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ELECTRICAL DISTRIBUTION ENGINEERING

2ND EDITION

by
Anthony J. Pansini, E.E., P.E.

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PREFACE TO THE SECOND EDITION

In the decade since the first edition made its appearance, events have caused the electric utility industry to reevaluate its goals as well as its position in society. Technical developments, together with substantial changes in the financial and environmental climates, aggravated by spiralling costs of fuel, have forced utility engineers to seek means of achieving greater efficiency and economy in the planning, design, construction, maintenance and operation of their electrical systems. Their long time philosophy of "reliable service at low cost" no longer adequately interprets the goals of the enterprise. While still an important incentive, engineers must pay greater attention to the financial and social problems affecting the society of which they are a part. This second edition discusses the changes that affect the distribution systems.

Distribution engineers have had to expand their scope and responsibilities beyond the traditional mechanical, electrical and economic considerations. Their new responsibilities now encompass the consumer's operations and intrude into the fields of generation and system operations as well as in that of public relations. The closer cooperation between distribution engineers and consumers' consultants has resulted in an effective amalgamation of the two disciplines.

In determining the physical plant necessary to supply consumers loads, distribution engineers not only meet the electrical and mechanical requirements according to Kelvin's Law, but must modify them to meet the constraints imposed by the availability of financial resources. And further modification that may be necessary to meet the environmental demands, varying from area to area, that must be met to maintain that priceless commodity in business dealings, the good will of the consumer, the community and the general public.

Like almost every other industry, the utility industry has felt the shock waves generated by the explosive developments in the world of electronics and computers.

PART ONE

THE DISTRIBUTION SYSTEM

CHAPTER 1

THE DISTRIBUTION SYSTEM: DESCRIPTION

Although there is no "typical" electric power system, a diagram including the several components that are usually to be found in the makeup of such a system is shown in Fig. 1-1; particular attention should be paid to those elements which will make up the component under discussion, the distribution system.

While the energy flow is obviously from the power generating plant to the consumer, it may be more informative for our purposes to reverse the direction of observation and consider events from the consumer back to the generating source.

Energy is consumed by users at a nominal utilization voltage that may range generally (in the United States) from 110 to 125 V, and from 220 to 250 V (for some large commercial and industrial users, the nominal figures are 277 and 480 V). It flows through a metering device that determines the billing for the consumer, but which may also serve to obtain data useful later for planning, design, and operating purposes. The metering equipment usually includes a means of disconnecting the consumer from the incoming supply should this become necessary for any reason.

The energy flows through conductors to the meter from the secondary mains (if any); these conductors are referred to as the consumer's *service*, or sometimes also as the *service drop*.

Several services are connected to the secondary mains; the secondary mains now serve as a path to the several services from the distribution transformers which supply them.

At the transformer, the voltage of the energy being delivered is reduced to the utilization voltage values mentioned earlier from higher *primary* line voltages that may range from 2200 V to as high as 46,000 V.

The transformer is protected from overloads and faults by fuses or so-called

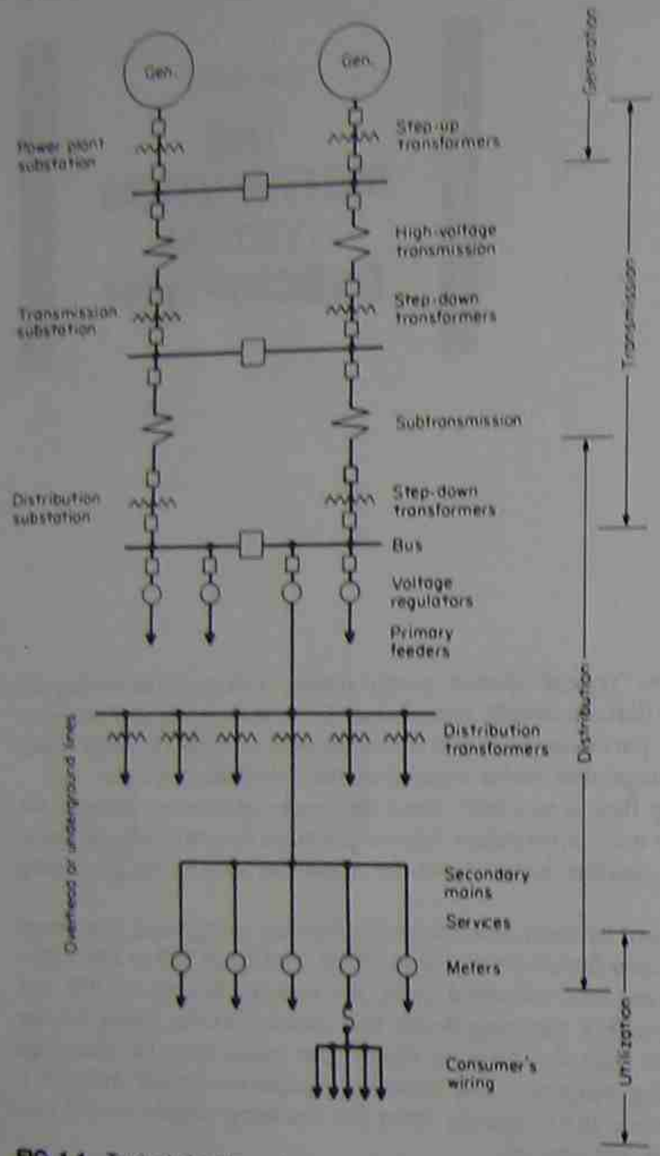


FIG. 1-1 Typical electric system showing operational divisions. Note overlap of divisions.

weak links on the high-voltage side; the latter also usually include circuit-breaking devices on the low-voltage side. These operate to disconnect the transformer in the event of overloads or faults. The circuit breakers (where they exist) on the secondary, or low-voltage, side operate only if the condition is caused by faults or overloads in the secondary mains, services, or consumers' premises; the primary fuse or weak link in addition operates in the event of a failure within the transformer itself.

If the transformer is situated on an overhead system, it is also protected from lightning or line voltage surges by a surge arrester, which drains the voltage surge to ground before it can do damage to the transformer.

The transformer is connected to the primary circuit, which may be a lateral or spur consisting of one phase of the usual three-phase primary main. This is done usually through a *line* or *sectionalizing fuse*, whose function is to disconnect the lateral from the main in the event of fault or overload in the lateral. The lateral conductors carry the sum of the energy components flowing through each of the transformers, which represent not only the energy used by the consumers connected thereto, but also the energy lost in the lines and transformers to that point.

The three-phase main may consist of several three-phase branches connected together, sometimes through other line or sectionalizing fuses, but sometimes also through switches. Each of the branches may have several single-phase laterals connected to it through line or sectionalizing fuses.

Where single-phase or three-phase overhead lines run for any considerable distance without distribution transformer installations connected to them, surge arresters may be installed on the lines for protection, as described earlier.

Some three-phase laterals may sometimes also be connected to the three-phase main through *circuit reclosers*. The recloser acts to disconnect the lateral from the main should a fault occur on the lateral, much as a line or sectionalizing fuse. However, it acts to reconnect the lateral to the main, reenergizing it one or more times after a time delay in a predetermined sequence before remaining open permanently. This is done so that a fault which may be only of a temporary nature, such as a tree limb falling on the line, will not cause a prolonged interruption of service to the consumers connected to the lateral.

The three-phase mains emanate from a *distribution substation*, supplied from a *bus* in that station. The three-phase mains, usually referred to as a *circuit* or *feeder*, are connected to the bus through a protective circuit breaker and sometimes a voltage regulator. The voltage regulator is usually a modified form of transformer and serves to maintain outgoing voltage within a predetermined band or range on the circuit or feeder as its load varies. It is sometimes placed electrically in the substation circuit so that it regulates the voltage of the entire bus rather than a single outgoing circuit or feeder, and sometimes along the route of a feeder for partial feeder regulation. The circuit breaker in the feeder acts to disconnect that feeder from the bus in the event of overload or fault on the outgoing or distribution feeder.

The substation bus usually supplies several distribution feeders and carries the sum of the energy supplied to each of the distribution feeders connected to it. In turn, the bus is supplied through one or more transformers and associated circuit breaker protection. These substation transformers step down the voltage of their supply circuit, usually called the *subtransmission* system, which operates at voltages usually from 23,000 to 138,000 V.

The subtransmission systems may supply several distribution substations and may act as *tie feeders* between two or more substations that are either of the *bulk power* or *transmission* type or of the distribution type. They may also be tapped to supply some distribution load, usually through a circuit breaker, for a single

consumer, generally an industrial plant or a commercial consumer having a substantially large load.

The transmission or bulk power substation serves much the same purposes as a distribution substation, except that, as the name implies, it handles much greater amounts of energy: the sum of the energy individually supplied to the subtransmission lines and associated distribution substations and losses. Voltages at the transmission substations are reduced to outgoing subtransmission line voltages from transmission voltages that may range from 69,000 to upwards of 750,000 V.

The transmission lines usually emanate from another substation associated with a power generating plant. This last substation operates in much the same manner as other substations, but serves to step up to transmission line voltage values the voltages produced by the generators. Because of material and insulation limitations, generator voltages may range from a few thousand volts for older and smaller units to some 20,000 volts for more recent, larger ones. Both buses and transformers in these substations are protected by circuit breakers, surge arresters, and other protective devices.

In all the systems described, conductors should be large enough that the energy loss in them will not be excessive, nor the loss in voltage so great that normal nominal voltage ranges at the consumers' services cannot be maintained.

In some instances, voltage regulators and capacitors are installed at strategic points on overhead primary circuits as a means of compensating for voltage drops or losses, and incidentally help in holding down energy losses in the conductors.

In many of the distribution system arrangements, some of the several elements between the generating plant and the consumer may not be necessary. In a relatively small area, such as a small town, that is served by a power plant situated in or very near the service area, the distribution feeder may emanate directly from the power plant bus, and all other elements may be eliminated, as indicated in Fig. 1-2. This is perhaps one extreme; in many other instances only some of the other elements may not be necessary; e.g., a similar small area somewhat distant from the generating plant may find it necessary to install a distribution substation supplied by a transmission line of appropriate voltage only.

In the case of areas of high load density and rather severe service reliability requirements, the distribution system becomes more complex and more expensive. The several secondary mains to which the consumers' services are connected may all be connected into a mesh or network. The transformers supplying these

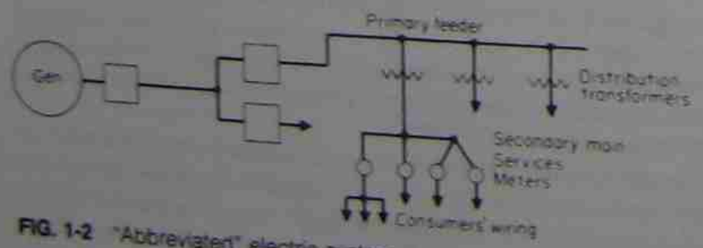


FIG. 1-2 "Abbreviated" electric system.

secondary mains or network are supplied from several different primary feeders, so that if one or more of these feeders is out of service for any reason, the secondary network is supplied from the remaining ones and service to the consumers is not interrupted. To prevent a feeding-back from the energized secondary network through the transformers connected to feeders out of service (thereby energizing the primary and creating unsafe conditions), automatically operated circuit breakers, called *network protectors*, are connected between the secondary network and the secondary of the transformers; these open when the direction of energy flow is reversed.

The two examples cited here are perhaps the two extremes in the design of distribution systems, the first the simplest, the latter the most complex. There are many variations in between these, and the basic ones will be described in their appropriate places.

Only distribution systems, however, will be the subject of further description and discussion in this book. In general, these include the distribution substation, primary feeders, transformers, secondary mains, services, and other elements between the substation and the consumers' points of service.

CHAPTER 2

DISTRIBUTION SYSTEM CONSIDERATIONS

In determining the design of distribution systems, three broad classifications of choices need to be considered:

1. The type of electric system: dc or ac, and if ac, single-phase or polyphase.
2. The type of delivery system: radial, loop, or network. Radial systems include duplicate and throwover systems.
3. The type of construction: overhead or underground.

DESIRED FEATURES

Electrical energy may be distributed over two or more wires. The principal features desired are safety; smooth and even flow of power, as far as is practical; and economy.

Safety

The safety factor usually requires a voltage low enough to be safe when the electric energy is utilized by the ordinary consumer.

Smooth and Even Flow of Power

A steady, uniform, nonfluctuating flow of power is highly desirable, both for lighting and for the operation of motors for power purposes. Although a direct current system fills these requirements admirably, it is limited in the distance over which it can economically supply power at utilization voltage.

Alternating current systems deliver power in a fluctuating manner following the cyclic variations of the voltage generated. Such fluctuations of power are not objectionable for heating, lighting, and small motors, but are not entirely satisfactory for the operation of some devices such as large motors, which must deliver mechanical power steadily and therefore require a steady input of electric power. This may be done by supplying electricity to the motors by two or three circuits, each supplying a portion of the power, whose fluctuations are purposely made not to occur at the same time, thereby decreasing or damping out the effect of the fluctuations. These two or three separate alternating current circuits (each often referred to as a single-phase circuit) are combined into one polyphase (two- or three-phase) circuit. The voltages for polyphase circuits or systems are supplied from polyphase generators.

Economy

The third factor requires the minimum use of conductors for delivery of electric energy. This usually calls for the use of higher voltages where conditions permit and the elimination of some conductors by providing a common return path for two or more circuits.

TYPES OF ELECTRIC SYSTEMS

Direct Current Systems

Direct current systems usually consist of two or three wires. Although such distribution systems are no longer employed, except in very special instances, older ones now exist and will continue to exist for some time. Direct current systems are essentially the same as single-phase ac systems of two or three wires; the same discussion for those systems also applies to dc systems.

Alternating Current Single-Phase Systems

Two-Wire Systems The simplest and oldest circuit consists of two conductors between which a relatively constant voltage is maintained, with the load connected between the two conductors; refer to Fig. 2-1.

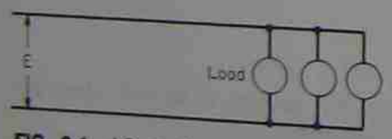


FIG. 2-1 AC single-phase two-wire system.

In almost all cases, one conductor is grounded. The grounding of one conductor, usually called the *neutral*, is basically a safety measure. Should the live conductor come in contact accidentally with the neutral conductor, the voltage of the live conductor will be dissipated throughout a relatively large body of earth and thereby rendered harmless.

In calculating power (I^2R) losses in the conductors, the resistance of the conductors must be considered. In the case of the neutral conductor, because the ground, in parallel with the conductor, reduces the effective resistance, the "return" current will divide between the conductor and ground in inverse proportion to their resistances. Thus the I^2R loss in the neutral conductor will be lower than that in the live conductor; the I^2R loss in the earth may, for practical purposes, be disregarded.

In calculating voltage drop in the circuits, both the resistance and reactance of the two conductors must be considered. (In dc circuits, reactance does not exist during normal flow of current.) This combination of reactance and resistance, known as impedance, is measured in ohms (Ω). Because the current in the grounded neutral conductor may be less than the current in the live conductor, the voltage drop in the neutral conductor may also be less.

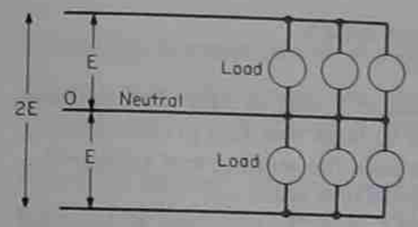


FIG. 2-2 AC single-phase three-wire system.

Three-Wire Systems Essentially the three-wire system is a combination of two two-wire systems with a single wire serving as the neutral of each of the two-wire systems. At a given instant, if one of the live conductors is E volts (say 120 V) "above" the neutral, the other live conductor will be E volts (120 V) "below" the neutral, and the voltage between the two live (or outside) conductors will be $2E$ (240 V). Refer to Fig. 2-2.

If the load is balanced between the two (two-wire) systems, the common neutral conductor carries no current and the system acts as a two-wire system at twice the voltage of the component system; each unit of load (such as a lamp) of one component system is in series with a similar unit of the other system. If the load is not balanced, the neutral conductor carries a current equal to the difference between the currents in the outside conductors. Here again, the neutral conductor is usually connected to ground.

For a balanced system, power loss and voltage drop are determined in the same way as for a two-wire circuit consisting of the outside conductors; the neutral is neglected.

Where the loads on the two portions of the three-wire circuit are unbalanced, voltages at the utilization or receiving ends may be different. These are shown schematically in Fig. 2-3. Let the distance between the dashed lines represent the voltage. There will be a voltage drop, with reference to the neutral, in each of the conductors 1 and 2. The neutral conductor will carry the difference in currents, that is, $I_2 - I_1$, or I_n. This current in the neutral conductor will produce a voltage drop in that conductor, as indicated in Fig. 2-3. The result will be a

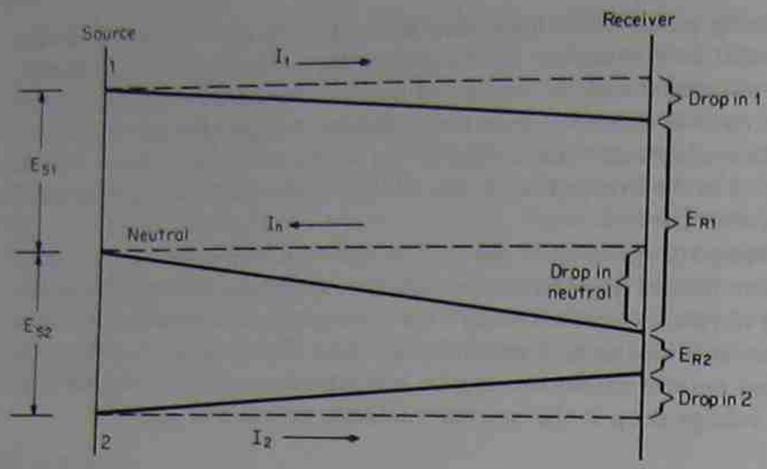


FIG. 2-3 Unbalanced load—single-phase three-wire system.

much larger drop in voltage between conductor 2 and neutral than between conductor 1 and neutral. If the unbalance is so large that I_n is greater than I_1, the receiving end voltage E_{R1} will be greater than the sending end voltage E_{S1}, and there will be an actual rise in voltage across that side.

The limiting case occurs when $I_1 = 0$ and $I_n = I_2$. In that case, all the load is carried on side 2; the rise in voltage on side 1 will be half as much as the drop in voltage on the loaded side 2. However, if an equal load is now added to side 1, the loads in both parts of the circuit will be balanced and I_n will equal 0. The drop in voltage between conductor 2 and the neutral will be reduced to half that obtained with the load on side 2 only, although the load now supplied is doubled.

Voltage drops in the conductors will depend on the currents flowing in them and their impedances. The power loss in each conductor (I^2R) will depend on the current flowing in it and its resistance.

In all of this discussion, the size of the neutral has been assumed to be the same as the live or outside conductors.

Series Systems The series type of circuit is used chiefly for street lighting and, although being rapidly replaced by multiple-circuit lighting, nevertheless still exists in substantial numbers. It consists of a single-conductor loop in which the current is maintained at a constant value, the loads connected in series; see Fig. 2-4. The voltage between the conductors at the source or at any other point depends on the amount of load connected beyond that point. The voltage at the source is equal to the vectorial sum of the voltages across the various loads and the voltage drop in the conductor.

The voltage drop in each section of the conductor depends on the current flowing in it (which is constant in value) and the impedance of that section of the conductor.

The power supplied the circuit equals the sum of the power for the individual units of load and the line losses. Power loss in each section of the conductor will

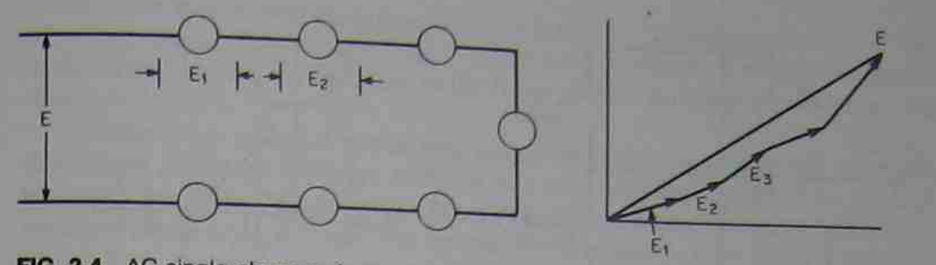


FIG. 2-4 AC single-phase series system and voltage vector diagram.

depend on the current (squared) and the resistance of that section of the conductor.

Alternating Current Two-Phase Systems

Two-phase systems are rapidly becoming obsolete, but a good number of them exist and may continue to exist for some time.

Four-Wire Systems The four-wire system consists of two single-phase two-wire systems in which the voltage in one system is 90° out of phase with the voltage in the other system, both usually supplied from the same generator. Refer to Fig. 2-5.

In determining the power, power loss, and voltage drops in such a system, the values are calculated as for two separate single-phase two-wire systems.

Three-Wire Systems The three-wire system is equivalent to a four-wire two-phase system, with one wire (the neutral) made common to both phases; refer to Fig. 2-6. The current in the outside or phase wires is the same as in the four-wire system; the current in the common wire is the vector sum of these currents but opposite in phase. When the load is exactly balanced in the two phases, these currents are equal and 90° out of phase with each other and the resultant neutral current is equal to $\sqrt{2}$ or 1.41 times the phase current.

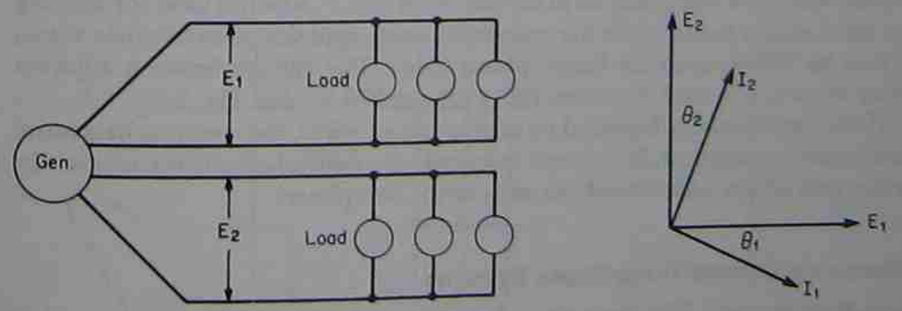


FIG. 2-5 AC two-phase four-wire system and vector diagram.

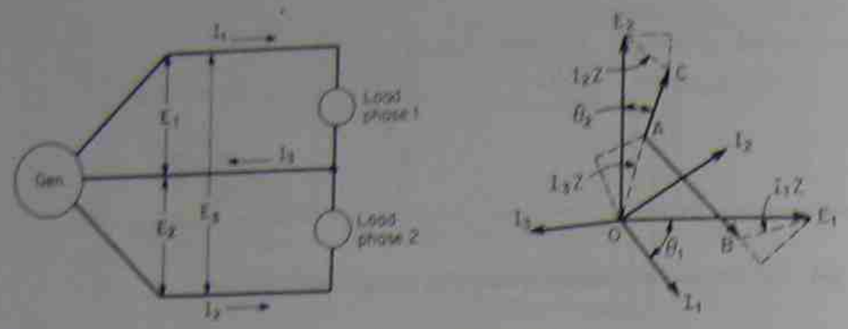


FIG. 2-6 AC two-phase three-wire system and vector diagram.

The voltage between phase wires and common wire is the normal phase voltage, and, neglecting the difference in neutral IR drop, the same as in the four-wire system. The voltage between phase wires is equal to $\sqrt{2}$ or 1.41 times that voltage.

The power delivered is equal to the sum of the powers delivered by the two phases. The power loss is equal to the sum of the power losses in each of the three wires.

The voltage drop is affected by the distortion of the phase relation caused by the larger current in the third or common wire. In Fig. 2-6, if E_1 and E_2 are the phase voltages at the source and I_1 and I_2 the corresponding phase currents (assuming balanced loading), I_3 is the current in the common wire. The voltage (IZ) drops in the two conductors, subtracted vectorially from the source voltages E_1 and E_2, give the resultant voltages at the receiver of AB for phase 1 and AC for phase 2. The voltage drop numerically is equal to $E_1 - AB$ for phase 1, and $E_2 - AC$ for phase 2. It is apparent that these voltage drops are unequal and that the action of the current in the common wire is to distort the relations between the voltages and currents—the effect shown in Fig. 2-6 is exaggerated for illustration.

Five-Wire Systems The five-wire system is equivalent to a two-phase four-wire system with the midpoint of both phases brought out and joined in a fifth wire. The voltage is of the same value from any phase wire to the common neutral, or fifth, wire. The value may be in the nature of 120 V, which is used for lighting and small motor loads, while the voltage between opposite pairs of phase wires, E, may be 240 V, used for larger-power loads. The voltage between adjacent phase wires is $\sqrt{2}$, or 1.41, times 120 V (about 170 V). See Fig. 2-7.

If the load is exactly balanced on all four phase wires, the common or neutral wire carries no current. If it is not balanced, the neutral conductor carries the vector sum of the unbalanced currents in the two phases.

Alternating Current Three-Phase Systems

Four-Wire Systems The three-phase four-wire system is perhaps the most widely used. It is equivalent to three single-phase two-wire systems supplied from the same generator. The voltage of each phase is 120° out of phase with the voltages

of the other two phases, but one conductor is used as a common conductor for all of the system. The current I_n in that common or neutral conductor is equal to the vector sum of the currents in the three phases, but opposite in phase, as shown in Fig. 2-8.

If these three currents are nearly equal, the neutral current will be small, since these phase currents are 120° out of phase with each other. The neutral is usually grounded. Single-phase loads may be connected between one phase wire and the neutral, but may also be connected between phase wires if desired. In this latter instance, the voltage is $\sqrt{3}$ or 1.73 times the line-to-neutral voltage E. Three-phase loads may have each of the separate phases connected to the three phase conductors and the neutral, or the separate phases may be connected to the three phase conductors only.

Power delivered is equal to the sum of the powers in each of the three phases. Power loss is equal to the sum of the I^2R losses in all four wires.

The voltage drop in each phase is affected by the distortion of the phase relations due to voltage drop caused by the current in the neutral conductor. This is not so, however, when the neutral conductor is grounded at both the sending and receiving ends, in which case the neutral drop is theoretically zero, the current returning through ground. The voltage drop may be obtained vectorially by applying the impedance drop of each phase to its voltage. The neutral point is shifted from O to A by the voltage drop in the neutral conductor and the resulting voltages at the receiver are shown by E_{1R}, E_{2R}, and E_{3R}. The voltage drops in each phase are numerically equal to the difference in length between E_{1S} and E_{1R}, E_{2S} and E_{2R}, and E_{3S} and E_{3R}. The effects of the distortion due to voltage drop in the neutral conductors are exaggerated in Fig. 2-8 for illustration.

Three-Wire Systems If the load is equally balanced on the three phases of a four-wire system, the neutral carries no current and hence could be removed, making a three-wire system. It is not necessary, however, that the load be exactly balanced on a three-wire system.

Considering balanced loads, on a three-phase three-wire system, a three-phase load may be connected with each phase connected between two phase wires—a

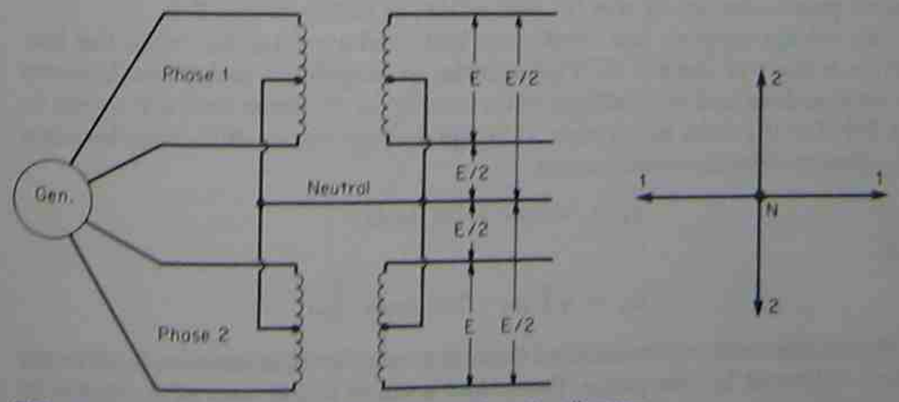


FIG. 2-7 AC two-phase five-wire system and vector diagram.

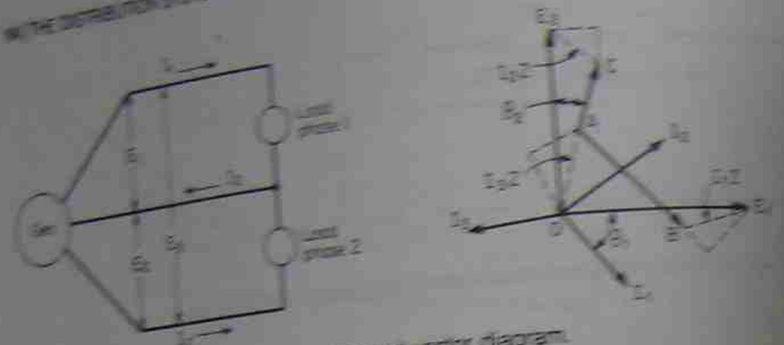


FIG. 2-5 AC two-phase three-wire system and vector diagram.

The voltage between phase wires and common wire is the normal phase voltage, and, neglecting the difference in neutral IR drop, the same as in the four-wire system. The voltage between phase wires is equal to $\sqrt{2}$ or 1.41 times that voltage.

The power delivered is equal to the sum of the powers delivered by the two phases. The power loss is equal to the sum of the power losses in each of the three wires.

The voltage drop is affected by the distortion of the phase relation caused by the larger current in the third or common wire. In Fig. 2-6, if E_1 and E_2 are the phase voltages at the source and I_1 and I_2 the corresponding phase currents (assuming balanced loading), I_3 is the current in the common wire. The voltage (IZ) drops in the two conductors, subtracted vectorially from the source voltages E_1 and E_2, give the resultant voltages at the receiver of AB for phase 1 and AC for phase 2. The voltage drop numerically is equal to $E_1 - AB$ for phase 1, and $E_2 - AC$ for phase 2. It is apparent that these voltage drops are unequal and that the action of the current in the common wire is to distort the relation between the voltages and currents—the effect shown in Fig. 2-6 is exaggerated for illustration.

Four-Wire Systems The five-wire system is equivalent to a two-phase four-wire system with the midpoint of both phases brought out and joined in a fifth wire. The voltage is of the same value from any phase wire to the common, or fifth, wire. The value may be in the nature of 120 V, which is used for lighting and small motor loads, while the voltage between opposite pairs of phase wires, E, may be 240 V, used for larger-power loads. The voltage between adjacent phase wires is $\sqrt{2}$, or 1.41, times 120 V (about 170 V). See Fig. 2-

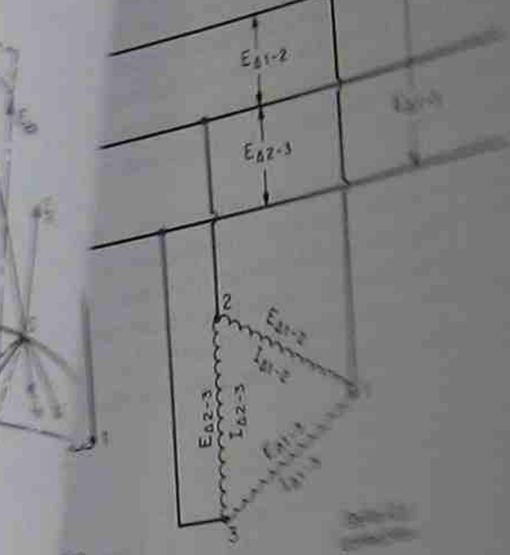
If the load is exactly balanced on all four phase wires, the common wire carries no current. If it is not balanced, the current in the common wire is the vector sum of the unbalanced currents in the four phase wires.

Alternating Current

Four-Wire Systems used. It is equivalent to a two-phase four-wire system with the midpoint of both phases brought out and joined in a fifth wire. The voltage is of the same value from any phase wire to the common, or fifth, wire. The value may be in the nature of 120 V, which is used for lighting and small motor loads, while the voltage between opposite pairs of phase wires, E, may be 240 V, used for larger-power loads. The voltage between adjacent phase wires is $\sqrt{2}$, or 1.41, times 120 V (about 170 V). See Fig. 2-

If the load is exactly balanced on all four phase wires, the common wire carries no current. If it is not balanced, the current in the common wire is the vector sum of the unbalanced currents in the four phase wires.

...ll in the wye (Y) voltages, may be ...in one conductor vectorially to E_{Y1}. ...same thing is done in determining ...desired. If $E_{\Delta 1}$ is the voltage between ...-to-neutral voltage, the drop due to



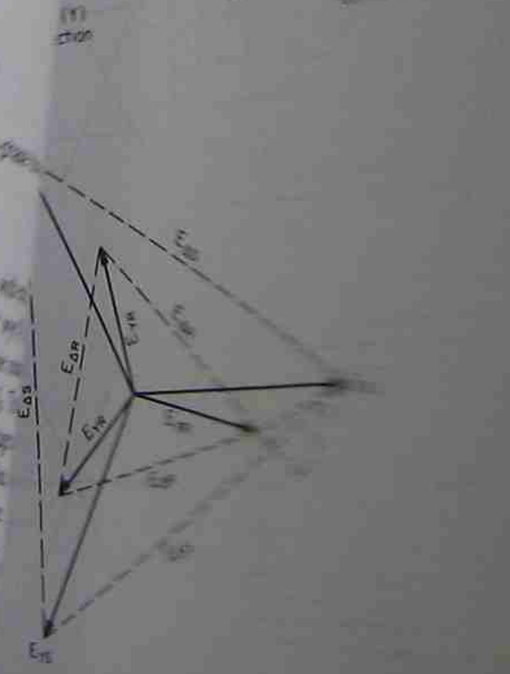


FIG. 2-6 (a) AC three-phase ... current vector diagram.

delta (Δ) connection—or ... neutral point—the star or wye ...

The voltage between ... current is the wye current ... the various delta and wye ... Fig. 2-9. For the delta ... the adjacent delta currents ...

and

$$I_1 = \sqrt{}$$

$$E_1 = \sqrt{}$$

Power delivered, when balanced ... power delivered by one phase ...



...hase three-wire system and ...

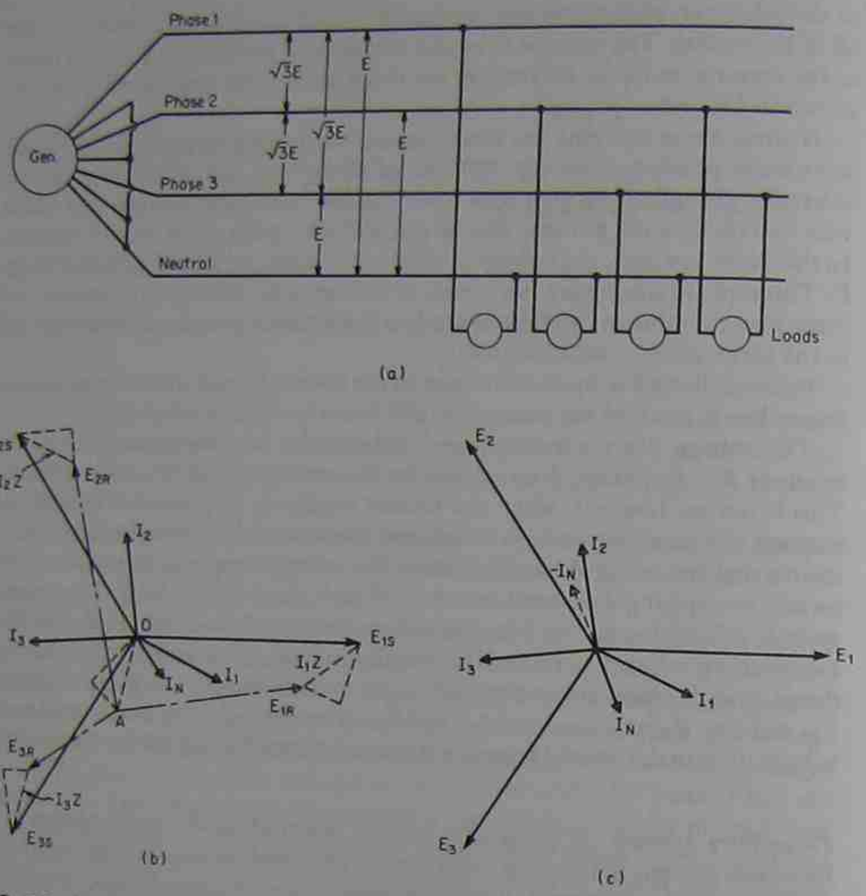


FIG. 2-8 (*a*) AC three-phase four-wire system; (*b*) voltage and current vector diagram; (*c*) current vector diagram.

delta (Δ) connection—or with each phase between one phase wire and a common neutral point—the star or wye (*Y*) connection, as shown in Fig. 2-9.

The voltage between line conductors is the delta voltage E_Δ, while the line current is the wye current I_Y. The relations in magnitude and phase between the various delta and wye voltages and currents for the same load are shown in Fig. 2-9. For the delta connection, I_Y is equal to the vector difference between the adjacent delta currents; hence:

$$I_Y = \sqrt{3} \text{ (or 1.73) times } I$$

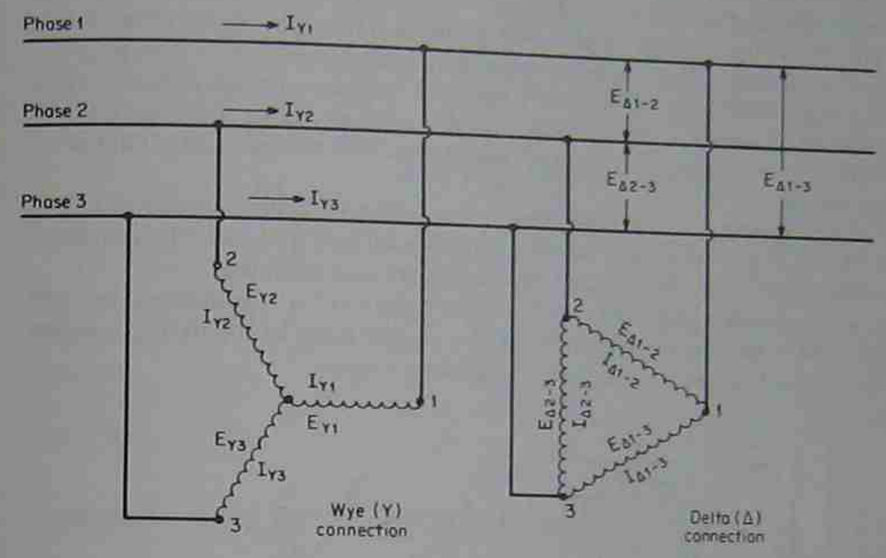
and

$$E_\Delta = \sqrt{3} \text{ (or 1.73) times } E_Y$$

Power delivered, when balanced loads are considered, is equal to 3 times the power delivered by one phase. Power loss is equal to the sum of the losses in

each phase, or when balanced conditions exist, it is 3 times the power loss in any one phase.

The voltage drop in each phase, referred to the wye (*Y*) voltages, may be determined by adding the impedance drop in one conductor vectorially to E_Y, when balanced loads are considered. The same thing is done in determining voltages where unbalanced loads are considered. If $E_{\Delta S}$ is the voltage between phases at the source and E_{YS} the phase-to-neutral voltage, the drop due to



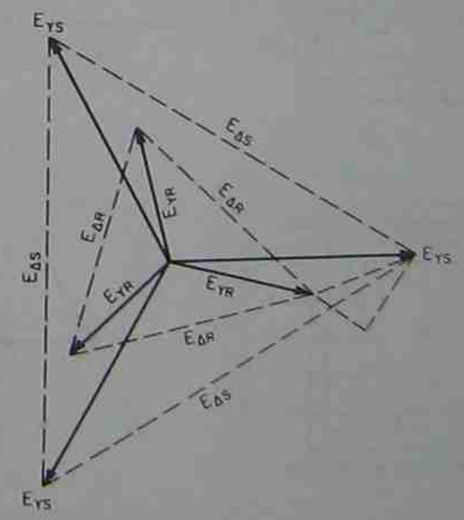


FIG. 2-9 AC three-phase three-wire system and voltage vector diagrams (current vector not shown).

conductor impedance, IZ, is subtracted vectorially from E_{YS} for each of the three phases, and the resulting voltages between phases at the receiving end ($E_{\Delta R}$) are obtained. The effects shown in the vector diagram of Fig. 2-9 are exaggerated for illustration.

Alternating Current Six-Phase Systems

Six-Wire Systems Six-phase systems consist essentially of two three-phase systems connected so that each phase of one system will be displaced 180° with reference to the same phase of the other system. These may consist of two banks of three transformers connected separately with the polarity of one bank reversed with reference to the second bank; or one bank of transformers may be employed, with the secondary windings divided into two equal parts and both ends of each winding part brought out to separate terminals (for a total of 12 terminals).

The windings may be connected in a double-delta fashion as shown in Fig. 2-10*a*, or in a double-wye arrangement as shown in Fig. 2-10*b*. The associated vector diagrams of the voltage relationships are also indicated.

In the double-wye connection, it is not necessary to have the windings brought out to 12 terminals; the neutral connection may be made by connecting together the midtap from each of the three secondary windings.

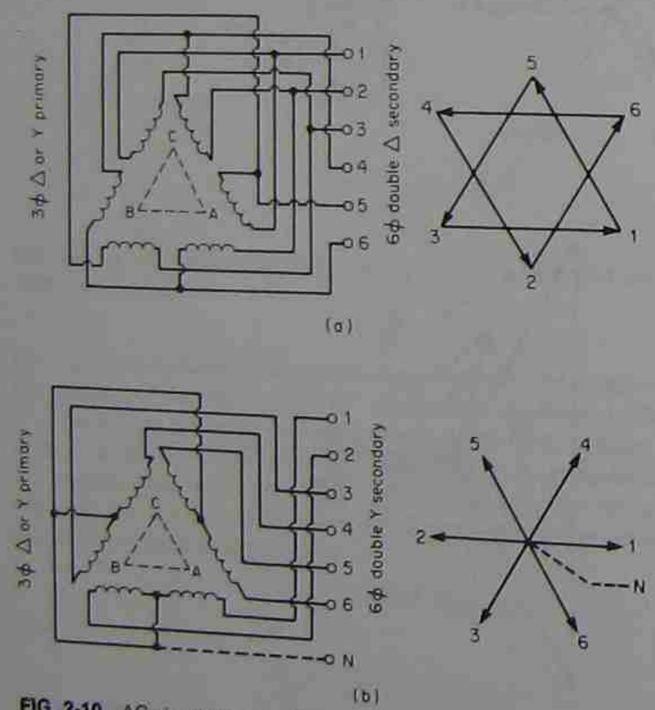


FIG. 2-10 AC six-phase six-wire double-delta system (*a*), AC six-phase six-wire (and seven-wire) double-wye system (*b*), and voltage vector diagrams.

Such systems are almost exclusively used in supplying rectifiers or synchronous converters to serve direct current loads; the synchronous converter also aids in improving power factor on the alternating current supply system.

Seven-Wire Systems A seventh, or neutral, wire may be brought out from the common junction of the double-wye connection, as indicated by the dashed line in Fig. 2-10*b*.

The seven-wire system may be used for distribution purposes, with the neutral connected to other common neutral systems. The disadvantage of the additional conductor is balanced against two major advantages:

1. The ability to serve single-phase loads from a source of higher voltage, i.e., twice the line-to-neutral voltage, compared with 1.73 times the line-to-neutral voltage in a three-phase system.
2. Reduction in overall line losses, as each conductor will carry only one-sixth of the load, compared with one-third in a three-phase system—only half the load per conductor in a three-phase system. The losses, therefore, will be one-quarter those in a three-phase (three- or four-wire balanced) system.

The overall savings in fuel costs for supplying the lesser losses may exceed the increased carrying charges associated with the additional conductors. The improved voltage in supplying three-phase delta (power) loads from such a system also contributes to its acceptability. As fuel and operating costs increase, such systems may find wider application.

Comparison Between Alternating Current Systems

A comparison of efficiencies for the several alternating current systems, assuming the same (balanced) loads, the same voltage between conductors, and the same conductor size is summarized in Table 2-1, which uses a single-phase two-wire circuit as a basis for comparison.

TABLE 2-1 COMPARATIVE EFFICIENCIES OF AC SYSTEMS

Type of ac system		*Amount of conductor*	*Power loss*	*Voltage drop (approximate)*
Single-phase	2-wire	1.0	1.00	1.00
	3-wire	1.5	0.25	0.25
Two-phase	3-wire	1.5	0.50	0.50
	4-wire	2.0	0.25	0.25
	5-wire	2.5	0.25	0.25
Three-phase	3-wire*	1.5	0.167	0.167
	3-wire**	1.5	0.50	0.50
	4-wire*	2.0	0.167	0.167
Six-phase	6-wire	3.0	0.042	0.042
	7-wire	3.5	0.042	0.042

*Wye (*Y*) voltage same as single-phase.

**Delta (Δ) voltage same as single-phase.

TYPES OF DELIVERY SYSTEMS

The delivery of electric energy from the generating plant to the consumer may consist of several more or less distinct parts that are nevertheless somewhat interrelated, described generally in Chap. 1. The part considered "distribution," i.e., from the bulk supply substation to the meter at the consumer's premises, can be conveniently divided into two subdivisions:

1. Primary distribution, which carries the load at higher than utilization voltages from the substation (or other source) to the point where the voltage is stepped down to the value at which the energy is utilized by the consumer.
2. Secondary distribution, which includes that part of the system operating at utilization voltages, up to the meter at the consumer's premises.

Primary Distribution

Primary distribution systems include three basic types:

1. Radial systems, including duplicate and throwover systems
2. Loop systems, including both open and closed loops
3. Primary network systems

Radial Systems The radial-type system is the simplest and the one most commonly used. It comprises separate feeders or circuits "radiating" out of the substation or source, each feeder usually serving a given area. The feeder may be considered as consisting of a main or trunk portion from which there radiate spurs or laterals to which distribution transformers are connected, as illustrated in Fig. 2-11.

The spurs or laterals are usually connected to the primary main through fuses, so that a fault on the lateral will not cause an interruption to the entire

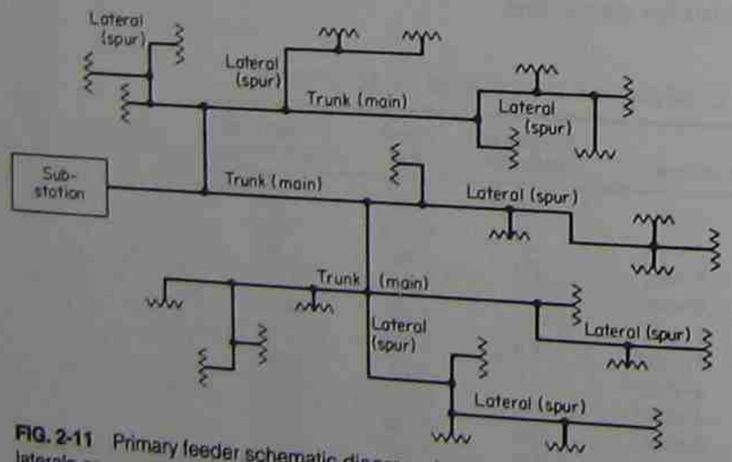


FIG. 2-11 Primary feeder schematic diagram showing trunk or main feeds and laterals or spurs.

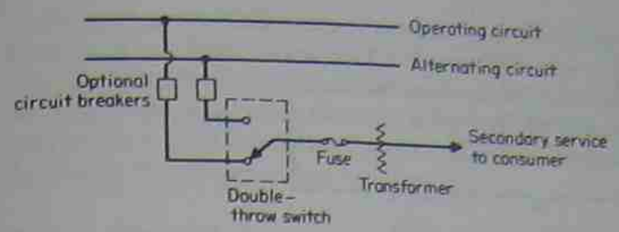


FIG. 2-12 Schematic diagram of alternate feed–throwover arrangement for critical consumers.

feeder. Should the fuse fail to clear the line, or should a fault develop on the feeder main, the circuit breaker back at the substation or source will open and the entire feeder will be deenergized.

To hold down the extent and duration of interruptions, provisions are made to sectionalize the feeder so that unfaulted portions may be reenergized as quickly as practical. To maximize such reenergization, emergency ties to adjacent feeders are incorporated in the design and construction; thus each part of a feeder not in trouble can be tied to an adjacent feeder. Often spare capacity is provided for in the feeders to prevent overload when parts of an adjacent feeder in trouble are connected to them. In many cases, there may be enough diversity between loads on adjacent feeders to require no extra capacity to be installed for these emergencies.

Supply to hospitals, military establishments, and other sensitive consumers may not be capable of tolerating any long interruption. In such cases, a second feeder (or additional feeders) may be provided, sometimes located along a separate route, to provide another, separate alternative source of supply. Switching from the normal to the alternative feeder may be accomplished by a throwover switching arrangement (which may be a circuit breaker) that may be operated manually or automatically. In many cases, two separate circuit breakers, one on each feeder, with electrical interlocks (to prevent connecting a good feeder to the one in trouble), are employed with automatic throwover control by relays. See Fig. 2-12.

Loop Systems Another means of restricting the duration of interruption employs feeders designed as loops, which essentially provide a two-way primary feed for critical consumers. Here, should the supply from one direction fail, the entire load of the feeder may be carried from the other end, but sufficient spare capacity must be provided in the feeder. This type of system may be operated with the loop normally open or with the loop normally closed.

Open Loop In the open-loop system, the several sections of the feeder are connected together through disconnecting devices, with the loads connected to the several sections, and both ends of the feeder connected to the supply. At a predetermined point in the feeder, the disconnecting device is intentionally left open. Essentially, this constitutes two feeders whose ends are separated by a

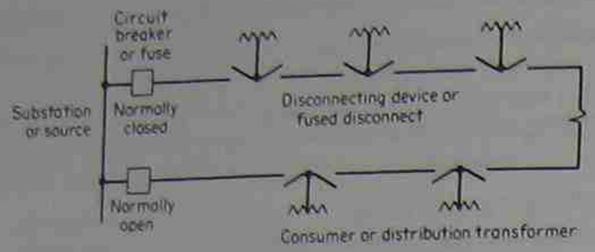


FIG. 2-13 Open-loop circuit schematic diagram.

disconnecting device, which may be a fuse, switch, or circuit breaker. See Fig. 2-13.

In the event of a fault, the section of the primary on which the fault occurs can be disconnected at both its ends and service reestablished to the unfaulted portions by closing the loop at the point where it is normally left open, and reclosing the breaker at the substation (or supply source) on the other, unfaulted portion of the feeder.

Such loops are not normally closed, since a fault would cause the breakers (or fuses) at both ends to open, leaving the entire feeder deenergized and no knowledge of where the fault has occurred. The disconnecting devices between sections are manually operated and may be relatively inexpensive fuses, cutouts, or switches.

Closed Loop Where a greater degree of reliability is desired, the feeder may be operated as a closed loop. Here, the disconnecting devices are usually the more expensive circuit breakers. The breakers are actuated by relays, which operate to open only the circuit breakers on each end of the faulted section, leaving the remaining portion of the entire feeder energized. In many instances, proper relay operation can only be achieved by means of pilot wires which run from circuit breaker to circuit breaker and are costly to install and maintain; in some instances these pilot wires may be rented telephone circuits. See Fig. 2-14.

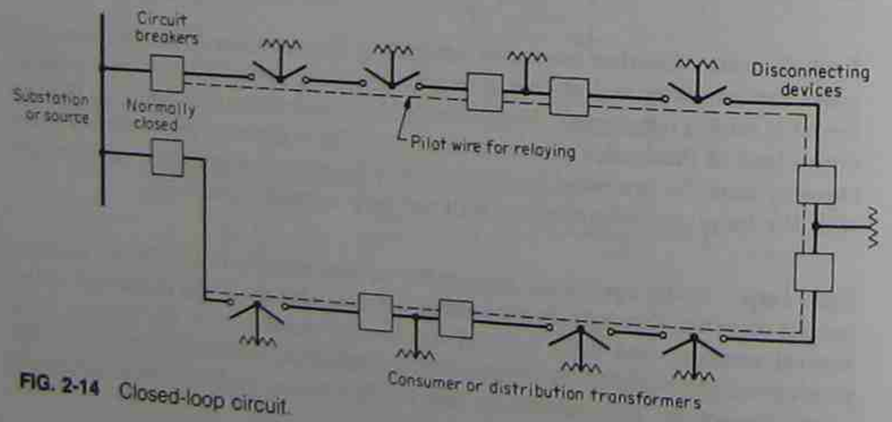


FIG. 2-14 Closed-loop circuit.

To hold down costs, circuit breakers may be installed only between certain sections of the feeder loop, and ordinary, less expensive disconnecting devices installed between the intermediate sections. A fault will then deenergize several sections of the loop; when the fault is located, the disconnecting devices on both ends of the faulted section may be opened and the unfaulted sections reenergized by closing the proper circuit breakers.

Primary Network Systems Although economic studies indicated that under some conditions the primary network may be less expensive and more reliable than some variations of the radial system, relatively few primary network systems have been put into actual operation and only a few still remain in service.

This system is formed by tying together primary mains ordinarily found in radial systems to form a mesh or grid. The grid is supplied by a number of power transformers supplied in turn from subtransmission and transmission lines at higher voltages. A circuit breaker between the transformer and grid, controlled by reverse-current and automatic reclosing relays, protects the primary network from feeding fault current through the transformer when faults occur on the supply subtransmission or transmission lines. Faults on sections of the primaries constituting the grid are isolated by circuit breakers and fuses. See Fig. 2-15.

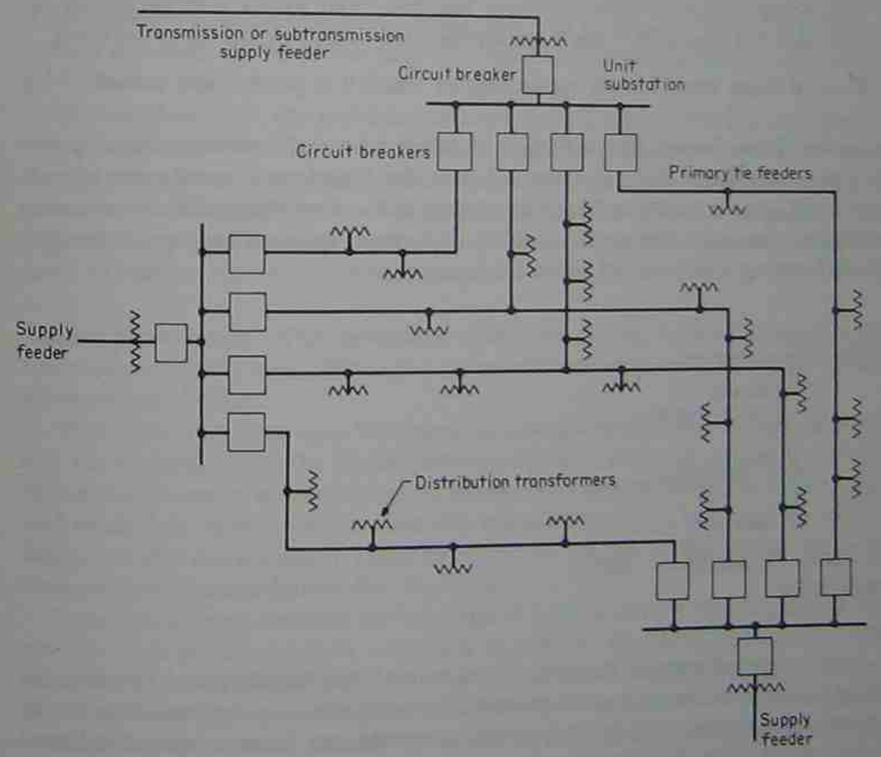


FIG. 2-15 Primary network. Sectionalizing devices on feeders not shown.

This type of system eliminates the conventional substation and long primary trunk feeders, replacing them with a greater number of "unit" substations strategically placed throughout the network. The additional sites necessary are often difficult to obtain. Moreover, difficulty is experienced in maintaining proper operation of the voltage regulators (where they exist) on the primary feeders when interconnected.

Secondary Distribution

Secondary distribution systems operate at relatively low utilization voltages and, like primary systems, involve considerations of service reliability and voltage regulation. The secondary system may be of four general types:

1. An individual transformer for each consumer; i.e., a single service from each transformer.
2. A common secondary main associated with one transformer from which a group of consumers is supplied.
3. A continuous secondary main associated with two or more transformers, connected to the same primary feeder, from which a group of consumers is supplied. This is sometimes known as *banking* of transformer secondaries.
4. A continuous secondary main or grid fed by a number of transformers, connected to two or more primary feeders, from which a large group of consumers is supplied. This is known as a *low-voltage* or *secondary* network.

Each of these types has its application to which it is particularly suited.

Individual Transformer–Single Service Individual-transformer service is applicable to certain loads that are more or less isolated, such as in rural areas where consumers are far apart and long secondary mains are impractical, or where a particular consumer has an extraordinarily large or unusual load even though situated among a number of ordinary consumers.

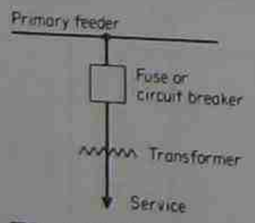


FIG. 2-16 Single-service secondary supply.

In this type of system, the cost of the several transformers and the sum of power losses in the units may be greater (for comparative purposes) than those for one transformer supplying a group of consumers from its associated secondary main. The diversity among consumers' loads and demands permits a

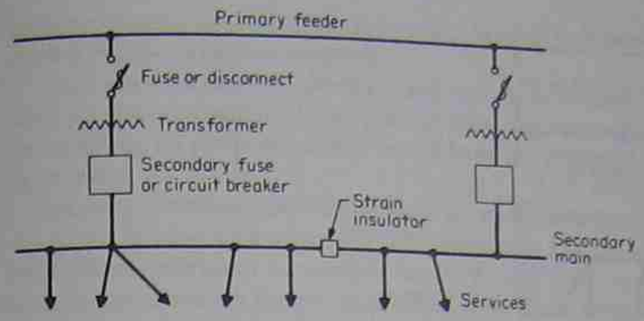


FIG. 2-17 Common-secondary-main supply.

transformer of smaller capacity than the capacity of the sum of the individual transformers to be installed. On the other hand, the cost and losses in the secondary main are obviated, as is also the voltage drop in the main. Where low voltage may be undesirable for a particular consumer, it may be well to apply this type of service to the one consumer. Refer to Fig. 2-16.

Common Secondary Main Perhaps the most common type of secondary system in use employs a common secondary main. It takes advantage of diversity between consumers' loads and demands, as indicated above. Moreover, the larger transformer can accommodate starting currents of motors with less resulting voltage dip than would be the case with small individual transformers. See Fig. 2-17.

In many instances, the secondary mains installed are more or less continuous, but cut into sections insulated from each other as conditions require. As loads change or increase, the position of these division points may be readily changed, sometimes holding off the need to install additional transformer capacity. Also, additional separate sections can be created and a new transformer installed to serve as load or voltage conditions require.

Banked Secondaries The secondary system employing banked secondaries is not very commonly used, although such installations exist and are usually limited to overhead systems.

This type of system may be viewed as a single-feeder low-voltage network, and the secondary may be a long section or grid to which the transformers are connected. Fuses or automatic circuit breakers located between the transformer and secondary main serve to clear the transformer from the bank in case of failure of the transformer. Fuses may also be placed in the secondary main between transformer banks. See Fig. 2-18.

Some advantages claimed for this type of system include uninterrupted service, though perhaps with a reduction in voltage, should a transformer fail; better distribution of load among transformers; better normal voltage conditions resulting from such load distribution; an ability to accommodate load increases by changing only one or some of the transformers, or by installing a new transformer at some intermediate location without disturbing the existing arrange-

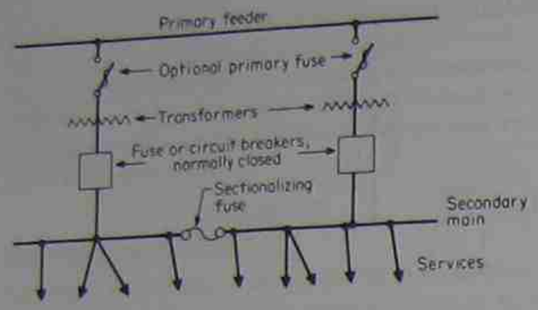


FIG. 2-18 Banked secondary supply.

ment; the possibility that diversity between demands on adjacent transformers will reduce the total transformer load; more capacity available for inrush currents that may cause flicker; and more capacity as well to burn secondary faults clear.

Some disadvantages associated with this type of system are as follows: should one transformer fail, the additional loads imposed on adjacent units may cause them to fail, and in turn their loads would cause still other transformers to fail (this is known as *cascading*); the transformers banked must have very nearly the same impedance and other characteristics, or the loads will not be distributed equitably among them; and sufficient reserve capacity must be provided to carry emergency loads safely, obviating the savings possible from the diversity of the demands on the several transformers.

Banked secondaries, while providing for failure of transformers, do not provide against faults on the primary main or feeder. Further, a hazard on any transformer disconnected for any reason may result from a back feed if the secondary energizes the primary (which may have been considered safe).

Secondary Networks Secondary networks at present provide the highest degree of service reliability and serve areas of high load density, where revenues justify their cost and where this kind of reliability is imperative. In some instances, a single consumer may be supplied from this type of system by what are known as *spot networks*.

In general, the secondary network is created by connecting together the secondary mains fed from transformers supplied by two or more primary feeders. Automatically operated circuit breakers in the secondary connection between the transformer and the secondary mains, known as *network protectors*, serve to disconnect the transformer from the network when its primary feeder is deenergized; this prevents a back feed from the network into the primary feeder. This is especially important for safety when the primary feeder is deenergized from fault or other cause. The circuit breaker or protector is backed up by a fuse so that, should the protector fail to operate, the fuse will blow and disconnect the transformer from the secondary mains. See Fig. 2-19.

The number of primary feeders supplying a network is very important. With only two feeders, only one feeder may be out of service at a time, and there must be sufficient spare transformer capacity available so as not to overload the

units remaining in service; therefore this type of network is sometimes referred to as a *single-contingency* network.

Most networks are supplied from three or more primary feeders, where the network can operate with the loss of two feeders and the spare transformer capacity can be proportionately less. These are referred to as *second-contingency* networks.

Secondary mains not only should be so designed that they provide for an equitable division of load between transformers and for good voltage regulation with all transformers in service, but they also must do so when some of the transformers are no longer in service when their primary feeders are deenergized. They must also be able to divide fault current properly among the transformers, and must provide for burning faults clear at any point while interrupting service to a minimum number of consumers; this often limits the size of secondary mains, usually to less than 500 cmil $\times$ 10^3, so that when additional secondary main capacity is required, two or more smaller size conductors have to be paralleled. In some networks, where insufficient fault current might cause long sections of secondary mains to be destroyed before the fault is burned clear, sections of secondary mains are fused at each end.

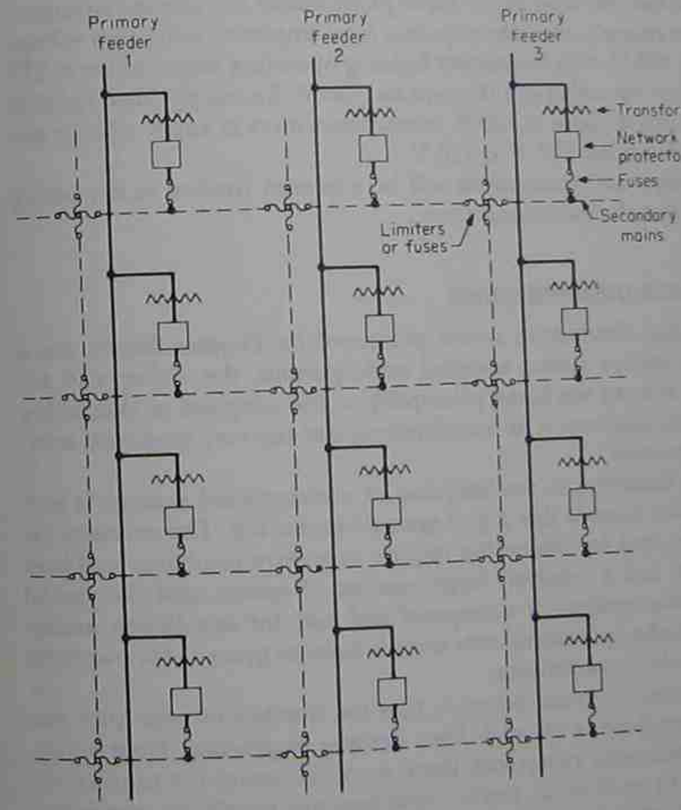


FIG. 2-19 Low-voltage secondary network.

Because these networks may represent very large loads, their size and capacity may have to be limited to such values as can be successfully handled by the generating or other power sources should they become entirely deenergized for any reason. When they are deenergized for any length of time, the inrush currents are very large, as diversity among consumers may be lost, and this may be the limiting factor in restricting the size and capacity of such networks.

Voltages

For all types of service, primary voltages are becoming higher. Original feeder primary voltages of about 1000 V have climbed to nominal 2400, 4160, 7620, 13,800, 23,000, and 46,000 V. Moreover, primary feeders that originally operated as single-phase and two-phase circuits are all now essentially three-phase circuits; even those originally operated as delta ungrounded circuits are now converted to wye systems, with their neutral common to the secondary neutral conductor and grounded.

Secondary voltages have changed from nominal 110/220 V single-phase values to those now operating at 120/240 V single-phase and 120/208 or 120/240 V for three-phase circuits, the 120-V utilization being applied to lighting and small-motor loads while the 208- and 240-V three-phase values are applied to larger-motor loads. More recently, secondary systems have employed utilization voltage values of 277 and 480 V, with fluorescent lighting operating single-phase at 277 V and larger motors operating at a three-phase 480 V. To supply some lighting and small motors single-phase at 120 V, autotransformers of small capacity are employed to step down the 277 V to 120 V.

Secondary voltages and connections will be explored further in discussing transformers and transformer connections.

OVERHEAD VERSUS UNDERGROUND

Although the original distribution system pioneered by Thomas Edison was a direct current low-voltage system installed underground, the widespread expansion of electric systems was based principally on the adoption of alternating current (through the application of transformers) and the very economic overhead type of construction.

While the chief limitation to the adoption of underground systems is economic, there are other reasons that argue against its selection. The necessity for ducts, for manholes, and for cables that require expensive insulation and lead sheaths, short pulls, and a relatively large number of splices, and the special requirements to make equipment waterproof and safe for installation underground all tend to make investment costs several times as great as for overhead systems of comparable characteristics.

Where loads become so great, however, that the number of pole lines and the congestion of conductors on such lines become impractical from safety, operational, and appearance viewpoints, there is no alternative but to place the lines underground. In such areas, traffic conditions are usually so severe that difficulty is experienced in building and maintaining overhead systems; moreover, the heavy traffic itself presents additional hazards from vehicles striking the poles.

While an underground system is not exposed to damage and interruptions from storms, traffic, etc., on the other hand, when trouble does occur, it is very much more difficult and time-consuming to locate and repair than in the overhead system. For this reason, additional provisions and expenditures are made for maintaining service reliability; these include duplicate facilities, throwover schemes, networks, etc. Also, the lesser ability for heat radiation in an underground system does not permit the loading and overloading of conductors and equipment possible with overhead systems.

With plastics taking over the functions of insulation and sheathing in underground cables, and the ability of these materials to be buried directly in the ground, the economic advantage of overhead systems, though still favorable, is markedly reduced. The recent greater emphasis on environment (appearance) also has contributed to a greater pressure for underground installations. Overhead systems will, however, prevail to a very great extent for some time, and will be in almost exclusive use in rural areas.

PART TWO

PLANNING AND DESIGN

CHAPTER 3

LOAD CHARACTERISTICS

In the planning of an electrical distribution system, as in any other enterprise, it is necessary to know three basic things:

1. The quantity of the product or service desired (per unit of time)
2. The quality of the product or service desired
3. The location of the market and the individual consumers

Logically, then, it would be well to begin with the basic building blocks, the individual consumers, and then determine efficient means of supplying their wants, individually and collectively.

CONNECTED LOADS

A good place to start is the tabulation of all electric devices (lamps, appliances, equipment, etc.) that consumers *can* connect to their supply system. The ratings of the devices at specified voltages (and sometimes frequency and temperature) limits are usually contained in the nameplate or other published data accompanying the devices. The devices can be classified into four broad general categories: lighting, power, heating, and electronic. Each of these has different characteristics and requirements.

Lighting Loads

Included under lighting are incandescent and fluorescent lamps, neon lights, and mercury vapor, sodium vapor, and metal halide lights. Nominal voltages specified for lighting are usually 120, 240, and 277 Volts (variations may exist

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from the base 120-V value, e.g., 115 and 125 V). All operate with dc or single-phase ac; the discussion will be in terms of ac, with comments concerning dc operation where applicable.

Incandescent Lighting Incandescent lamps operate at essentially unity power factor. Their light output drops considerably at reduced voltage, being some 16 percent less with a 5 percent lowered voltage, and decreasing at a geometrically faster rate from then on. They are also sensitive to sudden rapid voltage variations, producing a noticeable (and annoying) flicker at variations of as little as 3 Volts (on a 120-V base). Street lighting of the incandescent type can be operated in a multiple or a series fashion. The former operates as other lighting in a multiple or parallel circuit, while the light output for the series type depends on the amount of deviation from the standard value of current flowing through it (usually 6.6, 15, or 20 A); it is sensitive to variations of as little as 1 percent in the value of the current. The life of incandescent lamps is considerably reduced at voltages appreciably above normal.

Fluorescent and Neon Lighting Fluorescent lamps and neon lights operate at power factors of about 50 percent, but usually have corrective capacitors included so that, for planning purposes, they may also be considered to operate at 100 percent or unity power factor. Their light output, per unit input of electrical energy, is considerably greater (25 percent or more) than that of a similarly rated incandescent lamp. The life of fluorescent lamps and neon lights is affected by the number of switching operations they undergo. If fluorescent lamps are used on dc circuits, special auxiliaries and series resistance must be employed; operation is inferior to that on ac, with much less light produced per unit of energy and rated life reduced 20 percent. Neon lights are not usually employed on dc circuits. Fluorescent lamps, neon lights, mercury and sodium vapor, and metal halide lights *may*, if improperly installed or when deteriorating, cause radio and TV interference.

High-Intensity Vapor Lighting Mercury vapor (high pressure) and sodium vapor (high and low pressure) and metal halide lights operate at power factors of 70 to 80 percent, but also are associated with capacitors to raise the effective value to 100 percent. They are not as susceptible to voltage variations as are incandescent lamps. Their light output and life expectancy are greater than those for fluorescent lamps. They may be employed on dc circuits, but require additional starting auxiliaries. They are generally restricted to applications where large amounts of lighting are desirable, such as on expressways, in large manufacturing areas, or in photographic work; they are somewhat more expensive than other types and have the disadvantage of taking some time after being energized before maximum light output occurs.

Power Loads

Generally included in power loads are motors of all sizes: direct current shunt, compound and series types; alternating current single-phase and polyphase, induction and synchronous types; and universal (series) for both dc and ac

TABLE 3-1 SUMMARY OF MOTOR GENERAL CHARACTERISTICS

Type of motor	*Horsepower rating*	*Speed characteristics*	*General capability*
DC shunt	Up to 200	Constant speed or variable speed by armature or field control	Light or medium starting duty
DC compound	Up to 200	Varying speeds up to 25% from no load to full load	Heavy starting duty, heavy loads for short periods
DC series	Up to 200	Variable speeds	Heavy intermittent starting or heavy loads for short periods
AC 1ϕ	$^1/_{50}$ or less to 10	Constant speed; usually with some line means for varying speed	Constant speed; no speed control for light or heavy starting duty
AC polyphase (2ϕ or 3ϕ) induction	Squirrel-cage to 200; wound rotor to 1000	Speed change by field controls or reduced voltage; available for constant torque and constant hp	Constant speed; light, medium, and heavy starting duty
AC 3ϕ synchronous	Usually 300 to 5000+	Constant speed; for power factor control by over- or underexcitation	Constant speed; light, medium, and heavy starting duty and loads

operation. Table 3-1 summarizes the characteristics and general application of these various types of motors.

Single-Phase Fractional-Horsepower Motors The majority of fractional horsepower motors, generally used in appliances of various kinds, are single-phase and operate at power factor values of 50 to 70 percent, but many have corrective capacitors associated with them. When they operate without speed controls or starters, their starting currents may cause lights on the same circuit to flicker; where starts are relatively frequent, as with refrigerators and oil burners, the flicker may be annoying.

Induction Motors Most commercial and industrial ac motors are of the induction type; limited speed control may be obtained in some types by varying the applied voltage. Where accurate speed control is desirable, such as for elevators and printing presses, dc motors are employed, sometimes served from ac sources through motor-generator sets. Induction motors may operate at power factors of 50 to 95 percent but generally operate on the order of 80 to 90 percent; at less than full load, the power factors may drop to 50 to 60 percent. Most large motors for industrial loads (from about 2 hp and larger) are usually three-phase (although many older two-phase motors still exist). Voltage variations of about −10 percent can be accommodated with little lowering of motor efficiency and power factor values.

Synchronous Motors Synchronous motors, usually of large sizes, can operate at power factors leading or lagging 100 percent by adjusting their excitation: overexcitement draws leading current, underexcitement lagging current. Often this type of motor is used for power factor correction for the entire installation.

Since larger motors are apt to cause voltages to dip when starting, circuits separate from lighting circuits are provided to eliminate flicker problems; sometimes separate supply transformers are also provided. Also causing similar flicker problems are chemical and electrolytic devices and mechanical devices operated by coils or solenoids.

Heating Loads

The heating category may be conveniently divided into residential (small) and industrial (large) applications.

Residential Heating Residential heating includes ranges for cooking; hot water heaters; toasters, irons, clothes dryers, and other such appliances; and house heating. These are all resistance loads, varying from a relatively few watts to several kilowatts, most of which operate at 120 V, while the larger ones are served at 240 V; all are single-phase. The power factor of such devices is essentially unity. The resistance of the elements involved is practically constant; hence current will vary directly as the applied voltage. The effect of reduced voltage and accompanying reduced current is merely to cause a corresponding reduction in the heat produced or a slowing down of the operation of the appliance or device. While voltage variation, therefore, is not critical, it is usually kept to small values since very often the smaller devices are connected to the same circuits as are lighting loads, although hot water heaters, ranges, and other larger loads are usually supplied from separate circuits. (Microwave ovens employ high-frequency induction heating and are described below.)

Industrial Heating Industrial heating may include large space heaters, ovens (baking, heat-treating, enameling, etc.), furnaces (steel, brass, etc.), welders, and high-frequency heating devices. The first two are resistance-type loads and operate much as the smaller residential devices, with operation at 120 or 240 V, single-phase, and at unity power factor. Ovens, however, may be operated almost continuously for reasons of economy, and some may be three-phase units.

Electric Furnaces Furnaces may draw heavy currents more or less intermittently during part of the heat process and a fairly steady lesser current for the rest; on the whole, the power factor will be fairly high since continuous operation is indicated for economy reasons. The power factor of a furnace load varies with the type of furnace from as low as 60 percent to as high as 95 percent, with the greater number about 75 or 80 percent. Sizes of furnaces vary widely; smaller units with a rating of several hundred kilowatts are single-phase, while the larger, of several thousand kilowatts, are usually three-phase. Voltage regulation, while not critical, should be fairly close because of its possible effect on the material in the furnace.

Welders Welders draw very large currents for very short intermittent periods of time. They operate at a comparatively low voltage of 30 to 50 V, served from a separate transformer having a high current capacity. Larger welders may employ a motor-generator set between the welder and the power system to prevent annoying voltage dips. The power factor of welder loads is relatively low, varying with the load. The timing of the weld is of great importance and may be regulated by electronic timing devices.

High-Frequency Heating High-frequency heating generates heat in materials by high-frequency sources of electric power derived from the normal (60-Hz) power supply. High-frequency heating is of two types: induction and dielectric.

Induction heating. In induction heating, the material is conducting (metals, etc.) and is placed inside a coil connected to a high-frequency source of power; the high-frequency magnetic field induces in the material high-frequency eddy currents which heat it. Because of the skin effect, the induced currents will tend to crowd near the surface; as the frequency is increased, the depth of the currents induced will decrease, thus providing a method of controlling the depth to which an object is heating.

