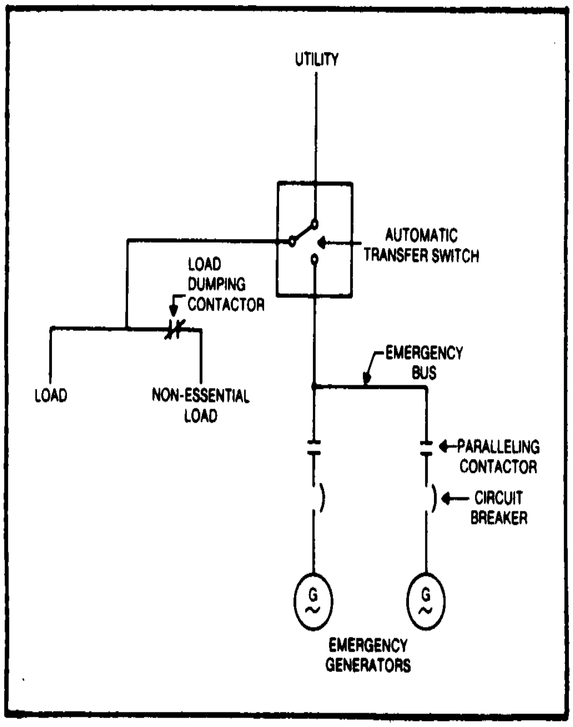

FIGURE 1-12
Engine Generators
(Parallel Operation)

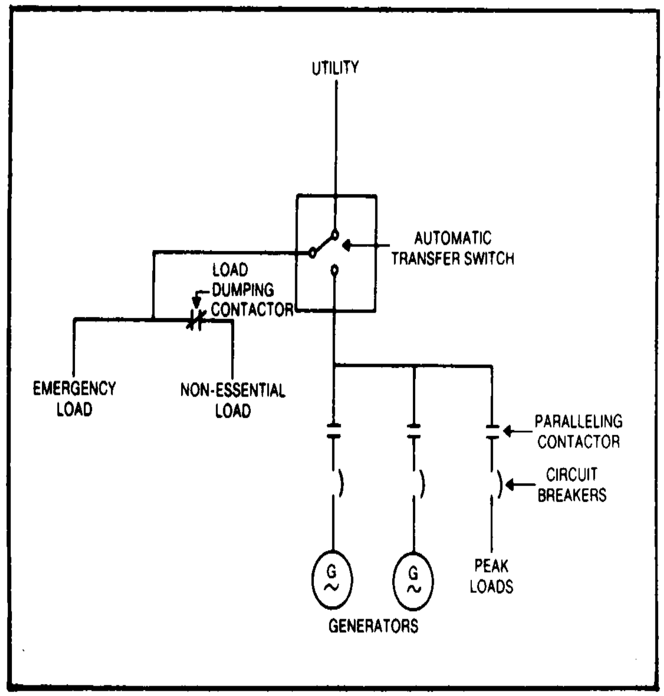

FIGURE 1-13
Peak Load Control System

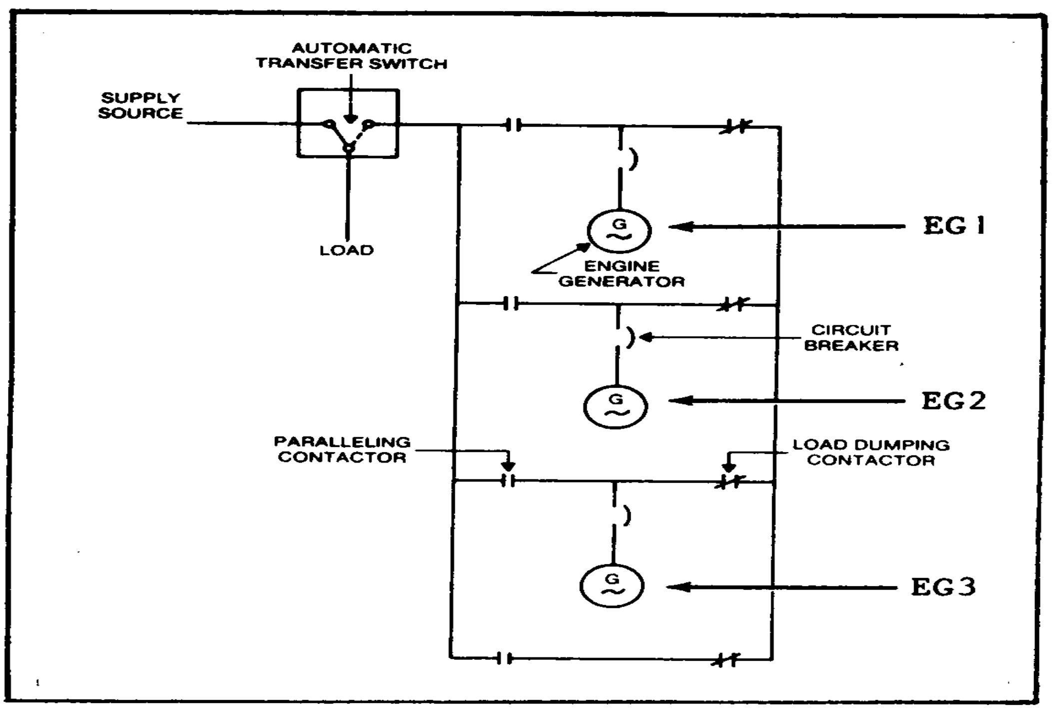

FIGURE 1-14
Combined Utility-Generator System

(a) A typical speed regulation for a governor operating with droop is 3 percent. Thus, if speed and frequency at full load are 1800 rpm and 60 Hz, at no load they would be approximately 1854 rpm and 61.8 Hz.

A governor would be set for droop only when operating in parallel (in this mode f = 60 Hz +/- 0) with a larger system or in parallel with another generator operating in the isochronous mode. In this way, system frequency is maintained and the droop adjustment controls load distribution among parallel engine generators.

(b) Under steady (or stable) load, frequency tends to vary slightly above and below the normal frequency setting of the governor. The extent of this variation is a measure of the stability of the governor. An isochronous governor should maintain frequency regulation within +/- 1/4 percent under steady load.

(c) When load is added or removed, speed and frequency dip or rise momentarily, usually for 1 to 3 seconds, before the governor causes the engine to settle at a steady speed at the new load.

1.6.5.2 Starting Methods. Most engine generator sets use a battery-powered electric motor for starting the engine. A pneumatic or hydraulic system normally is used only where starting of the electric plant is initiated manually.

1.6.6 <u>Turbine-Driven Generators</u>. Steam and petroleum are two general types of turbine prime movers for electrical generators currently available.

1.6.6.1 Steam Turbine Generators. Steam turbines are used to drive generators larger than those driven by diesel engines. Steam turbines are designed for continuous operation and usually require a boiler with a fuel supply and a source of condensing water. Because steam boilers usually have electrically powered auxiliary fans and pumps, steam turbine generators cannot start during a power outage. Steam turbine generators are, therefore, too large, expensive, and unreliable for use as an emergency or standby power supply. They may also experience environmental problems involving: fuel supply, noise, combustion product output, and heating of the condensing water. Steam turbines may also be used in cogeneration systems, where steam may be extracted from the turbine to serve process loads. In this configuration, no steam is condensed at the turbine exhaust, but rather the turbine operates with a back pressure and serves as a pressure reducing station.

1.6.6.2 Turbine Generators (Petroleum). The most common turbine-driven electric generator units employed for emergency or standby power today use gas or oil for fuel. Various grades of oil and both natural and propane gas may be used. Other less common sources of fuel are kerosene or gasoline. Gas or oil turbine generators can start and assume load within 40 seconds to several minutes for larger units. Gas turbine generators are generally used as emergency backup power sources because they start quickly, can assume full load in only one or two steps, and are less efficient than other prime movers. When there is a constant need for both process steam (or hot water) and electricity, the gas turbine generator (with an exhaust heat recovery system) may operate efficiently and continuously in a topping cycle cogeneration configuration. Combustion turbine generator sets exhibit excellent frequency control, voltage regulation, transient response, and behavior when operated in parallel with the utility supply.

1.6.7 Mobile Power Systems. One of the most important sources of emergency or standby power is mobile (transportable) equipment. For most industrial applications, mobile equipment will include only two types; diesel-engine-driven and gas-turbine-driven generators.

1.6.7.1 Ratings. Typical ratings of mobile generators range from kW to 2700 kW. Larger power ratings are satisfied by parallel operation.

1.6.7.2 Accessories. Mobile generators come anywhere from a stripped down unit with nothing but the prime mover and generator to units complete with soundproof chamber, control panel, relaying, switchgear, intake and exhaust silencers, fuel tank, battery, and other required operating and safety devices.

1.6.7.3 Navy Mobile Equipment. The Navy's Mobile Utilities Support Equipment (MUSE) program provides specialized, easily transportable utility modules for short-term support of shore utility systems. MUSE equipment includes generating units, substations, steam boilers, water treatment plants, and auxiliary equipment. Policy, procedures, and guidance for the management and use of MUSE are found in NAVFACENGCOM Instruction 11310.2. Detailed technical and general application data for the equipment are provided in the MUSE Application Guide, NEESA 50.1-001. Copies are available from Commanding Officer, Naval Energy and Environmental Support Activity, Port Hueneme, CA 93043-5014.

(a) For power plants, the nominal ratings of diesel engine generators are 750 kW to 2,500 kW. The gas turbine generators are rated at 750 kW.

(b) The nominal capacities of MUSE substations range from 1,500 kVA to 5,000 kVA. These substations are designed to provide maximum flexibility for transforming various system voltages. Presently, transformers rated 3,750 kVA and larger are two winding units, providing transformation between 13.2 kV or 11.5 kV and 4.16 kV. Either winding may be used as input or output. Units smaller than 3,750 kVA have three winding transformers. Their High Voltage (HV) winding nominal voltages are 13.2 kV or 11.5 kV; their Intermediate Voltage (IV) winding nominal voltages are 4.16 kV or 2.4 kV; and their Low Voltage (IV) winding nominal voltage is 480 V. These units can be operated with the HV or the IV acting as the input or output. The IV winding is an output winding only.

1.6.8 Uninterruptible Power Supply Systems. The UPS system includes all mechanical and electrical devices needed to automatically provide continuous, regulated electric power to critical loads during primary power system disturbances and outages. During normal conditions, the UPS system receives input power from the primary source and acts as a precise voltage and frequency regulator to condition output power to sensitive loads. During disturbance or loss of the input power, the UPS draws upon its stored-energy source to maintain the regulated output power. The stored energy source is usually sized to supply the UPS load for several minutes, until emergency or the normal input power is restored, or until the loads have undergone an orderly shutdown. There are two basic uninterruptible power supply systems: the rotary (mechanical stored-energy) system and the static (solid-state electronic system with storage-battery).

1.6.8.1 Rotary (Mechanical Stored-Energy) Systems. Upon loss of input power, rotary systems deliver uninterruptible power by converting the kinetic energy contained in a rotating mass to electric energy. These systems provide an excellent buffer between the prime power source and loads that will not tolerate fluctuations in voltage and frequency. Many types of systems are in use, but since static equipment has been used to replace rotary systems in the past ten years, only one configuration will be described.

The rotating flywheel no break system is shown in Figure 1-15. An induction motor is driven from the utility supply and this motor is directly coupled to an alternator with its own excitation and voltage regulating system. Coupled directly to the motor generator set is a large flywheel with one member of a magnetic clutch attached to the flywheel. The other half of the clutch is connected to a diesel engine or other prime power. Upon loss of alternating current input power, the generator is driven by energy stored in the flywheel until the engine can be started and drive the generator and flywheel. The voltage regulator maintains the voltage and, with proper selection of components to minimize the start and run times of the diesel engine, the frequency dip can be kept to approximately 1.5 to 2 Hz. Thus with a steady-state frequency of 59.5 Hz, the minimum transient frequency would be from 57.5 to 58 Hz. The time for the diesel to start, come up to speed, and assume the load would normally be from 6 to 12 seconds.

1.6.8.2 Static (Solid-State Electronic Circuitry) Systems. The basic static UPS system consists of a rectifier, battery, and DC-to-AC inverter. Static systems are very efficient power conversion devices. The advantages of static systems are stable operation, frequency unaffected by load changes, excellent voltage regulation, and fast transient response. These systems normally operate at 480Y/277 V or 208Y/120 V, 3-phase, 60 Hz input voltage and provide an output of 480Y/277 V or 280Y/120 V. Typical output specifications are: voltage regulation of +1 percent and frequency regulation of +0.001 percent. The ratings of these systems range from 50 VA to more than 1200 kVA. A UPS system can be designed with various combinations of rectifiers and inverters to operate in a nonredundant or redundant configuration.

(a) A nonredundant UPS system is shown in Figure 1-16. During normal operation, the prime power and rectifier supply power to the inverter, and also charge the battery which is floated on the direct current bus and kept fully charged. The inverter converts power from direct to alternating current for use by the critical loads. The inverter governs the characteristics of the alternating current output, and any voltage or frequency fluctuations or transients present on the utility power system are completely isolated from the critical load. When momentary or prolonged loss of power occurs, the battery will supply sufficient power to the inverter to maintain its output for a specified time until the battery has discharged to a predetermined minimum voltage. Upon restoration of the prime power, the rectifier section will again resume feeding power to the inverter and will simultaneously recharge the battery.

(b) The nonredundant UPS system reliability can be improved by installing a static switch and bypass parallel with the UPS as shown in Figure 1-17. When an inverter fault is sensed, the critical load can be transferred to the bypass circuit in less than 5 milliseconds. The static bypass adds about 20 percent to the cost of a nonredundant system, but is much more reliable.

(c) In the redundant UPS system shown in Figure 1-18, each half of the system has a rating equal to the full critical load requirements. The basic power elements (rectifier, inverter, and interrupter) are duplicated, but it is usually not necessary to duplicate the battery since it is extremely reliable. Certain control elements such as the frequency oscillator may also be duplicated. The static interrupters isolate the faulty inverter from the critical bus and prevent the initial failure from starting a chain reaction which might cause the remaining inverter to fail. The static bypass switch can also be applied to the redundant system.

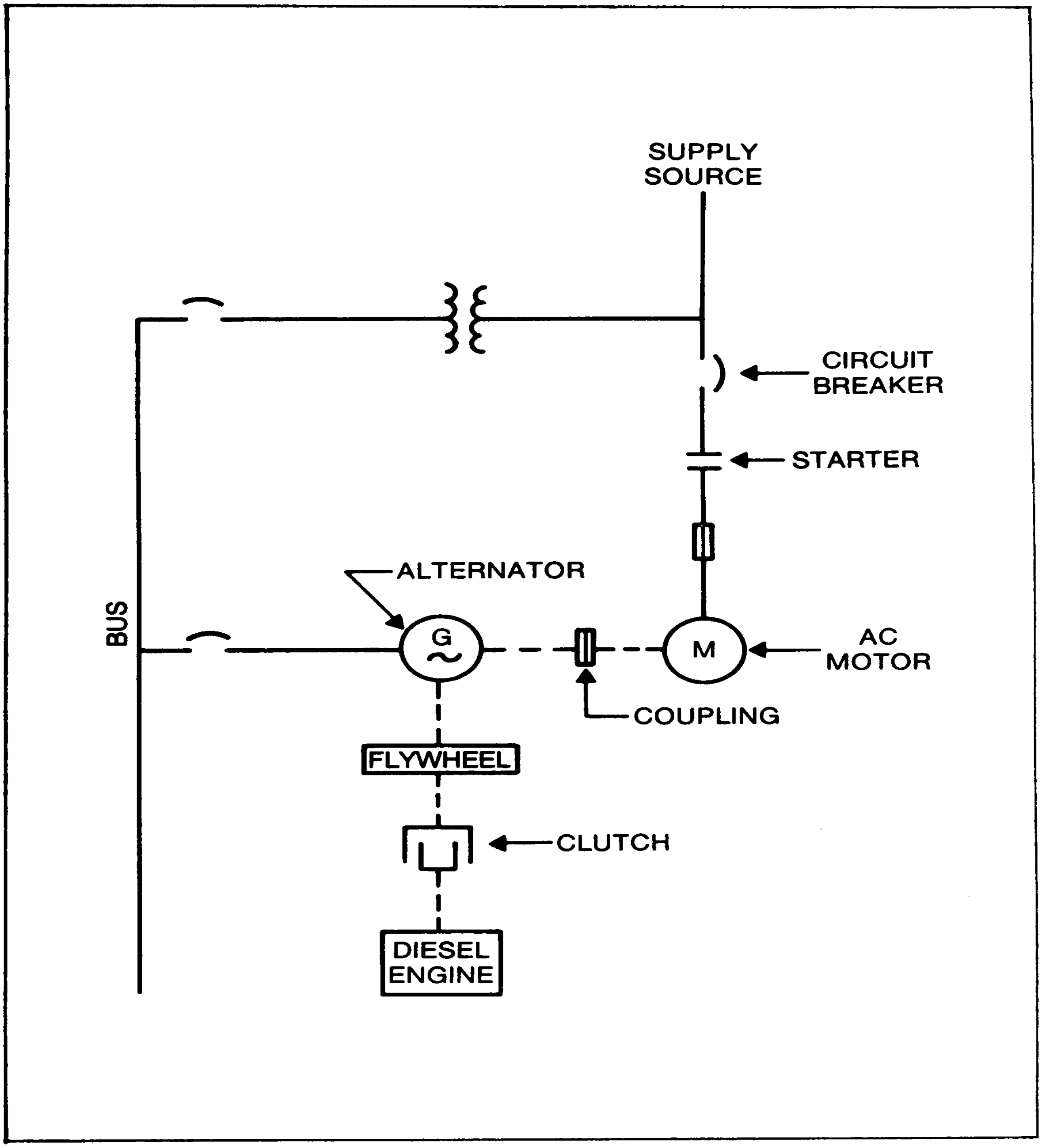

FIGURE 1-15
Rotating Flywheel No Break System

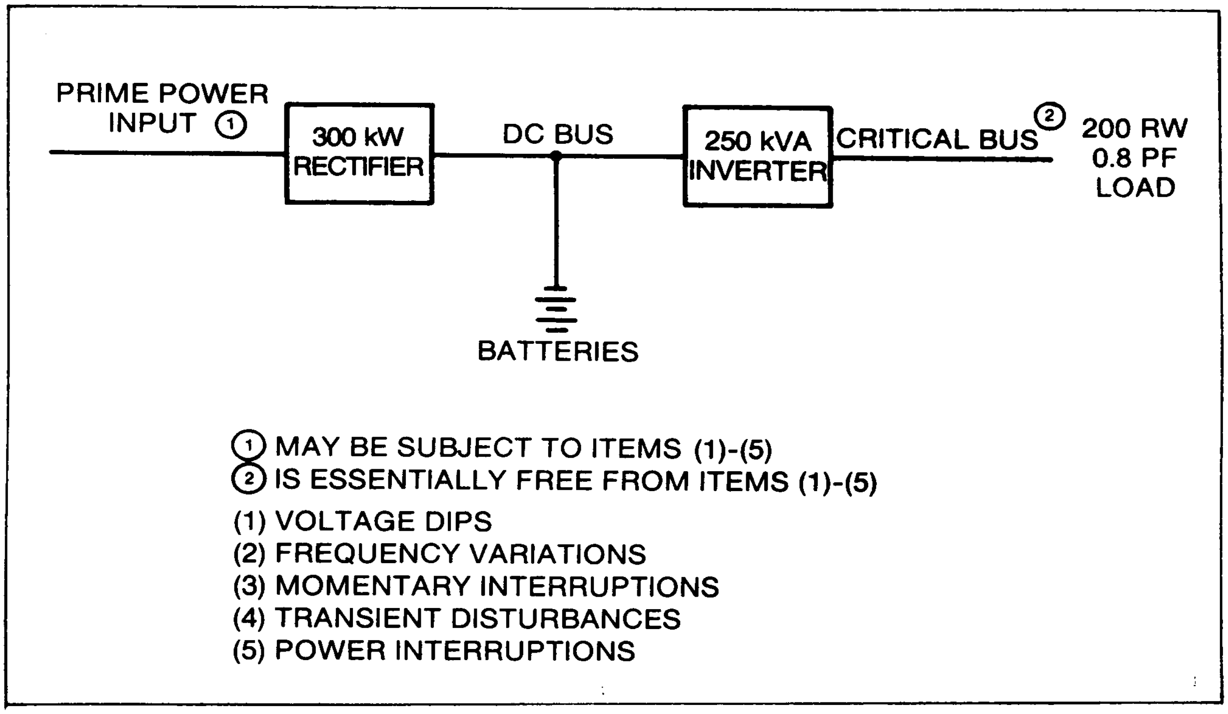

FIGURE 1-16
Nonredundant UPS System

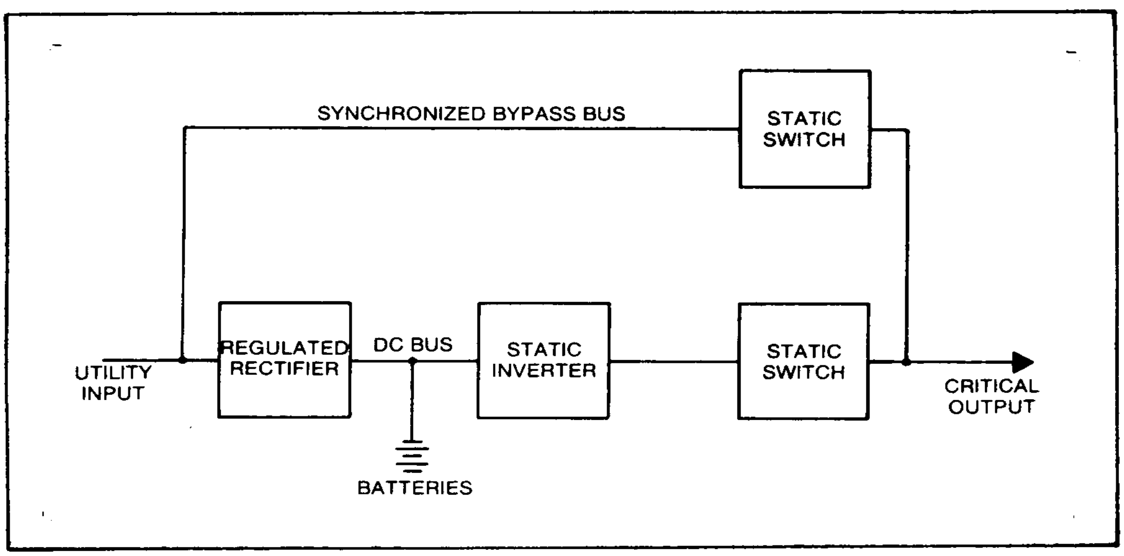

FIGURE 1-17
Nonredundant UPS System with Static Bypass

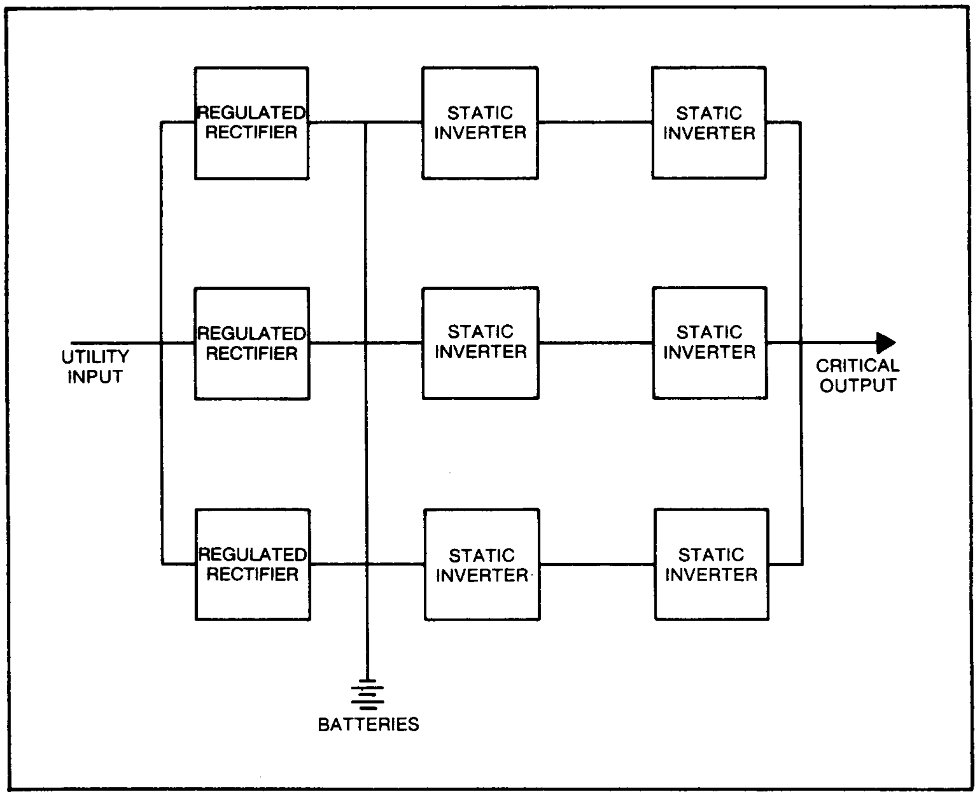

FIGURE 1-18
Redundant UPS System

CHAPTER 2. POWER DISTRIBUTION CABLE SYSTEMS.