Dielectric heating. In dielectric heating, a poor conducting material (plastic, plywood, etc.) is placed between two electrodes connected to a high-frequency source; the arrangement constitutes a capacitor, and an alternating electrostatic field will be set up in the material. (Some slight heating will also be set up from the induction effect described above, depending on the conducting ability of the material.) The alternating field passing uniformly through the material displaces or stresses the molecules, first in one direction and then in the other as the field reverses its polarity. Friction between the molecules occurs and generates heat uniformly throughout the material. Such friction and heat are proportional to the rate of field reversals; hence, the higher the frequency, the faster the heating. Because of heat radiation from the surface, however, the center may be hotter than the outside layers. Residential-type microwave ovens are an application of dielectric heating.

Oscillators Oscillators are used as the source of high-frequency power required for both induction and dielectric heating. This is an electronic application, and its characteristics and requirements are described in the following section.

Electronic Loads

The electronic load category includes radio, television, x-rays, laser equipment, computers, digital time and timing devices, rectifiers, oscillators for high-frequency current production, and many other electronically operated devices. In general, these employ electron tubes or solid-state devices such as transistors, semiconductors, etc. Practically all of these devices operate at voltages lower than the commercial power sources and employ transformers or other devices to obtain their specific voltages of operation. They are all affected by voltage variations.

Voltage variations may have a marked effect on electron tubes, affecting their

current-carrying abilities or emissions as well as their life expectancy. Because of the reduced life of the heater element and higher rate of evaporation of active materials from the cathode surface, the cathode life of electron tubes may be reduced as much as one-half by only a 5 percent rise in cathode voltage. Industrial-type tubes are normally designed to operate with a voltage tolerance of ±5 percent, though closer tolerances are often specified.

While voltage variations also affect the operation of solid-state devices, the effect on their life expectancy is not as serious as in the case of electron tubes. On the other hand, variations in frequency of the power supply have little effect on electron tubes but may have a pronounced effect on solid-state devices.

Both types of devices are very sensitive to voltage dips, and, from the power supply viewpoint, operate at essentially unity power factor. Some applications, such as computers, may require an uninterrupted source of supply, and various schemes are employed to achieve this, including the use of motor-generator sets capable of running on batteries for a limited time; the motor-generator set also eliminates the problems of voltage dips on the commercial power supply.

Except for some rectifier applications, most of these devices operate from single-phase ac supply circuits; large rectifiers may be supplied from three-phase sources.

Oscillators for commercial purposes employ industrial-type electron tubes in conjunction with capacitors and inductances that may be varied to produce the desired high-frequency sources. The regular tolerances in voltage supply from commercial power sources are suitable for this application.

CONSUMER FACTORS

It is obvious that an individual consumer is not apt to be using all of the electrical devices that constitute his or her "connected load" at the same time, or to their full capacity. It would evidently be unnecessary to provide facilities to serve such a total possible load, and much more economical to provide only for a probable load, the load creating the demand on the distribution facilities.

Maximum Demand

The actual load in use by a consumer creates a demand for electric energy that varies from hour to hour over a period of time but reaches its greatest value at some point. This may be called the consumer's instantaneous maximum demand; in practice, however, the maximum demand is taken as that which is sustained over a more definite period of time, usually 15, 30, or 60 min. These are referred to as 15-, 30-, or 60-min integrated demands, respectively.

Demand Factor

The ratio of the maximum demand to the total connected load is called the *demand factor*. It is a convenient form for expressing the relationship between connected load and demand. For example, a consumer may have ten 10-hp motors installed; at any one time, some will not be in use and others will not be fully loaded, so that the actual demand may be only 50 hp; the demand factor is 50 divided by 100, or 50 percent.

The demand factor differs for different types of loads, and by averaging a large number of loads of each type, typical demand factors can be obtained. These values are important in determining the size of facilities to be installed for a particular service; they are extremely useful in making estimates in planning new distribution systems or in expanding existing ones.

Load Factor

The load factor is a characteristic related to the demand factor, expressing the ratio of the average load or demand for a period of time (say a day) to the maximum demand (say 60 min) during that period. For example, a consumer household may have a maximum demand of 2 kW during the evening when many of its lights, the TV, the dishwasher, and other appliances are in use. During the 24-h period, the energy consumed may be 12 kWh; thus the average demand or load is 12 kWh divided by 24 h, or 0.5 kW, and the load factor in this case is 0.5 kW divided by 2 kW, or 25 percent. This provides a means of estimating particular consumers' maximum demand if both their consumption and a typical load factor for their kind of load are known.

Diversity

Consumer load diversity describes the variation in the time of use, or of maximum use, of two or more connected loads. Load diversity is the difference between the sum of the maximum demands of two or more individual consumers' loads and the maximum demand of the combined loads (also called the maximum diversified demand or maximum coincident demand). For example, one consumer's maximum demand may occur in the morning, while another's may occur in the afternoon, and still another's in the early morning hours, as shown in Fig. 3-1.

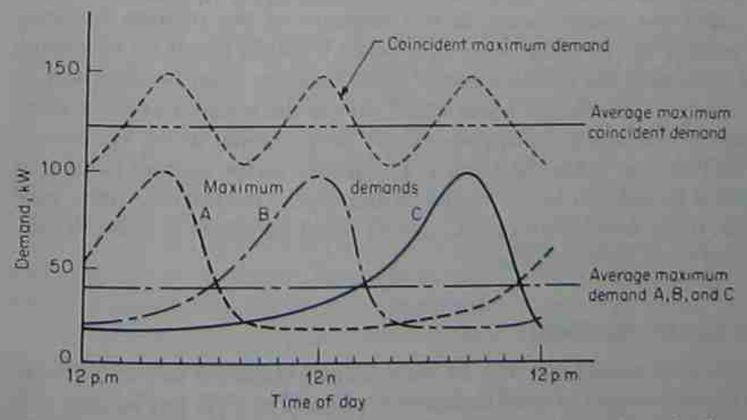


FIG. 3-1 Maximum demands and average maximum demands, coincident and noncoincident.

Diversity Factor

The diversity factor is the ratio of the sum of maximum demands of each of the component loads to the maximum demand of the load as a whole (or the coincident maximum demand). For example, each of the loads mentioned above may have a maximum demand of 100 kW, while the coincident maximum demand on the system supplying the three may be only 150 kW. The diversity factor is then 300 (100 + 100 + 100) divided by 150, or 2, or 200 percent. Such diversity exists between consumers, between transformers, and between feeders, substations, etc. Note that the *demand factor* is defined so that it is always less than 1 or 100 percent, while the *diversity factor* is the reciprocal of the demand factor and is always greater than 1 or 100 percent. This is a most important factor in the economical planning and design of distribution facilities.

Coincidence Factor

The coincidence factor is the ratio of the maximum coincident total demand of a group of consumers to the sum of the maximum demands of each of the consumers.

Utilization Factor

The ratio of the maximum demand of a system to the rated capacity of the system is known as the utilization factor. Both the maximum demand and the rated capacity are expressed in the same units. The factor indicates the degree to which a system is being loaded during the load peak with respect to its capacity. The rated capacity of a system is usually determined by its thermal capacity, but may also be determined by voltage drop limitations, the smaller of the two determining the capacity.

Power Factor

The ratio of power (in watts) to the product of the voltage and current (in volt-amperes) is called the power factor. It is a measure of the relation between current and voltage out of phase with each other brought about by reactance in the circuit (including the device served). Since facilities must be designed to carry the current and provide for losses which vary as the square of the current, and for voltage drops which are approximately proportional to the current, it is necessary that current values be known. The power factor enables loads and losses designated in watts to be converted to amperes. Transformer sizes, wire and cable sizes, fuses, switch ratings, etc., are all based on values of current they must carry safely and economically.

CONSUMER CLASSIFICATION

As aids in planning, consumers may be conveniently classified into certain categories and certain ranges of load densities expressed in kVA per square mile (where this unit is too broad to be useful, watts per square foot for specific occupancies may be used).

Residential	
Downtown, apartment buildings, hotels	10 to 50,000 kVA/mi²
Urban, suburban:	
Large homes (plots)	1 to 5,000 kVA/mi²
Small homes	0.5 to 1,000 kVA/mi²
Two-family homes	1 to 5,000 kVA/mi²
Rural, including farm loads	Less than 0.1 to 5 kVA/mi²
Commercial	
Stores and shopping centers	10 to 500,000 kVA/mi²
Office buildings	10 to 500,000 kVA/mi²
Service centers, warehouses	10 to 500,000 kVA/mi²
Hospitals, nursing homes	1 to 50,000 kVA/mi²
Schools, churches, clubs, etc.	1 to 500 kVA/mi²
Street and area lighting	1 to 500 kVA/mi²
Industrial	
Large manufacturing plants Small manufacturing plants Military bases	Extremely wide variations; consider them as spot concentrations of loads.

Further classifications may be based on such items as the dependence on electric service because of the critical nature of the consumer's operations, under either normal or emergency conditions; the resultant cost if critical processes are interrupted; or the sensitivity of loads to small voltage deviations.

FLUCTUATION IN DEMAND

There are three main factors that greatly influence the magnitude of maximum demand and the time of its occurrence. The most frequent is the weather as it affects light intensity during daylight hours and temperatures throughout the day and year. The sharpest factor and perhaps that of least duration is special events which result in a temporary slowdown of activities or a greatly increased usage of lighting, radio, and TV and associated increases in water pumping, cooking, and other loads. The largest factor is changes in business conditions accompanied by significant changes in industrial demands and consumption; while much less significant, fluctuations in both residential and commercial consumer demands also follow such changes in business conditions.

The nature, magnitude, and time of these fluctuations are generally unpredictable. Some estimate of them can be gleaned, however, from past experiences, which may vary widely in different areas of the country. Provision for these fluctuations should be taken into account in the planning of distribution systems.

FUTURE REQUIREMENTS

Good engineering requires that probable future growth of loads be considered in planning. This is usually provided for by spare capacity in the present design of the several elements, or by provisions for possible future additions or alterations, or both of these. Load growth is rarely uniform throughout an area, so that growths in various parts of a system will be different from each other and from that of the system as a whole.

Economics

How far present capacity should provide for future load is largely a question of economics: the cost of carrying excess capacity until it is needed versus the cost of replacing smaller units with larger when it becomes necessary. This is a problem of the future worth of present expenditure, which is affected by fluctuations in rates of interest and inflation. Standard sizes of the materials and equipment involved automatically provide for a limited amount of spare capacity for growth, so that any economic analysis can only be approximate. The relatively large proportion of labor to material in the construction of a distribution system or its parts lends itself to the installation of capacity greater than its immediate need. Such spare capacity incidentally provides a cushion for accommodating some of the unforeseen fluctuations in demands described above.

Past Performance

Data from past performances, such as total system loads, substation loads, and feeder loads, can be used as a basis for estimating such growth. The variations from year to year, or from month to month, can furnish a trend for such growth; separate trends can be developed for different parts or areas. Where such data are nonexistent or patently unreliable, estimates can include a fixed percentage growth above the values on which planning is made.

Future Performance

To obtain some idea of what may occur in the future, it may be well to look back a generation or two. Earlier, consumers' appliances could be contained in a relatively short table. To attempt to list all the electrically operated devices, appliances, and gadgets presently to be found in homes and commercial establishments would be an almost endless task. To attempt to foretell what may develop in the future would be an exercise in futility.

The advent of widespread air conditioning and space heating, together with the almost universal use of television, not only substantially changed consumers' maximum demands and consumption, but also materially affected loads, diversity, coincidence and (for larger units) power factors, and utilization factors as well.

While the demand factor may indicate how the connected loads are being used, the utilization factor indicates how the capacity of the supply system is being used. Since the capacity of the supply system is determined by its thermal

capability, the increased sustained demand on these facilities will lower their thermal capability, and hence the system capability.

The greater use of electronically operated computers will tend to call for narrower limits of voltage control (regulation and flicker) and a greater degree of service reliability by stiffening the supply distribution system, or through the installation of auxiliary equipment owned and maintained by the consumer or rented as another service by the utility; the choice will be determined by future developments.

VOLTAGE REQUIREMENTS

Electric devices utilizing secondary or low voltage in the United States have been standardized by almost all manufacturers at 120/240 V. While many utilities are following these standards for their systems, there are a significant number operating at 115/230 V and some at 125/250 V (and a small and diminishing number at 110/220 V). For polyphase or three-phase loads, the established ratings are 208 and 416 V for wye-connected systems and 240 and 480 V for delta-connected systems. In a few cities, and some downtown and heavy load centers, network systems supply a single-phase voltage of 277 Volts and a three-phase voltage of 480 V. (A few two-phase 115/230 V systems still exist.)

With distribution systems designed for practical voltage tolerances expressed in volts plus or minus in relation to their normal, "standard," base single-phase voltage of 115, 120, and 125 V, voltages of 110 to 130 V can exist at the terminals of the loads (lamps, appliances, etc.). This is a spread of ±10 V, or ±8.3 percent on a 120-V base, to which a flicker voltage drop of 3 V, or 2.5 percent, should be added to allow for motor starts. This would then give a total spread of 23 V, or 19.1 percent, from +8.3 to −10.8 percent—approximately within most manufacturers' rated maximum tolerances of ±10 percent for motors and heating devices. Closer coordination between manufacturers and utilities could do much to improve this situation. Electronic devices are more sensitive to voltage variations, and difficulty may be experienced with their operation at variations of this magnitude.

Some utilities provide for an estimated voltage drop of up to 2 V in the consumer's wiring by specifying normal voltage at the service point 2 V higher than mentioned earlier, i.e., 122 instead of 120 V (117 and 127 V on other bases). Their designs, however, provide for the same high and low voltage limits, but the variations above and below the usual base are unequal, e.g., 128 V high, 122 normal, 114 low. The 23-V spread and −10.8 percent variation mentioned above will be the same.

Not only does satisfactory operation of lights, appliances, and other devices make for good consumer relations, but the effect of high and low voltages (principally because of unity power factor lighting loads) on both revenue and fuel conservation measures should also be considered.

Higher voltages—660 V, 2400 V, and others—are also employed for larger motors, rectifiers, and some other purposes. Consumers using such large voltages are usually served at primary voltages and meet their own utilization voltage standards.

SERVICE RELIABILITY

Reliability of service generally is interpreted to mean the continuity of service or the lack of interruption to service. For a distribution system, or any of its parts, absolute reliability or continuity of service 100 percent of the time for 100 percent of its consumers is an impossibility, although this goal can be approached. The costs to achieve such goals, even partially, are usually not warranted.

Degree of Service Reliability

As a practical matter, all consumers may not require a uniformly high degree of service reliability. For some consumers, an extremely high degree of service is essential; these may include hospitals, military establishments, some larger theaters, department stores, apartment buildings, hotels, etc., where the safety of the public is concerned; often auxiliary sources of supply are provided to supplement the utility company supply.

For some other types of loads, a high degree of reliability is desirable but not so essential from the public safety viewpoint; smaller apartments and theaters are examples of these, as well as some manufacturing or service processes where interruption may result in substantial monetary losses. To the average residential or commercial consumer, however, a short interruption (and in some cases even an occasional long one) is more of an inconvenience than a hazard or cause for monetary loss.

As a rule, provisions for higher degrees of service reliability involve higher expenditures, for both additional facilities and increased maintenance. The expenditure to provide reliability should bear some proportion to the degree of reliability needed. Various system designs, outlined in Chap. 2, provide for varying degrees of service reliability, from a simple, unsectionalized radial feeder to a low-voltage secondary network supplied from a multiplicity of primary feeders isolated from each other. Each type of service should produce revenues to justify the additional expenditures for achieving the service reliability desired or required; exception may be made for such public services as hospitals and military establishments.

Overhead versus Underground

In this regard, comparisons between overhead and underground systems should be borne in mind. Overhead systems are generally much less costly but are more vulnerable to the hazards of nature (wind, ice, lightning, flood, etc.) and to the actions of people (vehicles hitting poles, kites, etc.); they are, however, easier to maintain, especially as faults can be more easily located and repaired. Underground systems, generally more expensive and less vulnerable to the vagaries of nature and people, nevertheless require longer times for the location and repair of faults that may occur.

Reliability Indices

Service reliability indices are maintained to measure and obtain trends in the performance of a distribution system and its components. Some of these include number of interruptions per consumer served; number of consumers affected per consumer served; number of consumer hours of interruption per consumer served; average duration of interruption (hours) per consumer affected; average number of consumers affected per consumer served; and average duration (hours) per consumer served. Further indices are maintained as to causes and duration of interruptions in the several parts of the system, e.g., on the basis of miles of conductor installed, on the miles of circuit, by voltage classification, or by geographic divisions. Compilation and analyses of these data lend themselves to computer application.

Trends

The trends, over a period of time, not only measure the effectiveness of system designs (and operating procedures), but also point out areas of need for further improvement of service continuity.

CHAPTER 4

ELECTRICAL DESIGN

The electrical design of distribution facilities is based on the loads they are to carry safely and the permissible voltage variations; the final design, however, cannot be divorced from mechanical, economic, and other considerations. Several different designs may serve the same electrical requirements adequately; each, in turn, may be modified by mechanical considerations. The design ultimately selected must reflect economic considerations: specifically, the design that results in the least annual expense in supplying the load or loads in question. This necessarily involves the evaluation of losses, as well as capital, maintenance, and operation expenses. Often, other considerations must also be taken into account including government regulations (at all levels), national and local industry construction and safety codes, taxes, public relations, and some other, intangible requirements.

SERVICES

Rather than design a separate service for each consumer, it is more practical and economical to determine the capacity and construction requirements on a group basis for different types of consumers. The maximum demand for a consumer group is determined by the connected load, to which a demand factor may be applied. The factor can be an estimate based on observation or a logical analysis of the operations of the several devices comprising the load, or it may be obtained from previous experience. Further, service entrance equipment specified by national and local codes (and often installed by the consumer) has minimum ratings based on the number and kinds of circuits installed within the consumer's premises.

Each group represents consumers whose maximum demands fall within cer-

TABLE 4-1 SERVICE DROP SPECIFICATIONS: THREE-WIRE SINGLE-PHASE 120/240 V SUPPLY

Group	*Maximum demand range, kVA*	*Ampere range*	*Conductor size*	
			Copper	*Aluminum*
A	0 to 2	0–20	no. 6	no. 4
B	2 to 5	20–40	no. 4	no. 2
C	5 to 9	40–70	no. 2	no. 0
D	9 to 20	70–150	no. 00	no. 0000

tain ranges, expressed in volt-amperes or kVA, and for which certain conductor sizes are specified, listed in Table 4-1. These values are based on a single-phase three-wire 120/240 V supply via three-conductor self-supporting cable for a 100-ft length, carrying the maximum amperes listed and producing a 1 percent voltage drop. Losses at the maximum loads are less than 2 percent. For longer service drops (sometimes in rural areas), these values may be exceeded.

Three-conductor self-supporting service cables are almost always specified because of their appearance and ease of installation as compared to older (now almost obsolete) open-wire-type services; voltage drop for the same load and length is slightly less than for the open-wire type. The sizes of conductors specified are more than ample to support the mechnical stresses imposed on them, even in severe weather conditions.

Local conditions, including varying costs of both labor and materials, rates of growth, and other factors, may substantially change the values shown in Table 4-1. Services for the relatively fewer larger commercial and industrial consumers served at secondary voltages are usually determined individually.

THE SECONDARY SYSTEM

Transformer-Secondary Combination

The combination of transformers, secondary circuit or main, and the consumers' services makes up the secondary system. Secondary systems are predominantly single-phase, except for larger commercial and industrial consumers, who are supplied from three-phase systems. While the discussion will be limited to single-phase systems, the principles and methods employed in their design will serve for other types of secondary systems.

The number of consumers' services and their loads, the voltage drop, the size of conductors, and the spacing and size of transformers are all variables that are interdependent. They are factors which must be considered in combination to arrive at a satisfactory design. There are many theoretical combinations of these factors that will achieve economical solutions to the problems of design.

For practical purposes, however, these combinations can be reduced to fewer and more manageable numbers. Certain assumptions can be made safely:

1. The load can be considered uniformly distributed along a secondary whose length can be considered fixed. Although not strictly true, this assumption does represent a majority of conditions, but concentrated or scattered loads must be considered separately.
2. The length of secondary circuit is fixed either by geography or by the type of design; e.g., each city block could be fed by one or more secondary circuits. Refer to Fig. 4-1.
3. In practice, the number and sizes of conductors and transformers are limited, usually to two or three in number, and to certain standard sizes because of manufacturing, purchasing, stocking, and construction economies.

The problem then is to determine the proper combination of conductor or wire, transformer, and transformer spacing for the least annual cost, using the materials available while providing for satisfactory voltage variations, including flicker. Also, the design should consider not only present loads, but the economics of supplying future loads as well. Computers permit study of a greater number of combinations.

Conductor Size

It may be well to begin with a determination of the size of conductor. The maximum demand for each of the consumers is known and a coincidence or diversity factor, determined by analyses or from previous experience, applied. Assuming uniformly distributed loads, the loading on each half of the circuit (each direction from the transformer) can be expressed as load density in kilowatts per thousand feet or similar units.

Voltage Drop

For determining voltage drop, the load can be assumed to be concentrated at the midpoint of the secondary main between the transformer and the last consumer, i.e., one-quarter of the length of the conductor from the transformer. The total load connected to one-half the circuit is converted into a coincident maximum demand in amperes.

A maximum tolerable voltage drop (to the last consumer) is assumed and divided by the coincident demand in half the circuit, expressed in amperes. The result will give the maximum permissible resistance of the conductor. On the basis of its length (one-quarter of the circuit), the resistance per unit (1000 ft)

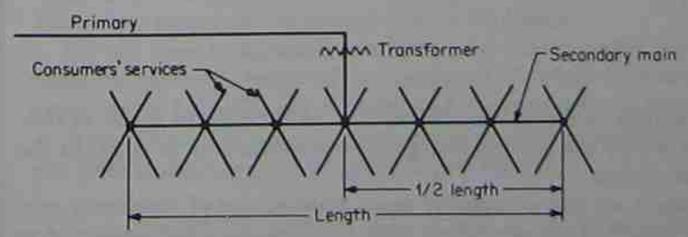


FIG. 4-1 Radial secondary of fixed length and uniformly distributed load.

can be determined. The standard-size conductor whose unit resistance is equal to or less than that calculated can be selected.

This assumes the loads are at or near unity power factor; where this is not so, impedance values based on the spacing between conductors must be used. Also, the drop in one conductor is calculated, which assumes no current in the neutral conductor and a load balanced equally between the two energized or line conductors; where this is not so, voltage drop in the neutral conductor must also be calculated and the greater of the drops in the two line conductors used in selecting the standard-size conductor.

Losses

The next step is to determine the loss in the secondary mains. The value of current and the unit resistance of the conductor are known; for the purposes of determining losses, the full load can be considered to be at one-third the distance from the transformer. This approximate value in watts or kilowatts is multiplied by an estimate of the "equivalent hours" duration to obtain the energy losses in watthours or kilowatthours. This should be multiplied by 4 for the entire length of the two conductors (neglecting the neutral).

It should be noted that while load curves for a particular period (day, month, year) vary with the value of current, corresponding curves for losses vary with the *square* of the current, even though the curves may have a similar configuration. Like the load factor, a *loss factor* is the ratio of average power loss for a certain period of time (day, month, year) to the maximum loss or loss at peak load (for a stipulated time: 15, 30, or 60 min) during the same period. This value can be determined with sufficient accuracy by analysis of a few typical daily load curves for the period involved. This loss factor always lies between the load factor (for long, sustained peak loads) and the square of the load factor (for short, sharp peaks). The loss factor multiplied by 24 equals the daily equivalent hours.

Returning to the energy losses, in watthours or kilowatthours, these are evaluated at the system cost per kilowatthour (which includes not only fuel costs, but carrying charges on equipment, operating costs, and other overheads). This value is compared with the carrying charges (including maintenance costs and appropriate overheads) on the *installed* cost of the conductors. If the two values are reasonably close, the conductor selected is economically satisfactory, according to Kelvin's law.

Kelvin's Law

Kelvin's law is generally expressed as follows: The most economical size of conductor is that for which the annual charge on the investment is equal to the annual cost of energy loss.

If these two values are not reasonably close, another size of conductor may be chosen, or the length of the secondary main (and its connected loads and its coincident maximum demand) may be changed; and either process may be repeated until the values of annual charges and annual cost of energy losses are reasonably close.

EXAMPLE 4-1 REFER TO FIG. 4-1.

Assume that the maximum demand of each consumer is 2 kW and the diversity or coincidence factor is 0.67. The total load on half the length of the conductor is 12 consumers × 2 kW = 24 kW, or 24,000 W; this divided by (approximately) 240 V equals 100 A per conductor, except the neutral, which carries no current (on the assumption that the load is balanced between line conductors). Assume the total length is 1000 ft.

For a voltage spread of ±5 V from the first customer to the last, on a 120-V base, the minimum voltage at the last customer is 115 V; if a 1-V drop in the service is assumed, the voltage required at the last service is 116 V. The maximum voltage at the first consumer is 126 V. The maximum permissible drop in 500 ft of secondary main is 126 − 116 = 10 V.

Assume the total load is applied at one-quarter of the length from the transformer; from Ohm's law,

$$R = \frac{E}{I} = \frac{10 \text{ V}}{100 \text{ A}} = 0.10\ \Omega, \text{ or } 0.40\ \Omega \text{ per } 1000 \text{ ft}$$

From Table 9-2 in Chap. 9, the resistance of no. 7 copper conductor is 0.498 Ω per 1000 ft and its weight is 63 lb per 1000 ft.

For energy loss: Assume the total load (for half the circuit) is applied one-third the distance from the transformer (or 500/3 ft) and the current is 100 A:

$$\text{Loss} = I^2R = 100^2 \times \frac{0.498}{1000} \times \frac{500}{3} = 830 \text{ W or } 0.83 \text{ kW}$$

For the total circuit (neglecting the neutral), multiply by 4, which gives 3.32 kW. Assume a loss factor of 0.75 of the square of the coincident load factor of 0.67, or 0.335.

$$0.335 \times 24 \text{ h} \times 365 \text{ days} = 2937 \text{ equiv h}$$
$$\text{Loss} = 3.32 \times 2937 = 9750.8 \text{ kWh/yr}$$

Assume a cost of 5 cents per kilowatthour, or $487.54 annually. Then estimate the cost of eight sections of no. 7 copper wire: 63 lb/1000 ft × 3 at 80 cents per pound, or $151 for material. Assume the labor cost is $100 a section; then eight sections at $100 plus the $151 for material gives a cost of $951. Assume an annual carrying charge of 20 percent, or $190.20. This is less than half the annual cost of the losses.

For the most economical conductor, the cost of losses should approximate the carrying charge of the conductor installed. By examination, the losses can be halved if the resistance of the conductor is halved.

From Table 9-2, no. 4 copper conductor has a resistance of 0.249 Ω per 1000 ft and a weight of 126.4 lb per 1000 ft.

$$\text{Loss} = I^2R = 100^2 \times \frac{0.249}{1000} \times \frac{500}{3} = 415 \text{ W or } 0.415 \text{ kW}$$

For the total circuit (neglecting the neutral), multiply by 4 to give 1.660 kW. The loss is 1.660 times 2937, or 4875 kWh per year; at 5 cents per

kWh that is $243.77 a year. Now estimate the cost of eight sections of no. 4 copper wire: 126.4 lb per 1000 ft times 3 at 80 cents a pound amounts to $303.36 for material; the labor cost of $100 a section is about the same; then eight sections at $100 plus the $303.36 gives a cost of $1103.36. At an annual carrying charge of 20 percent that amounts to $220.67 a year. This is comparable to the annual cost of losses, $243.77.

Improvement in voltage drop is directly proportional to the lowering of resistance; hence,

$$10\text{-V drop} \times \frac{0.249 \text{ (for no. 7 Cu)}}{0.498 \text{ (for no. 4 Cu)}} = 5.0 \text{ V}$$

This improvement not only will take care of the 3-V additional flicker drop, but will also improve operation of most of the connected devices (and increase revenue). No. 4 copper is apparently the better choice.

Transformer Size

Having determined the *tentative* size of conductor, the next step is to determine the size of the transformer to be installed. The value of the diversified coincident demand for the loads connected to the secondary main having been determined, the nearest standard-size transformer (in kVA) to the demand (in kW) is tentatively selected. To allow for future growth and not to prejudice the life of the transformer, the size chosen is usually larger than the demand.

The most economical load of a transformer is that for which the annual cost of its copper loss is equal to the annual carrying charges of the transformer *installed* plus the annual cost of the core loss. The core loss can be considered constant regardless of the load carried by the transformer. Values of core loss and transformer resistance, both expressed as percentages at full load, vary with the manufacturer, vintage, size, and other characteristics, and are found in the transformer specifications; core loss is usually a fraction of one percent, while resistance is usually less than 2 percent (reflecting the high efficiency of transformers). Here, too, if the two values are not close, another size of transformer may be chosen, or the secondary circuit may be changed so that two or more transformers supply the load. It may be necessary to review the conductor size and loads for the new resulting circuits.

EXAMPLE 4-2

The diversified maximum demand for 20 consumers at 2.25 kW demand each and a load factor of 0.67 is 30 kW. Assume the loads are at or near unity power factor.

The load can be served from one 25-kVa transformer, if the period of overload is not excessive; the next larger standard-size transformer is 50 kVA. From manufacturer's specifications (typical), the no-load loss for the 25-kVA transformer is 0.5 percent of the full load; for 50 kVA, it is 0.4 percent. Resistance as a percentage of full load for 25 kVA is 1.4 percent; for 50 kVA, it is 1.25 percent.

$$\text{No load loss (25 kVA)} = \frac{0.5}{100} \times 25{,}000 = 125 \text{ W or } 0.125 \text{ kW}$$

$$0.125 \text{ kW} \times 2937 \text{ equiv h} = 367 \text{ kWh}$$

At 5 cents per kilowatthour that equals $18.35 a year.

$$\text{No load loss (50 kVA)} = \frac{0.4}{100} \times 50{,}000 = 200 \text{ W or } 0.200 \text{ kW}$$

$$0.200 \text{ kW} \times 2937 \text{ equiv h} = 587.4 \text{ kWh}$$

At 5 cents a kilowatthour that comes to $29.37 a year.

Annual carrying charges: Assume a cost of $8 per kVA for 25 kVA and $6 per kVA for 50 kVA (typical) plus a $100 installation cost. For 25 kVA,

$$25 \times \$8 + \$100 = \$300$$

The carrying charge of 20 percent comes to $60.00. For 50 kVA,

$$50 \times \$6 + \$100 = \$400$$

The carrying charge of 20 percent amounts to $80.00. The total annual carrying charges are:

25 kVA: $18.35 + $60.00 = $ 78.35

50 kVA: $29.37 + $80.00 = $109.37

Load loss: Resistance as a percentage of full load is the same as the loss at full load. For 25 kVA:

$$\frac{1.4}{100} \times 25{,}000 = 350 \text{ W or } 0.350 \text{ kW}$$

Adjust for a 30-kW load:

$$\left(\frac{30}{25}\right)^2 \times 350 = 504 \text{ W or } 0.504 \text{ kW}$$

For 50 kVA:

$$\frac{1.25}{100} \times 50{,}000 = 625 \text{ W or } 0.625 \text{ kW}$$

Adjust for a 30-kW load:

$$\left(\frac{30}{50}\right)^2 \times 625 = 225 \text{ W or } 0.225 \text{ kW}$$

Annual cost of losses:

25 kVA: $0.504 \text{ kW} \times 2937 \text{ equiv h} = 1480 \text{ kWh}$

At 5 cents a kilowatthour the cost is $74.00.

50 kVA: 0.225 kW × 2937 equiv h = 660.8 kWh

At 5 cents a kilowatthour the cost is $33.04.

To compare the annual carrying charges to the cost of losses, for 25 kVA, the respective costs are $78.35 and $74.00; for 50 kVA, they are $109.37 and $33.04.

While the 25-kVA transformer figures are reasonably close and represent the more economical unit, they do so at a probable cost of shortening of life and no provision for future growth. Despite the greater difference, the 50-kVA unit probably should be preferred. As an exercise, different secondary-transformer combinations might be investigated—say, two secondary circuits with two 15-kVA or two 25-kVA transformers, or three secondary circuits with three 15-kVA units.

It is obvious that any secondary-transformer configuration represents a compromise. Much depends on the relative costs of material and labor, which may vary widely from time to time and from place to place. Further, other considerations may play a great part in the final determination; e.g., conductor sizes may change to meet mechanical requirements.

Future Growth

To provide for future growth, loads are adjusted upward by a percentage estimated to represent probable increase over a specified period of time. Facilities to serve these increased loads are designed in the same manner described. The difference in investment costs for each design is evaluated in terms of the future worth of the present increment of cost of the additional facilities provided for growth. This is compared to the cost of installing the facilities at the future time. If it is less, it is desirable to provide for the future load at the time of initial installation. If not, provision for future load growth should be dropped, or scaled down to values and timing that will justify some value of additional cost.

To accommodate the load growth, the transformer and conductors can be replaced with larger ones, or more popularly, the secondary circuit can be divided into two or more parts without changing conductors; a suitably sized transformer is then added to the newly formed secondary circuits. Comparison of costs and annual carrying charges dictate the method selected.

Networks

The analysis described pertains to radial secondary circuits. Where networks are involved, the same principles and methods can be applied by assuming the network to be divided into a number of adjacent radial-type circuits, as shown in Fig. 4-2; no appreciable error is introduced.

The general principles and methods applied to overhead single-phase radial-type secondary circuits may be applied to underground circuits and three-phase three- or four-wire circuits by proper adjustment of terms to fit the cases. With

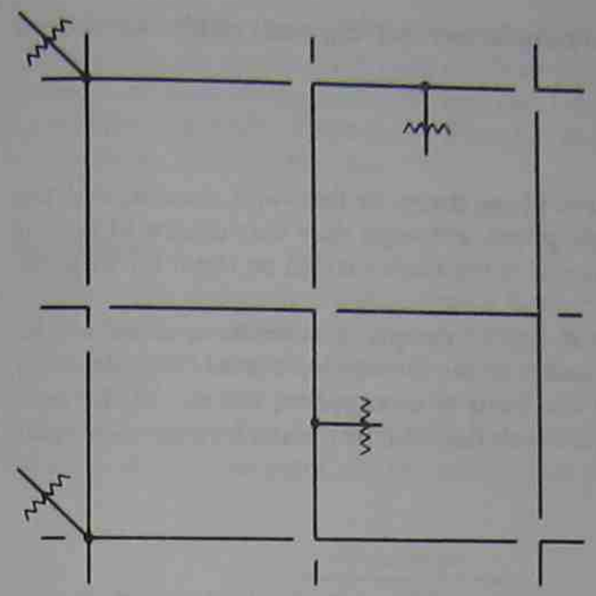


FIG. 4-2 Division of network into radial secondary circuits for design analysis.

underground circuits, the lesser current-carrying capacity of a size of conductor, without overheating, must be taken into account. In network design, the ability to burn clear the conductors in the cable under fault or short-circuit conditions should also be ascertained. These additional considerations may be taken into account after the economic studies are made.

Rural Systems

Where consumers are scattered, such as in rural areas on in the case of three-phase consumers in an area supplied essentially at single phase, the load may be served either by extending the secondary from one transformer or bank of transformers, or by installing a separate transformer or transformers to serve those consumers. Annual carrying charges, including costs of losses, should be compared in selecting the method of supply.

There are many other problems in the design of secondary systems, but they lend themselves to the application of the same basic principles and methods, with proper consideration given to their particular requirements.

THE PRIMARY SYSTEM

The primary system comprises the facilities that deliver power from the distribution substation to the distribution transformers. These take the form of one or more distribution feeders or circuits emanating from the substation, each supplying a portion of the entire load served from that substation. The feeders are made up of mains (or trunks) from which branches (or laterals, or spurs)

are provided to supply the several transformers serving loads within the feeder's designated area.

Feeder Mains

The feeder mains are usually three-phase three- or four-wire circuits, and the branches are predominantly single-phase, although they may consist of two or three phases of the three-phase circuit if the loads carried on them are large or require polyphase supply.

Like the secondary circuit, the design of the primary feeder is based on the maximum voltage variation permissible at the farthest consumer. This depends on the size, type, and location of the loads to be supplied, the size of the conductors, and the operating voltage, which may also be limited by local codes and regulations.

Conductor Size

The size of the conductors for the "main" portion of the feeder is usually larger than that of the branches. While a conductor's size may be reduced as it proceeds farther from the substation because of the smaller load it is normally required to carry, this is seldom done. The size of the conductor of the main near the substation is often carried all the way to its extremities; indeed, it is sometimes made even larger than normal operating conditions would dictate. This not only provides for rapid growth, in which it may be found desirable to divide the load so that the direction of supply may be reversed, but also provides spare capacity to carry all or part of the load of adjacent feeders under contingency conditions. Moreover, the larger conductor size may substantially reduce the voltage variation on this portion of the circuit, permitting greater freedom in the design of the branches. The sizes of wire for both main and branches, as in the secondary system previously discussed, will depend on the voltage variation or regulation desired and on economy, which includes evaluation of losses in the conductors.

Sectionalizing

Provision for moderating the effects of faults on the circuit usually takes the form of fuses and switches. Each of the single-phase branches is connected to the main through a fuse; a fault on the branch will blow the fuse and isolate the fault, leaving the remainder of the circuit intact. A fault on the three-phase main will affect the entire circuit; the size of the conductors may be such that the fault current will be beyond the capability of being safely interrupted by a fuse, and the circuit breaker at the substation is called upon to handle the fault current and disconnect the faulted circuit from the substation bus (which may also supply other circuits). Switches are installed in the main of the feeder, enabling the main to be sectionalized, isolating the fault between two switches or other sectionalizing devices. The unfaulted portion back to the substation is reenergized by closing the circuit breaker at the substation; the unfaulted portion

beyond the fault is energized from adjacent sources; the portion containing the fault will remain deenergized until the fault condition is repaired and the circuit restored to normal operation. Where the feeder main may consist of two or more parts, circuit breakers in the form of "reclosers" may be installed on each of the parts. Refer to Fig. 4-3.

Reclosers

Reclosers are designed to open when a fault occurs on that part of the main in which they are connected; a timing device, however, enables them to reclose a predetermined number of times for short durations. If the fault is of a temporary nature, such as wires swaying together or a tree limb falling on them, the recloser will remain closed and service will be restored; should the fault persist, the recloser will remain open and disconnect that part of the main from the circuit.

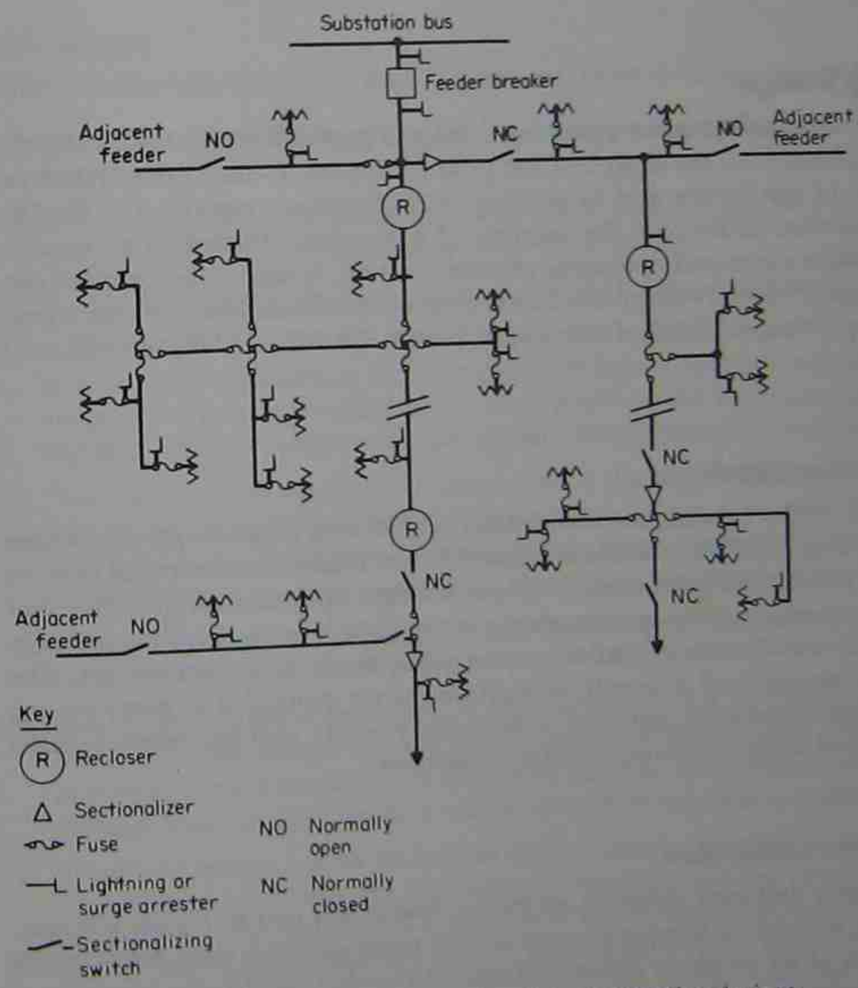


FIG. 4-3 Radial primary feeder showing location of protective devices.

Transformer Fuses

Similarly, a distribution transformer may be connected to the primary main or branch through a fuse. A fault or overload on the transformer or its associated secondary circuit will cause the fuse to blow and disconnect the faulted section from the remainder of the primary circuit.

Load Balancing

On polyphase portions of the feeder, on both main and branches, loads are balanced between phases as closely as practical by connecting transformers and single-phase branches to alternate phases of the circuit; this provides a more uniform balancing of loads along the line (contributing to better load and voltage conditions) than would balancing in large blocks of loads. An approximate method multiplies each load by its distance from the substation; the sum of these, uniformly distributed, should be about the same for each phase.

Operating Voltage

The selection of the primary operating voltage is probably the factor having the greatest influence on the design of the primary system. It has a direct effect on the length of the feeder and its loading, the substation supplying the feeders and the number of feeders, the number of consumers affected by an outage, and on maintenance and operating practices (which, in turn, affect annual carrying charges). Several voltage levels have evolved into "standard" nominal values of primary voltages: 2400, 4160, 7620, 13,200, 23,000, 34,500, 46,000, and 69,000 V.

Delta and Wye Circuits

Many of the older systems employed delta circuits with phase-to-phase voltages approximating 2400 V; as loads increased, it was found economical to convert these into wye circuits with phase-to-phase voltages approximating 4160 V, but with phase-to-neutral voltages remaining at the 2400-V level, permitting the use of the same transformers, insulators, and other single-phase equipment. The wye circuit necessitated a fourth, neutral conductor grounded in many places; later, a single conductor common to both the primary and secondary systems was employed safely, effecting greater economies.

Delta to Wye Conversion

As loads grew and load densities increased, resort was had to higher voltages, making use of subtransmission circuits, a great many of which were delta circuits operating at phase-to-phase voltages of approximately 13,200 V; the wye voltage or phase-to-ground voltage of this level is 7620 V. For the same economy reasons

the 13,200-V phase-to-phase delta subtransmission supply circuits to distribution substations were converted to 13,200-V phase-to-neutral wye circuits having phase-to-phase voltages of 23,000 V. Distribution circuits at these higher voltages required fewer substations, whose acquisition in the more developed areas became increasingly difficult. Circuits at these higher voltages also found employment in rural areas where distances between consumers were greater and load diversities lower.

This process continued with the development of distribution circuits operating at 34,500 and 46,000 V from subtransmission lines operating at these voltages. Advantage is taken of taps on transformers supplying these circuits, sometimes as much as 10 percent, in adapting these feeders to distribution requirements. Other voltages, outside the ranges mentioned above, may be found, e.g., 3000, 6600, 8800, 11,000, and 27,000 V.

Advantages

The principal advantages to such conversions from delta to wye systems are:

1. The wye system affords greater feeder capacity and usually improved voltage regulation.
2. Existing transformers, insulators, and other material can be used; in most cases, spacing between conductors is left unchanged.
3. Single-phase branches need not have any work done on them.
4. Existing secondary neutral conductors can be used as the fourth and neutral conductor in establishing the wye circuit. Where a new neutral conductor is required, it can be installed safely and readily in the secondary position on the pole with no conflict with the higher-voltage energized conductors.
5. The entire circuit need not be converted to the higher voltage at one time, but can be converted piecemeal over a period of time; a portion of the three-phase delta circuit can be maintained from a relatively small step-down transformer (pole-mounted) connected to the new supply three-phase wye circuit.
6. Transformers and other equipment at the substation can be rearranged and reutilized, like those on distribution lines.
7. Where the neutral is grounded at the substation and at many points along the feeder, the voltage stresses on the insulation of the lines, transformers, and other devices are limited to the lowest possible value; should an accidental ground occur on any phase, it will be cleared as the circuit breaker opens.
8. Important savings can be realized in the equipment installed on wye systems: transformers need only one high-voltage bushing; only one cutout and lightning arrester are required (if a completely self-protected transformer is used the cutout can be eliminated); and the single high-voltage line conductor may be mounted on one pin at the top of the pole, eliminating the need for a cross arm (and contributing to a neater appearance of the line).

Disadvantages

There are some disadvantages to the conversions from delta to wye:

1. The load and voltage advantages of the higher voltage apply only on the three-phase main and not on the single-phase branches, as they continue to operate at the existing voltage.
2. A ground on a phase conductor constitutes a short circuit, which will de-energize at least that portion of the circuit. On delta circuits, normally operated ungrounded, one or more accidental grounds on the same phase of the circuit will not cause any interruption to service. (The occurrence of a ground on another phase, however, will create a short circuit between phases, possibly connected together through long lengths of conductors; if the impedance of the intervening conductors between grounds is large, the fault current flowing to ground may not be sufficient to open the circuit breaker at the substation, and much damage can ensue until its magnitude either causes the circuit breaker to open or the conductors burn themselves clear at some point. A delta circuit may be hazardous, as a worker, unaware of a ground that may exist at a point farther away, may come in contact with an ungrounded phase wire.)
3. Because of the grounded nature of the wye system, greater care, reflected in greater maintenance costs (e.g., greater and more frequent tree trimming), may be required to achieve the same degree of reliability as in a delta circuit.
4. The higher voltage and the many grounds in a wye circuit may cause greater interference to communications circuits that parallel the power circuits.
5. Some local regulations and codes may require greater safety factors in the construction of facilities operating at the nominally higher voltages.

Higher-Voltage Circuits

When the need is indicated for a still higher-voltage distribution circuit, major reconstruction and a complete replacement of transformers and other devices is usually necessary. The new higher-voltage circuit is generally designed for immediate wye operation, omitting the intermediate delta operation. In addition to the greater construction costs, additional maintenance and operating costs must be considered in determining the economics of going to higher voltages. Beyond about 15 kV, handling such lines and equipment requires either "live line" tools and methods or the deenergizing of lines and equipment. This latter condition may require additional sectionalizing facilities, including a greater number of extensions between feeders to enable loads to be transferred from the circuit to be deenergized.

The greater load-carrying ability of the higher-voltage primary circuits tends to have them serve larger areas and a greater number of consumers, so that an interruption to an entire circuit will have a greater effect on the area served. Rapid sectionalizing and reenergizing means are therefore more necessary and must be considered in evaluating the service reliability factor in economic studies.

Voltage Drop and Losses

Sizes of conductors of primary circuits are also based on acceptable voltage drop and losses in the conductor and the cost of the facilities; the mechanical requirement may be the decisive factor. The principles and methods given for secondary circuits also apply here.

Branches of the primary circuit may supply from one to a great many transformers. Where only one transformer is involved, voltage drops and losses may be calculated as a concentrated load at the end of the line. Where the branch is relatively long and serves a few transformers widely spaced, these values may be derived from a circuit considered to have a distributed load. Where the length is short, or where a larger, more closely situated number of transformers exist, the circuit may be considered as supplying a uniformly distributed load; the total loads of these transformers can be assumed to be concentrated at a point half the length of the branch (from the tap-off at the main to the last transformer) in calculating the maximum voltage drop, and at one-third the distance (from the tap-off at the main) for calculating losses in the entire length of the branch. For single-phase circuits, the characteristics of the neutral conductor should also be considered. For polyphase branches, each phase and the transformers connected to it may be considered separately; the loads on the separate phases may be considered balanced and the neutral ignored.

Voltage and loss calculations for the three-phase main portion of the feeder may be considered to be concentrated at the tap-off point of the main; these, together with the transformers connected to the main, can be considered as a uniformly distributed load on the main. In some instances, the main may proceed from the substation for a certain length before serving any branches or transformers. In this case, the main can be considered in two parts. The portion to which branches and transformers are connected may be considered to have uniformly distributed load, with voltage and losses calculated accordingly. The untapped portion of the main (from the substation to the first load connected to it) may be considered to be a line with the entire load (the uniformly distributed load mentioned earlier) concentrated at its end (where the first load is connected). The loads may be assumed to be balanced and the neutral neglected. The total voltage drop is the sum of the drops in the two portions of the main; the total losses in the feeder main are also the sum of those in the two portions.

In considering the total annual cost of the primary line for comparison with the annual cost of the losses in it, in addition to the cost of the conductors in place, the cost of poles, insulators, switches, etc., must also be included as well as the annual costs of operation and maintenance.

Voltage drops and energy losses are reduced substantially as the applied voltage values increase. For primary circuits, particularly those operating at higher voltages, these values are considerably less than for comparable secondary quantities.

As indicated earlier for secondary systems, the most economical size of conductor for a proposed load (present, future, and contingency) may be determined by an analysis of the annual carrying charges for the system considered and the annual cost of energy losses in the conductor.

Conductor Size

A conductor size, though as near as possible to that indicated by the economic analysis, may still be subject to other considerations. The permissible voltage drop in the several parts of the circuit will determine the minimum size of conductor; if this size is greater than the indicated economical size, economy is disregarded; if smaller, the economical size should be chosen.

The choice of conductor size, however, will not only be limited to those which will carry the load with satisfactory voltage variations, but the size chosen must also be mechanically able to support itself even under unfavorable weather conditions, if overhead, and to withstand installation cable stresses if underground. As a rule, for overhead systems, conductors smaller than no. 6 AWG medium- to hard-drawn copper are not recommended, because of strength limitations, nor are those larger than no. 4/0, because of the difficulty in handling. For underground systems, soft-drawn copper may be used because of its ease in handling; no. 6 or no. 8 is the minimum for reasons of strength as well as load and voltage limitations, and no. 4/0 and 350,000-cmil are the largest sizes that may burn themselves clear under short-circuit conditions; where a conductor larger than these sizes is required, two smaller-size conductors in parallel may be substituted.

As indicated earlier for secondary systems, the sizes of conductors employed for primary (and secondary) circuits should be standardized for any one system, and limited to relatively few in number. Such standardization simplifies, and adds to economy in, their manufacture, purchasing, stocking, and handling in the field.

While the discussion applies principally to radial-type systems, it is also applicable to primary network systems, the network being divided into a number of adjacent radial-type circuits; the analysis will be very similar to that indicated for secondary networks.

VOLTAGE REGULATORS

Where the most economical size of conductor results in voltage drops or regulation greater than permissible, alternatives may be considered. These may include the installation of larger-size conductors, or a voltage regulator, or both, economics indicating the selection. Here the economic comparison is based on the annual carrying charges of the conductor installed together with those for the regulator—the energy losses in the regulator and its operating and maintenance costs.

Sizes

Regulator sizes specify the percentage of regulation in definite steps—e.g., 5 percent, 7½ percent, 10 percent, etc.—and hence the size of conductor that will give satisfactory regulation with each size of regulator is determined and the total annual costs for each alternative are compared. These are also compared with the annual costs for conductors that would prove satisfactory without a regulator. The alternative with the least total annual cost is the one preferred.

Controls

The regulator does not reduce the voltage variation along the feeder with which it is associated. It does reduce the voltage spread at the point of supply to that feeder, or a portion of the feeder. Refer to Fig. 4-32.

The regulator can be applied at the substation to reduce the supply-voltage spread on individual feeders or on the bus supplying a number of feeders. Unless the feeders are of about the same length and have the same kinds and magnitudes of loads, individual feeder regulators are generally preferred.

Where feeder voltages drop below permissible limits, voltage regulators may be inserted in the primary circuit to correct the condition. They should be located at the point on the feeder where, under full load, the voltage falls below the permissible limit; they are usually located some distance before this point in order to provide for some future increase in the loading of the feeder. Voltage regulators may be of either the induction type or of the tap-changing-under-load (TCUL) type; these are described in Chap. 12. They may be either single-phase or three-phase units.

Voltage-Regulating Relays

Regulators are usually controlled automatically, though they may be manually operated in association with a voltmeter. In older units (many of which still exist), the element for automatic control is essentially a *contact-making voltmeter*, which makes a contact to cause the regulator to raise the voltage when the voltmeter reads the minimum permissible outgoing voltage, and another contact to lower the voltage when the voltmeter reads the maximum permissible outgoing voltage. In newer units, electronic (solid-state) relays accomplish this function without any moving parts.

Line-Drop Compensators

Where it is desired to regulate or maintain the voltage band at some distance from the source of the distribution feeder (e.g., at the first consumer or at some other point farther out on the feeder), a *line-drop compensator* is used with the contact-making voltmeter. The line-drop compensator is an electrical miniature of the line to the point where the regulation is desired. See Fig. 4-4. Resistance and reactance values of the line are calculated and a resistance and reactance proportional to these values are set on the compensator; the line current, through a current transformer, flows through the compensator, producing a voltage drop proportional to that current. This drop is subtracted from the line voltage at the regulator terminals, thus applying at the contact-making voltmeter a voltage (varying with the load) representing the voltage at the point of compensation on the feeder. Refer to Fig. 4-32.

The point of compensation should be selected so that the consumer farthest from the regulator will have at least the lowest permissible voltage under the heaviest load while the consumer nearest the regulator will have the highest permissible voltage under light-load conditions.

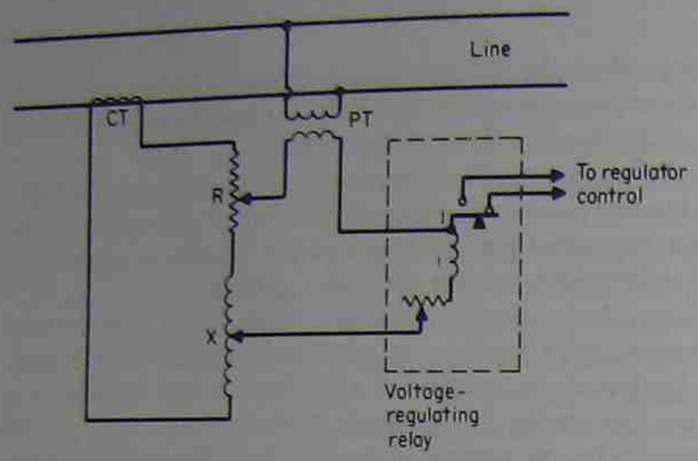


FIG. 4-4 Schematic diagram of line-drop compensator and voltage-regulating relay.

Networks

Where the regulators (at the substation) control the voltage on feeders supplying a secondary network, steps must be taken to prevent the regulators from becoming "unstable," i.e., some moving to their maximum increase position while others on adjacent feeders move to their minimum positions; this condition can reverse itself and be continuous, not only creating periodic voltage variations that might be annoying, but creating troublesome circulating currents. This is especially true for three-phase regulators that cause a phase displacement. Mechanical interconnections, *in-phase* regulators, and *phase shifters* are sometimes used to prevent this instability. Where two feeders only are involved, stability can be maintained by using the current from one line in the compensator for the other.

On some feeders, a lowering in voltage may be necessary under periods of light load or where other means of raising voltage are employed, such as taps, boosters, and capacitors.

TAPS

Where voltage improvement can be obtained by some fixed amount which will not cause voltages to exist outside permissible limits during both light and heavy load conditions, taps can be changed on the distribution transformers on certain portions of the feeder.

For example, assuming an evenly distributed load on a feeder, the taps on the transformers in the first third of the feeder from the substation can be changed to lower the secondary voltage a fixed amount; the taps on the second or center third of the feeder may be left on their normal setting; and those on the farthest third of the feeder may be changed to raise the secondary voltage a fixed amount.

The taps on the transformers merely change their ratios of transformation. If the normal ratio is (say) 20 to 1 to give a secondary voltage of 120 V, tap changes on those nearest the substation would result in a 21 to 1 ratio and a voltage drop of approximately 6 V, which, if subtracted from a high permissible voltage of 126 V, will still leave a voltage of 120 V; or put another way, the tap change allows the highest permissible voltage at the substation to be raised 6 V without exceeding the permissible high-voltage limit at the first consumer. Similarly, on those farthest from the substation, tap changes can result in a 19 to 1 ratio and a voltage increase of 6 V, allowing additional voltage drops in the feeder up to 6 V before the permissible low voltage at the last consumer is not met.

BOOSTERS

An increase or decrease in the primary voltage can also be obtained by the installation of a transformer in the line to provide a fixed voltage drop. A distribution transformer, connected as an autotransformer, may be used to boost or buck the feeder voltage at the point of its installation. The percentage of boost or buck will depend on the ratio of the primary and secondary coils, including the tap used, of the transformer selected. The capacity of the unit is determined by the current-carrying capacity of the secondary coil, through which the entire line current will flow. (Refer to Fig. 4-6*k*.)

The use of a distribution of normal design in this way is usually done in an emergency. It is an unsafe method, as the secondary is connected directly to the primary. For safety reasons, special attention should be given when connecting or disconnecting such units.

CAPACITORS

Voltage regulation can also be improved by the application of shunt capacitors: at the substation, out on the primary feeder, or both. The current drawn by a capacitor has a leading power factor characteristic and will cause a voltage rise from the location of the capacitor back to the current source. The voltage rise will be equal to the reactance of the circuit (back to the source) multiplied by the capacitor current (taking into account their vector relationship). The rise in voltage is independent of the load on the circuit and is greatest at the location of the capacitors and decreases to the source.

Capacitors provide a constant increase in the level of voltage at the location of the capacitor that is the same under any load condition of the feeder, from light to heavy loading. If capacitors are installed so that they may be switched on during heavy load periods and off at light load periods, voltage regulation can be improved. If a bank of capacitors is so arranged that some of its units can be switched on and off separately, voltage regulation can be improved even further.

Primary Feeder

When they are installed out on a primary feeder, the capacity of the capacitors (in kVA) and the location on the feeder where they are to be installed depends

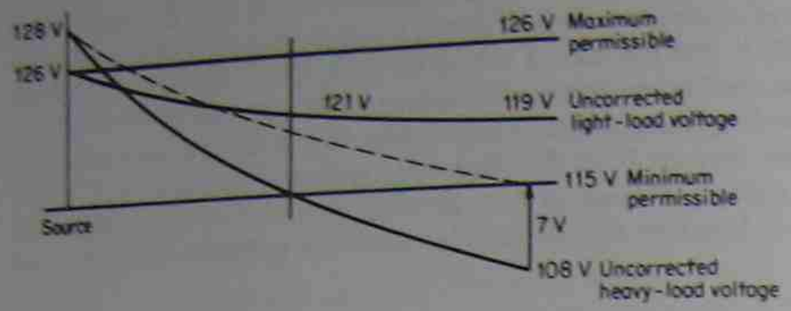


FIG. 4-5 Voltage improvement using capacitors.

on the manner in which the loads are distributed on the feeder, the power factor of the loads, the feeder conductor size and spacing between conductors, and the voltage conditions along the feeder. Like the line voltage regulator, capacitors should be installed approximately at the point where the voltage at heavy load is at the minimum permissible level (with some consideration given to load growth). The conditions under light load will determine what portion of the capacitance installed may be fixed and what may be switched.

EXAMPLE 4-3 Refer to Fig. 4-5.

Assume a 7200-V primary, single-phase. The minimum voltage at the last consumer is 108 V (uncorrected), and the minimum voltage at the capacitor point is 115 V (under heavy load). Thus the minimum correction required is 7 Volts.

The maximum voltage at the last consumer is 127 V (light-load-corrected), and the maximum voltage at the capacitor point is 128 V (also light-load-corrected). Assume the reactance from the source to the capacitor point is 0.277 Ω. Then

$$I_C = \frac{E}{X_L} = \frac{8}{0.277} = 28.8 \text{ A} \qquad \text{heavy load}$$

and

$$\frac{2}{0.277} = 7.22 \text{ A} \qquad \text{light load}$$

$$1 \text{ kVA} = \frac{1000}{7200} = 0.14 \text{ A/kVA}$$

To determine the capacity required to raise the voltage 8 V at heavy load:

$$\text{Capacitor kVA} = \frac{28.8}{0.14} = 206 \text{ kVA}$$

Say eight 25-kVA units.

At light load, the 128 V at the capacitor must be lowered a minimum of 2 V, and the 127 V at the last consumer must be lowered a minimum of 1 V.

To determine the capacity to be disconnected to lower the voltage 2 V at light load:

$$\text{Capacitor kVA} = \frac{7.22}{0.14} = 51.6 \text{ kVA}$$

Say two 25-kVA units.

Substations

Capacitors may also be installed at substations on the bus supplying the outgoing distribution feeders. They are usually installed in relatively large-capacity banks, and it is usually necessary to switch off portions of them at periods of light load to prevent excessively high outgoing voltage. The voltage drops along the feeders supplied from this substation bus remain the same as do their power factors, since the relationship between the voltage and current flowing through each of the feeders supplying their loads is unaffected by the capacitors added to the substation bus. The voltage level of each of the entire feeders is raised depending on the capacitance added at the substation, but the voltage spread on each feeder remains the same. In many instances, the principal reason for the capacitors at the substation bus is not necessarily to control the bus voltage, but, by counteracting the effect of induction (or reactance), to reduce the current to that necessary to supply the load at approximately unity power factor, thereby permitting larger loads to be supplied by the same transmission and substation facilities.

Series Capacitors

Capacitors can also be installed in series with primary feeders to reduce voltage drop, but they are rarely employed in this fashion. Where shunt capacitors, connected in parallel with the load, correct the component of the current due to the inductive reactance of the circuit, series capacitors compensate for the reactive voltage drop in the feeder.

A capacitor in series in a primary feeder serving a lagging-power factor load will cause a rise in voltage as the load increases. The power factor of the load through the series capacitor and feeder must be lagging if the voltage drop is to decrease appreciably. The voltage on the load side of the series capacitor is raised above the source side, acting to improve the voltage regulation of the feeder. Since the voltage rise or drop is produced instantaneously with the variations in the load, the series capacitor response as a voltage regulator is faster and smoother than the induction or TCUL-type regulator; moreover, no contact-making voltmeter and load compensator are required for its operation.

During fault conditions, however, the large fault current passing through the series capacitor can develop excessive voltage across the capacitor, sufficient to cause its destruction. It is essential, therefore, that it be taken out of service as quickly as possible. A resistor and air gap are connected between [illegible] terminals of the series capacitor. When the voltage becomes sufficiently high, the gap

breaks down and permits the capacitor to be short-circuited through the resistor; the resistor dampens out any oscillatory discharge current so the gap can break down and restrike repetitively without damaging the capacitor. Auxiliary relays operate to short-circuit and bypass the capacitor if the fault persists.

Because of the potential hazard, series capacitors as voltage regulators are usually restricted to supplying single large consumers where flicker may result from frequent motor starts or from electric welders, furnaces, and similar devices that may cause rapid and repetitive load fluctuations.

REACTORS

Primary

Where relatively high-voltage primary feeders (23-kV and above) operate in metallic sheathed cables and are rather long, the capacitance effect of the cable may cause undesirable voltage rises along the feeder. Reactors connected between the primary conductors and the neutral or ground are inserted in the feeder at appropriate points to hold customer voltages within permissible limits; shunt reactors act in a similar fashion as shunt capacitors.

Secondary

Where two or more transformers supply a common load, the transformers may not share the load equitably. This may be due to differing secondary voltages at the transformers' terminals either because the primary feeder voltages are different, or because the transformers have different impedances. Reactors inserted in the secondary leads of one or more of the transformers are installed in an effort to equalize the voltages and make the transformers share the load equitably. This phenomenon is often evident in low-voltage secondary networks, and especially in "spot networks." In this latter case, the terminals of the reactor coil of one transformer are interconnected to those of another transformer with the leads reversed. Hence, the voltage drop in each of the reactances is added to or subtracted from the several secondary voltages, tending to balance the load among the several supply transformers.

TRANSFORMERS

Transformers play a central part in the design of distribution systems; they reduce the high voltage of the primary to the low utilization voltage of the secondary. As with other elements of the distribution circuit, the energy losses and the drop in voltage due to the current flowing through them to supply loads are factors in the selection of the size and location of transformers.

Losses

Energy losses in a transformer are generally of two kinds:

1. No-load loss (also known as iron or core loss) results from the magnetizing or exciting current flowing in the primary coil regardless of the load carried.

Its value of about 0.5 percent at rated full load may vary substantially at voltages above or below rated values. Although small as a power loss, it goes on constantly, accumulating into significant annual energy losses (in kilowatthours).

2. Full-load losses (earlier known as copper losses) result from the load current passing through the resistance of both primary and secondary coils. This I^2R loss varies with the square of the current carried and therefore depends on the shape of the load curve. Since the current flowing in a circuit is inversely proportional to the voltage, the copper loss is inversely proportional to the square of the voltage; hence, for the same-size transformer, the losses in the primary coil are substantially less as the voltage ratings increase.

No-load and full-load losses for the various sizes of transformers vary with different manufacturers and are usually specified by them in some percentage of normal voltage and full-load ratings. No-load losses may be expressed in watts or as a percentage of the full rated load in watts.

Impedance—Resistance and Reactance

Copper losses, as well as voltage regulation, require that resistance and reactance values (and their vector sum, impedance) of the transformer be known. These three values represent both primary and secondary coils of the transformer. They are usually specified by the manufacturer as a percentage related to the percentage voltage drop. That percentage gives a value in volts when applied to either primary or secondary voltage; from that voltage and the full rated current the values in ohms may be derived.

The percentage impedance given for a transformer represents (and is equivalent to) the percentage drop from normal rated primary voltage that would occur when full rated load current flows in the secondary; thus the percentage impedance can be used to determine the impedances (in ohms) of the primary and secondary as follows. In reference to the primary,

$$Z_p = \frac{\% Z_p}{100} \frac{E_p}{I_p}$$

and in reference to the secondary,

$$Z_s = \frac{\% Z_s}{100} \frac{E_s}{I_s}$$

where I_p, E_p, I_s, and E_s are all full rated load-current values. Since $E_p = nE_s$, where n is the transformer turn ratio,

$$\frac{Z_p}{Z_s} = \left(\frac{E_p}{E_s}\right)^2 = n^2$$

The relationship between resistance R, reactance X, and impedance Z,

$$Z^2 = R^2 + X^2$$

applies whether the quantities are in percentages (% Z, % R, % X), in ohms referred to the primary (Z_p, R_p, X_p), or in ohms referred to the secondard (Z_s,

R_s, X_s). Since the percentage impedance and the percentage resistance for a given size of transformer are specified by the manufacturers, the percentage reactance may be computed:

$$\%\, X = \sqrt{(\%\, Z)^2 - (\%\, R)^2}$$

and the percentage resistance and percentage reactance can be reduced to ohms, referred to either the primary or the secondary side of the transformer:

$$R_p = \frac{\%\, R}{100} \frac{E_p^2}{\text{transformer kVA} \times 1000} \quad \Omega$$

$$R_s = \frac{\%\, R}{100} \frac{E_s^2}{\text{transformer kVA} \times 1000} = \frac{R_p}{n^2} \quad \Omega$$

$$X_p = \frac{\%\, X}{100} \frac{E_p}{\text{transformer kVA} \times 1000} \quad \Omega$$

$$X_s = \frac{\%\, X}{100} \frac{E_s^2}{\text{transformer kVA} \times 1000} = \frac{X_p}{n^2} \quad \Omega$$

The copper loss W, in watts at full load, is caused by the current passing through the resistance of the windings. Thus,

$$W = R_p I_p^2 = R_s I_s^2$$

Since the manufacturer specifies the copper loss, the equivalent resistance can be computed:

$$R_p = \frac{W}{I_p^2} \text{ and } R_s = \frac{W}{I_s^2} \text{ and } \frac{R_p}{R_s} = \frac{I_s^2}{I_p^2} = n^2$$

Voltage Drop

The determination of voltage drop through the transformer employs values of impedance, resistance, and reactance, as indicated in the previous discussion of primary and secondary systems. The drop must be referred to either the primary or the secondary side:

$$\text{Voltage drop (primary)} = I_p(R_p \cos \theta + X \sin \theta)$$

where I_p is the load current and $\cos \theta$ the power factor.

$$\text{Voltage drop (secondary)} = I_s(R_s \cos \theta + X \sin \theta)$$

$$\frac{\%\text{ voltage drop}}{100} = \frac{\text{voltage drop (primary)}}{\text{rated primary voltage}} = \frac{\text{voltage drop (secondary)}}{\text{rated secondary voltage}}$$

These same phase-to-neutral values of Z, R, and X can also be employed in polyphase circuits. Since phase to phase voltage (for a three-phase circuit) is $\sqrt{3}$ times the phase-to-neutral value and the voltage value in the equation is squared, the ratio between phase-to-phase and phase-to-neutral characteristics is 3 to 1. If the transformer kVA value is the three-phase total kVA and E_p is the phase-to-phase voltage,

Phase-to-phase:

$$R_p = \frac{\%\, R}{100} \frac{E_p^2 \times 3}{3\phi \text{ kVA} \times 1000} \quad \Omega$$

$$X_p = \frac{\%\, X}{100} \frac{E_p^2}{3\phi \text{ kVA} \times 1000} \quad \Omega$$

$$Z_p = \frac{\%\, Z}{100} \frac{E_p^2}{3\phi \text{ kVA} \times 1000} \quad \Omega$$

Phase-to-neutral:

$$R_p = \frac{\%\, R}{100} \frac{E_p^2}{3\phi \text{ kVA} \times 1000} \quad \Omega$$

X_p and Z_p will use the same expressions as for single-phase values, but with total three-phase transformer capacity in kVA.

Transformers connected in parallel or in banks should have impedances as nearly the same as possible, within a fraction of a percent. Transformers not having essentially the same impedance when in parallel will not divide the load in proportion to their ratings, and when in wye or delta banks they will cause circulating current to flow that reduces the capacity of the transformers, increases losses, and results in excessive heating.

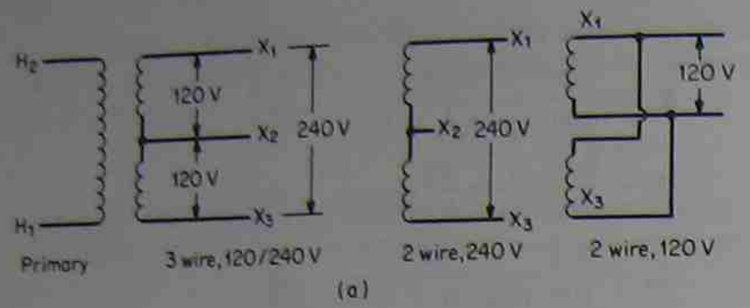
Transformers supplying radial secondary circuits, whether single-phase or in banks, have a reactance of from 3 to 5 percent, which results in reasonable voltage regulation. Transformers supplying low-voltage secondary networks have a higher reactance, sometimes as high as 10 percent, to ensure a better load division among the transformers, particularly under contingency conditions when one (or more) of the supply feeders may be out of service.

Transformer Connections

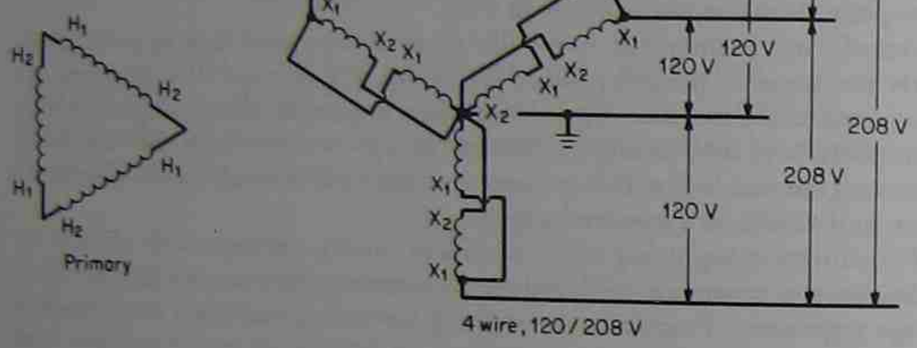
Transformer connections were already described in Chap. 2, together with some vector diagrams of current and voltage relationships; Fig. 4-6*a* through *k*, in which connections involving transformer polarity are shown, also portray those most apt to be found on distribution systems.

Single-Phase The standard single-phase distribution transformer is generally designed with the secondary coil in two parts, which may be connected in parallel for two-wire 120-V operation, or in series for three-wire 120/240 V operation. The latter is the most commonly used connection for single-phase distribution systems. The load is balanced between two 120-V circuits; with perfect balance, no current flows in the center or neutral wire. Refer to Fig. 4-6*a*.

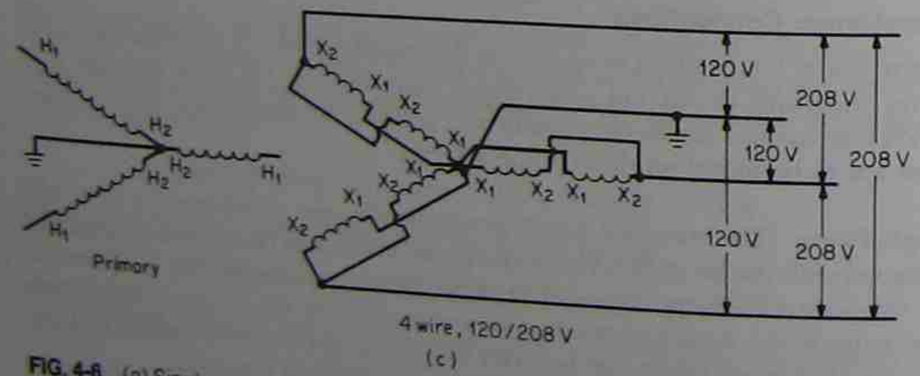
Three-Phase For three-phase systems, the wye-connected secondary can serve single-phase loads at 120 V for each phase; when the load is balanced, the neutral will carry no current. This connection can also supply three-phase power loads at 208 V between phases, and it is best adapted for use on secondary networks. It does have the disadvantage of a lowered three-phase (208 V) voltage supply



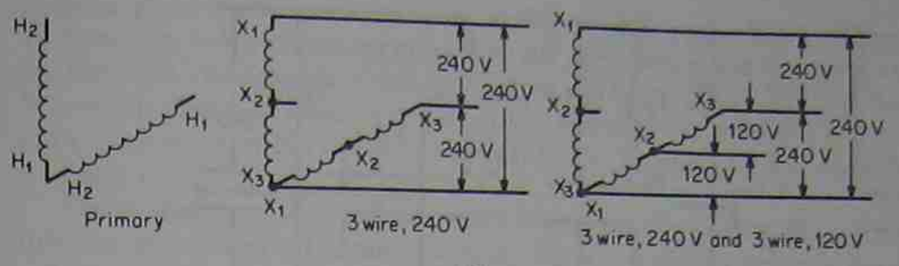
(a)



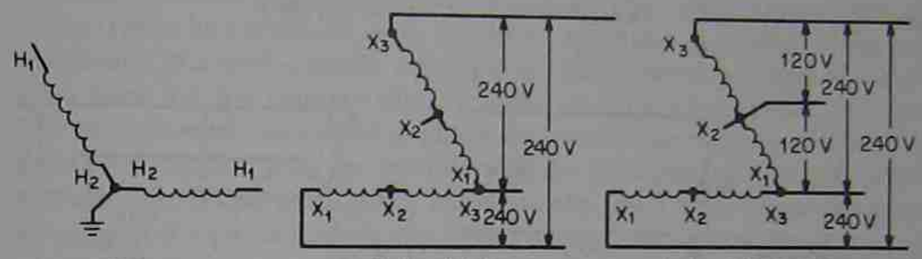
(b)



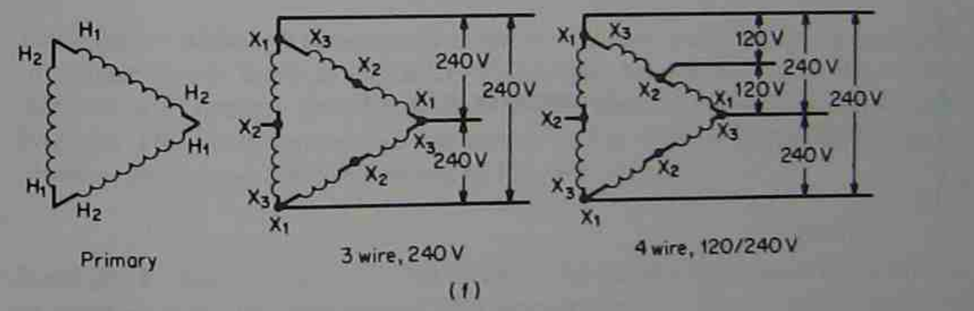
(c)



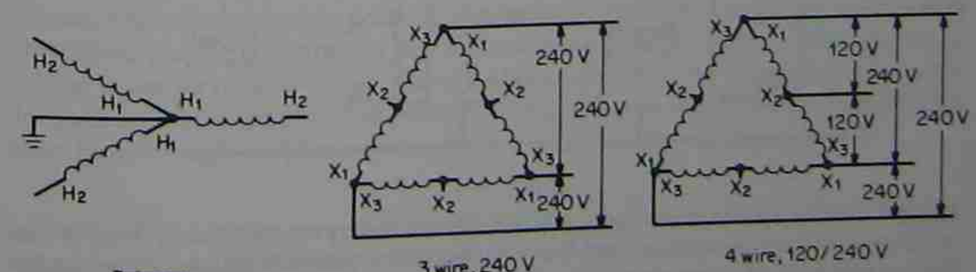
(d)



(e)

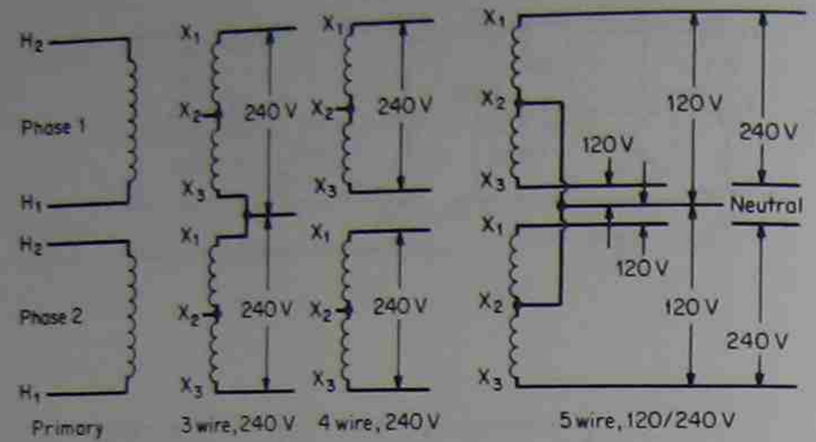


(f)

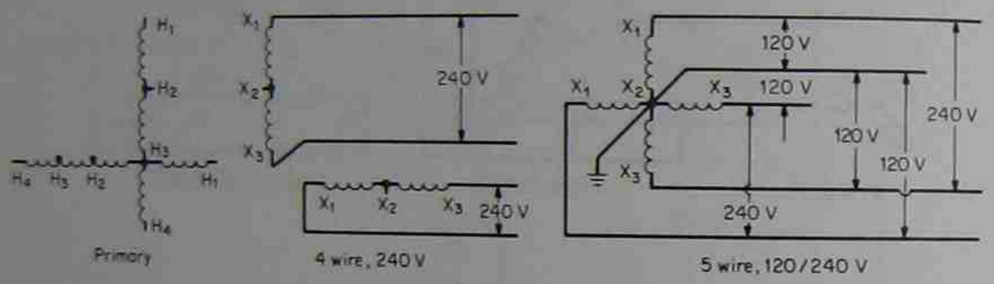


(g)

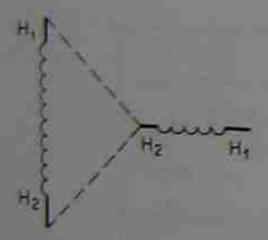
FIG. 4-6 (*a*) Single-phase two- and three-wire secondary connections. (*b*) Three-phase delta-to-wye four-wire secondary connection. (*c*) Three-phase wye-to-wye four-wire secondary connection. (*d*) Three-phase open delta three- and four-wire secondary connections. (*e*) Three-phase open wye–open delta three- and four-wire secondary connections. (*f*) Three-phase delta-delta three- and four-wire secondary connections. (*g*) Three-phase wye-delta three- and four-wire secondary connections.