2.1 CABLE SPECIFICATIONS. A cable is defined as a single conductor or an assembly of conductors covered by solid electrical insulation. Cable specifications generally start with the conductor and progress radially through the insulation and coverings. The following is a typical list of specifications:

(a) Number of conductors in cable.

(b) Conductor size (American Wire Gage (AWG), circular mil) and material.

(c) Insulation type.

(d) Voltage rating.

(e) Shielding system.

(f) Outer finishes (or sheath).

(g) Installation.

An alternate method of specifying cable is to furnish the ampacity of the circuit (amperes (A)), the voltage (phase to phase, phase to ground, grounded, or ungrounded), and the frequency, along with any other pertinent system data.

2.2 CABLE CONSTRUCTION. A typical cable is comprised of conductors shielded by various types of material. The cable may have one conductor or three conductors grouped as one.

2.2.1 Conductors. The two conductor materials in common use are copper and aluminum. Copper has historically been used for conductors of insulated cables primarily for its desirable electrical and mechanical properties. The use of aluminum is based mainly on its favorable conductivity-to-weight ratio (the highest of the electrical conductor materials), its ready availability, and the stable low cost of the primary metal.

2.2.1.1 Comparison Between Copper and Aluminum. Aluminum requires larger conductor sizes to carry the same current as copper. The equivalent aluminum cable, when compared to copper in terms of ampacity, will be lighter in weight and larger in diameter. For distribution, aluminum is commonly rated as equivalent to a copper conductor two AWG sizes smaller, which has almost identical resistance.

2.2.1.2 Classes of Conductors. Conductors are classified as solid or stranded. A solid conductor is a single conductor of solid circular section. A stranded conductor is composed of a group of small conductors in common contact. A stranded conductor is used where the solid conductor is too large and not flexible enough to be handled readily. Large solid conductors are also easily damaged by bending. The need for mechanical flexibility usually determines whether a solid or a stranded conductor is used, and the degree of flexibility is a function of the total number of strands. The strands in the stranded conductor are usually arranged in concentric layers about a central core. The smallest number of wires in a stranded conductor is three. The next number of strands are 7, 19, 37, 61, 91, 127, etc. Both copper and aluminum conductors may be stranded.

2.2.1.3 Conductor Sizes. Conductor sizes are ordinarily expressed by two different numbering methods: the AWG formerly known as the Browne and Sharpe gage, and the circular mil.

(a) The AWG or conductor sizes are numbered from 30 to 1, then continuing with 0, 00, 000, and 0000 (or 1/0, 2/0, 3/0, and 4/0 respectively). Number 30 is the smallest size and 4/0 the largest in this system. As an example of the actual physical size of the conductors commonly used in transmission and distribution work, the diameter of a number 8 AWG is 0.1285 inches and for a 4/0 AWG it is 0.460 inches.

(b) The circular mil is the unit customarily used in designating the cross sectional area of wires. A circular mil is defined as the area of a circle having a diameter of 1/1000 of an inch. The circular mils of cross section in a wire are obtained by squaring the diameter expressed as thousandths of an inch. For example, a wire with a diameter of 0.102 inches (102 thousandths of an inch) has a circular mils cross section of 102 X 102 = 10,404. Conductors larger than 4/0 AWG are designated in circular mils. These range from 250,000 to 2,000,000 circular mils (250 MCM or 250 kcmil to 2,000 MCM or 2,000 kcmil).

2.2.2 Insulations. Insulations can be classified in broad categories as solid, taped or special-purpose insulations. Basic insulating materials are either organic or inorganic. The following is a list of insulations commonly used:

(a) Thermosetting compounds (solid dielectric).
(b) Thermoplastic compounds (solid dielectric).
(c) Paper-laminated tapes.
(d) Varnished cloth-laminated tapes.
(e) Mineral inorganic insulation (solid dielectric granular).

Insulations in general use for voltages above 2 kV are listed below. Solid dielectrics of both plastic and thermosetting types are being more and more commonly used, while the laminated-type constructions, such as paper-lead cables are declining in popularity.

(a) Thermosetting Compounds:

- Cross-Linked polyethylene (XLP or XLPE).
- Ethylene propylene rubber (EPR).
- Styrene butadiene rubber (SBR).
- Silicone rubber.
- Oil-base rubber.
- Chlorosulfonated polyethylene rubber (CPR).
- Butyl rubber.

(b) Thermoplastic Compounds:

- Polyethylene (natural).
- Polyvinyl chloride (PVC).

(c) Paper-laminated Tapes.

(d) Varnished Cloth-laminated Tapes.

2.2.3 Shielding of Higher Voltage Cable. For operating voltages below 2 kV, nonshielded constructions are normally used. Insulation shielding is required for all nonmetallic, sheathed, single-conductor cables operating above 2 kV and all metallic sheathed cables and multiconductor cables above 5 kV.

2.2.3.1 Procedure. Shielding is the practice of confining the electric field of the cable to the insulation surrounding the conductor by means of conducting or semiconducting layers, closely fitting or bonded to the inner and outer surfaces of the insulation. In other words, the outer shield confines the electric field to the space between conductor and shield. The inner or strand stress relief layer is at or near the conductor potential. The outer or insulation shield is designed to carry the charging currents and in many cases fault currents.

2.2.3.2 Purpose. Insulation shields have several purposes:

(a) Confine the electric field within the cable.

(b) Equalize voltage stress within the insulation, minimizing surface discharges.

(c) Protect cable from induced potentials.

(d) Limit electromagnetic or electrostatic interference (radio, TV, etc.).

(e) Reduce shock hazard (when properly grounded).

2.2.4 Cable Outer Finishes. Cable outer finishes or outer coverings are used to protect the underlying cable components from the environmental and installation conditions associated with intended service. The choice of cable outer finishes for a particular application is based on electrical, thermal, mechanical, and chemical considerations. Combinations of metallic and nonmetallic finishes are usually required to provide the total protection needed for the installation and operation.

2.2.4.1 Nonmetallic Finishes.

(a) There are outer coverings (extruded jackets) either thermoplastic or vulcanized, which may be extruded directly over insulation or over electrical shielding systems of metal sheaths or tapes, copper braid, or semiconducting layers with copper drain wires or spiraled copper concentric wires, or over multiconductor constructions. Commonly used materials include: polyvinyl chloride, nitrile butadiene/polyvinyl chloride (NBR/PVC), polyethylene, cross-linked polyethylene, polychloroprene (neoprene), chlorosulfonated polyethylene, and polyurethane. These materials provide a high degree of moisture, chemical, and weathering protection. They are reasonably flexible, provide some degree of electrical isolation, and are of sufficient mechanical strength to protect the insulating and shielding components from normal service and installation damage.

(b) A commonly used material is braided asbestos fiber. Asbestos braid is used on cables to minimize flame propagation, smoking, and other hazardous or damaging products of combustion which may be evolved by some extruded jacketing materials. Special industrial applications may require synthetic or cotton fibers applied in braid form. All fiber braids require saturants or coating and impregnating materials to provide some degree of moisture and solvent resistance as well as abrasive and weathering resistance.

2.2.4.2 Metallic Finishes. These materials are widely used when a high degree of mechanical, chemical, or short-time thermal protection of the underlying cable components may be required. Commonly used are interlocked galvanized steel, aluminum, or bronze armor; extruded lead or aluminum; strip formed, welded, and corrugated steel and aluminum; and spirally laid round or flat armor wires. The use of any of these materials will reduce flexibility of the overall cable, but flexibility must be sacrificed to obtain the other benefits.

(a) The unprotected interlocked armor provides a high degree of mechanical protection without significantly sacrificing flexibility. While not entirely impervious to moisture or corrosive agents, interlocked armor does provide protection from thermal shock by acting as a heat sink for short-time localized exposure. Where corrosion and moisture resistance are required, in addition to mechanical protection, an overall jacket of extruded material may be used. Commonly used interlocked armor materials are: galvanized steel, aluminum (for less weight and general corrosion resistance), and marine bronze and other alloys (for highly corrosive atmospheres).

(b) Longitudinally corrugated metal sheaths (corrugations or bellows formed perpendicular to the cable axis) have been used for many years in direct-burial communications cables, but only recently has this method of cable core protection been applied to control and power cables. The sheath material may be of copper, aluminum, a corrosion resistant steel or copper alloy, or a bimetallic composition of materials selected to best meet the intended service.

(c) Lead or lead alloys are used for industrial power cable sheaths for maximum cable protection in underground manhole and tunnel or underground duct distribution systems subject to flooding. While not as resistant to crushing loads as interlocked armor, its very high degree of corrosion and moisture resistance makes lead attractive in the above applications. Protection from installation damage can be provided by an outer jacket of extruded material.

(d) Extruded aluminum, copper, die-drawn aluminum, or copper sheaths are used in certain applications for weight reduction and moisture penetration protection. While more crush resistant than lead, aluminum sheaths are subject to electrolytic attack when installed underground. Under these conditions, aluminum sheathed cable should be protected with an outer extruded jacket.

(e) A high degree of mechanical protection and longitudinal strength can be obtained by using spirally wrapped or braided round steel armor wire. This type of outer covering is frequently used in submarine cable and vertical riser cable for support.

2.2.5 Single-conductor and Multiconductor Constructions. Single-conductor cables are usually easier to handle and can be furnished in longer lengths than multiconductor cables. Multiconductor constructions give smaller overall dimensions than an equivalent single-conductor cable, providing a space advantage.

2.3 CABLE RATINGS AND SELECTION CRITERIA.

Cables come in various sizes. The size of a cable depends on the ampacity or voltage rating of the cable. Cables may contain various conductor sizes, and the electrical characteristics of the cable depends on the conductor size used.

2.3.1 Electrical and Environmental Specifications. The selection of power cables involves the consideration of various electrical and environmental conditions. These conditions include the quantity and characteristics of the power being distributed and the degree of exposure to adverse mechanical and thermal stresses. The selection of conductor size is based on the following criteria:

2.3.1.1 Voltage rating.

2.3.1.2 Load current criteria (as related to loadings, thermal effects of the load current, mutual heating, losses produced by magnetic induction, and dielectric losses).

2.3.1.3 Emergency overload criteria.

2.3.1.4 Voltage drop limitations.

2.3.1.5 Fault current criteria.

2.3.2 Voltage Rating. The selection of the cable insulation (voltage) rating is based on: the phase-to-phase voltage of the system in which the cable is to be applied, the general system category (depending on whether the system is grounded or ungrounded), and the time in which a ground fault on the system is cleared by protective equipment. It is possible to operate cables on ungrounded systems for long periods of time with one phase grounded due to a fault. This results in line-to-line voltage stress across the insulation of the two ungrounded conductors. Such cable, therefore, must have greater insulation thickness than a cable used on a grounded system (where it is impossible to impose full line-to-line potential on the other two unfaulted phases for an extended period of time). Consequently, 100 percent voltage rated cables are applicable to grounded systems provided with protection which will clear ground faults within one minute. 133 percent rated cables are required on ungrounded systems where the clearing time of the 100 percent level category cannot be met, and when there is adequate assurance that the faulted section will be cleared within one hour. 173 percent voltage level insulation is used on systems where the time required to deenergize a grounded section is indefinite.

2.3.3 Load Current Criteria. The manufacturer's ampacity recommendations should be used as load current criteria. The following publications contain ampacity tables for power cables.

(a) IEEE S-135-1-1962, Power Cable Ampacities, Copper Conductors.

(b) IEEE S-135-2-1962, Power Cable Ampacities, Aluminum Conductors.

Ampacity tables indicate the minimum size conductor required, however, conservative engineering practice, future load growth considerations, voltage drop, and short circuit considerations may require the use of larger conductors.

2.3.3.1 Skin and Proximity Effects. Careful consideration must be given when grouping cables, as de-ratings resulting from mutual heating may limit capacity. Paralleling two or more smaller size cables should be considered over installation of conductors (larger than 500 MCM) because the current carrying capacity, per circular mil of the conductor, decreases for alternating current circuits (due to skin effect and proximity effect). The reduced ratio of surface to cross-sectional area of larger size conductors is a factor in the reduced ability of the larger cable to dissipate heat. Cables larger than 500 MCM are also more difficult to handle during installation. When cables are used in multiple sets, consideration must be given to the phase placement of the cable to minimize the effect of reduced ampacity due to unbalanced distribution of current in the cables. Length of multiple sets should be the same.

2.3.3.2 Ambient Temperature. Cables must be de-rated when in proximity to other loaded cables or heat sources, or when the ambient temperature exceeds the ambient temperature at which the ampacity (current carrying capacity) tables are based. The normal ambient temperature of a cable installation is the temperature of the environment in which the cable is installed with no load being carried on the cable.

2.3.3.3 Surrounding Medium. The thermal characteristics of the medium surrounding the cables are of primary importance in determining the current carrying capacity of the cables. The type of soil in which the cable or duct bank is buried has a major effect on the current carrying capacity of the cables. Porous soils, such as gravel and cinder fill, usually result in higher temperatures and lower ampacities than sandy or clay soil. The moisture content of the soil has a major effect on the current carrying capacity of cables. In dry sections of the country, cables may have to be de-rated, or other precautions taken, to compensate for the increase in thermal resistance due to the lack of moisture. On the other hand, in ground which is continuously wet or under tidewater conditions, cables may carry higher than normal currents.

2.3.4 <u>EmergencyOverload Criteria</u>. Normal loading limits of insulated wire and cable are determined based on many years of practical experience. These limits account for a rate of insulation deterioration that results in the most economical and useful life of such cable systems. The anticipated rate of deterioration equates to a useful life of approximately 20 to 30 years. The life of cable insulation may be halved, and the average thermal failure rate almost doubled for each 5 to 15°C increase in normal daily load temperature. The normal daily load temperature is the average conductor temperature over a typical 24 hour period. It reflects both the change in ambient temperature and the change in conductor temperature due to daily load fluctuations. Additionally, sustained operation over and above maximum rated operating temperatures or ampacities is not an effective or economical practice, because the temperature rise is directly proportional to the conductor loss, which increases as the square of the current. The intensified voltage drop may also increase the risks to equipment and service continuity. Maximum emergency overload temperatures for various types of insulation have been established and are available as a practical guide. Operation at these emergency overload temperatures should not exceed 100 hours per year, and such 100 hour overload periods should not exceed five during the life of the cable.

2.3.5 <u>Voltage Drop Criteria</u>. The supply conductor, if not of sufficient size, will cause excessive voltage drop in the circuit, and the drop will be in direct proportion to the circuit length. Proper starting and running of motors, lighting equipment, and other loads having heavy inrush currents must be considered. It is recommended that the steady state voltage drop in distribution feeders be no more than four percent.

2.3.6 <u>Fault Current Criteria</u>. Under short-circuit conditions the temperature of the conductor rises rapidly then, due to the thermal characteristics of the insulation, sheath, and surrounding materials, it cools off slowly after the short-circuit condition is cleared. A transient temperature limit for each type of insulation for short-circuit durations not in excess of 10 seconds has been established, and many times this criterion is used to determine minimum conductor size. Insulated Power Cable Engineers Association (IPCEA) standards define the maximum conductor temperature limits allowable under worst-case fault conditions.

2.4 TYPES OF CABLE INSTALLATIONS. There are a variety of ways to install power distribution cables. Each method ensures distribution of power with a unique degree of reliability, safety, economy, and quality for any specific set of conditions. These conditions include the electrical characteristics of the power system, the distance and terrain of distribution, and the expected mechanical and environmental conditions.

2.4.1 Open-Wire. Open-wire construction consists of uninsulated conductors on insulators which are mounted on poles or structures. The conductor may be bare or it may have a thin covering for protection from corrosion or abrasion. The attractive features of this method are its low initial cost and the fact that damage can be detected and repaired quickly. On the other hand, the uninsulated conductors are a safety hazard and are also highly susceptible to mechanical damage and electrical outages resulting from short circuits caused by birds or animals. Proper vertical clearances over roadways, walkways, and structures are critical. Exposed open-wire circuits are also more susceptible to the effects of lightning than other circuits, however, these effects may be minimized by the use of overhead ground wires and lightning arresters. In addition, there is an increased hazard where crane or boom truck use may be involved. In some areas contamination on insulators and conductor corrosion can result in high maintenance costs.

2.4.2 Aerial Cable. Aerial cable consists of fully insulated conductors suspended above the ground. This type of installation is used increasingly, generally for replacing open wiring, where it provides greater safety and reliability and requires less space. Properly protected cables are not a safety hazard and are not easily damaged by casual contact. They do, however, have the same disadvantage as open-wire construction, requiring proper vertical clearances over roadways, walkways, and structures.

2.4.2.1 Supports. Aerial cables may be either self-supporting or messenger-supported. They may be attached to pole lines or structures. Self-supporting aerial cables have high tensile strength for this application. Cables may be messenger-supported either by spirally wrapping a steel band around the cables and the messenger or by pulling the cable through rings suspended from the messenger.

2.4.2.2 Distance. Self-supporting cable is suitable for only relatively short distances, with spans in the range of 100-150 feet. Messenger-supported cable can span relatively large distances, of over 1000 feet, depending on the weight of the cable and the tensile strength of the messenger. For this reason, aerial cable that must span relatively large distances usually consists of aluminum conductors to reduce the weight of the cable assembly. The supporting messenger provides high strength to withstand climatic rigors or mechanical shock. It may also serve as the grounding conductor of the power circuit.

2.4.3 Above-Ground Conduits. @Rigid steel conduit systems afford the highest degree of mechanical protection available in above-ground conduit systems. Unfortunately, this is also a relatively high-cost system. For this reason their use is being superseded, where possible, by other types of conduit and wiring systems. Where applicable, rigid aluminum, intermediate-grade steel conduit, thin-wall EMT, intermediate-grade metal conduit, plastic, fiber and asbestos-cement ducts are being used.

2.4.4 Underground Ducts. Underground ducts are used where it is necessary to provide a high degree of safety and mechanical protection, or where above-ground conductors would be unattractive.

2.4.4.1 Construction. Underground ducts use rigid steel, plastic, fiber, and asbestos-cement conduits encased in concrete, or precast multi-hole concrete with close fitting joints. Clay tile is also used to some extent. Where the added mechanical protection of concrete is not required, heavy wall versions of fiber and asbestos-cement and rigid steel and plastic conduits are direct buried.

2.4.4.2 Cables. Cables used in underground conduits must be suitable for use in wet areas, and protected against abrasion during installation.

2.4.5 Direct Burial. Cables may be buried directly in the ground where permitted by codes and only in areas that are rarely disturbed. The cables used must be suitable for this purpose, that is, resistant to moisture, crushing, soil contaminants, and insect and rodent damage. While direct-buried cable cannot be readily added to or maintained, the current carrying capacity is usually greater than that of cables in ducts. Buried cable must have selected backfill. It must be used only where the chance of disturbance is unlikely. The cable must be suitably protected, however, if used where the chance of disturbance is more likely to occur. Relatively recent advances in the design and operating characteristics of cable fault location equipment and subsequent repair methods and material have diminished the maintenance problem.

2.4.6 Underwater (Submarine) Cable. Submarine cable is used only when no other cable system can be used. It supplies circuits that must cross expanses of water or swampy terrain.

2.4.6.1 Construction. Submarine cable generally consists of a lead sheathed cable and is usually armored. Insulation material should be XLP or EPR, except when paper insulation is justified because of its high resistance to, and freedom from, internal discharge or corona. Multiconductor construction should be used, unless limited by physical factors. The lead sheathing usually consists of a copper-bearing lead material, however, other alloys may be required when special conditions warrant nonstandard sheathing. The most common type of armoring material used for submarine cables is the spirally wrapped round galvanized steel wire. In this type of cable, asphalt impregnated jute is usually applied over the lead sheath and the wire armor is applied over the jute to reduce mechanical damage and electrolytic corrosion. An additional covering of the asphalt impregnated jute may be applied over the wire armor. Nonmetallic sheathed cables are sometimes suitable for certain submarine applications. The cable must be manufactured specifically for submarine service and, generally, has an increased insulation thickness. The cable may require wire armor and should have electrical shielding for all voltage ratings above 600 V.