(h)

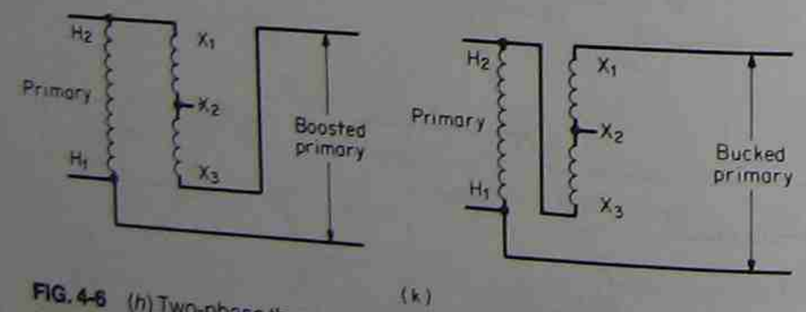


(i)



Secondary as in Fig. 4-6i.

(j)



(k)

FIG. 4-6 (*h*) Two-phase three-, four-, and five-wire secondary connections. (*i*) Three-phase/two-phase (or vice versa) four- and five-wire secondary connections (also known as the Scott connection). (*j*) Three-phase/two-phase (or vice versa) four- and five-wire secondary connection. Secondary connections same as for Fig. 4-6*i*. (*k*) Single-phase boost-buck primary connections.

to three-phase motors with standard ratings of 240 V; the 32-V difference, or 13.3 percent, below the rating may affect the operation of the motors. To remedy the situation, the secondary voltage is often raised to 125 V, yielding about 217 V between phases or about only 10 percent less than the standard 240-V rating, more likely to be within the design tolerances for satisfactory operation. See Fig. 4-6*b* and *c*.

The primary supply to this four-wire wye secondary connection can be either delta- or wye-connected; in the latter case, the wye is usually grounded to prevent voltage unbalances from unbalanced secondary loads from distorting phase relationships. Often, further economy is achieved if both the primary and secondary circuits employ a common neutral conductor.

Small amounts of three-phase power loads may be supplied on a chiefly single-phase system by a small-diameter-conductor extension of another phase and the installation of a small-capacity single-phase transformer in an open-wye or open-delta bank (on the primary side) with the principal single-phase transformer. The secondary of this second single-phase transformer is connected in an open-delta configuration with the secondary of the principal transformer, providing a small three-phase delta power supply to the small three-phase requirement. Because of the phase relationship of the voltage and current, however, only 86 percent of the capacity of this second, small single-phase transformer can be utilized. This is an economical method of supplying a small, isolated three-phase load in the midst of an area supplied from single-phase facilities. See Fig. 4-6*d* and *e*.

Two-Phase Although two-phase systems are virtually extinct, there are still some two-phase power loads in existence. These may be supplied from three-phase delta or wye systems through proper connections of two single-phase transformers. Two such connections are shown in Fig. 4-6*h*, as are those for three-phase to two-phase (and vice versa) in Fig. 4-6*i* and *j*.

Boost-Buck Earlier, reference was made to the use of single-phase transformers to boost or buck the line voltage of a primary feeder. Here, the primary and secondary of the transformer are connected in series, essentially operating as an autotransformer. The incoming primary coil is connected across the primary circuit, while the outgoing primary is connected between a common terminal of the primary of the transformer and the terminal of the secondary coil; the voltage of the secondary coil is either added to boost the primary voltage or subtracted to buck it. The capacity of the secondary coil limits the primary current that may flow through it. These connections are also shown in Fig. 4-6*k*.

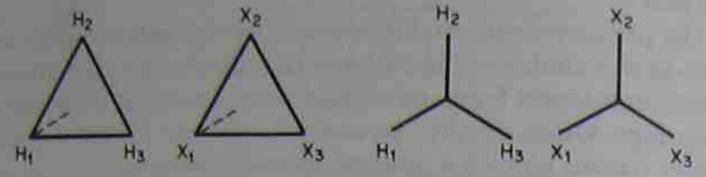
Three-Phase Units

Connections for three-phase transformers and lead markings are shown in the IEEE classification of polarities illustrated in Table 4-2.

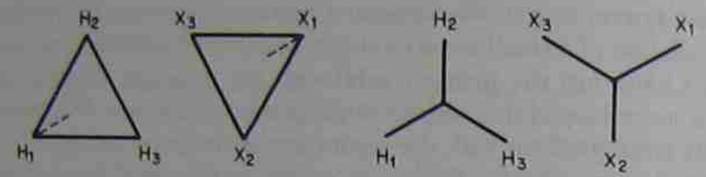
TABLE 4-2 IEEE CLASSIFICATION OF POLARITIES OF THREE-PHASE TRANSFORMERS

Three-phase transformers without taps

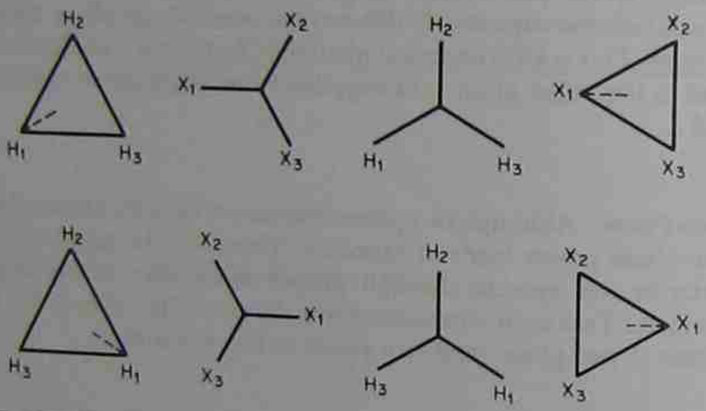
Group 1: angular displacement 0°



Group 2: angular displacement 180°

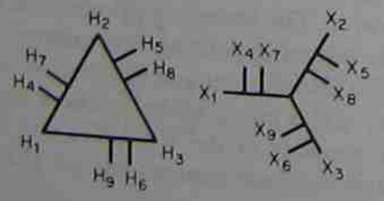


Group 3: angular displacement 30°



Three-phase transformers with taps

Group 3: angular displacement 30°



Courtesy General Electric Company

Autotransformers

Under certain conditions, when the ratio of transformation desired is low, usually not greater than about 5 to 1, and electrical isolation between primary and secondary circuits is not essential, the autotransformer has some advantages.

The autotransformer consists of one winding, a part of which may serve as both primary and secondary. In a two-winding transformer, all of the energy is transformed by magnetic action. In the autotransformer, a portion only is transformed magnetically and the remainder flows conductively through a part of its windings. Since only a portion of the energy is transferred, the autotransformer can be smaller than a two-winding unit; comparable costs of the unit and its installation are less. Also, the losses from currents flowing through it are lessened, resulting in greater efficiency and improved voltage regulation.

A schematic diagram is shown in Fig. 4-7. Voltage, current, and turn relationships are indicated. The same ratio of transformation exists as in a two-winding transformer:

$$\frac{N_p}{N_s} = \frac{E_p}{E_s} = \frac{I_s}{I_p}$$

The figure shows a step-down arrangement of the voltage from E_p to E_s; reversing E_s and E_p will give a step-up arrangement. The current in the coil from a to b is the sum of the exciting current I_p and the nontransformed, relatively large conductive current I_{ss}. This part of the coil, a to b, must be a sufficiently large conductor to carry this load, whereas the portion from b to c carries only the magnetizing current and hence can employ smaller-size conductors.

The percentage of volt-amperes transferred and the percentage of voltage transformed are the same (using the high voltage as a base). For example, if the autotransformer lowers the voltage 5 percent, it actually transforms only 5 percent of the volt-amperes supplied the load. Since the size of the autotransformer depends on only the volt-amperes transformed, the size of the unit can be only 5 percent of the load; if the load supplied is 100 kVA, the size of the autotransformer required would be 5 kVA.

As the ratio of transformation increases, the autotransformer becomes less and less economical until, at about 5 to 1, its advantages no longer apply. A

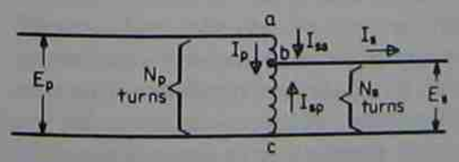


FIG. 4-7 Autotransformer.

larger and larger part of the coil would require a larger conductor and heavier insulation, since both portions are connected electrically.

The electric connection between the incoming and outgoing circuits is a disadvantage, as a disturbance on one side affects the other. For example, a ground on either circuit is a ground on both, and a ground on the high-voltage side

may impose a high voltage on the low side and on the loads connected thereto. The low-voltage side may be insulated to withstand the higher voltage, but the connected loads may not be so protected.

The autotransformer generally has a comparatively lower impedance, which may cause greater fault currents to flow through it during a contingency. The autotransformer, therefore, must be built very ruggedly to withstand the greater mechanical stresses produced, or else external impedances should be connected in the circuit to limit the magnitude of the fault currents, or both should be done in some combination.

Autotransformers may be used on both single-phase and polyphase circuits, as indicated previously. Voltage regulators of both the induction and TCUL types are autotransformers in principle.

Ratings and Temperature

The rating of any piece of electrical equipment is limited by the maximum permissible temperature in any of its components. For transformers, an additional consideration is the permissible voltage drop through the unit.

The maximum temperature generally accepted is that beyond which the insulation is apt to be damaged. Standards set by engineering and manufacturing groups specify an allowable temperature rise of 55°C above an ambient of 40°C, based on the average temperature of the windings; allowing a 10°C difference between "hot spot" and average temperatures in the windings, a maximum temperature of 105°C is indicated. This value is well below the temperature at which insulation fails, providing a large factor of safety.

Transformers are rated in volt-amperes (or kVA) rather than watts. Since the characteristics of the circuit and its loads affect the power factor of the power being transformed, a poor power factor can cause a large current flow in the coils of the transformer, producing losses and heat, with relatively little actual power delivered. The rating that takes into account the current flow and the voltage applied is the volt-ampere rating.

The rating is based on the current the transfofmer will carry *continuously* without exceeding the temperature rise limitations. In selecting a transformer to accommodate a load, other factors besides the maximum value of the load must be taken into consideration. Load duration and cyclic variations; the variations in ambient temperatures, especially because of latitudes and seasons; weather patterns of rain, snow, and ice; the age and condition of the transformer and its components—these are all factors that influence how much a transformer may be loaded with respect to its rating. Moreover, since transformers are not tailored to fit the load but are manufactured in standard sizes, there is normally a margin of transformer capacity available for supplying loads above the rating of the transformer for short periods of time.

Transformer Sizes

Standard sizes of distribution transformers change from time to time as economics and situations change. Kilovolt-ampere capacities presently in greatest use include:

Single-phase units: 10, 25, 37½, 50, 100, 167, 250, 333, and 500 kVA. Older units that still exist in service include 1, 1½, 3, 5, 7½, 15, 75, 150, and 200 kVA.

Three-phase units: 75, 150, 300, 500, 1000, and 3000 kVA. Other, older units still in service include 5, 7½, 10, 15, 25, 50, 100, 200, and 450 kVA.

Voltage Ratings

Standards of voltage ratings, on both the primary and secondary sides, as well as the numerical and percentage voltage variations above and below nominal voltage ratings, are specified in the selection of taps included in the primary winding of the transformer; these, too, are subject to revision from time to time in response to changing requirements.

SUBSTATIONS

Location versus Distribution Voltage

Perhaps the first consideration regarding a distribution substation is its location. In general, it should be situated as close to the load center to be served as practical. This implies that all loads can be served without undue voltage regulation, including future loads that can be expected in a reasonable period of time. The difficulty in obtaining substation sites is an important factor in selecting the distribution voltage, both in original designs and in later conversions.

The higher the distribution voltage, the farther apart substations may be located, but they also become larger in capacity and in the number of customers served. Thus, the problem of the number and location of distribution substations involves not only the study of transmission and subtransmission designs, but more emphasis on service reliability and consideration of additional costs that may be justified. The subjects of sectionalizing, field-installed voltage regulators and reclosers, capacitors, and ties to adjacent sources are discussed elsewhere, but are pertinent to the problem.

Supply Feeders and Circuit Breaker Requirements

The number and sources of supply subtransmission feeders to the distribution substation will depend not only on the load to be served, but also on the degree of service reliability sought. Some rural substations may be supplied from only one subtransmission feeder, while substations serving urban and suburban areas have a minimum of two supply feeders and may have several more. Each additional incoming feeder, however, adds to the bus and switching requirements, including auxiliary devices for their protection, all of which add to costs.

Circuit Breaker Arrangements

Some basic arrangements of incoming high-voltage circuit breakers and transformers are shown in Fig. 4-8. Each scheme progressively adds to the reliability of service to the substation and the loads it supplies. For example, in scheme *a*,

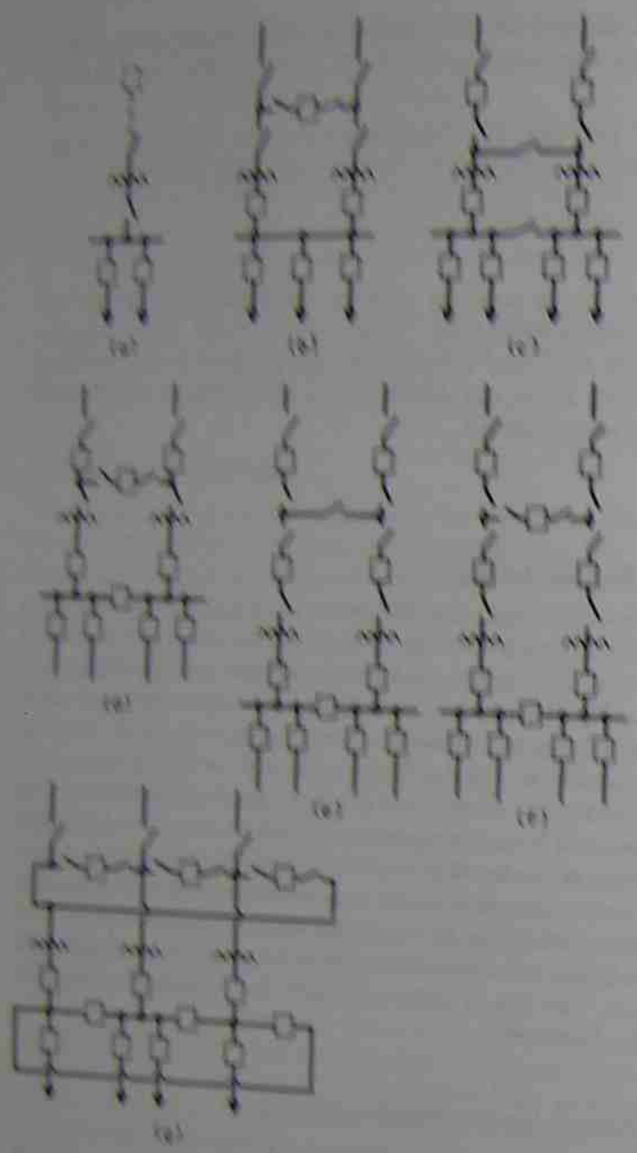


FIG. 4-8 Incoming feeder circuit breaker arrangements.

a failure on the transmission line or substation transformer or bus will trip the breaker back at the transmission source, and service may not be restored until the fault is *found and repaired*; in scheme *b*, such failures will trip the circuit breaker, but service can be restored as soon as the fault is *isolated*; in schemes *c*, *d*, *e*, *f*, and *g* (the last incorporating a ring bus), failures on the incoming transmission lines, transformers, or high-voltage circuit breaker will not interrupt (except for a short time or momentarily) the supply to the bus serving distribution

feeders. Since the cost of high-voltage circuit breakers, together with their accessories, is often as great as or greater than the cost of the transformers with which they may be associated, it is essential that the cost of additional circuit breakers not outweigh the protective advantages gained. It may prove desirable that a minimum number of circuit breakers be installed initially and others added as deemed necessary for any improvement in service reliability that time, increments of load, and customers' requirements may indicate.

Interrupting Duty

The circuit breakers must not only interrupt the normal load current, but must be mechanically able to withstand the forces resulting from the large magnetic fields created by the fault current flowing through them. Since the field will depend on the magnitude of the fault current, which in turn also depends on the voltage of the circuit, the stresses that must be accommodated depend on both of these values. A circuit breaker, therefore, is rated not only on its applied voltage and normal current-carrying capacity, but on its interrupting ability, expressed in volt-amperes (or kVA or MVA); for example, 100-A, 35-kV, or 50,000-kVA interrupting "duty" or capability.

Insulation Coordination—BIL

Circuit breakers and other equipment are subject to high-voltage surges resulting from lightning or switching operations, and the insulation of their energized parts must be capable of withstanding them. Lightning or surge arresters are installed on the conductors and buses of each phase as close to the circuit breakers as practical, with the intent of draining off the voltage surge to ground before it reaches the breaker.

To provide adequate insulation economically and to restrict and localize possible damage to the circuit breaker, the insulation provided for the several parts is coordinated. Internal parts are insulated as equally as practical, but their insulation is generally stronger than that of the bushings, which in turn is stronger than that of the "discharge" point of the associated arrester. Thus, a surge not drained to ground by the arrester will next tend to flash over at the bushings, outside the tank, where damage would be confined, comparatively light, and easier to repair. In general, the insulation of the weakest point in the circuit breaker should be weaker by such a margin as to ensure it will break down before the insulation of the principal equipment it is protecting.

The coordination of insulation requires the establishment of a basic insulation level (BIL) above which the insulation of the component parts of the system should be maintained, and below which lightning or surge arresters and other protective devices operate. This is discussed further in connection with protective devices.

Substation transformers also have their insulation coordinated with that of associated circuit breakers, buses, and other devices.

Capacitors

As mentioned earlier, banks of capacitors may be connected to the high-voltage incoming bus in connection with voltage regulation and increasing the capacity or capability of the substation to supply load. All or portions of these banks may be switched on and off to provide flexibility in maintaining voltage regulation and power factors. This is done with one or more circuit breakers, and arresters or other protective devices as indicated.

Transformers

Substation transformers may consist of three-phase units or banks of three single-phase units. The size of these individual installations may range from 150 kVA (three-phase) in small rural stations to upwards of 25,000 kVA at larger urban and suburban substations. Their impedances are generally low, restricting unregulated voltage variations at the bus to a few percent, except where fault current levels are high. In this case, transformer impedances are increased to limit fault current duty to design limits.

The impedances of the transformer banks in a station should match each other as closely as practical to have the banks share the load as equally as practical.

The transformers may be connected in a delta or wye pattern, on both the incoming high-voltage (subtransmission) side and the outgoing low-voltage (primary circuit) side. The transformers are ordinarily of the two-winding standard type, operating much as the distribution transformers.

For many reasons, including the random and nonuniform movement of the molecules in the core of the transformer, the alternating magnetic field that is set up may be distorted, producing serrated sine waves on both sides of the transformer. These serrations can be broken down into a series of harmonics or waves with frequencies of 3, 5, 7, etc., times the basic frequency (usually 60 cycles per second). If the transformers have a ground on either side, the harmonics or fluctuations flow to ground and the original sine wave essentially remains undistorted. If the windings are connected in delta fashion, these fluctuations circulate around the delta, filtering out the harmonics and eliminating them from the sine wave formed in the windings; however, they do cause some unnecessary heating.

Where the transformer windings are connected in a wye arrangement *without* a ground or neutral back to the source, the harmonics may be particularly bothersome. To overcome these, each of the single-phase transformations (singly or within a three-phase unit) is provided with a third, small-capacity winding; the three such windings are connected in delta (even though the main primary and secondary windings are connected in wye). The delta thus formed allows the harmonics to circulate within it, producing a little heat but essentially filtering them out, so that the sine wave produced on both the high and low sides of the transformer will be a more pure sine wave.

Low-Side Bus Arrangements

The low sides of the transformers are connected to their buses usually through circuit breakers. Several configurations are shown in Fig. 4-9. Some provision is

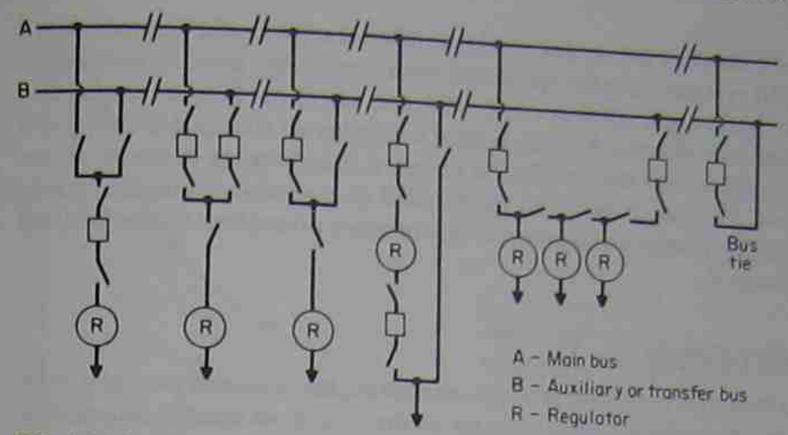


FIG. 4-9 Arrangement of distribution feeder buses at substations (see also Fig. 4-8).

usually made for permitting circuit breakers, switches, regulators, and other devices to be taken out of service for maintenance or for other reasons without causing an interruption to the outgoing distribution feeders. Each of the outgoing distribution feeders is usually equipped with its own circuit breaker. The relays operating these, as well as the transformer high-side circuit breakers, and the capacitors (if any) are coordinated so that only the proper circuit breaker will operate to clear a fault that may occur on some portion of the system; this is considered in more detail on pages 92 to 96.

Voltage Regulators

Each distribution feeder may have its voltage individually regulated, employing three single-phase regulators or one three-phase regulator. If all of the distribution feeders have approximately the same load cycles and voltage regulation (even if corrected by capacitors, field regulators, or other means out on the feeder) the bus to which they are connected may be regulated in place of individual feeder regulators. While this calls for a certain amount of compromise, it may prove economical in many instances.

Mobile Substations

Substations are often designed for three single-phase transformers so that, where they are connected in delta on the incoming side, they can operate in open delta in the event of failure of one of the units. In some instances, a spare single-phase transformer is installed at the substation so that, in the event of failure of one of the transformers, a replacement can be made readily.

With the advent of lighter transformers and improved transportation equipment, it has proven practical to mount a three-phase transformer and associated switching and surge arresters on a trailer especially designed for that purpose. Such a mobile substation can be readily transported to a substation where a failure has occurred. The terminal arrangements of both the mobile substation

and the fixed substation are so designed that often service can be restored more quickly than by reconnecting the spare unit (which no longer need be provided).

The mobile substation not only can be effective where the failure may involve more than one transformer, but can service a number of substations in a more economical fashion than the installation of spare transformers at many, if not all, substations. Further, it may also be installed as a separate, temporary substation, picking up portions of the load of one or more substations whose facilities may be overloaded.

PROTECTIVE DEVICES

For the distribution system to function satisfactorily, faults on any part of it must be isolated or disconnected from the rest of the system as quickly as possible; indeed, if possible, they should be prevented from happening. The principal devices to accomplish this include fuses, automatic sectionalizers, reclosers, circuit breakers, and lightning or surge arresters. Success, however, depends on their coordination so that their operations do not conflict with each other. Figure 4-3 indicates where these devices are connected on the system.

Fuses

Time-Current Characteristic A fuse consists basically of a metallic element that melts when "excessive" current flows through it. The magnitude of the excessive current will vary inversely with its duration. This time-current characteristic is determined not only by the type of metal used and its dimensions (including its configuration), but also on the type of its enclosure and holder. The latter not only affect the melting time, but, in addition, affect the arc clearing time. The *clearing time* of the fuse, then, is the sum of the melting time and the arc clearing time. Refer to Figs. 4-10 and 4-11. Note that for curve *b* in Fig. 4-11, the clearing time for a certain value of current is less than for curve *a;* the fuse with the characteristic *b* is therefore referred to as a "fast" fuse, compared with the fuse of curve *a*. Refer to Fig. 4-11.

Fuses are rated in terms of voltage, normal current-carrying ability, and interruption characteristics usually shown by time-current curves. Each curve actually represents a band between a minimum and a maximum clearing time

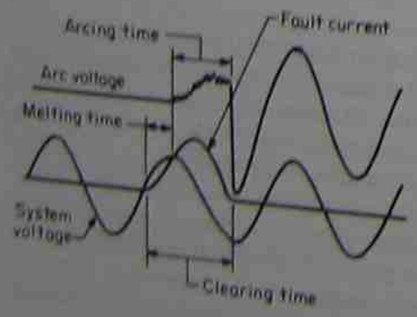


FIG. 4-10 Oscillogram of link melting and fault current interruption. *(Courtesy McGraw Edison Co.)*

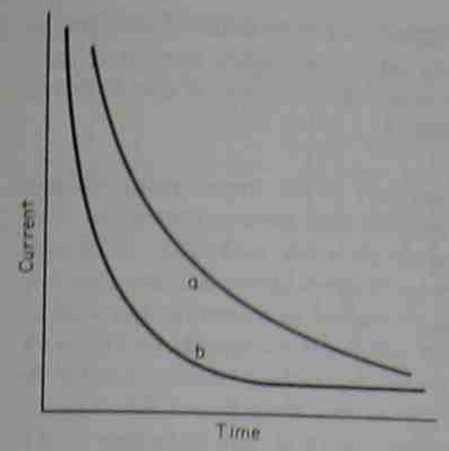


FIG. 4-11 Typical time-current characteristic for fuses.

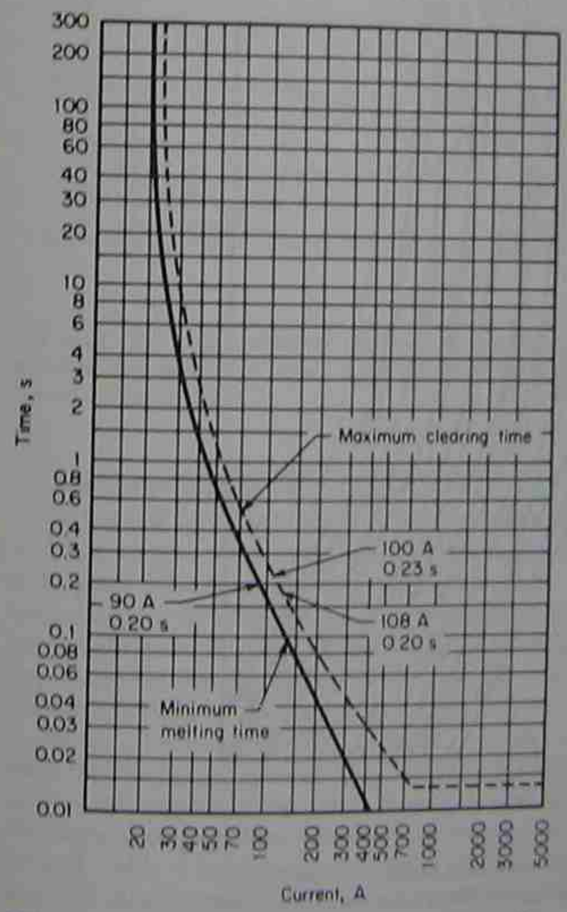


FIG. 4-12 Typical time-current characteristic for a 10-K fuse link. *(Courtesy McGraw Edison Co.)*

for a particular fuse; the difference between them is a predetermined percentage adjustment made to allow for manufacturing tolerances and to ensure an adequate clearing time. A set of such curves is developed for each of the different ratings and types of fuses; see Figs. 4-12 to 4-14.

Fuse Coordination The number, rating, and type of the interrupting devices shown in Fig. 4-3 depend on the system voltage, normal current, maximum fault current, the sections and equipment connected to them, and other local conditions. The devices are usually located at branch intersections and at other key points. When two or more such devices are employed in a circuit, they will be coordinated so that only the faulted portion will be deenergized. In Fig. 4-28 fuse D must clear before sectionalizer C, and C must clear before recloser B. Likewise, fuse G must clear before F, F before E, and both E and B before A. At the transformer locations, fuse M must clear before D, and N before G. All



FIG. 4-13 (*a*) "Representative" minimum and maximum time-current characteristic curves for EEI-NEMA type K (fast) fuse links. *(Courtesy Westinghouse Electric Co.)*

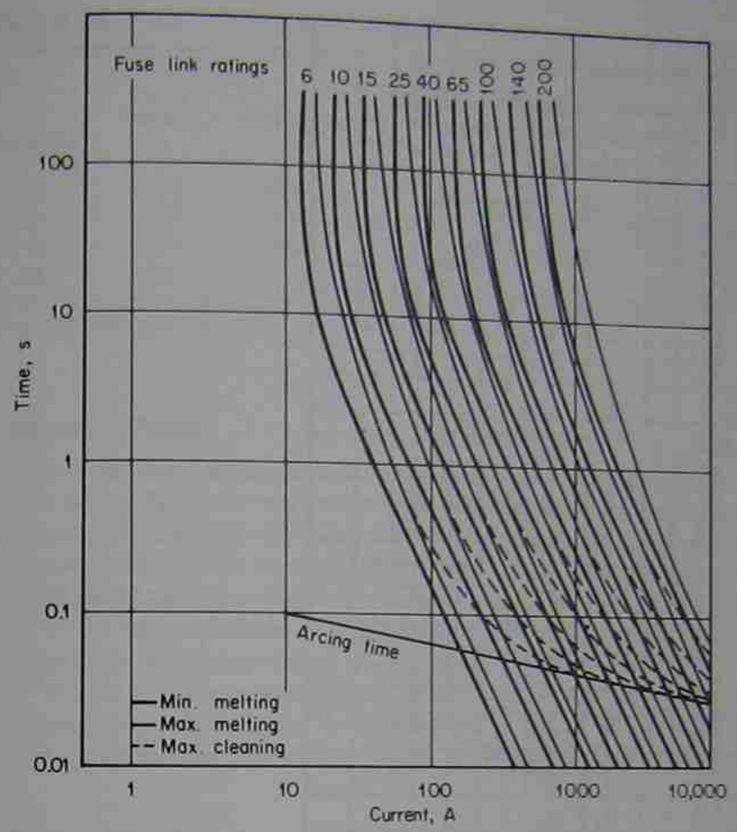


FIG. 4-13 (*b*) "Representative" minimum and maximum time-current characteristic curves for EEI-NEMA type T (slow) fuse links. *(Courtesy Westinghouse Electric Co.)*

of these devices must be coordinated; i.e., their ratings should provide for carrying normal load currents and for responding correctly to a fault.

Fault current will flow from the source to the fault through the various devices in its path. The magnitude of this fault current will depend on the impedance (resistance for dc circuits) between the source and the point of fault, or roughly, on the distance between them. When a fault is distant from the source, the impedance of this part of the circuit is high and the fault current is low; when the fault is close to the source, the fault current is high.

At the coordinating point farthest from the source, therefore, the fuse will have the lowest rating consistent with the maximum normal load at this point; at the other coordinating points along the path of the current the fuses will have increased ratings as they are closer to the source. These are indicated in Fig. 4-15 and Table 4-3. The characteristics of these fuses must also coordinate with those of other protective devices in the same path and with those of the circuit breaker at the source.*

*See reference to "current limiting fuse" in Preface to 2nd Edition.

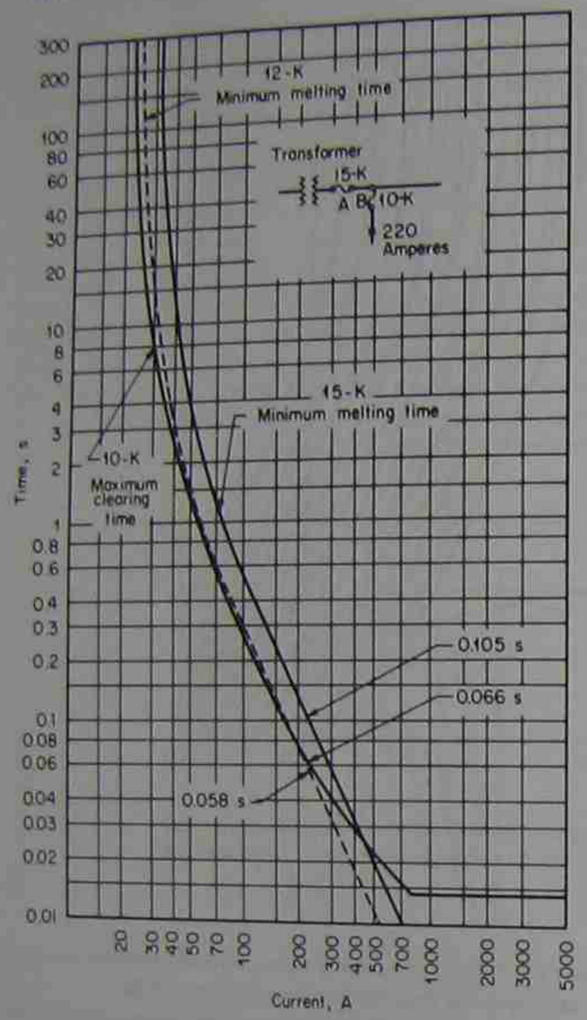


FIG. 4-14 Coordination by time-current curves. *(Courtesy McGraw Edison Co.)*

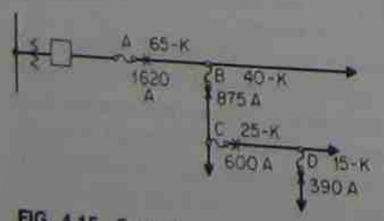


FIG. 4-15 Example of fuse-coordinated system

TABLE 4-3 FUSE-COORDINATED SYSTEM

Position	*Fault current, A*	*Protective link*	*Maximum clearing time M, s*	*Minimum melting time N, s*	*Clearing factor*	
					Ratio CT/MT, M(pos)/N(pos)	*Percent*
A	1620	65-K	0.078	—	—	—
B	875	40-K	0.066	0.120	0.078-A/0.120-B	65.0
C	600	25-K	0.061	0.093	0.066-B/0.093-C	71.0
D	390	15-K	—	0.084	0.061-C/0.084-D	72.6

Courtesy McGraw Edison Co.

Repeater Fuses

Line fuses are sometimes installed in groups of two or three (per phase), known as repeater fuses, having a time delay between each two fuse units. When a fault occurs, the first fuse will blow and the second fuse will be mechanically placed in the circuit by the opening of the first; if the fault persists, the second fuse will blow; if there is a third fuse, the process is repeated. If the fault is permanent, all of the fuses will blow and the faulted part of the circuit will be deenergized. New fuses must be installed to restore the line to normal.

Where capacitors are applied to feeders for power factor correction, fuses chosen to protect the line from the bank (and vice versa) must also coordinate with sectionalizing and other devices in the circuit back to the source.

Transformer Fuses

Fuses on the primary side of distribution transformers serve to disconnect the transformer from the circuit not only in the event of a fault in the transformer or on the secondary, but also when the normal load on the transformer becomes so high that failure is imminent. Fuses on the secondary side protect the transformer from faults or overloads on the secondary circuit it serves.

The characteristics of a primary fuse are a compromise between protection from a fault and protection from overload, yet the fuse also has to coordinate with other fuses on the line. One attempt at a solution is the completely self-protected (CSP) transformer, in which the primary fuse, with characteristics based only on protection against fault, is situated within the transformer tank (and, to differentiate, is called a *link*) while overload protection is accomplished by low-voltage circuit breakers (instead of fuses) on the secondary side of the transformer that are also situated within the tank. The circuit breakers, once open, however, must be reclosed manually.

Fuses are provided on the line side of the protectors on low-voltage secondary networks. These are backup protection in the event the protector fails to open during back feed from the network into the primary when it is faulted or deliberately grounded.

Secondary fuses, known as *limiters*, are also provided at the juncture of secondary mains to isolate faulted sections of the secondary mains and to prevent

the spread of burning in conductors (usually in cables) where sufficient fault current does not exist to burn them clear in a small portion of the mains.

Automatic Line Sectionalizers

Automatic line sectionalizers are connected on the distribution feeder in series with line and sectionalizing fuses; they are also in series with and electrically farther from the source than reclosers or circuit breakers with reclosing cycles. These devices are decreasing in usage, but many exist on distribution systems.

When a fault occurs on the circuit beyond the sectionalizer, the fault current initiates a *fault-counting relay* that is coordinated with the characteristics of the fuses and other devices. Each time the circuit is deenergized (from reclosers or circuit breakers), the relay moves toward the trip position; just before the final operation that will lock out the recloser or circuit breaker if the fault persists, the sectionalizer will trip (while no fault current is flowing) and open the circuit at that point, removing the fault and permitting the circuit breaker or recloser to close and reset into its normal position; service is thus restored to the rest of the circuit up to the location of the sectionalizer. If the fault is of a temporary nature and is cleared before the reclosing devices complete their operations, the sectionalizer will reset to its normal position after the circuit is reenergized.

Sectionalizers are rated on continuous current-carrying capacity, minimum tripping and counting current, and maximum momentary fault current, as well as for maximum system voltage, load-break current, and impulse voltage or basic insulation level (BIL).

More than one sectionalizer can be connected in series with a reclosing device. The sectionalizer nearest the reclosing device can be set to operate after (say) three operations while the more remote one is set for (say) two such operations.

Sectionalizers are relatively low-cost devices; they are not required to interrupt fault current although fault current flows through them. They may be operated manually and are considered the same as load-break switches.

Reclosers

Reclosers are essentially circuit breakers of lower capacity, both as to normal current and interrupting duty. They are usually installed on major branches of distribution feeders in series with other sectionalizing devices; they perform the same function as repeater fuses connected in the circuit or circuit breakers at the substation.

Reclosers are designed to remain open, or "locked out," after a selected sequence of tripping operations. A fault will trip the recloser; if the fault is temporary in nature and no longer exists, the next tripping operation does not take place and the recloser returns to its normally closed position, ready for another incident. If the fault persists, the recloser will close and the operation will be repeated until the recloser locks out. The reclosers are usually set for three automatic reclosing operations before locking out; the first operation is usually "instantaneous," i.e., occurring as quickly as the breaker contacts can

open with no time delay; the second and third operations have time delays inserted, that for the second tripping smaller than that for the third; a fourth tripping will result in the recloser's remaining open until it is automatically or manually restored to normal, ready for the next incident.

Reclosers can operate on one or more time-current characteristic curves, as shown in Fig. 4-16. The reclosing characteristics of the recloser for each operation are coordinated with those of the fuses at the coordinating points in the circuit and with those of the relays controlling the circuit breaker at the substation. These are illustrated in Fig. 4-17. The first and basic curve is a tripping setting representing the minimum clearing time of the recloser; the other curves are determined by deliberate time delays introduced by making minor changes in the hydraulic and mechanical linkage system.

Reclosers may be single-phase units or three-phase units. The latter usually consist of three single-phase units mechanically interlinked for a common lockout operation, and are installed in a common tank. Figure 4-18*a* and *b* are typical oscillograms of single-phase and three-phase faults interrupted by these units.

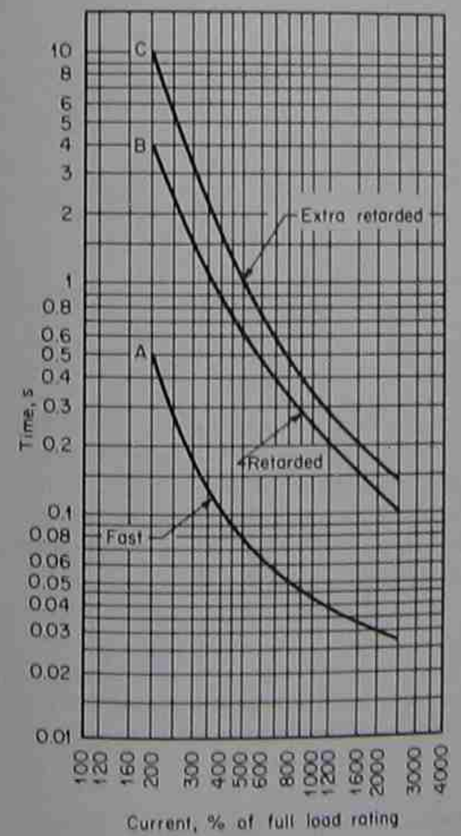


FIG. 4-16 Time-current curves of standard-duty reclosers. *(Courtesy McGraw Edison Co.)*

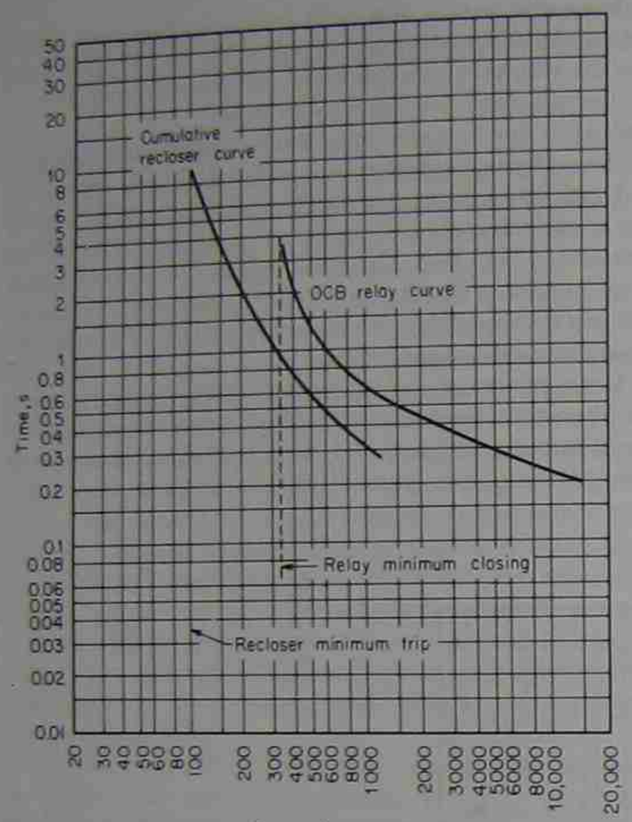


FIG. 4-17 Coordination of OCB relay and recloser. *(Courtesy McGraw Edison Co.)*

Circuit Breakers—Relays*

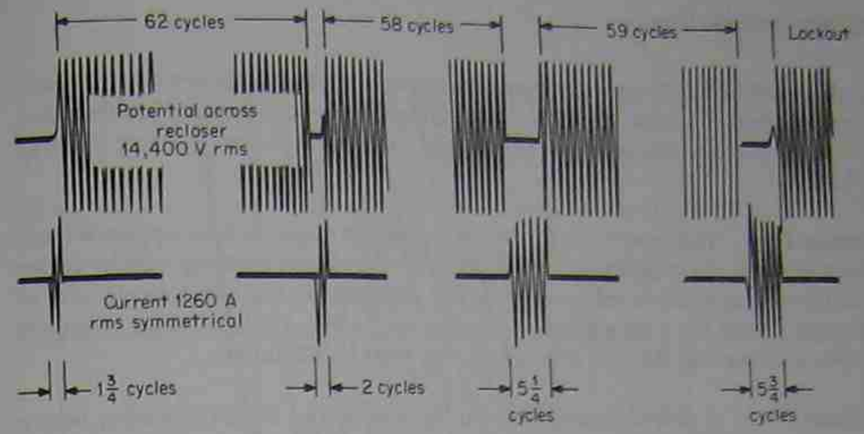
Where the fault current is beyond the ability of a fuse or recloser to interrupt it safely, or where repeated operation within a short period of time makes it more economical, a circuit breaker is used. The ability of circuit breakers has been touched upon earlier; their time-current characteristics, however, are dependent on the protective relays associated with them and must be coordinated with those of down-line reclosers, fuses, and other protective devices.

Overcurrent Relays

Overcurrent relays close their contacts to actuate the circuit that causes the circuit breaker to open or close when the current flowing in them reaches a predetermined value.

Instantaneous Without time delay deliberately added, the relay will close its contacts "instantaneously," i.e., in a relatively short time, in the nature of 0.5 to

*See reference to "electronic relays" in Preface to 2nd Edition.



Interruption of 1260 A at 14,400 V, power factor of 38 percent, by 822 standard-duty recloser

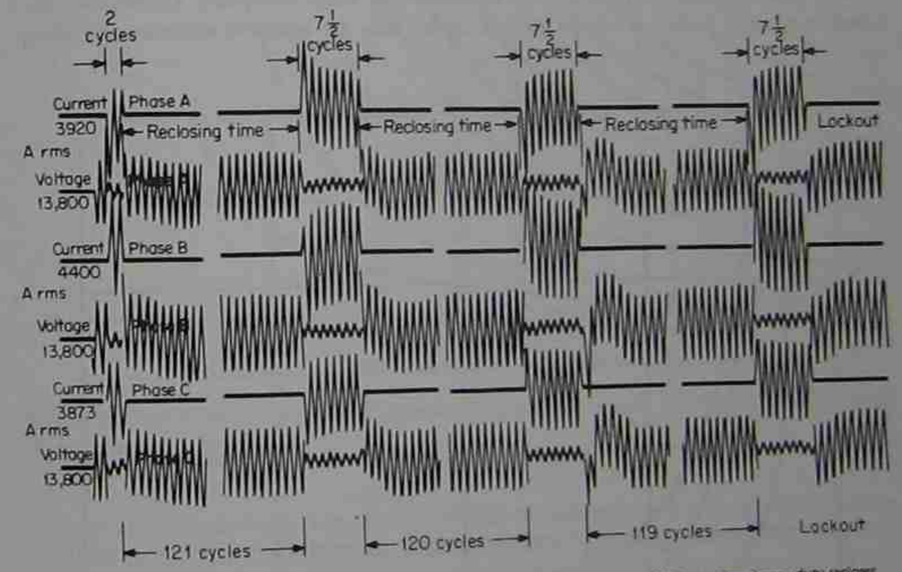
A. First opening. Total clearing time, 1¾ cycles. Arcing time at contacts, ½ cycle. Reclosing time, 62 cycles.

B. Second opening. Total Clearing time, 2 cycles. Arcing time at contacts, ½ cycle. Reclosing time, 58 cycles.

C. Third opening. Total clearing time, 5¼ cycles. Arcing time at contacts, ½ cycle. Reclosing time, 59 cycles.

D. Fourth opening. Total clearing time, 5¾ cycles. Arcing time at contacts, ½ cycle. Recloser locks out.

(a)



Interruption of three-phase fault current of 4000 A at 13,800 V, power factor of 12.5 percent, by C13 three-phase heavy-duty recloser.

A. First opening. Total clearing time, phase A, 1½ cycles; phase B, 1½ cycles; phase C, 2 cycles. Arcing time, all phases, approximately 1/2 cycle. Reclosing time, 121 cycles.

B. Second opening. Total clearing time, all three phases, 7½ cycles. Arcing time, all phases, approximately ½ cycle. Reclosing time, 120 cycles.

C. Third opening. Total clearing time, phases A and C, 7½ cycles; phase B, 8 cycles. Arcing time, all phases, approximately ½ cycle. Reclosing time, 119 cycles.

D. Fourth opening. Total clearing time, all three phases, 7½ cycles. Arcing time, all phases, approximately ½ cycle. Recloser locks out.

(b)

FIG. 4-18 (a) Typical oscillogram of recloser operation. (b) Typical oscillogram of three-phase fault interruption by heavy-duty recloser. *(Courtesy McGraw Edison Co.)*

perhaps 20 cycles. To prevent frequent operation of the breaker from transient, nonpersistent conditions, undesirably high settings may be applied to the relay. The time-current characteristic of this type of relay is shown in curve *a* in Fig. 4-19*a*.

Inverse Time The operation of the relay may be made to vary approximately inversely with the magnitude of the current. The current setting may be varied and time delay introduced by varying the restraint on the movable element of the relay; these are indicated in curves *b* and *c* in Fig. 4-19*a*. Greater selectivity between relays and fuses in the circuit may thus be obtained.

Definite Time A definite time delay can be introduced before the relay begins to operate, allowing greater selectivity to be achieved. This feature is often added to the inverse-time characteristic beyond a certain value of current after which the relay operation is completed after the fixed time delay. This inverse definite minimum time feature is employed in most overcurrent relay applications. It is shown in curve *d* of Fig. 4-19*a*, in which the flat portion of the characteristic results in only a small relay time increase for small values of fault current. Refer to Fig. 4-19*b*.

The distribution circuit may be sectionalized with reclosers, automatic sectionalizers, and fuses, at which points faults may be isolated without affecting

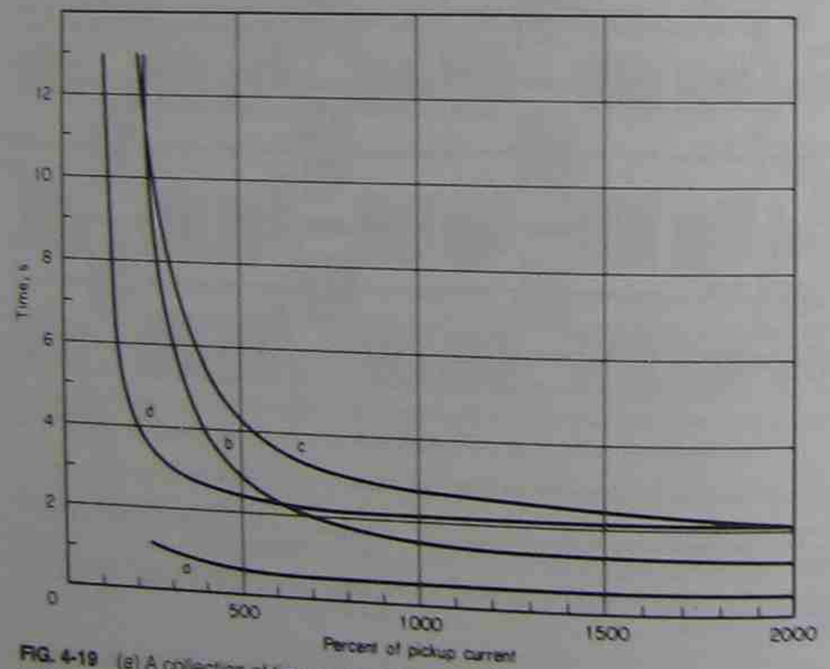


FIG. 4-19 (*a*) A collection of time curves. These are representative of the various types of time curves which are used on overcurrent relays.

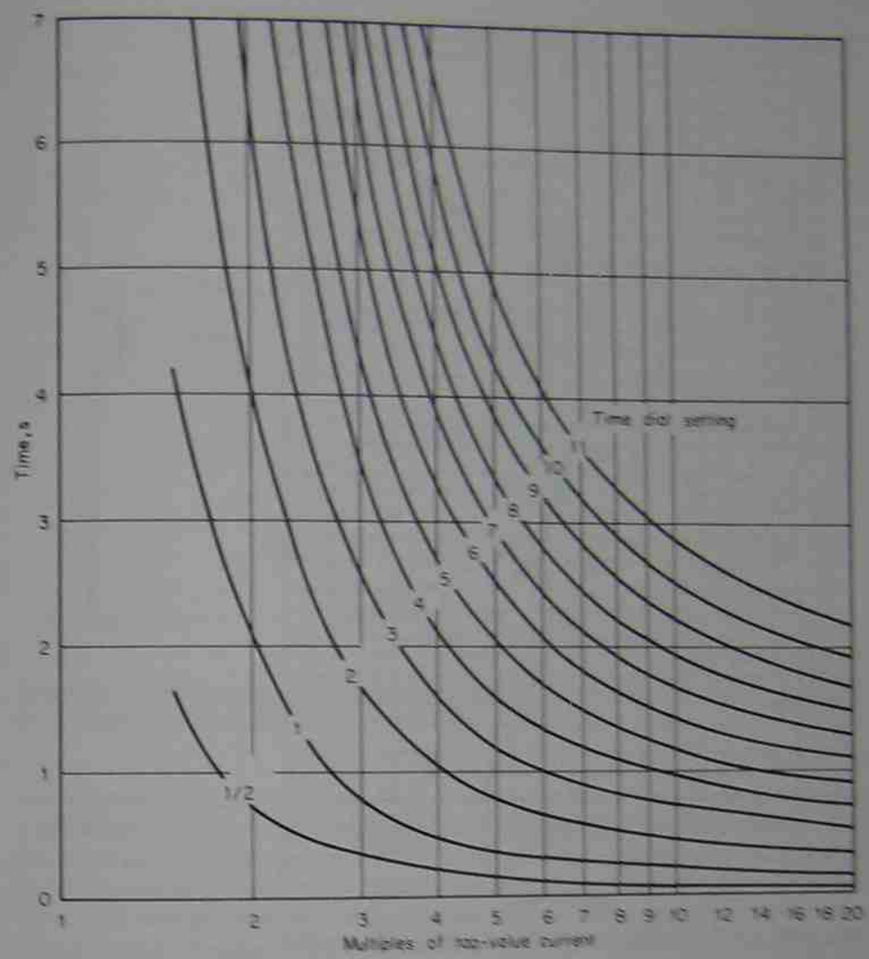


FIG. 4-19 (*b*) Type CO-8 overcurrent relay time-current curves, 50–60 cycles. *(Courtesy Westinghouse Electric Co.)*

the entire circuit; fuses are also provided on the primary side of distribution transformers. The definite time characteristic of the relay associated with the circuit breakers at the substation is coordinated with the characteristics of reclosers and fuses on the distribution circuit, as shown in Fig. 4-20.

Directional Relays

Directional relays are essentially overcurrent relays to which an element similar to a wattmeter is added, both sets of contacts being in series. The overcurrent element will operate to close its contacts regardless of the direction of flow of power in the line; the wattmeter element will tend to turn in one direction under

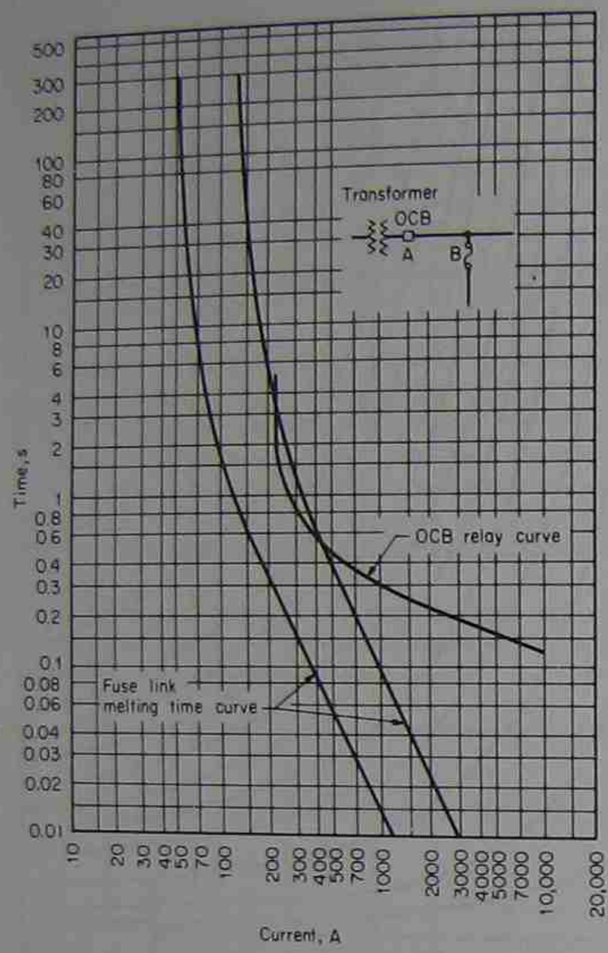


FIG. 4-20 OCB-fuse link coordination. *(Courtesy McGraw Edison Co.)*

normal flow of power and in the reverse direction when power flows in the opposite direction. Hence, both sets of contacts must be closed and power flowing in a given direction before the relay will operate. Both elements may be combined into one so that only a single set of contacts is required.

This type of relay is used in primary or secondary network operations to open the protectors to prevent current from the network from energizing the high side of the transformers and their supply feeder during contingencies. Refer to Fig. 4-21.

Differential Relays

Differential relays operate on the difference between the current entering the line or equipment being protected and the current leaving it. As long as the incoming current and the outgoing current are essentially equal, the relay will

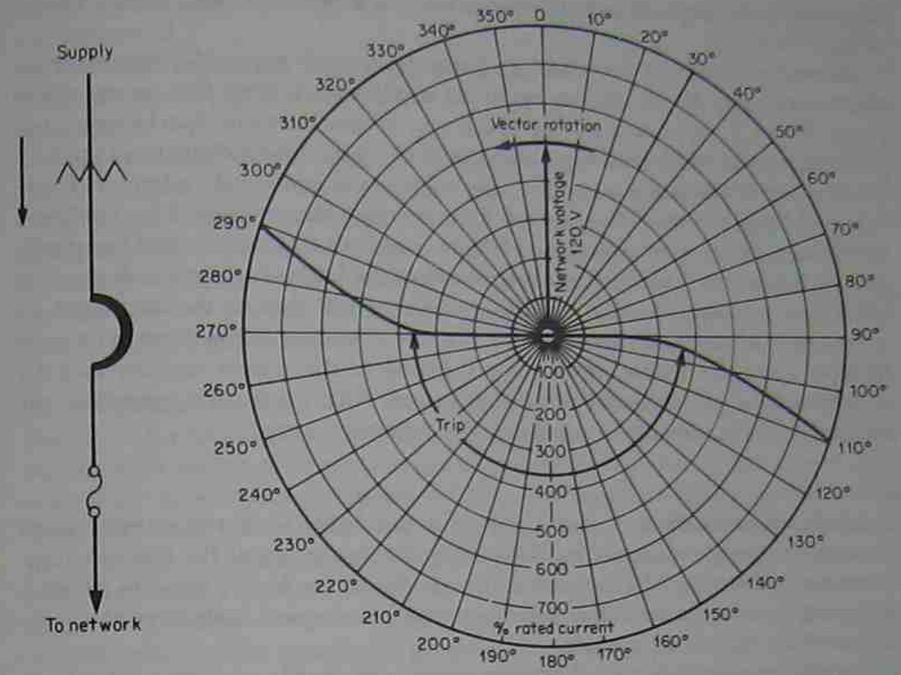


FIG. 4-21 Typical tripping characteristic of the CN-33 network master relay under balanced three-phase conditions. *(Courtesy Westinghouse Electric Co.)*

not operate. A fault within the line or equipment, however, will disturb this equilibrium, and the relay will operate to trip the supply circuit breaker or breakers on both sides of the line or equipment being protected. This type of relay is used to protect buses, transformers, and regulators at the substation. Since the voltages at which these operate may be high, current transformers installed on both sides of the equipment, with proper ratios in the case of transformers, supply the currents to the relay. Refer to Fig. 4-22.

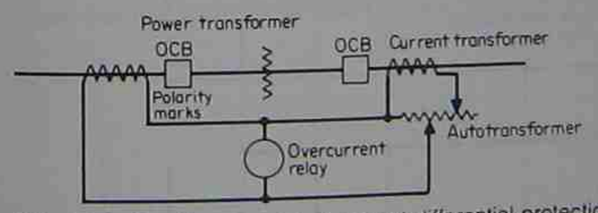


FIG. 4-22 One-line diagram of current-differential protection.

Surge or Lightning Arresters

The function of a surge or lightning arrester is to limit the voltage stresses on the insulation of the equipment being protected by permitting surges in voltage to drain to ground before damage occurs. The surges in voltage generally are

caused by lightning (either by direct stroke or by induction from a nearby stroke) or by switching.

Arresters consist of two basic components: a spark gap and a nonlinear resistance element (for a valve type) or an expulsion chamber (for an expulsion type). When a surge occurs, the spark gap breaks down or sparks over, and permits current to flow through the resistance (or chamber) element to ground. Since the arrester at this point presents a low-impedance path, a large current, referred to as *60-cycle follow current*, flows through the arrester. The nonlinear resistance, at the higher voltages, will tend to restrict this current and eventually cause it to cease to flow; here, the magnitude of the follow current is independent of the system capacity. The expulsion chamber will confine the arc, build up pressures that eventually blow out the arc, and cause the follow current to cease to flow; here, the follow current is a function of the system capacity and the expulsion chamber must be suitably designed. After each such operation, the arrester must be capable of repeating this operating cycle.

Insulation Coordination It must be kept in mind that while the arrester is operating, the surge voltage is also "attacking" the insulation of the line or equipment it is protecting; the arrester, however, drains the high voltage to ground, reducing its magnitude, *before* sufficient time has elapsed to damage the insulation of the line or equipment.

Insulation characteristics, therefore, can be expressed as functions of voltage and the time it is impressed. This is usually shown as a volt-time curve, known

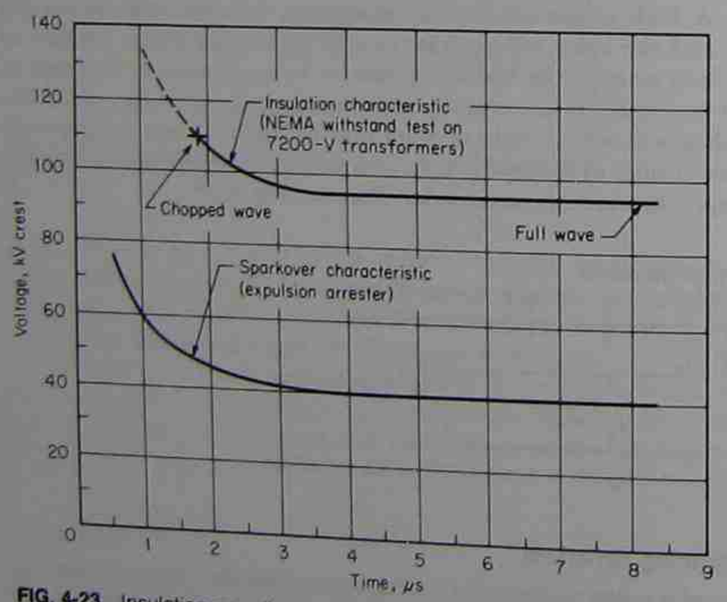


FIG. 4-23 Insulation coordination. *(Courtesy McGraw Edison Co.)*

as the *impulse level*, and represents the voltage and its duration the equipment can withstand.

The arrester also has a volt-time curve that indicates the voltage and time at which the spark gap begins to break down and permit the passage of the surge to ground.

The insulation characteristic of the line or equipment being protected must be at a higher voltage level than the volt-time characteristic of the arrester protecting it; indeed, a sufficient voltage differential must be provided to ensure safe and positive protection. Figure 4-23 illustrates typical curves and their relationship. While the impulse level of the line or equipment must be high enough that the arrester provides adequate protection, it should be as low as practical to hold down insulation costs.

Basic Insulation Level (BIL) The coordination of insulation requires the establishment of a minimum level above which are the components of a system and below which are the protected devices associated with those components. A joint committee of electrical engineers, utilities, and manufacturers adopted basic insulation levels which define the impulse voltages capable of being withstood by insulation of various insulation classes: "Basic impulse insulation levels are reference levels expressed in impulse crest voltages with a standard wave not longer than 1.5 by 40 microseconds. Apparatus insulation as demonstrated by suitable tests shall be equal to or greater than the basic insulation level."

The standard 1.5- by 40-μs wave selected simulates lightning surges, which are more prevalent than switching surges, and are more readily reproduced in the laboratory. The wave, shown in Fig. 4-24, reaches its maximum or crest value at 1.5 μs and at 40 μs reaches one-half its maximum value on the "wave tail." The steep rising portion of the wave is called the wave front, and the rate of rise (in kilowatts per microsecond) determines the slope or steepness of the wave front.

Recommended insulation levels for equipment of various voltage classes are listed in Table 4-4. These levels and the sparkover characteristic of arresters are determined by impulse tests.

The sparkover-time characteristics of the valve- and the expulsion-type arrester differ in that the characteristic curves for expulsion types are not as flat as those for the valve types: the two are shown in Fig. 4-25*a* and *b*, respectively.

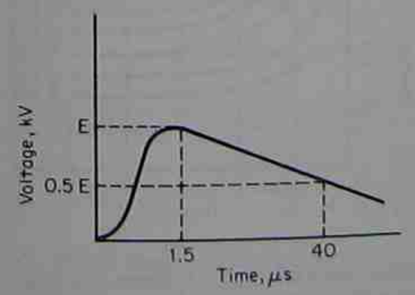


FIG. 4-24 1.5- by 40-μs voltage wave *(Courtesy McGraw Edison Co.)*

TABLE 4-4 TYPICAL BASIC INSULATION LEVELS*

	Basic insulation level, kV (standard 1.5- × 40-μs wave)	
Voltage class, kV	*Distribution class*	*Power class (station, transmission lines)*
1.2	30	45
2.5	45	60
5.0	60	75
8.7	75	95
15	95	110
23	110	150
34.5	150	200
46	200	250
69	250	350

*For current industry recommended values, refer to the latest revision of the National Electric Safety Code.

The flat curves of the valve types indicate their rapid response, especially to lightning voltages even during steep wave-front surges. Although expulsion arresters do not have sparkover voltages as low as the valve types, they do provide adequate protection for distribution systems; consideration must be given, however, to the maximum fault current at the expulsion arrester and its effect on coordination with overcurrent protection devices on the system. The curves are based on a standard 1.5- by 40-μs test wave.

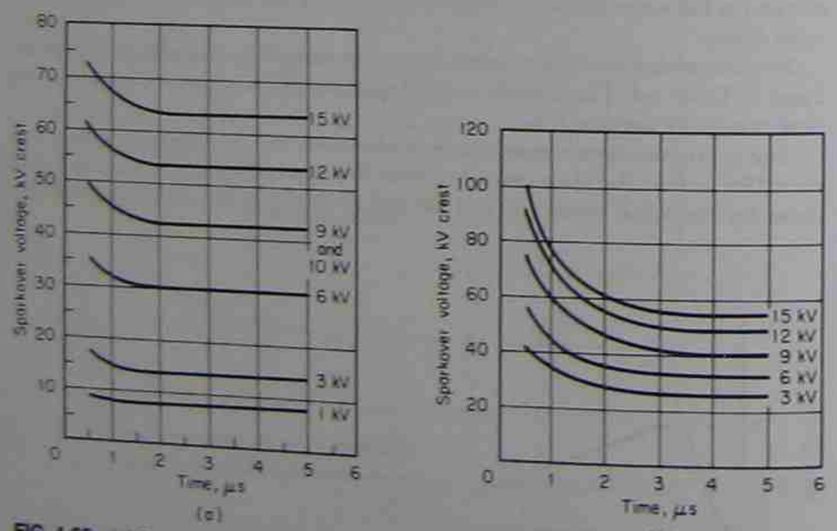


FIG. 4-25 (*a*) Sparkover characteristics of distribution valve arresters. (*b*) Sparkover characteristics of expulsion arresters. (*Courtesy McGraw Edison Co.*)

Arrester Connection Arresters should be placed as close to the equipment to be protected, and the lengths of the connections to the line and to the ground should be kept as short, as possible. That is because these connections offer relatively high-impedance paths to voltage surges, so that large currents flowing through them could cause a voltage drop in them which, added to the surge voltage, could impose additional stress on the insulation of the equipment being protected. Moreover, on longer lines, such surges can be "reflected," essentially doubling the value of the surge voltage.

Short leads and minimum distance between the arrester and equipment protected are desirable for all arrester applications. Further, if the equipment being protected has a ground, that ground and the arrester ground should be interconnected to relieve any potential stress that may develop from the voltage drop across the ground impedance.

Arresters should be connected to the primary side of distribution transformers and to capacitors, underground risers, and other equipment; at certain points on long primary lines; and at reclosers in substations. One arrester should be connected to each phase. For station circuit breakers, transformers, outdoor regulators, and reclosers situated on primary lines, arresters should preferably be connected to both incoming and outgoing sides of such equipment. Voltage ratings of arresters should take cognizance of whether the systems are delta or wye, grounded or ungrounded, and of the voltage distortions resulting from an accidental ground on one phase.

FAULT-CURRENT CALCULATION

For the proper coordination of protective devices on a distribution system, it is essential that the magnitude be known of the fault current which they may be called upon to handle. For dc systems, the calculation is a relatively simple application of Ohm's law; for ac systems, the procedures are more complex, but for most problems, practical solutions permit simplified procedures.

For ac systems, four general types of faults can be considered: three phases short-circuited together (with or without a ground), phase to phase to ground, phase to phase, and single phase to ground.

The following simplified equations yield symmetric current values that are sufficiently precise for purposes of coordination.

1. Three-phase fault current:

$$I_{3\phi} = \frac{0.58V}{Z_A + Z_B} \quad \text{A}$$

2. Phase-to-phase-to-ground fault current:

$$I_{\phi\text{-}\phi\text{-}G} = \frac{V\sqrt{(Z_A + Z_B)^2 + (Z_A + Z_C)^2 + (Z_A + Z_B)(Z_A + Z_C)}}{(Z_A + Z_B)\,[2(Z_A + Z_C) + (Z_A + Z_B)]} \quad \text{A}$$

3. Phase-to-phase fault current:

$$I_{\phi\text{-}\phi} = 0.87 I_{3\phi} \quad \text{A}$$

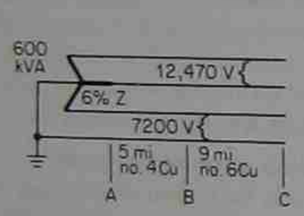
4. Single-phase-to-ground fault current:

$$I_{\phi\text{-}G} = \frac{1.73V}{3Z_A + 2Z_B + Z_C} \quad \text{A}$$

where V = normal phase-to-phase voltage of feeder
Z_A = impedance of substation transformer, Ω
Z_B and Z_C = impedances of feeder, Ω

These equations are for 60-cycle overhead radial distribution feeders and assume that an infinite source capacity is capable of maintaining normal voltage at the high side with the fault on the low side; that the impedances making up the total impedance of the faulted circuit are added arithmetically (impedances must be at the same voltage base); that transformers have 6 percent impedance (but other impedances can be calculated on their percentage ratio to 6 percent; and that conventional spacing exists between conductors on poles (though large variations cause only small changes in impedance values that can be disregarded without appreciable error).

EXAMPLE 4-4



From manufacturers' tables, $Z_A = 15.57\ \Omega$ and $Z_B = 0$. For a fault at point A, at the substation,

1. For a three-phase fault:

$$I_{3\phi} = \frac{0.58 \times 12{,}470}{15.57 + 0} = 465 \text{ A}$$

2. For a phase-to-phase-to-ground fault,

$$I_{\phi\text{-}\phi\text{-}G} = \frac{12{,}470\sqrt{15.57^2 + 15.57^2 + 15.57^2}}{15.57[2(15.57) + 15.57]}$$

$$= \frac{12{,}470\ \sqrt{3}}{3(15.57)} = 463 \text{ A}$$

3. For a phase-to-phase fault,

$$I_{\phi\text{-}\phi} = 0.87 \times I_{3\phi}$$

$$= 0.87 \times 465 = 404 \text{ A}$$

4. For a phase-to-gound fault,

$$I_{\phi\text{-}G} = \frac{1.73 \times 12{,}470}{3 \times 15.57} = 463 \text{ A}$$

For a fault at point B, 5 mi from the substation,

1. For a three-phase fault, with $Z_B = 7.85$ (from manufacturers' tables),

$$I_{3\phi} = \frac{0.58 \times 12{,}470}{15.57 + 7.85} = 309 \text{ A}$$

2. For a phase-to-phase-to-ground fault, with $Z_C = 15.8\ \Omega$ (from manufacturers' tables),

$$I_{\phi\text{-}\phi\text{-}G} = \frac{12{,}470\sqrt{23.42^2 + 31.37^2 + (23.42)(31.37)}}{23.42[2(31.37) + 23.42]}$$

$$= \frac{12{,}470 \times 47.5}{2017.9} = 293 \text{ A}$$

3. For a phase-to-phase fault,

$$I_{\phi\text{-}\phi} = 0.87 \times 309 = 269 \text{ A}$$

4. For a phase-to-ground fault,

$$I_{\phi\text{-}G} = \frac{1.73 \times 12{,}470}{3(15.57) + 2(7.86) + 15.8} = 276 \text{ A}$$

For a fault at point C, 14 mi from the substation,

1. For a three-phase fault, with $Z_B = 7.85 + 20.60 = 28.45$ (from manufacturers' tables),

$$I_{3\phi} = \frac{0.58 \times 12{,}470}{15.57 + 28.45} = 164 \text{ A}$$

2. For a phase-to-phase-to-ground fault, with $Z_C = 15.80 + 35.28 = 51.08$ (from table), $Z_A + Z_B = 15.57 + 28.45 = 44.02\ \Omega$, and $Z_A + Z_C = 15.57 + 51.08 = 66.65\ \Omega$,

$$I_{\phi\text{-}\phi\text{-}G} = \frac{12{,}470\sqrt{44.02^2 + 66.65^2 + (44.02)(66.65)}}{44.02[2(66.65) + 44.02]}$$

$$= \frac{12{,}470\ \sqrt{9316}}{7810} = 154 \text{ A}$$

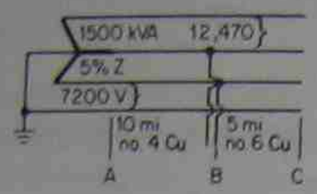
3. For a phase-to-phase fault,

$$I_{\phi\text{-}\phi} = 0.87 \times 164 = 143 \text{ A}$$

4. For a phase-to-ground fault,

$$I_{\phi\text{-}G} = \frac{1.73 \times 12{,}470}{3(15.57) + 2(28.45) + 51.1} = 139 \text{ A}$$

EXAMPLE 4-5



Since the branch in this case has two phases and a neutral, no three-phase fault can occur. V = 12,470 V. The impedance values, based on manufacturers' tables, are as follows. Z_A = 6.28 Ω for 6 percent impedance. For 5 percent impedance, $Z_A = 5/6 \times 6.28 = 5.2\ \Omega$. $Z_B = 15.7 + 11.45 = 27.15\ \Omega$. $Z_C = 31.6 + 19.60 = 51.20\ \Omega$. $Z_A + Z_B = 32.35\ \Omega$, and $Z_A + Z_C = 56.40\ \Omega$.