2.4.6.2 Installation. Submarine cable should lie on the floor of the body of water and should have ample slack so that slight shifting caused by current or turbulence will not place excessive strain on the cable. Where the cable crossing is subject to flow or tidal currents, anchors are often used to prevent excessive drifting or shifting of the cable. In addition to laying cables directly on the bottom, burying cable in a trench using the jetwater method should be considered. Cables must be buried in waters where marine traffic is present. The depth of burial should be enough to prevent damage caused by dragging anchors, which may be in excess of 15 feet for large ships on sandy bottoms. Warning signs located on shore at the ends of the submarine cable should be provided to prohibit anchoring in the immediate vicinity of the cable.

2.4.7 Grounding of Cable Systems. For safety and reliable operation, the shields and metallic sheaths of power cables must be grounded. Without such grounding, shields would operate at a potential considerably above ground. Thus, they would be hazardous to touch, and would incur rapid degradation of the jacket or other material intervening between shield and ground. This is caused by the capacitive charging current of the cable insulation which is approximately 1 milliampere (mA) per foot of conductor length. This current normally flows at a power frequency between the conductor and the earth electrode of the cable, normally the shield. In addition, the shield or metallic sheath provides the fault return path in the event of insulation failure, permitting rapid operation of the protection devices.

2.4.7.1 Grounding Conductor. The grounding conductor, and its attachment to the shield or metallic sheath, normally at a termination or splice, should have an ampacity no lower than that of the shield. In the case of a lead sheath, the grounding conductor must be able to carry the available fault current over its duration without overheating. Attachment to shield or sheath is frequently by means of solder, which has a low melting point; thus an adequate area of attachment is required.

2.4.7.2 Grounding Methods. The cable shield lengths may be grounded at both ends or at only one end. If grounded at only one end, any possible fault current must traverse the length from the fault to the grounded end, imposing high current on the usually very thin shield conductor. Such a current could damage or destroy the shield, and require replacement of the entire cable rather than only the faulted section. With both ends grounded, the fault current would divide and flow to both ends, reducing the duty on the shield, with consequently less chance of damage. There are modifications of both systems. In one, single-ended grounding may be attained by insulating the shields at each splice or sectionalizing point, and grounding only the source end of each section. This limits possible shield damage to only the faulted section. Multiple grounding, rather than just double-ended grounding, is simply the grounding of the cable shield or sheath at all access points, such as manholes or pull boxes. This also limits possible shield damage to only the faulted section.

2.5 POWER SYSTEM APPLICATIONS. A power system consists of transmission and distribution systems. The transmission system is typically of higher voltage and is usually referred to as a high side of the system. The distribution system is called a low side of the system. The two systems are usually connected by means of a transformer to transform the high voltage to low voltage.

2.5.1 <u>Transmission System</u>. Three-phase 3-conductor circuits are universally used in transmission systems. Transmission circuits consist of overhead or underground cables, or some combination of both.

2.5.1.1 Overhead Systems. Overhead circuits consist of aerial cables or open-wire conductors carried on poles or towers. Aluminum conductors have, to a large degree, replaced copper in overhead installations. Conductor sizes most commonly used vary from No. 2 AWG to 556 kcmil aluminum cable steel reinforced (ACSR) or stranded aluminum alloy.

An aluminum cable stranded around a steel core sized to give the required strength is known as ACSR. Other cables are aluminum conductor alloy-reinforced (ACAR) and all aluminum-alloy conductor (AAAC).

2.5.1.2 Underground Systems. In older areas, transmission circuits are often 3-conductor lead-covered cables. Cross-linked polyethylene and ethylene-propylene rubber are replacing lead. Ordinarily, a 3-conductor copper cable varying in size from 1/0 AWG to 500 kcmil is installed in underground conduits. Aluminum cable is seldom used in underground installations because these cables are larger than copper cables of equal ampacity.

2.5.2 <u>Primary Distribution System</u>. A 3-phase 3-wire system is commonly used in primary distribution.

2.5.2.1 Overhead Primaries. The conductor sizes most commonly used in overhead primaries range from No. 4 AWG ACSR to 336.4 kcmil stranded aluminum. Laterals, or branches, are often No. 4 or No. 2 AWG ACSR, but feeders run to the larger sizes. Aluminum, ACSR, and alloys of aluminum have largely displaced copper from primary circuit construction, although they may be specified on a copper-equivalent basis. Aerial cable is often used for primary conductors where clearances are too close for open wire or tree trimming is not practicable. The cable in some cases comprises three rubber-insulated, neoprene-insulated, or polyethylene-insulated conductors lashed to a bare messenger which serves as the neutral for 3-phase circuits. In other cases, the phase conductors are supported from the messenger by insulating spacers; this construction is commonly called spacer cable. Single-phase taps, in either case, are usually one insulated conductor and messenger or an insulated conductor with neutral strands spiralled around it.

2.5.2.2 Underground Systems. The conductor sizes most commonly used in underground primary distribution vary from No. 6 AWG to 500 kcmil copper. Feeders are usually 3- or 4-conductor cable, while laterals may be single-conductor because of the requirement for numerous transformer taps. On some systems, interconnected cable sheaths are used for the neutral conductor; others use a separate bare neutral or fourth conductor in the cable. Stranded aluminum conductors and aluminum sheaths have been used in some cases, but the increased outside diameter usually requires excessive duct space. Recent improvements in polyethylene insulation have extended the use of aluminum-conductor cable for direct-buried systems where overall size is not detrimental.

CHAPTER 3. POWER SYSTEM ELECTRICAL EQUIPMENT.

3.1 MAJOR APPARATUS. This chapter provides information regarding the requirements for, and the application of, major apparatus used in an electric power distribution system. More detailed information on this apparatus is available in trade standards, as well as in manufacturers' publications and NAVFAC MO-200.

3.1.1 System Components. The major system components described in this chapter are:

(a) Transformers.
(b) Voltage Regulators.
(c) Switches.
(d) Power Circuit Breakers.
(e) Automatic Circuit Reclosers.
(f) Power Capacitors.

3.1.2 Voltage Classes. Power equipment is normally rated according to the nominal system voltage. In equipment terminology, the voltage ratings fall into four classes:

(a) Low voltage - 600 V or less.
(b) Medium voltage - above 600 V to 72,500 V.
(c) High voltage - above 72,500 V to 242,000 V.
(d) Extra-high voltage - above 242,000 V to 800,000 V.

The equipment discussed in this chapter will generally be in the low and medium voltage classes.

3.1.3 Codes and Standards. In general, system designs and installation practices are governed by regulations in the National Electric Code (NEC) and the National Electric Safety Code (NESC). The NEC contains regulations governing the installation of electrical conductors and equipment within or on public and private buildings, mobile homes, recreational vehicles, float dwellings, and other premises such as yards, carnivals, parking lots and industrial substations. The NESC covers standards for safeguarding people from hazards arising from installation, operation and maintenance of electrical conductors and equipment. The provisions contained in the NEC define minimum requirements only, and are not intended to be used as design specifications. Minimum standards relating to electrical equipment have been established by the National Electrical Manufacturers Association (NEMA), the Institute of Electrical and Electronics Engineers (IEEE), and the American National Standards Institute (ANSI).

3.2 TRANSFORMERS. Transformers are an essential part of any electrical system. They come in various sizes and voltage ratings. Transformers are used for transforming power from one voltage level to another.

3.2.1 Fundamental Transformer Principles. A transformer consists of a magnetic core built up of silicon steel laminations with two sets of coils wound around the core. These coils are called the primary and secondary windings. This combination may be used to derive a voltage higher or lower than the voltage immediately available. The supply voltage is applied to the primary winding, whether it is the higher or lower voltage winding. The other winding, to which the load is connected, is termed the secondary winding. Since electromagnetic induction can only take place when the magnetic flux is continually varying, transformers can only be used in alternating current circuits.

3.2.1.1 Open-Circuit Characteristics. If an alternating electromotive force (emf) is applied to the terminals of the primary winding of a transformer with the secondary winding open-circuited (nothing connected between the secondary terminals), a very small current will flow in the primary circuit. The exciting current has a magnetizing current component that establishes the mutual magnetic flux that induces an emf in both primary and secondary windings. Since the primary and secondary windings are wound on the same core, and the magnetizing flux is common to the two windings, the voltage induced in a single turn of each winding will be the same, and the induced voltages in the primary and secondary windings are therefore in direct proportion to the number of turns in those windings. The exciting current also has a core loss component that accounts for the power absorbed by the hysteresis and eddy-current losses in the core.

3.2.1.2 Load Characteristics. The application of a load to the secondary side of the transformer produces a considerable change in the internal phenomena. When the secondary circuit is closed, a secondary current flows, the value of which is determined by the magnitude of the secondary terminal voltage and the impedance of the load circuit. The secondary load current produces in the core a load flux that is in phase with the secondary current, however, the secondary load current is immediately balanced by a primary load current of such a value that the primary and secondary load ampere-turns are equal. The secondary load flux is similarly counteracted by a primary load flux which is in phase with the primary load balancing current, and therefore in phase opposition to, and of the same magnitude as, the secondary load flux. Therefore, the core is left in its initial state of magnetization corresponding to the magnetizing current component of the exciting current; this explains why the iron loss is independent of the load. The total current in the primary circuit is the phasor sum of the primary load current and the no-load exciting current.

Low core loss transformers, made of a new amorphous type alloy, are still in the prototype development stage for most types of transformers. There are several test programs under way with utilities in different parts of the country in which selected.groups of these new type transformers have been placed in service in a test program to monitor long term performance of the units on overhead distribution circuits. Westinghouse has present capacity for 2400 unit/year in sizes 10 to 75 kVA and for primary voltages of 2.4 to 19.9 kV. Units for the typically larger three-phase substation applications are not yet readily available, as the transformer manufacturers are limited by the width of the amorphous steel material, as well as the quantity of material that is available from the Allied Corporation, which has the patent on this material. There are presently at least three manufacturers offering amorphous steel distribution type transformers for commercial use.

3.2.2 Losses. A transformer has three distinct circuits; electric, magnetic, and dielectric. Each of these circuits incurs losses, which may be subdivided as follows:

(a) Losses in the electric circuit.

- I^2R loss due to load currents.
- I^2R loss due to no-load exciting current.
- Eddy-current loss in conductors due to leakage fields.

(b) Losses in magnetic circuit.

- Hysteresis loss in core laminations.
- Eddy-current loss in core laminations.
- Stray eddy-current loss in core clamps, bolts, and other attachments.

(c) Loss in the dielectric circuit. This loss is small for all voltages up to 50 kV, and is consequently included in the no-load losses.

3.2.2.1 No-Load and Load Losses. The various losses are normally grouped as follows:

(a) No-load losses (commonly called iron losses).

- I^2R loss due to no-load exciting current.
- Hysteresis loss in core laminations.
- Eddy-current loss in core laminations.
- Stray eddy-current loss in core clamps, bolts and other attachments.
- Loss in the dielectric circuit.

In practice only the hysteresis and eddy-current losses are of importance in transformers. These losses are constant for a given applied voltage and unaffected by the load on the transformers. The dielectric losses are also functions of the primary and secondary voltages, but vary slightly with the temperature of the windings affected by the load on the transformer. The copper loss due to the magnetizing current is generally negligible and is independent of the load for a given excitation. This magnetizing current loss is very small in well designed and well constructed transformers, since this current does not usually exceed 5 percent of the full-load current, and in larger transformers may even be as low as 1 to 2 percent.

(b) Load losses (commonly called copper losses or short-circuit losses).

- I^2R loss due to load currents.
- Eddy-current loss in conductors due to leakage fields.

The I^2R losses due to load and exciting currents are inherent in the transformer design. The losses are determined by the length of the windings and the frame dimensions. The loss due to the additional current required to maintain the rated output is usually negligible. The eddy-current loss is set up by stray magnetic fields. This loss is also inherent in the transformer design and is usually calculated as a percentage of the I^2R loss. The I^2R losses are functions of the transformer core and winding design, and depend upon voltage transformation ratios, winding conductor sizes, and magnetic core dimensions and loss characteristics. The core hysteresis and eddy-current losses are a function of core dimensions, magnetic materials, and lamination thicknesses.

3.2.3 Insulation. Insulation mediums used in power transformers are either liquid or gas. In both cases some solid insulation for major separations is used. Solid insulation separates the high-voltage winding from the low-voltage winding. Liquid systems include oil, askarel, and high-fire-point liquids such as silicone. The gas systems include air, nitrogen, and fluorogases (such as sulfur hexafluoride). The selection of the insulation medium is dictated mainly by the installation site and cost.

3.2.3.1 Oil. Low cost, high dielectric strength, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. Due to its flammable property, oil-insulated transformers are normally used for outdoor installations. Indoor installations require vaults and venting or fire suppression systems.

3.2.3.2 Askarel. Askarel is a generic term for a group of nonflammable synthetic chlorinated hydrocarbons used as electrical insulating media. Each manufacturer of askarel transformers applied a special name for this material. For example, Inerteen(R) is the trade name for the nonexplosive insulating and cooling liquid produced by Westinghouse. Inerteen(R), nearly water white in color, is produced by chlorination of biphenyl (a common chemical). The resulting polychlorinated biphenyls (PCBs) are relatively insoluble in water but soluble in fat, and are extremely persistent in the environment. While Inerteen(R) is generally regarded as being nontoxic but carcinogenic to humans, very high standards of control against pollution must be exercised. The combustion of Inerteen(R) and other askarels has been known to create dioxins as a solid residue or dust. In the public sector, there have been several well documented fires in which askarel filled transformers have become involved in large building fires. In each case, a dioxin residue was found which caused additional environmental problems in cleanup and repair after the fire incident.

Askarel liquids have been classified as toxic to animals and humans by the Environmental Protection Agency (EPA). As of 1 October 1977, the EPA no longer allows the manufacture of PCB fluids or the sale of askarel-filled transformers. To avoid an uncontrolled discharge to the environment, the users of askarel-insulated transformers must monitor and dispose of PCB liquid in accordance with applicable standards. (See ANSI C107.1-1974, Guidelines for Handling and Disposal of Capacitor- and Transformer-Grade Askarels, Containing Polychlorinated Biphenyls; and IEEE Standard 76-1974, Guide for Acceptance and Maintenance of Transformer Askarel in Equipment.)

3.2.3.3 High-Fire-Point Insulating Liquids. In the late 1970s, less-flammable, nontoxic, high-fire-point (greater than 3000C) fluids were introduced to replace askarel as a transformer dielectric (insulating) fluid. These fluids are designated as either polydimethylsiloxane (silicone) or high-molecular-weight hydrocarbons. These liquids will burn, but they do so very slowly and release much less heat than flammable mineral oil. They are also nontoxic, unlike askarel. Because of these characteristics, transformers insulated with high-fire-point liquid may be installed inside building areas not containing vaults, liquid confinement areas, or fire suppression systems. Although it is rarely economical to do so, askarel transformers may be drained, flushed, and refilled with a high-fire-point liquid. The kVA rating of a retro-filled transformer must be decreased for continuous service. The National Electric Code (NEC) contains installation information for less-flammable liquid insulated transformers. The Factory Mutual Research Corporation lists high-fire-point qualifying liquids.

3.2.3.4 Air or Gas. The ventilated dry-type transformer has applications in distribution systems, and may be installed indoors without a vault. The sealed or gas-filled dry-type transformer has very limited use, due principally to the higher price. Nitrogen and air-insulated transformers are generally limited to 15 kV and lower operating voltages.

3.2.3.5 Basic-impulse Insulation Level (BIL). It is characteristic of most insulations that the maximum voltage which they can successfully withstand varies inversely with the duration of the voltage. Since power systems are subject to various types of overvoltage, some of long and some of short duration, power distribution equipment is usually required to withstand at least two different types of dielectric tests. The first are the so-called low-frequency (60-cycle) tests, usually of one minute duration, that establish the ability of the insulation to withstand moderate overvoltage of relatively long duration. The others are the impulse tests designed to prove that the insulation will not break down on voltage surges of high magnitude but short duration, such as those produced by lightning. The impulse test commonly used consists of the application of a very short duration full-wave voltage surge of a specified crest value to the equipment insulation. The crest value of the wave the insulation can withstand without breakdown is the BIL. To simplify the design and application of electrical equipment, a series of Standard BIL's have been established. As an example, for a reference insulation class rated at 15 kV, the BIL is 110 kV.

3.2.4 Cooling. Removal of heat caused by losses is necessary to prevent excessive internal temperature which would shorten the life of the insulation. The transformer life is cut in half by a 10°C rise in temperature. The general classes of cooling are: self-cooled, forced-air or forced-oil-cooled, and water-cooled. The basic types of cooling are referred to by standard designations.

3.2.4.1 Oil Immersed Self-Cooled (OA). In this type of transformer the insulating liquid circulates by natural convection and heat is dissipated over the radiating surface. The OA transformer is a basic type and serves as a standard for capacity rating.

3.2.4.2 Oil Immersed Self-Cooled/Forced-Air-Cooled (OA/FA). This type of transformer is basically an OA unit with the addition of external fans to increase heat dissipation from the radiators. It is usually possible to obtain between 15 percent - 33 1/3 percent more capacity relative to the OA rating with the fans running. The OA/FA transformer is applicable in situations that require short-time peak loads to be carried recurrently, without affecting normal expected transformer life.

3.2.4.3 Oil Immersed Self-Cooled/Forced-Air Cooled/Forced-Oil (OA/FA/FOA). The rating of an OA transformer can be increased by the addition of fans and oil pumps. Automatic controls responsive to liquid temperature are normally used to start the fans and pumps in a selected sequence as transformer loading increases. The increase in capacity over the OA rating is usually obtained in two stages: first stage - 33 1/3 percent and second stage - 66 2/3 percent. A variation of these triple-rated transformers is the OA/FOA/FOA type.

3.2.4.4 Oil Immersed Forced-Oil Cooled Forced-Air Cooled (FOA). This type of transformer uses external oil-to-air heat exchangers requiring both air fans and fluid pump for all operating conditions. FOA transformers cannot, without pumps and fans, carry rated loads.

3.2.4.5 Oil Immersed Water Cooled (OW). The cooling water runs through coils of pipe which are in contact with the insulating oil of the transformer. The oil flows around the coils of pipe by natural convection, thereby effecting the heat transfer to the cooling water. This type of transformer has no self-cooled rating. The OW/A type is water cooled and self cooled.

3.2.4.6 Oil Immersed Forced-Oil Cooled with Forced-Water Cooled (FOW). This type of transformer is similar to the FOA unit, except that external oil-to-water heat exchangers are used.

3.2.4.7 Dry-Type Transformers. In dry-type transformers, available at voltage ratings of 15 kV and below, cooling is accomplished primarily by internal air flow. Three classes of dry-type transformers are: self-cooled (AA), forced-air cooled (AFA) and self-cooled/forced-air cooled (AA/FA).

3.2.5 Transformer Impedance. The turns ratio of a-two-winding transformer determines the ratio between primary and secondary terminal voltages, when the transformer load current is zero. When load is applied to the transformer, however, the load current encounters an apparent impedance within the transformer which causes the ratio of terminal voltages to depart from the actual turns ratio. This internal impedance consists of two components:

(a) A reactance derived from the effect of leakage flux in the windings.

(b) An equivalent resistance which represents all losses traceable to the flow of load current, such as conductor I^2R loss and stray eddy-current loss.

3.2.5.1 Percent Impedance. Transformer impedance is conveniently expressed in percent, and is determined by the ratio of impedance voltage to rated primary voltage. In three-phase transformer banks, it is usually appropriate to refer both impedance voltage and rated voltage to a line-to-neutral basis. Percent impedance is also equal to measured ohmic impedance, expressed as a percentage of base ohms. Base ohms for a transformer circuit is defined as the rated current (per phase) divided into rated voltage (line-to-neutral), with the rated current derived from the self-cooled rating of the transformer.

3.2.5.2 Impedance Values. The percent impedance values depend on various factors including the number of windings, particular phase, high and low voltage ratings, transformer kVA rating, and the insulation medium and cooling class. In general, impedance values increase with higher voltage and kVA ratings. For most purposes, the impedance of power transformers may be considered equal to their reactances because the resistance component is negligible.

3.2.5.3 Fault Current Stresses. The standard transformer is designed with a limited ability to withstand the stresses imposed by external short circuits. The maximum short-circuit current magnitude and duration that a transformer can endure without incurring thermal and magnetic damage varies with transformer size and the number of phases. ANSI Std. C57.1200 defines the fault current withstand capability for liquid-immersed transformers.

3.2.6 Regulation. The full load regulation of a power transformer is the change in secondary voltage, expressed in percent of rated secondary voltage, that occurs when the rated kVA output at a specified power factor is reduced to zero, with the primary voltage maintained constant. The percent regulation can be calculated from the measured impedance characteristics at any load and power factor. The regulation can also be determined by loading the transformer according to the required conditions at rated voltage and measuring the rise in secondary voltage when the load is disconnected.

3.2.6.1 Effect of Variables. The percent regulation varies inversely with respect to the power factor (being lowest at unity power factor) and directly with the impedance. Transformers having very good regulation (low impedance), however, are also susceptible to higher fault currents. This relationship is an important factor in transformer engineering.

3.2.6.2 Voltage Taps. Voltage taps permit incremental changes in the ratio of the primary to secondary voltage transformation. Voltage tap adjustments can be used to maintain a constant secondary voltage despite changes in the primary voltage or secondary load currents.

(a) The most commonly selected tap arrangement is the manually adjustable no-load type, consisting of four 2 1/2 percent steps or increments from the nominal primary voltage rating. These tap positions are usually numbered 1 through 5, with the number 1 position providing the greatest number of effective turns. With a constant incoming voltage, selecting a higher voltage tap (lower tap number) will lower the output voltage. Tap positions can be manually changed only when the transformer is removed from service.

(b) Load Ratio Control automatically adjusts the primary to secondary voltage ratio +/- 10 percent in incremental steps, and can be controlled by a voltage sensor at the transformer secondary or at a remote location of the distribution system. Usually there are 32 (5/8 percent) steps to enable close voltage control over the range of +/- 10 percent. Automatic tap changing is accomplished by a voltage regulating relay and motor mechanism.

3.2.7 Connections. Standard 3-phase two-winding power transformers are connected in various configurations. The transformers used in main substations and at other points in primary distribution systems are typically Delta primary and Wye secondary. Other transformations, used by the Navy, are the Wye-Delta, Wye-Wye, and Delta-Delta. Less commonly used transformations, include the ZigZag, Open-Delta, Scott, and Six-Phase Star.

3.2.7.1 Delta-Wye. The Delta-Wye connection is shown in Figure 3-1. The wye secondary with external neutral bushing provides a convenient neutral point for establishing a system ground, or a neutral conductor for phase-to-neutral load. The delta-connected primary winding minimizes the flow of third harmonic currents and eliminates zero-sequence currents in the supply lines to improve the supply system voltage wave shape and to allow detection and isolation of line-to-ground faults (zero-sequence currents is a significant factor in symmetrical components analysis terminology). The delta connection may be used whether the primary is connected to a three-wire or four-wire system. Principal applications of a Delta-Wye connections are stepping down to supply a four wire load and stepping up to supply a high-voltage distribution or transmission system.

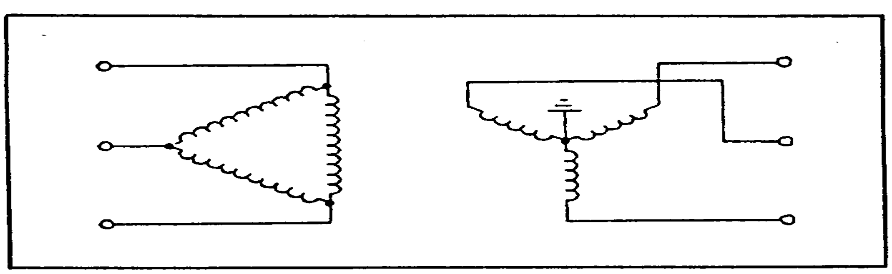

FIGURE 3-1
Delta-Wye

3.2.7.2 Wye-Delta. The Wye-Delta connection is shown in Figure 3-2. Wye-Delta connections are generally used for large-ratio step-down transformers. The primary is a wye connection due to the inherent mechanical and electrical advantages of wye circuits, while a delta connected secondary provides an improved waveform to loads.

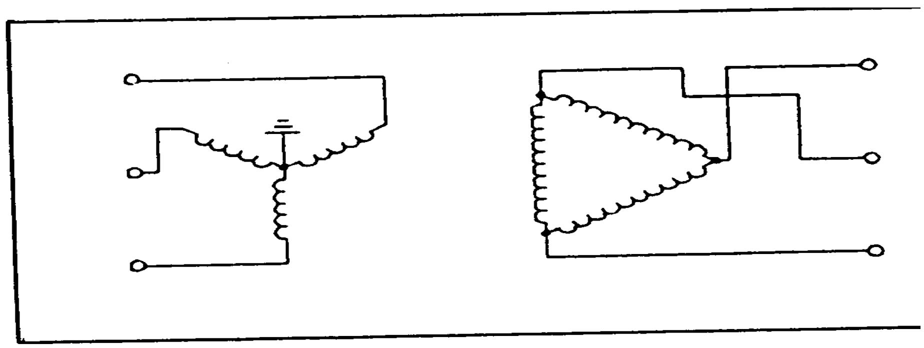

FIGURE 3-2
Wye-Delta

3.2.7.3 Wye-Wye. The Wye-Wye connection is shown in Figure 3-3. Wye-Wye connections are seldom used since they are subject to disturbances from harmonic voltages and currents. Unbalanced loads cannot be carried on the secondary unless the primary neutral is provided. For those applications which require a wye-wye transformation, a third winding, delta connected and designated as the tertiary is recommended to provide a low impedance path for zero-sequence currents. The third winding can also be used to serve an auxiliary load if external connection facilities are provided.

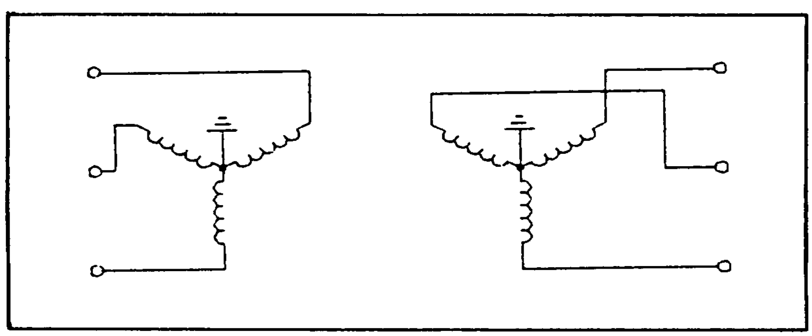

FIGURE 3-3
Wye-Wye

3.2.7.4 Delta-Delta. The Delta-Delta connection is shown in Figure 3-4. The Delta-Delta connection is also seldom used. It is used on Naval ships to enhance damage control. A phase to ground fault will be detected but does not trip breakers because there is minimal fault current.

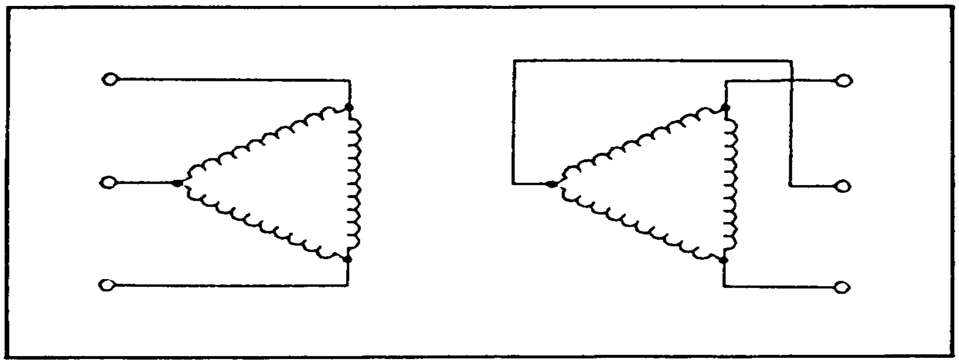

FIGURE 3-4
Delta-Delta

3.2.7.5 Zigzag. The Zigzag connection is shown in Figure 3-5. The interconnected wye connection is commonly referred to as the zigzag connection. It may be used with either a delta-connected winding or a wye-connected winding for step-up or step-down operation. In either case, the zigzag winding produces the same angular displacement as a delta winding and it provides a neutral for grounding purposes. A discussion of the internal connection of a three-phase zigzag transformer, with no secondary winding, can be found in subparagraph 3.2.11.2, Grounding Transformers.

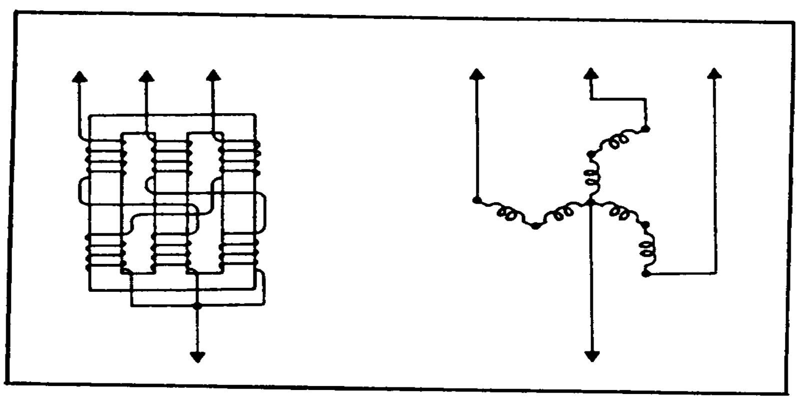

FIGURE 3-5
Zigzag

3.2.7.6 Open-Delta. The open-delta connection is shown in Figure 3-6. Under balanced conditions, an open-delta bank can be operated at slightly less than 58 percent of the throughput of an equivalent delta-delta bank; and the voltages and currents are, for practical purposes, the same as for a delta-delta bank. Open-delta banks have two important roles in power distribution. First, they allow operation at reduced initial investment on systems subject to future expansion. A balanced three-phase load can be served with an open-delta bank, allowing future expansions in load up to 72 percent of the open-delta rating, simply by adding the third transformer. Second, a distribution system, that is reasonably well balanced, can be operated at reduced load while one transformer is being serviced or replaced. This is particularly important in plants that can reduce throughput at low cost but cannot afford periods of shutdown for significant portions of the load being served.

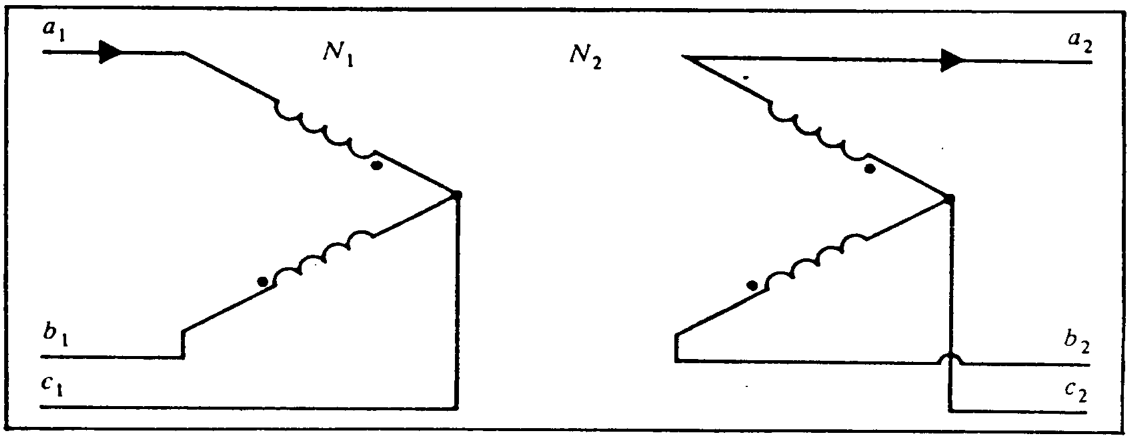

FIGURE 3-6
Open-Delta

3.2.7.7 Scott Connection. The Scott connection is a means of converting three-phase to two-phase transformations or vice versa. Usually, two identical transformers are purchased so that they will be interchangeable. This requires an 0.866 tap on one transformer and a midwinding tap on the other. The Scott connection is shown in Figure 3-7.

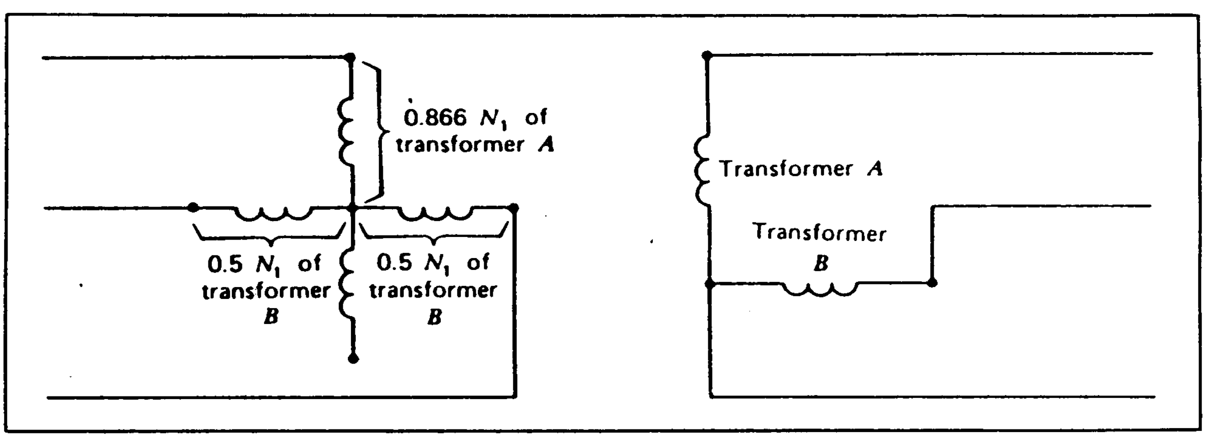

FIGURE 3-7
Scott Connection
(Three-Phase to Two-Phase Transformations)

3.2.7.8 Six-Phase Star. The six-phase star connection is shown in Figure 3-8. It provides a means for converting three-phase to six-phase transformations and is used in many rectifier and thyristor circuits where a path for DC current flow is required. The characteristic angle of a six-phase system is 60 degrees.

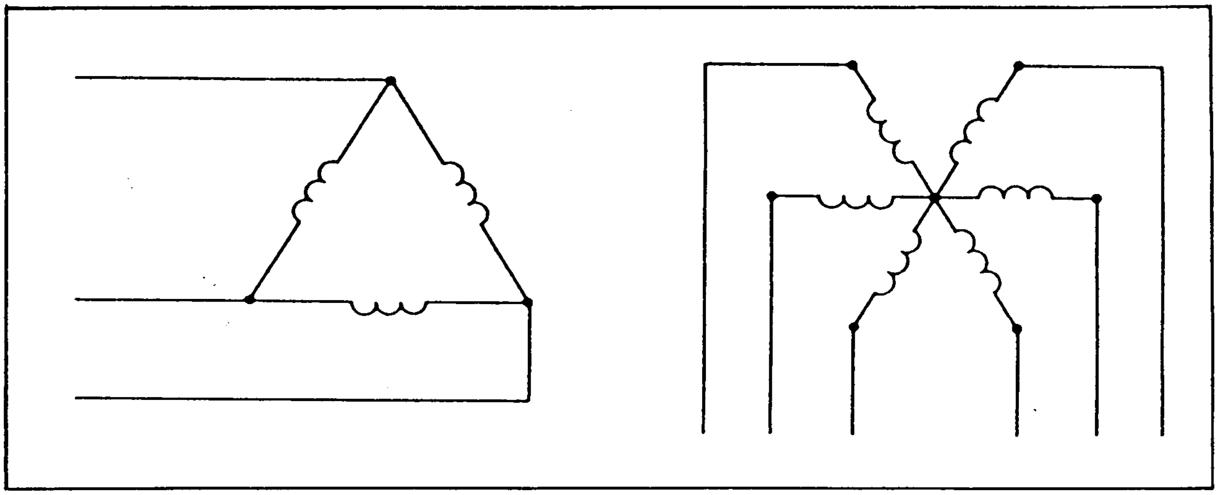

FIGURE 3-8
Six-Phase Star
(Three-Phase Delta to Six-Phase Star Connection)

3.2.8 <u>Loading of Transformers</u>. Ordinarily the kVA that a transformer should carry is limited by the effect of reactance on regulation or by the effect of load losses on system economy. At times it is desirable to ignore these factors and increase the kVA load until the effect of temperature on insulation life is the limiting factor. High temperature decreases the mechanical strength and increases the brittleness of fibrous insulation, making transformer failure increasingly likely, even though the dielectric strength of the insulation material may not be seriously degraded. Overloading of transformers should be limited by reasonable consideration of the effect on insulation and, consequently, transformer life.

3.2.8.1 Kilovolt-Amperes (kVA) Ratings. Ratings in kVA or megavolt-amperes (MVA) will include the self-cooled rating at a specified temperature rise, as well as the forced-cooled ratings if the transformer is so equipped. As a minimum consideration, the self-cooled rating should be at least equal to the expected peak demand.

3.2.8.2 Winding Temperature. The standard allowable average winding, of copper, temperature rise (by resistance test) for the modern liquid-filled power transformer is either 55°C/65°C or 65°C, based on an average ambient of 30°C (40°C maximum) for any 24 hour period. Since temperature distribution is uneven in most transformers, hottest-spot insulation temperature usually determines insulation life and, therefore, transformer loading. A 65°C rated transformer in a 30°C ambient environment is usually rated for a hottest spot temperature of 110°C.

3.2.8.3 Overloads. Transformers have certain overload capabilities, varying with ambient temperature, pre-loading, and overload duration. These capabilities are defined in ANSI Std. C57.92, Guide for Loading Mineral-Oil-Immersed Distribution and Power Transformers, and ANSI Std. C57.96, Guide for Loading Dry-Type Distribution and Power Transformers.

3.2.9 Parallel Operation. The theoretically ideal conditions for paralleling transformers are:

(a) Identical turns ratios and voltage ratings.
(b) Equal percent impedances.
(c) Equal ratios of resistance to reactance.
(d) Same polarity.
(e) Same phase angle shift.
(f) Same phase rotation.

3.2.9.1 Single-Phase Transformers. Only the first four conditions for paralleling transformers (listed above) apply to single-phase transformers, as there is no voltage transformation related to phase angle shift or phase rotation. All six conditions apply, however, to paralleling three-phase-banks of single-phase transformers. If the turns ratios are not the same, a circulating current will flow even at no load. If the percent impedance or the ratios of resistance to reactance are different, there will be no circulating current at no load, and the division of load between the loaded transformers will no longer be proportional to their kVA ratings.

3.2.9.2 Three-Phase Transformers. While the same transformer paralleling conditions apply to three-phase transformers, consideration must be given to the phase angle shift and to phase rotation. The transformers must have the same winding arrangement.

(a) Certain transformer connections as the Wye-Delta or Wye-Zigzag produce a 30° shift between the line voltages on the primary side and those on the secondary side. Transformers with these connections cannot be paralleled with transformers not having this shift such as Wye-Wye, Delta-Delta, Zigzag-Delta, or Zigzag-Zigzag.

(b) Phase rotation refers to the sequence in which the terminal voltages reach their maximum values. In paralleling, those terminals whose voltage maximums occur simultaneously are paired.

3.2.9.3 Power Transformer Practice. The preceding discussion covered the theoretically ideal requirements for paralleling. In actual practice good paralleling is obtained even though the actual transformer conditions deviate by small percentages from the theoretical ones.

(a) In order to insure maximum use of transformer capacity, and to prevent overloading of one transformer inadvertently, the criterion generally accepted is that the circulating current for any combination of ratios and impedances should not exceed ten percent of the full-load rated current of the smallest unit. This can generally be accomplished if the impedances are within 7.5 percent of each other, as this is the standard ANSI tolerance from a nominal specified value for a group of transformers that are manufactured to the same specifications. The X/R ratio of the transformers should also be within 7.5 percent of each other. A more detailed discussion of parallel operation of transformers with equations to evaluate whether parallel operation can be safely achieved, is contained in Chapter 5 of Transformers, Second Edition, K. L. Gebert and K. R. Edwards, American Technical Society, Chicago, IL.

(b) When it is desired to parallel transformers having widely different impedances, reactors or autotransformers having the proper ratio should be used. If a reactor is used, it is placed in series with a transformer having a lower impedance. It should have an impedance value sufficient to bring the total effective percent impedance of the transformer and reactor up to the value of the percent impedance of the second transformer. When an autotransformer is used, the relative currents supplied by each transformer are determined by the ratio of the two sections of the autotransformer. The autotransformer adds a voltage to the voltage drop in the transformer with the lower impedance and subtracts a voltage from the voltage drop in the transformer with the higher impedance. Autotransformers for use in paralleling power transformers are designed specifically for each installation.

3.2.10 Classifications. Transformers have many classifications which are useful in the industry to distinguish or define certain characteristics of design and application.

3.2.10.1 Distribution and Power. Transformers may be classified according to the rating in kVA. The distribution type covers the range of 3 kVA through 500 kVA, and the power type all ratings above 500 kVA or over 67 kV system voltage.

3.2.10.2 Insulation. Transformers may be classified by insulation type, as liquid and dry. Liquid insulated can be further defined according to the types of liquid: mineral oil, askarel, or other synthetic liquids. The dry-type grouping includes the ventilated and sealed gas-filled types.

3.2.10.3 Substation or Unit Substation. The title substation transformer usually denotes a power transformer with direct cable or overhead line termination facilities. This distinguishes it from a unit substation transformer designed for integral connection to primary or secondary switchgear, or both, through enclosed bus connections. The substation classification is further defined by the terms primary and secondary. The primary substation transformer has a secondary or load-side voltage rating greater than 1000 V, whereas the secondary substation transformer has a load-side voltage rating of 1000 V or lower.

3.2.11 Special Transformers. There are various transformers used in special applications, such as autotransformers, grounding, constant-current, furnace, and self-protected transformers.

3.2.11.1 Autotransformers. Autotransformers are constructed with a single winding per phase, such that part of the winding is common to both primary and secondary sides. The common portion is called the common winding, and the remainder is called the series winding. The high-voltage terminal is called the series terminal, and the low-voltage terminal is called the common terminal. Part of the power passes from one winding to the other by transformation, and the rest passes directly through without transformation. A solid connection exists between the primary and secondary circuits. This is generally of little consequence with low-voltage circuits, but with high-voltage systems the neutral point must be grounded for safe operation.

Autotransformer voltage transformation ratios rarely exceed 2:1. They are commonly used to connect two transmission systems at slightly different voltages, frequently with a delta tertiary winding. Similarly, autotransformers are used for generator step-up transformers to feed two different transmission systems.

3.2.11.2 Grounding Transformers. A grounding transformer is intended primarily for the purpose of providing a neutral point for grounding purposes. One such application could be grounding a Delta-connected system. Grounding transformers may be either of the Zigzag- or Wye-Delta type.

(a) The type of grounding transformer most commonly used is a zigzag three-phase transformer with no secondary winding. The internal connection of this transformer is illustrated in Figure 3-9. The impedance of the transformer to three-phase currents is high, so that when there is no fault on the system, only a small magnetizing current flows in the transformer windings. The transformer impedance to ground current, however, is low so that it allows high ground currents to flow. The transformer divides the ground current into three equal in-phase current components, flowing in the three windings of the grounding transformer.

(b) A Wye-Delta transformer can also be used as a grounding transformer. in this case the delta must be closed to provide a path for the zero-sequence current, but can be made up at any convenient voltage level. It may or may not be used to serve other loads. The wye winding must be of the same voltage rating as the circuit which is to be grounded.