For a fault at point C,

1. For a phase-to-phase-to-ground fault,

$$I_{\phi\phi G} = \frac{12{,}470\sqrt{32.35^2 + 56.40^2 + (32.35)(56.40)}}{32.35[2(56.40) + 32.35]}$$

$$= \frac{12{,}470\sqrt{6052}}{4696} = 207\ \text{A}$$

2. For a phase-to-phase fault, since the three-phase fault current would be 224 A,

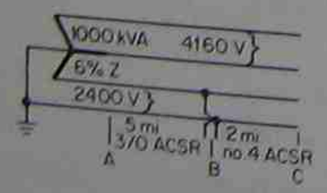
$$I_{\phi\phi} = 0.87 \times 224$$

$$= 195\ \text{A}$$

3. For a phase-to-ground fault,

$$I_{\phi G} = \frac{1.73 \times 12{,}470}{3(5.2) + 2(27.15) + 51.20} = 178\ \text{A}$$

EXAMPLE 4-6



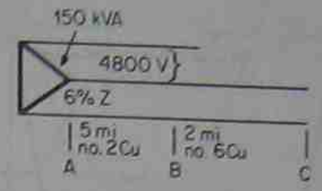
Since the branch here is single-phase, only a phase-to-ground fault can occur. V = 4160 V. From manufacturers' tables, Z_A = 1.037 Ω, Z_B = 1.78 + 4.52 = 6.3 Ω, and Z_C = 4.16 + 6.90 = 11.1 Ω.

For a fault at point C,

$$I_{\phi G} = \frac{1.73 \times 4160}{3(1.037) + 2(6.3) + 11.1}$$

$$= 268\ \text{A}$$

EXAMPLE 4-7



With two branch lines, only a phase-to-phase fault can occur. V = 4800 V. From manufacturers' tables, Z_A = 9.22 Ω and $Z_B = 5.55 + 4.52 = 10.07\ \Omega$.

For a fault at point C,

$$I_{\phi\phi} = \frac{0.87 \times 0.58 \times 4800}{9.22 + 10.07}$$

$$= 125\ \text{A}$$

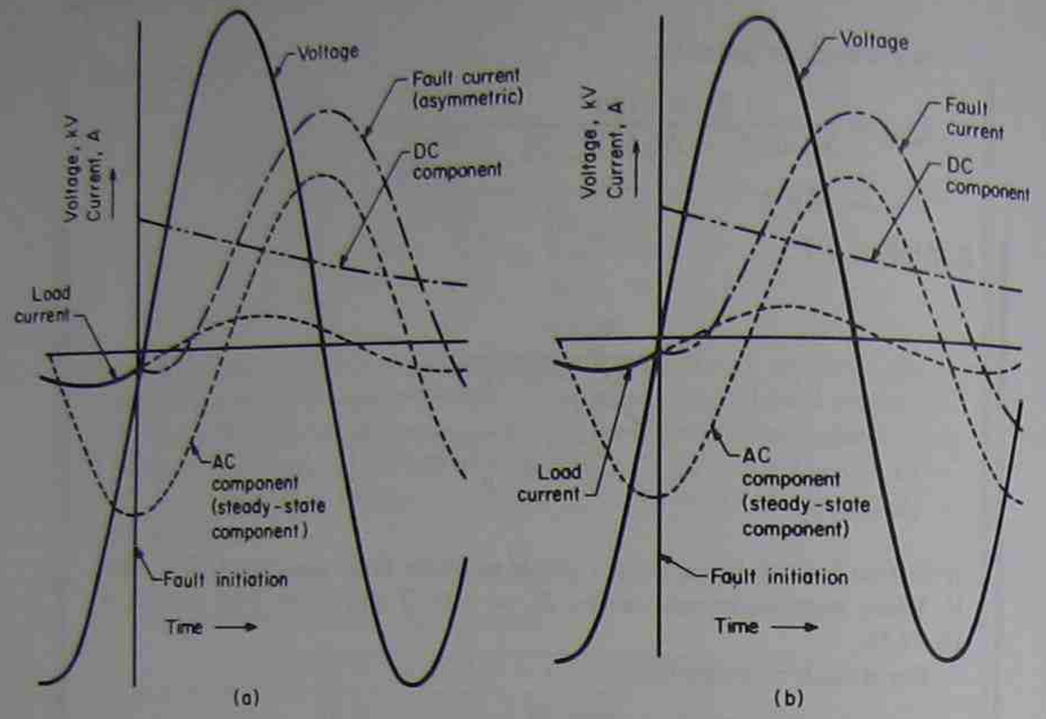
Actual Fault Current

The actual fault current may be broken into two components, ac and dc. The simplified equations give values of the ac, or steady-state, component, which remains constant throughout the duration of the fault. The value of this current follows Ohm's law and is equal to the voltage divided by the impedance of the circuit from the source to the point of fault.

As shown in Fig. 4-26*a*, the ac component is symmetric about its axis and is known as the symmetric current. The dc, or transient, component occurs at the instant of the fault and drops rapidly to zero. Its magnitude depends on the time the fault is initiated; on a system carrying load, its maximum value is equal to the ac component at the beginning of the fault less the load current at that time. Standard measurement of the two components is taken at one-half cycle after the start of the fault. The total (root mean square) fault current is the square root of the sum of the squares of the two components; this composite rms current is not symmetric, and is known as the asymmetric current.

The magnitude of the total fault current during the transient period, therefore, depends on the type of fault and the time of its initiation. After the transient period, the magnitude of the fault current depends only on the type of fault.

The time of fault initiation is measured angularly along the voltage wave, i.e., as a number of degrees from a known point, such as peak voltage or voltage zero. Since there is usually a phase angle between voltage and current, a fault will occur at a different point on the current wave.



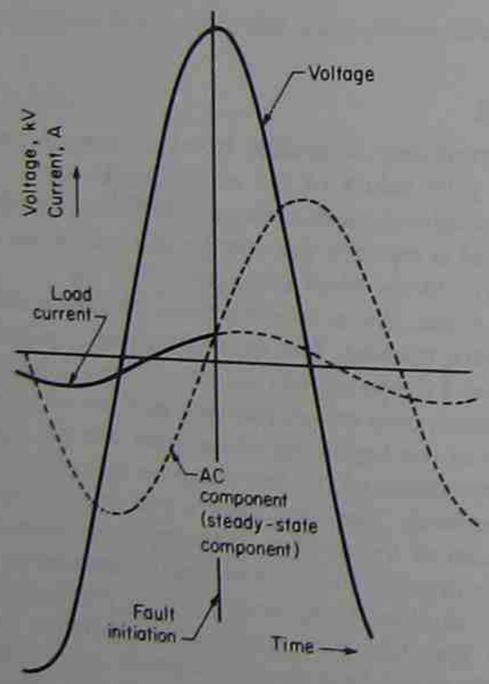


FIG. 4-26 Components of actual fault current and effect of time of fault initiation upon magnitude of rms fault current. Fault initiation at (*a*) ac component peak, (*b*) voltage zero, and (*c*) instant when ac component and load current are equal (no dc component exists). *(Courtesy McGraw Edison Co.)*

Figure 4-26*a* through *c* shows the effect of the time of fault initiation. If it occurs at the ac component peak, maximum transient current occurs. This dc component is equal to the difference between the instantaneous values of the ac fault current and the ac load current. Maximum transient current occurs at the ac component peak, but maximum rms fault current occurs at voltage zero. The transient component is zero when the fault occurs at the time the instantaneous values of the load current and steady-state current are equal. Between the maximum and zero transient points, a transient component will exist in which the rms fault current is less than the rms current when the fault occurs at voltage zero. Since protective devices operate during transient periods, they are designed to interrupt the maximum possible fault current.

Factors of Asymmetry

As the reactance to resistance ratio (*X/R*) and the power factor of a faulted circuit change, the magnitude of the asymmetric current will vary with respect to the symmetric current. As this ratio increases and the power factor decreases, the asymmetric current will increase. A ratio, known as the factor of symmetry, of the asymmetric to the symmetric current can be found for different *X/R* ratios and corresponding power factors. As shown in Fig. 4-27, a specific factor exists for each *X/R* ratio and corresponding power factor.

When the symmetric current and the *X/R* ratio are known, the maximum asymmetric current can be found. This is useful in the design of fuse cutouts which are rated asymmetrically.



FIG. 4-27 Factors of asymmetry for various power factor percentages and *X/R* ratios. *(Courtesy McGraw Edison Co.)*

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Symmetrical Components

The simplified equations for calculating fault currents are derived from the symmetrical equations:

1. $I_{3\phi} = \dfrac{E_{\phi\text{-}N}}{Z_1}$

2. $I_{\phi\text{-}\phi\text{-}G} = \dfrac{E_{\phi\text{-}N}a^2(Z_0 + Z_2) - aZ_0 - Z_2}{Z_1Z_0 + Z_1Z_2 + Z_0Z_2}$

3. $I_{\phi\text{-}\phi} = \dfrac{3E_{\phi\text{-}N}}{Z_1 + Z_2}$

4. $I_{\phi\text{-}G} = \dfrac{3E_{\phi\text{-}N}}{Z_1 + Z_2 + Z_0}$

where Z_1 is the positive-sequence impedance, Z_2 is the negative-sequence component, Z_0 is the zero-sequence component, and each one represents the summation of like components throughout the faulted circuit. Also, a is the unit vector $e^{j120} = -0.5 + j0.866$, that is, an operator which indicates that the vector to which it is attached has been rotated through 120° in a positive or clockwise direction; a^2 indicates rotation through 240°. Further, theoretically, the three impedance components for a transformer are equal; that is, $Z_1 = Z_2 = Z_0$; also the positive- and negative-sequence components for conductors are equal; that is, $Z_1 = Z_2$. The three transformer components can be set equal to Z_A, the two conductor components equal to Z_B, and the conductor zero-sequence component equal to Z_C.

1. Substituting in the basic equations above:

$$E_{\phi\text{-}N} = \frac{E_{\phi\text{-}\phi}}{\sqrt{3}}$$

$Z_1 = Z_A$ (positive transformer component)

$+ Z_B$ (positive conductor component)

$$I_{3\phi} = \frac{E_{\phi\text{-}\phi}/\sqrt{3}}{Z_A + Z_B} = \frac{0.58E_{\phi\text{-}\phi}}{Z_A + Z_B}$$

2. Eliminating the factor a by trigonometry,

$$I_{\phi\text{-}\phi\text{-}G} = \frac{\sqrt{3}(E_{\phi\text{-}\phi}/\sqrt{3})\sqrt{Z_0^2 + Z_0Z_2 + Z_2^2}}{Z_1Z_0 + Z_1Z_2 + Z_0Z_2}$$

$$= \frac{E_{\phi\text{-}\phi}\sqrt{(Z_A + Z_C)^2 + (Z_A + Z_C)(Z_A + Z_B) + (Z_A + Z_B)^2}}{(Z_A + Z_B)(Z_A + Z_C) + (Z_A + Z_B)(Z_A + Z_B) + (Z_A + Z_C)(Z_A + Z_B)}$$

$$= \frac{E_{\phi\text{-}\phi}\sqrt{(Z_A + Z_B)^2 + (Z_A + Z_C)^2 + (Z_A + Z_B)(Z_A + Z_C)}}{(Z_A + Z_B)[2(Z_A + Z_C) + (Z_A + Z_B)]}$$

3. $$I_{\phi\text{-}\phi} = \frac{3(E_{\phi\text{-}\phi}/\sqrt{3})}{(Z_A + Z_B) + (Z_A + Z_B)} = \frac{\sqrt{3}E_{\phi\text{-}\phi}}{2(Z_A + Z_B)}$$

$$= \frac{1.73}{2}\frac{E_{\phi\text{-}\phi}}{Z_A + Z_B} = 0.87I_{3\phi}$$

4. $$I_{\phi\text{-}G} = \frac{3(E_{\phi\text{-}\phi}/\sqrt{3})}{(Z_A + Z_B) + (Z_A + Z_B) + (Z_A + Z_C)}$$

$$= \frac{1.73E_{\phi\text{-}\phi}}{3Z_A + 2Z_B + Z_C}$$

EXAMPLE 4-8 System coordination (refer to Fig. 4-28)

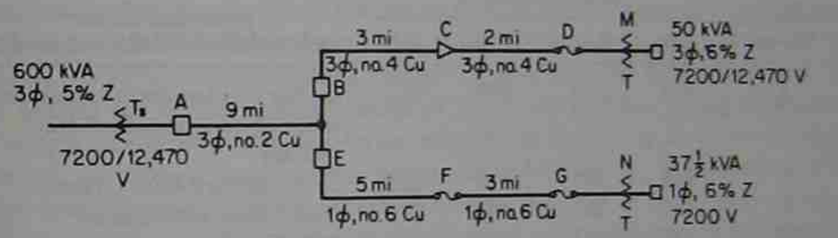


FIG. 4-28 One-line diagram of illustrative typical system.

The impedance of transformer T_1 is 15.57 Ω (from the manufacturer's table for 6% Z); Z_A for a 5% Z transformer is 5/6 of 15.57 or 12.98 Ω. The impedance of the lines (from manufacturers' tables):

Line section	*Wire size*	*Length, mi*	*Impedance, Ω**	
			Z_B	Z_C
3ϕ AB	no. 2 Cu	9	10.17	23.23
3ϕ BC	no. 4 Cu	3	4.71	9.48
3ϕ CD	no. 4 Cu	2	3.14	6.32
1ϕ EF	no. 6 Cu	5	11.45	19.60
1ϕ FG	no. 6 Cu	3	6.87	11.76

*Z_B is the positive- or negative-sequence value. Z_C is the zero-sequence value.

Total impedance from substation to load side of protective device:

Protective device	Line voltage	Impedance, Ω			
		Transformer Z_t	Line* Section	Line* Z_s	Line* Z_c
A	12,470	12.98	—	0.00	0.00
B	12,470	12.98	AB	10.17	23.13
C	12,470	12.98	AC	14.88	32.61
D	12,470	12.98	AD	18.02	38.93
E	12,470	12.98	AE	10.17	23.13
F	12,470	12.98	AF	21.62	42.73
G	12,470	12.98	AG	28.49	54.49

*Z_s is the positive- (or negative-) sequence value; Z_c is the zero-sequence value.

Available fault currents on load side of protective device and selection:

Protective device	Fault currents, A				Protection device selected (EEI-NEMA standards)
	3-Φ	Φ-Φ-G	Φ-Φ	Φ-G	
A	567	567	486	567	Circuit breaker and overcurrent relay, or 35-A standard-duty recloser
B	312	290	272	262	15-A standard-duty recloser
C	259	241	225	212	25-A 3-shot sectionalizer*
D	233	217	203	189	8 (A) T link fuse
E	—	—	—	262	15-A 14t standard-duty recloser
F	—	—	—	173	10 (A) K link fuse
G	—	—	—	143	6 (A) K link fuse

*Recloser B has one fast operation when a fault occurs on the load side of D; the sectionalizer counts one operation, but the link fuse at D does not melt. During the second time-delayed operation of recloser B, the link fuse at D melts and clears the fault. The sectionalizer counts this as the second operation; with the fault removed, both recloser and sectionalizer reset and the line is energized to D.

STREET LIGHTING

Street lighting may be supplied from either series or multiple circuits. Series circuits and lamps have been extensively used in the past and many such systems are still in operation. Multiple supply, however, has been used almost exclusively in later installations, especially with the development of economical light-sensitive control devices, which has made practical the connection of such lighting to the same secondary mains that also supply other types of customers.

Multiple Circuits

Multiple street lighting is usually served from secondary mains at normal utilization voltages. The secondary may be a separate circuit serving only street lighting loads, or part of the secondary circuit supplying other customers. The former may have controls exclusive to the circuit, while the latter may have individual controls for individual lamps or groups of lamps. As mentioned earlier, such circuits may be controlled from a variety of relays, some actuated from series street lighting circuits. Photocells, activated by the light intensity of the ambient, and connected between the secondary supply and the streetlight, have proven economical and desirable, as they simplify controls, eliminating additional wires and improving the appearance of overhead lines.

The principal advantage of multiple supply is the use of the secondary distribution systems, with only minor effects on transformer load and voltage conditions; additional advantages include greater safety because of the low voltages involved as well as lower handling and installation costs, as the equipment used is essentially that in use on distribution circuits. In most instances, separate lightning or surge arresters are not required.

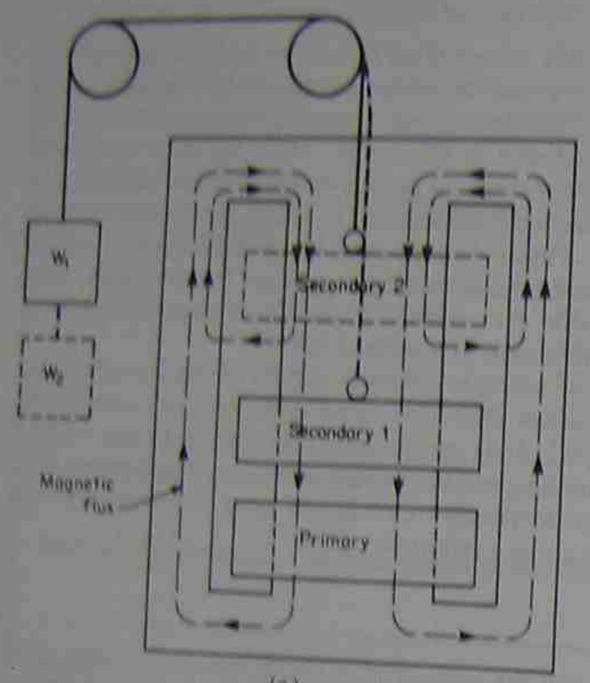
Series Circuits

As the name denotes, lamps in the series type of circuit are connected in series and supplied from a constant-current transformer; the usual current output rating is 6.6 A, with the outgoing voltage varying with the load connected. The light output for different-sized lamps at this fixed current rating depends on the length of the filament; for larger-size lamps operating at 15 or 20 A, the filaments are also of heavier cross section in order to carry the greater current safely. Series lamps often are rated in lumens, the unit of light flux, while the wattage may vary with the size of the lamp. Lamp efficiency is expressed in lumens per watt, with 600-lm lamps operating at 6.6 A requiring about 43 W while 6000-lm lamps require approximately 320 W. Light efficiency is further increased with reflectors and refractors.

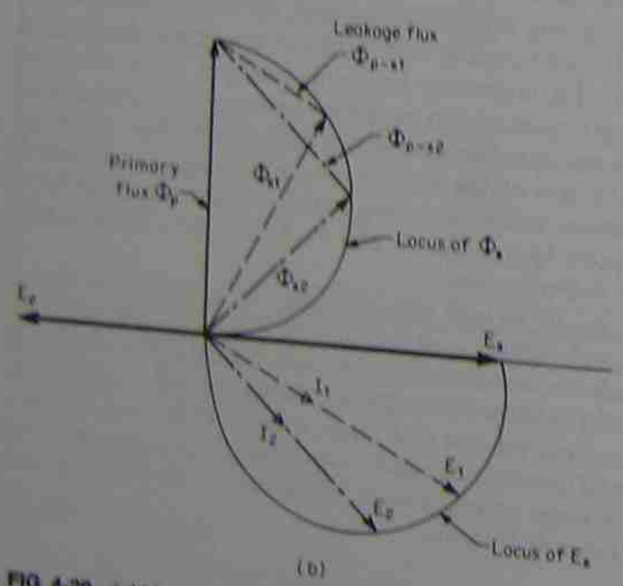
Advantages of series circuits include high efficiency for a widely distributed load, the ability to use a high-voltage and low-current supply that permits long lengths of relatively small-size conductors to be used with low loss and small voltage drop, and the ability to keep the variation in light intensity at a minimum because of the constant current value at each lamp. Disadvantages mainly center around the need for special transformers and control devices, as well as the need for separate lightning or surge arresters at the transformer, the switches, and certain points along an extended circuit.

Constant-Current Transformers

To obtain a constant current output from an essentially constant voltage supply, the two coils of the transformer are so arranged that the distance between them may be varied. The primary coil, receiving power at a constant voltage, is fixed in position. The secondary coil is movable along the common core; its position



(a)



(b)

FIG. 4-29 (a) Movable-coil constant-current transformer. (*b*) Vector diagram of relation between primary and secondary voltage, current, and magnetic flux.

depends on the load. The secondary coil is balanced by a weight that reacts proportionally with the repulsion forces to maintain its output at the rated value.

When the two coils are close together, the magnetic field or flux produced by the primary interlinks maximally with the secondary coil, inducing a maximum secondary voltage. The coils act as magnets and tend to repel each other. As the load on the secondary decreases, the current in the secondary will tend to increase, increasing the repulsion between the coils. The secondary coil is raised, decreasing the magnetic field or flux linking the two coils, thereby decreasing the secondary voltage, and the current is dropped to its rated value. Refer to Fig. 4-29*a* and *b*.

The majority of series street lighting circuits are operated without grounds. When an accidental ground occurs, the circuit is generally not affected. When a second ground occurs, the lamps between the two grounds will go out or burn dimly, giving ready indication of the location of the grounds. In some instances, however, an intentional ground is placed at mid-circuit. This not only reduces the normal stresses on the insulation of the several units in the circuit to one-half the voltage of the constant-current transformer, but serves to help locate the point of accidental ground, as indicated above.

Constant-current transformers may be installed at the substation, in underground vaults, or mounted on poles.

Series Lamps

Series lamps are usually rated at 6.6 A. Larger lamps, generally 4000 lm or larger, are supplied at 15 or 20 A through transformers that supply an individual lamp (referred to as IL transformers) or transformers that supply several lamps (referred to as SL transformers).

Lamp failure in a series circuit causes a momentary opening of the circuit and a high voltage at the terminals of the lamp. A *film disk cutout*, connected between the terminals of the lamp, normally acting as an insulator, breaks down

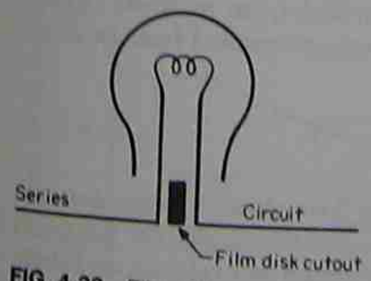


FIG. 4-30 Film disk cutout schematic diagram.

and short-circuits the failed lamp. Refer to Fig. 4-30. Thus circuit continuity and service to the rest of the circuit are restored. The slight reduction in load causes the constant-current transformer to reduce the total voltage on the circuit, maintaining the current at the rated constant value.

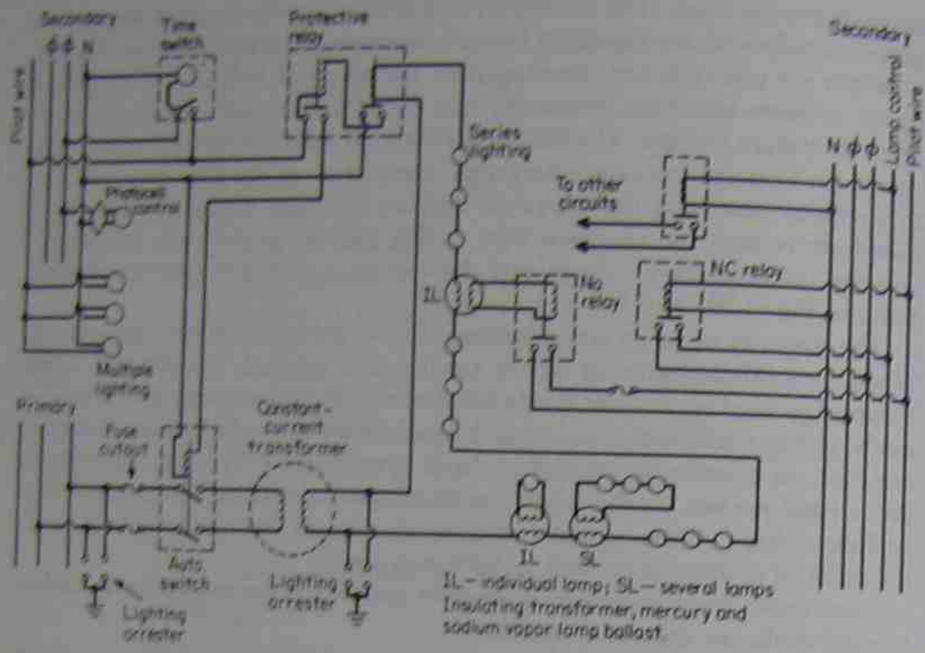


FIG. 4-31 One-line diagram series-multiple and multiple-series controlled street lighting.

Control Devices

Series circuits may be controlled from the substation manually or through time switches that automatically turn them on and off at predetermined times; one such switch operates in accordance with the hours of sunset and sunrise, and is called an *astronomical time switch*.

Control circuits employing a variety of relays and schemes that "cascade," one control circuit controlling one or more additional control circuits, are shown in Fig. 4-31. Note that series circuits can be controlled from multiple circuits supplying only street lights, or from light-sensitive relays supplied from multiple circuits.

PRACTICAL BASIS OF DESIGN

In distribution system studies, particularly where growth and expansion are contemplated, several plans are usually taken under consideration. For purposes of comparison, design voltage-drop limits are determined beforehand, and these same limits are used in all of the studies.

A peak-load voltage profile is developed and plotted in terms of equivalent secondary voltages, as shown in Fig. 4-32. Comparable layouts are made to provide adequate voltages and suitable equipment loadings with the design loads. A light-load voltage profile is assumed to fall within permissible limits, although regulator changes at the substation may be relied upon to maintain maximum permissible voltage at the first customer.

The utilization voltage spread of 15 V, the estimated service and customer wiring voltage drops, and contact-making-voltmeter (voltage-regulating relay) bandwidth setting are derived from industry standards accepted for the design of utilization devices. Reference to Fig. 4-32 shows that there is a spread of 10 V to "spend" in the design of the distribution system between the primary of the first transformer and the end of the secondary of the last transformer on the circuit. In general, industry experience indicates that a feasible and economical allocation of this 10 V is to use a voltage drop of 3 to 4 V in the primary between the first and last transformer and 6 to 7 V in the transformer-secondary combination.

For example, an economical means of providing for load growth, particularly where obtaining substation sites is a problem, is the conversion of 2400/4160 V distribution systems to 7620/13,200 V operation. Conversion may be most easily accomplished by first converting the areas most remote from existing 4160-V substations. The 4160-V substation facilities can thus be kept operating at approximately their capacity although the area served will become smaller as the load density increases. All 4160-V equipment, including distribution transformers, can be used continuously and economic loss from premature retirement of such equipment can be avoided. New equipment for 13,200-V service will take care of load growth on the 13,200 V system.

In comparing an existing 4160-V system with a proposed 13,200-V system, voltage drops and energy losses are calculated, and circuits are designed to keep voltage drops within the limits expressed above—and shown in Fig. 4-32—and to keep energy losses to a minimum.

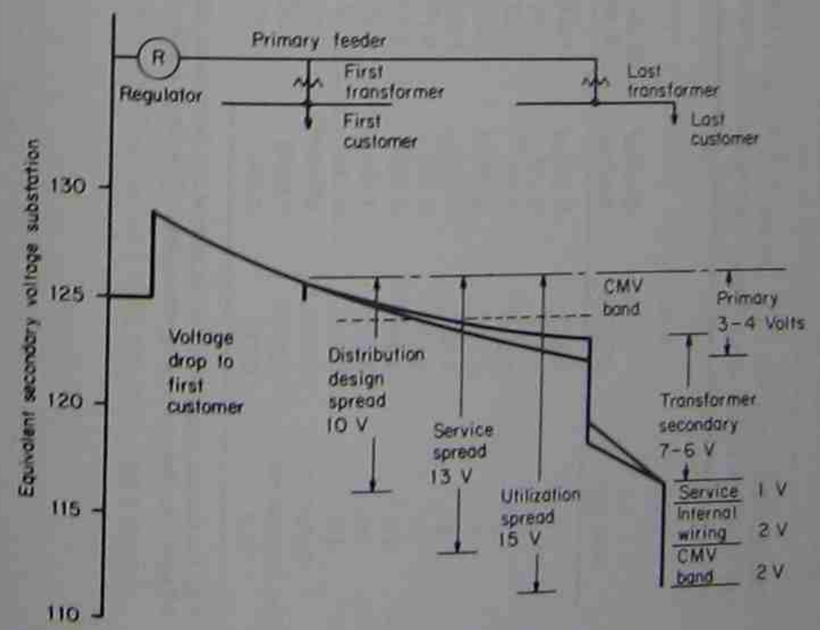


FIG. 4-32 Allocation of voltage drops on distribution systems.

TABLE 4-5A UNIT VOLTAGE DROPS FOR PRESENT 4160-V SYSTEM
(10 kVA, 100 ft, *L/N* voltage drop, 2360/4080 receiver volts)

			Power factor 0.85			*Power factor 0.90*		
Wire size	*R(25°C)*	*X(35-in spacing*	*R cos θ + X sin θ*	*3φ unit voltage drops*	*1φ unit voltage drops*	*R cos θ + X sin θ*	*3φ unit voltage drops*	*1φ unit voltage drops*
8	0.657	0.151	0.638	0.901	5.40	0.657	0.929	5.57
6	0.413	0.145	0.428	0.605	3.63	0.435	0.615	3.69
4	0.260	0.140	0.295	0.417	2.50	0.295	0.417	2.50
3	0.209	0.135	0.249	0.352	2.11	0.247	0.349	2.09
2	0.167	0.133	0.212	0.300	1.80	0.208	0.294	1.76
1/0	0.105	0.128	0.157	0.222	1.33	0.150	0.212	1.27
2/0	0.0833	0.125	0.138	0.195	1.17	0.130	0.184	1.10
3/0	0.0663	0.120	0.120	0.170	1.02	0.112	0.158	0.950
4/0	0.0527	0.119	0.107	0.151	0.906	0.0994	0.140	0.841
3c, 1/0	0.105	0.031	0.106	0.150	0.899	0.108	0.152	0.915
3c, 300,000 cmil	0.0372	0.0270	0.0458	0.0647	0.388	0.0453	0.0640	0.384
2c,6	0.413	0.034	0.370	—	3.13	0.387	—	3.28

Note: For the two phase wires and the neutral of a three-phase system, use 0.5 times the single-phase unit voltage drops. For the two-phase 4-wire system, use 0.5 times the single-phase unit voltage drops. The above voltage drops are line-to-neutral for a wye-connected system.

TABLE 4-5B UNIT VOLTAGE DROPS: CALCULATIONS FOR PROPOSED CONDITIONS
(10 kVa, 1000 ft, *L/N* voltage drop, 122-V equivalent receiver, 0.90 power factor)

				4160-V system		*13,200-V system*	
Wire size	*R(25°C)*	*X (54-in spacing)*	*R cos θ + X sin θ*	*3φ unit voltage drops*	*1φ unit voltage drops*	*3φ unit voltage drops*	*1φ unit voltage drops*
8	0.657	0.160	0.661	0.903	5.42	0.284	1.71
6	0.413	0.155	0.440	0.600	3.60	0.189	1.14
4	0.260	0.150	0.300	0.410	2.46	0.129	0.774
3	0.209	0.145	0.251	0.343	2.06	0.108	0.648
2	0.167	0.143	0.212	0.290	1.74	0.0912	0.548
1/0	0.105	0.138	0.155	0.212	1.27	0.0666	0.400
2/0	0.0833	0.135	0.134	0.183	1.10	0.0576	0.346
3/0	0.0663	0.130	0.116	0.158	0.950	0.0498	0.299
4/0	0.0527	0.128	0.103	0.141	0.845	0.0443	0.266
3c, 1/0	0.105	0.031	0.108	0.148	—	0.0463	—
3c, 300,000 cmil	0.0372	0.0270	0.0453	0.0619	—	0.0195	—
2c, 6	0.413	0.034	0.387	—	3.17	—	0.998

Note: The above voltage drops are line-to-neutral values.

The computation of voltage drops and losses on an extensive distribution circuit is a rather long and tedious process. A method for making calculations easily and providing a record of basic data employs a system of "unit voltage drops"; a self-explanatory data form also indicates the procedure for making the computations.

For convenience, the unit selected for the voltage-drop calculations may be 10,000 kVA-ft, that is, 10 kVA at a distance of 1000 ft or 100 kVA at a distance of 100 ft, etc. Power factors and equivalent spacings used for calculations are indicated in Tables 4-5A and 4-5B for the two voltages under consideration. Circuit loads are assumed distributed in proportion to the connected transformers except where relatively large individual loads are known, in which case equivalent transformer capacity is estimated on the basis of known demands.

Included with the calculations is a sketch of the existing and proposed circuit with station numbers for each branch, transformer or group of transformers, or wire size change; these correspond to numbers on the calculation sheet. Factors for each wire size to convert from percent voltage drop to percent kilowatt loss are shown in Table 4-5C; losses in some smaller branches are

TABLE 4-5C RELATION OF PERCENT VOLTAGE DROP AND PERCENT KILOWATT LOSS

3 phase, unit length, load concentrated at end:

Factor = $R \cos\theta + X \sin\theta$; θ = power factor angle

$$\frac{kVA \times \text{factor}}{(kV)^2 \times 10} = \%\ \text{voltage drop} = \%\ V$$

$$\frac{(kVA)^2 \times R}{(kV)^2 \times 10 \times kVA \times PF} = \frac{kVA \times R}{(kV)^2 \times PF \times 10} = \%\ kW\ \text{loss} = \%\ L$$

where PF = power factor and R = resistance of one conductor.

$$\frac{\%\ L}{\%\ V} = \frac{kVA \times R}{(kV)^2 \times PF \times 10} \qquad \frac{9(kV)^2 \times 10}{kVA \times \text{factor}} = \frac{R}{PF \times \text{factor}}$$

For single-phase, the same ratio applies.

Conductor size	R (25°C)	Factor ($R \cos\theta + X \sin\theta$)	$\%\ L/\%\ V$
6	0.413	0.440	1.04
3	0.209	0.251	0.925
2	0.167	0.212	0.875
1/0	0.105	0.155	0.752
2/0	0.0833	0.134	0.680
4/0	0.0527	0.103	0.569

Assumed power factor = 0.90.

TABLE 4-5D SAMPLE PRIMARY CIRCUIT DATA AND CALCULATIONS

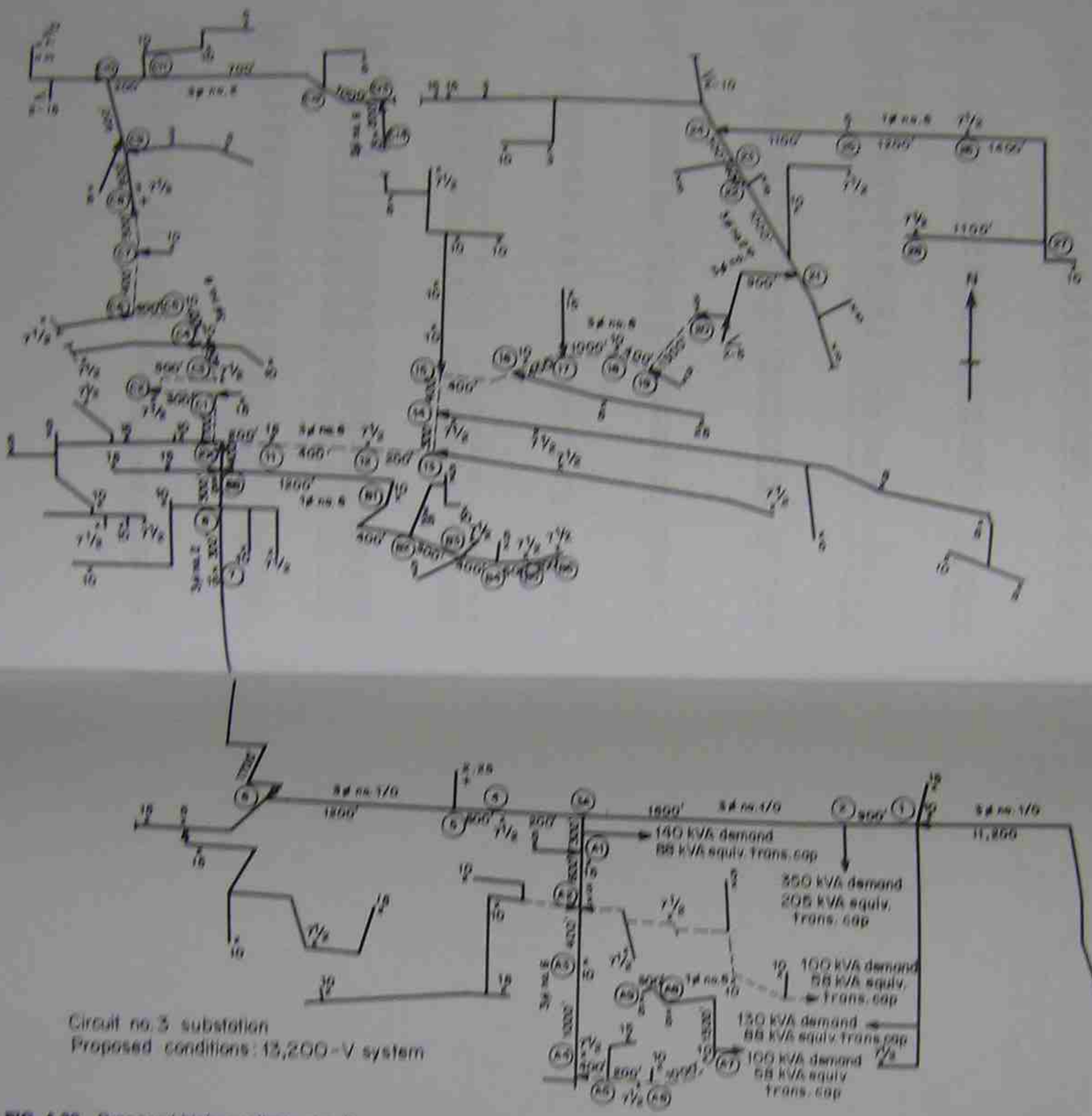
Circuit No. *x*, substation ABC, nominal circuit voltage 13,200, lamp voltage 120. Average delivered primary voltage 7750 (line-to-neutral for wye circuits), load condition peak.

1. Total transformer kVA:	1614
2. Maximum circuit load:	2760 kVA
3. Capacity factor (item 2 ÷ item 1):	1.71
4. Basic voltage drop, sub to last transformer:	193.5
5. Basic voltage drop, sub to first transformer:	104.1
6. Basic voltage drop, first to last transformer:	89.4
7. Calculated voltage drop, first to last transformer (item 3 × item 6):	152.9
8. Percent voltage drop, first to last transformer (item 7 ÷ average delivered primary voltage, × 100):	1.9
9. Percent voltage drop, sub to first transformer (item 3 × item 5 ÷ average delivered primary voltage, × 100):	2.3
10. Percent voltage drop, sub to last transformer:	4.2

	Distance, ft			Transformer kVA				Basic voltage drop		
Station	Between stations	From substation	Conductor size	At station	Subtotal from last station	$\frac{kVA \cdot ft}{10{,}000} = \frac{B \times F}{10{,}000}$	Unit voltage drop	From previous station ($G \times H$)	From substation (subtotal col. I)	Percent kV loss
A	B	C	D	E	F	G	H	I	J	K
1	11,200	11,200	3φ, 2/0	115	1614	1807.7	0.0576	104.1	104.1	1.56
2	900	12,100	3φ, 1/0	205	1499	134.9	0.0666	8.9	113.0	
3A	1,600	13,700	3φ, 1/0	376	1294	207.0	0.0666	13.8	126.8	
4	200	13,900	3φ, 1/0	8	918	18.4	0.0666	1.2	128.0	
5	600	14,500	3φ, 1/0	50	810	48.6	0.0666	3.2	131.2	
6	1,200	15,700	3φ, 1/0	68	860	103.2	0.0666	6.9	138.1	0.56
7	1,700	17,400	3φ, 2	15	792	134.6	0.0912	12.3	150.4	
8	300	17,700	3φ, 2	38	777	23.3	0.0912	2.1	152.5	
9B	500	18,200	3φ, 2	118	739	36.9	0.0912	3.4	155.9	
10C	400	18,600	3φ, 2	275	621	24.8	0.0912	2.3	158.2	0.38

TABLE 4-5D SAMPLE PRIMARY CIRCUIT DATA AND CALCULATIONS *(Continued)*

	Distance, ft			Transformer kVA				Basic voltage drop		
Station	Between stations	From substation	Conductor size	At station	Subtotal from last station	$\frac{kVA \cdot ft}{\frac{10000}{B \times F}} = \frac{}{10000}$	Unit voltage drop	From previous station (G × H)	From substation (subtotal col. I)	Percent kV loss
A	B	C	D	E	F	G	H	I	J	K
11	200	19,200	3ϕ, 6	15	346	6.9	0.189	1.3	159.5	
12	400	19,200	3ϕ, 6	8	331	13.2	0.189	2.5	162.0	
13	200	19,400	3ϕ, 6	15	323	6.5	0.189	1.2	163.2	
14	500	19,900	3ϕ, 6	43	308	15.4	0.189	2.9	166.1	
15	400	20,300	3ϕ, 6	53	265	10.6	0.189	2.0	168.1	
16	400	20,700	3ϕ, 6	40	212	8.5	0.189	1.6	169.7	
17	400	21,100	3ϕ, 6	15	172	6.9	0.189	1.3	171.0	
18	1,000	22,100	3ϕ, 6	10	157	15.7	0.189	2.9	173.9	
19	400	22,500	3ϕ, 6	5	147	5.9	0.189	1.1	175.0	
20	1,300	23,800	3ϕ, 6	13	142	18.5	0.189	3.5	178.5	
21	900	24,700	3ϕ, 6	26	129	11.6	0.189	2.2	180.7	
22	1,000	25,700	3ϕ, 2	3	103	10.3	0.0912	0.9	181.6	
23	400	26,100	3ϕ, 2	3	100	4.0	0.0912	0.4	182.0	
24	300	26,400	3ϕ, 2	66	97	2.9	0.0912	0.3	182.3	
25	1,100	27,500	1ϕ, 6	5	31	3.4	1.14	3.9	186.2	
26	1,200	28,700	1ϕ, 6	8	26	3.1	1.14	3.5	189.7	
27	1,400	30,100	1ϕ, 6	10	18	2.5	1.14	2.8	192.5	
28	1,100	31,200	1ϕ, 6	8	8	0.9	1.14	1.0	193.5	0.81
3A	—	13,700	—	—	376	—	—	—	126.8	
A1	300	14,000	3ϕ, 6	101	376	11.3	0.189	2.1	*128.9*	
A2	600	14,600	3ϕ, 6	146	275	16.5	0.189	3.1	*132.0*	
A3	400	15,000	3ϕ, 6	10	129	5.2	0.189	0.9	*132.9*	
A4	1,000	16,000	3ϕ, 6	8	119	11.9	0.189	2.2	*135.1*	
A5	400	16,400	2ϕ, 6	15	111	4.4	0.57	2.5	137.6	
A6	200	16,600	2ϕ, 6	18	96	1.9	0.57	1.1	138.7	
A7	1,000	17,600	2ϕ, 6	68	78	7.8	0.57	4.4	143.1	
A8	1,500	19,100	1ϕ, 6	5	10	1.5	1.14	1.7	144.8	
A9	300	19,400	1ϕ, 6	5	5	0.2	1.14	0.2	145.0	0.42
9B	—	18,200	—	35	118	—	—	—	155.9	
B1	1,200	19,400	1ϕ, 6	10	83	9.9	1.14	11.3	167.2	
B2	900	20,300	1ϕ, 6	40	73	6.6	1.14	7.5	174.7	
B3	300	20,600	1ϕ, 6	12	33	0.9	1.14	1.0	175.7	
B4	400	21,000	1ϕ, 6	5	21	0.8	1.14	0.9	176.6	
B5	500	21,500	1ϕ, 6	8	16	0.8	1.14	0.9	177.5	
B6	700	22,200	1ϕ, 6	8	6	0.6	1.14	0.7	178.2	0.51
10C	—	18,600	—	78	275	—	—	—	158.2	
C1	700	19,300	3ϕ, 6	22	197	13.8	0.189	2.6	160.8	
C2	300	19,600	3ϕ, 6	8	175	5.3	0.189	1.0	161.8	
C3	500	20,100	3ϕ, 6	8	167	8.3	0.189	1.6	163.4	
C4	400	20,500	3ϕ, 6	28	159	6.4	0.189	1.2	164.6	
C5	300	20,800	3ϕ, 6	10	131	3.9	0.189	0.7	165.3	
C6	400	21,200	3ϕ, 6	8	121	4.8	0.189	0.9	166.2	
C7	400	21,600	3ϕ, 6	10	113	4.5	0.189	0.9	167.1	
C8	500	22,100	3ϕ, 6	10	103	5.1	0.189	0.9	168.0	
C9	900	23,000	3ϕ, 2	13	93	8.4	0.0912	0.8	168.8	
C10	400	23,400	3ϕ, 2	40	80	3.2	0.0912	0.3	169.1	
C11	200	23,600	3ϕ, 2	25	40	0.8	0.0912	0.1	169.2	
C12	700	24,300	3ϕ, 2	5	15	1.1	0.0912	0.1	169.3	
C13	1,000	25,300	3ϕ, 2	—	10	1.0	0.0912	0.1	169.4	
C14	200	25,500	1ϕ, 6	10	10	0.2	0.0912	0.0	169.4	0.26
								Total percent loss		4.50



Circuit no. 3 substation
Proposed conditions: 13,200-V system

FIG. 4-33 Proposed higher-voltage circuit

neglected to simplify calculations, but results are sufficiently accurate for purposes of comparison.

In making comparisons, evaluation of losses should include both a demand component reflecting system investment and an energy component. Also, costs of conversion reflecting both additional capital investment and annual operating and maintenance expenses should be taken into account. All of these values are different for each utility. The data sheet and circuit configuration for only the proposed circuit are included in this example; refer to Table 4-5D and Fig. 4-33.

CHAPTER 5

MECHANICAL DESIGN: OVERHEAD

CRITERIA

The mechanical design of the distribution system, and its several parts, must not only be adequate to sustain the normal stresses and strains, but must safely sustain them during abnormal conditions brought about by the vagaries of nature and people. While design criteria for overhead systems are substantially different from those for underground systems, in both instances prudent design takes into account economic and other nontechnical considerations.

For overhead systems, the supports for the conductors and equipment must withstand the forces imposed on them, while the conductors themselves must be sufficiently strong to support their own weight and the forces imposed on them.

National Electric Safety Code (NESC)

Minimum design criteria are suggested in the National Electric Safety Code (NESC) issued by the Institute of Electrical and Electronics Engineers (IEEE). The NESC has received wide acceptance by utilities and other industries in this country and elsewhere.

In general, the code specifies:

1. Clearances between conductors and surrounding structures for different operating voltages and under different local conditions
2. Strength of materials and safety factors used in proposed structures
3. Perhaps the most basic, the probable loading imposed on the conductors and structures based on climatic conditions, approximately defined by geographic areas

TABLE 5-1 WIND AND ICE LOADINGS ON OVERHEAD SYSTEMS

Type of loading	Radial thickness of ice		Wind load on projected area of conductors		Temperature	
	in	cm	lb/ft²	kg/m²	°F	°C
Heavy	0.5	1.27	4	20	0	−18.0
Medium	0.25	0.63	4	20	+15	−9.4
Light	0.0	0.0	9	44	+30	−1.1

For current industry recommended values, refer to the latest revision of the National Electric Safety Code.

The NESC divides the country into heavy, medium, and light load areas. The heavy loading area comprises roughly the northeast quarter of the "lower 48" states, and Alaska; the medium loading area comprises the northwest quarter plus a strip across the middle of the country; the light loading area comprises California and all the southern part of the country to a depth of some 300 to 400 mi, and Hawaii. The degrees of loading are indicated in Table 5-1, and the geographic areas for the continental United States in the map shown in Fig. 5-1. The values and areas of demarcation are approximate and should be subject to other practical considerations, including probable deviations based on actual experience, local codes and regulations, and other environmental requirements.

POLES

Stresses

The forces acting on a pole stem from the vertical loading occasioned by the weight it has to carry and from the horizontal loadings applied near the top of the pole. These latter are exerted by the conductors as a result of uneven spans,

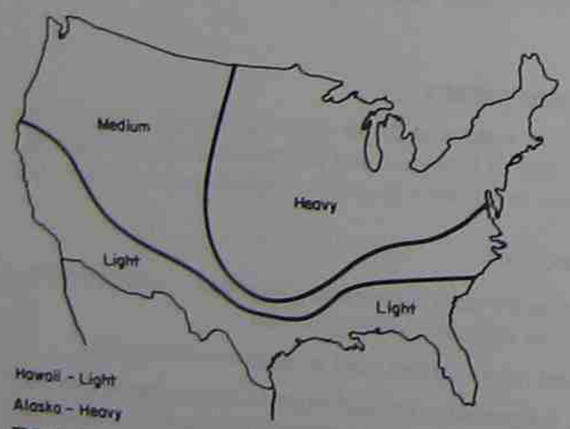


FIG. 5-1 Loading districts.

of offsets and bends in the lines, and of the pressure of wind blowing against them. Both vertical and horizontal loadings include the effects of ice collecting radially about the conductors.

The vertical force on the pole is the dead weight of the conductors with their coatings of ice, cross arms, insulators, and associated hardware. This vertical force exerts a compressive stress that may be considered uniformly distributed over the cross section of the pole. This loading, however, is almost always overshadowed by the requirements of the horizontal loadings, and is usually not given further attention. Even a very light pole can safely carry the dead weight of a multicircuit, large-conductor line.

EXAMPLE 5-1

Assume relatively long spans of 200 ft, six primary conductors on two cross arms, and one heavy neutral (for two three-phase feeders) and three secondary conductors on a rack; moreover, the cross arms are two sets of double arms, with insulators and associated pins and hardware.

Assume no. 4/0 copper or 397,500-cmil ACSR (250 cmil × 10^3 copper equivalent), the largest usual distribution conductor, with a radial half-inch coating of ice (at 57 lb/ft³).* Assume a light pole, class 5 pine, with a minimum (top) circumference of 19 in (disregard the effect of the larger, lower cross-sectional areas because of taper; i.e., assume a cylindrical column).

From wire manufacturers' tables, no. 4/0 copper wire has a diameter of 0.528 in and a weight of 640.5 lb per 1000 ft; and 397,500-cmil ACSR has a diameter of 0.806 in and a weight of 620.6 lb per 1000 ft. The total weight, including ice, for 200 ft (100 ft on each side of pole) for the copper conductors is 2120 lb plus 500 lb allowed for four cross arms, insulators, etc., or 2620 lb. For the ACSR conductors, it is 2840 lb, plus the same 500 lb, or 3340 lb.

The cross-sectional area at the top of a class 5 pole is

$$A = \pi r^2 = \pi\left(\frac{19}{2\pi}\right)^2 = \frac{90.25}{3.14} = 28.7 \text{ in}^2$$

This may be rounded off to 25 in².

Conservatively, the dead weight of the copper conductors is 2750 lb divided by 25 in², or 110 lb/in²; that of the ACSR conductors is 3500 lb divided by 25 in², or 140 lb/in².

*Traditionally, the wire manufacturing industry has used the abbreviations cm and mcm for circular mils and thousands of circular mils. However, as the metric system becomes more familiar in the United States, the abbreviation cm is more likely to be mistaken for more familiar in the United States, the abbreviation cm is more likely to be mistaken for centimeters and the prefix m- for a multiplier of 10^{-3}. Therefore, throughout this book the more current U.S. abbreviation cmil will be used for circular mils; for thousands, either the number will be spelled out in full, or the multiplier 10^3 will be given, whichever is appropriate.

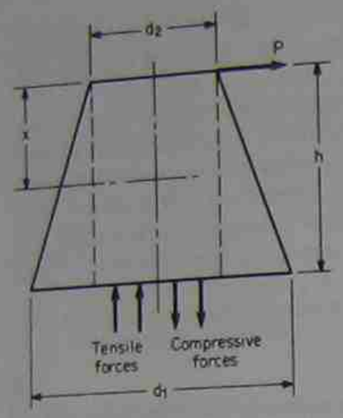


FIG. 5-2 Diagram of stresses on pole.

The maximum permissible compressive stress for wood ranges from about 300 lb/in² for western red cedar to 600 lb/in² for southern long-leaf yellow pine.

For the horizontal loading, the pole can be considered a cantilever beam anchored at one end with a load applied at the other. The bending moment produces stresses in the wood, with the maximum fiber stress occurring at the edge of the cross section farthest from the neutral axis; the stresses are compressive on the side on which the load is pulling and tensile on the opposite side. Refer to Fig. 5-2.

Bending Moment The bending moment M is equal to the horizontal force applied P, multiplied by its perpendicular distance to the point where failure may occur, h, usually taken at the ground line.

$$M = Ph$$

Maximum Fiber Stress The maximum fiber stress f at any cross section is

$$f = M\frac{c}{I}$$

where c is the distance from the extreme fibers of cross section to the neutral axis and I is the moment of inertia of the cross section. For a circular cross section, where d is the diameter,

$$c = \tfrac{1}{2}d$$

$$I = \frac{\pi d^4}{64} = 0.0491d^4$$

so that

$$f = \frac{M}{0.0982d^3}$$

and

$$\frac{I}{c} = \frac{\pi d^3}{32} = 0.0982d^3 \qquad \text{(called the section modulus)}$$

Wind Pressure In arriving at M, if P is the wind pressure on the length of the conductor, including its coating of ice, and h the distance or height from the ground at which the circular cross section is to be determined, the total moment for the several conductors that may be supported is the sum of the values of Ph for all the conductors.

To this must be added the wind pressure on the pole itself. Here, the longitudinal cross section of the pole may be broken down into a rectangle and a triangle, as indicated in Fig. 5-2.

The pressure on the rectangle (P_R) will be

$$P_R = P_1 d_2 h$$

where P_1 is the unit pressure in pounds per square inch. Its moment M_R about the base will be

$$M_R = P_1 d_2 \frac{h^2}{2}$$

The pressure on the triangle (P_T) will be

$$P_T = P_1(d_1 - d_2)\frac{h}{2}$$

and its moment about the base will be

$$M_T = P_1(d_1 - d_2)\frac{h^2}{6}$$

and the total pressure on the pole (P_p) will be

$$P_p = P_1 h \frac{d_1 + d_2}{2}$$

and the total moment on the pole (M_p) will be

$$M_p = P_1 h^2 \left(\frac{d_2}{3} + \frac{d_1}{6}\right)$$

The total moment the pole must accommodate will be the sum of the moments for the several conductors and the moment on the pole itself.

EXAMPLE 5-2

Assume a 40-ft pole (required for clearance) set 6 ft in the ground with three no. 4/0 stranded copper conductors on a cross arm with the conductors level at the top of the pole, and 150-ft balanced spans, in a heavy loading area (see Table 5-1).

The moment due to wind on the conductors when ice-coated is as follows. No. 4/0 stranded copper wire has a diameter of 0.528 in; allow 1 in of ice, for a unit diameter of 1.528 in of area to the wind.

$$M = 3\frac{1.528 \text{ in}}{12 \text{ in/ft}}(150 \text{ ft} \times 4 \text{ lb/ft}^2)(40 - 6 \text{ ft})$$

$$= 7792.8 \text{ ft·lb or } 93{,}513.6 \text{ in·lb}$$

The moment on the pole itself due to wind (for an estimated diameter at the top of 8 in, and 12 in at the bottom) is as follows:

$$M = \frac{4}{144}(34 \times 12)^2 \times \left(\frac{8}{3} + \frac{12}{6}\right) = 21{,}580 \text{ in·lb or } 1798 \text{ ft·lb}$$

Say 1800 ft·lb. The total for both is 115,093.6 in·lb; say 115,000 in·lb; and

$$f = \frac{115{,}000}{0.0982 \times 12^3} = 678 \text{ lb/in}^2$$

Say 700 lb/in^2.

The ultimate fiber stresses for several woods and the resultant factors of safety for those woods are as follows.

Wood	*Ultimate stress, lb/in²*	*Factor of safety*
Northern white cedar	3,600	5+
Western red cedar	5,600	8
Long-leaf yellow pine	7,400	10+
Wallaba	11,000	15+

The total moment at the pole is 9591 ft·lb; say 9600; multiplied by a factor of safety of 2, it is 19,200 ft·lb; say 20,000.

From the ASA Standards Table of Wood Pole Classification, for a 40-ft class 5 pole, the resisting moments at 6 ft from the butt, nearest to this value but greater, are as shown in Table 5-2. Any of these poles will sustain the loading due to wind.

As a check, the pole circumference C, in inches, required to withstand a bending moment M, in foot-pounds, for a wood having a permissible fiber stress f, in pounds per square inch, is:

$$C = \sqrt[3]{\frac{3790M}{f}}$$

Assume long-leaf yellow pine, $f = 7400$ lb/in^2, is used:

$$C = \sqrt[3]{\frac{3790 \times 20{,}000}{7400}} = 21.71 \text{ in}$$

This is the minimum required, as opposed to the 31.5-in actual circumference. The difference provides a margin which insures the performance of the pole should it rot at the ground line and reduce the cross-sectional area there.

TABLE 5-2 RESISTING MOMENTS AND DATA FOR 40-ft POLES

Wood	*Class*	*Resisting moment, ft-lb*	*Circumference, in*	
			Minimum, at top	*6 ft from butt*
Northern white cedar	5	60,800	19	40.0
Western red cedar	5	60,700	19	34.5
Long-leaf yellow pine	5	60,900	19	31.5

From ASA Standards Table of Wood Pole Classifications.

Because of the wide discrepancies that occur in the structure of the wood, average values based on tests and experience are used in compiling standard values. Hence, the results from computations cannot be exact, but are sufficient for practical purposes of design.

EXAMPLE 5-3

While the ground line is almost always assumed to be the weakest cross section of the pole, theoretically this occurs at a point above the ground where the diameter is 1.5 times the diameter where the resultant load, i.e., the total moment divided by the total load, is applied. Refer to Fig. 5-2, where

P = total load applied where diameter is d_2

d = diameter at weak section at distance x from P

t = taper of pole $= \frac{d_1 - d_2}{h} = \frac{d - d_2}{x}$

At d, the bending stress is:

$$f_d = \frac{Px}{0.0982(d_2 + tx)^3}$$

For f to be at a minimum, the first derivative df/dx must equal 0. If this is so, then

$$d_2 + tx - 3tx = d_2 - 2tx = 0$$

$$d_2 = 2tx = 2(d - d_2)$$

$$d = \frac{3}{2}d_2$$

Substituting this value and expressing x in terms of h gives:

$$f_d = \frac{Ph}{0.662(d_1 - d_2)d_2^2}$$

in which the maximum unit stress at the weakest point is given in terms of the known dimensions h, d_1, and d_2.

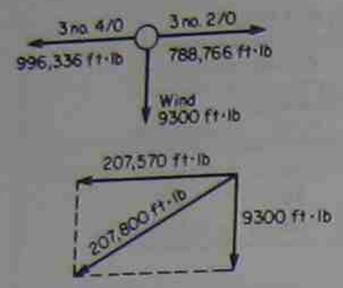


FIG. 5-3 Unequal loading on pole.

The conductors supported by a pole are in tension and also cause a loading to be applied on the pole at the first point of support. Where the conductors are in a straight line and the span lengths on both sides of the pole are equal, the loadings caused by the conductors are equal and opposite in direction and cancel each other. Where the conductors on each side of the pole are different, or where there is an offset or change in direction of the line, or where the conductors dead-end on the pole, the pole will be subjected to loadings for which provision should be made. The same principles are employed in obtaining moments acting on the pole, and this can best be illustrated by the following examples.

EXAMPLE 5-4

Assume that the 40-ft pole in Example 5-2 supports three no. 4/0 bare stranded copper conductors in one direction and three no. 2/0 bare stranded copper conductors in the other in a straight line; there are 150-ft spans in both directions. Refer to Fig. 5-3.

The moment on the pole caused by the wind for the three no. 2/0 conductors is as follows:

$$M = 3 \times \frac{1.418}{12} \times \frac{150}{2} \times 4 \times 34 = 3616 \text{ ft·lb}$$

For the three no. 4/0 conductors (from Example 5-2),

$$M = \tfrac{1}{2} \times 7792 = 3896 \text{ ft·lb}$$

For the 40-ft pole, from Example 5-2,

$$M = 1798 \text{ ft·lb}$$

Assume that the ultimate strength of the copper conductors is 37,000 lb/in^2 and that they are sagged to one-half their ultimate strength. The total moment on the pole caused by conductor tension, for the three no. 2/0 conductors, is:

$$M = 3 \times 0.418 \times \frac{37{,}000}{2} \times 34 = 788{,}766 \text{ ft.lb}$$

For the three no. 4/0 conductors,

$$M = 3 \times 0.528 \times \frac{37{,}000}{2} \times 34 = 996{,}336 \text{ ft·lb}$$

The difference between the two is 207,570 ft·lb (say 207,600 ft·lb). The total moment on the pole from conductor tension and wind is:

$$M = \sqrt{M_t^2 + M_w^2} = \sqrt{207.6^2 + 9.3^2} \times 10^3 = 207.8 \times 10^3$$

Multiplied by 2 for a factor of safety, $M = 415.6 \times 10^3$; say 420,000 ft·lb.

To find the pole circumference required to withstand this bending moment, assume $f = 7400$ lb/in^2 for long-leaf yellow pine:

$$C = \sqrt[3]{\frac{3790 \times 420 \times 10^3}{7400}} = 59.91 \text{ in at ground line}$$

This is beyond the strength of a 40-ft pole of the maximum class, 00; a guy should be installed.

Check for the possibility of using a wallaba pole, $f = 11{,}000$ lb/in^2:

$$C = \sqrt[3]{\frac{3790 \times 420 \times 10^3}{11{,}000}} = 52.50 \text{ in at ground line}$$

A 40-ft wallaba pole of maximum class 00 will not accommodate this loading; a guy is still required.

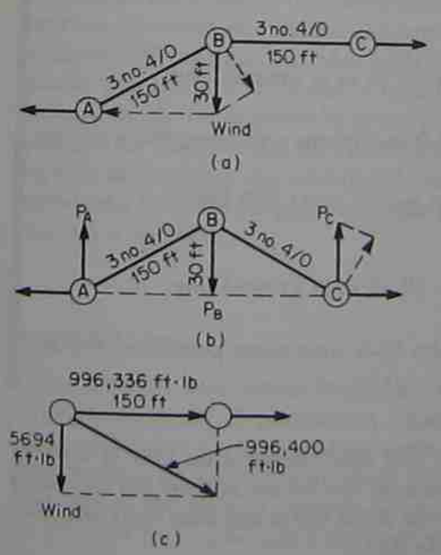


FIG. 5-4 Loadings due to (*a*) offset in line and (*b*) bend in line. (*c*) Loading due to dead end.

EXAMPLE 5-5

Assume the same 40-ft pole and three no. 4/0 stranded copper conductors, level with the top of the pole, with equal 150-ft spans on each side, as in Example 5-2, but with the line offset this time by 30 ft, as shown in Fig. 5-4*a*. The moments on pole B due to the conductors, from Example 5-4, from A toward B, and B toward C, are 996,336 ft·lb, and:

$$X = \sqrt{150^2 - 30^2} = 146.96 \text{ ft}$$

where X is the portion of the conductors exposed to wind. The moment on pole B, the portion in line with BC, is:

$$M_{BC} = \frac{146.96}{150} \times 996{,}336 = 976{,}144 \text{ ft·lb}$$

The moment on pole B due to wind for one 150-ft span, from Example 5-4, is 3896 ft·lb, and:

$$M_{Bw} = 3896 + \frac{146.96}{150} \times 3896 = 7713 \text{ ft·lb}$$

The total moment on pole B, in line, is 996,336 − 976,144, or 20,192 ft·lb. At right angles, it is 199,267 ft·lb, or (30 ft + 146.96 ft) × 976,144. The wind moment is 7713 ft·lb, and the total right-angle moment is 206,980 ft·lb.

$$M_B = \sqrt{20{,}192^2 + 206{,}980^2}$$

say

$$\sqrt{20^2 + 207^2} \times 10^3 = 208{,}000 \text{ ft·lb}$$

Multiply by 2 for the factor of safety; the result is 416,000 ft·lb. For pine,

$$C = \sqrt[3]{\frac{3790 \times 416{,}000}{7400}} = 59.73 \text{ in at ground line}$$

This is beyond the strength of the 40-ft maximum pole class, 00; a guy is required.

Check for possible use of a wallaba pole, $f = 11{,}000$ lb/in^2:

$$C = \sqrt[3]{\frac{3790 \times 416{,}000}{11{,}000}} = 52.33 \text{ in at ground line}$$

This is also beyond the strength of the 40-ft maximum pole class, 00; a guy is still required.

It must be noted that the right-angle and wind moment on pole B actually amount to less than what is indicated because the vector sum of the moments is that shown by the dashed line in Fig. 5-4*a*. Since this is less than was calculated above, the error introduced is on the safe side.

Similar procedures are used in determining the moments on, and the adequacy of, poles A, B, and C, as shown in Fig. 5-4*b*.

EXAMPLE 5-6

Assume that the 40-ft pole in Example 5-2 supports three no. 4/0 bare stranded copper conductors dead-ended on the pole, with a span of 150 ft, as shown in Fig. 5-4*c*.

The moment on the pole due to three no. 4/0 conductors with a 150-ft span, from Example 5-5, is 996,336 ft·lb. The moment on the pole due to wind on the conductors is 3896 ft·lb, and that due to wind on the pole is 1798 ft·lb. The total moment on the pole due to wind is 5694 ft·lb.

Total moment on pole $= \sqrt{996.3^2 + 5.694^2} \times 10^3 = 996{,}316$ ft·lb

Multiply by 2 for a factor of safety:

$$M = 1{,}992{,}632 \text{ ft·lb}$$

For pine,

$$C = \sqrt[3]{\frac{3790 \times 1993 \times 10^3}{7400}} = \sqrt[3]{1{,}020{,}000} = 100.65 \text{ in}$$

This circumference is much beyond any 40-ft pole, pine or wallaba (from the conclusions in Example 5-5). Guying must be used or other means employed to accommodate the loading safely.

Equipment on Poles Poles supporting transformers, capacitors, regulators, switches, or other equipment support loads which are principally compressive in nature; the equipment also adds to the wind loading. Since the center of gravity projects out from the pole, a moment is created on the upper portion of the pole, pivoting about its lower point of support. Ordinarily, the pole class selected for supporting the conductors, with its factors of safety included, is capable of carrying this additional load safely. For larger-scale equipment installations, however, a pole one class greater than that adequate for the conductors is specified.

CROSS ARMS

Cross arms are now almost limited to carrying polyphase circuits in areas where appearance is not of paramount importance. They are also used where lines cross each other or make abrupt turns at large angles to each other. They are used as alley or side arms in which the greater part of their length extends on one side of the pole to provide adequate clearances where pole locations may be affected by limited-space rights-of-way. Cross arms are shown in Fig. 5-5.

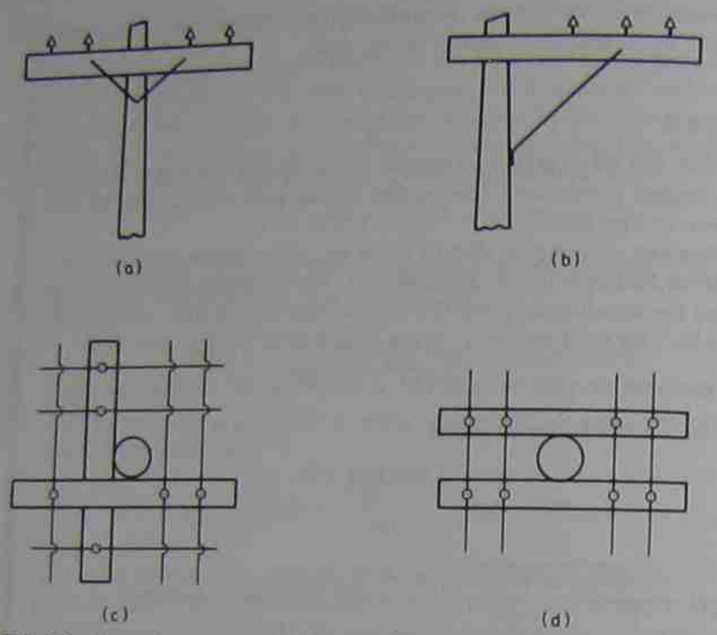


FIG. 5-5 Uses of cross arms: (*a*) line arm; (*b*) side arm; (*c*) buck arm; (*d*) double arms.

Loadings

The cross arm acts as a beam, supported at the point of attachment to the pole, and must be capable of being subjected to vertical loadings from the weight of the conductors (encased in ice) and a 225-lb worker (specified as an additional safety measure). It is also subjected to horizontal loadings stemming from winds and from tension in the conductors where the tensions on each side of the pole do not cancel each other; e.g., where spans or conductors are not the same on each side of the pole, at dead ends, bends, or offsets in the line, or where consideration is given to conductor breaking contingencies.

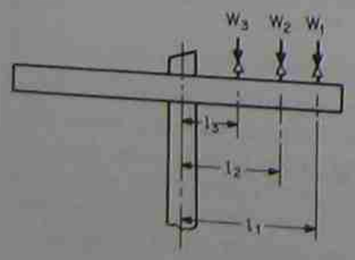


FIG. 5-6 Bending moment on cross arm.

Stresses

The same principles for determining stresses in beams as were applied in the case of poles may also be applied to cross arms; see Fig. 5-6.

Bending Moment The total bending moment M is equal to the sum of all the individual loads multiplied by their distances from the cross section under consideration. Ordinarily, the weakest section should be at the middle of the arm where it is attached to the pole. At the pin holes, however, the cross section of the cross arm is reduced and may, under unusual circumstances, be the weakest point in the cross arm. The determination can easily be made by computing unit fiber stress at the several points. Like the pole, the cross arm acts as a beam and the same formula for determining stresses may be employed:

$$f = \frac{M}{I/c}$$

where f = maximum unit fiber stress occurring at extreme edges of cross section, lb/in^2
M = total bending moment, in·lb
I = moment of inertia of cross section
c = distance from neutral axis to extreme edge, in

The moment of inertia for a rectangular cross section is

$$I = \frac{1}{12}bd^3 \qquad \text{and} \qquad c = \frac{d}{2}$$

so that the section modulus

$$\frac{I}{c} = \frac{1}{6}bd^3$$

where the neutral axis is parallel to side d, as shown in Fig. 5-7.

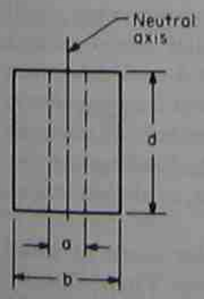


FIG. 5-7 Cross-arm cross section.

Where the cross section is reduced by a pinhole in the cross arm, the section modulus becomes:

$$\frac{I}{c} = \frac{1}{6}d\left(b^2 - \frac{a^3}{b}\right)$$

where a is the diameter of the hole.

EXAMPLE 5-7

Assume a standard 8-ft six-pin arm mounted at its center on a pole, supporting six conductors, each of which, with a half-inch coating of ice, has a maximum weight of 100 lb. The lengths, or moment arms, from the center of the arm to each of the pins are respectively 15, 29½, and 44 in.

The moment *about* the first pin hole from the pole is:

$$M = 100 \text{ lb} \times 14\tfrac{1}{2} \text{ in} + 100 \text{ lb} \times 29 \text{ in} = 4350 \text{ in·lb}$$

With the 3½- × 4½-in cross section reduced by a 1-in pin hole, the section modulus at that point is:

$$\frac{I}{c} = \frac{1}{6}(3.5 - 1.0) \times 4.5^2 = 8.4375$$

and the fiber stress is:

$$f = \frac{M}{I/c} = \frac{4350}{8.4375} = 515.56 \text{ lb/in}^2$$

Double Arms

When fiber stresses approach the maximum safe values for a particular kind of wood (always keeping in mind a factor of safety of 2), two arms or double arms are used. Ordinarily, these are found at dead ends, at points where loads are greatly unbalanced (such as large offsets or bends in the line), and at intermediate points along a long line to limit damage in the event that conductor breaks create severe load unbalances on the supporting structures.

The two arms are placed one on each side of the pole and bolted together near the ends, and often at intermediate points. Properly constructed, with spacers of wood or steel between the arms, the structure created would act as a truss with strengths of 10 to 12 times that of a single arm, or 5 to 6 times that of the two arms considered individually. Since such quality trusses may not always be constructed in the field, prudence dictates that only the ultimate fiber strength equivalent to that of two cross arms be considered. Where the loadings on the arms may exceed their fiber strengths, the arms may be guyed, as shown in Fig. 5-8, or steel arms may be substituted for wooden ones.

Douglas fir and long leaf yellow pine are the most popular kinds of wood used for cross arms, though other kinds may also be found in use. Their ultimate bearing strengths are listed in Table 5-3.

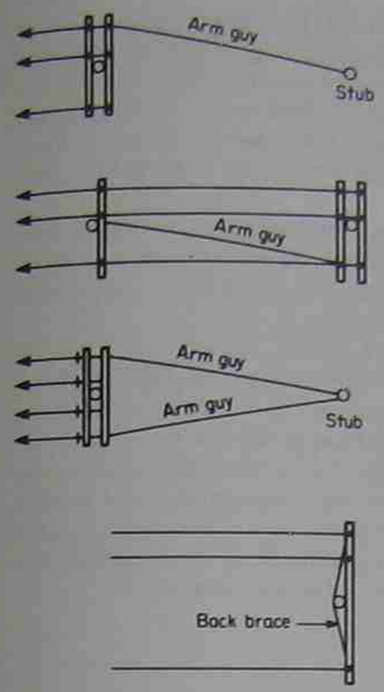


FIG. 5-8 Typical arm guys.

Bearing strength on an inclined surface at an angle to the direction of the grain is given as follows:

$$f_a = f \sin^2 a + n \cos^2 a$$

where a is the angle of inclination of the load to the direction of the grain.

Cross-Arm Braces

Cross arms fastened to poles are usually steadied in position by braces. Flat braces, usually flat strips of galvanized steel bolted to the cross arm and fastened

TABLE 5-3 ULTIMATE BEARING STRENGTH OF WOOD, lb/in²

Wood	*End-grain bearing f*	*Cross-grain bearing n*
Long-leaf yellow pine	5000	1000
Douglas fir	4500	800
Western red cedar	3500	700
Cypress	3500	700
Redwood	3500	700
Northern white cedar	3000	700

to the pole by a lag screw, are most commonly used. The support given the cross arm by the flat braces is questionable, and is usually neglected in determining the effects of loads on the cross arm. Where the cross arm is not symmetrically loaded on each side of the pole, the brace on the load side is in compression and is of little benefit because of its slenderness; the brace on the other side is in tension and aids in transmitting some of the load to the pole, but does not reduce the bending moment.

For heavier loads, a preformed brace made of angle iron, of larger cross section than the flat brace, aids in supporting the loads on the cross arm. Here, the moments acting on the cross arm are usually computed about the point of attachment of the angle brace to the cross arm.

For alley or side arms, an angle-iron brace is used; usually it is a straight length with the ends adapted to be fastened to the arm and the pole. The brace transmits a considerable part of the load on the arm to the pole; when all the load on the arm is beyond the brace, the vertical compressive stress on the brace may be even greater than the load. The points of attachment at the cross arm and at the pole are important; the smaller the angle between the pole and the brace, the greater the load transmitted to the pole. On the other hand, as the length of the brace increases, the slenderness ratio (the brace acting as a slender column) becomes larger and the effectiveness of the brace diminishes.

Bolts

The stability of a cross arm and its strength rely heavily on the strength of the bolts through which the stresses are transmitted. The distribution of stresses on the through bolt holding the cross arm to the pole are shown in Fig. 5-9*a*. The vertical load on the cross arm is transferred by the bolt to the pole.

The unit pressure on the bolt in the cross arm is:

$$P_a = \frac{W}{b_1 d}$$

where d is the diameter of the bolt; the maximum unit pressure in the pole is:

$$P_p = \frac{W}{b_2 d}$$

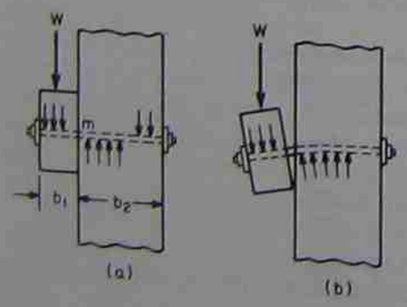


FIG. 5-9 Action on bolt holding cross arm to pole. *m* is point of maximum shear stress.