3.2.11.3 Constant-Current Transformers. A constant-current transformer automatically maintains an approximately constant current in its secondary circuit under varying conditions of load impedance when its primary is supplied from an approximately constant-potential source. The moving coil design is the most commonly used type, having separate primary and secondary

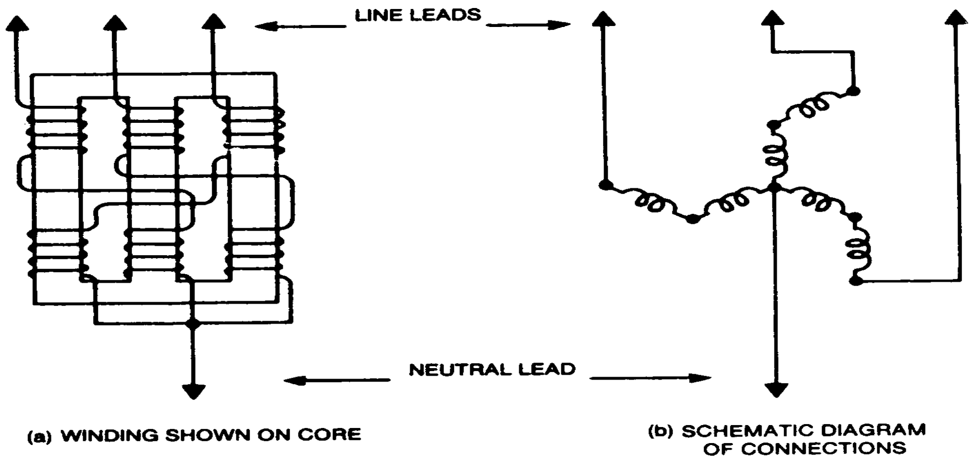

FIGURE 3-9
Zigzag Three-Phase Grounding Transformer

coils which are free to move with respect to each other, thereby varying the magnetic leakage reactance of the transformer. This reactance automatically adjusts itself to a value which, when added to the load impedance, permits a constant current to flow. Constant-current transformers are used primarily for series street lighting circuits. Standard output ratings are 10, 15, 20, 25 and 30 kW. The standard rated output current of these transformers is 6.6 or 20 A.

3.2.11.4 Furnace Transformers. Furnace transformers supply power to various types of electric furnaces. The secondary voltages are low, generally several hundred volts, and occasionally less than 100 V. Sizes range from a few kVA to over 50 MVA, with secondary currents over 60,000 A. High currents are obtained by parallel connection of many winding sections and collected by internal bus bars.

3.2.11.5 Self-Protected Transformers. Self-protected transformers generally have an internally mounted, thermally controlled secondary breaker for overload and short-circuit protection; an internally mounted protection link in series with the high-voltage winding to disconnect the transformer from the line in the event of an internal coil failure; and a lightning arrester, or arresters, integrally mounted on the outside of the tank for overvoltage protection.

3.3 VOLTAGE REGULATORS. The function of a transmission and distribution system is to deliver power to the user at a voltage that is within acceptable limits. It is impractical, however, to regulate large systems solely by means of generator regulators. Other devices for correcting the voltage, therefore, are commonly used throughout the system. These devices include transformers with automatic load-tap-changers, synchronous condensers, switched capacitors, and voltage regulators.

3.3.1 <u>Definition</u>. A voltage regulator (transformer type) is an induction device having windings in shunt with the primary circuit and secondary windings in series with the regulated circuit. Although similar in operation to transformer load-tap-changing equipment, voltage regulators are distinct pieces of power system apparatus.

3.3.2 <u>Types of Voltage Regulators</u>. There are three types of regulators; step, induction, and ferroresonant. The induction regulator was commonly used in the past for power circuits, however, it has been generally replaced by the less expensive and more serviceable step regulator. The ferroresonant transformer (FRT) has been used as a constant voltage transformer in low power applications (less than 1 kVA to approximately 15 kVA) for many years. With proper filtering, the FRT is now used quite often to serve sensitive electronic and computer equipment.

3.3.2.1 Step Voltage Regulator. The step voltage regulator is an autotransformer equipped with a mechanism capable of changing taps under load. Standard step regulators have a regulation range of +/- 10 percent of the applied voltage. This range is usually divided into thirty-two 5/8 percent steps so that each change represents a specific increment of voltage.

3.3.2.2 Induction Voltage Regulator. Induction voltage regulators operate on the transformer principle although their construction resembles that of a wound-rotor induction motor. The shunt winding is connected across the line and supplies excitation for the regulator. Upon excitation of the shunt winding, a voltage is induced in the series winding. Although it remains constant in magnitude, the phase relationship of the induced voltage, with respect to the voltage of the shunt winding, changes as the rotor is turned. The position of the rotor, therefore, determines how much buck or boost voltage is imparted by the regulator at any given time.

3.3.2.3 Ferroresonant Constant Voltage Transformer. The ferroresonant constant voltage transformer was patented in 1938. Generally, it consists of a resonant electrical circuit and a high leakage reactance magnetic circuit. The output voltage remains essentially constant for a wide range (+/- 15 percent) of input voltage. The principle of operation is a resonant circuit, consisting of a series coil and a capacitor, tuned to resonate at approximately 60 Hz. A saturable inductor is the secondary winding of the transformer and operates in saturation in the design input voltage range of the unit to deliver a constant output voltage. The output voltage is rich in harmonics (usually 20 percent or more harmonic distortion). For use with loads sensitive to these harmonics, extra filtering coils must be added to the output circuitry to reduce harmonic distortion to less than 3 percent. The FRT's are available in designs up to approximately 15 kVA and are usually used on low voltage (120 to 240 V) circuits. Higher power and voltage ratings are limited by the capacitor sizing and other methods of regulation are more economic at the higher voltage and power levels. These types of units are frequency sensitive. The units designed to operate at 60 Hz are not suitable for use at 50 Hz, which is the power source available in many foreign countries.

3.3.3 <u>Ratings</u>. Voltage regulators are rated in terms of the number of phases, capacity in kVA, primary voltage, percent regulation, and frequency. In addition, information concerning temperature rise, impedance, insulation level, type of cooling, method of making connections, and similar data is given on the nameplate.

3.3.3.1 kVA Rating. The kVA rating of a regulator is the product of the load amperes and the voltage of the series winding in kilovolts. Standard ratings of regulators are available up to 833 kVA single-phase and 2500 kVA three-phase for line voltages of 2500 V to 34,500 V. To enable regulation of 25,000 kVA circuits, 10 percent regulation units have a kVA regulated circuit reading ten times higher than that of the regulator kVA.

3.3.3.2 Insulation and Cooling. Standard regulators are oil-immersed and self-cooled. Units above 500 kVA can usually accommodate fans for forced cooling, adding up to 66 percent to the self-cooled rating.

3.3.4 <u>Applications</u>. Voltage regulators are installed on distribution systems to keep voltages at a selected value. The location of a regulator is determined by the type of loads and circuits served. Regulators are available for ground or pole installation.

3.3.4.1 Bus Regulators. Bus regulation is often used when a substation has two or more circuits with similar load characteristics and requirements. For such applications the regulator installation controls the voltage on the substation bus rather than on individual circuits. Voltage regulation of the bus can also be accomplished by equipping the station's power transformer with a load tap changing (LTC) mechanism.

3.3.4.2 Feeder Regulators. Feeder regulators maintain a constant voltage on a particular circuit with variation in load. They may be installed at a substation or located between the substation and the load being served. On long lines, or lines with critical loads, two or more regulator installations may be warranted in order to cope with the circuit requirements. These may be located either on the main feeder or branch feeder circuits.

3.3.5 Regulator Control. Most modern regulators are motor-operated and automatically controlled. Facilities are provided for the regulator to control the voltage at a point remote from the regulator location. The components required to automatically control a motor-operated regulator are:

(a) Voltage sensing device.
(b) Amplifying section.
(c) Motor drive.
(d) Line-drop compensator.

A voltage sensing device is connected through a potential transformer across the feeder or bus to be regulated. The voltage sensing device, which may be either a voltage-regulating relay or a static voltage sensor, operates a switch that controls the operating motor of the regulator. A current transformer connected in series with the regulated circuit has its secondary winding normally connected to a line-drop compensator. This line-drop compensator contains variable resistance and reactance (each independently adjustable) which represents the impedance of a regulated circuit. The voltage drop in the regulated circuit is, thus, easily detected by a proportional voltage drop across the compensator. Once adjusted, the compensator permits the regulator to hold constant voltage at a selected point on the circuit, regardless of load or power factor.

3.3.6 Single- and Three-Phase Connections. Single-phase regulators are applied to control the voltage on a single-phase circuit. They may, however, be applied to three-phase circuits and have some advantage over three-phase units that regulate all three phases in the same manner. Single-phase units, when applied to three-phase circuits, can be adjusted for separate regulation levels. A three-phase unit can only be adjusted for an average value of the three phase

3.3.7 Parallel Operation of Step Regulators. Special adaptations make it possible to operate step regulators in parallel, however, certain restrictions are imposed by each method. The choice of a method is dependent upon such factors as circuit impedances, proximity of units, and the types of equipment being paralleled. This is to prevent off-step operation, which could lead to excessive circulating current between regulators.

3.3.8 Bypassing Single-Phase Voltage Regulators. In order to provide continuity of service and to prevent injury to the regulator, special facilities and procedures are necessary for switching regulators on and off a line. The following are general procedures; individual manufacturer's instructions should be followed.

3.3.8.1 Disconnecting Regulator. Referring to Figure 3-10 (Bypass Switching Arrangement for Single-Phase Voltage Regulator), the sequence of operation for disconnecting a voltage regulator is summarized as follows:

(a) Place regulator control on manual and adjust to neutral position.

(b) Open the control power switch.

(c) Close switch D shorting series winding.

(d) Open switch C and then B.

(e) Open switch A, if used. This switch is required only when terminal S_2 - L_2 is not connected to the neutral or ground wire.

3.3.8.2 Connecting Regulator. Referring to Figure 3-10, the sequence of operation for connecting a voltage regulator is summarized as follows:

(a) Verify that the regulator control switch is in the manual position and that the regulator is in the neutral position.

(b) Close switch A, if used.

(c) Close switch B and switch C.

(d) Open switch D.

(e) Close the control power switch.

(f) Turn control switch from manual to automatic.

3.3.8.3 Regulator Bypassing Equipment. Equipment used to bypass regulators includes circuit breakers, interlocking switches, and cutouts with disconnecting blades. A convenient switching device is the regulator bypass switch, which includes switches B, C, and D of Figure 3-10, as an integral unit. When the regulator bypass switch is operated, the correct switching sequence occurs.

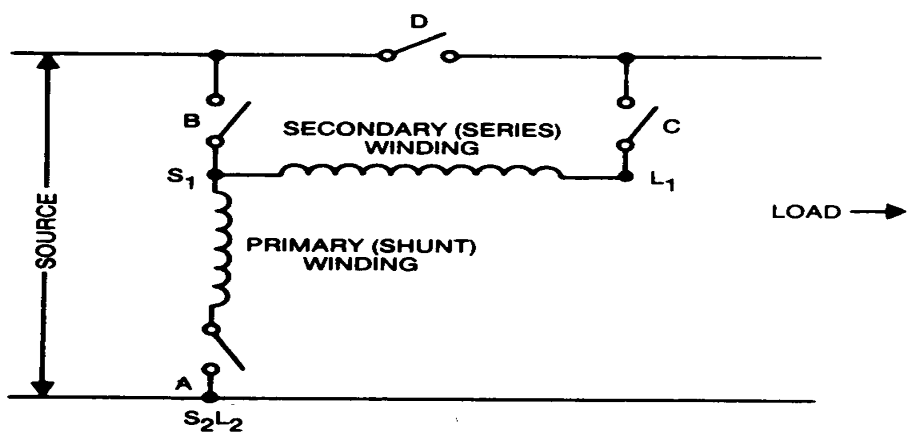

FIGURE 3-10
Bypass Switching Arrangement for Single-Phase Voltage Regulator

3.3.9 Bypassing Three-Phase Voltage Regulators. With the exception of the single-core, 3-phase induction regulator, the switching sequence of subparagraph 3.3.8 applies to each phase of a 3-phase regulator. In such cases, three identical sets of switches would be used. Since the single-core, 3-phase induction regulator has no neutral position within the regulation range where the series winding voltage is zero, special facilities must be provided.

3.3.10 Regulator Protection.

3.3.10.1 Surge Protection. As previously stated, regulators are constructed very much like autotransformers, having primary (shunt) and secondary (series) windings. Surge protection requirements for regulators are consequently very similar to those for transformers.

3.3.10.2 Short-Circuit Protection. Because voltage regulators are connected in series in the circuit, they may be subjected to exceptionally severe short-circuit currents. For this reason, current-limiting devices are often installed in the circuit to limit possible fault currents to a value that the regulator can withstand.

3.3.10.3 Thermal Protection. There is no inherent thermal protective device built into a regulator. Consequently, the operator must be watchful for overloads that may damage the regulator. Like transformers, regulators have some overload ability and may be overloaded under certain conditions.

3.4 SWITCHES. A switch is a device for making, breaking, or changing the connections in an electric circuit. Switches are normally divided into three classes relative to the operating medium; air, oil, and vacuum switches.

3.4.1 General Purpose. Air switches are an essential element of electrical power transmission and distribution systems. They provide positive, visible air-gap isolation for equipment, bus and line sections and facilitate examination, maintenance, and repair. Oil and vacuum switches are primarily used in underground distribution systems, especially where submersible switching equipment is required. In addition, oil switches are often used on capacitor circuits.

3.4.2 Ratings. Switches are rated in terms of one or more of the following characteristics; voltage, Basic-impulse Insulation Level (BIL), continuous current, short-time current, and interrupting current.

3.4.2.1 Voltage Rating. The voltage rating is a value assigned for the purpose of designating dielectric characteristics and should not be exceeded under normal operating conditions.

3.4.2.2 Basic-impulse Insulation Level. This is the reference insulation level expressed as the impulse crest value of withstand voltage of a specified full impulse wave (see subparagraph 3.2.3.5).

3.4.2.3 Continuous Current Rating. The continuous current rating is the designated limit of current in amperes that the switch will carry continuously without exceeding a maximum temperature rise of 30° above ambient. For switches having copper-to-copper contacts or the equivalent, this ambient may be 40°. For switches having all contacts silver-surfaced or the equivalent, this ambient may be 55°C. The limited heat storage capacity of a switch precludes any overload rating. Switches, therefore, should not be operated in excess of their continuous current rating, except under emergency conditions.

3.4.2.4 Interrupting Rating. The interrupting rating indicates the maximum short-circuit current that a switch can interrupt without sustaining damage. No switch should ever be operated (open or close) on an energized power system unless it has sufficient interrupting capacity. For personnel safety, this precaution cannot be overemphasized.

3.4.2.5 Short-Time Rating. All switches have a short-time current rating corresponding to the switch's ability to carry short-circuit current in the closed position. This rating incorporates the limitations imposed by both thermal and electromagnetic effects. The short-time current rating of a switch is the highest current that the switch is designed to carry without damage for specified short-time intervals. The short-time current rating consists of two values:

(a) That which the switch can carry for one cycle, referred to as its momentary rating.

(b) That which it can carry for four seconds.

Numerically, the momentary rating is 1.6 times the four-second rating.

3.4.3 <u>Types of Switches and Their Application</u>. There are a variety of switches used in the transmission and distribution of electric power. The switches are designed for specific purposes and operational conditions. In general, the switches are distinguished by the current handling capability; i.e., continuous, loadbreak or non-loadbreak, and fault current.

3.4.3.1 Air Switches.

(a) A disconnect switch is one used for; closing, opening, or changing the connections in a circuit or system, or for isolating purposes. It has no interrupting rating and is intended to be operated only after the circuit has been deenergized by some other means. Disconnect switches may be either hook- or gang-operated. A series-connected circuit breaker or circuit recloser should be open on all three phases before a disconnect switch is opened or closed.

(b) Air-break switches are normally mounted on top of their supporting structure and are gang-operated. They are either manually operated by means of an operating handle or electrically operated by means of a motor-operated mechanism. They are used to perform various switching assignments such as isolating transformers, bypassing circuit breakers, and for line sectionalizing (where small amounts of magnetizing or charging currents are to be interrupted).

(c) An interrupter switch can use either air or oil as its interrupting medium. Load-interrupter switches are used to interrupt transformer-magnetizing current, line-charging current, capacitor current to isolated banks, and load current within the limits of their rating. They are normally used where the cost of a circuit breaker with fault-interrupting ability cannot be justified and where the use of air-break switches is hazardous because of the danger of inconvenient and uncontrolled arcs. oad-interrupter switches differ from circuit breakers and fault interrupter switches in that they cannot interrupt overload or short-circuit currents. Interrupter switches may be either single-pole hook-stick operated or gang-operated, depending upon their location and application.

(d) A grounding switch is used to connect a circuit or a piece of apparatus to ground. Grounding switches are normally subdivided into two separate groups: manually operated and high-speed. Where a manually operated grounding switch is installed, it is normally connected to an air-break or gang-operated disconnect switch. It is used to effectively ground a line after the air-break or disconnect switch has isolated it. The manually operated grounding switch is generally interlocked with its associated switch so that the grounding switch cannot be closed until the disconnect is open. A high-speed grounding switch has a stored-energy mechanism capable of closing the switch automatically, within a specified rated closing time. The switch is opened either manually or by a power-operated mechanism. High-speed grounding switches are used to provide protection to a differential relayed area in coordination with a remote circuit breaker. Normally, the arrangements are such that the differential relay detects the fault and initiates the closing of the high-speed grounding switch and results in tripping the remote circuit breaker to clear the fault.

3.4.3.2 Oil Switches. An oil switch has its main contacts submerged in oil. Oil acts as an insulator to help quench the arc between the contacts. In addition, since the tank is airtight, the vaporized oil caused by the arc develops pressure which assists in breaking the arc. If the voltage is not very high, a three-pole switch can be placed in a single tank. At higher voltages, three separate tanks are used to make it impossible for a phase-to-phase fault to occur. Oil switches will normally open only load current. A separate trip coil is necessary to interrupt overload or fault currents. Oil switches are generally used in capacitor switching, distribution sectionalizing, and transformer primary switching.

3.4.3.3 Vacuum Switches. Vacuum switches (See Figure 3-11 for an example of a three-phase vacuum loadbreak switch) are interrupters which use vacuum chambers for contact separation. They are generally used to interrupt load, capacitor, or transformer magnetizing currents. Unlike oil switches, vacuum switches require virtually no maintenance. They can be used for submersible or padmount operation.

3.4.4 Switch Accessories. Switch accessories are devices that perform a secondary or minor duty as an adjunct or refinement to the primary operation of a switch or to assist in the operation of a switch. Some accessories that are commonly associated with switches are as follows:

3.4.4.1 Operating Mechanisms. The operating mechanism of a switch is a power-operated or manually-operated mechanism complete with an assembly of levers, mechanical linkages, and interphase connecting rods by which the contacts of all poles are actuated simultaneously.

3.4.4.2 Hook Sticks. A hook stick is a hook provided with an insulating handle (usually specially treated wood) for opening and closing hook-stick-operated switches. When not being used, hook sticks should be stored in a dry location.

3.4.4.3 Interlocks. An interlock is a device applied to two or more movable parts, preventing or allowing a movement of one part only when one or more other parts are locked in a predetermined position. An interlock system is a series of these devices applied to equipment to allow operation of the equipment only in a prearranged sequence. Switches used only for isolating purposes must be interlocked to prevent opening of the isolating switch under load, or the switch must be provided with a highly visible sign warning against opening the switch under load. Interlocks are classified into three main divisions: mechanical interlocks, electrical interlocks, and key interlocks.

3.4.4.4 Auxiliary Switches. Auxiliary switches are low-voltage switches that are attached to the operating mechanism of gang-operated switches. The open or closed position of auxiliary switches is governed by the position of the main contacts. Auxiliary switches are used for electrical interlocking, remote position indication, or control of electrically operated switches.

3.4.5 Operation. Disconnect switches, grounding switches, and air-break switches have no interrupting rating. It is, however, common practice to use air-break switches to interrupt small values of current and to use the following general rules.

3.4.5.1 Operation Rules.

(a) Prior to operating, check the circuit to see that no load is being carried by the switch. If the disconnect switch is installed in series with a circuit breaker or automatic circuit recloser, inspect the position of the series device to be sure that it is open before operating the disconnect switch. The indicating lamp or targets on the switchboard should not be relied upon for positive indication that a circuit breaker is open.

FIGURE 3-11. THREE-PHASE VACUUM LOADBREAK SWITCH
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

(b) Disconnect switches should be closed with a quick positive motion, with sufficient force to ensure full contact with the clips. Excessive force should not be exerted in the movement, as such force may break the insulators. If a disconnect switch is accidentally closed when the associated circuit breaker or other circuit interrupting device is closed, do not attempt to reopen the disconnect switch. Leave it closed, get away from it at once, and open the circuit by means of the circuit breaker or other suitable circuit interrupting device.

(c) A disconnect switch should be opened slowly so that it can be reclosed quickly, if necessary. If an operator should start to open a disconnect switch and finds that an arc of unusual severity is formed, this indicates that the circuit breaker or other circuit interrupting device is closed or that there is trouble on the circuit or equipment controlled by the disconnect switch. The operator should immediately reclose the disconnect switch, leave it closed, and open the circuit by means of a circuit breaker or other suitable circuit interrupting device before attempting to open the disconnect switch again.

(d) After operating a switch, check to see that it is fully closed and latched or fully open as intended.

(e) Do not use undue force in attempting to operate a switch. The operating mechanism is carefully designed for the switch. Any undue force applied by an extension of the operating handle, or an extra person on the operating handle or switch stick, may cause severe damage to the switch or mechanism.

(f) Power-operated switches should be operated periodically to assure that the switches, their mechanism, and control features are functioning properly. Where the circuit conditions will not permit operating the switch energized, and the circuit cannot be deenergized for this purpose, it is suggested that arrangements be made to disengage the operating mechanism to be checked (provided that this method does not adversely affect the overall adjustment).

3.5 CIRCUIT BREAKERS. A circuit breaker is a mechanical device for closing and interrupting a circuit and carrying current under both normal load and fault current conditions.

3.5.1 Purpose. One function of circuit breakers is to prevent or limit damage to circuits and apparatus during fault or overload conditions and to minimize their effect on the remainder of the system. During a fault or overload, the zone that includes the faulted or overloaded apparatus is isolated from the system. A circuit breaker is also used for circuit switching under normal conditions. A circuit breaker, when operated within its rating, is capable of closing into, of carrying, and of interrupting short-circuit current without being damaged. A circuit breaker maintains open-circuit conditions with operating voltage across its terminals.

3.5.2 Classes. There are generally two classes of circuit breakers.

3.5.2.1 Medium and High Voltage Power Circuit Breakers (rated above 1000 VAC).

3.5.2.2 Low Voltage Circuit Breakers (rated at 1000 VAC or less).

Section 5 discusses the medium and high voltage power circuit breaker. The low voltage circuit breaker, which includes the molded-case type, is discussed in Chapter 4, Section 6.

3.5.3 Application. Circuit breakers are used in distribution substations, switching stations, and generating stations for protecting and switching electrical service apparatus such as transformers, motors, generators, substation buses, and distribution feeder circuits. Circuit breakers are normally used where less expensive fuses and switches are not adequate because switching is frequent or available fault current is high.

3.5.4 Rating. Circuit breakers are rated in terms of voltage, continuous current, momentary current, and interrupting capability. In the normal operation of a circuit breaker the limitations imposed by a given breaker rating should not be exceeded; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

3.5.4.1 Voltage Rating. Circuit breakers are assigned a voltage rating that designates the maximum system voltage at which the breaker is intended to be operated.

3.5.4.2 Continuous Current Rating. This is the maximum value of the continuous current which the contacts and conductors are designed to carry. It should not be exceeded, except for short periods; as in starting motors or rotary converters, or energizing cold loads. In an emergency, circuit breakers can be overloaded provided the associated protective relays do not trip the breaker.

3.5.4.3 Maximum Momentary Current Rating. This is the maximum instantaneous current for which the breaker has been designed to close and latch under fault conditions.

3.5.4.4 Interrupting Rating. Circuit breakers have an interrupting rating representing their design limitation for interrupting fault current. Associated with the interrupting rating is the circuit breaker's capability to close into, carry, and interrupt short-circuit current. The interrupting rating of a circuit breaker takes into account the value of current to be interrupted, the voltage across the circuit breaker contacts at the time of current interruption, and the standard duty cycle. The interrupting capacity is given as the maximum amperes the breaker is designed to interrupt at normal circuit volts, as a function of the ratio of system reactance to resistance at the point of fault.

3.5.5 Types of Circuit Breakers. Circuit breakers are divided into two broad classes: oilless and oil circuit breakers.

3.5.5.1 Oilless Circuit Breakers. The oilless class includes: air, magnetic-blast, compressed-air, gas-filled, and vacuum circuit breakers.

(a) In the air type, the arc is extinguished, or interrupted, in substantially static air in which the arc moves into arcing chutes containing metal or insulating fins. The metal fins break the arc into many short segments while the insulating fins stretch the arc. Both methods are effective in extinguishing the arc. A circuit breaker arc chute interruption is shown in Figure 3-12.

(b) The magnetic-blast type differs from the air type in that it uses a magnetic field to blow the arc into the arc chute which elongates and cools the arc.

(c) In the compressed-air and gas-filled types, high-pressure air or gas is forced through the arcing path to elongate the arc and increase the resistance to the fault current.

(d) In a vacuum circuit breaker the arc is drawn in a vacuum. The high dielectric strength and the rapid recovery rate of a vacuum gap makes arc extinguishing extremely fast and clean.

3.5.5.2 Oil Circuit Breakers. As an interrupting medium, oil is much better than air at room pressure. Its dielectric strength is greater and, in addition, the arc generates hydrogen gas from the oil which helps to cool the arc. The use of a small arcing chamber to build up pressure greatly increases the interrupting capacity of an oil circuit breaker. The major disadvantages of oil circuit breakers are their inherent fire hazard and their relatively high cost.

3.5.6 <u>Major Component Parts</u>. All power circuit breakers, regardless of the type and construction, have certain structural components that are designated similarly for all. Such components include contacts, bushings, and the operating mechanism. Following are brief descriptions of major components of circuit breakers and their functions.

3.5.6.1 Contacts. The contacts are the most vital part of a circuit breaker. They consist of a pair of separable members that are opened and closed by mechanical means. Normally the contact members are held together under pressure and the electric current flows from one to the other through the point or points of contact. Circuit breakers are provided with main contacts made of silver for carrying the continuous current. In addition, there is a pair of arcing contacts made out of tungsten which protect the main contacts from damage due to arcing. The arcing contacts, which close before and open after the main contacts, carry current only during the interrupting process and are easily renewable. Twice during each cycle of an alternating current the current amplitude drops to zero value and the arc is extinguished for an instant. In order to interrupt the circuit, therefore, it is only necessary to prevent reignition of the arc after the current reaches zero value. Whether or not the arc is extinguished immediately after the current is zero depends upon whether the dielectric strength of the arc gap builds up at a faster rate than

FIGURE 3-12. CIRCUIT BREAKER ARC CHUTE INTERRUPTION
(REPRODUCED COURTESY OF WESTINGHOUSE ELECTRIC CORPORATION)

FIGURE NOT INCLUDED

the current waveform and permanently exceeds the system recovery voltage. This tends to reestablish the flow of current across the arc gap. In the case of an oil circuit breaker, the dielectric strength build up is accomplished by forcing clean oil into the arc path. In the case of a magnetic-blast circuit breaker, the arc is magnetically forced into the arc chute where it is elongated, cooled, and restricted to a point where the dielectric strength of the arc gap permanently exceeds the system recovery voltage.

3.5.6.2 Bushings. The bushing is the structure used to insulate the current-carrying parts from ground and from other live parts. It has a through conductor for carrying current from the line connection to the contacts. In many breaker designs it is also used to support the main contacts and interrupters. Bushings for oil circuit breakers are normally made of a porcelain or glass outer shell with an internal insulation material of: paper, oil, compound, ceramic materials, or a combination of these.

3.5.6.3 Housing. Circuit breakers are enclosed in some form of a housing to protect the essential parts from the environment, and also to protect personnel from live parts. Padmount housings normally enclose vacuum breakers in freestanding, tamperproof metal enclosures that have a neat appearance. A padmounted vacuum circuit breaker is shown in Figure 3-13. The two basic, most common forms of housings used are the tank and cubicle. In oil circuit breakers the tank is used to contain the oil in which the contacts and interrupters are immersed. The cubicle-type circuit breaker is one designed for use in a switchgear assembly. The switchgear cubicle is an indoor or outdoor assembly enclosed on all sides and top containing circuit breakers, buses, connections, and auxiliary devices. Design of the cubicle is such that when a circuit breaker is installed in its operating position, all operating parts are adequately insulated with a protective grounded barrier between all live parts and the operator. Cubicle-type switchgear is normally divided into the following types:

(a) A line-up of low voltage metal-enclosed air circuit breaker switchgear is shown in Figure 3-14. It consists of a front section; and a cable-entrance section. Each circuit breaker must be isolated from all other equipment. Circuit breakers may be either the fixed or draw-out type. The fixed type is rigidly mounted and has no provisions for quick removal. The draw-out type can be easily disconnected and removed from the switchgear cubicle while the bus remains energized. Vents are provided in the circuit breaker compartments for cooling and to release ionized gases that form when the circuit breaker opens to interrupt fault currents. Other sections of the switchgear must also be ventilated to allow circulation of air for cooling. Barriers between the bus compartment and the cable compartment are not required, but they may be furnished to permit connecting or disconnecting of the cables without danger of contacting the energized bus. If barriers are provided, all cable terminations should be insulated after installation, so that there will also be no danger of workmen contacting these hot terminals when making changes in the cable connections. Aside from having a weatherproof structure, outdoor metal-enclosed switchgear is similar to indoor equipment. Heaters, however, must be provided to keep the inside cubicle temperature greater than the outside temperature to prevent condensation. Indoor

FIGURE 3-13. PADMOUNTED VACUUM CIRCUIT BREAKER
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

switchgear is usually painted a light gray, ANSI Std. 70, using lacquer or enamel. Outdoor switchgear is usually painted the same color inside, but the outside is painted a dark gray, ANSI Std. 24. Epoxy paints may be necessary where corrosive atmospheres exist and special protection is required. Outdoor switchgear is mounted on sill channels and the structure is undercoated with a heavy coat of an asphalt material to prevent rusting.

(b) Metal-clad switchgear may be obtained for use indoors or in weatherproof structures for outdoor use. The same comments that apply to outdoor metal-enclosed switchgear (paragraph (a) above) apply to outdoor metal-clad switchgear. Outdoor switchgear may be used to serve indoor loads when indoor space is limited, when corrosive or explosive atmospheres are present inside the building, or when the indoor atmosphere is excessively dusty. Metal-clad switchgear structures differ from the standard low-voltage switchgear structures in several respects. By definition of metal-clad switchgear the circuit breakers must be of the removable type. Circuit breakers must be enclosed, as in low-voltage switchgear, but buses, potential transformers, control power transformers and cable terminals must also be enclosed in separate metal compartments. All metal barriers must be grounded. Shutters must be provided, which close automatically when a breaker is withdrawn, to prevent operators from contacting the primary contacts or the bus which may be energized. Interlocks must also be provided to prevent moving the breaker into or out of the connected position when it is closed and to prevent closing the breaker when in an intermediate position. Instruments and relays may be mounted on the door through which the breaker is inserted into the cubicle, but when this is done, a barrier must be provided between the instruments and the breaker. Circuit breakers may be moved into the connected position in metal-clad switchgear by either the horizontal-draw-out or the vertical-lift method. When the horizontal-draw-out method is used, the breaker is moved horizontally into position in the cubicle; then a racking mechanism is provided to force the breaker into the operate position where the primary contacts are fully engaged. The secondary contacts for control of the breaker must also be in contact. A test position is also provided where the secondary contacts are separated from the primary contacts by a safe distance. Vertical-lift breakers are moved into the cubicle beneath the stationary primary contacts, then raised with either a manually or electrically operated hoist until the primary and secondary contacts are fully engaged. To connect a breaker located outside the cubicle, a plug-jumper (replacing a test position) is provided to control circuits in the switchgear for test breaker electrical operation.

3.5.6.4 Mechanism. The mechanism of a circuit breaker is the complete assembly of levers and other parts that actuates the moving contacts. The mechanism consists of two parts, the tripping mechanism and the closing mechanism.

(a) The tripping mechanism is an electrically or mechanically operated device that releases the contacts with a mousetrap like spring-driven snap action. The tripping mechanism consists of an electromagnet (trip coil) acting as a trigger that releases a latch permitting the breaker to open. The opening energy is normally supplied by accelerating springs that are charged (compressed) when the breaker is closed. All circuit breakers are equipped with a

FIGURE 3-14. LOW-VOLTAGE METAL-ENCLOSED AIR CIRCUIT BREAKER SWITCHGEAR

(REPRODUCED COURTESY OF WESTINGHOUSE ELECTRIC CORPORATION)

FIGURE NOT INCLUDED

manual trip device that is connected to the tripping linkage. Automatic tripping is normally performed by one of three methods:

- o Series-overcurrent tripping.
- o Shunt tripping.
- o Undervoltage tripping.

Series-overcurrent tripping is the tripping of a circuit breaker from a trip coil in series with the circuit responding to an increase in the circuit current above a predetermined value. Series tripping is normally used on low-voltage circuit breakers. These breakers are complete with adjustable (long-time, short-time, and instantaneous) direct-acting series overload tripping devices. Most manufacturers offer static trip units on large low-voltage air circuit breakers as an alternate to magnetic overcurrent devices. These solid-state devices are more reliable, have time-current curves with narrower performance tolerance bands, are easier to coordinate with other protective devices, and are easier to calibrate and set. Shunt tripping of a circuit breaker involves a trip coil energized from the same or a separate circuit or source of power, and controlled by contacts of a protective relay, control switch, or other means. The tripping energy for shunt tripping is either provided by a control battery or an AC control power transformer. Where AC power source is used, the most common method of tripping is the capacitor trip scheme. The AC supply is taken from the source side of the circuit breaker and the capacitor is charged before the circuit breaker is closed. To ensure adequate voltage, the capacitor is used to store tripping energy. Tripping a circuit breaker from a trip coil, responsive to a decrease in voltage below a predetermined value of circuit voltage, results in undervoltage tripping.

(b) The closing mechanism is a manually operated or power-operated device that closes and latches the moving contacts against the stationary contacts. Since the amount and speed of application of power derived directly from manual effort is limited, there are definite limitations to the size and type of circuit breakers that can be successfully operated by manual closing mechanisms. All breakers with frame sizes above 1600 A must be electrically operated. There are four general types of power-driven operating mechanisms. These are classified according to the source of energy used to actuate them, as follows:

- o A solenoid mechanism is one deriving its operating power from the electromagnetic effect of a coil on a movable part of a magnetic circuit. It can either be AC or DC actuated.
- o A pneumatic mechanism is one in which compressed air from an air receiver actuates a piston to provide the operating power.
- o A charged-spring mechanism is one deriving its operating power from energy stored in a charged spring. In most cases the spring is compressed by an electric motor. In some cases facilities are provided so that the spring can be charged by hand in case of a loss of control power.

- o A hydraulic mechanism is one deriving its operating power from a fluid accumulator in which the closing energy, prestored by compressed, confined gas, is transmitted through the medium of a liquid (usually oil).

3.5.6.5 Auxiliary Relays and Meters. For both indoor and outdoor low-voltage and metal-clad switchgear the relays, meters, and control switches are normally mounted on a hinged panel attached to the circuit breaker cubicle. For outdoor oil circuit breakers the relay and meter panel is normally mounted in a weatherproof cabinet connected to the frame of the circuit breaker, or in some cases mounted in the mechanism housing.

3.5.7 Operation.

3.5.7.1 General Instructions. It is imperative that the operator be thoroughly familiar with equipment tagging procedures when opening circuits. In no case shall open circuit breakers, used for the control of lines, circuits, or station equipment, be considered as providing adequate protection to personnel working on the associated lines, circuits, or equipment. Isolating disconnect switches, if present, shall also be opened so there will be visible assurance that the line or.circuit is open. If the circuit breaker is a draw-out type, the circuit breaker shall be withdrawn and tagged before the circuit is considered cleared. Where no isolating disconnect switches are available or the circuit breaker is not the draw-out type, the control circuits to electrically-operated circuit breakers, which have been opened for personnel protection, must be disconnected from the control power source. This may be accomplished by removing the fuses or opening a switch in the control circuit, or by making the breaker inoperative by other means. The position of the control switch handle or the indicating lamp or targets on the switchboard should not be depended upon to determine whether the circuit breaker is open. The circuit breaker position indicator, which is mechanically connected to the operating mechanism of the circuit breaker, should be checked to give a more definite indication of the open or closed position of the circuit breaker contacts.

3.5.7.2 Electrical Control. Electrically operated circuit breakers are usually controlled from a control switch mounted on a switchboard, control desk, relay and instrument panel associated with metal-clad switchgear, or relay and instrument panel located in a cabinet mounted on the circuit breaker frame. All circuit breaker control switches have a hole in the nameplate for a red and green target indicator to show the last manual operation of the switch. In the trip position, the green signal lamp circuit can be opened by pulling the handle forward. The handle can be latched in this position and when so latched the blackout of the lamps indicates that the circuit controlled by the breaker is not in use. Indicating lamps are also used to indicate the circuit breaker position. A green light indicates that the breaker is open, and a red light indicates that the breaker is closed. On circuit breakers that are controlled from a DC power source, the red light is commonly wired so that it is energized through the trip coil circuit of the breaker to supervise the trip circuit and indicate that the trip coil circuit has continuity. When the breaker is closed, a dark red lamp would indicate that the lamp is burned out or that there is an opening in the trip coil circuit.

3.5.7.3 Automatic Reclosing. When a circuit breaker is provided with automatic reclosing equipment, the automatic reclosing shall be cut off (rendered inoperative) before the breaker is tripped or closed. The recloser relay can be cut off by moving the recloser cutoff switch to the off position. The automatic reclosing shall be left inoperative until the circuit breaker is again closed and has remained closed for a few seconds. The automatic reclosing can be turned on by moving the recloser cutoff switch to the on position. If a circuit breaker has opened automatically, and the automatic reclosing has operated to lock out or has failed to operate, the automatic reclosing shall be cut off before the circuit breaker is closed manually or electrically.

3.5.7.4 Manual Closing. Manually operated circuit breakers are closed by hand with a handle that is connected directly to the circuit breaker or is remotely connected to the circuit breaker through a system of levers, a bell crank, and rods. Successful operation of such breakers is dependent upon the operator applying positive unhesitating force through the entire travel of the operating handle. Even under normal load-switching conditions, slow or hesitant closing may result in excessive burning of the contacts, which may ultimately impair the breaker's ability to function properly. Some stored-energy closing mechanisms, such as a charged spring or hydraulic type, can be closed manually in case of control power failure. The spring or the hydraulic system can be charged manually to close the breaker.

3.5.7.5 Electrical Operation. The basic functional requirements of the controls of all modern circuit breakers are as follows:

(a) The circuit breaker mechanism will complete its closing operation, including automatic cutoff of the closing power, after a closing operation has been initiated, even though the operator releases the control switch before the circuit breaker is completely closed.

(b) Only one closing operation of the circuit breaker mechanism will result from each actuation of a manual control device (push button, switch), even though the circuit breaker trips while the control switch is being held in the closed position.

(c) If the control power supply is removed during an uncompleted closing operation, all control devices will be restored to the normal circuit breaker upon position. An additional operation of the control switch will be required to close the circuit breaker.

(d) When a circuit breaker is in the closed position, initiation of a closing operation will not result in an operation of the closing mechanism.

(e) When a closing operation of a circuit breaker (having a stored-energy-type operating mechanism; such as air, oil, or charged spring), cannot be completed successfully because of the absence of an adequate supply of stored energy, all actuating devices in the control circuit remain in the normal circuit breaker open position (when the initiating control device is operated and the breaker will not operate).

(f) A manually operated control disconnect device is provided with all circuit breakers. When opened, this device will prevent the electrical closing of the circuit breaker; both remotely and locally.

3.5.7.6 Malfunction. There are many things that can be the cause of a circuit breaker not performing correctly. Problems that can be corrected by the operator are indicated in Table 3-1 (Troubleshooting Chart for Circuit Breaker Operation). The maintenance crew is, however, responsible to remedy many circuit breaker malfunctions.

TABLE 3-1

TROUBLESHOOTING CHART FOR CIRCUIT BREAKER OPERATION

Trouble	Probable Cause	Course of Action
Failure to trip.	o Mechanism binding or sticking - caused by:	
	Lack of lubrication.	Lubricate mechanism.
	Mechanism out of adjustment.	Adjust all mechanical devices, such as toggles, stops, buffers, opening springs, etc., according to instruction book.
	o Failure of latching latch.	Examine surface of device. If worn or corroded, it should be replaced. Check latch "wipe", and adjust according to instruction book.

TABLE 3-1 ... (continued)
TROUBLESHOOTING CHART FOR CIRCUIT BREAKER OPERATION

Trouble	Probable Cause	Course of Action
	o Blown fuse in control circuit.	Replace blown fuse.
	o Loose or broken wire in trip circuit.	Repair faulty wiring. See that all binding screws are torqued to manufacturer's or U.L. specifications.
	o Dirty contacts on tripping device (Control switch, protective relays, or auxiliary switch).	Clean dirty contacts.
	o Failure of control power.	Investigate.
Failure to close.	o Blown fuse in control circuit.	Replace blown fuse.
	o Loose or broken wire in trip circuit.	Repair faulty wiring. See that all connections torqued to manufacturer's or U.L. specifications.
	o Dirty contacts on tripping device (Control switch or auxiliary switch).	Clean dirty contacts.
Failure to close.	o Failure of control power.	Investigate.
	o Insufficient air pressure.	Investigate.
Unnecessary tripping (that is tripping when tripping should not occur).	o Setting of relays or calibration setting of direct tripping device too low.	Set relay or device for proper value according to ampere load of circuit.

3.5.8 Operating Condition of Breaker.

3.5.8.1 Condition of Circuit Breaker During Interrupting Operation. An oil circuit breaker should perform at, or within, its interrupting rating without emitting flame and without releasing oil (except for minimum quantities through vent openings). Oilless circuit breakers (including compressed-air circuit breakers and magnetic air circuit breakers) should perform, at or within, their respective interrupting ratings without emitting injurious flame. The generally accepted duty cycle is two close-open operations at 15 second intervals.

3.5.8.2 Condition of Circuit Breaker Following Interrupting Performance. After completing an interruption, the components of the circuit breaker should be in essentially the same mechanical condition as prior to the interruption.

3.6 AUTOMATIC CIRCUIT RECLOSERS. An automatic circuit recloser is a self-contained protective device that automatically interrupts and recloses alternating current circuits with predetermined sequences of opening and reclosing, followed by resetting or lockout. Unlike fuse links, which interrupt either temporary or permanent faults indiscriminately, reclosers give temporary faults repeated chances to clear themselves or to be cleared by a subordinate protective device. If the fault is not cleared, the recloser recognizes it as permanent and operates to lock out.

3.6.1 Purpose. Reclosers are installed to maintain power to distribution loads with a minimum of outages. Reclosers instantly clear and reclose a circuit subjected to: a temporary fault due to lightning, trees, or similar causes; or by removing a permanently faulted circuit from the system.

3.6.2 Application. Automatic circuit reclosers are used in distribution substations and on branch feeders that are vulnerable to temporary short circuits (such as bare overhead conductor systems) to protect and switch feeder circuits. Their proper application requires a study of the load characteristics of both the protecting and the protected equipment. This includes the medium-voltage fuses or other protection in the supply to a substation; circuit breakers or reclosers at the distribution voltage supplying the feeders originating at the substation; various line reclosers, sectionalizers or fuses; and the conductors of the system.

3.6.3 Ratings. Automatic circuit reclosers are rated in terms of voltage, continuous current, minimum trip current and interrupting current. In operating a recloser, the limitations imposed by a given recloser rating must not be exceeded in any respect; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

3.6.3.1 Voltage Rating. Nominal voltage specifies the nominal system voltage at which the recloser can be applied. Maximum design voltage indicates the highest voltage at which the recloser is designed to operate. Voltage ratings of automatic circuit reclosers range from 14.4 kV to 69 kV for oil reclosers and from 14.4 kV to 34.5 kV for vacuum reclosers (per ANSI C37.60-1981). Units rated 14.4 kV may be applied at any system voltage from 2.4 - 14.4 kV, as long as the proper interrupting ratings are used. Older units, that carry nominal voltage ratings below 14.4 kV (i.e., 2.4 kV or 4.16 kV), may still be in service.

3.6.3.2 Continuous Current Rating. The continuous current rating is the magnitude of rms current in amperes that the recloser is designed to carry continuously. In many cases the continuous current rating is limited by the series solenoid coil rating. As load current requirements change, therefore, it is necessary to replace the solenoid coil with one having the required rating. The continuous current ratings of automatic circuit reclosers range from 5 to 1120 A.

3.6.3.3 Minimum Trip Current Rating. The minimum trip current rating is the minimum current at which a recloser will operate. The pickup is adjustable, but generally a setting of 140 or 200 percent of the continuous current rating is used. The differential between minimum trip and continuous current ratings normally provides sufficient margin for inrush current pickup after an extended outage on a feeder circuit.

3.6.3.4 Interrupting Current Rating. The interrupting current rating is the maximum rms symmetrical current that a recloser is designed to interrupt under the standard operating duty, circuit voltage, and specified circuit constants.