The maximum unit pressure must not exceed the bearing value of the wood, or distortion will take place. As the ultimate strength of the wood is approached, the bolt will tend to bend as the fibers of the wood begin to give way, as shown in Fig. 5-9*b*.

PINS

Loading

Pins are subject to both vertical and horizontal loadings. The vertical loading results from the weight of the conductor and its half-inch radial coating of ice. The horizontal loading stems from the wind, from differential tensions in adjacent conductor spans, from nontangent spans, or from broken-wire conditions in which the tensions in the conductor spans become unbalanced.

Under vertical load, the pin acts as a simple column, transmitting its load to the cross arm at the shoulders resting on the cross arm. The stress is equal to the load divided by the area under pressure, the area of the shoulder resting on the cross arm. This component is usually not large compared with the other components acting on the pin and is often neglected.

Under horizontal loadings, the pin acts as a cantilever beam, and the maximum stress occurs at the point where the pin rests on the arm; refer to Fig. 5-10. The bending moment M is equal to the load P multiplied by the distance of the conductor above that point *(h)*:

$$M = Ph$$

The maximum fiber stress is usually considered to be at the point where the shoulder comes in contact with the cross arm. Its unit value, in pounds per square inch, may be calculated:

$$f = \frac{Ph}{0.0982d^3}$$

where d is the diameter of the shank of the pin.

Since the balancing of moments may occur at the edge of the shoulder of the pin (for either wood or metal) rather than at the edge of the shank of the pin, some crushing effect may take place on the wood of the cross arm, which may affect its strength substantially. In such instances, the weak point may occur at the cross section of the pin above the cross arm; the value may be found by

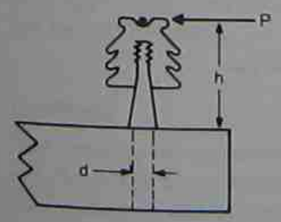


FIG. 5-10 Loading on pins.

substituting the diameter of the pin at about one-third of the distance down from the point of the conductor attachment, approximately the diameter at the weak point.

Double Pins Double pins, one on each of the double arms, are used where the strength of one pin is inadequate.

Pins in Lieu of Cross Arms The advent of wye primary systems employing a common neutral with the secondary (situated on the pole in the secondary position) allowed single-phase primary conductors to be supported on a steel ridge pin, as shown in Fig. 5-11. The vertical loading on the pin, the weight of the ice-coated conductor, is transmitted to the pole through the bolt by which the pin is attached to the pole. Horizontal loadings, from both wind and conductor tension, act on the pin as a cantilever beam, and the same analysis of stresses in the pin, bolt, and pole applies here as with cross arms.

In polyphase systems, the conductors may be supported on pins attached directly to the pole, eliminating the use of cross arms (this method of support is sometimes referred to as "armless construction"). This not only makes for a neater appearance, but, as indicated earlier, improves electrical performance by mitigating the voltage drop due to the reactance of the line. (The arrangement and spacing of the conductors accounts for the lessened reactance. Also, this construction employs bucket trucks or platforms for easier access to the conductors.)

In this instance, the vertical loading acts on the end of the pin, with the pin acting as a cantilever beam; the bending stress occurs at the pole, and the fiber stresses on the pin are calculated in the same manner described above for cross

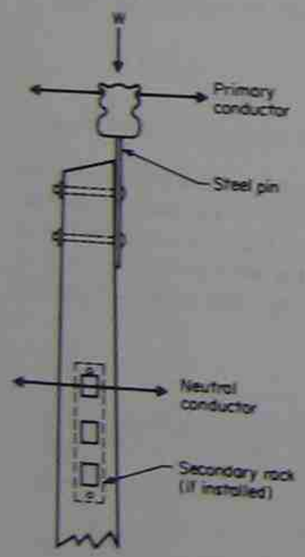


FIG. 5-11 Pin support for single-phase primary.

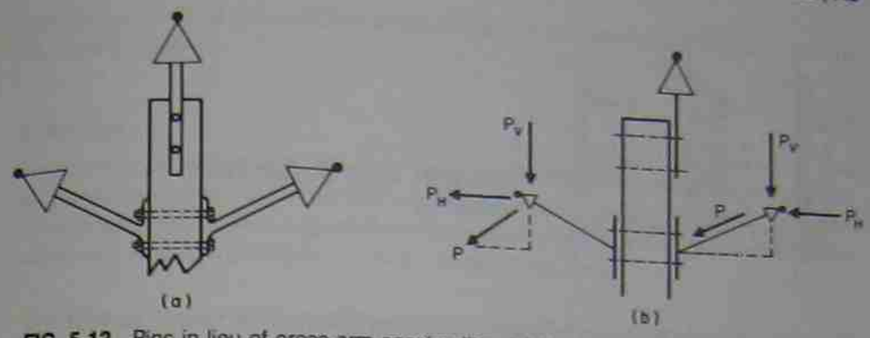


FIG. 5-12 Pins in lieu of cross-arm construction. (a) Use of long steel pins. (b) Stresses on long steel pins.

arms and poles. The horizontal loading acts to create compressive stresses in the pin, which acts as a slender column. Again, this component is small compared with the other components and is often neglected. On the other side of the pole, however, the horizontal forces act to pull the conductor away from the pole; while there is ample strength for the tensile stress imposed on the pin and the bolts with which it is attached to the pole, these forces do dictate that the conductors be so attached to the insulators as to ensure the conductor will not be separated from the insulator under the stresses imposed.

For higher voltages, additional space requirements may necessitate longer pins or the installation of insulated conductors (or both). The pins may be attached to the pole as indicated in Fig. 5-12. Here, the stresses on the pin from both the vertical and horizontal loads impose bending moments about the bottom of the pin at the pole. The moments and stresses on the pins and supporting bolts, indicated in Fig. 5-12, are computed in the same fashion as for the cases mentioned above.

For all applications of the pins, a minimum strength of 700 lb per pin is usually specified in withstanding unbalanced tension in a conductor supported by the pin.

SECONDARY RACKS

Secondary racks usually support three spool insulators mounted on a common shaft attached to a steel backing that is bolted to the pole by one or more bolts (though sometimes, depending on the stress to be accommodated, a lag screw may take the place of a bolt). The spool insulators are usually spaced 8 in apart, although sometimes less. If the rack is properly mounted, the insulators may fail before the rack.

Loadings

The loading on secondary racks has both vertical and horizontal components; see Fig. 5-13. The vertical loading consists of the weight of the conductors (with the coating of ice) of both the mains and services attached to them. With spool-

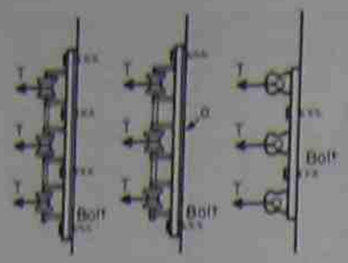


FIG. 5-13 Loading on secondary racks

type racks, the load is carried by small arms acting as cantilever beams, supporting the insulators. Generally, the insulator is located between two such arms, but only the lower one carries the load. With the knob-type rack, the vertical load is transmitted to the rear plate by the U bolts attaching the insulators to the plate, and to the pole by the bolts attaching the rack to the pole.

The horizontal load is due to wind acting on ice-laden conductors and the tension in them, for both the secondary mains and the services. If the rack is attached to the pole by a bolt under each insulator, the strength of the back plate plays little part, as the stress is transmitted almost directly by the bolts. Where the spool-type rack is mounted with the bolts at the ends only (or by a bolt and a lag screw), the back of the rack acts as a cantilever beam supported at both ends, with the load applied at each of the points where the arms are attached to the back. The greatest stress is at the point in the back where either of the two arms supporting the middle insulator is attached, the bending moment being greatest at that point. In the knob-type rack, both the vertical and horizontal loadings are transmitted to the back of the rack and through the mounting and bolts to the pole.

Where the conductors dead-end on a rack mounted on the side of a pole (or where there is an unbalanced pull from broken conductors), the side pull on the rack is limited by the strength of the arms or the U bolts supporting the insulators. It is preferable to mount the rack on the face of the pole, with the arms and U bolts supporting the insulators in tension, and the stresses transmitted to the pole almost directly by the mounting bolts.

In general, like pins, conductor fastenings should be able to withstand a 700-lb stress.

Messenger Clamp As mentioned earlier, when the secondary conductors are cabled about the neutral conductor acting as the supporting messenger, a clamp supporting the neutral is bolted to the pole. Here, both the vertical and horizontal loadings are transmitted to the pole by the through bolt by which the clamp is attached to the pole.

INSULATORS

Insulators used on overhead distribution systems are made of porcelain, glass, and, more recently, synthetic materials. Glass insulators, though no longer widely installed, exist in abundant numbers and will probably remain in service for some time. Several types of insulators employed in distribution line designs are discussed below.

Loadings

In general, porcelain has relatively little tensile strength but excellent strength in sustaining compressive stresses, properties substantially true also of glass. Lines are therefore so designed that the insulator materials will be in compression when carrying the (mechanical) loads imposed on them.

Pin Type As the name implies, pin-type insulators are mounted on pins (of wood or metal) and the conductors are fastened to them. Their strengths (in compression) are usually greater than those of the pins upon which they are mounted. The dimensions of the insulating material necessary to meet the mechanical requirements are usually ample in meeting the electrical requirements, including surge voltages when wet.

Post Type The post-type insulator is essentially a pin-type insulator that incorporates its own steel pin. Vertical loads are provided for by the porcelain, while horizontal loads act to create a moment about the point of attachment to the pole. Stress is transmitted by its steel core (or pin) to the cross arm or pole.

The post-type insulator is meant to be installed in a vertical (or near-vertical) position but is also sometimes installed horizontally (or nearly so) in lieu of cross arms to carry the conductors of a polyphase primary circuit; see Fig. 5-14. Here, the horizontal loadings create compressive stresses on one side of the pole and tensile stresses on the other, both of which are transmitted through the steel core to the pole. Vertical loadings create a compressive stress in the porcelain between the conductors and the inner steel core or pin; this stress is transmitted to the steel pin, which in turn transmits it to the pole; see Fig. 5-12. In instances where the post insulators are mounted at an angle to the pole, the stresses created will be the horizontal and vertical vector components of the forces acting on the porcelain and the steel pin.

One advantage of the pin- or post-type insulator is that, if it is mounted on a cross arm, a shorter pole is required to achieve the same height of the conductor above ground than is needed for suspension- or strain-type insulators.

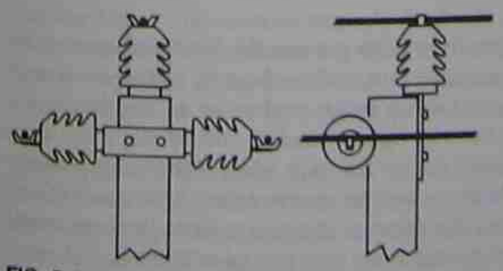


FIG. 5-14 Use of post-type insulators.

Suspension or Strain Type The suspension- or strain-type insulators are also known as disk or string insulators. They are not generally used on distribution circuits except at turning points and at dead ends, where pins and pin-type insulators may not provide sufficient strength; they are particularly useful in providing for the unbalance of stresses caused by broken conductors where pins, and even double pins, may be inadequate and some form of insulated clamp or other means of attachment is required. Here the conductors are dead-ended on each side of the pole, and the disk insulator, designed for heavy loadings of 10,000 to 20,000 lb (and similar to those used for transmission lines, but smaller in diameter), serves this purpose. Often, two or more such disks are assembled as a unit to accommodate higher operating voltages.

Strain-Ball Type The strain-ball type of insulator has been used to dead-end lower-voltage primary and secondary conductors, and as an insulator in guy wires in older installations; many still exist. Here, the porcelain is under compression, accommodating the stresses imposed on it. Standard ratings include strengths (in compression) of 10,000, 12,000, and 15,000 lb.

Spool Type Insulators of the spool type are associated with secondary racks, described earlier, and are standardized in design. The compressive strength of the spool porcelain is usually greater than the strength of the other parts of the rack.

Other Types Among the other types of insulators are knob types, sometimes used for services and on secondary racks, and other shapes for use as bushings, bus supports, and other purposes.

GUYS AND ANCHORS

Stresses

When the horizontal loads imposed on poles and cross arms may exceed the safe carrying strengths of the wood involved (or the holding power of the soil), guys of steel wire are usually installed to take up or counteract the excessive stress. The various types of guys are shown in Fig. 5-15. Note that the guys take up the horizontal stresses and distribute them to other cross arms, to other poles and into the ground, or directly into the ground. The structural and environmental conditions peculiar to each situation dictate the type of guy used.

Arm Guys Several forms of arm guy have been previously discussed under the subject of cross arms. The guy is normally attached to the end of the cross arm having the heavier load and is carried down to an anchor or to another pole; sometimes the guy wire is attached to the lighter-loaded end of the cross arm and carried back to the adjacent pole in the direction in which the load is pulling. Where the cross arm, or the double arms, may be overstressed, both ends of the cross arm or arms may be guyed. Any deviation of these guys from the horizontal imposes a vertical compressive load on the cross arm (equal to the vertical component of their tensions) and this loading must be included when considering the design of the poles.

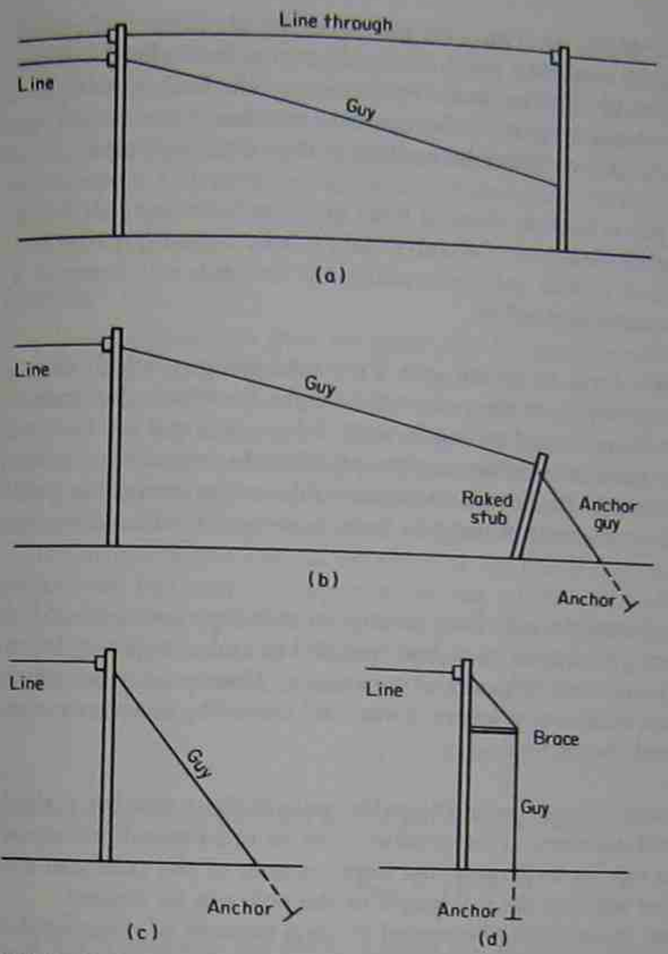


FIG. 5-15 Typical pole guys: (*a*) pole-to-pole guy; (*b*) pole-to-stub guy; (*c*) anchor guy; (*d*) sidewalk guy.

Anchor Guy The most commonly used guy is the anchor guy, of which one end is fastened to the pole and the other end to a rod to which is attached an anchor that is buried in the ground. The anchor selected depends on the holding power of the soil: from poor in swamps to excellent in hard and dry earth.

Span Guy In the span guy, the guy wire extends from the head of the pole under load horizontally to an adjacent pole; since this merely transfers the load through the guy wire to the other pole, the receiving pole must be strong enough to take the additional load, or the receiving pole must be guyed.

Head Guy In the case of the head guy, the guy wire extends from the head of the pole under load at an angle to a point on an adjacent pole at a height above ground sufficient to provide for clearance requirements. The load thus applied to the adjacent pole reduces the ground-line moment (the horizontal pull of the wire multiplied by its height on the pole) applied to this receiving pole.

Stub Guy The stub guy is another form of head guy, the receiving pole being a stub or strut to maintain clearance; the stub usually has an anchor guy attached to it and may be raked so that the force acting on the stub will produce a compressive stress as much as possible.

Sidewalk Guy Another form of anchor guy is the sidewalk guy, which uses a strut extending horizontally from the pole at the height for which clearance is specified, the anchor being buried as nearly vertical from the end of the strut as practical. This guy places a bending moment equal to the lateral component of support times the distance between the strut and guy attachments to the pole. The maximum bending moment at the pole base, however, is reduced by this type of guy.

Storm Guy Long and straight pole lines having no side taps and unshielded from the elements are guyed four ways, both parallel to and at right angles to the line, at locations based on judgment and experience. This serves to minimize damage resulting from accidents or severe storms and caused by uneven stresses from broken poles and conductors.

Crib Bracing Although not perfectly attainable, pole designs aim for a rigid structure, one that will not move in the ground when an unbalanced horizontal load is applied at its top. In large part, the depth setting of the pole and the kind of soil determine whether the full length of the pole can be utilized.

Where unbalanced loads cannot be served by guys because of space limitations, appearance, consumer requirements, or other reasons, resort is had to

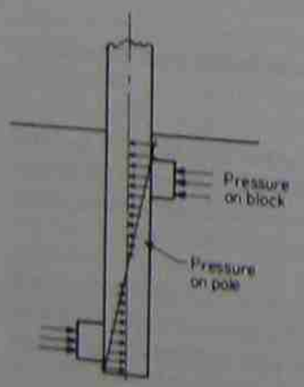


FIG. 5-16 Stresses on cribbed pole.

cribbing or *crib bracing*. Here, planks, logs, sections of poles, or steel anchors are installed at the base of the pole to provide additional holding power; see Fig. 5-16. The tension of the conductors on the pole is reduced by increasing their sag until the total moment at the ground line is within the strength limitations of the pole; the cribbing is then installed and the space about the pole refilled and tamped. The addition of cribbing does *not* add to the strength of the pole.

Loading

The loads imposed on guys are generally due to the tension in the conductors and the angle between adjacent conductor spans, if any; the magnitude of the tension depends on the size of the conductor, its loading (including wind and ice), and the sag in the span. The design limits are usually based on the elastic limit of the conductors (e.g., 50 to 60 percent of the ultimate strength of copper). The usual stress is generally less than that, as the design limits are based on the worst assumed loading conditions, which are approached only occasionally.

The stress on the pole at an angle in the line is also due to tension in the conductors, but only a component of that tension is handled by the guy; the amount depends on the size of the angle in the line. Refer to Fig. 5-17*a*.

If T is the total tension caused by all the conductors, and a is the angle of the line, the component of the total tension T in line with the guy is

$$T_a = T \sin \frac{a}{2}$$

and the total stress handled by the guy is twice that, or

$$T_{\text{guy}} = 2T \sin \frac{a}{2}$$

If the tensions in the two spans are not balanced, then the resultant stress will be the vector sum of the two, and will be the stress handled by the guy. Wind pressure on the pole itself must also be taken into account in determining the total load to be handled by the guy.

If the angle is large, usually more than 60°, the loading on the guy bisecting the angle will be greater than the dead-end loading of the line, and it is generally better to install two guys, considered as dead-end guys, if practical.

The guy should be attached as near as practicable to the center of loading of the loads it supports. Where the individual loads act at different elevations, they should be converted into an equivalent single load at the point of attachment of the guy. Referring to Fig. 5-17*b*, if T_p is the loading (say of the primary) at height h_p, T_s is the loading (say of the secondary) at height h_s, P_w is the wind pressure on the pole assumed to be concentrated at height h_w, and L_H is the equivalent horizontal loading, then

$$L_H = \frac{T_p h_p + T_s h_s + P_w h_w}{h}$$

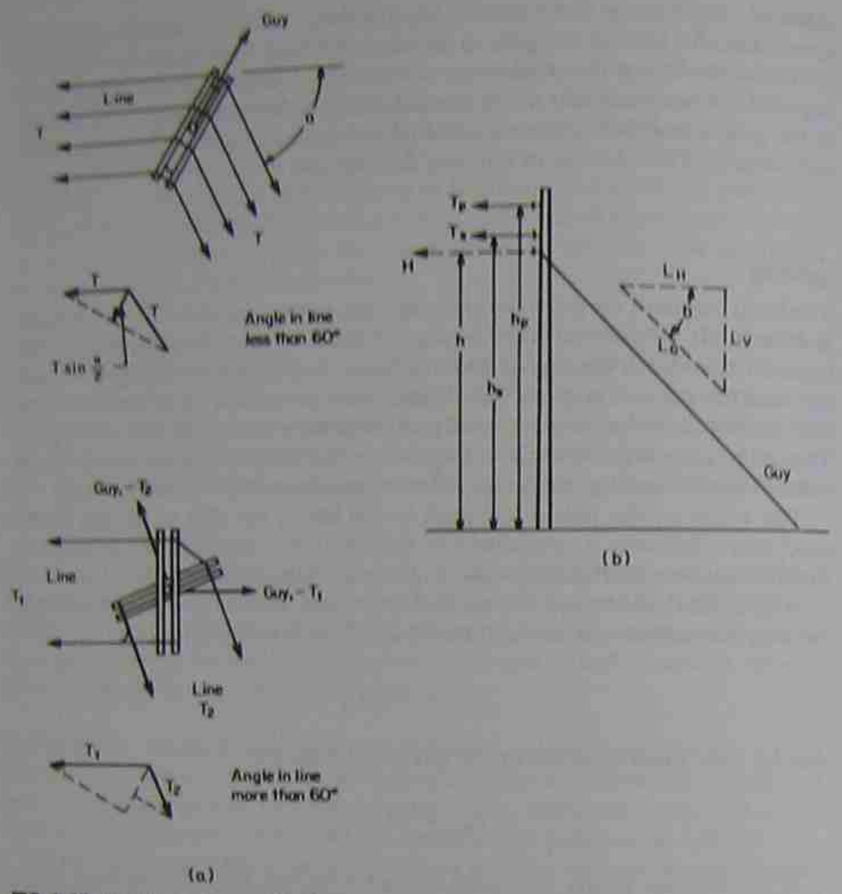


FIG. 5-17 Loading on guys. (*a*) Guys at angles. (*b*) Guy loading.

Since the guy is not usually horizontal, the actual tension in it will be greater than L_H. If b is the angle the guy makes with the horizontal, then the loading in the guy, L_G, is:

$$L_G = \frac{L_H}{\cos b}$$

The vertical component L_V is:

$$L_V = L_H \tan b \qquad \text{or} \qquad L_V + L_G \sin b$$

and acts as an additional vertical load on the pole.

EXAMPLE 5-8

Assume three no. 4 medium-hard-drawn copper primary conductors dead-ended at the top arm 33 ft above the ground, and 4 no. 2 soft-drawn copper cabled secondaries dead-ended 2 ft below, or 31 ft above the ground; a pole face area of 25 ft²; and a wind pressure of 4 lb/ft² applied one-third the distance down from the top arm, or 22 ft above the ground. The guy is attached 30 ft above ground at an angle of 45°.

$$T_p = 3 \times 950 = 2850 \text{ lb}$$

$$T_s = 4 \times 990 = 3960 \text{ lb}$$

$$P_w = 25 \times 4 = 100 \text{ lb}$$

$$L_H = \frac{(2850 \times 33) + (3960 \times 31) + (100 \times 22)}{30} = 7300 \text{ lb}$$

$$L_G = \frac{7300}{\cos 45°} = \frac{7300}{0.707} = 10{,}325 \text{ lb}$$

If the guy is attached at a point too far from the center of the load, a significant stress may be imposed on the pole, as the section of the pole above that point acts as a beam, and the moment at that point will be approximately

$$M = T_p(h_p - h) + T_s(h_s - h) - P_w(h - h_w)$$

and the fiber stress in the pole at the point of attachment of the guy will be

$$f = \frac{M}{0.0982d^3}$$

where d is the diameter of the pole at this point.

Guys should be attached to the pole as near as possible to the center of the load; when installed, they should take the entire horizontal load, with the pole acting as a strut.

Guy Wires

Guy wire is made of stranded steel cable (usually 7 or 19 strands) so that the failure of one or two strands will not cause the immediate failure of the cable. The strands are usually galvanized or copper-clad to resist the effects of weather. The strands may be of mild steel or high-strength steel, but must be of sufficient strength to support the loads imposed on the guy. Such steel wires usually come in four grades of strength, and standards further specify that guy wires not be stressed beyond 75 percent of their ultimate strengths. Wires are manufactured in diameter differences or steps of $\frac{1}{32}$ in, but sizes less than $\frac{1}{4}$ in or greater than $\frac{1}{2}$ in are seldom, if ever, used, two or more guys being employed if stresses greater

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TABLE 5-4 GUY WIRE CHARACTERISTICS

Wire Class	*Ultimate strength, lb/in²*	*Elastic limit, lb/in²*
Standard	47,000	24,000
Regular	75,000	38,000
High-strength	125,000	69,000
Extra high-strength	187,000	112,000

Weight of steel wire: 0.002671 lb/in³.

Modulus of elasticity: 29×10^6.

Coefficient of linear expansion: 11.8×10^{-6}/°C; 6.62×10^{-6}/°F

Within the ¼- to ½-in range, for the four classes of wire, ultimate strengths vary from a minimum of 1900 lb to a maximum of 27,000 lb.

than the maximum strength of the guy wire are required. In practice, however, only three sizes are usually stocked and specified: light, medium, and heavy; they are often referred to by their maximum permissible strengths, e.g., 6000-lb, 10,000-lb, and 20,000-lb (6M, 10M, and 20M).

The characteristics of steel wire used for guys are given in Table 5-4.

Guy wires are attached to poles and cross arms by eye bolts, thimbles, clamps, clips, hooks and plates, and special guy bolts which have the eye shaped and bent at an angle to accommodate the wire.

Push Braces

Where guys are impractical to install, push braces are sometimes installed. These are essentially compression-type "guys." The pole used for a brace must be of sufficient length for the purpose and its class must be capable of withstanding the compressive stress imposed on it. This stress is the vector sum of the horizontal and vertical loads on the pole being reinforced in the direction of the axis of the pole as a brace. Figure 5-18 illustrates such a brace and the stresses imposed on it.

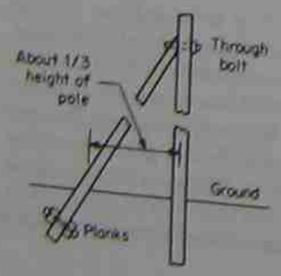


FIG. 5-18 Push brace.

Anchors

The holding power of the anchor should obviously match the strength of its associated guy wire. In general, the holding power will depend on the area the anchor offers the soil, the depth at which it is buried as a function of the weight or resisting force of the soil, and the kind and nature of the soil.

Types of Anchors Anchors come in many shapes and types. They may be classified into four general types:

1. Buried logs, planks, or plates attached to the end of a rod.
2. Screw anchors, screwed into the soil at varying depths. A very large screw anchor, known as the swamp anchor, is used in swampy areas.
3. Expanding anchors, in which a plate in sections is folded into a small diameter, the unit set into a small-diameter hole (or at the bottom of a pole), and the anchor rod screwed or pounded into it so that the sections spread out, biting into the adjacent soil. If the expanding anchor plate is divided into eight sections, for example, the anchor is known as an eight-way expanding anchor.
4. Rock anchors, which are merely rods driven into the rock, hard shale, or hardpan, at approximately right angles to the guy wire. The depth at which they are installed will vary with the strength required and the character of the rock.

TABLE 5-5A CLASSIFICATION OF SOILS

Class	*Description*
1	Hard rock: solid.
2	Shale, sandstone: solid or in adjacent layers.
3	Hard, dry: hardpan, usually found under class 4 strata.
4	Crumbly, damp: clay usually predominating. Insufficiently moist to pack into a ball when squeezed by hand.
5	Firm, moist: clay usually predominating with other soils commonly present. Sufficiently moist to pack into a firm ball when squeezed by hand (most soils in well-drained areas fall into this classification).
6	Plastic, wet: clay usually predominating as in class 5, but because of unfavorable moisture conditions, such as in areas subjected to seasonally heavy rainfall, sufficient water is present to penetrate the soil to appreciable depths and, though the area be fairly well drained, the soil becomes plastic during such seasons, and when squeezed will readily assume any shape (a soil not uncommon in fairly flat areas).
7a	Loose, dry: found in arid regions, sand or gravel usually predominating (filled-in or built-up areas in dry regions fall into this class, and as the name implies, there is very little bond to hold the particles together).
7b	Loose, wet: same as loose, dry for holding power; high in sand, gravel or loam content. Holding power in some seasons is good, but during rainy seasons soil absorbs excessive moisture readily with resultant loss of holding power, especially in poorly drained areas. This class also includes very soft wet clay.
8	Swamps and marshes.

Courtesy Long Island Lighting Co.

TABLE 5-5B SELECTION OF ANCHORS—APPROXIMATE HOLDING POWER, lb
Diameter of screw or expanded anchor plate; diameter and length of rod

	Type of anchor and rod size					
	*Screw**	*Expanding*			*Swamp***	
Soil class	*8-in 1 in × 5.5 ft*	*Eight-way 8-in ¾ in × 8 ft*	*Eight-way 10-in 1 in × 10 ft*	*Four-way 12-in 1¼ in × 10 ft*	*13-in 2-in pipe*	*15-in 2-in pipe*
1***	NR	NR	NR	NR	NR	NR
2***	NR	NR	NR	NR	NR	NR
3	NR	26,500	31,000	40,000	NR	NR
4	11,000	22,000	26,500	34,000	NR	NR
5	8,000	18,500	21,000	26,500	NR	NR
6	6,500	15,000	16,500	21,500	NR	NR
7	3,500	10,000	12,000	16,000	NR	NR
8	NR	NR	NR	NR	12,000	15,000

*Screw anchors are used especially in temporary installations because of easy removal.

**At least one 10-ft length of 2-in pipe should be installed; additional lengths should be installed until pipe can no longer be turned (say, by four workers operating the wrenches).

***Special rock anchors of varying holding power should be used.

NR—Not recommended.

Courtesy Long Island Lighting Co.

Soils

Soils may be classified very roughly as indicated in Table 5-5A; anchor requirements for the different classes of soil are shown in Table 5-5B. Moist soils will vary in their classification during the year because of changes in moisture content, and the worst condition should be considered for design purposes.

CONDUCTORS

Tensions and Sags

The stringing of conductors on an overhead system presents other problems than those created by their dead weight and the effects of wind and ice on them. If they are stretched too tightly between poles, the stresses imposed on the pole structure (including pins, insulators, cross arms, racks, and hardware) would be such as to render them impractical. The stresses on the conductors themselves increase rapidly as remaining sag is eliminated, causing them to exceed their elastic limits by any small movement of the pole or conductor. The result would be greater permanent elongation, a reduction in overall cross section of the conductor, and a greater possibility of conductor failure.

On the other hand, if they are stretched too loosely, the swaying or deflection of the conductors would necessitate exceedingly wide spacing, in both the horizontal and vertical planes, with the support system approaching impracticability. The final construction should, therefore, provide for sufficient sag so that the

elastic limit of the conductors will not be exceeded by a sufficient margin, while maintaining clearances that may be required under the probable conditions that may be encountered.

The tension in a conductor may be controlled by maintaining a proper sag in it, the tension being approximately inversely proportional to the sag. The sag in a conductor must be determined not only by the loading conditions (i.e., light, medium, or heavy), but also by probable temperature variations; local physical conditions and restrictions of codes and regulations must also be taken into consideration.

Calculation

In calculating sags and tensions in a conductor, the loading is assumed to be applied uniformly over its length, with the conductor capable of assuming its final shape freely, that of a catenary. To simplify the calculation, the loading can be assumed to be uniformly applied over its span, as shown in Fig. 5-19, resulting in a parabola. For relatively short spans, such as are found in distribution systems, the error is well within the practical limits of construction practices in the field, and may be neglected. (For long transmission spans, however, the differences become significant and reference should be made to calculating catenary methods for such lines.)

For parabolas, the relation between sag or deflection d, tension T, and span length L is expressed:

$$d = \frac{wL^2}{8T}$$

where d and L are in feet, T in pounds, and w, the resultant load (conductor, ice, etc.), in pounds per foot.

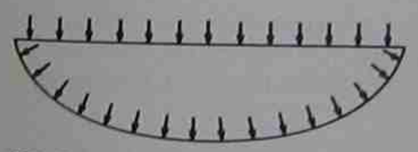


FIG. 5-19 Uniform loading on conductors.

For long spans, the horizontal component H of the tension in the conductor is given by the right-angle triangle relation:

$$H^2 = T^2 - (wx)^2$$

where x is one-half the length of the conductor in the span, but may be taken as approximately one-half the length of the span itself. The conductor, at the

point of support where the tension T is maximum, is at an angle $\tan^{-1}(wx/H)$ to the horizontal; its length l compared to the span length L is given by

$$l = L + \frac{8d^2}{3L}$$

where d is the sag in feet.

The sags and tensions vary with temperatures; they are usually calculated at a "standard" temperature (say 60°F) and adjusted to other temperatures. As the temperature increases, the conductor expands and becomes longer; the sag increases and the tension in the conductor decreases. The elongation of a conductor from temperature *change* is equal to its length l multiplied by the change in temperature t and the coefficient of expansion e:

$$\text{Elongation} = lte$$

Likewise, if the tension is lessened, the elongation of the conductor decreases, as does the sag; if the loading on the conductor is increased, the tension and the accompanying elongation are increased, increasing in turn the sag and decreasing the tension. The elongation, or change in length, because of change in tension is given by:

$$\text{Change in length} = \frac{T_1 - T_2}{aE}$$

where $T_1 - T_2$ is the *change* in tension, a is the cross-sectional area, and E the modulus of elasticity.

Unequal Spans It is often impractical to have all spans of equal length, but each span in a level line should have approximately the same tension, with differing sags or severe stresses imposed on the supporting structure. Where the difference in adjacent span lengths is large, the conductors of the unequal adjacent spans should be dead-ended on the common pole.

Different Elevations Conductors suspended between supports at different elevations must be sagged so that the low point occurs between the center of the span and the lower support; if the low point is higher than the lower support,

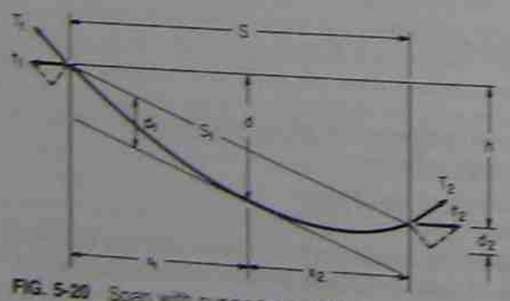


FIG. 5-20 Span with supports at different elevations.

an uplifting force will develop that may upset the balance of the lower support. As temperatures and loadings change, the low point will move horizontally along the span. For purposes of design, it may be assumed that this point remains fixed.

Referring to Fig. 5-20, the sags and tensions are based on the half-span between that point and the upper support, the sag being measured from a horizontal line through the upper support. The location of the low point may be determined approximately:

$$x_1 = \frac{S}{2} + \frac{ht}{Sw} \quad \text{or} \quad x_1 = S\frac{\sqrt{d}}{\sqrt{d-h} + \sqrt{d}}$$

$$x_2 = S - x_1 \quad \text{or} \quad x_2 = \frac{S}{2}\left(1 - \frac{h}{4d_1}\right)$$

and

$$d_2 = d_1\left(1 - \frac{h}{4d_1}\right)^2$$

The horizontal components of the conductor tensions t_1 and t_2 must be equal and the vertical component must be greater on the upper support; that is, t_1 must be greater than T_2 and

$$T_1 = T_2 + wh$$

where w is the weight per foot of conductor.

The sag in the inclined span is more nearly equal to the sag in a level span of a length equal to $S_1 + (S_1 - S)$. For practical purposes, however, the sag may be computed as if the supports were on the same elevation and the span length were S; the sag may be conveniently measured as the vertical distance d_1 from the line through the points of support.

Sag for ACSR

The processes described for determining sag pertain to conductors of a single, homogeneous material, e.g., copper, aluminum, or steel. For composite conductors, such as ACSR, the stresses on each of the different materials of the conductors are taken into consideration. At low levels of tension, the permanent set in the aluminum strands and the slight looseness of the steel cause all the load to be carried by the steel strands; the conductor stretches as if it consisted only of the steel strands. For greater loads, however, the aluminum and steel work together essentially as a single conductor.

Temperature changes change the length of the aluminum and steel strands in relation to each other, and also the point at which the steel and aluminum strands work together. The distribution of the tension between the steel and aluminum strands also changes, creating, in turn, a different expansion or contraction of the composite conductor. The coefficient of expansion for the con-

TABLE 5-6 TYPICAL CONDUCTOR SEPARATION

Voltage between conductors	*Minimum horizontal spacing*	*Minimum vertical spacing*
Up to 8700	12 in	16 in
8701 to 50,000	12 in, plus 0.4 in for each 1000 V above 8700 V*	40 in
Above 50,000	Same as for 8701 to 50,000 V	40 in, plus 0.4 in for each 1000 V above 50,000 V

*This is approximate. To determine spacing, the following formulas are specified. For conductors (copper or the equivalent) smaller than no. 2 AWG:

$$S = 0.3E + 7\sqrt{\frac{d}{3} - 8}$$

For conductors larger than no. 2 AWG:

$$S = 0.3E + 8\sqrt{\frac{d}{12}}$$

where the separation S is in inches, the line voltage E is in kilovolts, and the greatest sag d of the conductor at 60°F is in inches.

For current industry recommended values, refer to the latest revision of the National Electric Safety Code.

posite conductor is, therefore, not the same at all tensions as it is in conductors of one material only.

This coefficient of expansion for the composite conductor may be derived with sufficient accuracy for practical purposes from the coefficients of expansion a and the modulus of elasticity E and the percent area H for each of the metals involved:

$$E_{AS} = E_A H_A + E_S H_S$$

and

$$a_{AS} = a_A \frac{E_A H_A}{E_{AS}} + a_S \frac{E_S H_S}{E_{AS}}$$

EXAMPLE 5-9

For a no. 4/0 ACSR conductor,

$$E_A = 9 \times 10^6 \quad H_A = 0.857 \quad a_A = 12.8 \times 10^{-6} \text{ per °F}$$
$$E_S = 29 \times 10^6 \quad H_S = 0.143 \quad a_S = 6.6 \times 10^{-6} \text{ per °F}$$
$$E_{AS} = 9 \times 10^6 \times 0.857 + 29 \times 10^6 \times 0.143 = 11.860 \times 10^6$$

and

$$a_{AS} = 12.8 \times 10^{-6} \times \frac{7.713 \times 10^6}{11.860 \times 10^6} + 6.6 \times 10^{-6} \times \frac{4.147 \times 10^6}{11.860 \times 10^6}$$
$$= 10.632 \times 10^{-6} \text{ per °F}$$

Sag is a limiting factor in the allowable horizontal spacing between conductors because of the possibility of their whipping together in the wind. Typical minimum separation distances are shown in Table 5-6.

As a practical matter, for distribution systems, the construction, maintenance, and operating conditions, including climbing and working space, and experience—all are reflected in the standards for separation distances that exceed the minimum requirements (based on electrical considerations).

GRADES OF CONSTRUCTION

Good engineering practice recognizes different conditions and circumstances, in which prudence dictates that construction reflect the hazards involved and the potential consequences of failure. Construction is divided into three grades labeled B, C, and N, in declining order of importance.* These specify greater factors of safety in the utilization of materials, e.g., poles and conductors. See Table 5-7.

In general, grade B construction is specified for all supply circuits crossing over railroad tracks; for open-wire supply circuits of over 7500 V or constant-current circuits exceeding 7.5 A where crossing over communication circuits; and in urban and suburban districts.

Grade C construction is specified for open-wire supply circuits of over 7500 V in rural districts where crossing over or in conflict with supply circuits of 0 to 750 V, excepting services; and for open-wire supply circuits of 750 to 7500 V in urban districts under nearly all conditions except as noted for grade B construction, and also where crossing over or in conflict with communication circuits.

Grade N construction is specified for all other types of construction where grade B or C construction is not specified.

Conflict with communication lines includes not only those structures where the two are on the same pole, but also where they are so near each other that the overturning of one at the ground line would cause it to fall onto the other.

*The fourth edition (1940) of the National Electric Safety Code specified five grades of construction for power lines: A, B, C, D, and E. Later editions simplified these and grades A and E were eliminated; grade A was combined with B, grade E combined with D, and grade N established, generally defined as "safe construction." Grades B, C, and N apply to power lines, and are specified in later editions.

TABLE 5-7 TYPICAL SAFETY FACTORS FOR POLES AND CONDUCTORS

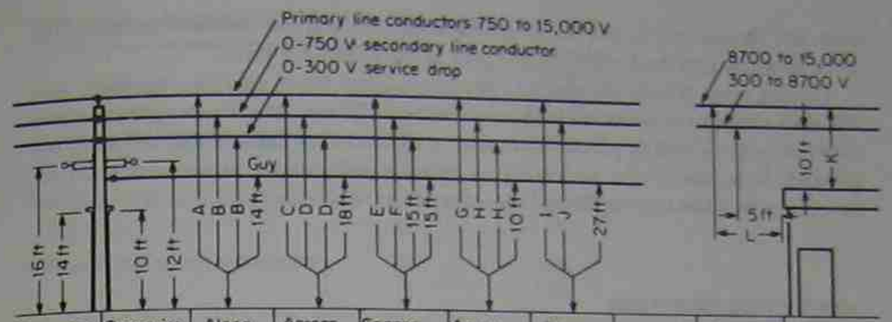
Situation	When installed: Treated poles	When installed: Untreated poles	At replacement: treated or untreated poles
1. Safety factors for poles			
At crossings: pole lines of one grade of construction throughout			
Grade B	4.0	4.0	2.67
Grade C	2.0	2.67	1.33
Grade N	1.33	1.33	0.67
Poles in isolated sections of higher-grade construction in pole lines of lower grade			
Grade B	3.0	4.0	2.0
Grade C	2.0	3.0	1.33
Grade N	1.33	1.67	0.67
Elsewhere than at crossings			
Grade B	4.0	4.0	2.67
Grade C	2.0	2.0	1.33
Grade N	1.0	1.33	0.67
2. Safety factors for conductors			
Grade B 50 % of ultimate strength			
Grade C 50 % of ultimate strength			
Grade N 60 % of ultimate strength			

For current industry recommended values, refer to the latest revision of the National Electric Safety Code.

CLEARANCES

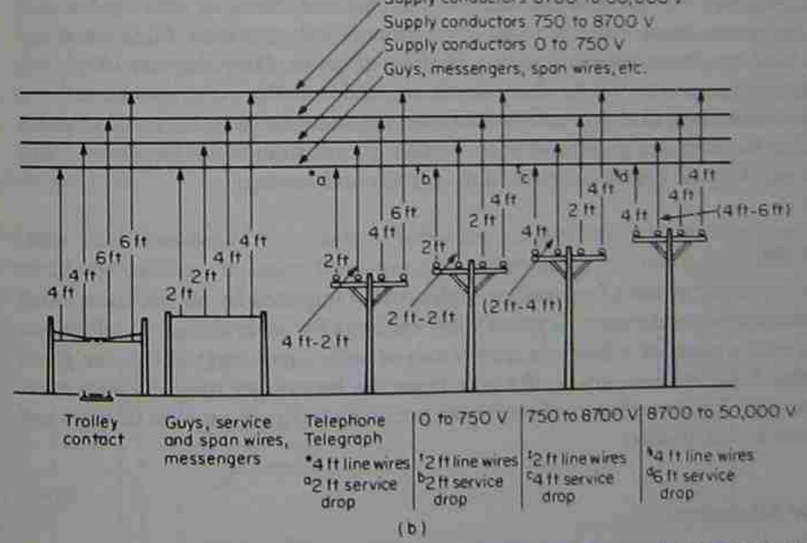
Prudent design provides for the safety of both the public and the worker when in the vicinity of power lines; moreover, it is desirable that interruptions to electric service be held to a practical minimum. In addition to adequate construction, certain clearances should be maintained between energized conductors and the surrounding structures in both horizontal and vertical planes. The NESC recommends minimum clearances for most of the situations that may be normally encountered.

Clearances include those between conductors and the ground, along and across roads, walkways, driveways, and railroads, and those over buildings and structures; these are shown graphically in Fig. 5-21*a*. Clearances between conductors and other lines, guy wires, service conductors, and communication cir-



For heavy loading district except for 3-strand conductors each wire of which is 0.09 in or less in diameter.
Clearances in table are increased for spans above the basic span length.

(a)



(b)

FIG. 5-21 (a) Typical minimum basic clearances, feet and inches. (b) Typical minimum wire crossing clearances. *(From E. B. Kurtz, Lineman's Handbook, 3d ed., McGraw-Hill, New York, 1955.)*

cuits are shown in Fig. 5-21*b*. These clearances are from conductors energized at both secondary and primary voltages at 60°F and no wind.

During high winds, conductors may sway into trees, or tree branches may fall and come in contact with the conductors. These may cause grounds and short circuits as well as physical breakages of lines that cause them to fall to the ground. It is, therefore, necessary to provide safeguards to prevent such occurrences by maintaining liberal clearances to trees.

JOINT CONSTRUCTION

Advantages

The joint use of poles for both electrical distribution and communication circuits, usually supplying the same consumers, has advantages that are well recognized. Not only are better appearance and cost savings achieved by a single line, but it is often easier to maintain proper clearances between the facilities of the several users when they are on the same pole and do not have to cross over or under each other. The largest employers of joint construction are the power and telephone utilities; others that may also be included are telegraph, traffic and special light controls, police and fire alarms, and (increasingly) cable television circuits. In rural areas, where appearance is not a paramount consideration, where long spans and lower clearances are permitted, and where services are few, joint construction may not prove practical.

In general, however, joint use appears desirable for urban and suburban areas, whether the facilities are located in streets and alleys, or on rear-lot lines and easements from which services to consumers are extended. Such construction, however, may require heavier loading of poles, frequent use of higher poles, often a greater grade of construction, additional guying, special maintenance procedures, and greater coordination between the joint users. Clearances between facilities and grades of construction are considered in the allotment of space on the pole and the distribution of costs and savings.

Stresses

In determining stresses imposed on poles, those imposed by all the users must be taken into consideration. Typical wind loadings for several sizes of telephone cable, with a wind of 4 lb/ft² on wires covered with a half-inch of ice, are given in Table 5-8. Tension acts on the pole from the messenger only. Typical maximum loads for several sizes of steel wire are given in the discussion of guys and anchors in this chapter.

Space Allocation

The space allotted on a pole for each purpose should be definitely specified. Usually the first point of attachment on a pole (from the ground up) is a communication conductor; its sag is taken into account to produce the minimum ground clearance at the center of its span. Other communication circuits follow

TABLE 5-8 LOADINGS ON TELEPHONE CABLES

Telephone cable sizes	*Gauge (Cu)*	*Wind loading, lb/ft*
50-pair, including messenger	24	1.02
	22	1.03
200-pair, including messenger	24	1.23
	22	1.27
600-pair, including messenger	24	1.53
	22	1.54

above, with the neutral zone separating them from the power circuit or circuits located at the top of the pole.

The division of space on a pole can be based on the assumption that the communication lines will take as much space as is necessary, with the power line taking the remainder above the neutral zone, making the construction conform to the space allowed. Refer to Fig. 5-22. Another method specifies a standard division of space on a "standard pole"; since minimum ground clearance is not the same for all locations, more space may be allotted to the communication circuits than may be required. If more space is required by the power conductors, a higher pole may be necessary, unless agreement can be reached decreasing the communication requirements.

Division of Costs The division of costs in joint use may be more complex than appears on the surface, and distribution engineers are usually assigned this chore. In general, there are two ways of accomplishing this: the pole can be jointly owned—i.e., each user owns a share of the pole; and it can be wholly owned by one user, who then rents space to the other users. While such divisions appear to be equitable and readily attainable, other factors enter to complicate the process.

Other Considerations In practice, poles are set and replaced by the power or telephone utilities. In many instances, the power utility has the equipment to set

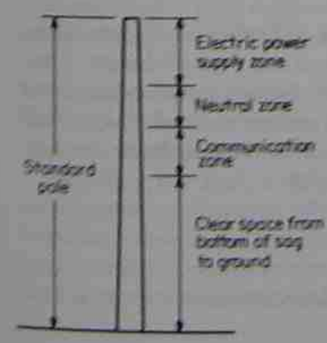


FIG. 5-22 Allotment of space on joint-use standard pole.

poles longer than 40 ft and is the sole utility stocking them. When emergencies occur, the power utility must respond as quickly as it can, while the telephone utility can defer its work until after the power crews complete their work. Where replacement of poles involving primary voltages above 5000 V is necessary, the power company is equipped to make the replacement, often cutting the old pole below the lowest power circuit, permitting the telephone crews to relocate their facilities to the new pole and remove the stub of the old pole without coming near the power lines. Also, tree trimming costs are almost always totally assumed by the power company although all users benefit.

Power lines on the top of the pole provide lightning protection for the facilities installed farther down. Obtaining rights-of-way, franchises, permits, etc., is usually done by one of the utilities. On the other hand, power lines may cause inductive interference in the operations of the other users, and can cause dangerous and widespread damage should they fall on the facilities of the others. Liability of each party in case of injury to workers or the public must be given consideration. These account for some—not all—the factors that the ingenuity of electrical distribution engineers and their counterparts in the communication utility must consider in order to come to an equitable and fair solution acceptable to all the parties concerned.

PRACTICAL DESIGN METHODS*

General

While a pole line must be designed pole by pole and the necessary strength must be built into each section of the line, much of the repetitious, time-consuming, and tedious calculation can be eliminated through the use of previously prepared tables and charts. Deviations from calculated theoretical values are compensated for by the tolerances incorporated in the standardization of the component parts, by the application of relatively liberal factors of safety, by provisions for future growth, and by the approximation of values inherent in the determination of the strength of materials, especially of wood products (and these carry an even greater margin of safety when treated by preservatives).

Design procedures containing necessary instructions and engineering data are prepared for selecting the proper pole, guy, and anchor for each segment of distribution pole line construction.

Design considerations should include conductors and other equipment to be added in the future, based on available information at the time of design. Also, the loading of communication (usually telephone) conductors must be taken into account in the selection of poles and anchors; sizes of guy wires are often specified to accommodate only the power conductors, while those for telephone conductors are specified and installed by the telephone utility.

*Adapted from Long Island Lighting Co. *Design & Application Standards.*

Use of the Tables

The tension at which a conductor is installed on a pole is a function of its material, its size, and the thickness of the covering, if any, over the conductor. This tension (in pounds) multiplied by the height of the conductor above ground (in feet) gives a value of foot-pounds of energy applied at the ground line of the pole. This is also called the ground-line moment, and poles are rated according to their ability to resist the moment.

In order to evaluate the total ground-line moment on a pole, multiply each conductor's tension by its respective height above ground and then add the results together.

To simplify calculations, the tables express values in *units*, making the job of analysis one of simple addition. All conductors—primary, secondary, telephone—are compared to *one* reference conductor at the primary level, having a design loading tension of 150 lb and a unit value of 1.0.

EXAMPLE 5-10

A no. 1/0 bare aluminum conductor, with a loading tension of 1200 lb, is given a unit value of 1200 divided by 150, or 8.0; 336,400-cmil aluminum with a loading tension of 2000 lb thus has a unit value of 2000 divided by 150, or 13.3 units; and so forth.

EXAMPLE 5-11

A three-conductor no. 1/0 aluminum secondary cable is converted first to its reference unit value, i.e., 2000 divided by 150, or 13.3 units. This is referenced up to the primary position by multiplying this unit value by the ratio of secondary height to primary height: for a 40-ft pole, this is 30.5 ft divided by 33 ft, or 0.92. The resulting unit value is 13.3 × 0.92, or 12.3 units. This means that a no. 1/0 triplex secondary conductor is equivalent to 12.3 primary conductors, each with a loading value of 150 lb of tension.

Selecting the Pole

The ability of a pole to be self-supporting depends on the class of the pole and the load it must carry (ignoring for the present the characteristics of the soil).

Classes of Poles All wood poles are divided into classes based on thickness and circumference. One system uses five classes: 5, 4, 2, 0, and 00, ranging from moderately thin (class 5) to extra heavy (class 00).

Knowing the load, it is possible then to select the proper class of pole for each location and degree of loading. If the number of units of loading is greater than the number of units the pole can support by itself, either the pole must be guyed or the conductors slackened to reduce the tension. Tables 5-9, 5-10, and 5-11 provide the necessary data for selecting the proper size of pole.

TABLE 5-9 GUYING TABLE: CONDUCTOR LOADING VALUES FOR 45-ft POLES (IN UNITS)*

Conductor size	Maximum loading, lbs	Turn angle, degrees						
		5	10	15	20	25	30	35
Primary								
Al 1/0 bare	1200	0.7	1.4	2.1	2.8	3.5	4.1	4.8
1/0 HDPE-PVC	1500	0.9	1.7	2.6	3.5	4.3	5.2	6.0
3/0 bare	1450	0.8	1.7	2.5	3.4	4.2	5.0	5.8
3/0 HDPE-PVC	1800	1.0	2.1	3.1	4.2	5.2	6.2	7.2
350,000-cmil bare	2000	1.2	2.3	3.5	4.6	5.8	6.9	8.0
350,000-cmil HDPE-PVC	2000	1.2	2.3	3.5	4.6	5.8	6.9	8.0
Cu 6 bare	640	0.4	0.7	1.1	1.5	1.8	2.2	2.6
3 bare	1070	0.6	1.2	1.9	2.5	3.1	3.7	4.3
2 PVC	1250	0.7	1.4	2.1	2.8	3.5	4.2	4.9
1/0 bare	1550	0.9	1.8	2.7	3.6	4.5	5.3	6.2
1/0 HDPE-PVC	2000	1.2	2.3	3.5	4.6	5.8	6.9	8.0
4/0 bare	1650	1.0	1.9	2.9	3.8	4.8	5.7	6.6
4/0 HDPE-PVC	2000	1.2	2.3	3.5	4.6	5.8	6.9	8.0
Secondary								
Al 3 c or 4c—all	2000	1.1	2.1	3.2	4.3	5.3	6.3	7.4
Cu 3c or 4c—6	640	0.3	0.7	1.0	1.4	1.7	2.0	2.4
3c or 4c—2	1500	0.8	1.6	2.4	3.2	4.0	4.8	5.5
4c—2	2000	1.1	2.1	3.2	4.3	5.3	6.3	7.4
Telephone								
6M	5600	1.8	3.4	5.1	6.8	8.5	10.2	11.8
10M	9000	2.9	5.7	8.6	11.4	14.2	17.0	19.8
16M	9600	4.6	9.2	13.7	18.2	22.7	27.2	31.6

Turn angle, degrees										
40	45	50	55	60**	65	70	75	80	85	90
5.5	6.1	6.8	7.4	8.0	8.6	9.2	9.7	10.3	10.8	11.3
6.8	7.6	8.5	9.2	10.2	10.7	11.5	12.2	12.9	13.5	14.1
6.6	7.4	8.2	9.0	9.7	10.4	11.1	11.8	12.5	13.1	13.7
8.2	9.2	10.1	11.1	12.0	12.9	13.8	14.6	15.4	16.2	17.0
9.1	10.2	11.2	12.3	13.3	14.3	15.3	16.2	17.1	18.0	18.9
9.1	10.2	11.2	12.3	13.3	14.3	15.3	16.2	17.1	18.0	18.9
2.9	3.3	3.6	3.9	4.3	4.6	4.9	5.2	5.5	5.8	6.0
4.9	5.5	6.0	6.6	7.1	7.7	8.2	8.7	9.2	9.6	10.1
5.8	6.5	6.9	7.6	8.2	8.8	9.4	10.0	10.5	11.1	11.6
7.1	7.9	8.7	9.5	10.3	11.1	11.8	12.6	13.3	13.9	14.6
9.1	10.2	11.3	12.3	13.3	14.3	15.3	16.2	17.1	18.0	18.9
7.5	8.4	9.3	10.2	11.0	11.9	12.6	13.4	14.1	14.9	15.6
9.1	10.2	11.3	12.3	13.3	14.3	15.3	16.2	17.1	18.0	18.9
8.4	9.4	10.4	11.3	12.3	13.2	14.1	15.0	15.8	16.6	17.3
2.7	3.0	3.3	3.6	3.9	4.2	4.5	4.8	5.1	5.3	5.6
6.3	7.0	7.8	8.5	9.2	9.9	10.6	11.2	11.8	12.4	13.0
8.4	9.4	10.4	11.3	12.3	13.2	14.1	15.0	15.8	16.6	17.3
13.6	15.1	16.6	18.2	19.7	21.1	22.6	24.0	25.3	26.6	27.8
22.4	25.1	27.7	30.3	32.8	35.2	37.6	39.9	42.2	44.3	46.4
35.9	40.8	44.6	48.5	52.5	56.4	60.2	63.9	67.5	70.9	74.2

*The conductor loading value, in units, appropriate to each combination of conductor size and turn angle is the resultant force on the pole due to conductors pulling in two directions.

**Conductor loading values for dead-end poles are in the 60° angle column.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

Courtesy Long Island Lighting Co.

TABLE 5-10 GUYING TABLE: TRANSVERSE LOADING VALUES FOR 40-ft POLES (IN UNITS)

Conductor size		Wind load, lb/ft	Average span length, ft									
									Long-span construction			
			75	100	125	150	175	200	250	300	350	400
Primary												
Al	1/0	0.566	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.5
	3/0	0.601	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.6
	336,000-cmil	0.655	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.3	1.5	1.7
Cu	3	0.524	0.3	0.3	0.4	0.5	0.6	0.7	—	—	—	—
	1/0	0.558	0.3	0.4	0.5	0.6	0.7	0.7	0.9	1.1	1.3	1.5
	4/0	0.609	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.6
Secondary												
Al 3c	4	0.572	0.3	0.4	0.4	0.5	0.6	0.7	—	—	—	—
	1/0	0.676	0.3	0.4	0.5	0.6	0.7	0.8	—	—	—	—
	3/0-1/0-1/0	0.725	0.3	0.4	0.6	0.7	0.8	0.9	—	—	—	—
	3/0	0.749	0.3	0.5	0.6	0.7	0.8	0.9	—	—	—	—
	336,000 cmil-3/0-3/0	0.749	0.3	0.5	0.6	0.7	0.8	0.9	—	—	—	—
Al 4c	1/0	0.708	0.3	0.4	0.5	0.7	0.8	0.9	—	—	—	—
	3/0-1/0-1/0-1/0	0.741	0.3	0.5	0.6	0.7	0.8	0.9	—	—	—	—
	3/0	0.780	0.4	0.5	0.6	0.7	0.8	1.0	—	—	—	—
	336,000 cmil-3/0-3/0-3/0	0.846	0.4	0.5	0.6	0.8	0.9	1.0	—	—	—	—
Cu 3c	6	0.519	0.2	0.3	0.4	0.5	0.6	0.6	—	—	—	—
	2	0.601	0.3	0.4	0.5	0.6	0.6	0.7	—	—	—	—
	1/0-2-2	0.636	0.3	0.4	0.5	0.6	0.7	0.8	—	—	—	—
	4/0-2-2	0.679	0.3	0.4	0.5	0.6	0.7	0.8	—	—	—	—
Cu 4c	6	0.556	0.2	0.3	0.4	0.5	0.6	0.7	—	—	—	—
	2	0.622	0.3	0.4	0.5	0.6	0.7	0.8	—	—	—	—
	1/0	0.657	0.3	0.4	0.5	0.6	0.7	0.8	—	—	—	—
	4/0-1/0-1/0-1/0	0.707	0.3	0.4	0.5	0.7	0.8	0.9	—	—	—	—
Copperweld-Alumoweld												
Three no. 6 to $\frac{7}{16}$ in		0.480	0.2	0.3	0.4	0.4	0.5	0.6	—	—	—	—
Unbalanced service												
Concentric and twisted, 200 lb		—	1.2	1.2	1.2	1.2	1.2	1.2	—	—	—	—
Telephone												
6M		1.20	0.5	0.7	0.8	1.0	1.1	1.3	—	—	—	—
10M		1.50	0.6	0.8	1.0	1.2	1.4	1.6	—	—	—	—
16M		1.80	0.7	1.0	1.2	1.5	1.7	2.0	—	—	—	—
25M		2.10	0.9	1.1	1.4	1.7	2.0	2.3	—	—	—	—
Twin		0.50	0.2	0.3	0.3	0.4	0.4	0.5	—	—	—	—

The transverse loading value, in units, is the unbalanced loading force on the pole due to the wind blowing against the pole and conductors.

Note: Where the computed average span length does not equal one of the numbers heading the column, use the column headed by the number *closest* to the computed span length.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

Courtesy Long Island Lighting Co.

TABLE 5-11 GUYING TABLES: GROUND-LINE RESISTING MOMENTS FOR 40-ft POLES (IN UNITS)

	Grade B construction						*Grade C construction*					
	Longitudinal loading		*Dead-end loading*		*Angle loading*		*Vertical and transverse loading*		*Dead-end loading*		*Angle loading*		*Vertical and transverse loading*	
Pole class	*A*	*B*	*A*	*B*	*A*	*B*	*A*	*B*	*A*	*B*	*A*	*B*	*A*	*B*
00	30.5	40.6	20.3	30.5	17.5	24.3	18.2	30.5	32.5	40.6	25.9	33.3	18.2	30.5
0	25.8	34.4	17.2	25.8	14.8	20.9	13.7	25.8	25.6	34.4	21.9	28.2	13.7	25.8
2	18.0	23.9	12.0	18.0	10.3	14.5	9.6	18.0	18.0	23.9	15.2	19.5	9.6	18.0
4	11.4	15.2	7.6	11.4	6.6	9.2	6.1	11.4	11.4	15.2	9.7	12.5	6.1	11.4
5	9.0	12.1	6.0	9.0	5.2	7.3	4.8	9.0	9.0	12.1	7.7	9.8	4.8	9.0

Ultimate strength values: A—when installed; B—at replacement.

Directions. Read down the appropriate column until a value is reached that is equal to or greater than the loading value computed from Tables 5-9 and 5-10. Looking left to the first column, read the class of pole to be used.

Note: If the pole comes out to be *greater* than a class 2, a smaller pole and guy should be specified. A class 5 pole is adequate for usual conditions; however, the pole selected should conform to other sections of this procedure. Use Table 5-12 to select the guy wire and Table 5-13 to select the anchor.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

Courtesy Long Island Lighting Co.

Heavier-Class Poles Poles one class heavier than the class specified by the tables should be used for each of the following purposes:

1. Junction poles
2. Poles supporting alley or side arms
3. Poles supporting line disconnects (except in-line types) or fuse cutouts

In addition, a pole of at least class 4 should be specified for dead-end poles, angle poles, and transformer (or capacitor, regulator, or other equipment) poles.

Extra Heavy-Class Poles Class 0 and class 00 poles are special oversize poles and are used primarily in the following situations:

1. In place of sidewalk guys, the most expensive guys to install
2. At an angle in the line in place of the combination of a span guy with a stub pole and sidewalk guy on the opposite side of the road
3. At T intersections, where normally a sidewalk guy or a span guy with a stub pole would be used
4. Where guying permission or rights cannot be obtained
5. To satisfy consumer complaints, by replacing an existing or proposed anchor guy

Selecting the Guy Wire

When the loading exceeds the strength of a pole, the pole should be guyed. The physical location of the pole in the field will determine what type of guy should be used: anchor, span, head, or sidewalk type. Tables 5-12A and 5-12B provide the necessary data for selecting the proper size of guy wire and lead. Guy protectors should be installed on all anchor guys accessible to the public.

When a pole line changes direction and the turn angle is less than 60°, the corner, or "pivot," pole may be guyed with a single guy bisecting the angle. At angles greater than 60°, the pole should be guyed against the stress in each direction.

Selecting the Anchor

Anchors come in many types and sizes, each designed for certain soil and guying conditions. While each will do its specific job better than another design of anchor, most find use under more than one set of conditions. Table 5-13 provides the necessary data for selecting the type and size of anchor.

Sag Calculation

Occasionally, the stringing tension of the conductors must be lessened, either in conjunction with cribbing or because the wire tension is too great.

Increasing the sag reduces the tension, and the procedure for calculating

TABLE 5-12A GUYING TABLE: GUY WIRE AND LEADS, ft, FOR 40-ft POLES—GRADE B CONSTRUCTION

	Alumoweld						*Copperweld*					
	Dead-end and angle loading			*Transverse loading*			*Dead-end and angle loading*			*Transverse loading*		
Number of units	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*
10	11	5	3	—	10	7	13	6	4	—	12	8
11	12	6	4	—	11	8	14	7	5	—	13	9
12	13	7	5	—	13	8	16	8	5	—	15	9
13	14	8	5	—	14	9	18	9	5	—	17	10
14	15	8	5	—	15	10	19	9	6	—	18	11
15	17	9	6	—	17	11	21	10	6	—	21	12
16	18	9	6	—	18	11	—	11	7	—	—	13
17	21	10	6	—	20	12	—	11	8	—	—	14
18	—	11	7	—	—	13	—	13	8	—	—	15
19	—	11	7	—	—	14	—	13	8	—	—	16
20	—	12	8	—	—	15	—	14	9	—	—	18
21	—	13	8	—	—	16	—	15	9	—	—	18
22	—	13	9	—	—	17	—	16	10	—	—	20
23	—	14	9	—	—	18	—	17	10	—	—	—
24	—	15	9	—	—	19	—	18	11	—	—	—
25	—	15	10	—	—	20	—	18	11	—	—	—
26	—	16	10	—	—	—	—	20	12	—	—	—
27	—	17	11	—	—	—	—	—	13	—	—	—
28	—	18	11	—	—	—	—	—	13	—	—	—
29	—	19	12	—	—	—	—	—	13	—	—	—
30	—	20	12	—	—	—	—	—	13	—	—	—
31	—	—	13	—	—	—	—	—	14	—	—	—
32	—	—	13	—	—	—	—	—	15	—	—	—
33	—	—	13	—	—	—	—	—	15	—	—	—
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
38	—	—	16	—	—	—	—	—	19	—	—	—

Directions. (1) Read down the first column, number of units, to the total units of loading—power conductors only—computed from Tables 5-9 and 5-10. (2) Move to the right to the group of three columns that pertains to the type of loading on the pole; e.g., Alumoweld, transverse loading. (3) The number in each box is the ground-line distance ("lead" distance) in feet between the base of the pole and the anchor rod. (4) Looking up, the number at the head of each column (6M, 11M, 17M) corresponds to the guy wire.

Note: In certain cases of heavy loading, more than one (or one size of) guy wire may be required to do the job. Care should be taken to ensure that the lead distances are identical for the guy wires specified.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

Courtesy Long Island Lighting Co.

TABLE 5-12B GUYING TABLE: GUY WIRE AND LEADS FOR 40-ft POLES—GRADE C CONSTRUCTION

	Alumoweld						*Copperweld*					
	Dead-end and angle loading			*Transverse loading*			*Dead-end and angle loading*			*Transverse loading*		
Number of units	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*	*6M*	*11M*	*17M*
10	8	4	3	15	8	5	9	5	3	18	9	6
11	9	5	3	17	8	5	10	5	3	20	10	6
12	9	5	3	18	9	6	11	6	3	—	11	7
13	10	5	3	21	10	6	12	6	4	—	12	8
14	11	6	4	—	11	7	13	7	5	—	13	8
15	12	6	4	—	12	8	15	8	5	—	14	9
16	13	7	5	—	13	8	15	8	5	—	15	9
17	14	7	5	—	14	9	17	8	5	—	16	10
18	15	8	5	—	15	9	18	9	6	—	18	11
19	16	8	5	—	16	10	20	9	6	—	19	11
20	18	9	6	—	17	11	—	10	6	—	21	12
21	18	9	6	—	18	11	—	11	7	—	—	13
22	20	9	6	—	19	12	—	11	7	—	—	14
23	—	10	6	—	21	13	—	12	8	—	—	15
24	—	11	7	—	—	13	—	13	8	—	—	15
25	—	11	7	—	—	14	—	13	8	—	—	16
26	—	12	8	—	—	15	—	13	9	—	—	17
27	—	12	8	—	—	15	—	14	9	—	—	18
28	—	13	8	—	—	16	—	15	9	—	—	18
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
37	—	18	11	—	—	—	—	—	13	—	—	—
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
41	—	—	13	—	—	—	—	—	15	—	—	—
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
43	—	—	13	—	—	—	—	—	15	—	—	—
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
49	—	—	16	—	—	—	—	—	18	—	—	—

The procedure for using this table is the same as that described in the footnote to Table 5-12A.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

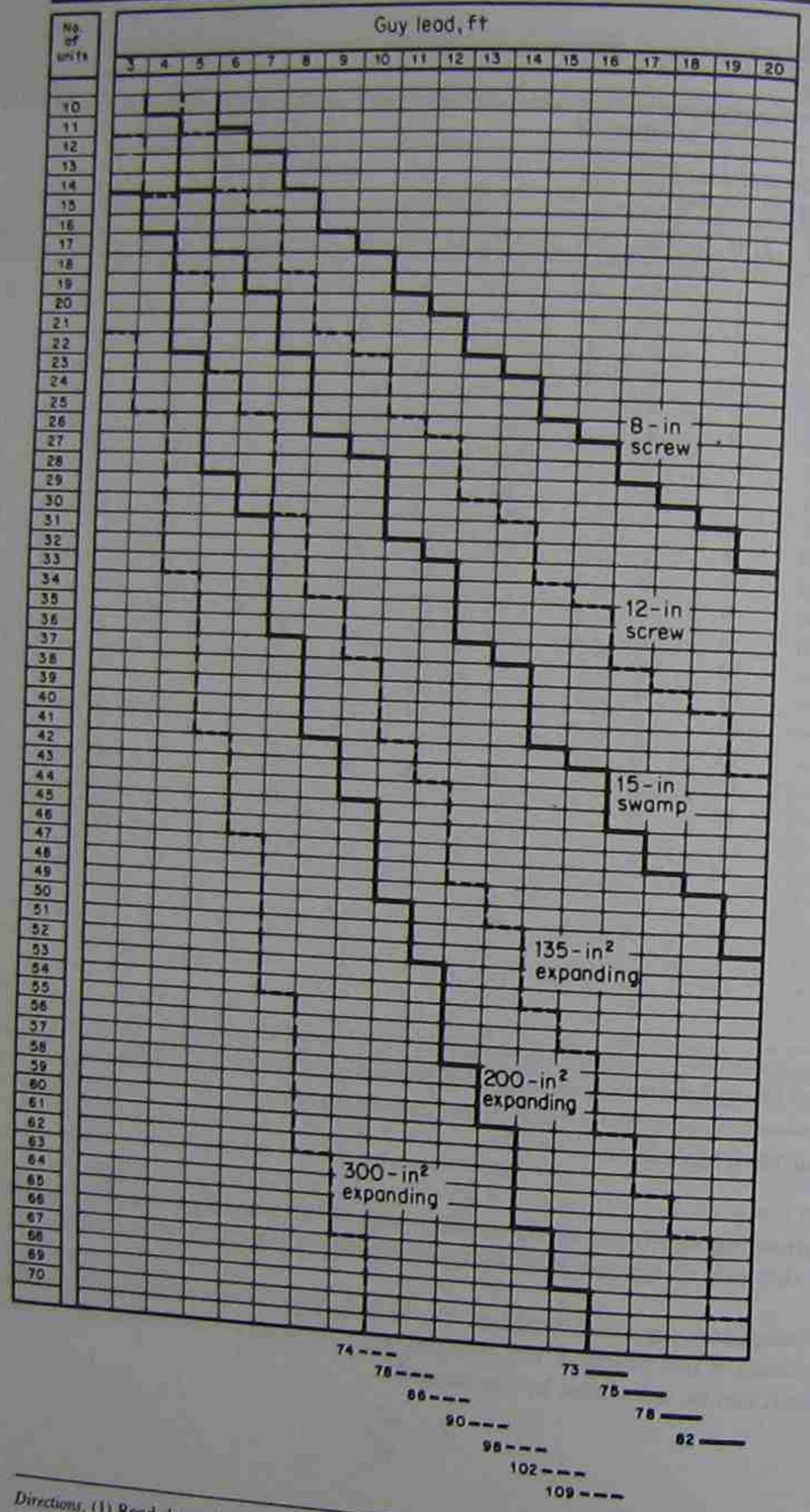
Courtesy Long Island Lighting Co.

new stringing sags based on the tension desired in the conductor is given below. Note that safe clearances must be maintained between conductors at all times.

Sag Calculation for Slack Sections On dead-end poles where adequate guying or cribbing is not practical, the stringing sags for slack sections, limited to 100-ft spans, can be calculated by the formula:

$$S = \frac{wL^2}{8T}$$

TABLE 5-13 GUYING TABLES: ANCHOR HOLDING POWER FOR 40-ft POLES



Directions. (1) Read down the first column to the loading value in units computed from Tables 5-9 and 5-10. This value should include telephone conductors. (2) Read right to the column for guy wire lead length, in feet, selected from Table 5-12A or 5-12B. (3) The first curve to the left of this point denotes the minimum size of anchor to use. Anchor selection should be in accordance with other sections of the procedure.

Note: In cases where the loading value exceeds the strength of the desired anchor, an adjustment can be made by increasing the guy wire lead (see values above) or reducing the tension in the conductor. See text for calculation of slack sections.

Similar tables have been prepared for other pole sizes, from 25 to 55 ft.

Courtesy Long Island Lighting Co.

TABLE 5-14 CONDUCTOR HEAVY LOADING VALUES, lb/ft

Number of conductors	*Type*	*Size*	*Heavy loading*
Copper			
1	Bare, solid	6	0.916
		3	1.028
	Bare, stranded	1/0	1.269
		4/0	1.67
	Insulated (HDPE)	3	1.355
		1/0	1.60
		4/0	2.05
3	Insulated (XLPE)	6	1.38
		2	1.945
		1/0-2-2	2.15
		4/0-2-2	2.32
4	Insulated (XLPE)	6	1.545
		2	2.185
		1/0	2.81
		4/0-1/0-1/0-1/0	2.935
Aluminum			
1	Bare or stranded, alloy	1/0	1.129
		3/0	1.267
	Pure	336,400 cmil	1.490
	HDPE-insulated, alloy	1/0	1.39
		3/0	1.60
	Pure	336,400 cmil	1.85
3	XLPE-Insulated, pure, with alloy neutral	4	1.39
		1/0	1.822
		3/0-1/0-1/0	1.979
		3/0	2.15
	Pure	336,400 cmil-1/0-1/0	2.214
4	XLPE-insulated, pure, with alloy neutral	1/0	2.030
		3/0-1/0-1/0-1/0	2.295
		3/0	2.42
	Pure	336,400 cmil-3/0-3/0-3/0	2.77

HDPE = high-density polyethylene insulation.

XLPE = cross-linked polyethylene insulation.

Courtesy Long Island Lighting Co.

where S is the sag in feet, w is the heavy loading value in pounds per foot from Table 5-14, L is the length of the span in feet, and T is the maximum tension desired in the conductor in pounds.

EXAMPLE 5-12

Calculate the required sag for a 75-ft span of a three-phase four-wire section of no. 1/0 bare copper where the dead-end pole cannot be guyed. From previous calculations, it is necessary to limit the tension under loading conditions to 1000 lb per conductor.

$$w = 1.269 \text{ lb/ft} \qquad L = 75 \text{ ft}$$

$$S = \frac{1.269(75)^2}{8 \times 1000} = 0.9 \text{ ft or } 11 \text{ in}$$

Alternative Method

Some guying situations cannot be resolved using the method described above. Appendix 5A contains basic guying theory and a detailed method of determining pole, guy, and anchor sizes in terms of ground-line moments, pounds of tension in the guy wire, etc.

Examples As part of this procedure, examples are included illustrating problems in selecting poles, guys, and anchors for small-angle turns, for dead ends, and for right-angle turns in the line. These are contained in Appendix 5B.

APPENDIX 5A
PRACTICAL METHOD OF CALCULATING POLE AND GUY SIZES

INTRODUCTION

This Appendix describes a method of determining pole and guy sizes, including a step-by-step solution of loading problems. It covers the general run of design problems, but in some instances, more detailed calculations may be required.

POLE CLASS REQUIREMENTS

Factors Involved

The total loading on a pole is the accumulation of all the individual stress-producing forces that act on the pole. In this method of solution, eight factors, *a* through *h*, will determine the class of pole required:

a. Tension in wires or cables at dead ends: Table 5-17 (see the column for a 60° angle)

TABLE 5-15 TRANSVERSE LOADING PER CONDUCTOR

Type	*Size*	*Loading, lb/ft*
Primary wire		
PVC or HDPE: Cu	3	0.524
	1/0	0.558
	4/0	0.609
Al	1/0	0.566
	3/0	0.601
	336,400 cmil	0.655
Secondary mains		
XLPE: Cu, 3c	6	0.519
	2	0.601
	1/0-2-2	0.636
	4/0-2-2	0.679
Cu, 4c	6	0.556
	2	0.622
	1/0	0.657
	4/0-1/0-1/0-1/0	0.707
Al, 3c	4	0.572
	1/0	0.676
	3/0-1/0-1/0	0.725
	3/0	0.743
	336,400 cmil-1/0-1/0	0.749
Al, 4c	1/0	0.708
	3/0-1/0-1/0-1/0	0.741
	3/0	0.782
	336,400 cmil-3/0-3/0-3/0	0.846
Copperweld or Alumoweld		
	Three no. 8 to $\frac{7}{16}$ in	0.48 (max.)
Telephone and guy wire		
	6M	1.20
	10M	1.50
	16M	1.80
	25M	2.10
Twin		0.50

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b. Tension in wires or cables due to an angle in the line: Table 5-17
c. Transverse loading per wire or cable: Table 5-15
d. Transverse loading on poles: included in Table 5-19
e. Transverse loading on equipment: Table 5-18
f. Tension from unbalanced services: Table 5-16
g. Longitudinal loading at a change in grade: Table 5-17 (*see the 60° angle column*)
h. Factors of safety prescribed for poles: Table 5-19

Classification of Poles

To simplify the analysis, poles have been classified as:

1. Straightaway poles (in a straight line)
2. Angle poles (at angles or offsets in the line)
3. Dead-end poles

The procedures, each designed for a particular classification of pole, start on page 184.

TABLE 5-18 TENSION RESULTING FROM UNBALANCED SERVICES

Type	*Number of conductors*	*Size, AWG*	*Tension, lb*
Copper: open wire	1	8	75
	1	6	75
	1	3	100
	1	1/0	150
	1	4/0	300
Copper: concentric (cable)	2	8	100
	3	8	150
	3	6	180
	3	4	225
Copper: twisted (cable)	3	2	300
	4	6	450
	3	2	450
	4	2	450
Aluminum: twisted (cable)	4	1/0	450
	3	4	450
	3	1/0	450
	4	1/0	450
Telephone drop	4	3/0	450
	2	—	75

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TABLE 5-17 TENSION IN CONDUCTORS—ANGLES AND DEAD ENDS—lb
For spans up to 200 ft

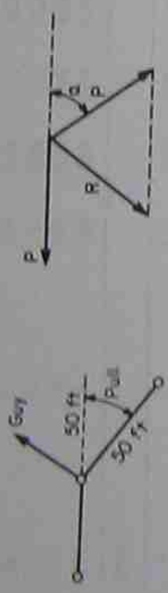
Type	*Size*	*5°*	*10°*	*15°*	*20°*	*25°*	*30°*	*35°*	*40°*	*45°*	*50°*	*55°*	*60°**
All primary**													
—	—	175	348	522	694	866	1036	1203	1367	1531	1640	1846	2000
Bare													
Cu	3	93	187	279	372	463	554	643	732	821	904	988	1070
	1/0	135	270	405	538	677	802	958	1060	1186	1310	1431	1550
	4/0	141	288	430	573	714	854	993	1129	1262	1394	1524	1650
Al	1/0	104	208	313	418	521	622	721	821	918	1015	1109	1200
	3/0	126	253	379	501	628	751	872	992	1110	1226	1339	1450
	336,400 cmil	175	348	522	694	934	1170	1380	1483	1609	1740	1840	2000
PVC and HDPE													
Cu	3	107	214	321	428	533	637	739	842	921	1041	1137	1230
	1/0	175	348	522	694	866	1036	1203	1367	1530	1690	1846	2000
	4/0	310	570	720	1086	1376	1684	1942	2209	—	—	—	—
Al	1/0	131	262	392	521	651	779	904	1030	1151	1270	1390	1500
	3/0	157	314	470	625	779	932	1083	1231	1390	1521	1662	1800
	336,400 cmil	175	348	522	694	866	1036	1203	1367	1530	1690	1846	2000
XLPE													
Cu	6	56	111	167	222	277	333	385	439	490	541	591	640
	3	131	262	392	521	651	779	904	1030	1151	1270	1390	1500
	1/0	187	373	569	743	928	1111	1289	1469	1589	1798	1931	2000
	1/0-2-2 4/0-2-2	175	348	522	694	866	1036	1203	1367	1530	1690	1846	2000
	4/0-1/0-1/0-1/0												
Al	1/0 3/0 1/0-1/0-1/0- 3/0-1/0-1/0-1/0 336,400 cmil-1/0-1/0 336,400 cmil-1/0-1/0-1/0	175	348	522	694	866	1036	1203	1367	1530	1690	1846	2000

TABLE 5-17 TENSION IN CONDUCTORS—ANGLES AND DEAD ENDS—lb (Continued)
For spans up to 200 ft.

Type	Size	5°	10°	15°	20°	25°	30°	35°	40°	45°	50°	55°	60°*
Guy wire													
—	6M	319	628	940	1250	1559	1865	2165	2412	2755	3043	3324	3600
—	10M	524	1046	1541	2083	2548	3100	3609	4104	4585	5071	5540	6000
—	16M	837	1674	2507	3333	4156	4969	5774	6567	7346	8014	8865	9600
Angle (pull feet)**													
		4.35	8.7	13.1	17.4	21.7	25.9	30.0	34.2	37.3	42.3	46.2	50.0

*Use these values for dead ends.
**Spans longer than 200 ft.
***Determination of line angle in pull-feet (see diagram). Interpolate for other angles.

Table based on:
P = 1 ultimate strength of conductor, or 2000 lb, whichever is less
R = Resultant tension due to angle
$R = 2P \sin \frac{a}{2}$



Adapted from Long Island Lighting Co. design standards.

TABLE 5-18 EQUIPMENT DATA AND MAXIMUM ALLOWABLE EQUIPMENT WEIGHTS ON POLES

Equipment				Allowable weight for transverse loading, lb	
		Weight lb			
Type	Size	Maximum	Minimum	Maximum	Minimum
Distribution transformers, 1ϕ	10 kVA	403	210	25	10
	15	649	265	30	15
	25	959	363	50	25
	37½	1139	540	55	35
	50	1305	640	65	40
	75	1869	825	95	50
	100	2240	1015	110	55
	167	2640	1430	130	70
	250	2200	1600	110	90
	333	2450	2100	110	105
	500	3100	2500	—	—
Regulators: induction, step	24 kVA	1215	—	65	—
	12	965	1000	50	55
	25	1200		65	
	76.2	1700		90	
Reclosers	50–200 A	170	—	10	—
	560	755	—	30	15
Oil switch, 15-kV	200 A	60	—	5	—
	400	456	—	20	10
Capacitors, unit-type	25 kVAR	100	—	—	—
	50	90	65	5	—
	100	135	100	5	—
	150	110	80	5	—
Capacitors, switched	300 kVAR	1320	1090	65	60
	600	1290	875	65	50
Interrupter switch, 15-kV	600 A	450	150	55	—
Air-break switch, 34.5-kV	400 A	600	—	100	—
Street lighting transformer, types RO, ROC	10 kW	965	—	45	—
	15	1045	—	60	—
	20	1300	—	90	—

Maximum permissible weight of equipment on poles

Pole class	Weight, lb
5	900
4	1800
3	2500
2	3200
1	4000
0	5050
00	6750

Notes. (1) Pole classes specified are minimum to be used on new installations. Where poles already exist in the field, use of poles one class lighter than specified above is permitted. (2) Use 3 times the transverse loading for three transformers or other groups of equipment. (3) Allowance for transverse loading on equipment is equal to 4 lb/ft² on the projected area angles to the line.

Courtesy Long Island Lighting Co.

TABLE 5-19 GROUND-LINE RESISTING MOMENTS FOR CREOSOTED SOUTHERN PINE POLES
In thousands of foot-pounds. Number above each column represents factor of safety.

Pole			Grade C construction loading								Grade B construction loading					
			Longitudinal		Dead-end		Vertical and transverse				Longitudinal		Dead-end		Vertical and transverse	
							Crossing		Other							
Height, ft	Class	Ultimate strength 1.0	A —	B —	A 1.33	B 1.0	A 2.66	B 1.33	A* 2.0	B 1.33	A 1.33	B 1.0	A 2.0	B 1.33	A 4.0	B 2.66
30	00	154.2	No data		115.9	154.2	58.0	115.9	61.7	115.9	115.9	154.2	77.1	115.9	38.6	59.0
	0	124.0	required where		93.2	124.0	46.6	93.2	49.6	93.2	93.2	124.0	62.0	93.2	31.0	46.6
	1	103.7	grade C		78.0	103.7	39.0	78.0	41.5	78.0	78.0	103.7	51.9	78.0	25.9	39.0
	2	84.5	construction is		63.4	84.5	31.7	63.4	35.2	63.4	63.4	84.5	42.2	63.4	21.1	31.7
	3	67.5	used and no		50.9	67.5	25.4	50.6	27.0	50.8	50.8	67.5	33.8	50.8	16.9	25.4
	4	53.0	change in grade		39.8	53.0	19.9	39.8	21.2	39.8	39.6	53.0	26.5	39.6	13.3	19.9
	5	43.1	of construction		32.4	43.1	16.2	32.4	17.2	32.4	32.4	43.1	21.6	32.4	10.8	16.2
	6	34.4	exists.		25.9	34.4	12.9	25.9	13.8	25.9	25.9	34.4	17.2	25.9	8.6	12.9
35	00	176.5			132.7	176.5	66.4	132.7	70.6	132.7	132.7	176.5	88.3	132.7	44.1	66.4
	0	146.5			111.6	148.5	55.8	111.6	59.4	111.6	111.6	149.5	74.3	111.6	37.1	55.6
	1	123.6			93.0	123.6	46.5	93.0	49.4	93.0	93.0	123.6	61.8	93.0	30.9	46.5
	2	101.7			76.5	101.7	36.2	76.5	40.7	76.5	76.5	101.7	50.9	76.5	25.4	36.2
	3	82.5			62.0	82.5	31.0	62.0	33.0	62.0	62.0	82.5	41.3	62.0	20.6	31.0
	4	62.9			47.3	62.9	23.6	47.3	25.2	47.3	47.3	62.9	31.5	47.3	15.7	23.6
	5	51.7			38.9	61.7	19.4	38.9	20.7	38.9	36.9	51.7	25.9	36.9	12.9	19.4
	6	39.7			29.8	39.7	14.9	29.8	15.9	29.8	29.8	39.7	19.9	29.8	9.9	14.9
40	00	200.6			150.6	200.6	75.4	150.6	80.2	150.6	150.8	200.6	100.5	150.8	50.2	75.4
	0	170.1			127.9	170.1	63.9	127.9	66.0	127.9	127.9	170.1	85.1	127.9	42.5	63.9
	1	142.7			107.3	142.7	83.6	107.3	57.1	107.3	107.5	142.7	71.4	107.3	36.7	53.6
	2	110.6			89.2	110.6	44.6	89.2	47.4	89.2	89.2	116.6	59.3	89.2	29.7	44.6
	3	97.3			73.2	97.3	36.6	73.2	36.6	73.2	73.2	97.3	48.7	73.2	24.3	36.6
	4	75.1			56.5	75.1	26.2	56.5	30.0	56.5	56.5	75.1	37.6	56.5	18.6	26.2
	5	59.5			44.7	59.5	22.4	44.7	25.8	44.7	44.7	59.5	29.6	44.7	14.9	22.4
45	00	241.4			181.5	241.4	90.8	181.5	96.6	181.5	181.5	241.4	120.7	181.5	60.4	90.8
	0	200.1			150.5	200.1	75.2	150.5	80.0	150.5	150.5	200.1	100.1	150.5	50.0	76.2
	1	161.6			121.5	161.6	60.6	121.5	64.6	121.5	121.5	161.6	60.8	121.5	40.4	60.8
	2	135.2			101.7	135.2	50.6	101.7	54.1	101.7	101.7	135.2	67.6	101.7	33.8	50.8
	3	107.5			80.8	107.5	40.4	80.8	43.0	80.8	80.8	107.5	53.6	80.8	26.9	40.4
	4	87.6			65.9	87.6	32.9	65.9	35.0	65.9	65.9	87.6	43.8	65.9	21.9	32.9
50	1	181.9			136.8	181.9	68.4	136.8	72.6	136.8	136.8	181.9	91.0	136.8	45.5	68.4
	2	148.0			111.3	148.0	55.6	111.3	59.2	111.3	111.3	148.0	74.0	111.3	37.0	55.6
	3	118.5			89.1	118.5	44.5	89.1	47.4	89.1	89.1	118.5	59.3	69.1	29.6	44.5
	4	97.2			73.1	97.2	36.5	73.1	39.9	73.1	73.1	97.2	48.6	73.1	24.3	36.5
55	1	197.5			148.5	197.5	74.2	148.5	79.0	148.5	148.5	197.5	98.6	148.5	49.4	74.2
	2	161.5			121.4	161.5	60.7	121.4	64.6	121.4	121.4	161.5	80.8	121.4	40.4	60.7
	3	130.2			97.9	130.2	48.9	97.9	52.1	97.9	97.9	130.2	65.1	97.9	32.6	48.9
	4	108.2			81.4	108.2	40.7	81.4	43.3	81.4	81.4	108.2	54.1	81.4	27.1	40.7

A = when installed; B = at replacement.

*These values include an additional factor of safety to allow for pole deflections and soil conditions peculiar to a territory.

Courtesy Long Island Lighting Co.

Straightaway Poles

Step 1. Determine the grade of construction applying, B or C.

Step 2. From Table 5-19, determine the factor of safety required for transverse loading, and calculate the total load on the pole.
a. For grade B construction, the factor of safety is 4 and the total load is $4(c + d + e + f)$.
b. For grade C construction, the factor of safety is 2 and the total load is $2(c + d + e + f)$.
c. For grade C construction at crossings, the factor of safety is 2.66 and the total load is $2.66(c + d + e + f)$.

Step 3. Calculate the total ground-line moment on the pole by multiplying the total load (step 2) by the average height of the conductors or equipment.

Step 4. From Table 5-19, select the pole class having a ground-line resisting moment at least equal to that calculated in step 3.

Step 5. If the pole is to support equipment, from Table 5-18 determine the pole class required by the weight of the equipment. If it exceeds that selected in step 4, the larger class should be specified.

Step 6. If the transverse loading is too great for the unsupported pole, proceed to the section Guying Requirements in this appendix.

Angle Poles

Step 1. Determine the grade of construction applying.

Step 2. From Table 5-19 determine the factor of safety required for the type of loading and calculate the total load on the pole.
a. For grade B construction, the factors of safety are 4 and 2 and the total load is $4(c + d + e + f) + 2b$.
b. For grade C construction, the factors of safety are 2 and 1.33 and the total load is $2(c + d + e + f) + 1.33b$.
c. For grade C construction at crossings, the factors of safety are 2.66 and 1.33 and the total load is $2.66(c + d + e + f) + 1.33b$.

Step 3. Calculate the total ground-line moment on the pole by multiplying the total load (step 2) by the average height of the conductors.

Step 4. From Table 5-19 select the pole class having a ground-line resisting moment at least equal to that calculated in step 3.

Step 5. If the pole is to support equipment, from Table 5-18 determine the pole class required by the weight of the equipment. If it exceeds that calculated in step 4, the larger class should be specified.

Step 6. If the calculation in step 4 results in a class 5 pole, guying or cribbing will generally not be required unless soil conditions are poor. If the result is other than class 5, proceed to the section Guying Requirements.

Dead-End Poles

Step 1. Determine grade of construction applying, B or C.

Step 2. From Table 5-19 determine the factors of safety required for dead-end loading, and calculate the total load on the pole.
a. For grade B construction, the factor of safety is 2 and the total load is $2a$.
b. For grade C construction, the factor of safety is 1.33 and the total load is $1.33a$.

Step 3. Calculate the total ground-line moment on the pole by multiplying the total load (step 2) by the average height of the conductors.

Step 4. From Table 5-19 select the pole class having a ground-line resisting moment at least equal to that calculated in step 3.

Step 5. If the pole is to support equipment, from Table 5-18 determine the pole class required by the weight of the equipment. If it exceeds that calculated in step 4, the larger class should be specified.

Step 6. If the calculation in step 4 results in a class 5 pole, guying or cribbing will not generally be required unless soil conditions are poor. If the result is other than class 5, proceed to the section Guying Requirements.

GUYING REQUIREMENTS

General

Smaller poles may be specified on the assumption they will be used with guying; this is possible because the pole acts as a strut only, the horizontal load being supported by the guy wire. Poles supporting equipment, or placed at a turn angle greater than 10°, however, should not be smaller than class 4.

The steps enumerated above under Pole Class Requirements should cover all extreme cases of transverse or longitudinal loading. If the loading is too great for the unsupported pole, the following additional steps for each classification of pole, designed to determine guying requirements, should be considered.

Straightaway Poles

Step 7. From Table 5-19 determine the factor of safety required for transverse loading, and calculate the total load on the pole.
a. For grade B construction, the factor of safety is 2.66 and the total load is $2.66c$.
b. For grade C construction, the factor of safety is 2 and the total load is $2c$.

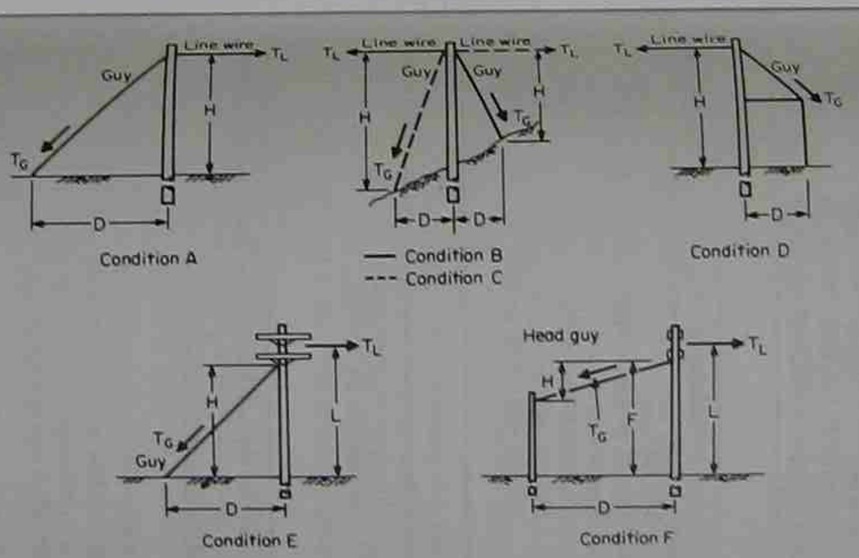
Step 8. From Table 5-20, calculate the guy tension.

Step 9. From Table 5-21, select the proper guy wire for the guy tension (step 8).

TABLE 5-20 MULTIPLIERS FOR DETERMINING TENSION IN GUY WIRE WHEN TENSION IN LINE WIRE IS KNOWN

Applicable to conditions A to D inclusive; see illustrations below.

H, *ft*	*D*, *ft*												
	5	*6*	*7*	*8*	*10*	*12*	*14*	*16*	*18*	*20*	*25*	*30*	*35*
15	3.16	2.69	2.36	2.12	1.80	1.60	1.46	1.37	1.30	1.25	1.16	1.12	1.09
16	3.35	2.85	2.47	2.24	1.89	1.67	1.52	1.41	1.34	1.28	1.19	1.13	1.10
17	3.54	3.00	2.63	2.35	1.97	1.73	1.57	1.46	1.37	1.31	1.21	1.15	1.11
18	3.73	3.16	2.76	2.46	2.06	1.79	1.63	1.50	1.41	1.35	1.23	1.17	1.12
19	3.93	3.32	2.89	2.58	2.15	1.87	1.68	1.55	1.49	1.38	1.26	1.19	1.14
20	4.12	3.48	3.03	2.69	2.24	1.94	1.74	1.60	1.49	1.41	1.28	1.20	1.15
21	4.32	3.64	3.17	2.81	2.33	2.01	1.80	1.65	1.54	1.45	1.31	1.22	1.17
22	4.51	3.80	3.30	2.93	2.42	2.09	1.86	1.70	1.58	1.49	1.33	1.24	1.18
23	4.71	3.96	3.44	3.04	2.51	2.16	1.92	1.75	1.62	1.52	1.36	1.26	1.20
24	4.90	4.12	3.57	3.16	2.60	2.24	1.98	1.80	1.67	1.56	1.39	1.28	1.21
25	5.10	4.28	3.71	3.28	2.69	2.31	2.04	1.85	1.71	1.60	1.41	1.30	1.23
26	5.29	4.45	3.84	3.40	2.79	2.39	2.11	1.91	1.76	1.64	1.44	1.32	1.25
27	5.51	4.62	3.99	3.52	2.88	2.46	2.17	1.96	1.80	1.68	1.47	1.34	1.26
28	5.69	4.78	4.13	3.64	2.97	2.54	2.24	2.01	1.85	1.72	1.50	1.37	1.28
29	5.89	4.94	4.27	3.76	3.07	2.61	2.30	2.06	1.90	1.76	1.53	1.39	1.30
30	6.08	5.09	4.41	3.88	3.16	2.68	2.36	2.12	1.95	1.80	1.54	1.41	1.32
31	6.28	5.26	4.54	4.04	3.26	2.77	2.42	2.18	1.99	1.84	1.59	1.44	1.33
32	6.48	5.42	4.68	4.13	3.36	2.85	2.49	2.24	2.04	1.89	1.62	1.46	1.35
33	6.68	5.59	4.82	4.24	3.45	2.93	2.56	2.29	2.09	1.93	1.65	1.48	1.37
34	6.88	5.75	4.96	4.36	3.54	3.01	2.62	2.34	2.14	1.97	1.69	1.51	1.39
35	7.08	5.92	5.10	4.48	3.64	3.09	2.69	2.40	2.19	2.02	1.72	1.53	1.41
36	7.27	6.08	5.24	4.60	3.74	3.16	2.76	2.46	2.24	2.08	1.75	1.56	1.44
37	7.63	6.28	5.38	4.73	3.83	3.24	2.83	2.52	2.26	2.10	1.79	1.59	1.46
38	7.66	6.40	5.52	4.86	3.93	3.32	2.89	2.58	2.34	2.15	1.82	1.61	1.48
39	7.87	6.59	5.66	4.98	4.03	3.40	2.96	2.64	2.39	2.19	1.85	1.64	1.50
40	8.07	6.74	5.91	5.10	4.12	3.49	3.28	2.69	2.44	2.24	1.89	1.67	1.52



Example:

H = height of guy on pole = 25 ft
D = distance of guy from centerline of pole = 16 ft
T_L = tension in line wire = 2000 lb
T_S = tension in guy wire = T_L × multiplier (from table)
= 2000 × 1.85 = 3700 lb

For condition E,

T_G = guy tension
T_L = resultant line tension

$$T_G = \frac{LT_L D^2 + H^3}{DH}$$

For condition F,

T_G = guy tension
T_L = resultant line tension

$$T_G = \frac{LT_L D^2 + H^3}{FD}$$

Courtesy Long Island Lighting Co.

TABLE 5-21 ALLOWABLE GUY TENSIONS

	Guy wire			Loading, lb			
				Dead-end and angle		Transverse	
Material	*Reference*	*Strand*	*Ultimate strength, lb*	*Grade C, SF = 1.14*	*Grade B, SF = 1.50*	*Grade C, SF = 2.00*	*Grade B, SF = 2.66*
Copperweld	6M	3 #8	6,280	5,500	4,100	3141	2360
	11M	11/32"	11,280	9,860	7,520	5640	4240
	17M	7/16"	16,890	14,780	11,260	8445	6340
Alumoweld	6M	3 #8	7,210	6,330	4,810	3605	2710
	11M	11/32"	12,960	11,370	8,640	6480	4870
	17M	7/16"	19,060	16,720	12,700	9530	7160

Dead-end loadings or 60° angles: primary

Copper	*Loading, lb*	*Aluminum*	*Loading, lb*
No. 6 bare	640	No. 1/0 bare	1200
No. 3 bare	1070	No. 1/0 HDPE or PVC	1500
No. 3 PVC	1230	No. 3/0 bare	1450
No. 1/0 bare	1550	No. 3/0 HDPE or PVC	1800
No. 1/0 HDPE or PVC	2000	336,400 cmil bare	2000
No. 4/0 bare	1650	336,400 cmil HDPE or PVC	2000
No. 4/0 HDPE or PVC	2000		

Secondary

3 c or 4c no. 6	640	All triplex or quadruplex
3c or 4c no. 2	1500	secondaries are 2000 lb
Over 4c no. 2	2000	

For open wire secondary, use primary tensions.

Note: All 1/0, 3/0 and 336,400-cmil Al or 1/0 and 4/0 Cu, where the span exceeds 200 ft, are to be considered at 2000 lb of tension.

All triplex or quadruplex unbalanced services to be considered at 250 lb of tension.

Courtesy Long Island Lighting Co.

GUYING REQUIREMENTS (cont. from page 185)

Angle Pole

Step 7. If the pole class calculations result in a pole within the range from class 4 to class 2, the pole should be cribbed.

Step 8. If the result is a pole larger than class 2, a smaller pole and guying should be specified; a class 5 pole may be specified.

Step 9. From Table 5-19, select the factors of safety and calculate the total load on the pole.
a. For grade B construction, the total load is $(1.78c + b)1.50$.
b. For grade C construction, the total load is $(1.78c + b)1.14$.

Step 10. From Table 5-20 calculate the guy tension.

Step 11. From Table 5-21 select the proper guy wire for the guy tension (step 10).

Step 12. If the pole class calculations result in a pole larger than class 2 and the pole cannot be guyed, specify a class 0 or class 00 pole and determine if it has sufficient strength to handle the ground-line resisting moment, with cribbing specified if necessary.

Step 13. If even a class 00 double-cribbed pole is inadequate for the ground-line resisting moment and the pole cannot be guyed, a lighter pole and cribbing should be specified, with guying of the adjacent pole or poles and sagging of the line sufficiently to relieve the strain.

Dead-End Pole

Step 7. If the pole class calculations result in a pole within the range from class 4 to class 2, the pole should be cribbed.

Step 8. If the result is a pole larger than class 2, a smaller pole and guying should be specified. A class 5 pole will be adequate where either primary or secondary conductors terminate; where both terminate, a class 4 pole should be specified.

Step 9. From Table 5-19 select the factors of safety and calculate the total load on the pole.
a. For grade B construction, the total load is $1.50a$.
b. For grade C construction, the total load is $1.14a$.

Step 10. From Table 5-20 calculate the guy tension.

Step 11. From Table 5-21 select the proper guy wire for the guy tension (step 10).

Step 12. If the calculations above result in a pole larger than class 2 and the pole cannot be guyed, specify a class 0 or class 00 pole and determine if it has sufficient strength to handle the ground-line resisting moment, with cribbing specified if necessary.

Step 13. If even a class 00 double-cribbed pole is inadequate for the ground-line resisting moment and the pole cannot be guyed, a lighter pole and cribbing should be specified, with guying of the adjacent pole or poles and sagging of the line sufficiently to relieve the strain.

EXAMPLE 5-13 Straightaway pole, grade C construction, transverse loading, safety factor of 2

Assume a 40-ft pole line, 100-ft spans, a three-phase no. 3/0 aluminum-HDPE primary at 33 ft; a four-conductor no. 3/0 aluminum-XLPE secondary at 25 ft; three 15-kVA transformers at 30 ft; and a 10,000-lb telephone cable at 20 ft.

Solution

Use the values in Tables 5-15 and 5-18. (Weight of cross arms, insulators, etc., is ignored, but is taken into account with factors of safety, rounded values, and other considerations.)

The transverse loading on wires and cable is taken from Table 5-15. For the no. 3/0 aluminum-HDPE, 0.601 × 100 × 3 = 180 lb. For the four-conductor no. 3/0 secondary, 0.782 × 100 × 1 = 78 lb. The loading of one 10M telephone cable is 1.50 × 100 × 1 = 150 lb.

For the moment at the ground line:

Primary	180 × 33 =	5,940 ft·lb
Secondary	78 × 25 =	1,950
Telephone	150 × 20 =	3,000
Total		10,890 ft·lb

From Table 5-18, for the maximum transverse loading of three 15-kVA transformers, 30 × 3 × 30 = 2700 ft · lb. Thus the total moment is 10,890 + 2700 = 13,590 ft · lb.

From Table 5-19, the ground-line resisting moment for a 40-ft class 5 pole is 23,800 ft · lb. Therefore a 40-ft class 5 pole is adequate for transverse loading. Since it is, check for vertical loading from Table 5-18.

$$649 \text{ lb} \times 3 = 1947 \text{ lb}$$

Since the class 5 limit is 900 lb, a class 3 or class 2 pole must be used.

EXAMPLE 5-14 Dead-end pole, grade C construction, safety factor 1.33

Assume a 40-ft pole line; a three phase no. 3/0 aluminum-HDPE primary at 33 ft; a four-conductor no. 3/0 aluminum-XLPE secondary at 30 ft; one 10M telephone cable at 20 ft; and a 14-ft lead available. The soil is class 5.

Solution

First check that a normal pole class cannot hold the conductors.

Table 5-21 gives the dead-end loadings. For the primary,

$$3 \times 1800 \text{ lb} \times 33 \text{ ft} = 178{,}000 \text{ ft·lb}$$

For the secondary,

$$1 \times 2000 \text{ lb} \times 30 \text{ ft} = 60{,}000 \text{ ft·lb}$$

This gives a total loading of 238,000, multiplied by a safety factor of 1.33. This exceeds any pole class from Table 5-19. Guying will have to be used, as follows.

From Table 5-21, the tension at the guying points is found. For the three-phase primary,

$$3 \times 1800 \text{ lb} = 5400 \text{ lb}$$

For the three-phase secondary,

$$1 \times 2000 \text{ lb} = 2000 \text{ lb}$$

The total tension is 7400 lb.

From Table 5-20, for a 14-ft lead and a 32-ft height and a factor of safety of 1.14, the multiplier is 2.49, so guy tension is 1.14 × 2.49 × 7400 = 18,400 × 1.14. Since the tension is 18,400 lb, use two 11M guy wires attached to the same anchor plate. From Table 5-5B, for class 5 soil, use a 10-in expanding anchor plate. If a telephone cable is attached, use a 12-in expanding anchor plate.

Set the next line pole and install a head guy at a 10-ft height on it. The tension at 10 ft will be 7400 lb; the total moment will be 7400 × 10 = 74,000 ft·lb. From Table 5-19, with a safety factor of 1.33, a class 2 pole will be required.

EXAMPLE 5-15 20° angle pole, safety factor of 1.33 for angle loading and 2.00 for transverse loading

Assume a 35-ft pole with 100-ft spans; a two-phase no. 1/0 aluminum-HDPE primary at 28 ft; a one-phase three-conductor no. 1/0 aluminum-XLPE secondary at 25 ft; and a 6M telephone cable at 20 ft.

Solution

The problem requires combining transverse and angle loadings. For transverse loadings, the values are given by Table 5-15. For the no. 1/0 aluminum-HDPE,

$$100 \text{ ft} = 0.566 \text{ lb/ft} \times 2 \times 28 \text{ ft} = 3170 \text{ ft·lb}$$

For the three-conductor no. 1/0 aluminum-XLPE,

$$100 \text{ ft} \times 0.676 \text{ lb/ft} \times 25 \text{ ft} = 1690 \text{ ft·lb}$$

For the 6M telephone cable,

$$100 \text{ ft} \times 1.2 \text{ lb/ft} \times 20 \text{ ft} = 2400 \text{ ft·lb}$$

The total is 7260 ft · lb; the factor of safety of 2 gives 14,520 ft·lb.

For angle loading (Table 5-17), for the no. 1/0 aluminum-HDPE,

$$2 \times 521 \text{ lb} \times 28 \text{ ft} = 29{,}176 \text{ ft·lb}$$

For the three-conductor no. 1/0 aluminum-XLPE,

$$1 \times 694 \text{ lb} \times 25 \text{ ft} = 17{,}350 \text{ ft·lb}$$

For the 6M telephone cable,

$$1 \times 1250 \text{ lb} \times 20 \text{ ft} = 25{,}000 \text{ ft·lb}$$

The total angle loading is 71,526 ft·lb; when multiplied by the factor of safety 1.33, it is 95,130 ft · lb; this plus the transverse loading of 14,520 ft · lb gives a total loading of 109,650 ft·lb.

From Table 5-19, under the ultimate strength of a 35-ft pole (since the safety factors have already been multiplied into the loadings), a load of 109,650 ft · lb requires a class 0 pole. If guying is possible, then use a class 5 pole and calculate the guy wire size for an 8-ft lead attached at 26 ft.

From Table 5-15, the transverse load at a factor of safety of 2.00 is found as follows. For the no. 1/0 aluminum-HDPE,

$$2 \times 100 \text{ ft} \times 0.566 \text{ lb/ft} = 113 \text{ lb}$$

For the three-conductor no. 1/0 aluminum-XLPE,

$$100 \text{ ft} \times 0.676 \text{ lb/ft} = 68 \text{ lb}$$

(The transverse loading of the 6M telephone cable need not be considered here; it is standard practice for each pole user to provide the guying only for its own facilities.) The load is thus 181 lb; multiplying by the safety factor of 2.00 gives 362 lb.

The angle load is determined from Table 5-17:

No. 1/0 aluminum-HDPE	2 × 521 lb = 1042 lb
Three conductor no. 1/0 aluminum-XLPE	1 × 694 lb = 694 lb
	1736 lb

(Again, the loading of the telephone cable is ignored.)

The sum of the two loadings is 1736 + 362 = 2098 lb. From Table 5-20, the multiplier for an 8-ft lead at 26 ft is 3.40. Since the guy wire safety factor is 1.14,

$$3.40 \times 2098 \text{ lb} \times 1.14 = 7133 \text{ lb} \times 1.14$$

From Table 5-21, an 11M guy is required.

APPENDIX 5B EXAMPLES

EXAMPLE 5-16

A 40-ft pole suporting a no. 1/0 aluminum-HDPE primary conductor and three-conductor no. 1/0 aluminum triplex secondary is situated where the pole line makes a 30° turn; all poles are 100 ft apart. Select the proper class of pole for this installation.

Solution

From Table 5-9, conductor loading values for a 40-ft pole, loading at 30°,

No 1/0 aluminum-HDPE conductor	5.2 units
Three-conductor no. 1/0 triplex aluminum	6.3
Total	11.5 units

From Table 5-10, transverse loading values for a 40-ft pole, for poles 100 ft apart (average span length in feet),

No. 1/0 aluminum-HDPE conductor	0.4 units
Three-conductor no. 1/0 triplex aluminum	0.4
Total	0.8 units

Total loading force = 11.5 + 0.8 = 12.3 units.

From Table 5-11, ground-line resisting moments, for a 40-ft pole, assuming grade C construction, the smallest pole capable of supporting 12.1 units is a class 2 pole, which should be specified.

EXAMPLE 5-17

A 40-ft dead-end pole must support three no. 4/0 copper-HDPE primary conductors, a three-conductor no. 2 copper triplex cable, and a 10M telephone messenger cable; the poles are spaced 100 ft apart. Select the proper class of pole and guy, if necessary, for this installation.

Solution

From Table 5-9, conductor loading values for a 40-ft pole for dead-end loading (see the 60° column),

No. 4/0 copper-HDPE conductor	13.3 × 3 = 39.9 units
Three-conductor no. 2 copper triplex	9.2
Subtotal	49.1 units
10M telephone cable	32.8
Total	81.9 units

From Table 5-10, of transverse loading values for a 40-ft pole, for a 100-ft average span length,

No. 4/0 copper-HDPE conductor	3 × 0.4 = 1.2 units
Three-conductor no. 2 copper triplex	0.4
Subtotal	1.6 units
10M telephone cable	0.7
Total	2.3 units

Since the transverse loading is very small in comparison to the conductor loading and acts in a direction perpendicular to the larger force, it is insignificant and can be neglected.

From Table 5-11, of ground-line resisting moments, for a 40-ft pole, assuming grade C construction, the heaviest class of pole, 00, cannot support 81.9 units. A smaller pole, class 4, should be specified, with guying. The guy wire selected supports only power conductors, which (as computed earlier in this example) apply a load of 49.1 units to the pole. From Table 5-12B, of guy wires and leads for a 40-ft pole and grade C construction, for 49.1 units, in the column Copperweld: Dead-End and Angle Loading, note that neither the 6M nor the 11M wire can handle the load, and the 17M wire requires a 13-ft lead.

If a shorter lead is desired, move up the 17M column to a shorter lead length, say, 11 ft. Moving left to the first column, note that a 17M wire with an 11-ft lead can support only 43 units of loading. Another guy wire is needed. Moving over to the 6M column, note that with an 11-ft lead, this wire can handle 16 units of loading. The two wires, 17M (43 units) + 6M (16 units), can handle 59 units. Both a 17M and a 6M Copperweld wire should be specified. The anchor, however, must support both power and telephone guy wires.

From Table 5-13, of anchor holding power for 40-ft poles, the total loading on the pole is 81.9 units and the lead length is 11 ft; move down the 11-ft lead column to 81.9 loading units; the anchor capable of meeting these conditions is the 300-in^2 expandable anchor, and this should be specified. Summing, a class 4 pole with two Copperweld guy wires, 6M and 17M, with a lead length of 11 ft and a 300-in^2 expandable anchor should be specified.

EXAMPLE 5-18

A single-phase pole line with a no. 1/0 aluminum-HDPE primary conductor, a three-conductor no. 1/0 triplex aluminum secondary cable, and a 6M telephone messenger makes a 90° turn; the poles are 40 ft and spaced 125 ft apart. Select the corner pole.

Solution

From Table 5-9, of conductor loading values for a 40-ft pole,

No. 1/0 aluminum-HDPE conductor	14.1 units
Three-conductor no. 1/0 aluminum triplex	17.3
6M telephone cable	27.8
Total	59.2 units

From Table 5-10, of transverse loading values for a 40-ft pole, for a 125-ft average span length,

No. 1/0 aluminum-HDPE conductor	0.5 units
Three-conductor no. 1/0 aluminum triplex	0.5
6M telephone cable	0.8
Total	1.8 units

The total loading force is 59.2 + 1.8 = 61.0 units.

From Table 5-11, of ground-line resisting moments, the heaviest pole, class 00, can only support 30.5 units. A class 4 pole with guying should be specified.

From Table 5-12B, of guy wires and leads for 40-ft poles and grade C construction, since this is a corner pole, it should be guyed in each direction. The conductor loading in each direction will act on the pole as a dead-end condition. From Table 5-9, the 60° column,

No. 1/0 aluminum-HDPE conductor	10.2 units
Three-conductor no. 1/0 aluminum triplex	12.3
6M telephone cable	19.7
Total	42.2 units

Reading down in the first column of Table 5-12B, to 23 units (the total for the power conductors only), moving right to Alumoweld: Dead-End and Angle Loading, note that the 6M wire cannot handle the load, the 11M wire needs a 10-ft lead, and the 17M wire needs a 6-ft lead. Unless field conditions conflict, specify the smaller wire, 11M with a 10-ft lead. (Where the pole cannot be guyed in each direction, one guy may be used; follow the procedure set forth in Table 5-10.)

From Table 5-13, of anchor holding power for a 40-ft pole, using a lead length of 10 ft, and using the first column (number of units) as a guide, move down the 10-ft column to the level of 42 units, and left to the first curve intersected, the 200-in^2 expandable anchor, which should be specified.

Summing a class 4 pole with one Alumoweld 11M wire in each direction, each with a 10-ft lead, and a 200-in^2 expandable anchor on each, should be specified.

APPENDIX 5C
CONCRETE AND METAL POLES

INTRODUCTION

While the overwhelming number of poles employed in electric distribution systems in the United States are made of wood (and are likely to remain so for the indefinite future), poles made of reinforced concrete and of steel and aluminum are also to be found where, for one reason or another, wooden poles are considered unsuitable. See reference to "concrete poles" in Preface to 2nd Edition.

In general, concrete poles are used in those areas, swampy and persistently wet, where the soils greatly shorten the life expectancy of wood poles. Moreover, in such instances, the rate of decay of wood may be so erratic and uncertain as to permit unsafe conditions to arise that may not be discovered before accidents result. Concrete poles are sometimes also specified in areas of chemical contamination and pollution that may cause rapid deterioration of wood.

Concrete poles and poles made of steel or aluminum are specified in special situations where poles of unusually high strength are required, beyond the range of wood poles, and where guying may be difficult or unobtainable.

Again, concrete and metal poles may be specified where their appearance is preferred to poles made of wood. They find particular application for street and highway lighting, for parking lot and security lighting, and for recreational and industrial lighting, applications often included in the planning and design functions of the distribution engineer.

In general, the first cost of such poles is greater than that of wooden poles of equal strength. Improved methods of manufacture, however, have already made these concrete and metal poles competitive for the larger transmission pole requirements, and prospects for distribution application appear promising. In addition, they are much heavier than corresponding wood poles and consequently much harder to handle, especially when they are to be replaced in the field.

CONSTRUCTION

Concrete Poles

Concrete poles are manufactured in several cross-sectional shapes: round, square, and polygons (usually six or eight sides). Moreover, they may be solid or hollow. The method of pouring the hollow poles involves spinning the form while the concrete is being poured, and forcing it to the outside while leaving the center hollow; the result is a highly uniform, compact, prestressed concrete of high strength and texture.

As concrete has a higher strength under compressive loads than under tensile loads, the overall strength of concrete poles depends a great deal on the steel reinforcement. Its strength also depends considerably on the mixture of cement and how it is cured.

Where cross arms or other distribution devices and equipment are to be mounted directly on the pole, provision is made for the necessary bolt holes when the concrete is being poured.

Besides their appearance and greater strength, hollow poles provide a means for electrical risers to be installed inside the pole out of sight and not readily accessible to the public. Other advantages claimed include resistance to fire, birds (especially woodpeckers), rot, and vandalism; also the elimination of harm and clothing damage to the public from contact with some wood preservatives. A variety of colors and finishes also is possible with concrete poles; these may contribute to their acceptance.

Metal Poles

Usually made of steel or aluminum, metal poles are made in the same cross-sectional shapes as the concrete poles: round, square, polygonal. In addition, they may also be fabricated in the form of angles, channels, or tees, or sometimes two of these forms tied together with lacing of some kind; expanded metal is also sometimes used. They may be bolted, welded, or riveted together, the method selected depending on a number of factors—the required strength, desired appearance, cost, and maintenance requirements.

INSTALLATION

Poles

Concrete poles, whether solid or hollow, are installed in the same manner as wood poles, enabling the same methods and equipment to be used for setting this type of pole.

Steel and aluminum poles may also be installed in this same fashion. In many instances, however, they are bolted to a base plate that is anchored in a concrete footing buried in the ground.

Attachments

Concrete cross arms, frequently used in transmission structures, are seldom used in distribution systems. The regular wood cross arm may be bolted to the concrete pole in the same manner as to wood poles; it may also be attached to the pole by metal U-shaped brackets which are clamped around the pole and to which the cross arm is bolted at the proper height.

Transformers, capacitors, cutouts, insulator pins, and other devices are attached to the concrete poles in a similar manner. Where bolt holes are provided, they may be bolted directly to the pole; otherwise brackets, as described above, may be used.

In many instances, steps are incorporated in the concrete poles, or provision is made for their temporary installation to permit workers to reach the upper parts of the pole.

Attachment to metal poles may be made in the same manner. Because drilling of holes in the metal pole is more readily accomplished than in concrete poles, bolted attachments to such poles are usually preferred.

DESIGN

Stresses

Stresses imposed on concrete and metal poles are calculated in the same manner as for wood poles: as if they were a cantilever beam fixed at one end. These values, with proper factors of safety applied, are used in the selection of the pole.

TABLE 5-22 HOLLOW ROUND CONCRETE POLE DESIGN DATA

Wood, ASA class	*Reinforced concrete class*	*Ultimate strength, lb*	*Allowable strength, SF = 2,* lb*
—	A	3200	1600
—	B	2700	1350
1	C	2250	1125
2	D	1850	925
3	E	1500	750
4	F	1200	600
5	G	950	475

Note: Assume load is applied 2 ft from the top of the pole and break occurs at the ground line.

*Safety factor of 2; these working loads are equivalent to ASA standard classes for wood poles.

Courtesy Centrecon, Inc.

Selection of Poles

In selecting a concrete pole, in addition to the ultimate ground-line moment and overall pole length requirements, similar to those required in selecting a wood pole, attention is also given to the size and location and number of holes, if they are included in the pole standards, and to the length of "embedment," or depth of burial in the ground. As a rule, this embedment is taken as 10 percent of the pole length plus 2 ft.

Concrete poles have not yet been standardized into classes as have wood poles, but there are indications pointing to that goal. Standards of one manufacturer are shown in Table 5-22, which includes a general comparison of ASA class standards for wood poles with round, hollow, steel-reinforced concrete poles. Additional data on these and some square-cross-section, hollow, reinforced concrete poles are contained in Chap. 10.

Metal poles also find widespread use as supports for a variety of lighting purposes as well as for supports for signs and platforms, as flag and pennant staffs, and in many other fields. Such poles are usually designed specially for the use to which they will be put, though some relatively minor standardization of sizes, diameters, thicknesses, etc., exists.

CHAPTER 6

MECHANICAL DESIGN: UNDERGROUND

The placing of cables and equipment underground presents problems completely different from those of installing similar facilities overhead. For downtown areas of high load density served by low-voltage secondary networks, underground service can be justified economically, satisfying the rather rigid reliability and environmental demands associated with this type of area. Such reasoning, however, can hardly justify the installation of the same kind of underground service in less dense urban areas and in suburban areas, which call for different construction, maintenance, and operating practices. The discussion, therefore, will be divided into two parts: that for city areas, particularly the downtown areas; and that for urban and suburban areas of lighter load densities. In general, cables and transformers in the former are placed in ducts, manholes, and vaults; while in the latter they are buried directly in the ground, with transformers installed in metal enclosures situated at ground level, or totally or partially buried in the ground.

HIGH-DENSITY LOADS: CITY AND DOWNTOWN AREAS

In congested areas, it is essential that conductors, transformers, and other equipment can be installed, maintained, repaired, and replaced, that faults can be located without causing undue inconvenience to the public. Cables are placed in conduits or ducts and spliced in manholes and service boxes, and transformers and equipment are installed in manholes and vaults. Ducts and manholes must be designed not only with regard to the facilities they do and will contain, but also with regard to the type of soil and terrain they are installed in and the existence of other utilities and obstructions (e.g., water, gas, sewer, telephone,

and railway). The design engineer's work is made more difficult by the economic desirability of installing prefabricated (precast) ducts, service boxes, and manholes, as well as the need to comply with codes and regulations at all governmental levels: national, state, county, and local city or village.

Ducts

The number of ducts installed should provide for whatever growth may be reasonably expected at the time of installation, but it may be limited by the space available. Ducts may vary in size, but those of a 4-in diameter are most commonly used. Ducts may be of wood, tile, fiber, plastic or other compounds, steel and iron pipe, or concrete; precast reinforced concrete appears to be greatly preferred. Some ducts are encased in concrete envelopes, and others are formed from concrete poured over cores (usually made of rubber or plastic) which are removed after the concrete has set; precast reinforced concrete sections are laid in the ground and connected together, formed into banks. The arrangement of ducts in a bank, though often dictated by the space available, is important from the viewpoint of dissipation of heat and its effect on the current-carrying ability of the cables installed within; see Fig. 6-1.

Ducts should be installed at a depth below the surface to avoid possible damage from accidental driving of so-called bullpoints and, if possible, should be below

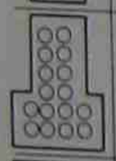
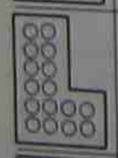
	Cost of duct construction	Ability to radiate heat	Cable support and racking conditions in manhole
	Expensive	Best	Best
	Moderate	Very good	Very good
	Moderate	Very good	Good
	Cheapest	Very poor	Very poor

FIG. 6-1 Comparative duct characteristics. *(From EEI Underground Systems Reference Book.)*

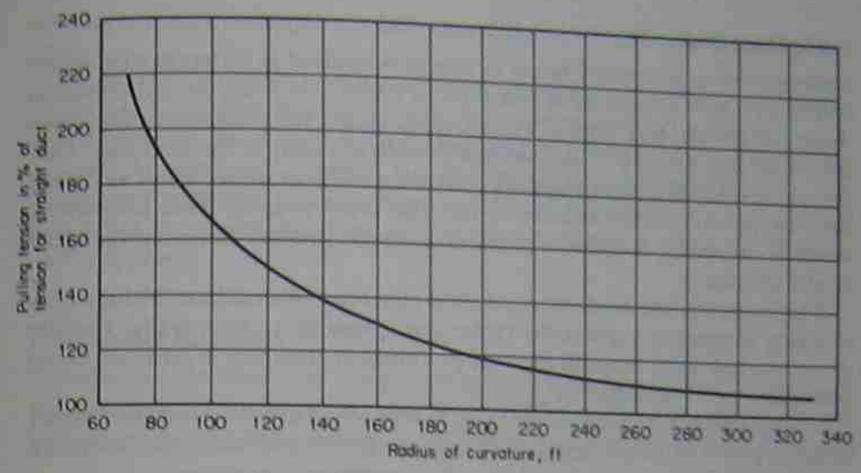


FIG. 6-2 Effect of radius of curvature of conduit on pulling tension (applicable to a conduit consisting of one continuous curved section). *(From EEI Underground Systems Reference Book.)*

the frost line to prevent dislocation from motion caused by severe changes in temperature. They should also be graded between manholes so that water will not accumulate in them. Moreover, where there are bends or offsets in the line, ducts should be gradually bent to accommodate the minimum bending radii of the largest cables to be installed; this bending radius should be from 7 to 20 times the diameter of the cable, depending on its size, voltage classification, type of insulation, type of sheath, and other characteristics. The bends in the duct line should preferably be located near the manholes, as each bend will increase the pulling tension on the cable and thus reduce the maximum length or distance between manholes; see Fig. 6-2.

Service Boxes

Secondary mains are installed in ducts buried at shallower depths than those carrying primary conductors. These terminate in distribution or service boxes from which service cables to consumers emanate. Constructed of precast reinforced concrete, they are usually standardized at dimensions approximately 4 ft square and 2 to 4 ft deep, and are thus suitable for secondary distribution in four directions. They are usually located so as to accommodate the secondary mains and the largest number of services without overcrowding the box and without introducing too many bends in the service conduits. The entrance (or "throat" or "chimney") to these boxes is usually quite large, generally about 3 ft square, providing ample room for the worker to work from ground level or standing erect with head and shoulders above ground. Covers are usually made of steel, with an inner cover installed to prevent dirt from entering, and may be locked to keep out unauthorized persons.

Cable Manholes

Cable manholes are usually larger in size, standardized at different dimensions and shapes, with headroom of about 6 ft or better. They may be rectangular in shape for straight-line conduit construction, square for accommodating cables from four directions, or L-shaped where there is a turn in the duct line. They may accommodate ducts containing secondary mains at upper levels and ducts carrying primary cables at lower levels. The latter proceed from manhole to manhole, bypassing the service boxes, and the conduits are sometimes referred to as trunk ducts.

The manholes are made of reinforced concrete with facilities included for installing hangers to support the cables and splices along their walls. The size of the manhole shaft through the roof (or throat or chimney) is generally about 3 ft square or 3 ft in diameter.

The manholes are spaced as far apart as is practical to hold down the number of splices required. Proper selection of locations for the manholes will also reduce the number of bends in the conduit or duct system to a minimum.

The various shapes of manholes also take into account the need for training, splicing, and racking of cables; typical "standard" shapes are shown in Fig. 6-3. The essential difference among them is the number of conduit lines entering

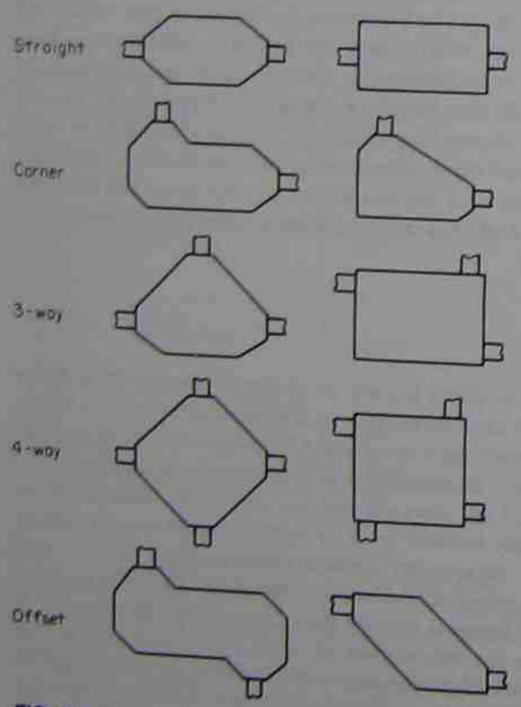


FIG. 6-3 Typical shapes of cable manholes. *(From EEI Underground Systems Reference Book.)*

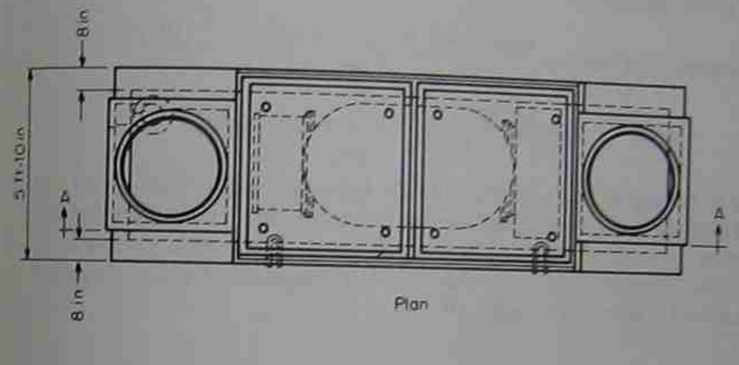
the manhole and the angle at which they enter in the walls in relation to each other.

Where the standard precast manholes cannot be installed for any reason, manholes of various shapes and sizes may be constructed in the field.

It is generally desirable to keep the earth fill over the manhole at a minimum, not only for economic reasons, but also for making the installation of local services and streetlight connections more practical. Local ordinances and existing subsurface structures, however, may dictate the depth at which the manhole roof is located.

Transformer Manholes

Transformer manholes are designed to contain transformers and other equipment required for radial or network systems. Their dimensions depend on the location and the equipment they are to contain. Standard transformer manholes



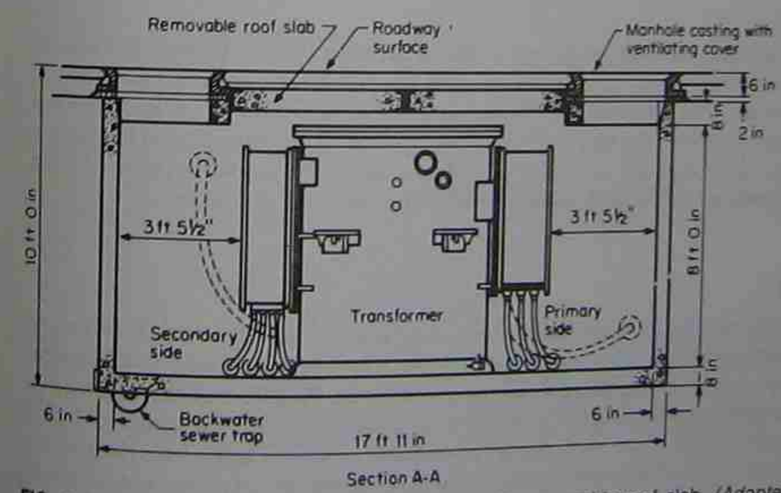


FIG. 6-4 Transformer manhole under roadway, with removable roof slab. *(Adapted from EEI Underground Systems Reference Book.)*

of reinforced prefabricated concrete are generally approximately 6 ft by 17 ft, by 8 ft of headroom, essentially to accommodate a 500-kVA three-phase network unit, as shown in Fig. 6-4; the manhole may also house other types of transformers and switches as part of a radial distribution system. The dimensions provide space for workers to operate and maintain switches on the primary side and network protectors on the secondary side.

Design Loading

The loading on the several parts of the manhole depends on the maximum load imposed on the street surface. The live load on the surface affects both the design of the roof slab and the walls. Wheel loads of 21,000 lb and impacts of 50 percent are typical values for heavily traveled streets over which truck traffic may be concentrated. For conservative values, wheel areas as little as 6 by 12 in, or a surface area of 0.5 ft^2, are also considered. The concentrated load may then be as much as 63,000 lb/ft^2:

$$\text{Concentrated load} = \frac{\text{wheel load} \times (1 + \% \text{ impact} \div 100)}{\text{wheel area}}$$

$$= \frac{21{,}000(1 + 0.5)}{0.5} = 63{,}000 \text{ lb/ft}^2$$

The type of pavement, the nature of the soil beneath the pavement, and the depth (thickness) of the soil above the roof of the manhole serve to mitigate the actual effect of the concentrated load. The reduction in effective pressures at different depths below the surface is shown in the diagrams of Fig. 6-5*a* and *b* and the associated Tables 6-1A and 6-1B.

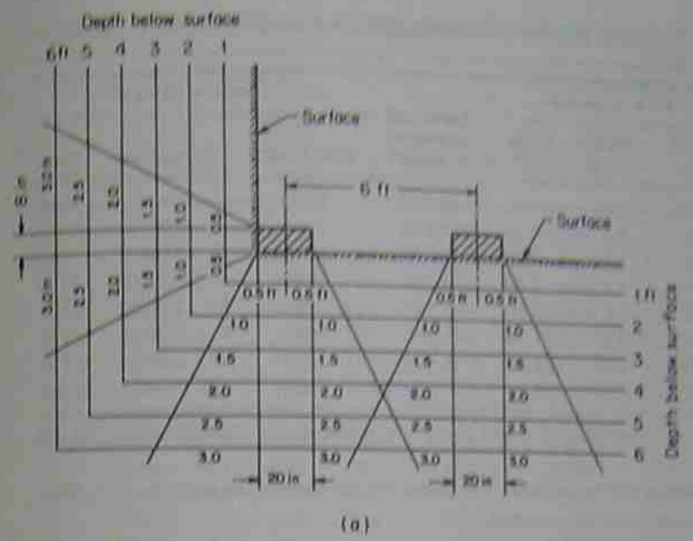
Roofs

Manhole roofs are designed as a series of structural steel beams or rails, or reinforced concrete with extra-heavy steel reinforcement or structural steel to support the manhole frames. Where installed in sidewalks or other areas not subjected to heavy vehicular traffic, roof designs may take into account the lighter loading. If there is any possibility of its being subjected to loads approximating street loadings, the design should be based on the heavier loadings.

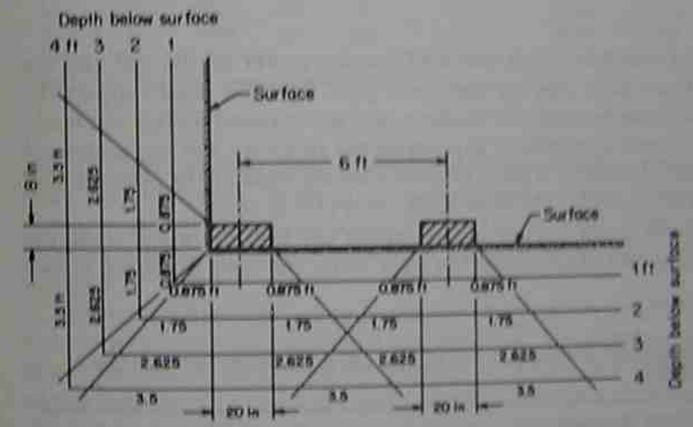
Walls

Manhole wall designs are based on the horizontal component of the effect of both live and dead loads acting on the walls. The horizontal forces will depend on the surface, the angle of repose of the soil, and the effect of the water table.

At depths below about 5 ft, as shown in Table 6-1B, for the spread of wheel loads, the weight of the earth above the manhole predominates. Here, the average of the live-load effects approximates 450 lb/ft^2; it appears to be constant at lower depths.



(a)



(b)

FIG. 6-5 Diagram showing area of spread of wheel loads (*a*) based on 1:1 spread and (*b*) based on 1½:1 spread. *(From EEI Underground Systems Reference Book.)*

The dead loads at various depths and various horizontal pressures as a percentage of the vertical pressure are shown in Table 6-2, which extends the tabulation associated with Fig. 6-5*a* and *b*. Table 6-2 serves as a guide in determining the horizontal pressures with various headrooms and depths for the several corresponding angles of repose of the soil and pressures from the hydrostatic head of the water table.

TABLE 6-1A PRESSURE CALCULATIONS BASED ON A 21,000-lb WHEEL LOAD—1:1 WHEEL SPREAD

Depth from surface, ft	Area of spread			Live-load pressure on cover*	Pressure on roof		
	Length L, ft	Width W, ft	Area, ft²		Live load**	Surcharge	Total
0	0.67	1.67	1.12	18,500	5200	0	5200
1	1.67	2.67	4.46	4,710	2100	150	2250
2	2.67	3.67	9.80	2,140	1310	250	1560
3	3.67	4.67	17.10	1,230	960	350	1310
4	4.67	5.67	26.50	790	750	450	1200
5	5.67	6.67	37.80	560	620	550	1170
6	6.67	7.67	51.10	410	520	650	1170
7	7.67	8.67	66.50	320	450	750	1200

*Average pressure P_w that might be imposed on cover by maximum concentrated load, or (21,000 lb)/area.

**The surface concentrated load uniformly distributed over the width of the manhole, or $P_w W/6$.

From *EEI Underground Systems Reference Book.*

Floors

In the design of manhole floors, the load-bearing power of the soil and the height of the water table play an important part. The soil must support the weight of the manhole structure, its contents, and any imposed surface live loads. In firm soils, the earth is capable of supporting the structure and any additional weight. The floor, therefore, is often poured after the walls are in place, adding to the strength of the walls. The floor wells are 4 to 6 in thick.

Where the earth is not capable of supporting the loading of the walls, the floor is used as a means of spreading the load. Here, the floor is poured before

TABLE 6-1B PRESSURE CALCULATIONS BASED ON A 21,000-lb WHEEL LOAD—1½:1 WHEEL SPREAD

Depth from surface, ft	Area of spread			Live-load pressure on cover*	Pressure on roof, lb/ft²		
	Length L, ft	Width W, ft	Area ft²		Live-load**	Surcharge	Total
0	0.67	1.67	1.12	18,500	5200	0	5200
1	2.42	3.42	8.27	2,500	1430	150	1580
2	4.17	5.17	21.5	970	840	250	1090
3	5.92	6.92	41.0	510	590	350	940
4	7.67	8.67	66.5	315	450	450	900

*Average pressure P_w that might be imposed on cover by maximum concentrated load, or (21,000 lb)/area.

**The surface concentrated load uniformly distributed over the width of the manhole, or $P_w W/6$.

From *EEI Underground Systems Reference Book.*

TABLE 6-2 HORIZONTAL EARTH PRESSURES AT VARIOUS DEPTHS

Depth	No live load				Live and dead loads				
	Dead load	Horizontal pressure, lb/ft²			Live load 1½:1	Total live and dead load	Horizontal pressure, lb/ft²		
		25%	30%	35%			25%	30%	35%
0	0	—	—	—	5200	5200	—	—	—
1	150	38	45	53	1430	1580	395	474	553
2	250	63	75	88	840	1090	273	327	382
3	350	88	105	123	590	940	235	282	329
4	450	113	135	158	450	900	225	270	315
5	550	137	165	193	450	1000	250	300	350
6	650	162	195	228	450	1100	275	330	385
7	750	187	225	262	450	1200	300	360	420
8	850	212	255	298	450	1300	325	390	455
9	950	237	285	333	450	1400	350	420	490
10	1050	263	315	367	450	1500	375	450	525
11	1150	288	345	402	450	1600	400	480	560
12	1250	312	375	438	450	1700	425	510	595
13	1350	338	405	472	450	1800	450	540	630
14	1450	352	435	507	450	1900	475	570	665
15	1550	387	465	542	450	2000	500	600	700

From *EEI Underground Systems Reference Book.*

the walls are installed. Similar measures are employed in areas of high water table. Such floors are usually made of reinforced concrete, a minimum thickness of 6 in, and are constructed with a keyway for the walls. Where the hydrostatic pressure is high, an additional pour of 2 to 4 in of concrete is added on top of the floor.

Prefabricated manholes may be completely precast in one piece, or in a caisson type in which the roof and floor are separate. The caisson walls are sunk in place, the precast floor is placed within it (or a floor is poured), and a precast roof is installed in keys in the walls provided for that purpose (such roofs are also installed in other types of manhole construction). Small manholes or service boxes may also be completely precast or formed from precast individual pieces.

Frames and Covers

The frames and covers are made of cast iron, malleable iron, or steel, and are designed to withstand the loadings mentioned earlier; covers infrequently used may be made of reinforced concrete. Depending on the area over which the load is applied, frames and covers may have to withstand wheel loads from 50,000 to 200,000 lb, though sidewalk covers may be designed for lowered loadings. Although covers may be either square or round, the latter shape is preferred to insure against their falling into the manhole when being replaced. Frames and covers for transformer manholes may be of the completely fabricated

grating type, or of the combination type—part solid and part grating—that is specified for roadway use, but they will be of lower loading rating.

Transformer manholes are usually built with a removable roof slab covering an opening capable of admitting large distribution and network units. The manholes are of reinforced concrete with the slabs sealed and made watertight, the pavement being replaced after the transformers are installed. The pavement is cut and the slab removed when transformer replacements are required. When the transformer manhole is located under the sidewalk, the roof slabs are flush and made part of the sidewalk surface, and are readily removed when necessary. Prefabricated manholes may be completely precast or formed from precast individual floors, walls, and roofs.

Ventilation

The principal source of heat within a transformer manhole is that caused by losses in the core and windings of the transformer, losses which can be obtained from the manufacturer's data or can be calculated approximately. The dissipation of heat is to some extent based on the area of the enclosing walls and the nature of the adjacent soil conditions. For proper operation of transformers, the manhole should have sufficient cubic content supplemented with natural ventilation to keep the temperature within prescribed limits. Air temperatures in the manhole should not exceed 40°C, mainly occurring at periods of maximum load. The approximate number of cubic feet of air per minute to dissipate the heat may be found conveniently from the curve in Fig. 6-6. When such limits cannot be attained by normal circulation of air between the two ventilating gratings of the transformer manhole, it may be necessary to provide some means of forced ventilation, such as blowers, water coolers, etc.

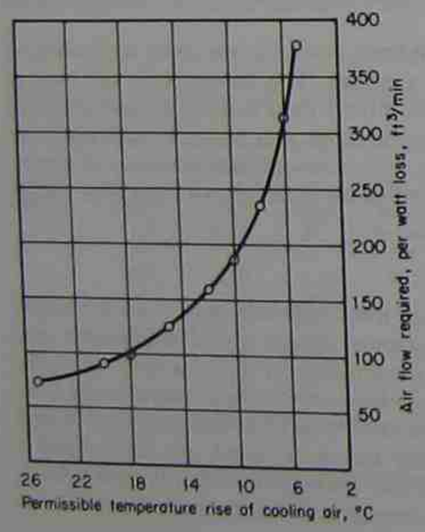


FIG. 6-6 Airflow requirements for limiting temperature rise in transformer vaults. *(From EEI Underground Systems Reference Book.)*

The ventilation of transformer manholes must not only provide sufficient cooling to keep the transformer within proper limits even under extreme operating conditions, but must provide a sufficient vent area outlet to prevent the explosion of gases or oil vapors that may develop from transformer failure. This vent area must bear a relationship to the volume of the transformer manhole: the smaller the ratio of the volume of air in the manhole to the total ventilating area (or area of openings), the less will be the pressure developed in the manhole and the lighter the construction necessary to withstand the force of the possible explosion.

Gratings situated at either end of the manhole, generally over the cleared areas reserved for workers, not only provide access but help to ventilate the transformer and manhole.

Transformer Vaults

Where the transformers are to be installed inside a building, or sometimes outside under a sidewalk, vaults are constructed. They are usually of reinforced concrete, the dimensions of which are dependent on the transformers and accessories to be installed, the space available and its location, the adjacent structures and substructures, and applicable code requirements and local ordinances. The same minimum ventilation and vent-volume requirements apply as for transformer manholes. Access for both equipment and personnel from the outside are usually sought, but may be substituted by adequate internal means of access. In very tall buildings, such vaults may be located on upper floors, in addition to the usual vault at basement level.

Vault ceilings or roofs should be designed to take into account possible fire and explosion from transformer failure or other causes.

Cables

Multiple-conductor cables are preferred for installation in duct systems because of the advantages of handling one cable in the field. Where the conductors are rather large, each single-conductor cable may be installed in a separate duct. Primary mains are almost always three-conductor cables. Single-conductor cables are generally used for secondary mains; they are also used for the secondary feeds from transformers, for streetlight circuits, and in special instances for primary mains.

Cable Insulation For both primary and secondary cables, plastics such as cross-linked polyethylene are now almost exclusively used; some oil-impregnated paper is still installed in special cases where much of that kind of insulation exists. Varnished cambric and rubber, for primary, and rubber, for secondary cables, were widely used, and many cables using these types of insulation are still in use. Some polyethylene (PE) and polyvinyl chloride (PVC) insulation is also being used, principally for secondary cables. The trend toward plastic insulations, it appears, will continue, with new and better compounds certain to make their appearance.

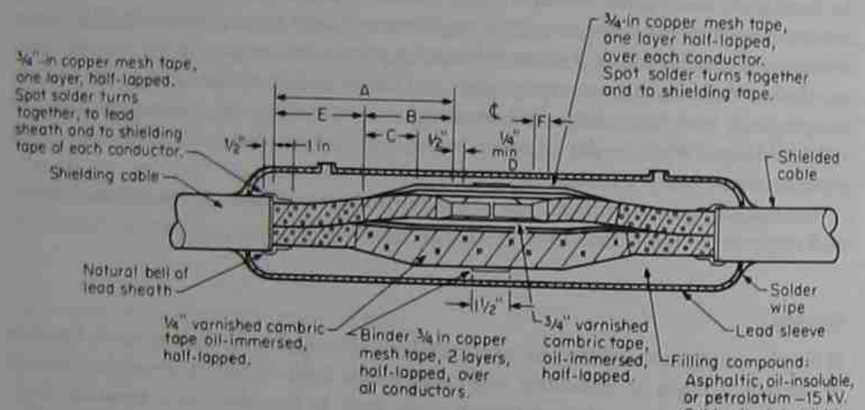
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Cable Sheaths Lead sheaths, again, though still used in decreasing amounts, appear to be giving way to plastics. Many lead-sheathed cables exist and will exist for a long time, but new installations are almost exclusively plastic, principally cross-linked polyethylene, used as both insulation and sheath.

Splices

Splices or joints in cables with nonplastic insulation and with metallic sheaths are much more complex and require greater time and skill to make than those in plastic-type cables. Such a splice is shown in Fig. 6-7. Cables with plastic insulation and plastic sheaths are simpler and quicker to splice as, generally, the splice consists of a wrapping of tape of the same material over the connectors, crimped on the two conductors being spliced. The plastic tape eventually solidifies into a homogeneous mass integral with the insulation or sheath.

Conductor connectors are usually copper or aluminum tubes crimped onto the ends of the conductors to be joined. Some of the older connectors were tubes split horizontally and squeezed onto the ends of the conductors, with solder



Voltage rating, kV	Dimensions, in						
				D			
	A*	B	C	P	V.C	E*	F**
15	9-11	6	3	3/8	7/16	3-5	¾
27	11-13	8	4	9/16	¾	3-5	1½
35	12½-14½	9½	4	11/16	–	3-5	1½

Dimension D
P – for paper insulated cable
VC – for varnished cambric insulated cable
*The upper limit applies to larger cables
**Cable paper insulation may be either penciled or stepped. For joints on cables rated 35,000 V, stepped is preferred.

FIG. 6-7 Straight joint for three-conductor shielded paper- or varnished-cambric-insulated lead-covered cable, 15 to 35 kV. *(From EEI Underground Systems Reference Book.)*

poured into the slit and over the connector. Soldered connectors are now almost entirely obsolete.

Underground Equipment

Transformers, oil-filled cutouts, and oil switches for use underground are hermetically sealed so as to be waterproof. Such submersible equipment is usually of welded construction. Wiping sleeves are welded or brazed directly to the tank or terminal chamber, to which cable sheaths are attached. Barriers in the conductors prevent the equipment oil from being siphoned into the cables.

In low-voltage network areas, network transformer units are installed, comprising switching facilities on the primary side and a network protector on the secondary, low-voltage side of the transformer.

PRACTICAL MANHOLE DESIGN PROCEDURE*

Practical procedures containing instructions and technical data for designing underground facilities have been prepared, reducing the work necessary in preparing plans and orders to the field. A procedure outlining the basis of the structural design for field-poured or precast reinforced concrete manholes and vaults used in electric distribution systems follows.

DESIGN LOADING

Live Load

Live-load requirements are based on those of the American Association of State Highway and Transportation Officials (AASHTO) for an HS-20 or H20 16,000-lb wheel load plus a 30 percent impact factor, or a maximum wheel load of 20,800 pounds. They must also meet prevailing local building codes and ordinances that usually specify 600 lb/ft². The basis for design is the greater of these two requirements.

Live-Load Criteria

1. *Sidewalk and driveway:* A 600 lb/ft² uniform live load or a 16,000-lb wheel load without impact, whichever produces the greatest stresses
2. *Roadway:* A 600 lb/ft² uniform load or a 16,000-lb wheel load with a 30 percent impact factor, or 20,800 lb, whichever produces the greatest stress

Wheel Load The 16,000-lb (HS-20 or H20) wheel load shall be taken as acting on a 12- by 20-in area, and no more than two such loads shall be acting at a spacing of 5 ft; see Fig. 6-8.

*The material from this point through the end of the section Construction Practices on p. 232 is adapted from *Application & Design Manual*, courtesy Consolidated Edison Co. of New York.

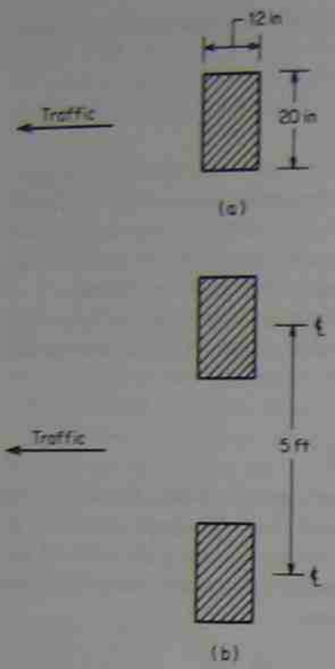


FIG. 6-8 Multiple wheel load. (*a*) H20 (HS-20) wheel load. (*b*) Multiple wheel load. *(Courtesy Consolidated Edison Co.)*

Wheel Load Distribution The effective area over which a wheel load acts at any depth below the pavement surface shall be determined by spreading the wheel load through pavement (concrete or asphalt) and soil in the following manner:

1. *Pavement:* The wheel load is to be spread at a 45° angle with the vertical in all directions.
2. *Soil:* The wheel load is to be spread at a 30° angle with the vertical in all directions.

The wheel load area as a function of depth for a 9-in pavement is shown in Fig. 6-9.

Surcharge Load The uniform 600 lb/ft² live load shall be taken, when applicable, as acting on the surface as a surcharge load.

Earth Pressure Coefficient The active earth pressure coefficient shall be taken as $K_a = 0.33$, which assumes an angle of repose or internal friction of 30°.