3.6.4 <u>Three-Phase Versus Single-Phase Reclosers</u>. Automatic oil circuit reclosers are available in both single-phase and three-phase (Figure 3-15). The application of reclosers is dependent upon the type of loads being served. Three-phase equipment should not be served by a feeder using single-phase reclosers. Operation and lockout of one of the reclosers would cause single-phase operation of the three-phase equipment and result in possible damage. A three-phase recloser for such an application would disconnect all three phases regardless of which phase is faulted.

3.6.5 <u>Construction</u>. An automatic circuit recloser is made up of five major components: housing, bushings, mechanism, interrupter, and controls.

3.6.5.1 Housing. A vacuum recloser may be housed in a pad-mounted metal enclosure. These enclosures are easy to install, are tamperproof, and are neat in appearance. A tank is used to house the interrupter and the tripping and closing coils of an oil-filled recloser. The tank is usually made of steel and is rectangular for a three-phase recloser and cylindrical for a single-phase unit. Typical single-phase automatic recloser construction is shown in Figure 3-16.

3.6.5.2 Bushings. The bushings are the insulating structures including through-conductors with provision for mounting on the top of the recloser.

3.6.5.3 Operating Mechanism. The operating mechanism of an automatic circuit recloser provides the power to open, close, or lock out the main contacts.

(a) The tripping mechanism releases the holding means and permits the contacts to open. In most cases the opening force is furnished by springs that are charged by the closing action.

(b) The closing mechanism is normally a solenoid coil or a motor and gear arrangement. The closing force serves to close the main contacts and at the same time to charge the spring providing the opening force. The lockout mechanism locks the main contacts in the open position following the completion of a predetermined sequence of operation; i.e., when the fault is not cleared after a predetermined number of reclosures.

3.6.5.4 Interrupter. The interrupter contains separable contacts that operate within an oil or vacuum chamber. Low-energy arc interruption in a vacuum results in quiet and reliable operation.

3.6.5.5 Control. Reclosers are provided with sequence control devices and an operation integrator to change the recloser from instantaneous operations to time-delay operations, and to lock out the recloser after a prescribed number of operations. Individual tripping operations of a recloser can be made to follow instantaneous or time-delay time-current characteristics.

(a) Examples of operational sequences:

- Four time-delay operations. This consists of three open-close operations and a final open operation. All operations are preceded by a fixed time delay to allow the fault to clear. After three open-close operations, it is assumed that the fault is permanent and the fourth operation is a lockout trip.

- One instantaneous operation followed by three time-delay operations. This consists of three open-close operations and a final open operation. The first operation is instantaneous, and the subsequent three operations are preceded by a fixed time delay. The fault may be intermittent, so that the first operation, which is instantaneous, often clears the fault in a shorter time than if a time delay were used for the first operation.

- Two instantaneous operations followed by two time-delay operations. These are similar to the above, in that the first two operations are made with no intentional time delay. This is based on the assumption that most faults are transient in nature, and that possibly the fault did not clear on the first try, but no intentional time delay is needed for the second operation.

FIGURE 3-15. AUTOMATIC OIL CIRCUIT RECLOSERS
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

FIGURE 3-16. TYPICAL SINGLE-PHASE AUTOMATIC RECLOSER CONSTRUCTION
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

(b) Two major categories of sequence control devices:

- o In the hydraulic type, a pump piston attached to the recloser plunger raises the trip piston a certain amount by pumping a measured amount of oil under the trip piston with each operation of the recloser. This changes the sequence from fast to delayed tripping and eventually locks the recloser out.

- o In the electronic control scheme, minimum phase and ground trip values and timing of tripping, reclosing, and resetting are established by a plug-in resistance-capacitance network. Current transformers provide sensing for overcurrent or faults. The battery-powered electronic control panel sends signals to a solenoid to open or reclose the contacts.

3.6.6 <u>Automatic Operation</u>. When an overcurrent of sufficient magnitude flows through the trip coil or current transformers, the tripping action is initiated and the contacts are opened. The recloser contacts then reclose following a predetermined length of time. By the time the recloser has reclosed the circuit, the sequence control device has moved to count the trip operation. If the fault still persists on the circuit when the recloser closes, the tripping and reclosing sequence is repeated (a predetermined number of times), as established by the sequence control device, until the recloser goes to lockout. If the fault has cleared from the circuit during any open period, the recloser closes and remains closed, and the sequence control device resets so that it is in position for the next sequence of operations.

3.6.7 <u>Manual Operation.</u>

3.6.7.1 Manual Tripping. An automatic circuit recloser can be tripped open manually by moving the manual operating handle to the trip position by means of a hookstick. If the recloser is provided with a nonreclosing lever, it should be pulled down as far as possible to cut out the automatic reclosing before the recloser is manually tripped.

3.6.7.2 Manual Closing. An automatic circuit recloser can be closed manually by moving the manual operating handle to the close position by means of a hookstick or, if the recloser is provided with remote control, by moving the control switch to the close position. If the recloser is provided with a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is closed manually. After the automatic circuit recloser has been successfully closed, the automatic reclosing should be placed in service.

3.6.7.3 Manual Reclosing After Lockout Operation. Reclosers in service are designed to lock out following a selected sequence of tripping and automatic reclosing operations. When a recloser appears to be locked out, the operator is always faced with the possibility that the recloser itself may have failed. The following procedure is recommended for reclosing of recloser after a lockout operation.

(a) Locate and repair or isolate the fault.

(b) Make a careful visual inspection for evidence of housing or bushing damage, or oil leakage.

(c) Close the recloser with a hookstick, keeping the hook in the operating ring momentarily so that the recloser can be opened manually in case local trouble or failure becomes evident. If no local trouble develops, and the recloser again locks out after going through its proper sequence, it should not be reclosed again until the entire circuit on the load side has been patrolled and cleared to all sectionalizing devices.

3.6.7.4 Cold-Load Pickup. The inrush current experienced in closing a recloser after a lockout operation may occasionally introduce some complications. The highest inrush current can be from automatic starting motors or magnetizing current of transformers; however, these types of inrush currents are normally short-lived (in the order of three to thirty cycles). Some reclosers may operate on the instantaneous trip due to this inrush current, and may have to open and automatically reclose until the sequence of operation comes to the time-delay trip before the recloser will stay closed. Other reclosers, when reclosed after lockout, do not operate on the instantaneous trip. They have a time-delay trip operation to lock out, which will normally override the inrush current and pick up the load. Careful observation by the operator may indicate whether failure to hold onto the load is caused by a fault or by a momentary overload. Instant, and perhaps violent, action would indicate a fault, whereas some delay might mean overload due to inrush current. In the latter case, sectionalizing to drop part of the load, rather than a patrol, is necessary.

3.7 POWER CAPACITORS. Power capacitors are used in distribution systems to supply reactive volt-amperes (Vars) to the system. When applied to a system or circuit having a lagging power factor, several beneficial results are obtained. These results include power factor increase, voltage increase, system loss reduction, and release of electric system capacity.

3.7.1 Low Power Factor. A low system power factor can be increased by adding corrective equipment to the system. There are many devices used for power factor correction, including synchronous motors and power factor correction capacitors.

3.7.1.1 Synchronous Motors. Any synchronous motor may be used for power factor correction by overexcitation.

3.7.1.2 Power Factor Correction Capacitors. For general use, the most practical and economical power factor correction device is the capacitor. Capacitors are used at power stations where an elaborate and expensive synchronous condenser installation is not justified. The following paragraphs deal exclusively with power capacitors.

3.7.2 Ratings. Capacitors are rated in continuous kVar (kilovolt-ampere-reactive), voltage, and frequency. They are designed to give not less than rated and not more than 135 percent rated kVar when operated at rated voltage and frequency. Capacitor units are normally available in voltage ratings of 2,400 V to 34,500 V and kVar ratings from 15 kVar to 300 kVar. Various manufacturers' medium-voltage units up to 200 kVar are interchangeable. Capacitors are generally rated at a frequency of 60 Hertz (Hz), however, they are also suitable for operation at frequencies below 60 Hz. There is no physical limit to the under-frequency operation of the capacitors. The limit is economic, in that the capacitor kVar output is directly proportional to frequency and applied voltage. If a capacitor is operated at a frequency lower than rated, consequently, its kVar rating is reduced. Since capacitors are installed in theory to utilize their rated capacity, utilization at reduced frequencies is not economical, as the unit's design rating can never be achieved.

3.7.3 Construction. A capacitor unit consists of two aluminum foil strips or plates with thin high-grade insulating paper or a synthetic film placed between them. The strips or plates are compactly wound and connected in groups, each of which is connected to a terminal. There is no contact between the two metal surfaces. When these two surfaces are connected to a source of power, energy is stored in the capacitor. The capacitor remains charged at, or above, full line voltage when disconnected from the source of power until a discharge path is provided between the terminals. Capacitors have a built-in discharge resistor designed to drain off or reduce this residual charge. National Electrical Code requires capacitors rated 600 V or more to be discharged to a residual voltage of 50 V or less in 5 minutes. Since the built-in resistor has the disadvantage that it cannot be visually inspected for an open circuit, it should not be relied upon for positive drain-off of the residual charge (see subparagraph 3.7.9). The wound plates and discharge resistor of a capacitor are enclosed in a welded sheet steel or stainless steel container, which is hermetically sealed to protect the capacitor from deterioration due to entrance of foreign material or moisture. The contents are vacuum dried and are usually impregnated with a dielectric fluid. As of 1 October 1977, dielectric fluids containing polychlorinated biphenyls (PCBs) can no longer be installed. The connecting leads from the capacitor are brought up through the bushings to a joint at the top directly under the brazed terminal. The bushings supplied on capacitors are usually made of porcelain. As of 1 October 1988, existing PCB capacitors in unrestricted areas must be removed.

3.7.4 Types of Installations. The greatest electrical benefits are derived from capacitors connected directly at the loads. This would permit maximum loss reduction and released line capacity. However, economics and physical limitations are usually the governing factors. Capacitors may be divided into two classes, primary capacitors and secondary capacitors. Primary capacitors are those rated 2400 V and above and secondary capacitors are those used on the low-voltage side of distribution transformers or at motor terminals and are normally rated 600 V and below. The three most common types of power capacitor installation are: pole-mounted, metal-enclosed, and open-rack.

3.7.4.1 Pole-Mounted. Pole-mounted capacitors (Figure 3-17) are packaged as a complete unit containing all necessary items for a switched distribution capacitor bank installation. The banks consist of an aluminum or steel mounting frame that supports the capacitor units, interconnecting wiring, and capacitor switches. Overcurrent protection is usually provided by group fuses.

3.7.4.2 Metal-Enclosed. Metal-enclosed capacitor banks (Figure 3-18) consist of a factory assembled group of individual capacitor units mounted in a protective housing complete with bus connections, controls, and protective and switching equipment within the enclosure. Personnel safety and compactness are the major benefits. Each capacitor unit is normally protected by an individual current-limiting fuse.

3.7.4.3 Open-Rack. An open-rack capacitor installation (Figure 3-19) is a field-assembled group of capacitor units mounted in an open-rack structure without enclosing plates or screens. Open-rack installations are normally made up of several stack-type capacitors connected in parallel to provide desired kVar capacity. All the units in a given stacking unit are normally connected in parallel with the steel frame forming one terminal and the insulated bus forming the other. For open-rack installations the capacitor units are protected by individual fuses, group fuses or relays, and a circuit breaker.

3.7.5 Fixed Capacitors. Fixed capacitor installations are those that are continuously on-line. Fixed capacitor banks are connected to the system through a disconnecting device that is capable of interrupting the capacitor current, allowing removal of the capacitors for maintenance purposes. Fixed capacitor banks should be applied to give a voltage boost to the system during heavy load periods. Caution must be used, however, to ensure the boost will not be excessive during light-load conditions. To isolate or deenergize a fixed capacitor installation, the disconnecting switches should be opened with rapid positive action. The successful switching of capacitors depends, to a considerable extent, on the technique of the operator and the speed of opening. It is more difficult to deenergize a capacitor bank than it is to energize it, because the ease with which capacitor current is interrupted depends on the point on the voltage wave when the switch contacts separate. If the arc is reestablished and maintained with the disconnecting device open, the switch should be reclosed at once to avoid damage to the switch. Another attempt should then be made to open the disconnecting device. After the disconnecting device has been opened, the capacitor installation is isolated but still charged. The capacitors should be left open from the line for at least five minutes before they are returned to service. This precaution will prevent a buildup of the line voltage above normal, which may occur if a fully charged capacitor bank was closed on a line.

3.7.6 Switched Capacitors. Switched capacitor installations are those where the capacitor bank is switched in and out of service depending upon system operating conditions. They are usually switched on when the load requirements are the greatest and switched off during

FIGURE 3-17. POLE MOUNTED CAPACITOR
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

FIGURE 3-18. METAL-ENCLOSED CAPACITOR BANK
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

FIGURE 3-19. OPEN-RACK CAPACITOR INSTALLATION
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

light-load conditions.   Sometimes the capacitor banks are installed to enable incremental switching, depending on the system reactive requirements and the amount of system voltage required. To remove a switched capacitor bank from service, the control box should be opened and the automatic control lever or control switch should be placed in the off position. The circuit breaker or the switching device should then be tripped. To ensure the circuit breaker or switching device remains open, the fuses should be removed from the control circuit. Before it can be assumed that the capacitor bank has been deenergized, the position of the switching device should be inspected. On a circuit breaker, the position indicator should be checked. For oil switches, the position of the operating handle can be checked with a switch stick.

3.7.7 Types of Switching Devices. Switching capacitors imposes severe duty on switching devices because of the differences in phase relationship between the current and voltage on a capacitor circuit. When a capacitor bank is energized, high transient overvoltages and high-frequency transient inrush currents may be produced. The magnitude of the transient overvoltages may easily be three times the rated line voltage, and transient inrush currents may approach the short-circuit current duty values. These factors are especially important when one or more capacitor banks is already energized and another one at the same location is switched on to the bus.   The methods for determining the values of inrush current, transient overvoltage and resonant frequency of the circuit are discussed in more detail in ANSI C37.99, IEEE Guide for Protection of Shunt Capacitor Banks, and ANSI C37.012, Application Guide for Capacitance Current Switching of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

Switching devices, as discussed below, have a separate capacitive switching rating for the reasons mentioned above, and the switching rating of the device must be at least 135 percent of the capacitor bank rating to which the switching device is connected. This rating is a minimum specified by the National Electric Code, and includes allowances for operation at overvoltage, allowance for capacitance manufacturing tolerance, and allowance for harmonic components above the fundamental frequency. Some common types of switching devices used on capacitor banks are discussed in the following paragraphs.

3.7.7.1 Indoor Circuit Breakers. Metal-enclosed capacitor equipment on circuits 13.8 kV, or below, often use indoor air or oil circuit breakers. These breakers are housed in a separate compartment to protect them from the weather and to increase operating personnel safety.

3.7.7.2 Outdoor Circuit Breakers. On large open-rack outdoor installations, outdoor oil circuit breakers are usually used. In some cases, the interrupting chambers of these breakers is modified to ensure proper switching of the capacitive load by controlling prestrikes when energizing or restrikes when interrupting.

3.7.7.3 Oil Switches. Single-phase or three-phase oil switches are often used on pole-mounted or metal-enclosed capacitor banks. These switches are generally solenoid or motor-operated and do not have fault interrupting capability.

3.7.7.4 Load Interrupter Switches. A load interrupter switch is employed for capacitor switching. The most common types are air, gas-filled, and vacuum switches. These devices do not provide fault protection and are backed up by fuses or circuit breakers.

3.7.7.5 Fused Cutouts. On small fixed installations, fused cutouts are sometimes used to perform the switching operation.

3.7.8 Control Devices. Switched capacitor bank control systems initiate the switching of the capacitors into, or out of, the circuit at predetermined conditions. The auxiliary components of the controls include sensors, circuit breakers or switches, and the control power source. The controls normally include an automatic control lever or control switch that permits the operation of each capacitor switch either by manual operation of its control switch or in response to a signal initiated by a sensor. The most commonly used inputs for capacitor bank control are time, voltage, current, and load kVar.

3.7.8.1 Time Switch Control. Time switch or time clock control is often used with small switched capacitor banks. Time control switches the capacitor bank on at a certain time of the day and off at a later time. A carry-over device is normally used for each time clock to keep the clock running during temporary power outages. If a carry-over device is not used, it will be necessary for the operator to go to each capacitor location that is affected and reset the clock after a power outage.

3.7.8.2 Voltage Control. Voltage control is widely used for capacitor switching in substation applications. It is generally used to correct steady-state undervoltage conditions caused by heavy circuit loading, or inadequate voltage regulation from upstream transformers and line regulators. Voltage control includes a voltage-sensitive relay, and time-delay and auxiliary relays to open and close the capacitor switching device in response to predetermined values of steady-state circuit voltage. The time-delay relay is incorporated so that the switching operation is not initiated for momentary line voltage dips, that may be caused by a lightning strike, a momentary dip caused by a line fault, or by a large motor load starting on a downstream bus.

3.7.8.3 Current Control. Current control is often used on regulated circuits where voltage cannot be used for capacitor switching. Voltage control includes a current-sensitive relay plus time-delay and auxiliary relays to open and close the capacitor switching device in response to predetermined values of load current.

3.7.8.4 Kilovar Control. The capacitor bank will be energized at a certain value of lagging power factor. It will be switched off at a lower value or when there is leading power factor. Kilovar control is used to reduce peak kVar loads.

3.7.8.5 Combined Controls. Combined controls can be used for more complex situations.

For example, kVar control can be used to maintain a power factor value and voltage control can be incorporated as an override to remove the bank under abnormal voltage conditions.

3.7.9 Service Conditions. The life of a capacitor unit is shortened by overvoltage, overheating, chemical change, physical damage, and repeated temperature changes.

3.7.9.1 Operating and Ambient Temperatures. Capacitor units are suitable for continuous operation with an ambient temperature range of -40°C to +46°C. When ambient air temperatures higher than 46°C are expected, forced circulation of air may be used. Normally, the maximum surface temperature of an individual capacitor unit is used to indicate the operating-temperature condition. The temperature (at any point on the case), generally should not exceed 55°C (131°F) under usual operating conditions or 70°C (158°F) under emergency operating conditions. Capacitor units may be operated continuously at ambient temperatures as low as -40°C. When energizing capacitors after they have been deenergized for a period of time, the temperature of the capacitor unit should be considered. There is a risk of damage to capacitor units if they are energized at temperatures less than -20°C.

3.7.9.2 Operating Voltage. Capacitors cause a voltage rise at their application point. Thus, capacitors are more likely to operate at overvoltages than equipment that causes voltage drop at its application point. The maximum permissible working voltage of power capacitors is 110 percent of rated voltage. Because the kVAR rating of a capacitor varies as does the square of the ratio of the applied voltage to the rated voltage, applied voltage must be nominally limited to rated voltage. Operation of capacitors above rated voltage increases capacitor kVAR, which further increases the voltage level. Under emergency conditions, however, capacitors may be operated above 110 percent of rated voltage. The recommended maximum rms overvoltage without loss of capacitor life is dependent on the duration of each overvoltage. Table 3-2 lists the recommended limits of overvoltage, expressed as a percent of rated voltage, versus the time duration of the overvoltage condition. For example, a capacitor could be applied at 2.2 times rated voltage for a period of one second without incurring any loss of usable life. The recommended overvoltage limits are listed in Table 3-2.

Large capacitor banks are usually protected by fuses located (or installed) at each capacitor. Fusing provides each capacitor with proper protection and also allows partial operation of the bank when an individual capacitor fails. The fuse also serves to indicate unit failure. When a large shunt capacitor bank is made up of series-connected groups of parallel units, the removal of one or more units from a group will cause overvoltages on the remaining units. The failure rate of capacitor units increases rapidly when subjected to overvoltage. Some type of protection is, therefore, normally installed on large banks. This protection disconnects the bank from the system or sounds an alarm when a significant number of units have been removed from service. There are several schemes used to provide this protection. Most schemes require potential or current transformers on the capacitor bank neutral.

TABLE 3-2
OVERVOLTAGE LIMITS

Duration	Multiplying Factor Times Rated rms Voltage
1/2 cycle	4.8
1 cycle	4.2
6 cycles	3.0
15 cycles	2.6
1 second	2.2
15 seconds	1.8
1 minute	1.7
5 minutes	1.5
30 minutes	1.35

3.7.9.3 Overload Current. Abnormal capacitor currents due to resonance may occasionally be encountered. Blowing of fuses or high-temperature operation may indicate an overload condition. Capacitors and auxiliary devices are normally designed to carry at least 135 percent rated kVar maximum including kVar due to resonance. If the capacitor kVar exceeds 135 percent of its rating, it should be reported.

3.7.10 Personnel Protection. Operators, working on capacitors or other equipment to which capacitors are connected, should wear rubber gloves and safety glasses or a face shield for protection from arcing. Such work includes opening or closing switches or fused cutouts, testing, short-circuiting terminals, and grounding capacitor terminals to the case or rack. When the area around capacitors and other electrical apparatus is wet, wood platforms, insulated stools, or rubber boots should be used. After disconnecting a capacitor, and before any work is attempted, the operator should wait at least five minutes to allow time for the resistors to drain off the major portion of the residual charge. The capacitors should then be short-circuited several times or until no arc is observed. An insulated jumper should be used for short-circuiting. Each terminal should then be grounded. The short-circuiting device and ground connection should be left in place until the work is finished, but must be removed from the capacitor before the unit is reenergized.

3.8 DISTRIBUTION SUBSTATION. Each distribution substation normally serves a single load area. At the distribution substation the subtransmission voltage is reduced for general distribution throughout the area. The substation consists of one or more power-transformer banks together with the necessary voltage regulating equipment, buses, and switchgear.

3.8.1 Substation Grounding. In the past, substation grounding has been taken for granted and has even been ignored. The large growth of the electrical system and the number of interconnections with the power suppliers increase the ground fault current and the probability of electric shock when substation equipment is not grounded.

Utilization of sound engineering principles is required for acceptable substation grounding providing a safe and shockproof grid around the substation. The old practice of installing just a few conductors for a substation grid around the substation transformer is no longer acceptable.

The four steps presented on the following pages (soil resistivity test, maximum ground fault current, design of grid, and measurement of soil resistivity) are all necessary functions to ensure safety around the substation.

3.8.1.1 Soil Resistivity Test. Preliminary designs of substations should include an investigation of the general soil type to aid in foundations design. Any such investigation will indicate a rough approximation of the soil resistivity similar to the typical values shown in Table 3-3. Testing soil samples in the lab, the three pin method, and the four pin method are three procedures used to determine soil resistivity in the substation lot.