Dead Load

The unit weights used for computing dead load shall be as follows:

1. Soil—100 lb/ft³ wet soil weight
2. Soil—65 lb/ft³ submerged soil weight

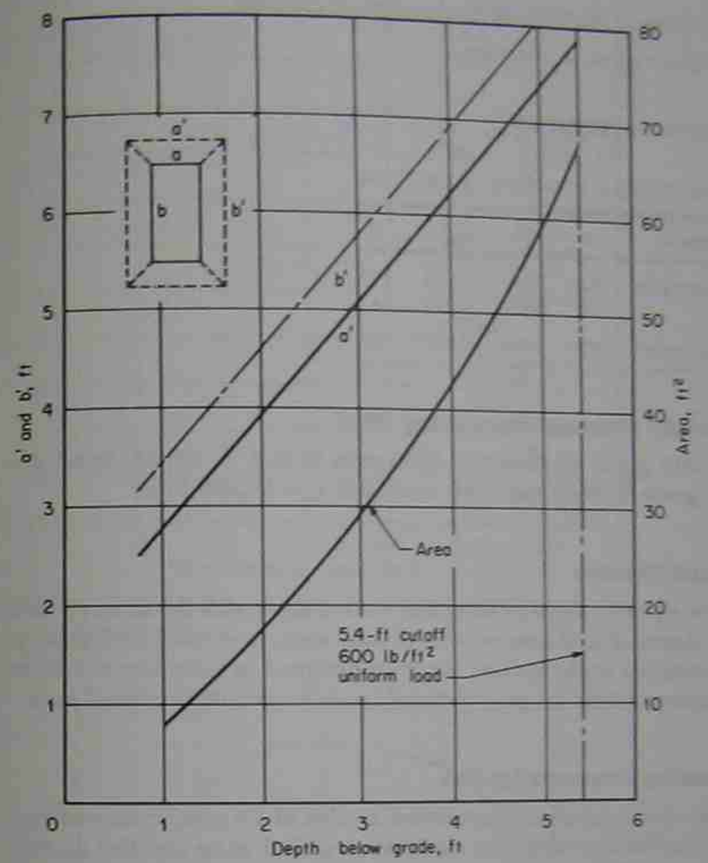


FIG. 6-9 Spread of wheel for 9-in pavement. *(Courtesy Consolidated Edison Co.)*

3. Pavement (concrete or asphalt)—144 lb/ft³
4. Concrete (plain)—144 lb/ft³
5. Concrete (reinforced)—150 lb/ft³

DESIGN STRESS BASES

Allowable stresses are given in terms of the following quantities:

f_c allowable compressive strength in concrete, lb/in²

f'_c 28-day compressive strength of concrete, lb/in²

f_s allowable strength in steel, lb/in²

n ratio of modules of elasticity of steel to that of concrete

V_c allowable shear stress in concrete

Allowable Stresses—Concrete

TABLE 6-3 ALLOWABLE STRESSES—CONCRETE

Type of concrete	n	f'_c	f_c	V_c
Precast plant concrete	8.5	3500	1575	118
	7.0	5000	2250	141
Field-placed concrete	8.5	3500	1100	83

Allowable Tensile Stresses—Reinforcing Steel

For ASTM A615 grade 40 deformed-billet steel bars, $f_s = 20{,}000$ lb/in^2. For ASTM A615 grade 60 deformed-billet steel bars, $f_s = 24{,}000$ lb/in^2.

Allowable Steel Stresses

Structural steel elements are to be designed in accordance with the latest revision of the AISC *Manual of Steel Construction*. All solid steel covers and steel gratings subjected to repeated traffic loading are to be designed in accordance with the AASHTO *Requirements for Design of Repeated Loads* for 500,000 cycles of load.

Allowable Bearing Pressures for Soil

Unless organic clays or silts are encountered, a value of 1.5 tons/ft^2 may be used as a conservative bearing value. If a manhole or vault is to be installed on clay, clayey soils, or organic material, careful evaluation should be made of the potential for settlement. The use of a crushed-stone base or piles may be required and soil borings may be necessary.

WALL DESIGN

Rigid Horizontally Reinforced Frame

The wall loading for lateral earth pressure due to live and dead loads shall be taken from the design chart in Fig. 6-10. The frame shall be analyzed using conventional indeterminate structural techniques. Midspan moments and corner moments may be calculated by using formulas given in the sample design problem in this chapter or by using the moment coefficients for each moment given in Figs. 6-11, 6-12, and 6-13.

Simply Supported Vertically Reinforced Structure

The wall loading for lateral earth pressure due to live and dead loads shall be taken from the design chart in Fig. 6-10. The wall should be analyzed as a simply supported strip with a height equal to the headroom of the manhole plus one-

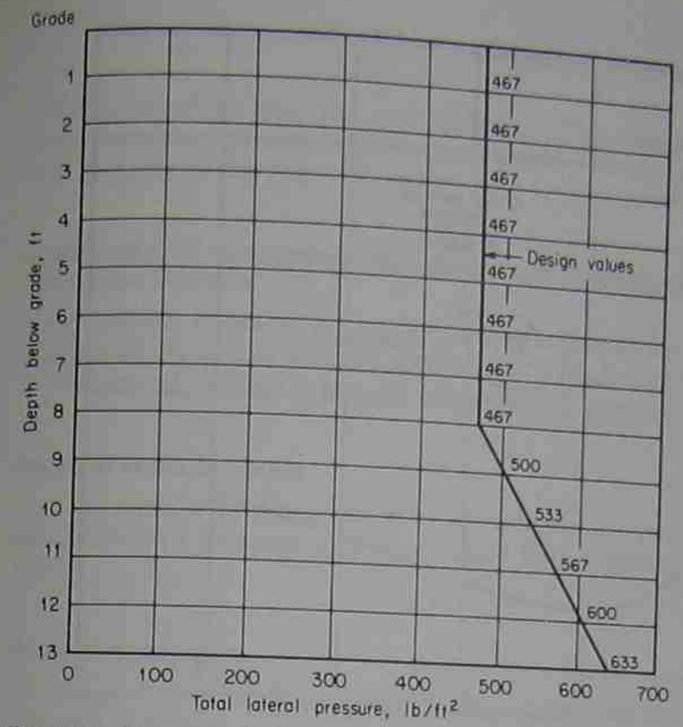


FIG. 6-10 Design chart—lateral pressures on walls. *(Courtesy Consolidated Edison Co.)*

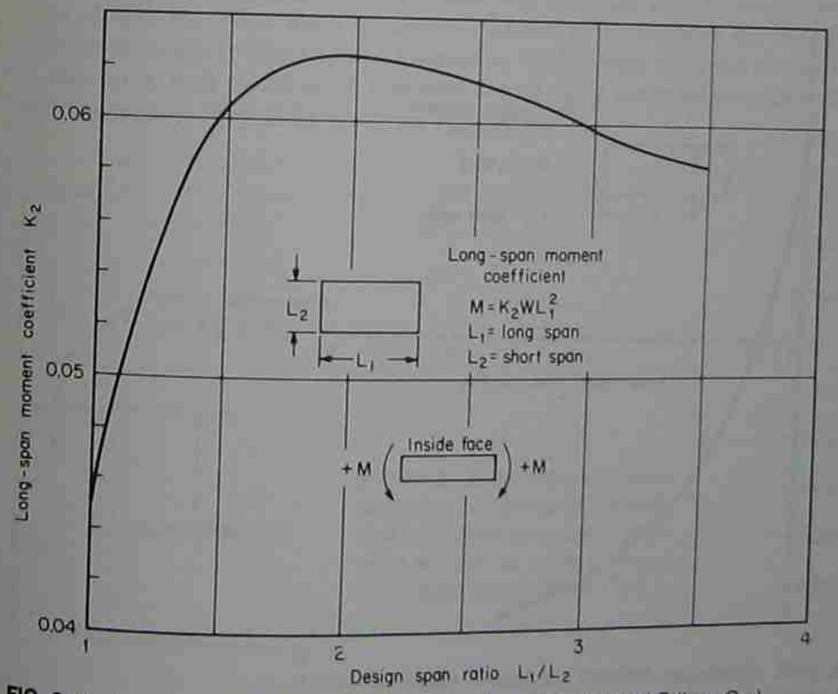


FIG. 6-11 Long-span moment coefficient. *(Courtesy Consolidated Edison Co.)*

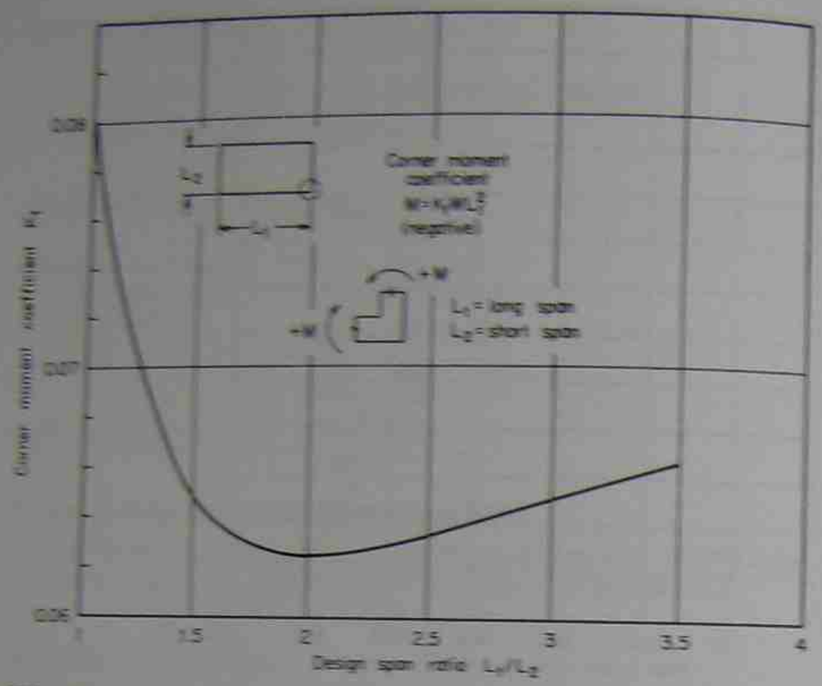


FIG. 6-12 Corner moment coefficient. (*Courtesy Consolidated Edison Co.*)

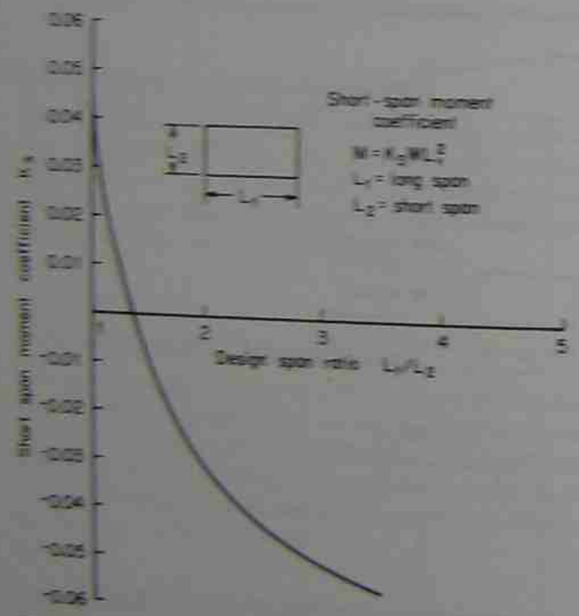


FIG. 6-13 Short-span moment coefficient. (*Courtesy Consolidated Edison Co.*)

half the sum of the floor and roof thicknesses. This method is to be used with field-poured manholes *only* and requires a field-poured roof connected to the walls and able to carry the wall reaction.

Combination of Horizontally Rigid Frame and Vertically Reinforced Designs

A method that combines the two methods described above may be used when conditions indicate that there are areas where the reinforcing for both the vertical and horizontal methods is severely interrupted by openings.

Partition Walls in Vaults

Partition walls in field-poured vaults which house oil-type transformers inside the consumer's property shall be designed for an internal blast load of 600 lb/ft^2.

Other Requirements

All field-poured vertically reinforced vaults and manholes shall have a minimum thickness of 6 in.

All field-poured horizontally reinforced rigid-frame-type vaults and manholes shall have a minimum wall thickness of 8 in.

Where watertight construction is required, the walls shall be monolithically poured with the floor for a minimum distance of 12 in above the top of the floor level. A water stop shall be inserted at this location, as shown in Fig. 6-14. A minimum wall of 10 in is required for all vault construction under these conditions, and 5000 lb/in^2 concrete may be used.

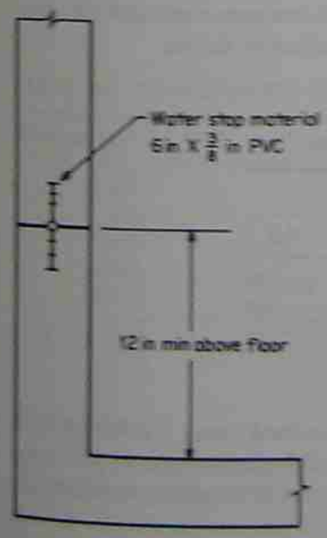


FIG. 6-14 Water stop detail; water stop to be lap-spliced 4 in on each side of vertical joints and continuous around all corners. (*Courtesy Consolidated Edison Co.*)

ROOF DESIGN

Live Loads

All roof structures for manholes or vaults shall be designed to carry the live loads specified above in the section Design Loading.

Wheel-Load Area

The design wheel load (HS-20 or H20) shall be taken acting on an area which is to be determined using the method of spreading a concentrated load defined under Wheel Load Distribution in the section Design Loading, above.

Field-Poured Manholes

All field-poured manhole roofs shall be designed using structural steel sections around the roof opening to support the manhole frame.

Precast Manholes

Precast manhole roofs may be designed using a simply supported reinforced concrete beam around the opening to support the manhole frame.

Roof Slabs

Roof slabs shall be designed as one- or two-way reinforced concrete slabs; where the ratio of short span to long span exceeds 0.5, a one-way slab design shall be used.

One-Way Slab The design moment shall be determined using a simply supported beam strip loaded with the effective live-load intensity and uniform dead load. Table 6-4 gives the design moments as a function of depth.

TABLE 6-4 SIMPLE-SUPPORT ROOF SLAB MOMENT, ft·lb

	Design span				
Design depth, ft	*4 ft*	*5 ft*	*6 ft*	*7 ft*	*8 ft*
0.75 to 1.75	5,500	7,860	10,270	12,740	15,260
1.75 to 5.0	2,860	4,690	6,330	8,130	10,460

Two-Way Slab The design moment shall be determined using Table 6-4 for a one-way slab and then proportioning the one-way slab design moments for the short-direction and long-direction moments using the conversion constants in Table 6-5.

TABLE 6-5 CONVERSION FACTORS FOR TWO-WAY SLAB MOMENTS

Ratio of clear spans	*Long-span moment factor K_l*	*Short-span moment factor K_s*
1.0	0.500	0.500
0.9	0.396	0.604
0.8	0.295	0.709
0.7	0.194	0.806
0.6	0.114	0.886
0.5	0.059	0.940

Short-span moment $M_s = K_s \times$ simple-span moment
Long-span moment $M_l = K_l \times$ simple-span moment

Above-Grade Vault Roofs

All above-grade vault roofs shall be designed for a uniform dead load plus a live load of 30 lb/ft^2 of projected area plus internal blast load.

Other Requirements

The minimum thickness of a precast roof shall be 6 in. The minimum thickness of a field-poured roof shall be 8 in.

FLOOR DESIGN

Loading

The loading on the floor of a manhole or vault depends on the size of the transformers or equipment to be installed. The weights of some transformers are listed in Table 6-6, together with some approximate areas upon which the loads are imposed.

TABLE 6-6 TRANSFORMER WEIGHTS AND LOAD AREAS

Transformer size, kVA	*Weight or load, lb**	*Area for direct load*
300	9,000	2 ft × 3½ ft
500	12,000	2 ft × 4 ft
1000	16,000	2 ft × 4 ft
2000	24,000	3½ ft × 4½ ft
2500	30,000	3½ ft × 4½ ft

*Add 3000 lb for network protectors.

Manholes

Soils In all soil conditions *other* than soft clay, medium clay, organic material, and a water condition where the groundwater level is higher than the top of the floor level, the floor shall be designed as a reinforced concrete slab capable of

resisting a bending moment produced by a partial uniform load which results from dividing the entire dead and live load by the area bounded by the outside perimeter of the structure and of the strip extending 24 in inward. The resulting partial uniform load shall be applied to the floor design span and a design moment shall be calculated.

In areas of soft clay, medium clay, organic material, and a water condition where the groundwater is higher than the floor level, the floor shall be designed as a reinforced slab resisting a uniform load which is the result of the total dead and live load divided by the total area of the base of the manhole. The floor slab may be designed as either a one- or a two-way slab. In severe water areas (tidal zones, high water table) provision shall be made for moment continuity at the junction of the floor and wall. Negative-moment steel shall be provided by using one-sixth the clear floor span plus 12 in as the reinforcing rod length to be carried into the wall and the floor. The rod size and spacing shall be taken as the same as those used for the floor reinforcing.

Precast Floors Precast floors shall be designed for soil conditions as described above. If poor soil conditions exist, discretion should be used in specifying a precast manhole. A layer of crushed stone or concrete may be required to improve the foundation characteristic of the soil.

Precast floors shall be designed for lifting, using a dynamic load factor of 1.1.

Other Requirements Minimum floor thickness, regardless of loading, shall be as follows:

Precast structures—6 in

Field-poured manholes—8 in

Field-poured vaults on soil—10 in

Field-poured vaults on rock—8 in

Field-poured vaults on steel frames—6 in

REINFORCING SPECIFICATIONS

Minimum Protection of Beams and Reinforcement Bars

The minimum concrete protection or cover of beams and reinforcement bars (in inches) is shown in Table 6-7. At no time, however, shall the required reinforcing in the roof, walls, or floor slab be less than that required for temperature reinforcing as defined in the American Concrete Institute Code, latest revision.

GRATINGS

Loadings

Loadings for gratings are shown in Table 6-8.

TABLE 6-7 MINIMUM CONCRETE PROTECTION, in

	Field-poured			*Precast*		
Structure	*Bottom*	*Sides*	*Top*	*Bottom*	*Sides*	*Top*
Roof beams—Manhole	1.0	1.0	1.0	1.0	1.0	1.0
Vault*	2.0	2.0	2.0	2.0	2.0	2.0
Roof slabs—Manhole	1.0	2.0	2.0	1.0	2.0	2.0
Vault*	1.0	2.0	2.0	1.0	2.0	2.0
Floors—Manhole	3.0	2.0	1.0	1.0	2.0	1.0
Vault:* Soil	3.0	2.0	1.0	2.0	2.0	1.0
Rock	3.0	2.0	1.0	—	—	—
Steel	0.75	—	—	—	—	—
Walls—Clear of inside face	—	1.0	—	—	1.0	—
Clear of outside face	—	2.0	—	—	1.0	—

*Vault includes transformer manhole.

Sidewalk Areas

Gratings over vaults and transformer manholes in sidewalk areas shall be formed of bearing bars riveted to reticuline bars at 7-in centers and, for grating doors, at 3½-in centers.

TABLE 6-8 LOADINGS FOR GRATINGS

Type	*Location*	*Minimum live-load requirement*
Roadway	Vehicular way	20,800-lb wheel on 12- × 20-in arc
Heavy-duty	Driveway	Same as for vehicular way
Medium-duty	Sidewalk, nonindustrial	600 lb/ft²

CONSTRUCTION PRACTICES

Precast Manholes and Vaults

Precast manholes and vaults shall be constructed as follows:

1. Three separate precast parts consisting of a four-wall unit, a floor unit, and a roof unit.
2. Two parts, a lower and an upper part horizontally joined at the centerline of the walls, to be used for manholes only.
3. Precast structures shall be designed for a 4-ft depth of soil cover.

Field-Poured Manholes and Vaults

Field-poured manholes and vaults shall be designed and constructed as follows:

1. Field-poured roof with vertically reinforced walls
2. Precast roof with horizontally reinforced walls where size and conditions permit

Other Requirements

1. Precast and field-constructed transformer manholes located in roadways shall have grating roofs. Transformer manholes located in sidewalks or driveways shall have removable precast roofs incorporating grating sections.
2. Precast or field-poured transformer vaults are to be designed and constructed with partially or entirely removable roofs with an open area sufficient to clear transformer passage.
3. Precast vaults with dimensions exceeding transportation height limitations may be designed with top and bottom wall units for field assembly.

REINFORCED CONCRETE DESIGN*

General

Beam design must provide against failure by tension, compression, and diagonal tension. Longitudinal tension reinforcement is always required. Compression reinforcement is sometimes necessary where the dimensions of the member are limited. Reinforcement against diagonal tension, where necessary, is provided by stirrups, bent-up bars, or both. Beam formulas employed here are based on the following assumptions:

1. The concrete provides no tensile resistance in flexure.
2. The concrete is perfectly bonded to the reinforcing steel.
3. There are no initial stresses.

Standard Notation—Rectangular Beams

a area of stirrup steel in one plane
A_s area of longitudinal reinforcement
b width of beam
C total compressive stress in concrete

*This section is adapted from L. S. Marks, ed., *Mechanical Engineers' Handbook*, McGraw-Hill, New York.

C' total compressive stress in steel
d effective depth of beam, from compression face to centroid of steel
d' distance from compressive face to center of compressive steel
f_c compressive unit stress in concrete
f_s tensile unit stress in steel
f'_s compressive unit stress in steel
jd arm of resisting couple
kd distance from compression face to neutral axis
M resisting moment
n ratio of modulus of elasticity of steel E_s to that of concrete E_c
p steel ratio, A_s/bd
p' steel ratio for compression steel
R coefficient in formula $M = Rbd^2$
s horizontal spacing of stirrups
T total tensile stress in steel bars
u bond stress per unit area of bar
v shearing unit stress
V total vertical shear
V' vertical shear, in excess of that allowed on unreinforced web
z distance from compression face to resultant of compressive stresses; the resultant of C and C'
Σ_o sum of perimeters of all longitudinal bars at a section

Resisting Moments

Referring to Fig. 6-15, the resisting moment for tension, in terms of steel stress, is given by:

$$M_s = A_s f_s jd$$

The resisting moment for compression, in terms of concrete stress is given by:

$$M_c = \frac{f_c kjbd^2}{2}$$

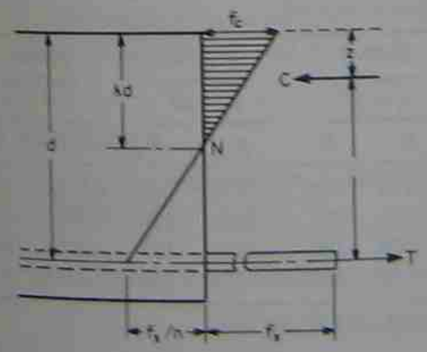


FIG. 6-15 Distribution of stress in reinforced concrete beam. (*From L. S. Marks, ed., Mechanical Engineers' Handbook, McGraw-Hill, New York.*)

For a balanced design:

$$M_s = M_c = Rbd^2$$

where $R = f_s pj = \dfrac{f_s kj}{2}$

$$k = \sqrt{2pn + (pn)^2} - pn = \frac{1}{1 + f_s/nf_c}$$

$$j = 1 - \frac{k}{3}$$

For fiber stresses:

$$f_s = \frac{M}{A_s jd} = \frac{M}{pjbd^2}$$

$$f_c = \frac{2M}{jkbd^2}$$

For balanced reinforcement:

$$p = \frac{1}{(2f_s/f_c)(f_s/nf_c + 1)}$$

Table 6-9 gives values of the several factors for rectangular beams. For shearing unit stress in a rectangular beam or slab:

$$v = \frac{V}{bjd}$$

For bond stress in a rectangular beam or slab:

$$u = \frac{V}{\Sigma_o jd}$$

TABLE 6-9 DESIGN FACTORS FOR RECTANGULAR BEAMS

			2000-lb concrete, n = 15		*2500-lb concrete, n = 12*		*3000-lb concrete, n = 10*		*4000-lb concrete, n = 7.5*	
f_s	f_c	k	p	R	p	R	p	R	p	R
18,000	$0.4f_c$	0.400	0.0088	138	0.0110	173	0.0134	208	0.0178	277
18,000	$0.45f_c$	0.428	0.0107	165	0.0134	207	0.0161	248	0.0214	330
20,000	$0.4f_c$	0.375	0.0075	131	0.0094	164	0.0112	197	0.0150	262
20,000	$0.45f_c$	0.403	0.0090	157	0.0112	196	0.0135	236	0.0180	314

From L. S. Marks, ed., *Mechanical Engineers' Handbook*, McGraw-Hill, New York.

Stirrups—Web Reinforcement Where the shearing stress exceeds $0.02f'_c$, or $0.03f'_c$ where the reinforcement bars are anchored at the ends, the spacing is given by:

$$s = \frac{af_s jd}{V'}$$

This may be multiplied by $\sqrt{2}$, or 1.41, where the stirrups are inclined 45°.

Design Procedure for Rectangular Beams

1. Determine the appropriate ratio b/d to be used. This often varies from $\frac{1}{3}$ to $\frac{1}{1}$, and may be less for very large beams.
2. Determine the area bd required by the allowable shearing stress v.
3. From steps 1 and 2, select b and d.
4. From the equation for steel fiber stresses f_s, determine A_s and p. From the equation for steel ratio, for balanced reinforcement, determine the value of p. If the first value of p is equal to less than the second value of p, the tensile resisting moment governs and the depth d is satisfactory. If the first value of p exceeds the second value, increase d or provide compression reinforcement.
5. Determine bar sizes to provide the area of longitudinal reinforcement A_s, and check to see that the width b will permit proper bar spacing. Bar spacing should be at least $2\frac{1}{2}$ diameters for round bars and 3 times the width for square bars; clear spacing between bars should be at least $1\frac{1}{2}$ times the maximum width of the aggregate particles used.
6. Determine the shear and bond stresses to check that they are within the allowable values for the rectangular beam of the size selected.

SAMPLE DESIGN PROBLEM

This problem is meant to demonstrate the methods outlined in the procedure described above; some simplifications have been made for the sake of brevity.

The manhole to be designed is shown in Fig. 6-16*a*, together with the properties of the concrete and steel to be used.

Roof Design

For the steel beam design, refer to Fig. 6-16*b*. The design span is 4 in + 5 ft + 4 in or 5.67 ft.

Load Spread For the load spread, refer to Fig. 6-16*c*.

$$w_1 = 7 \text{ in} + 12 \text{ in} + 7 \text{ in} = 26 \text{ in}$$

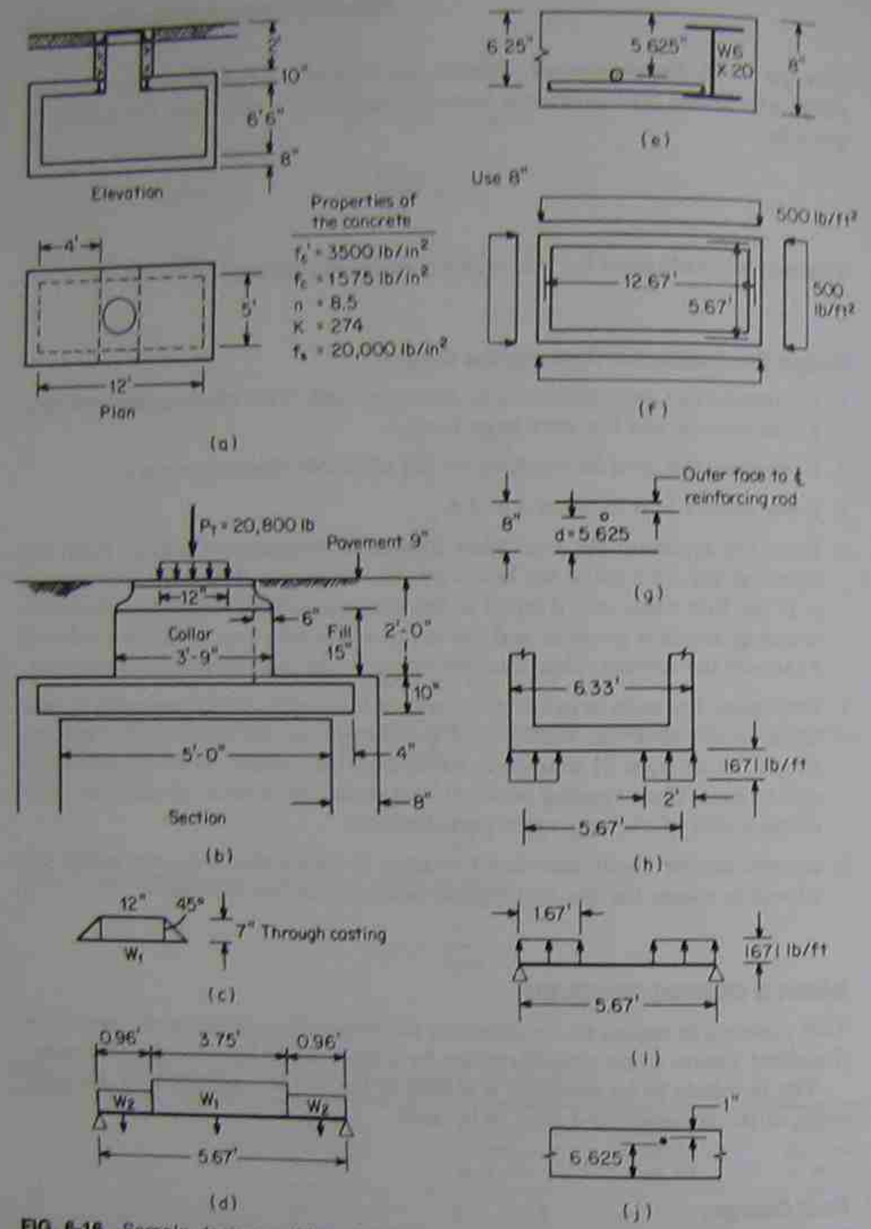


FIG. 6-16 Sample design problem. (*a*) Assumed manhole design and properties of the concrete. (*b*) Assumed manhole roof design and loading. (*c*) Diagram showing assumed load spread through casting at top of manhole collar. (*d*) Design showing dead loads imposed on manhole roof. (*e*) Assumed roof slab design showing steel beam and reinforcing rods. (*f*) Approximate wall dimensions and assumed lateral pressures on walls. (*g*) Assumed reinforcing rod cover for 8-in concrete beam. (*h*) Assumed manhole floor design and reaction areas. (*i*) Diagram showing moments acting on manhole floor. (*j*) Assumed reinforcing requirements for 8-in floor slab. *(Courtesy Consolidated Edison Co.)*

Continue the spread at 45° through the concrete portion of the collar (see Fig. 6-16*b* and the section Design Loading in this chapter):

$$24 \text{ in} - 7 \text{ in} = 17 \text{ in}$$

$$w_2 = 26 \text{ in} + 34 \text{ in} = 60 \text{ in}$$

This dimension is greater than the width of the collar, 45 in. The wheel is therefore reacted over 45 in times the wall thickness of the collar, i.e., 6 in (Fig. 6-16*b*).

Dead Load on Roof, Fill, and Pavement Refer to Fig. 6-16*b* and the section Design Loading. The load of the pavement is 9 in (i.e., 0.75 ft) × 144 lb/ft³ or 108 lb/ft². The loading of the fill is 15 in times 100 lb/ft³, or 125 lb/ft²; and that of the roof is 10 in times 150 lb/ft³, or 125 lb/ft². The total dead load of roof, fill, and pavement is 358 lb/ft².

Weight Distribution The weight distribution of the collar, in pounds per foot, is 17 in × 6 in × 150 lb/ft³, or 106 lb/ft. Assume four frames and casting weigh 660 lb; then

$$\frac{660 \text{ lb}}{4} = 165 \text{ lb}$$

and

$$\frac{165}{3.75} = 44 \text{ lb/ft}$$

For the pavement,

$$9 \text{ in} \times 6 \text{ in} \times 144 \text{ lb/ft}^3 = 54 \text{ lb/ft}$$

The weight distribution is as shown in Fig. 6-16*d*.

Assume w_1 acts on one-half of the 4-ft-wide slab (one of three slabs). Then the dead load on roof, fill, and pavement is 2 ft × 358 lb/ft², or 716 lb/ft. To this, add collar, frame, and pavement load of 106 + 44 + 54 = 204 lb/ft, and the wheel load of 20,800 lb/3.75 ft, or 5547 lb/ft. The total is 6467 lb/ft.

Assume that w_2 acts on half the 4-ft slab and the other part of the slab on either side of the steel beams. Then the dead load on roof, fill, and pavement is 4 ft × 358 lb/ft², or 1432 lb/ft. For the maximum moment on the roof slab (from one end), see Fig. 6-16*d*:

1432 lb × (0.96 + 3.75 + ½ × 0.96) ft = 5.19 × 1432 = 7432 ft·lb
6467 lb × (0.96 + ½ × 3.75) ft = 2.835 × 6467 = 18,334 ft·lb
1432 lb × (½ × 0.96) ft = 0.48 × 1432 = 687 ft·lb

The total moment is 26,453 ft·lb.

From AISC Standard 5-17, F_b = 24,000 in·lb and S_{xx} = (26,453 × 12)/24,000 = 13.2, where S_{xx} (a ratio) is the section modulus about the vertical axis. From the U.S. Steel *Structural Steel Handbook*, use a W6 × 20-in I beam whose S_{xx} = 13.4.

Roof Slab The roof design span (see Fig. 6-16*b*) is 4 in + 5 ft + 4 in = 5.67 ft. From Table 6-4 and the design depth of 2.0 ft, and interpolating, the maximum moment is 5789 ft·lb.

In the two-way slab design (for a 4- × 5-ft slab; see Fig. 6-16*a*), the short-long ratio is 4 ft/5 ft, or 0.80 (use clear span). From Table 6-5, $K_l = 0.295$ and $K_s = 0.709$. To determine the design moments, for the short span,

$$M_s = 0.709 \times 5789 = 4104 \text{ ft·lb}$$

For the long span,

$$M_l = 0.295 \times 5789 = 1708 \text{ ft·lb}$$

To determine reinforcing, see Fig. 6-16*e*, and check for adequacy. For the short span,

$$d = 6.25 \text{ in}$$

Try a ½-in bar with 8-in spacing.

From *Structural Steel Handbook*, $A_s = 0.47$ in², from which are derived: $p = 0.0063$, $k = 0.283$, $j = 0.905$, $jd = 5.66$ in, and

$$C = T = \frac{4104 \text{ ft·lb} \times 12}{5.66 \text{ in}} = 8700 \text{ lb}$$

$$f_s = \frac{M}{A_s jd} = \frac{Cjd}{A_s jd} = \frac{C}{A_s}$$

$$f_s = \frac{8700 \text{ lb}}{0.47 \text{ in}^2} = 18{,}511 \text{ lb/in}^2$$

as opposed to the 20,000 lb/in² specified. For the 12-in strip,

$$b = 12$$

$$f_c = \frac{2M}{jkbd^2} = \frac{2Cjd}{(jk)(12d^2)} = \frac{C}{6kd}$$

$$f_c = \frac{8700 \text{ lb}}{6 \text{ in} \times 0.283 \times 6.25 \text{ in}} = 820 \text{ lb/in}^2$$

as opposed to the 1575 lb/in² specified.

For the long span:

$$d = 6.25 \text{ in} - 0.625 \text{ in} = 5.625 \text{ in}$$

Try a ⅝-in bar with 12 in spacing. From *Structural Steel Handbook*, $A_s = 0.31$ in², from which are derived: $p = 0.00459$, $k = 0.245$, $j = 0.918$, $jd = 5.16$ in, and

$$C = T = \frac{1708 \text{ ft·lb} \times 12}{5.16 \text{ in}} = 3972 \text{ lb}$$

$$f_s = \frac{3972 \text{ lb}}{0.31 \text{ in}^2} = 12{,}812 \text{ lb/in}^2$$

as opposed to the 20,000 lb/in² specified.

$$f_c = \frac{3972 \text{ lb}}{6 \times 0.245 \times 6.25 \text{ in}} = 432 \text{ lb/in}^2$$

as opposed to the 1575 lb/in² specified.

Wall Design

Use the rigid-frame method. The procedure is as follows:

1. Obtain the total uniform design load from Fig. 6-10.
2. Compute corner moments M_c by using the following formula, or Fig. 6-12:

$$M_c = \frac{(L_1 \times \text{FEM}_1) + (L_2 \times \text{FEM}_2)}{L_1 + L_2}$$

where FEM = fixed end movement for span = $^1/_{12}wL^2$

L_1 = long span

L_2 = short span

M_p = positive moment for span = $\frac{1}{8}wL^2 - M_c$

3. From the corner moment compute the design moments or use Figs. 6-11 and 13.

For the wall depth from street level, see Fig. 6-16*a*:

$$24 \text{ in} + 10 \text{ in} + 78 \text{ in} = 112 \text{ in or } 9.33 \text{ ft}$$

The design depth = 9.33 ft; use 9 ft. From Fig. 6-10, $w = 500$ lb/ft².

$$M = {}^1/_{12}wL_1^2 = {}^1/_{12} \times 500 \times 12^2 = 6000 \text{ ft·lb}$$

$$d = \sqrt{\frac{M}{K}} = \sqrt{\frac{6000}{274}} = 4.67 \text{ in} \qquad \text{(use 8 in)}$$

$$\text{FEM}_1 = {}^1/_{12}(500 \text{ lb/ft})(12.67 \text{ ft})^2 = 6688.7 \text{ ft·lb}$$

$$\text{FEM}_2 = {}^1/_{12}(500 \text{ lb/ft})(5.67 \text{ ft})^2 = 1339.5 \text{ ft·lb}$$

Corner moment M_c:

$$M_c = \frac{(12.67 \text{ ft} \times 6688.7 \text{ ft·lb}) + (5.67 \text{ ft} \times 1339.5 \text{ ft·lb})}{12.67 \text{ ft} + 5.67 \text{ ft}}$$

$$= 5034.9 \text{ ft·lb}$$

Say 5035 ft·lb. From Fig. 6-12,

$$\text{Span ratio} = \frac{12.67 \text{ ft}}{5.67 \text{ ft}} = 2.23$$

$$K_1 = 0.0627$$

$$M_c = 0.0627 \times 500 \text{ lb} \times (12.67)^2 = 5032.6$$

or approximately 5035. The long-span positive moment is:

$$M_p = \tfrac{1}{11}wL_1^2 - 5035 = \tfrac{1}{11}(500)(12.67)^2 - 5035 = 4998 \text{ ft·lb}$$

The short-span midspan moment is:

$$M_s = \tfrac{1}{14}wL_2^2 - 5035 = \tfrac{1}{14}(500)(5.67)^2 - 5035 = -3025.7 \text{ ft·lb}$$

Reinforcing is required for the corner moment; refer to Fig. 6-16*g*.

A 2-in cover is required on the corner rods. Try a $\frac{5}{8}$-in bar with 6-in spacing (because of the 8-in wall); $d = 5.625$ in.

From *Structural Steel Handbook*, $A_s = 0.62$ in², from which are derived: $p = 0.62/(5.625 \times 12) = 0.0092$, $k = 0.40$, $j = 0.87$, $jd = 4.90$ in, and

$$C = T = \frac{5035 \text{ ft·lb} \times 12}{4.9 \text{ in}} = 12{,}330 \text{ lb}$$

$$f_s = \frac{12{,}330 \text{ lb}}{0.62 \text{ in}^2} = 19{,}887 \text{ lb/in}^2$$

as against the 20,000 lb/in² specified.

$$f_c = \frac{12{,}330 \text{ lb}}{6 \text{ in} \times 0.40 \times 5.625 \text{ in}} = 913 \text{ lb/in}^2$$

as opposed to the 1575 lb/in² specified.

Shear

$$V = \tfrac{1}{2}wL_1 = \tfrac{1}{2}(500 \text{ lb/ft})(12.67 \text{ ft}) = 3167.5 \text{ lb}$$

$$v = \frac{V}{bjd} = \frac{3167.5}{12 \times 4.90 \text{ in}} = 53.9 \text{ lb/in}^2$$

Allowable $v = 0.03f_c = 0.03 \times 3500$ lb/in² (from the concrete specifications in Fig. 6-16*a*), or 105 lb/in².

Bond For a $\frac{5}{8}$-in bar with 6-in spacing, $\Sigma_0 = 3.9$ (the circumference of the rod).

$$u = \frac{V}{\Sigma_0 jd} = \frac{3167.5}{3.9 \times 0.87 \times 5.625} = 165.9 \text{ lb/in}^2$$

Allowable u is up to but not in excess of 200 lb/in².

Floor Design

Calculate the total dead load and live load on the manhole floor:

Dead Load The approximate dead load for the pavement is

$$(5.00 + 1.33) \text{ ft} \times (12.00 + 1.33) \text{ ft} = 84.37 \text{ ft}^2$$

At 108 lb/ft², that comes to 9112 lb. The weight of the fill, 84.37 ft² at 125 lb/ft², is 10,547 lb.

The dead load of the manhole is calculated as follows:
For the 10-in-thick roof,

$$84.37 \text{ ft}^2 \times 125 \text{ lb/ft}^2 = 10{,}547 \text{ lb}$$

For the (8-in-wide) long sides,

$$6.5 \text{ ft} \times (12 + 1.33) \text{ ft} \times 2 \times 125 \times 0.8 \text{ lb/ft}^2 = 17{,}329 \text{ lb}$$

For the short sides,

$$6.5 \text{ ft} \times (5 \text{ ft}) \times 2 \times 125 \times 0.8 \text{ lb/ft}^2 = 6500 \text{ lb}$$

The total manhole dead load without the floor is 34,375 lb. The total dead load is 54,035 lbs.

Live Load The weight of two wheels at 20,800 lb each is 41,600 lb; or 600 lb/ft² × 13.33 ft × 6.33 ft = 50,627 lb. Use 50,627 lb

The *total* of live load and dead load is 50,627 + 54,035 = 104,662 lb. The reaction area is assumed to be at 2 ft from the outer edges of the floor slab. See Fig. 6-16*h*, and for weight distribution, Fig. 6-16*i*.

$$\text{Area} = (2 \times 13.33 \text{ ft} \times 2 \text{ ft}) + (2 \times 2.33 \text{ ft} \times 2 \text{ ft}) = 62.64 \text{ ft}^2$$

$$\text{Uniform load} = \frac{104{,}662 \text{ lb}}{62.64 \text{ ft}^2} = 1671 \text{ lb/ft}^2$$

$$\text{Design span} = 6 \text{ ft } 4 \text{ in} - 8 \text{ in} = 5 \text{ ft } 8 \text{ in or } 5.67 \text{ ft}$$

The maximum moment (from one end) is the weight times the moment arm:

$$M = 1671 \text{ lb/ft}^2 \times 1.67 \text{ ft} \times \frac{1.67 \text{ ft}}{2} = 2790 \times 0.833 = 2324 \text{ ft·lb}$$

Reinforcing is required; the floor is assumed to be 8 in thick; refer to Fig. 6-16*j*.

Try a $\frac{5}{8}$-in bar with 15-in spacing; $d = 6.625$ in. From *Structural Steel Handbook*, $A_s = 0.25$ in², from which are derived: $p = \dfrac{0.25 \text{ in}^2}{6.625 \text{ in} \times 12 \text{ in}} = 0.003$, $k = 0.227$, $j = 0.89$, $jd = 5.90$ in, and

$$C = T = \frac{2324 \text{ ft·lb} \times 12}{5.90 \text{ in}} = 4727 \text{ lb}$$

$$f_s = \frac{4727 \text{ lb}}{0.25 \text{ in}^2} = 18{,}909 \text{ lb/in}^2$$

compared with the 20,000 lb/in² specified;

$$f_c = \frac{4727 \text{ lb}}{6 \text{ in} \times 0.227 \times 6.625 \text{ in}} = 524 \text{ lb/in}^2$$

compared with the 1575 lb/in² specified.

As a check:

$$A_s \text{ (required)} = \frac{4727 \text{ lb}}{20{,}000 \text{ lb/in}^2} = 0.236 \text{ in}^2$$

Use a $\frac{1}{2}$-in bar with 15-in spacing.

For further details, reference should be made to mechanical and civil engineering texts on reinforced concrete design.

UNDERGROUND RESIDENTIAL DISTRIBUTION (URD)

The development of plastics having high dielectrical and mechanical strengths, and the more widespread use of aluminum conductors, have contributed to economically practical underground systems for application in areas of light load density, including residential areas. The use of such plastics as the protective sheath for cables has also made practical their direct burial in the ground without the need for ducts and manholes. Splicing procedures for such cables are also more simple and less costly. Moreover, the installation of long lengths of cable capable of being plowed directly into the ground or placed in narrow and shallow trenches naturally reduces installation and maintenance costs.

Such designs make the consideration of this type of underground system economically more competitive with overhead systems, often replacing them where new construction is contemplated. Further economies may be realized if other facilities, such as telephone, CATV, gas, and water facilities, are installed simultaneously. With greater emphasis placed on appearance and reliability, studies comparing costs in particular areas and conditions should be made to determine the feasibility of this type of distribution.

Cables

Primary and secondary cables are designed specifically for this type of system. For a single-phase primary supply, the cable is designed with a stranded conductor completely embedded in plastic insulation, which also serves as the protective sheath, and a neutral of bare wire or ribbon wrapped concentrically over a layer of semiconducting Mylar. This one cable is easier to handle than two, and the neutral acts as protection during installation. Electrically, the reduced reactance from this arrangement results in a reduced voltage drop, while the neutral, acting as an electrostatic shield around the cable, tends to distribute the electrostatic stresses in the insulation more uniformly, eliminating sharp peaks that may cause insulation failure.

The neutral conductors are often exposed to electrolytic action and corrosion from stray currents and chemicals in the soil, resulting in voltage fluctuations from corroded neutrals and interference with nearby communication circuits. To prevent this, the entire cable is covered with an insulating jacket of plastic that is impervious to moisture and chemicals; see Fig. 6-17*a*.

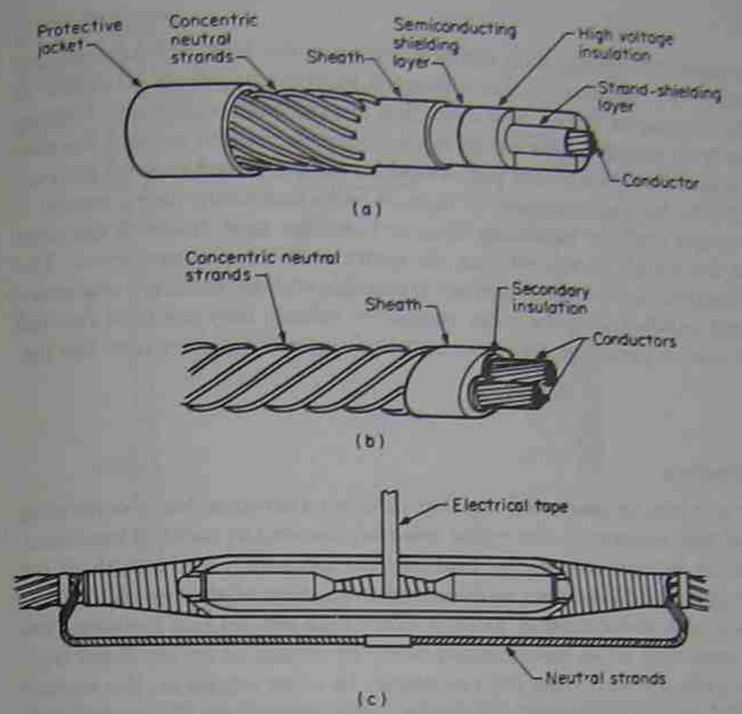


FIG. 6-17 (a) Primary concentric neutral underground cable. (*b*) Secondary concentric twin underground cable. (c) Typical single-conductor-cable splice. *(Courtesy Long Island Lighting Co.)*

Secondary cables likewise may consist of one or more insulated conductors and a neutral wrapped concentrically about them. Like the primary, the entire cable including the neutral may be jacketed for protection from corrosion, or it may have the neutral exposed. Refer to Fig. 6-17*b*.

Both primary and secondary cables have identification marks—colored plastic and metal tags—attached to them.

Cable Insulation

Cross-linked polyethylene (XLPE) is the material predominantly used for insulation purposes. Other insulating plastics include high-molecular-weight polyethylene (HMWP), also sometimes called high-density track-resistant polyethylene (HDPE), and ethylene propylene rubber (EPR). The earlier neoprene, polyvinyl chloride (PVC), and polyethylene (PE) cable sheaths have been replaced with the improved plastic materials mentioned. Plastic ducts made of polyvinyl chloride are sometimes installed to carry the cables or as spare ducts to make replacement of such cables easier.

Splices

The procedure for splicing such cables is the same for both primary and secondary cables. The conductors are connected together usually by a copper or an aluminum crimped sleeve. The insulation around the connector is built up by tape made of plastic similar to the cable insulation, wound around the connector to a specified thickness; a preformed insulation placed around the connector may also be used in place of tape. A semiconducting tape, usually of Mylar, is wound over the insulating tape, and another tape, made of the same material as the sheath, is wound over the entire assembly for protection. The concentric neutrals are bundled together to one side and mechanically connected together and bundled with the other conductor splices; they are then covered by a plastic tape to protect them from electrolytic action and corrosion. See Fig. 6-17*c*.

Terminal Devices

The cables may also be connected together through a terminal block containing a number of stud connectors, the entire assembly covered by molded insulation. The conductor is connected to the stud and the insulation and sheath of the cable are taped to the insulation and molded protection of the terminal block. The terminal may also consist of molded load-break elbows and bushings, enabling the conductor to be disconnected safely by means of an insulated hook stick which pulls the stud from the receptacle. In some instances, the molded terminal block may be combined with similar types of terminals of a transformer or switch. These disconnecting devices may be used to rearrange, deenergize, or energize primary circuits and equipment; see Fig. 6-18.

Risers

Risers, connecting underground lines to overhead lines, have been described earlier in the discussion of overhead systems.

Transformers

Transformers for this type of underground residential system are hermetically sealed against moisture, including their bushings and terminals. The terminals may contain one or more insulated disconnecting elbows, enabling the disconnection of the transformer and the sectionalizing of the primary circuit.

The transformers may be completely buried or installed on ground-level pads or semiburied pads, as shown in Fig. 6-19. Some have connections made behind an insulating panel with only the insulated disconnecting elbows protruding so that no energized parts are exposed when the enclosure is opened; these are known as *dead-front* units, in contrast to those in which the energized parts may be exposed when the enclosure is opened.

Transformers may be of the conventional type with associated oil-fuse cutouts

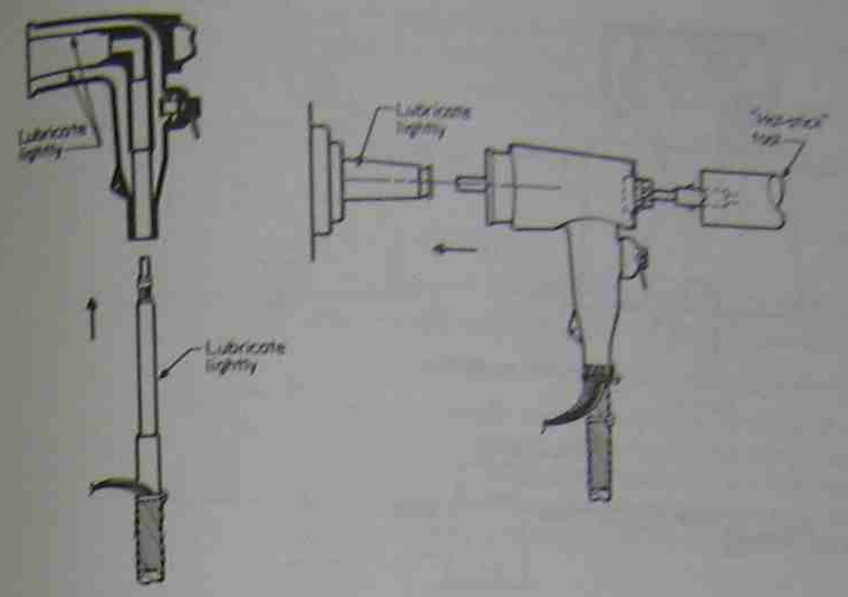


FIG. 6-18 Load-break elbow-type cable tap assembly. (*Courtesy Long Island Lighting Co.*)

or switches, or they may be of the completely self-protected (CSP) type with an internal weak link and secondary circuit breakers; they may also have taps on the primary coil for voltage ratio adjustment.

Corrosion

Corrosion of metallic parts may take place when they are exposed to chemicals and stray currents in the soil. This is especially critical in the case of neutral conductors and the tanks of transformers and other equipment.

Chemicals may exist naturally in the soil or may find their way there from sources of pollution. These may attack the metallic parts, resulting in the gradual destruction of the metal. Such action may be prevented or slowed by coating the metallic parts with preservative paints or, in the case of neutrals, covering them with an insulating plastic covering.

Stray currents may result from railroad return dc circuits, from galvanic action that takes place between dissimilar metals, especially in wet or damp soils, or from bacteria and other causes. Two or more metallic objects, reasonably close together and immersed in the chemical solutions present in the soil, will have an electric current flow between them. This flow of current causes a flow of ions (molecules carrying an electric charge) from one to the other, a phenomenon known as galvanic action or electrolysis, resulting in metal traveling or flowing from one object and depositing itself on the other object or structure. The direction of this flow will depend on the relative voltages between the two objects.

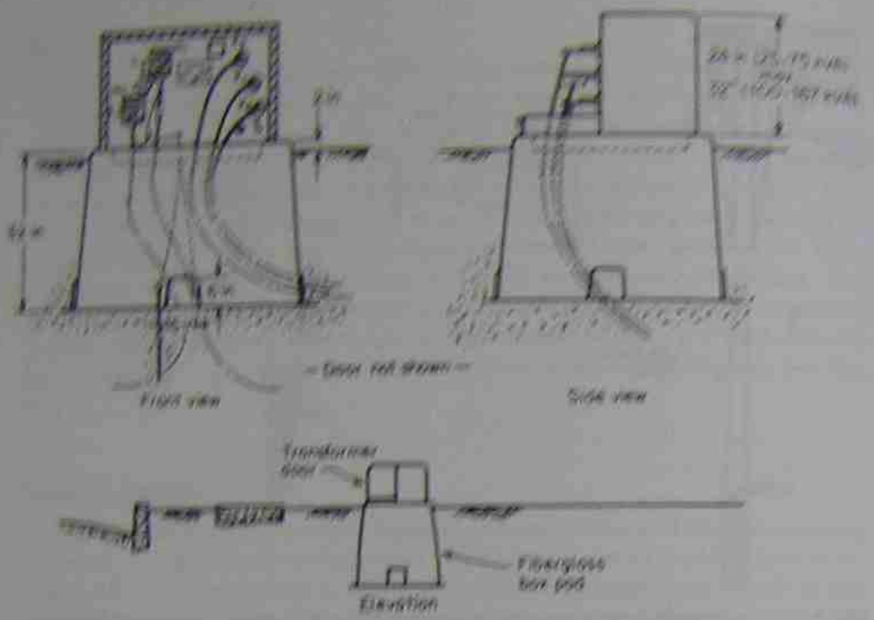


FIG. 6-19 URD underground transformer installations. (*a*) pad-mount transformer; (*b*) three-phase, 4-kV or 13-kV dead-front metal-clad transformer. (*Courtesy Long Island Lighting Co.*)

the flow being from the one of higher voltage to that of lower voltage; typical voltages for different materials are shown in Table 6-10.

The amount of corrosion that will occur due to electrolytic action will depend on:

1. The direction of the flow of current
2. The duration of the flow
3. The magnitude of the current flowing
4. The current density in the area over which the current flow takes place
5. The moisture content of the earth with which the objects are in contact
6. The chemical properties of the solutions through which the current flows

The material of a higher-voltage metallic object, such as the steel tank of an underground transformer or other equipment, will be drawn away from it, and in time the corrosion will cause failure. Although anticorrosive and insulating paints are of some usefulness in slowing down the process, they are uncertain in their results. A more positive means is to connect to the steel tank a metal,

TABLE 6-10 GALVANIC SERIES

Material	*Approximate potential with respect to a saturated Cu-$CuSO_4$ electrode, V**
Commercially pure magnesium	−1.75
Magnesium alloy (6% Al, 3% Zn, 0.1% Mn)	−1.6
Zinc	−1.1
Aluminum alloy (5% Zn)	−1.0
Commercially pure aluminum	−0.8
Cadmium	−0.8
Mild steel (clean and shiny)	−0.5 to −0.8
Mild steel (rusted)	−0.2 to −0.5
Cast iron (not graphitized)	−0.5
Lead	−0.5
Tin	−0.5
Stainless steel, type 304 (active state)	−0.5
Copper, brass, bronze	−0.2
Mild steel (in concrete)	−0.2
Titanium	−0.2
High-silicon cast iron	−0.2
Nickel	+0.1 to −0.25
Monel	−0.15
Silver solder (40% Ag)	−0.1
Stainless steel, type 304 (passive state)	+0.1
Carbon, graphite, coke	+0.3

*These values are representative of the potentials normally observed in soils and waters which are neither markedly acid nor alkaline.

From *EEI Underground Systems Reference Book.*

TABLE 6-11 TYPICAL RATES OF METALLIC CORROSION

Anode metal	*Density, lb/in³*	*Penetration (in/yr) caused by discharge of 1 mA/in²*
Magnesium	0.063	0.139
Zinc	0.258	0.091
Aluminum	0.098	0.065
Steel	0.284	0.071
Lead	0.409	0.182
Copper	0.323	0.142

From *EEI Underground Systems Reference Book.*

such as magnesium, that will produce a voltage higher than that produced by the steel tank. This will cause a current, and a flow of material, to flow from it instead of the steel tank. The attached metal, called an anode, will be sacrificed to protect the steel tank. The anodes should be inspected regularly and replaced when necessary.

The rate of penetration of a metal (in inches per year) is roughly inversely proportional to the area from which the current discharge takes place. This assumes the current is constant, i.e., the rate of corrosion varies directly with the intensity of current discharge. Theoretical rates of corrosion for some metals are given in Table 6-11.

If dissimilar metals are used, good design favors coupling a large anode with a small cathode (the receiving metallic object), rather than the reverse. When using coatings to prevent galvanic action caused by dissimilar metals, it is usually preferable to coat the cathode rather than the anode.

DESIGN OF DIRECT-BURIED ELECTRICAL DISTRIBUTION SYSTEMS*

General

The procedure described here covers the design of direct-buried electrical distribution systems to supply service to new residential development areas consisting of five or more new single-family homes. Similar procedures have been prepared for multiple-dwelling development areas and for commercial and industrial development areas.

Assumptions

1. The homes to be supplied are situated on individual building lots fronting on residential streets.
2. No electrical distribution system exists within the development.

*Adapted from Long Island Lighting Co. design standards. Other voltages are in use in other areas of the country, but this procedure may serve as a guide.

3. Only single-phase 120/240 V service is required by the consumers.
4. A 4-kV or 13-kV primary system exists near the development area.

Basic Design Considerations

Radial Design The radial design is usually more economical than the loop design and is permitted (but not mandatory) in any case where loop design is not indicated for any of the reasons specified below.

Loop Design Loop design shall be used in all cases where any of the following conditions apply:

1. The existing (external) primary distribution system, to which the development area system will be interconnected, is underground.
2. The area requires more than two transformers, or a total transformer capacity rating exceeding 150 kVA.
3. Two transformers are, or will be, needed that will be spaced not more than 1200 ft apart.

Radial and Loop Designs Both designs apply where any of the following conditions are to be met:

1. The character of the land area adjoining the development area, or any other factor, indicates a potential future need for further extension of the new underground system.
2. For both designs, if the existing primary distribution line is an overhead system remote from the perimeter of the development area, an overhead line extension shall be constructed to approach the perimeter.
3. The selection of existing primary lines to be used in supplying the new system shall be made with the usual consideration of physical availability, adequacy of load capability, the desired allocation of new loads among existing circuits and substations, primary circuit voltage drop, etc., consistent with long-range development plans for the area primary system.
4. When the existing distribution is 4 kV, consideration should be given to the possibility of conversion to 13 kV prior to initial operation of the new system, which would avert the need for transformers to operate initially at 4 kV.
5. All primary system conductors shall be insulated with cross-linked polyethylene (XLPE), the insulation rated at 15 or 24 kV.
6. Riser pole locations shall be selected with due consideration to accessibility to personnel and vehicles for operating purposes. Locations prone to vehicular accidents or tree damage shall be avoided.
7. The trench routes for installation of the primary cable shall be run parallel to the curb line or roadway edge and may be located either in the roadway or in the area behind the curb. Installation in the roadway is usually preferred

because of least construction cost and probable least cost for future operation and maintenance, but extenuating circumstances may sometimes justify installations behind the curb.

8. In choosing the transformer locations, care shall be taken to avoid conflicts with driveways, trees, fire hydrants, storm drains, etc.
9. Transformer load estimates and kVA ratings shall be selected in accordance with Tables 6-12 and 6-13 and Fig. 6-20; see Appendix 6A.

Radial System Design

Riser Interconnection The new radial primary system shall originate at a riser interconnection to the existing primary system at a single-phase riser. This interconnection shall include a fused cutout to provide an overhead sectionalizing point to protect the overhead system from underground system faults.

Primary Conductors

1. The standard size for all radial system primary conductors shall be no. 2 aluminum.
2. The primary cable run shall be extended to the transformer nearest the riser pole. It shall be interconnected to that transformer by means of a load-break elbow terminator. The transformer shall be either a pad-mount (PM) type or a below-grade, semiburied (SB) type.
3. The location of the riser cable termination facility—the transformer or the load-break elbow-type cable tap assembly (LETA)—shall be selected so as to avoid existing or foreseeable obstacles to inspection, operation, and maintenance of the terminal equipment. Locations subject to soil erosion, flooding, collection of debris, obstruction by vehicles, etc., shall be avoided.
4. If the distance from the riser to transformer exceeds 1200 ft, a load-break cable tap assembly (LBCTA) shall be installed to limit the riser cable run and the distance between the LBCTA itself and the nearest transformer each to 1200 ft or less. (The 1200-ft limit is based on the length of cable available for on-the-ground installation between two switch points in emergencies.) Primary cable from this point is then extended to the first transformer, which shall be of the PM or SB type.

Loop System Design

Switch Points

1. Loop design provides two underground radial primary lines, each originating at a different interconnection to the external primary system, and routed to meet at a common normally open switchable tie point within the development area. This switch point and other (normally closed) switch points on the loop configuration formed by the pair of radial lines are provided by means of LBCTA-type terminations installed at the primary terminals of all SB- or PM-type transformer installations. These switch points, and switching devices at the interconnections to the external system, allow switching operations on the loop system whereby any one transformer, or a section of primary cable between switch points, can be isolated while all other parts of the loop are able to be maintained energized from one or the other of the two loop sources.

2. In all loop systems, a sufficient number of switch points must be provided to limit the distance between any pair of switch points associated with the same cable section to 1200 ft or less. Where the required locations for loop interconnections (e.g., risers) and transformers of the PM or SB type are spaced too far apart to comply with this requirement, the LETA or LBCTA installations are used at intermediate locations to reduce the spacing of switch points to within the 1200 ft limit.
3. The switch point selected to be maintained normally open shall be located so as to divide the total loop load into two approximately equal parts.

Conductor Sizes Standard conductor sizes for primary loop system cables shall be no. 2 and no. 1/0 aluminum. The choice between these two sizes will depend upon the area dimensions and load density. This choice shall be determined by the use of a primary conductor selection chart and procedure; refer to Fig. 6-21*a* and *b* and Appendix 6A. The selection chart is designed to indicate the choice of conductor required to limit voltage drop on either segment of the loop to 1.5 V or less (on a 120-V base) under peak load conditions. The chart allows for a moderate imbalance in the sharing of load between the two sections and in the lengths of sections. It limits the no. 2 aluminum to cases in which the total loop load current will not exceed 150 A when the loop is operated in a contingency mode, i.e., with all load supplied from one end of the loop (tie point closed). No. 1/0 aluminum is permitted by the chart to carry load up to 200 A in the contingency operation mode. Use of the chart also indicates when neither conductor size is adequate for supplying the area load with a single-loop system, in which case alternative layouts, employing two or more loops, must be tried.

Multiple-Loop Systems

1. Load density and load distribution in some areas may require the installation of two-, three-, or more loop systems in the same trench route; loads (transformers) shall be allocated as evenly as practical among the loop systems to maintain load balance.
2. Only pad-mount (PM) or semiburied (SB) transformers shall be installed along the trench routes occupied by multiple-loop systems; direct-buried units shall not be installed. (This is to facilitate connection of the 1200-ft emergency cable.)
3. The 1200-ft limit between switch points is satisfied when each switch point is located not more than 1200 ft from another switch point on the same loop or on another loop in the same trench route.

Interconnections to External Systems Whenever the external primary system is underground, consideration should be given regarding the facilities to be used (existing or required) for interconnections of the loop system.

1. Equipment to be used will generally be pad-mounted switch gear having in-and-out gang-operated three-phase switches rated for 600-A interruption duty. These are to provide main line sectionalizing points. They also provide for one, or two, three-phase sets of single-phase, fusible tap connections, rated for 200-A duty, which can be used as interconnection points for one or more loop systems.
2. A loop system interconnected to an underground external system shall not have more than one of its two terminals located in the same pad-mount facility.
3. Fuses used at these interconnections shall be selected in accordance with a predetermined schedule.
4. Rules governing the pairing of loop terminations with external source circuits and phases, where pad-mount-type interconnections are employed, are similar to those that apply where riser installations are used, as described in items 5, 7, 9, and 10.
5. When the external primary system is overhead, loop system interconnections shall be made via riser installations. The pair of risers required for each loop system shall be such that the two risers are installed on different poles.
6. Both interconnections must be of the same operating voltage class, i.e., 4 kV or 13 kV, and both must be interconnected to the same phase of the same primary circuit, or the same phase of two primary circuits supplied from the same substation, or the same phase of two primary circuits supplied from different substations supplied at the same transmission voltage, attention being paid to the phase relationships.
7. In areas requiring more than one loop system, terminals of more than one loop may be located on the same riser pole, either in separate riser conduits, or in the same conduit (e.g., a three-phase riser may be used for the riser cable runs of three different loops). However, as previously indicated, no one loop may have both terminals installed on the same pole.
8. Each loop interconnection shall be individually fused using a cutout fused in accordance with a predetermined schedule.
9. The riser cable run from each terminal of each loop system shall be extended to the first loop switch point as described for radial system design. No tee splices shall be installed in a riser cable run.
10. To facilitate future operation and maintenance, riser cable runs from the same or different loops should be routed to minimize confusion in locating each line. Crossovers of these cables should be avoided if possible.

Radial Lateral Extensions from Loop Systems Where the main route of a loop system intersects a side street (or a cul-de-sac, etc.) in which transformers are required, it may be economical to avoid routing the loop into and out of the side street by installing a tee splice in the main run and extending a radial lateral line from the splice to the required location, subject to the following conditions:

1. Such extensions shall not be made to serve more than two transformers, nor a total transformer capacity rating exceeding 150 kVA.
2. The first transformer location on the extension must be within 1200 ft or less, measured along the most direct street route, from at least one of the two switch points that bound the loop section.
3. The radial line shall not be extended to a second transformer location if that location is more than 1200 ft from the first transformer (i.e., if the second transformer cannot be otherwise supplied, the loop systems must be extended into the side street).
4. The first transformer on a radial lateral line shall be of the switchable type appropriate to the area (PM or SB).
5. If a second transformer is required and permitted, the second unit shall be either a pad-mount (PM) unit in areas where PMs are used as switch points, or a direct-buried unit where below-grade units are used.

Transformer Installations

Transformers used in residential developments may be of two general types: pad-mount (PM), or a below-grade type, either semiburied (SB) or direct-buried (DB).

1. The PM type, designed for installation at grade, is contained within a metal enclosure that provides access to primary and secondary terminal compartments. The unit is mounted on a below-grade box-pad, and primary cable connections are of the load-break elbow terminator type.
2. In SB installations, primary cable connections are of the load-break elbow terminator type. Two primary terminal bushings are available, permitting the unit to be connected to either one or both of the primary loop sections adjoining the unit. To enable use of these connections as loop system switch points, SB installations employ a vertical cylindrical steel enclosure, with a removable cover placed level with grade, which provides acess to the elbow terminators.
3. In DB installations, primary cable connections are made using dead make–dead break type terminators, and these are completely buried (no enclosure provided). Direct-buried units must be deenergized, and reexcavation is required, whenever it is necessary to disconnect these units from the primary cable system after initial installation.
4. Transformers capable of operation at both 4 kV and 13 kV should be installed where such conversion appears probable. Since operation of the voltage selection mechanism to change from one voltage level to the other requires physical access to the transformer, no DB units are to incorporate this feature.

5. All transformer primary terminals not connected to primary cables shall be provided with insulating caps.
6. Below-grade transformers shall be installed between the curb line and the front property line, near the intersection of the front property line with a common side property line of the two adjoining lots.
7. Pad-mounted transformers shall be installed within a 10- by 10-ft easement behind the front property line and adjacent to the common side property line between two adjoining lots.

Secondary System Design

Splice Boxes A secondary splice box shall be used at each below-grade-type transformer to house the connections between the transformer secondary leads and the secondary main conductors or service conductors. A removable cover allows for future access to the connections.

Main and Service Conductor System

1. Secondary main cables are those which supply two or more consumers. Cables supplying only one consumer are classified as service cables. Cables shall be either of the following:
   a. Three-single-conductor no. 1/0 aluminum triplex 600-V (with no. 2 neutral)
   b. Three-single-conductor no. 3/0 aluminum triplex 600-V (with no. 1/0 neutral)
2. Allowable limits for voltage drop and voltage dips on motor starts are the same as for overhead systems.
3. Subject to the voltage limits indicated, the preferred arrangements for secondary systems are those that result in the least cost for trenching, cable installation, and splicing, and with due regard for avoidance of conditions that would impede future operation and maintenance of the conductor systems.
4. For economy reasons, cable runs should use a common trench for road crossings and in connecting to meters located on private property.
5. Consideration should be given to secondary main and service runs on private property to consumers not ready to receive service at the time of initial construction. In all cases, the entrance onto private property shall be made at a point on the front property line not more than 5 ft away from the intersection with the side property line. Front-to-rear trenching on private property shall be extended in a line parallel to the side property line for the distance required to reach the point(s) opposite the meter locations.
6. At those locations that are not ready to receive service, trenching and cables shall be terminated just short of the front property line. This trenching will be extended onto private property when the premises become ready to receive service. The cables are left disconnected at their splice box terminations or at the secondary terminals of PM units.
7. When meter location(s) are ready to receive service, trenching and installation of cables shall be completed in their entirety, including those portions between the front-to-rear trench run and the meter location(s). These cables are energized by making appropriate connections at their splice box or secondary compartment terminations.
8. At locations where only one of a pair of meter locations sharing a common side property line will be initially ready to receive service, the objective should be to minimize reexcavation of areas previously trenched. To accomplish this, the trench required initially should also have installed within it those cables that will be needed later. In general, it is more economical to provide an extra length of coiled cable at the end of a trench run than to plan for the installation of a splice. The choice will depend upon the comparative cost of these alternatives considering the physical dimensions involved. In any case, buried cable ends or splices shall be moisture-proofed.

APPENDIX 6A
TECHNICAL REFERENCE DATA

This appendix contains the reference materials that are referred to in the preceding procedure. The data are common to the associated procedures for this type of service to multiple-dwelling development areas and to commercial and industrial development areas. The reference data are presented in Tables 6-12 and 6-13 and in Figs. 6-20 and 6-21.

TABLE 6-12 LOAD ESTIMATING GUIDE: COINCIDENT TRANSFORMER LOAD, kVA

Living area per home, ft²	*Season*	*Number of homes per transformer*									
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Load condition 1: All-electric dwellings including electric space heating and central air conditioning											
1200	Winter	12	23	34	44	53	63	72	82	91	100
	Summer	7	12	16	19	22	25	28	30	33	36
1200–1700	Winter	17	32	46	60	73	87	99	112	125	138
	Summer	9	15	20	25	28	32	36	39	43	47
1700–2200	Winter	21	40	59	77	94	110	126	143	159	175
	Summer	11	18	24	30	34	39	43	47	52	56
2200–2700	Winter	26	49	71	93	114	134	153	173	193	213
	Summer	12	21	28	34	40	45	50	55	60	65
2700–3200	Winter	30	58	84	109	134	157	181	204	227	250
	Summer	14	24	33	39	46	51	57	63	69	75
3200–3700	Winter	35	66	97	126	154	181	207	234	261	288
	Summer	16	27	37	44	51	57	64	71	77	84

TABLE 6-12 LOAD ESTIMATING GUIDE: COINCIDENT TRANSFORMER LOAD, kVA (Continued)

Living area per home, ft²	*Season*	*Number of homes per transformer*									
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Load condition 2: Electric base load plus central air conditioning											
1200	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	3	6	9	11	14	17	19	22	25	28
1200–1700	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	3	6	9	11	13	15	17	19	21	22
1700–2200	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	4	8	12	15	18	21	24	27	29	31
2200–2700	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	5	10	15	19	23	26	29	32	35	38
2700–3200	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	7	14	20	25	30	35	39	44	47	51
3200–3700	Winter	2	3	5	6	7	8	9	10	11	12
	Summer	8	16	24	30	36	41	46	50	54	57
Load condition 3: Base load plus central air conditioning plus electric range											
1200	Winter	4	8	10	11	12	14	16	17	18	19
	Summer	6	8	11	13	15	18	20	23	26	28
1200–1700	Winter	5	9	12	14	16	18	20	21	23	25
	Summer	7	11	15	18	21	24	26	29	31	34
1700–2200	Winter	5	9	12	14	16	18	20	21	23	25
	Summer	8	14	18	22	26	30	33	36	39	42
2200–2700	Winter	5	9	12	14	16	18	20	21	23	25
	Summer	9	15	21	26	30	35	39	42	46	49
2700–3200	Winter	5	9	12	14	16	18	20	21	23	25
	Summer	11	19	26	33	39	44	49	54	59	64
3200–3700	Winter	5	9	12	14	16	18	20	21	23	25
	Summer	12	21	29	36	42	48	53	58	63	69

1. Load values indicated in Table 6-12 and Fig. 6-20 allow for load growth, including addition of central air conditioning if not initially present. Central air conditioning capacity ratings per dwelling are assumed as follows:

Living area, ft²	Capacity, Btu/h
1700	15,000
1700–2199	20,000
2200–2699	30,000
Over 2699	50,000

2. To match estimated transformer loads obtained from Table 6-12 and Fig. 6-20 to transformer capacity rating required, refer to Table 6-13.

Note: Group coincident loads indicated by this table shall be used only for estimating summer season transformer loading and transformer secondary voltage drop. Selection of transformer ratings for supplying homes with electric space heating shall be based on loadings obtained from Fig. 6-20.

Courtesy Long Island Lighting Co.

TABLE 6-13 TRANSFORMER RATING SELECTION CHART

*For estimated load, kVA**		
Winter	*Summer*	*Select rating, kVA***
A. For below-grade transformers		
0–35	0–28	25
35–52	28–42	37½
52–70	42–55	50
70–105	55–86	75
105–140	86–110	100
B. For pad-mount transformers		
0–23	0–23	25
23–50	23–50	37½
50–110	50–80	50
110–135	80–120	75
135–180	120–160	100
180–370	160–270	167

*Load as estimated from Table 6-12 or from Fig. 6-20 (for electric space heating).

**If different ratings are called for by winter and summer estimated loads, install the larger rating.

Courtesy Long Island Lighting Co.

USE OF LOAD-ESTIMATING CURVES FOR RESIDENTIAL LOADS INCLUDING ELECTRIC SPACE HEATING

For URD areas supplying residential consumers with electric space heating, the selection of transformer ratings shall be based upon house service load estimates obtained from the curves in Fig. 6-20. These curves indicate the load conditions that can exist after a long power outage during cold weather. These loads exceed normal levels because, after an outage, heating equipment operates at maximum capacity continuously until normal indoor temperatures are restored. The curves also allow for the demand of some other appliances, such as water heaters and refrigerators, which are also likely to resume operation coincidentally and to continue to operate for longer periods than normal.

To use the curves, it is necessary to know the approximate square footage of all rooms in the house that are used on a regular basis daily (i.e., the main living area), such as bedrooms, living room, dining room, bathrooms, and family room. Where additional heating capacity is provided for areas that are used only occasionally (the supplemental areas), such as garage, basement, and enclosed patio, the total square footage data are then used as illustrated in Example 6-1.