3.8.1.2 Maximum Ground Fault Current. The value of maximum ground fault current must be calculated for use in the substation ground design. An allowance for future growth should be made, and an adjustment should also be made for the effect of direct current offset and attenuation of alternating current and direct current transient components of fault current.

3.8.1.3 Grid Design. The preliminary design of the station grounding should consist of placing and noting of all the required grounding. The following is a list of the grounding requirements normally found in substations.

(a) Power transformers require two grounds, each capable of carrying full fault current.

(b) Lightning arresters require one ground connected from the grid directly to the lightning arrester base. The ground must be capable of carrying the discharge.

(c) Dead-end towers normally require one ground per each leg connected to the structure.

(d) The following items or structures require a minimum of one ground per each leg:

- o Switch Stand.
- o Bus Support Structures.
- o Potential and Current Transformers.
- o Coupling Capacitors.
- o All Miscellaneous Structures.

TABLE 3-3
EXPECTED SOIL RESISTIVITIES

Soil Types	Resistivity OHM-Centimeters Minimum	Maximum	OHM-Meters Minimum	Maximum
Clay, Moist	1,400	3,000	14	30
Swampy Ground	1,000	10,000	10	100
Humus and Loam	3,000	5,000	30	50
Sand Below Ground-Water Level	6,000	13,000	60	130
Sandstone	12,000	7,000,000	120	70,000
Dry Sand	20,000	7,000,000	200	70,000
Broken Stone Mixed with Loam	20,000	35,000	200	350
Limestone	20,000	400,000	200	4,000
Dry Earth	100,000	400,000	1,000	4,000
Dense Rock		1,000,000		10,000
Crushed Rock	300,000	400,000	3,000	4,000

(e) Oil circuit breakers require two grounds.

(f) Station fences require complete perimeter ground cables, located three feet outside the fences, and are connected to the station grid. Ground spacing should not exceed 75 feet. Fences require a fabric ground for approximately every 75 feet and a post ground for every third post.

(g) All station gates require connection to both gate posts and copper braid to connect the hinge posts to the gate.

3.8.1.4 Measurement of Soil Resistivity. An earth resistivity measurement of the soil is important and should be carried out upon installation of the ground grid to assure accuracy of the grid placement and to assure no loose ends or bad connections exist. The most common method used to measure the soil resistivity is the four pin method.

3.8.2 Cable Placement. After the above ground connections are completed, the underground cable, connecting cable, and ground rods should be placed. Cables should be laid in parallel lines with reasonable spacing to connect these points. Ground rods should be placed at crossings and should be as close as possible to transformers, lightning arresters, and ground switches, but should not be spaced closer than ten feet. Cables shall be sized accordingly:

(a) Able to resist fusing and deterioration of electric joints for the worst case fault current magnitude and duration possible.

(b) Mechanically rigged to a high degree. Normally 1/0 is adequate, mechanically, for brazed joints and 2/0 for bolted joints.

(c) Have sufficient conductivity to prevent contribution to dangerous local potential differences.

3.8.3 Preventive Maintenance. Proper maintenance of line and substation equipment will reduce both unnecessary outages and operating costs. Preventive maintenance is also less costly than maintenance that must be performed on already damaged or faulty units. Procedures for maintaining the following apparatus are discussed in detail below:

3.8.3.1 Transformers. Transformer maintenance procedures may be divided into the following service classifications:

(a) Distribution Transformers:

- Check all the overhead connections monthly.
- Check the oil content for PCB contamination annually.
- Check oil level annually.
- Check the bushings for cracks or loose contacts annually.
- Obtain oil sample and perform lab tests for dielectric strength, neutralization number, interfacial tension, and gas-in-oil analysis every two years.

(b) Substation Transformers:

- Check all the overhead connections monthly.
- Check the oil content for PCB contamination annually.
- Obtain oil sample and perform lab tests for dielectric strength, neutralization number, interfacial tension, and gas-in-oil analysis annually. For arc furnace, rectifier, and on-load-tap changer type units, the frequency should be from quarterly to annually, depending on the service and history of the individual unit.
- Check the bushings for cracks or loose contacts annually.
- Check the connections of incoming and outgoing overhead/underground conductors at the bushings biannually.
- Check the service transformer connection annually.
- Check the fuses on the high side and the low side annually.

- o Check the current and potential transformers and the disconnect switches for manual operation annually.
- o Check the transformer tank, cooling fins, tubes, radiators, and all gasketed and other openings visually for any possible leaks monthly.
- o Check the gauges on the transformer for oil level, oil temperature, and tank pressure weekly. Look for signs of overheating or corrosion.
- o Observe any change in operating sound regularly. A louder hum than normal could indicate low oil level or temperature rise inside the tank.

(c) Dry Type Transformers:

- o Retorque connections, vacuum out dirt, and blow with a maximum of 25 psi compressed air every two years.
- o Check temperature and cleanliness weekly. Look for signs of overheating or corrosion.

3.8.3.2 Voltage Regulators. The following represents a maintenance checklist for voltage regulators. Each item should be spot checked on a periodic basis to ensure proper function:

(a) Check for physical damage to the tank periodically.

(b) Check the connections.

(c) Check the operation lever setting for boosting and bucking voltage.

(d) Check the accuracy of the regulator by checking the voltage across the bus with the help of a voltmeter.

3.8.3.3 Switches. There are several different types of switches on line and on the substation busses. The primary function of a switch is to open or close a feeder.

(a) Check for loose connections and proper operation biannually.

(b) Check contact surfaces biannually.

3.8.3.4 Circuit Breakers. The following represents a maintenance checklist for low voltage and high voltage circuit breakers. Each item should be checked every three years for low voltage circuit breakers, every two years for high voltage circuit breakers, and annually for high voltage circuit breakers used in generating stations.

(a) Check mechanical and electrical operation and alignment.

(b) Check condition of contacts and measure the contact resistance.

(c) Check and tighten the connections.

3.8.3.5 Reclosers.

(a) Check the reclosing capabilities annually.

(b) Check and replace oil in the tank at least biannually.

(c) Check the physical condition of the tank periodically.

(d) Check the tripping coils for proper function, periodically.

3.8.3.6 Power Capacitors. Capacitors are usually maintenance free, although routine checks will extend service life.

(a) Check the connections visually with regard to the conductor and service transformers.

(b) Check for PCB contamination annually by checking the dielectric strength.

(c) Check the tank for damage.

(d) Visually check the rack for corrosion.

(e) Manually test control operation annually.

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 System Protection and Coordination. 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.

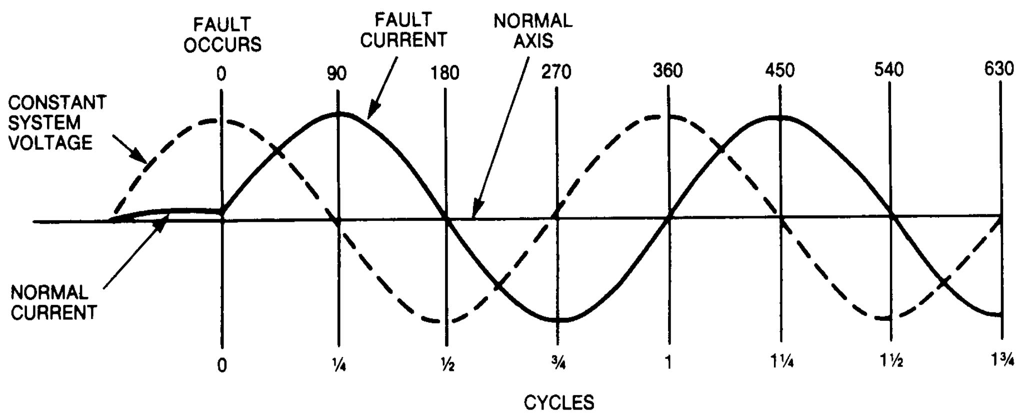

FIGURE 4-1
Symmetrical Short-Circuit Current Wave

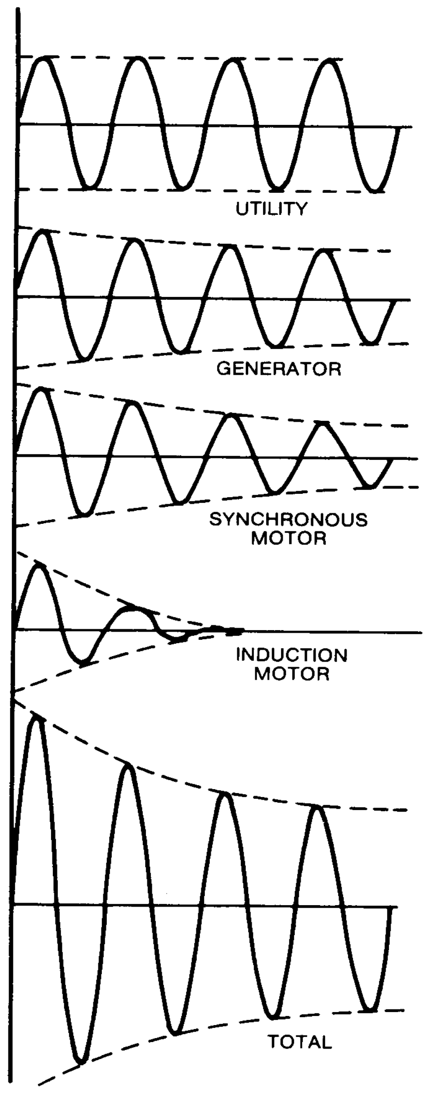

FIGURE 4-2
Decreasing Symmetrical Short-Circuit Current

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.

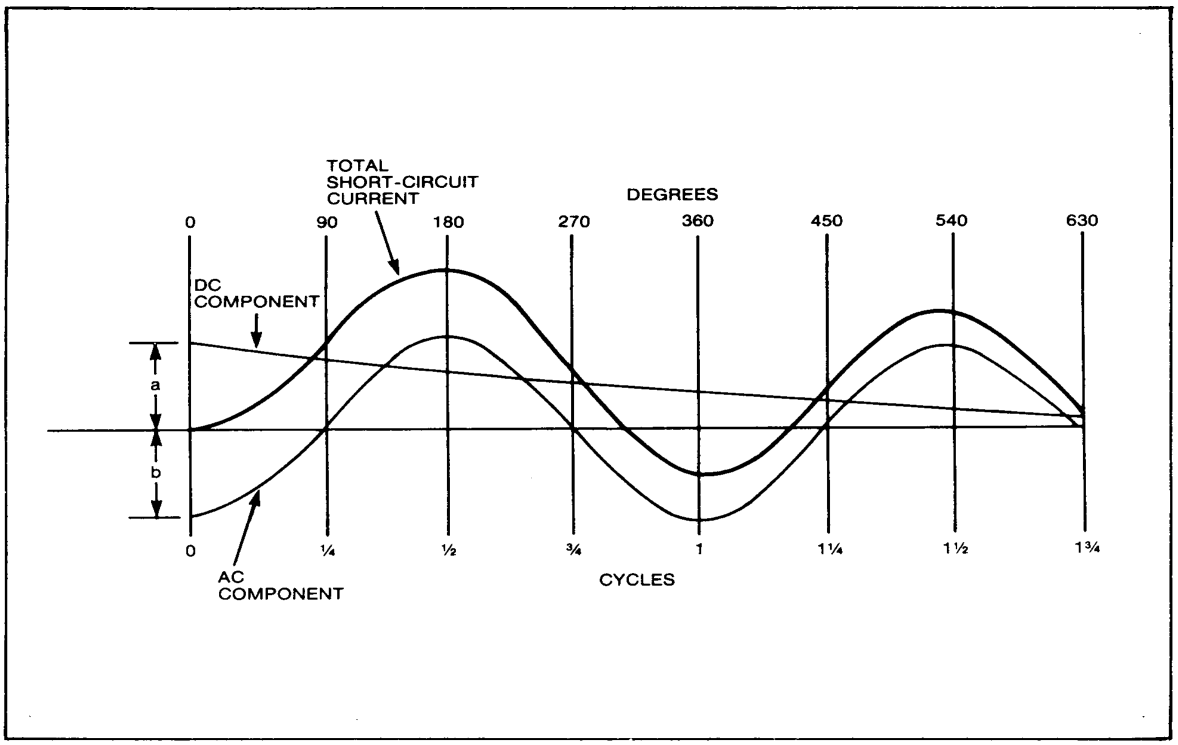

FIGURE 4-3
Asymmetrical Short-Circuit Current Wave

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.

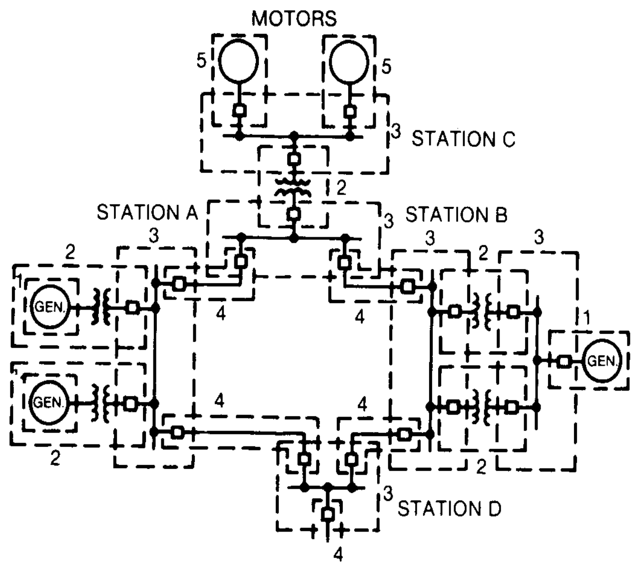

FIGURE 4-4
A Typical Power System and Its Zones
of Protection

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 <u>High-Voltage Fuses</u>. 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

FIGURE 4-5. OPEN FUSE CUTOUT
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

FIGURE 4-6. OPEN-LINK CUTOUT
(REPRODUCED COURTESY OF MCGRAW-EDISON COMPANY)

FIGURE NOT INCLUDED

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:

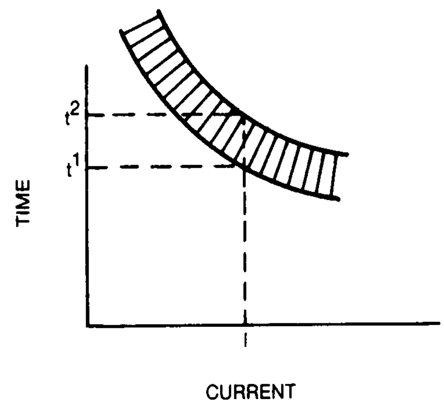

FIGURE 4-7
Time-Current Curve Band

(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 Supervisory Control Equipment. 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 Need for an EPM Program. 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 Benefits of an EPM Program. 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 <u>Objectives</u>. 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 <u>Long Range System Planning</u>. 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.

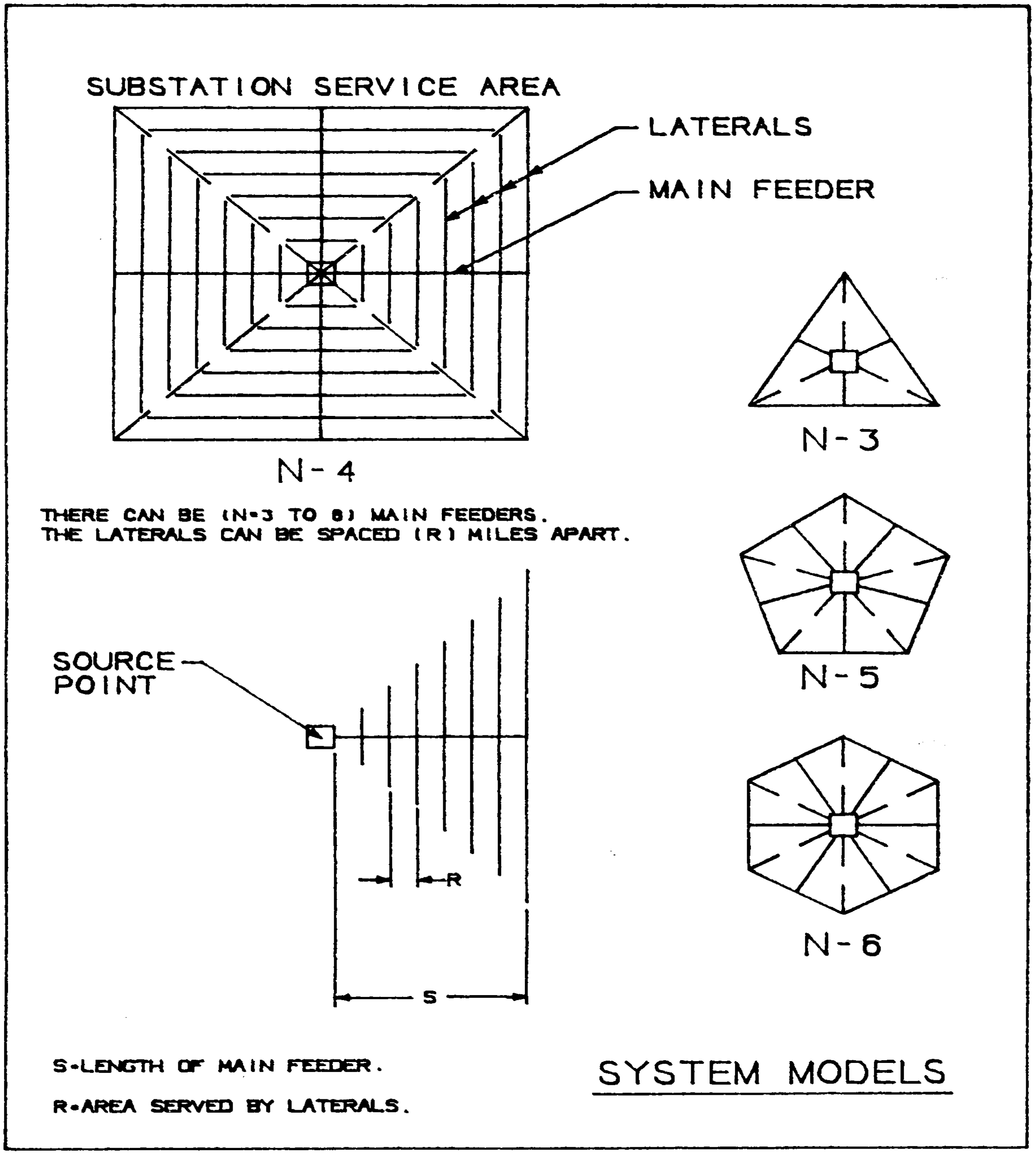

FIGURE 8-1
System Model

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:

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

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.

APPENDIX A

OPERATING RESPONSIBILITIES AND ORGANIZATIONAL RELATIONSHIPS

1. OPERATING RESPONSIBILITIES. Generally, the Utilities Division of the activity Public Works Department (PWD) is responsible for operation of electric power distribution systems. All functions concerning the electric power distribution system that are not specifically assigned or identifiable as engineering, design, or maintenance functions, are considered the responsibility of operating personnel. However, because they are closely related and affected by other functions of the PWD, it is difficult to classify functions as strictly operational and assign responsibilities accordingly. There must be complete cooperation, coordination, and correlation between operations and other groups of the PWD. Frequently, this extends to the elements of the supporting Public Works Center (PWC). Operating personnel are frequently required to render service and initiate suggestions and recommendations on functional areas of other groups that ultimately affect operations.

2. ORGANIZATIONAL RELATIONSHIPS. The following are brief descriptions of functions and responsibilities of the Naval Facilities Engineering Command, its Divisions, Public Works Centers, and Public Works Departments and its divisions:

a. Naval Facilities Engineering Command (NAVFACENGCOM). NAVFACENGCOM is responsible for the public works management systems of the Naval shore establishment, specifically, to assure that PWDs are structured and supported to obtain the most effective and efficient results.

b. Engineering Field Divisions (EFDs). EFDs support Naval shore establishments in a specific geographic area. They represent NAVFACENGCOM in the provision of technical support and system implementation, in the design, construction, operation, maintenance and repair of public works, public utilities, weight handling, construction, and transportation equipment.

c. Public Works Center (PWC). A PWC is under the command of the Commander, Naval Facilities Engineering Command. The commanding officers of the PWCs command all functions in the accomplishment of its assigned mission, and provide public works support to supported activities for maintenance and operation of facilities and collateral equipment, including utilities plants and systems; maintenance and operation of facilities and collateral equipment, including utility plants and systems; maintenance and operation of transportation and weight handling equipment; and facility design, engineering and planning.

d. Public Works Department (PWD). A PWD is an organizational component of a Naval shore activity. As a department head, under the commanding officer of the activity, the Public

Works Officer (PWO) is responsible for the maintenance and operation of facilities and collateral equipment, including utility plants and systems; maintenance and operation of transportation and weight-handling equipment; and facility design, engineering, and planning.

There are many variations in PWD organizations. Many of the PWDs, particularly those of smaller activities, combine operations and maintenance functions and other functions for efficiency and economy and rely more on supporting PWCs. The following are brief descriptions of functions and responsibilities of a PWD organization of a significantly large activity (See NAVFAC P-318 "Organizations and Functions for PWDs" for more detailed descriptions):

(1) Administrative Division. The Administrative Division is responsible for all matters pertaining to organization, methods, procedures, work flow, work measurement (except shop work methods and techniques), civilian personnel matters, office services, reproduction, reports and statistics and budget and finance and, when local conditions warrant, material purchases.

(2) Engineering Division. The Engineering Division is responsible for all matters pertaining to engineering studies and reports, preliminary designs and estimates for special repair and improvement projects, engineering design, and facilities planning.

(3) Maintenance Control Division. The Maintenance Control Division is responsible for determining need for maintenance, planning and programming maintenance work, determining the need for engineering advice and assistance, advising PWO of hazardous facilities, providing support for developing real property and minor construction budgets, issuing work orders in accordance with development spending plans, and reviewing, evaluating, and justifying projects which minimize recurring or costly maintenance.

(4) Family Housing Division. The Family Housing Division is responsible for management of all aspects of family housing, including programming of housing acquisitions, planning for operation, maintenance, repairs, alterations, and improvements.

(5) Maintenance Division. The Maintenance Division is responsible for the preventive maintenance program and maintenance of all public works, including utilities such as electric power distribution systems.

(6) Utilities Division. The Utilities Division is responsible for operating utilities plants and distribution systems; for monitoring the maintenance of plants and systems; performing operator and preventive maintenance inspections of utilities plants in accordance with maintenance management procedures; providing feeder data for the Utilities Management System; and for promoting and supporting utilities conservation methods and procedures.

e. Activity Command. Frequent and close liaison between PWD personnel and Activity Commands is essential for efficiently and economically providing the current and future electric power requirements.

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