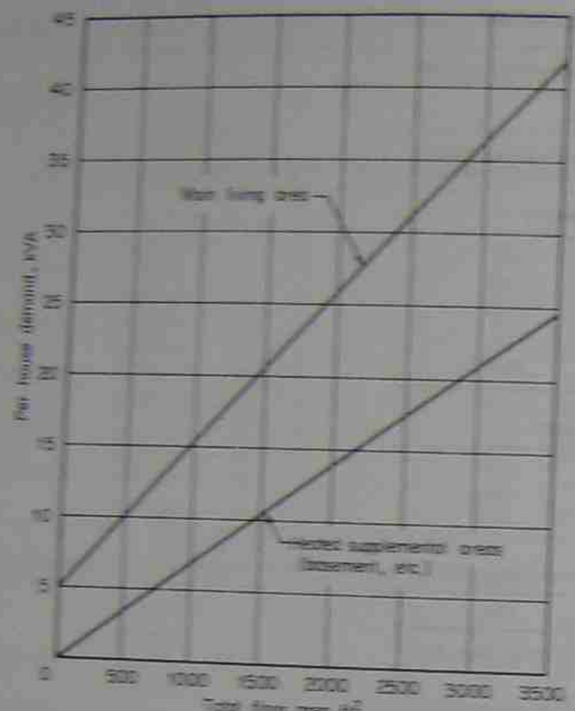


FIG. 6-20 Load-estimating curves for residential loads including electric space heating; see Example 6-1. *(Courtesy Long Island Lighting Co.)*

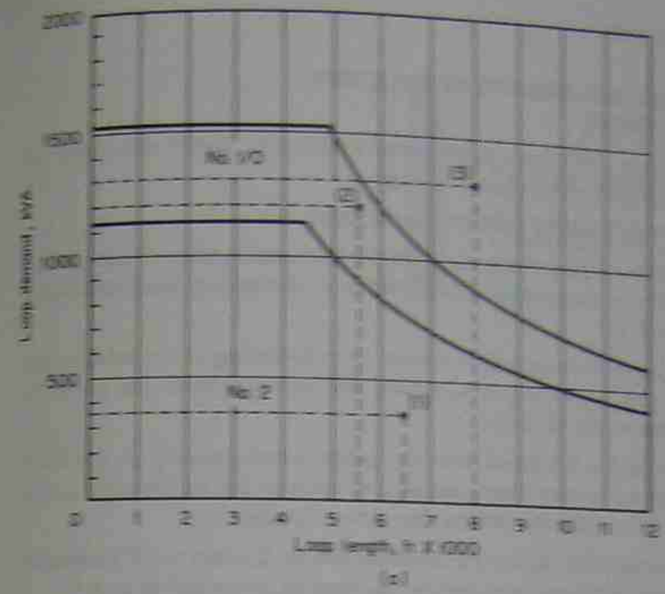
Example 6-1 Find the load that must be supplied for two houses, each of which has a main living area of 2000 ft² and heated supplemental areas totaling 1000 ft².

Solution

The demand for each house resulting from the main living area load is obtained by entering the chart at the 2000-ft² point on the horizontal axis scale and projecting upward to the intersection with the "main living area" line, and projecting a horizontal line from this intersection to the scale at the left (read 26.35 kVA). The supplemental area load is obtained in a similar manner using the supplemental area line intersection (read 7.00 kVA).

Total load per house is 26.35 + 7.00 kVA, or 33.35 kVA. For the two houses, the total load on the transformer will be 2 × 33.35 kVA, or 66.5 kVA.

This result is used in Table 6-13 to select the required capacity rating of the transformer to supply the two houses.



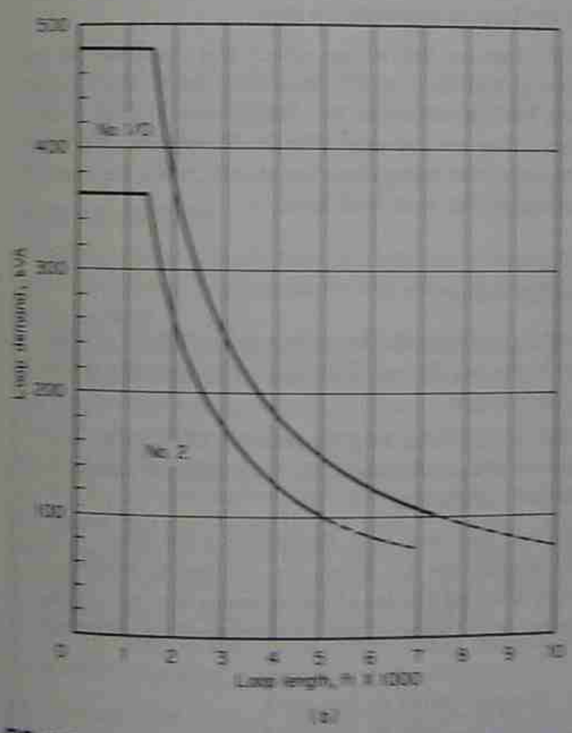


FIG. 6-21 URD loop primary conductor size selection chart. (a) For 13-kV systems. For (1), (2), and (3), see Example 6-2. (b) For 4-kV systems. *(Courtesy Long Island Lighting Co.)*

USE OF THE URD-LOOP PRIMARY CONDUCTOR SIZE-SELECTOR CHART

1. Lay out a tentative URD loop to serve the URD area. Defer the choice of transformer locations and required ratings.
2. Determine the total length of the proposed loop.
3. Determine the normal peak demand (kVA) for the total number of consumers to be supplied from the proposed loop. Refer to the group load-estimating guides in Table 6-12.
4. Enter the chart at the bottom axis at a point corresponding to the total length determined in step 2 and project a vertical line upward from this point (to the length in thousands of feet).
5. Enter the chart at the left-hand axis at a point corresponding to the kVA demand determined in step 3 and extend a horizontal line to the right to the point of intersection with the vertical line drawn in step 4.
6. a. If the intersection falls within the zone labeled no.2, select no. 2 aluminum as the primary conductor and design the loop as proposed in step 1.
   b. If the intersection falls within the no. 1/0 zone, select no. 1/0 aluminum conductor and design the loop as proposed in step 1.
   c. If the intersection point does not fall within either the no. 2 or the no. 1/0 zone, the loop layout proposed in step 1 cannot be used. Try another layout dividing the area load between the two loops, then repeat steps 1 to 6 for each loop. Depending on the total area load and size, it may be necessary to repeat this procedure using three loops, etc., until the number of loops is adequate to supply the area load level.

Example 6-2 Refer to Fig. 6-21a.

1. The loop length is 6500 ft, and the total loop demand is 350 kVA. The intersection point falls in the no. 2 zone. The loop may be designed as proposed, using no. 2 aluminum.
2. The loop length is 5500 ft, and total loop demand is 1200 kVA. The intersection point falls in the no. 1/0 zone. The loop may be designed as proposed, using no. 1/0 aluminum.
3. The loop length is 8000 ft, and total loop demand is 1300 kVA. The intersection point falls outside the no. 2 and no. 1/0 zones. Redesign the layout for two loops, dividing the area load between the two loops. (In this example, assume the subsequent layout consists of two loops as follows:

   Loop a—6500 ft, 800 kVA
   Loop b—7500 ft, 500 kVA

   The proposed loops are both acceptable designs, using no. 2 aluminum.)

CHAPTER 7

DISTRIBUTION SUBSTATIONS

The design of a distribution system is affected by the location and design of its supply substation. Indeed, the distribution substation is an integral part of the electrical distribution system.

SITE SELECTION

The availability of land, annual costs, taxes, zoning laws, and environmental and public relations considerations are some of the factors that determine the ultimate location.

The number and locations of the substations may affect the voltage selected for the primary distribution system. The fewer and farther apart the substations, the higher the primary voltage selected and the larger the loads supplied. Also, the length of distribution feeders (and the distance of consumers from the substation) and the number of consumers supplied from a feeder are reflected in the size of conductors, voltage-regulation measures, and, equally important, the losses that may be incurred. Hence, the study of the most economical design of a distribution system must include substation and transmission supply costs as well as the effect of primary voltage on feeders, transformers, equipment, and methods of maintenance and operation.

In addition to the factors cited, other considerations should be taken into account in choosing a site for a substation:

1. It should be located as near as practical to the centers of the loads to be served; the summation of the loads (which are assumed to be concentrated at some points) multiplied by their distances from the proposed substation site should be at a minimum.

2. It should be possible to supply the loads without undue voltage regulation and with available standard equipment.
3. Access for incoming transmission lines and outgoing distribution feeders should be available with a minimum of inconvenience, and should allow for future expansion of such facilities.
4. A shutdown of the substation should not affect an undue number of consumers; the substation location in relation to other, adjacent substations, both present and future, should permit ties to them in event of emergency.

GENERAL DESIGN FEATURES

Since the substation is the link between the transmission and distribution systems, its continuous and uninterrupted operation is of prime importance. For this reason, multiple incoming supply feeders are provided, relays are installed to operate switches and circuit breakers automatically to disconnect faulted feeders and equipment, and spare equipment may be provided for rapid restoration of service in the event of failure.

Equipment Installation

Arrangement Equipment may be connected in various arrangements by means of buses, switches, and circuit breakers as described in Chap. 4. The arrangements are usually such as to insure safety to workers and reliability of operation, the usual arrangement in many substations permitting work on almost any piece of equipment without interruption to the incoming or outgoing feeders. The choice of arrangement is based on economics and the degree of reliability desired; see Fig. 7-1.

Insulation Coordination (BIL)

The feature of coordination of insulation, associated with the reliability of the substation, has been detailed in Chap. 4. The impulse values of the insulation of transformers, circuit breakers, switches, lightning or surge arresters, regulators, bus supports, and other elements are chosen at different levels, determined from a minimum basic insulation level (BIL), usually based on the minimum line-to-ground voltage rating of the surge arresters. Such design assures that potential failures of insulation from overvoltages can be made to occur at the least destructive and most accessible points, where they can be readily found and repairs or replacement of damaged equipment can be made.

Coordination of Protective Devices

The coordination of protective devices, both within the same substation and with devices on the associated transmission and distribution feeders, has been discussed in Chap. 4. Such coordination is essential to ensure that the operation of a particular device does not unnecessarily deenergize remaining unfaulted portions of the distribution system.

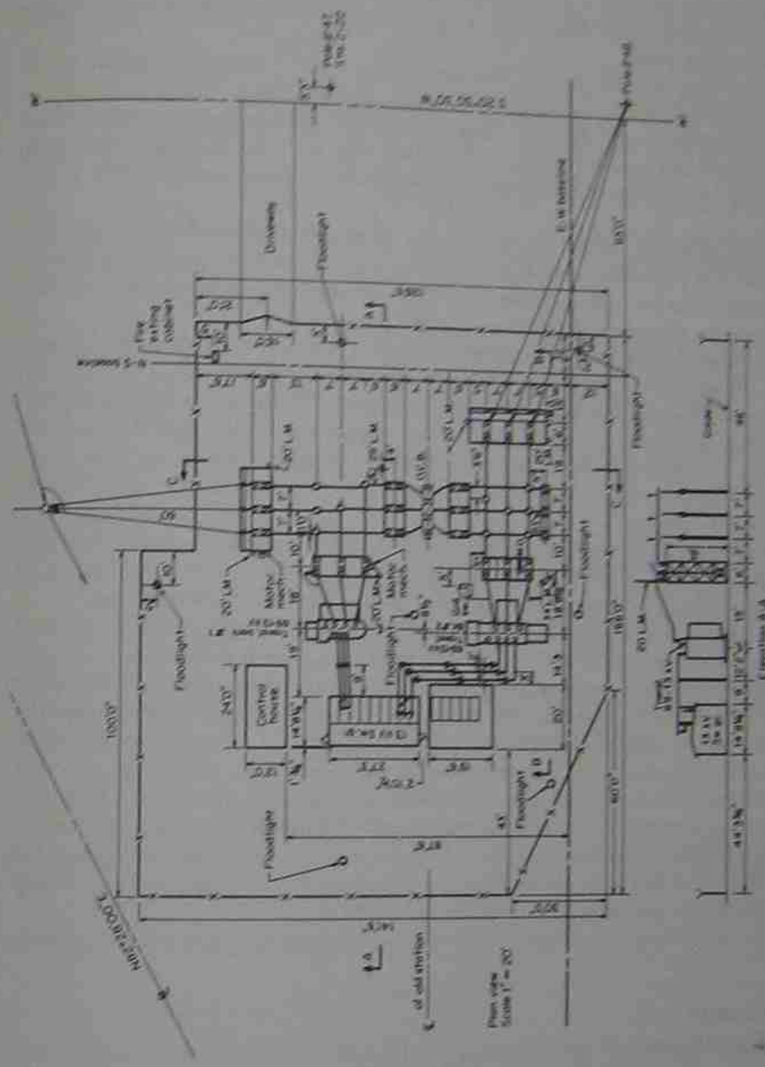


FIG. 7-1 Typical substation arrangement. (*Courtesy Long Island Lighting Co.*)

Protection Control

Instrument Transformers The circuit breakers that serve to deenergize equipment require two sources of power for their proper operation: that which actuates the relays, and that which causes the mechanical operation of the equipment to take place.

The relays receive their actuating power (usually) from instrument transformers which measure the electrical quantities associated with the circuits or equipment they are to protect. These include current transformers, with a standard secondary current rating of 5 A, and, where a voltage input is required, potential transformers, with a standard secondary voltage rating of 120 V.

Auxiliary Circuits While the instrument transformers furnish the power that actuates the protective relays, a separate source of auxiliary power is provided to operate the trip coils, solenoids, and motors that may be involved. This separate source of power must be as reliable as practical.

In substations in which the power supply bus is sectionalized into two or more parts, transformers supplying station power may be connected to two sections separated from each other, with the transformer supplying the auxiliaries connected to one section and the equipment connected to the other. In other instances, the station transformer may be equipped with a throwover switch, operated manually or automatically, in order to improve the reliability of the supply of auxiliary power.

Where reliability must be of the highest order, storage batteries, "floating" on the line, connected to an ac supply through rectifiers, are also installed to complement other power sources; here, the auxiliary circuit is a dc one.

In almost every instance, one or more of the distribution feeders supplied by the substation are so arranged in the field as to permit them to be energized from adjacent feeders emanating from a different substation. Should the entire substation become deenergized, such feeders may be utilized to reenergize the station power supply, enabling the circuit breakers and other equipment to be operated electrically. Where the substations involved are fed from different transmission or generating sources, care should be taken to avoid the interconnection of transmission and generating sources through the substation buses.

As a further precaution, control and auxiliary wiring systems are ungrounded and are provided with ground-detecting devices that actuate a light or alarm indicating the presence of a fault on the circuit involved.

The auxiliary power supply may also supply some emergency station lighting.

Bus Design

Electrical Considerations The design of buses in a substation must take into account not only the current-carrying requirements under both normal and short-circuit conditions, but also voltage drops, power losses, and temperature rises (usually a maximum of 30°C above a 40°C ambient). The current-carrying ability of buses, especially for the higher-capacity and higher-voltage circuits, must also take into account the skin effect of the ac flowing through them. Also, where buses are very closely situated (between phases or between circuits), a proximity effect must also be considered which may further distort the distribution of the current flowing in the conductor and may affect the current-carrying ability of the bus.

Voltage drops must also take into account the reactance of the buses, including the self-reactance of the buses themselves (which may be affected by their shapes and composition) as well as the mutual reactance from adjacent buses.

The enclosure of buses, for fire or mechanical protection, may lower the current rating, since the heat generated by the I^2R losses is not as freely dissipated. Further, if the enclosures are metallic, or cause the buses to be spaced farther apart, reactance values may be changed, in turn affecting the voltage drop in the buses. Where individual-phase buses are separately enclosed, no part of the enclosure or any phase may form a loop of conductive material, since such a loop would form a short-circuited turn and would overheat under normal and fault-current flow in the bus.

Mechanical Considerations Buses are usually made of copper or aluminum. Their cross-sectional shapes may include flat bars (single, or several in parallel), tubing, channels, or hollow squares. Sections may be joined together by means of bolts or clamps, or may be brazed or welded together; at intervals, however, expansion-type joints are employed to take care of the expansion and contraction due to load cycles.

The buses must also take into account the forces set up by short-circuit or fault currents that may flow through them (or in adjacent buses), as well as the voltage surges that may result from switching or lightning. The shape of the bus may provide sufficient rigidity and strength. They must also be supported on insulators capable of meeting both the electrical and mechanical requirements. Bus supports specified, therefore, usually include a fairly large safety factor, between 2 and 4.

Current transformers that are connected in these circuits must also withstand both the electrical and mechanical forces imposed on them.

Substation Electrical Grounds

Grounding at a substation is of the greatest importance. Because of the strong alternating magnetic fields set up by the heavy short-circuit currents that may flow in the several elements, voltages of appreciable values may be induced in the metallic structural members, in the equipment tanks and their supporting frames, in metal conduits for power and communication circuits, in metal fences, etc. All of these must be grounded, preferably to a common ground. The ground connections of the surge arresters, as well as the neutral conductors of the feeders, both incoming and outgoing, and of the grounded wye-connected transformers (if any), should also be connected to the common ground.

Draining of the induced voltages to ground prevents dangerously high voltage rises from forming, especially in the vicinity of the substation during fault conditions.

Grounds may consist of a multitude of metal rods driven into the ground at frequent locations and connected together, or of a mesh buried (usually) beneath

the substation. The number, spacing, size, and depth of burial of the conductors making up the mesh will depend on the nature of the soil and the ground resistance desired. Both rods and mesh may be installed and connected together.

SUBSTATION CONSTRUCTION

Distribution substations may be constructed entirely indoors, entirely outdoors, or in a combination of the two ways.

Indoor

In purely indoor construction, all the equipment is completely enclosed within a structure, protected from the weather. Measures are taken to ensure that the failure of a piece of equipment does not spread and involve other units. Reinforced concrete fire- and explosion-resistant walls or barriers are installed between major pieces of equipment, such as transformers, circuit breakers, and regulators. Sumps are usually provided beneath oil-filled equipment and connected to waste lines where they exist. The sumps should be of ample size to contain all of the oil in the equipment should its failure result in an oil spill. Control equipment, switchboards, batteries (if any), and other communication facilities may be located in separate fireproof compartments.

Automatic fire-extinguishing systems may be installed to smother any oil fire that may ensue; foam, carbon dioxide, a high-pressure fine spray of water, and other materials may be specified.

Ventilation may be by natural circulation of air, or by means of fans that may operate at peak load periods or when the internal ambient temperature exceeds a predetermined value.

In general, the rating and capacity of the equipment, particularly transformers and circuit breakers, may be lower than for similar units installed outdoors. On the other hand, the units need not provide for inclement weather conditions (e.g., bushings may have shorter creepage distances, tanks need not be watertight, etc.).

Provision, in the form of rails, rollers, or other devices, is made to permit the replacement of the several pieces of equipment. Space around each unit is provided to permit safe access for the maintenance, repair, or replacement of the unit.

The architecture of the exterior should blend with the surroundings, as should the associated landscaping, lawns, or other environmental prerequisites. Incoming and outgoing feeders are installed underground, out of sight.

Outdoor

Outdoor substations have all of the equipment located outdoors within a securely fenced off area. Here, too, provisions are made for the maintenance, repair, and replacement of the pieces of equipment. Sumps may be constructed beneath a unit, in the form of dikes or pits containing coarse gravel or crushed stone,

of a sufficient volume to hold possible oil spillage from the unit. Depending on the availability of land and the spacing between units, fire walls between major units may be found desirable.

Transformers, circuit breakers, and other outdoor equipment are designed to operate in all kinds of weather. Tanks are usually hermetically sealed or are equipped with "breathing" devices; bushings and insulators have creepage paths sufficiently long to prevent flashover. Control facilities may be located in sealed compartments either associated with each unit or grouped together in an outdoor-type housing. Small strip heaters may be required to keep condensation from forming in the compartments.

The location of the outdoor substation may present serious environmental problems. These include appearance; sometimes extensive and expensive landscaping is required to conceal the substation partially or entirely from neighboring observers. Another source of objection may be the sound emanating from the transformers; sound barriers then have to be erected around those units to deflect or mitigate the sound emissions in a particular direction.

Combination Indoor and Outdoor

In the combined indoor and outdoor arrangement, the major units, usually the transformers only (with their associated surge arresters), but sometimes circuit breakers also, are located outdoors, and the remaining equipment is housed in a building of some kind. The requirements already outlined should be followed in connection with each portion of the substation. Such substations are located in areas where appearances may not be a major consideration and some equipment, sometimes concealed by landscaping, may be found acceptable.

Unit Substations

Unit substations are small, self-contained, metal-clad units, usually installed in residential areas where larger sites are unobtainable. They are usually well landscaped, and their incoming and outgoing feeders are placed underground. Primary feeders from one unit substation extend to meet those from other, adjacent unit substations so that, when one unit substation is out of service, its load can be picked up by the feeders from the adjacent unit substations. Each unit substation, therefore, must be designed with spare capacity to enable this transfer of load to be made during contingency conditions.

Mobile Substations

Mobile substations, which may be considered portable outdoor-type substations, have been discussed in Chap. 4. Provisions are generally made at the several types of substations to permit a mobile substation to be connected to pick up all or part of the load should a substation be out of service for a prolonged period of time.

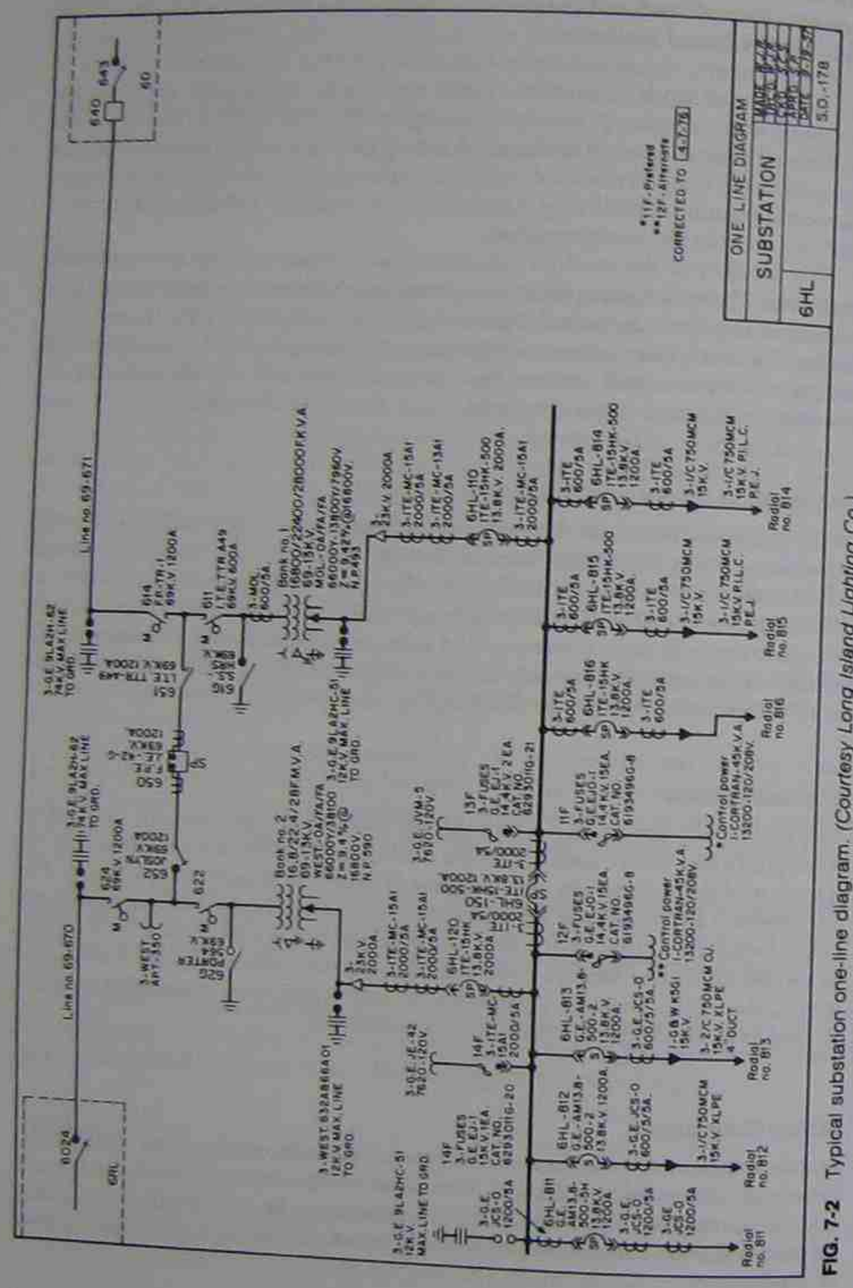


FIG. 7-2 Typical substation one-line diagram. *(Courtesy Long Island Lighting Co.)*

Operation

When an operator is in attendance, the speed and smoothness of restoration of service at times of interruption very often depend on the efficient performance of the operator.

Unattended substations may be designed in which some or all of the equipment is to function automatically. They may be operated by remote control from other substations, or from a central dispatching point, or they may be serviced by a "roving" or multistation operator. Automatic stations may, in many instances, shorten the time of interruption occurring from temporary abnormal conditions.

ONE-LINE DIAGRAMS OF CONNECTIONS

The connection of apparatus in a substation is usually drawn in the form of a "one-line diagram" for convenience and simplicity. Inasmuch as all the phase connections in a polyphase system are alike, it is only necessary to show the connections for one phase to indicate the simultaneous operation (as nearly as practical) of all the phases.

There are two types of one-line diagrams. The first, usually referred to as an operating diagram, merely indicates all the major equipment and connections, with such pertinent information as will enable the engineer, field supervisor, and operator to call for and complete the desired switching.

The second type is an elaboration of the first and includes additional information, such as fusing, relaying, and location and rating of instrument transformers and other auxiliary equipment. Such a diagram lends itself to rapid analysis in the event of improper operation of equipment. See Fig. 7-2.

CHAPTER 8

METERING

SCOPE

There are two broad classes of metering that interest the distribution engineer: that used to operate or monitor the several elements of the distribution system, and that mainly used for revenue purposes. With the advent of the digital computer (used for billing, among other applications), the latter may also be employed in furthering the purposes of the first class of metering. Further, the development of microelectronic technology has made possible operations of the electric system heretofore thought impractical if not impossible.

The principle of operation of most meters is that of the interaction of two (or more) magnetic fields tending to produce rotation of one of the elements. They may, however, be thought of as small but accurate motors, with their rotation restrained by springs or other magnetic fields.

Basic electric meters include the ammeter for measuring current in amperes, the voltmeter for measuring electrical pressure in volts, and the wattmeter for measuring power in watts. The ammeter operates on the interaction of a magnetic field, set up by the current to be measured, with the field of a permanent magnet. The voltmeter is essentially an ammeter connected in series with a fixed resistance. A wattmeter is a combination of both the ammeter and voltmeter elements.

OPERATION-MONITORING METERS

Applications

Ammeters are used for measuring loads on substation transformers, distribution feeders and transformers, secondary mains, and services. Voltmeters are used for measuring bus voltages at substations, both on the supply side of power

transformers and on outgoing distribution feeders and regulators, at distribution transformers, secondary terminals, and consumer services. In a modified form they serve as control relays for voltage regulators. Both kinds of meters are also used in the setting and maintenance of protective relays and in determining the volt-ampere loads on equipment. Wattmeters measure the power input and output at substations, and at other points where such measurements are desirable.

The three basic meters used in association with each other can determine the power factor of circuits and loads; the three elements may be combined in one instrument to read power factor directly. Likewise, resistance, reactance, and impedance measurements may be obtained from the ammeters and voltmeters used in association with each other, or in one instrument that is made to read such quantities directly.

Extending Ranges

The range of these meters may be extended by means of auxiliary equipment. Ammeters for dc measurements may use a shunt calibrated so that only a predetermined proportion of the current flowing through it is measured by the ammeter; for ac measurements, a current transformer of a predetermined ratio achieves the same results. A voltmeter for dc measurements may use a potentiometer calibrated so that a predetermined proportion of the voltage across the entire potentiometer coil is measured by the meter; for ac measurements, a potential transformer of a predetermined ratio achieves the same results. Shunts and potentiometers are used to extend the range of dc wattmeters, and current and potential transformers are used to extend that of ac wattmeters.

Types

These meters may be of the indicating type or of the recording type; they may also be of the portable or of the station or switchboard type. Indicating ammeters may also be constructed to retain maximum values of current readings; they are sometimes referred to as maximeters.

In ac systems, separate current and voltage measurements are made for each phase of a polyphase circuit, but power and volt-ampere measurements for the sum of all of the phases may be made with one polyphase meter, or may be made using two or more single-phase wattmeters.

Polyphase Power Measurements

Power in a polyphase circuit may be measured by connecting a separate wattmeter in each of the phases and algebraically adding the values obtained. Equal accuracy, however, may be obtained by using one less wattmeter, the remaining ones being properly connected among the phases of the polyphase circuit. This is known as Blondel's theorem for the measurement of power in a polyphase

system of any number of wires without regard to any unbalance of currents and voltages that may exist among the phases.

Blondel's Theorem The theorem may be stated as follows: In any system of N wires, the true power may be measured by connecting a wattmeter in each line but one ($N - 1$ wattmeters), the current coil being connected in series in the line and the potential coil being connected between that line and the line that has no current coil connected in it; the total power is the algebraic sum of all the readings of the wattmeters so connected.

According to the theorem, then, the total power in a three-phase three-wire circuit, either wye- or delta-connected, may be measured by two wattmeters; a three-phase four-wire circuit would require three wattmeters.

If the power factor of the circuit falls below approximately 50 percent, it is likely that the reading of one of the wattmeters may be negative, and it may be necessary to reverse the terminals of the current or potential coil; this change should be noted in connection with any later measurement when the power factor may be greater than 50 percent.

REVENUE METERING

Metering for revenue purposes, in itself, is not the responsibility of the distribution engineer, but the data accumulated by meters so used can serve in optimizing the planning and design as well as the operation of distribution systems. The same computer that translates meter readings into consumers' bills can also be programmed to make selective summaries of such data, simultaneously converting such consumption data into loads and demands on the several elements of the distribution system. The grid coordinate system of mapping is extremely useful in such instances; it is described in Appendix C at the end of this book.

Meters for revenue purposes measure energy in kilowatthours and power demand in kilowatts. Although constructed differently, they are connected in circuits in the same manner as wattmeters, and have both current and potential coils.

Watthour Meters

The watthour meter is essentially a small motor whose rotor, usually a metallic disk, is caused to turn by the torque produced by the reaction of the magnetic fields set up by the current and voltage coils with a magnetic field of the disk resulting from the eddy currents set up in it by those magnetic fields. Its speed of rotation can be made to be proportional to the power flowing in the coils of the meter; a magnetic brake regulates this speed to obtain the desired accuracy. A register which counts the revolutions of the disk acts to integrate the instantaneous values of power over a period of time; the integral is the expression for energy.

Watthour meters may be single-phase or polyphase, although the single-phase units constitute the greatest number in use, measuring the energy consumption of residential consumers.

Transformer Load Monitoring

The consumptions of each of the consumers supplied from one distribution transformer can be totaled to obtain the energy supplied through that transformer over the billing period of time, usually approximately a month. Factors can be applied to this total to convert it into an approximate demand in kW or kVA. In this manner, the loading of that transformer can be monitored. The computer which compiles the consumers' bills for that period of days can be programmed to perform this function. Conversion factors are obtained and kept current by sample testing of small groups of representative consumers.

Similarly, the consumption supplied from each distribution transformer can be summarized for the transformers on each phase of an entire feeder or portions of that feeder. Carrying it a step further, these consumptions can be summarized for all the feeders on a substation bus or on the supply transformers. These values can also be converted to approximate kilowatt demands on the several elements of the distribution system. Comparison of the sum of the individual consumptions on a feeder to such readings on the feeder at the substation (making correction for differences in the time of the readings, if any) can give a rough indication of actual losses on the feeder.

The computer can be programmed to produce periodic readouts of these data together with average demands per consumer, and to identify distribution transformers and other elements that exceed values predetermined to indicate overloads and potential sources of troubles.

The distribution engineer is thus able to initiate actions not only to prevent inconveniences to consumers, but also to avert damage or destruction of equipment and other facilities that could cause long and costly interruptions affecting the safety and well-being of the public. Moreover, the updated values of consumer demands and circuit loadings enable the engineer to do a more effective and economical job of planning and design of the electric distribution system.

Power Factor Correction

For some larger (usually industrial) consumers, the reactive kVA load is also measured in kVA-hours (by shifting the voltage 90° by means of reactors) along with kilowatthour consumption. By properly interrelating these quantities for the period of time covered, a value of average power factor of the consumer's load is obtained. With rate schedules tailored to reflect rewards (or penalties) for power factor, the installation of power factor-corrective measures at the consumer's expense is encouraged; these may be banks of capacitors, synchronous motors, or both. Such power factor improvement enables the distribution engineer to design more economical distribution systems affecting costs to all consumers.

Demand Meters

The measurement of maximum demand for a consumer may be obtained by adding another dial and set of gears to the registers of the watthour meters. Kilowatt demands for consumer billing purposes are obtained basically by measuring the kilowatthour consumption over a 15-min period, multiplying this by 4 to obtain an hourly demand. In some instances, a period of 30 or 60 min is used and the multiplier adjusted accordingly. This is accomplished essentially by a "floating" hand that is pushed by the watthour element that returns to zero every period, after which the action is repeated.

At the billing period, the meter reader reads this floating hand and returns it to zero, eliminating any record of that demand reading. Another system does the same thing, but records the demand on a separate register, the actuating element returning to zero every period; the action is repeated, but the demand value is added to the previous reading. At the billing period, the reader reads the second register, which has "accumulated" the maximum demands, and resets the actuating element to zero. The maximum demand for the period is the difference between the last reading and the previous one on the demand register; hence, a record of the maximum demands for each billing period is maintained.

Demand Control

Rate schedules are designed to encourage the consumer to arrange the operation of loads so as to hold down maximum demand.

Many of the relatively smaller consumers arrange the operation of major pieces of equipment on a predetermined schedule in an effort to hold down their overall maximum demand, usually concentrating on reducing or eliminating short-term peaks.

In large industrial and commercial installations, the demand is continuously monitored by the consumer using impulses generated by the utility's demand meter (impulses that trigger the demand meter's 15-min periodic return to zero). These impulses are fed into the computer that supervises the operation of the consumer's equipment; in some programs, actual shedding of less critical loads within the billing (15-min) interval is done so as not to exceed a predetermined value; see Fig. 8-1.

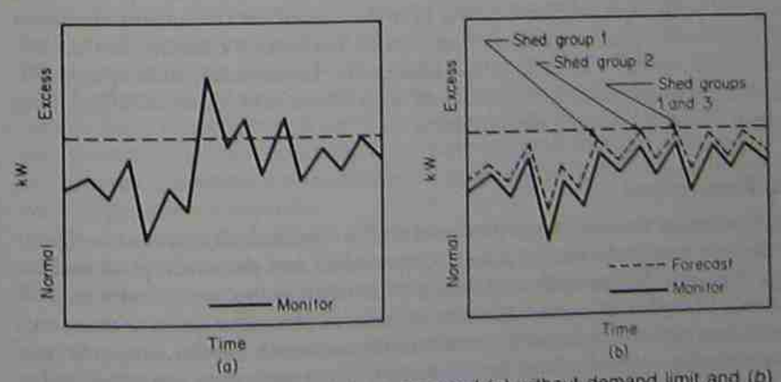


FIG. 8-1 Continuously monitored demand control (a) without demand limit and (b) with demand limit. *(Courtesy Johnson Controls, Inc.)*

In general, the goal is to improve the consumer's load factor, and the first step usually is to obtain the consumer's load profile. If the profile shows only a few 15-min intervals where sharp peaks occur, it is a relatively easy matter to identify the equipment causing those demand peaks and take remedial measures. In most cases, however, a more detailed approach is followed to determine what, if any, demands can be reduced or eliminated. This generally calls for classifying the consumer's major loads into four categories: those which (1) can be rescheduled, (2) can be deferred, (3) can be curtailed or eliminated, and (4) are essential base loads.

Often, this control of consumers' demands is a cooperative effort between the consumers and the utility's distribution engineer. Success of such efforts is beneficial to both the consumer and the utility. While this may reduce the consumer's demand payments and reduce the utility's revenue, the loss in revenue is almost always overshadowed by the utility's reduced carrying charges from the improved usage of fewer facilities and reduced energy costs from the reduction in losses that accompany the reduction of peaks. The reduction of these costs is of increasing concern to the distribution engineer.

WIRING DIAGRAMS

Wiring diagrams for the various meter connections for different types of distribution systems are shown in Fig. 8-2.

ELECTRONIC METERING

The development of so-called microelectronic processing (including solid-state) techniques is making the kilowatthour meter more than just a device for billing purposes; it also provides another tool for use by the distribution engineer and operator. By adding memory and other circuitry to the register of the meter, its functions can be expanded to provide additional data valuable to the distribution engineer. Further, microprocessors can be programmed to process the data and execute predetermined commands. This last feature can be extended to control individual consumer loads in order to restrict consumers' demands and, collectively, reduce the peak demands on the several elements of the electrical system all the way back to the generators. Incidentally, such systems facilitate the remote reading of consumers' meters and instantaneous billing, long the goal of the accounting departments.

Data Procurement

Data that can be obtained from the meter and its electronically enhanced register can include real and reactive power consumption and demands, peak and average demands, power factors, and such other items as the power factor at peak demands of both kW and kVA. Also, calendar information such as time, day, month, and year can be included, and different seasonal, holiday, leap year, and other complex rate schedules can be stored; when such data are employed at predetermined times and conditions, the price in effect and the rate-of-usage information can be readily obtained.

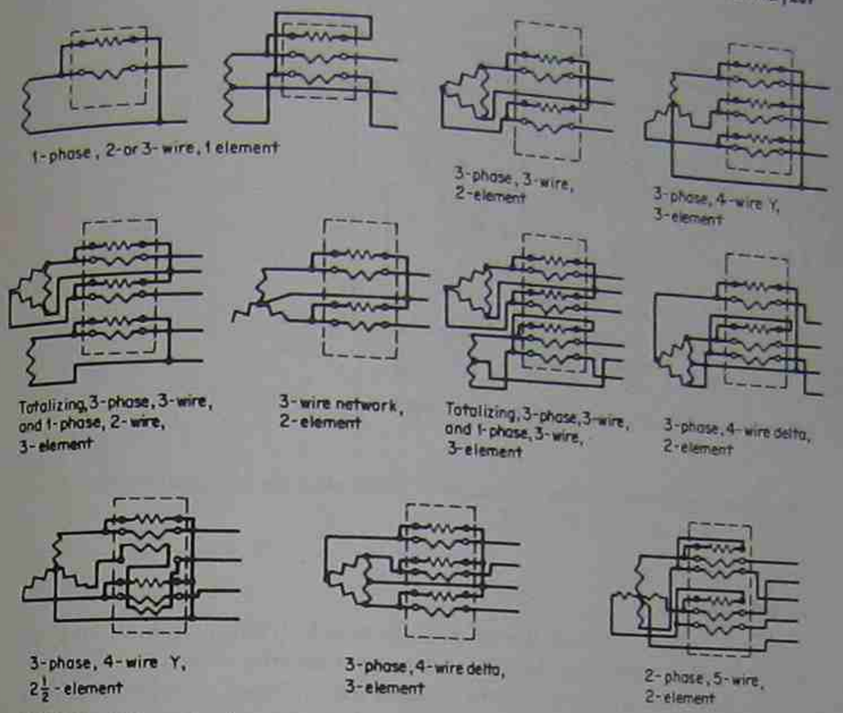


FIG. 8-2 Schematic diagrams of meter applications for different types of distribution systems. *(Courtesy Westinghouse Electric Co.)*

Operating Functions

By coupling this electronic metering with its sophisticated registers to a communications network (microwave, radio, telephone, carrier, or combinations of these), control of consumers' loads (with prearranged and contractual assent) by the utility operator becomes practical. Such control is directed primarily at restricting demands on the several parts of the *entire* electrical system, starting with elements of the distribution system. Not only is it possible to reduce capital outlays (and related annual carrying charges) for additional facilities, but it is also possible to reduce operating (e.g., fuel) expenses through the reduction of losses in the transmission and distribution systems and in the amount of spinning reserve generation required.

There are several methods which may be used to shift or reduce electrical demands. One simple and "minimum" system limits a consumer's maximum demand during peak periods from a signal actuated by the utility operator. The metering circuit monitors the load automatically with a signal light at the meter and an alarm of some kind on the consumer's premises. Exceeding the limit (after actuating by the operator) triggers the alarm and starts a programmable time delay of (say) 14 min (of the 15-min demand cycle), allowing the consumer time to reduce the demand before service is interrupted; see Fig. 8-3. A second

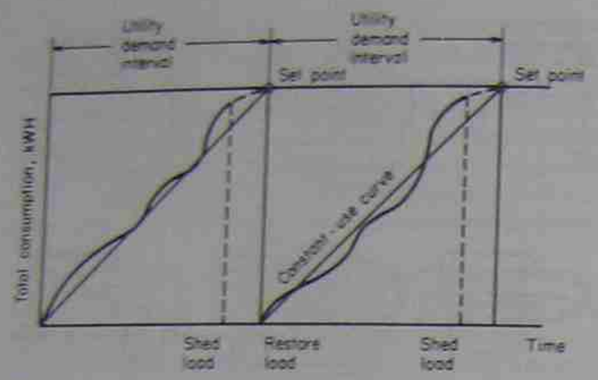


FIG. 8-3 Last-moment method of demand control.

time delay prevents appliance damage to loads such as air-conditioning compressors, when service is restored.

TRANSDUCERS

In many instances, it is desirable to measure nonelectrical quantities, and this may be done by converting them into electrical quantities, which are then metered or measured in the usual manner. This is accomplished by a class of devices generally called *transducers*. Thermocouples, photocells, and microphones are examples of devices which convert heat, light, or sound into electrical quantities; when these quantities exceed predetermined limits, they act to control the equipment with which they are associated. Other devices convert pressure or pressure differences into variations of electrical quantities, which again serve to actuate or control the equipment with which they may be associated.

Transducers may also be applied to convert electrical quantities into nonelectrical quantities.

PART THREE

MATERIALS AND EQUIPMENT

CHAPTER 8

CONDUCTORS

INTRODUCTION

Conductors, as carriers of the electrical energy, are perhaps the most important element of an electric circuit; often they are called wires, and the terms are used interchangeably. They may be installed overhead as bare, covered, or insulated conductors; and, in cable form, they may be installed underground in ducts or buried directly in the ground. Cables are also sometimes installed in trays in substation or industrial installations where immediate access to them is of relatively great importance.

Since a failure of a conductor results in a complete interruption to a circuit, it is imperative that the causes of such failure be minimized. The failure may occur from mechanical causes where the stresses and strains imposed are simply too great and the conductors literally tear apart. More often, however, the cause may initially be an electrical failure which then affects the conductor mechanically. Overloads or short-circuit currents, for example, may cause heating of the conductors to the point where they begin to liquefy (or melt) and ordinary mechanical stresses can no longer be sustained and the conductors pull apart, perhaps vaporizing in the process.

MATERIALS

It is evident, therefore, that both the mechanical and electrical characteristics must be considered in the choice of conductors. In addition, the all-important element of cost limits the number of economically available materials suited for conductors. A brief discussion will highlight the properties of those most commonly used: copper; aluminum; aluminum conductor, steel-reinforced (ACSR);

TABLE 9-1 CHARACTERISTICS OF CONDUCTOR MATERIALS (COMMERCIAL GRADES)

Material	Conductivity, % (pure Cu = 100%)	Weight		Ultimate strength, lb/in² (× 1000)	Elastic limit, lb/in² (× 1000)	Modulus of elasticity (× 10⁶)	Temperature coefficient of linear expansion per degree (× 10⁻⁶)	
		lb/in³	lb/1000 ft per 1000 cmil				°C	°F
Copper—SD	99–100	0.320	3.027	36 to 40	18 to 20	12	17.1	9.5
MHD	98.5–99.5	0.320	3.027	42 to 60	23 to 33	14	17.1	9.5
HD	97–99	0.320	3.027	49 to 67	30 to 35	16	17.1	9.5
Aluminum, plain	61	0.0967	0.920	23 to 27	14 to 16	9	23.0	12.8
Aluminum, steel-reinforced	61	0.147	1.390	44	31	—	19.1	10.6
Steel	8.7	0.283	2.671	45 to 189	23 to 112	29	11.9	6.6
Copper-clad steel—30%	29.25	0.298	2.810	60 to 100	—	16 to 20	13.0	7.2
40%	39	0.298	2.810	60 to 100	—	16 to 20	13.0	7.2

To convert to metric system:
lb/in³ × 0.0277 = kg/cm³
lb/1000 ft × 0.1488 = kg/km
lb/in² × 0.0703 = kg/cm²

Courtesy The Anaconda Co., Wire and Cable Div.

steel; and copper-clad steel. The chief characteristics of these conductor materials are compared in Table 9-1.

Copper

For many years, copper has been the most satisfactory conductor for electrical purposes. Its electrical and mechanical properties, coupled with comparative cost benefits, made it almost exclusively used universally.

Its conductivity is high, surpassed only by that of silver and some other rare metals; indeed, its conductivity is used as a reference for that of other materials.

Degrees of Hardness Although basically soft enough to be handled easily, copper can be increased in strength through annealing processes. It is available in three standard degrees of strength and hardness: hard-drawn, medium-hard-drawn, and soft-drawn. Hard-drawn copper results from the repeated drawing of the wire down to the desired size without annealing, i.e., without deliberate after-heating and cooling. Medium-hard-drawn copper results from drawing the wire down to the desired size; annealing must be made under controlled conditions or the degree of hardness will not be consistent enough to be considered constant for design purposes. Soft-drawn copper results from annealing after drawing is complete; here, too, annealing must be controlled to result in constant values of hardness.

As the names imply, the difficulty in handling copper wire depends on its hardness, as does its strength. Hence, for overhead lines, hard-drawn copper finds greatest application for long spans, medium-hard-drawn for intermediate-length spans, and soft-drawn for short spans and for such other uses as connecting leads, tie wires, and other applications where strength is not a major requirement and flexibility is highly desirable.

For cables, interior wiring, and other uses where mechanical strength is not of paramount importance, soft-drawn copper is almost always preferred because of its flexibility.

Flexibility To obtain additional flexibility, particularly where hard-drawn and medium-hard-drawn copper are involved, conductors are sometimes stranded; i.e., a conductor of a specific size may be made up of a number of smaller-cross-section conductors whose sum is equal to the cross section of the specific conductor. While this makes the conductor more flexible, it does increase the overall diameter of the conductor.

Aluminum

Although the conductivity of aluminum is only some 61 percent that of copper, the weight of aluminum is only about one-third that of copper. For the same conductivity, therefore, an aluminum conductor would weigh only about half as much as copper, although somewhat larger in diameter. The breaking strengths of aluminum and soft-drawn copper are also about the same. The result is that these two materials are economically competitive as conductors.

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Aluminum Conductor, Steel-Reinforced (ACSR)

From the viewpoint of mechanical strength, plain aluminum conductors cannot be hardened and, hence, cannot compare with medium- and hard-drawn copper conductors. It is sometimes alloyed, however, with other materials to increase its strength slightly, but more often, its deficiency in strength is overcome by having steel reinforce the aluminum. This is accomplished by having strands of aluminum wire wrapped around a central core of one or more strands of high-strength steel wire. The breaking strength of this type of conductor, 2 or more times that of plain aluminum, is considerably greater than even that of a hard-drawn copper conductor of the same conductivity.

Steel

Although its conductivity is relatively low, yet because of its very high mechanical strength, steel is sometimes used as an electrical conductor. Its use is limited to those few occasions where mechanical strength is of paramount importance. It is usually protected from corrosion by galvanizing or otherwise protected by some covering.

Copper-Clad Steel

The advantages of steel for strength and copper for conductivity are combined into a solid nonstranded-type copper-clad steel conductor. Obviously, this type of conductor is limited to the smaller-size copper conductor equivalents. The layer of copper is continuously bonded to the steel, resulting in a material that is essentially homogeneous. Such conductors are made in two grades of conductivity, 30 and 40 percent copper (as a percentage conductivity compared to the conductivity of hard-drawn copper of the same cross section) and in two grades of strength depending on the grade of steel around which the copper is placed. The copper covering acts to insure the conductors against destructive corrosion. This type of conductor is handled in the same manner as solid-type hard-drawn copper conductors.

Other Materials

From time to time, other materials have been employed as conductors of electricity. Silver, because of its very high conductivity, has sometimes been used in very special situations where strength and cost are not the principal concerns.

Alloys of both copper and aluminum have also found special applications. Brass and bronze, though stronger than copper mechanically, have lower conductivities, and have found application in relatively few special situations.

Similarly, aluminum alloyed with small percentages of silicon, magnesium, iron, and other metals has been used where increased hardness and tensile strength are desired along with light weight, and where conductivity is of secondary importance.

Characteristics of Conductor Materials

The more important characteristics of the several conductor materials mentioned above are given in Table 9-1. Conductivity and weight have already been discussed. While the words *strength* and *tension* have been used, further description is needed; these are quantified in the table in terms of elastic limits and ultimate strengths.

Elastic Limit and Modulus of Elasticity (Sag) The elastic limit of a metal is the amount of elongation or stretch that the material can make under stress while still being able to return to its original dimensions, i.e., without permanent deformation after the stress is removed. The elasticity of a material can be measured as a ratio between the stress applied (in pounds per square inch or kilograms per square centimeter) and the elongation produced per unit length (say, inches per foot or millimeters per meter). This ratio is known as the *modulus of elasticity* and is a measure of the way a conductor will sag under loading.

A very small percentage elongation of a conductor is accompanied by a comparatively large increase in sag. Tension is approximately inversely proportional to sag; i.e., when the sag is increased, the tension (or stress) in the conductor is decreased. The elongation, up to the elastic limit and including a factor of safety, is taken into account in computing sags.

Elongation beyond the elastic limit can continue until the conductor is at or near the breaking point, which is a measure of the ultimate strength of the conductor. For stranded conductors, the ultimate strength is taken at about 90 percent of the sum of the strengths of the individual strands. The ultimate strength has little importance in the design of electric lines, but is a figure which allows factors of safety to be determined, i.e., a ratio of stress that would ultimately cause the conductor to fail to the allowed stress.

Temperature Coefficient of Linear Expansion There is still another characteristic of materials that affects the performance of conductors: the temperature coefficient of linear expansion, or a measure of the change in length of the material with temperature. This is of great importance, as a sag installed in a line at a particular temperature, say in summertime, may be considerably different at another temperature, say in wintertime. These variations caused by temperature differences are taken into account in the design and construction of overhead lines.

Conductor Sizes Since it is impractical to manufacture an infinite number of wire sizes, standards have been adopted for an orderly and simple arrangement of such sizes for manufacturers and users. The American Wire Gauge (AWG), formerly known as the Browne and Sharpe Gauge (B&S), is the standard generally employed in this country and where American practices prevail.

In defining conductor sizes, the *circular mil* (cmil) is usually used as the unit of measurement. It is the area of a circle having a diameter of 0.001 in, which works out to be 0.7854×10^{-6} in^2. In the metric system, these figures are a diameter of 0.0254 mm and an area of 506.71×10^{-6} mm^2.

Wire sizes are given in gauge numbers, which, for distribution system purposes, range from a minimum of no. 12 to a maximum of no. 0000 (or 4/0) for solid-type conductors. Solid wire is not usually made in sizes larger than 4/0, and stranded wire for sizes larger than no. 2 is generally used. Above the 4/0 size, conductors are generally given in circular mils (cmil) or in thousands of circular mils (cmil $\times 10^3$); stranded conductors for distribution purposes usually range from a minimum of no. 6 to a maximum of 1,000,000 cmil (or 1000 cmil $\times 10^3$) and may consist of two classes of strandings. These wire sizes and their dimensions are given in Table 9-2.

Gauge numbers may be determined from the formula:

$$\text{Diameter, in} = \frac{0.3249}{1.123^n}$$

or

$$\text{Cross-sectional area, cmil} = \frac{105{,}500}{1.261^n}$$

where n is the gauge number (no. 0 = 0; no. 00 = −1; no. 000 = −2; no. 0000 = −3).

It will be noted that the diameter of the wire doubles approximately every sixth size (e.g., no. 2 has twice the diameter of no. 8), and the cross-sectional area therefore doubles every third size and is 4 times as great every sixth size (e.g., no. 2 has twice the area of no. 5 and 4 times that of no. 8).

The diameter of stranded wire is approximately 15 percent greater than the diameter of a solid wire of the same cross-sectional area.

The gauge numbers and wire designations apply to conductors of all materials. Usually, however, the equivalent wire sizes are denoted for the several materials in comparison to copper (e.g., 4/0 aluminum is equivalent to 2/0 copper). These are indicated in the tables for such conductors.

Conductor Coverings Although the practice has essentially been discontinued, in the early days of overhead line construction, conductors were sometimes provided with weatherproof coverings. Such coverings usually consisted of cotton braids impregnated with a water-resistant compound wrapped about the wire. These conformed to no standards, but the various thicknesses of covering used were designated by the number of braids: single-braid, double-braid, and triple-braid. These coverings were used on conductors operating at secondary voltages usually less than 500 V, and at primary voltages under 5000 V. It was felt that such coverings would prove useful in preventing short circuits in stringing new wire, when wires swung together, when they came in contact with tree limbs, or when objects fell or were thrown across the wires. Although the insulating value of such coverings is unreliable, it will be more or less in proportion to the thickness of the covering, the preservative, age, and other considerations. As indicated earlier, this practice has been essentially discontinued, but a great many such installations still exist and will be met in maintenance and reconstruction activities.

TABLE 9-2 CHARACTERISTICS OF SOLID AND STRANDED CONDUCTORS

Both solid and stranded conductors									Stranded conductor	
	Cross section		Weight, lb/1000 ft*		Resistance, Ω/1000 ft at 20°C		Solid conductor diameter, in		Number and diameter of strands, in	Diameter, in
Size	cmil	in²	Cu	Al	Cu	Al				
—	1,000,000	0.7854	3026.9	921.6	0.010	0.017	—		61 × 0.128	1.150
—	750,000	0.5891	2270.2	691.2	0.014	0.022	—		61 × 0.111	0.998
—	500,000	0.3927	1513.5	460.8	0.021	0.034	—		37 × 0.116	0.815
—	350,000	0.2749	1059.4	322.5	0.030	0.048	—		37 × 0.097	0.681
									19 × 0.136	0.678
—	250,000	0.1964	756.7	230.4	0.041	0.068	—		37 × 0.082	0.575
									19 × 0.115	0.573
4/0	211,600	0.1662	640.5	195.0	0.049	0.080	0.4600		19 × 0.106	0.528
									7 × 0.174	0.522
3/0	167,772	0.1318	507.9	153.6	0.063	0.102	0.4096		19 × 0.094	0.470
									7 × 0.155	0.464
2/0	133,079	0.1045	402.8	122.0	0.078	0.128	0.3648		19 × 0.084	0.418
									7 × 0.138	0.414
1/0	105,625	0.0830	319.5	97.0	0.098	0.161	0.3250		19 × 0.075	0.373
									7 × 0.123	0.368
1	83,694	0.0657	253.3	76.9	0.124	0.203	0.2893		19 × 0.066	0.322
									7 × 0.109	0.328
2	66,388	0.0521	200.9	61.0	0.156	0.256	0.2576		7 × 0.097	0.292
3	52,624	0.0413	159.3	48.4	0.197	0.323	0.2294		7 × 0.087	0.260
4	41,738	0.0328	126.4	38.4	0.249	0.408	0.2043		7 × 0.077	0.232
5	33,088	0.0260	100.2	30.4	0.313	0.514	0.1819		7 × 0.069	0.207
6	26,244	0.0206	79.5	24.1	0.395	0.648	0.1620		7 × 0.061	0.184
7	20,822	0.0164	63.0	19.1	0.498	0.817	0.1443		7 × 0.053	0.167
8	16,512	0.0130	50.0	15.2	0.628	1.030	0.1285		7 × 0.047	0.134

*For PE- and PVC-insulated conductors, add 550 lb per square inch of cross section for every 1000 ft.

To convert to metric system:
in² × 645 = mm²
in × 2.54 = cm

Courtesy The Anaconda Co., Wire & Cable Div.

Tree Wire Where wires are strung among trees with the possibility of abrasion from contacting limbs and resultant short circuits, an especially heavy covering was applied to the wires. Often, this consisted of thick fiber, hemp, or sisal coverings, in some instances applied over some rubber insulation. Again, this practice is virtually obsolete, though some tree wire still remains in place.

Where fear of wires' coming together and tree problems are still considerations to be taken into account, present practice calls for installing fully insulated wire.

Insulated Wire Use of insulated wire on overhead systems was formerly restricted to transformer connections, overhead-to-underground and other jumper connections, and an occasional span or two. Insulation consisted of rubber covered with one or more weatherproof braids. The rubber insulation was subject to deterioration from temperature changes, moisture, sunlight, pollution, and other causes.

The development of plastics, such as polyethylene (PE) and polyvinyl chloride (PVC), has made available insulated conductors in which the plastic serves both as insulation and covering or sheathing. It has completely taken the place of weatherproof covered conductors, tree wire, and other insulated wire mentioned above. Indeed, the availability of such plastic-insulated wire has increased its usage in place of bare wire for overhead and for lead-sheathed underground cables, resulting in generally improved reliability for the former and wider application of underground systems.

One of the features of some of these plastics is their hardness, particularly at low temperatures. They are therefore somewhat more difficult to handle, and the plastic must sometimes be heated before it can be removed by knife or other tool, for making connections or for other purposes.

CABLES

Conductors for use in underground systems must be provided with insulation sufficient to withstand the voltages at which they must operate. Generally, these consisted of stranded copper conductors (except very small-size conductors which were solid) with insulation of rubber, varnished cambric, or special oil-impregnated paper, all contained within a sheath made of lead. In some special circumstances, such as in heavy tree areas or where appearance was an important factor, these cables were installed on overhead systems, usually attached to a messenger wire for support between poles.

Because the rubber insulation sometimes contained sulfur compounds which reacted destructively with the copper, the conductor strands were often tin-plated, adding to the complexity and cost of such insulated cables; these were generally limited to secondary voltage applications of 500 V or less and to primary voltages of 5000 V or less.

Single-conductor cables are used for spur or lateral or branch lines of feeders where numerous branch joints or splices are required, for secondary and service supply, for street lighting, and other such purposes, or where the conductor may be very large, making a multiconductor cable impractical. Multiple-conductor cables of two, three, or four conductors are used in the main portion of feeders, where there may be few branch connections required; in such instances they may be more economical, both from material and labor standpoints, than a number of single-conductor cables.

In some instances, where electrolytic or other chemical conditions may cause sheath corrosion or erosion, lead sheaths may be replaced with nonmetallic sheaths or the sheath (and cable) may be covered with nonmetallic materials such as plastics.

In some instances, such lead-sheathed cables may be buried directly in the ground, or laid under water in submarine installations. In these instances, the lead sheath is covered with jute or tar and armor wires of steel are wound around the whole for protection.

Although the installation of lead-sheath cables is a disappearing practice, many miles of such installations exist and will continue to exist for many years to come.

Cables in which the plastic takes the place of both insulation and sheath are now used almost exclusively for distribution circuits, and are more extensively buried directly in the ground. This not only eliminates ducts and manholes, but permits longer sections of cable to be used with fewer splices required. Aluminum often replaces copper as the conductor in these newer types of cables.

SECONDARY MAINS

Secondary mains consisting of two or more conductors were sometimes fastened to insulators mounted on cross arms and more often on insulated racks attached to the sides of the poles. The "live" conductors were generally of weatherproof covered wire, though sometimes they were rubber-insulated with a covering wrapped about the rubber. The "neutral" conductor was generally a bare wire.

More recently, with the advent of plastics in this field, secondary conductors with plastic insulation are wound together or "cabled" with the bare neutral wire, the assembled conductors thus becoming self-supporting; more often, the conductors are made of aluminum, rather than the copper formerly almost universally used. Besides taking up less space on the top or side of the pole, cabled secondaries are easier to install and their reactance (which contributed to a loss or drop in voltage) is less than for the open-type conductors.

SERVICE CONDUCTORS

Overhead services for many years were of the open-wire or multiple-conductor types. Open-wire construction, with separate weatherproof covered wire and bare neutral, held apart on separate insulators, not only was cheaper, but allowed a third or fourth conductor to be added very readily. In multiple-conductor construction, sometimes known as "duplex" or "triplex" cables, the service cable consisted of one or two insulated conductors about which the neutral conductor strands were wound, the whole enclosed by weatherproof braiding. This type of construction made for better appearance, and a slightly better reactance. Many of both open-wire and multiple-conductor services still exist and will continue to do so for an indefinite time.

Services also have employed "cabled" conductors, similar to those used for secondary mains. In some instances, consumers are served from midspan taps; in others, from poles. Economics and appearance are the determining factors.

In many instances, services are placed underground, generally for the sake of appearance. Lead-sheath rubber-insulated cables installed in ducts or conduits, or supplied with armor and buried directly in the ground, have been used. Plastic-insulated conductors requiring no sheathing have largely taken the place of such underground cables. They are buried directly in the ground, as previously described for main-line conductors.

CONNECTIONS

Connections made between conductors, in joining two ends together or in making a tap off the other, should be electrically and mechanically sound. They not only should introduce no additional resistance (and associated heating) at the

points of contact, but they should also not be subject to corrosion or conductor stresses or movements.

In earlier times, such connections usually consisted of wires wrapped together and soldered. Later, twisted sleeves were employed in which the two ends of the conductor were inserted in a sleeve and the whole assembly twisted. Stranded conductors had each strand serviced separately before soldering. Many of these connections still exist.

The later development of "solderless" or mechanical connectors made obsolete the wrapped and soldered splices. Parallel-groove clamps, split-bolt connectors, and crimped sleeves made splicing more simple and more uniform, with substantial reduction in labor costs. Some of these are shown in Fig. 9-1. For rapid installation, usually during periods of emergency, the "automatic" splice, employing wedges which, under pressure of the sagging wire, grip the ends of the conductors to be spliced, was also developed; this is relatively more expensive.

When necessary, friction tape, or insulating tape covered with friction tape, is employed to continue the covering or insulation. In present-day applications, the splices are often left bare.

In many instances, where it is desirable to disconnect the connection readily,

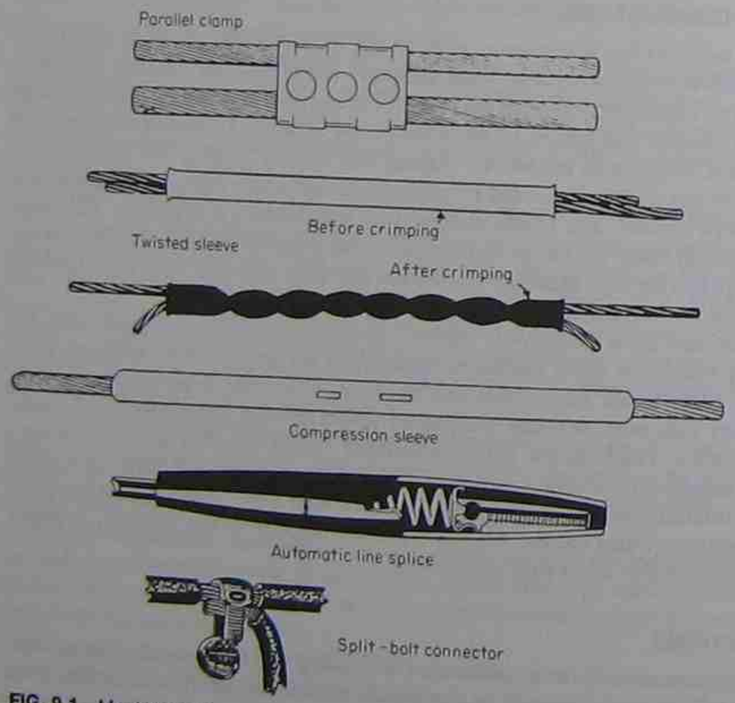


FIG. 9-1 Mechanical connectors. *(Courtesy Burndy Corp.)*

special clamps, sometimes known as "live-line" or "hot-line" clamps, are used; these are shown in Fig. 9-2.

The advent of aluminum conductors into a field in which the conductors previously were exclusively copper presents problems where conductors of dissimilar metals need to be connected together. Special care is exercised, since the connection may be affected by chemical interaction between the two metals, especially when wet and in the presence of some pollutants; but even more, because of the different rates of expansion when heated. The uneven expansion and contraction will eventually cause such splices to become loose, and their resistance to increase with consequent abnormal heating, with possible dire results.

Connectors for copper-to-copper conductors are usually made of copper, though bronze is sometimes used for greater strength. Where aluminum or ACSR conductors are to be connected to similar conductors, connectors of aluminum are used. Where the conductors to be connected are of dissimilar metals, connectors are so designed that only surfaces of similar metals come in contact with each other; aluminum clamps with copper bushings, or vice versa, are employed for this purpose. Care is taken to prevent water dripping from copper items, which may contain copper salts, from coming into contact with aluminum items.

While this discussion applies equally to overhead and underground installations, it must be noted that splices on underground cables, especially where lead-sheath cables are involved, are very much more complex. The connector must be smooth so that no corona discharge will pit the metals. The insulation covering the connector is carried over from one cable to the other by means of insulating tapes wound about the connector. The lead sheath is sweated or soldered to the cable sheaths and is usually larger in diameter. The splice may be filled with an insulating compound, which is heated and poured into the splice, where it hardens on cooling. The new plastic-insulated cables are spliced with a connector between the two conductors and plastic tape of the same material as the insulation wrapped about the assembly; the tape tends to become homogeneous with time.

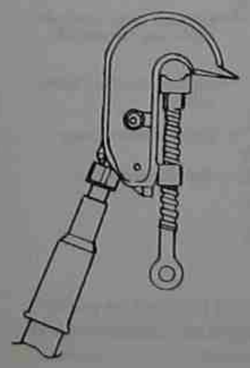


FIG. 9-2 Live-line or "hot-line" clamp. *(Courtesy A. B. Chance Co.)*

OVERHEAD-TO-UNDERGROUND CONNECTION

Connections are often required to be made between overhead and underground conductors. With the advent of plastic-insulated cables, connections have been made directly between the overhead and underground conductors. Live-line clamps furnish a means for easy and rapid disconnection of the conductors involved. Potheads and weatherheads are dispensed with.

In older installations, many of which will continue to exist, special devices have been used. For primary voltages, *potheads* have been used. Here the conductors of the underground cable are connected to terminals in which the conductors are surrounded by poured insulation compound to prevent moisture or air from entering the cable insulation. The overhead wires are connected to the female end of the terminal, enclosed in an insulated cap. The connection is made by placing the cap over the terminal extending from the pothead case. Potheads so described are known as *disconnecting* potheads. Where the connections are made directly to the terminal extending from the pothead in a permanent fashion, the pothead does not carry this distinction.

For lower secondary voltages of 500 V or less, a simpler device was used. Here the conductors of the underground cable are brought out through a preformed insulator, usually of porcelain, in an assembly which inverts the leads so that rain cannot enter the cable. Such devices are known as *weatherheads*. Connection to the overhead wires is made with ordinary connectors of the several types described; see Fig. 9-3.

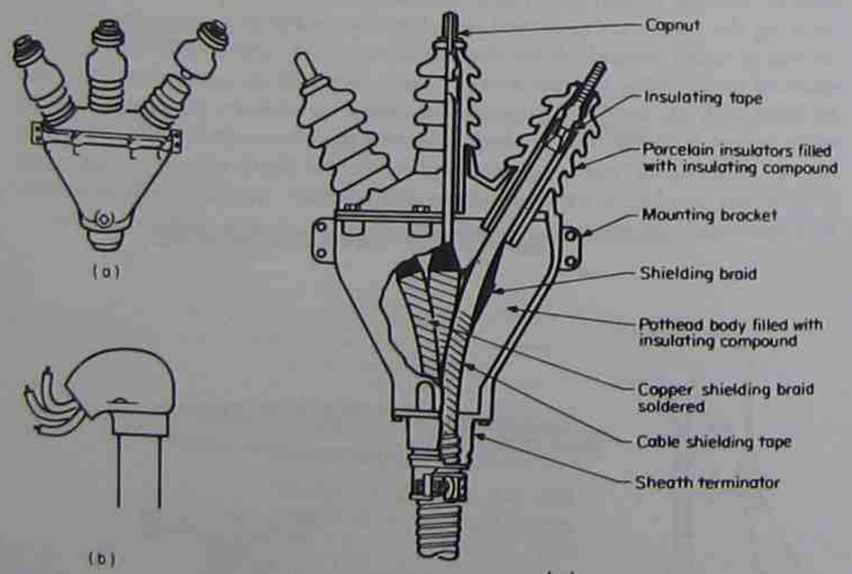


FIG. 9-3 Connection between overhead and underground lines: (*a*) pothead for primary lines; (*b*) weatherhead for secondary lines; (c) cross section of pothead. *(Courtesy G&W Electric Specialty Co.)*

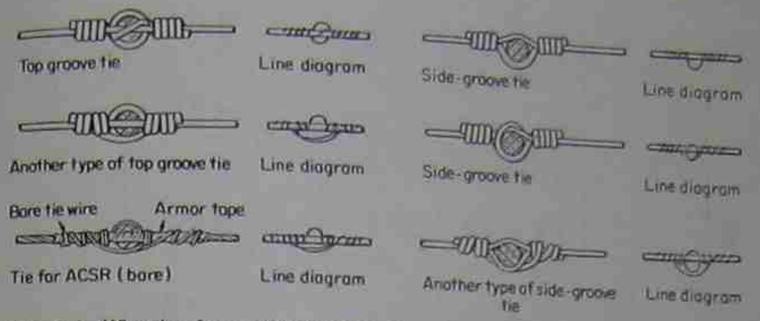


FIG. 9-4 Wire ties for overhead conductors: handmade wire ties. *(Courtesy EEI Overhead Reference Book.)*

TIES

Ties are pieces of wire used to attach the conductors to the insulators on overhead systems. They should be flexible enough to be handled easily, but must be mechanically strong to prevent the conductor from pulling away from the insulator under stress. For bare copper conductors, this tie wire is usually of soft-drawn copper; for weatherproof covered conductors, bare or weatherproof covered wire is used. For aluminum or ACSR conductors, soft-drawn aluminum wire is used. Wire sizes are optional, but are generally small enough to be flexible but strong enough for the purpose. Often such ties are made from old or discarded conductors of small sizes, no. 6 or no. 8 conductor. Where such ties

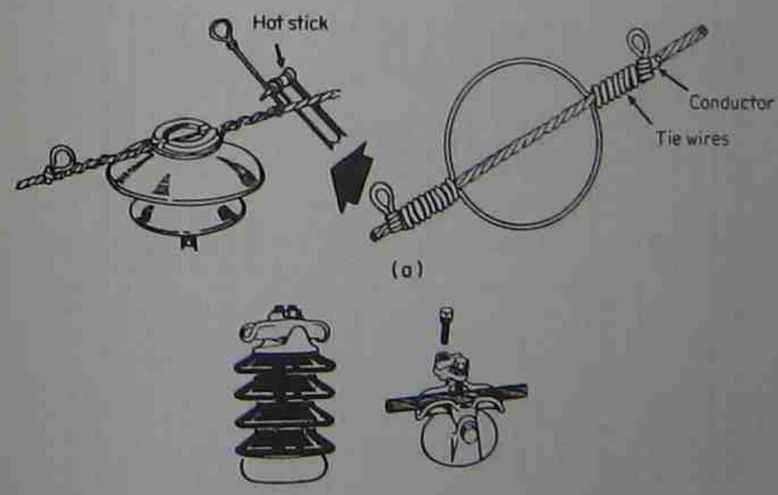


FIG. 9-5 Wire ties for overhead conductors: (*a*) live-line-type tie; (*b*) clamp-type tie. *(Courtesy A. B. Chance Co.)*

TABLE 9-3 INDUCTIVE REACTANCE PER SINGLE CONDUCTOR: COPPER OR ALUMINUM, 60 CYCLE, Ω/1000 ft

	Spacing between conductors, in											
Wire size,	$\frac{3}{4}$	$\frac{1}{2}$	1	2	4	6	8	12	18	24	30	36
Cmil or no. stranded												
1,000,000	—	—	—	0.0377	0.0534	0.0628	0.0693	0.0787	0.0881	0.0947	0.1000	0.1042
750,000	—	—	0.0250	0.0419	0.0568	0.0663	0.0727	0.0823	0.0915	0.0982	0.1025	0.1073
500,000	—	—	0.0286	0.0445	0.0604	0.0696	0.0762	0.0855	0.0948	0.1014	0.1065	0.1107
350,000	—	—	0.0354	0.0487	0.0646	0.0738	0.0803	0.0897	0.0990	0.1055	0.1107	0.1149
250,000	—	—	0.0365	0.0524	0.0683	0.0775	0.0841	0.0934	0.1027	0.1093	0.1144	0.1180
4/0	—	—	0.0384	0.0543	0.0702	0.0794	0.0860	0.0953	0.1046	0.1112	0.1163	0.1205
3/0	—	—	0.0411	0.0570	0.0729	0.0821	0.0887	0.0980	0.1073	0.1139	0.1190	0.1232
2/0	—	—	0.0437	0.0596	0.0755	0.0847	0.0913	0.1006	0.1099	0.1165	0.1210	0.1258
1/0	—	—	0.0464	0.0623	0.0782	0.0874	0.0940	0.1033	0.1126	0.1192	0.1248	0.1285
1	0.0276	0.0342	0.0501	0.0660	0.0819	0.0911	0.0977	0.1070	0.1163	0.1229	0.1280	0.1322
Solid												
2	0.0303	0.0369	0.0528	0.0686	0.0845	0.0938	0.1004	0.1097	0.1990	0.1256	0.1307	0.1348
3	0.0329	0.0395	0.0554	0.0713	0.0872	0.0964	0.1030	0.1123	0.1216	0.1282	0.1334	0.1375
4	0.0356	0.0422	0.0581	0.0740	0.0899	0.0991	0.1057	0.1150	0.1243	0.1309	0.1360	0.1402
6	0.0409	0.0475	0.0634	0.0793	0.0952	0.1044	0.1110	0.1203	0.1296	0.1362	0.1413	0.1455
8	0.0462	0.0528	0.0687	0.0846	0.1005	0.1097	0.1163	0.1256	0.1349	0.1415	0.1466	0.1508

Note: For stranded conductors, the inductance is approximately 0.0013 Ω less than for the same size solid conductors.

From *Overhead Systems Reference Book.*

are handled while the conductors remain energized, ties designed with loops that can be handled with so called hot-line tools or hot sticks are employed. Several types of ties are shown in Figs. 9-4 and 9-5.

For special conditions, especially for live-line operations, clamps that are designed to hold the conductors, but are easily opened, are used. The economics of such clamps, however, are such that they are rarely used. Tie wires are almost universally used.

ELECTRICAL CHARACTERISTICS

Resistance values for the various sizes of conductors are assumed to be the same for ac and dc operation; the skin effect prevalent in ac circuits at the values normally encountered in distribution circuits is small and may be neglected; refer to Table 9-2.

Inductive reactance values, for multiwire circuits, depend on the distance between conductors with respect to each other; these are shown in Table 9-3. For distances between conductors not shown, values of inductive reactance may be interpolated from the values shown.

CHAPTER 10

POLES, CROSS ARMS, PINS, RACKS, AND INSULATORS

WOOD POLES

Overhead distribution lines are almost universally supported on poles made of wood, though concrete and metal (steel and aluminum) are also used.

Kinds of Wood

The kinds of wood used frequently reflect the availability of materials in the different areas of the country. Western red cedar has wide application in western and northern regions, while southern or long-leaf yellow pine predominates in the rest of the country. Large amounts of northern white cedar and chestnut, however, still exist among older installations; limited amounts of Douglas fir may be found in the west and redwood in the far west, while cypress is occasionally used locally in some swampy areas of the southeast. Other woods are sometimes also used in the local areas in which they are produced. For special situations where high strength is required, wallaba may be used, though it is imported from northern South America and is comparatively denser and heavier and more expensive than other woods.

Blight has accounted for the rapid disappearance of chestnut, and northern white cedar has become obsolete not only because of diminished supply, but because it is inclined to be knotty and not very straight, making it harder to handle and work on, while it also does not present the best of appearances. Both chestnut and northern white cedar, however, have relatively long natural lives, and many still exist and may continue in service for some time. Most other woods (and particularly long-leaf yellow pine), however, are more susceptible to decay and must be treated with some kind of preservative to attain an economical life span.

Moisture Absorption

Wood, being porous, has a tendency to absorb moisture, and the moisture content depends on the conditions under which the material is used. Wood exposed to the weather can absorb large amounts of water. Since wood is a hygroscopic substance, it tends to give off or take on water vapor until it comes into equilibrium with the surrounding air; changes in atmospheric humidity produce a continual fluctuation in the moisture content of the wood. The relation of the equilibrium moisture content of wood to the relative humidity of the ambient at three different temperatures is shown in Fig. 10-1.

Decay

Much of the difficulty experienced with wood poles is due to decay, particularly at the ground line. Decay is caused by fungi attacking the wood fibers, and the conditions most favorable to the growth of decay fungi are air, moisture, and heat, with the wood acting as their food supply. In the part of the pole below ground, moisture is usually present but air is in short supply; in the part above ground, the reverse is generally true. At and near the ground line, both of these elements exist in relatively substantial quantities and, hence, this particular area is more subject to decay.

Preservatives

To eliminate, or at least retard, this destructive process, wood poles are first heated in a vacuum to drive out moisture (and to kill some of the fungi) and then treated with a preservative under pressure to fill the pores of the wood fiber; this not only poisons the food supply of the fungi (and insects), but also inhibits the absorption of moisture. Many different preservatives have been employed with varying degrees of effectiveness. No penetration process, however, is completely successful, and so periodic inspection and maintenance of the poles is usually scheduled.

Poles are turned on large lathes to improve their appearance before being subjected to treatment with preservatives for their full length. Preservatives may add as much as 25 percent to the weight per cubic foot of the wood.

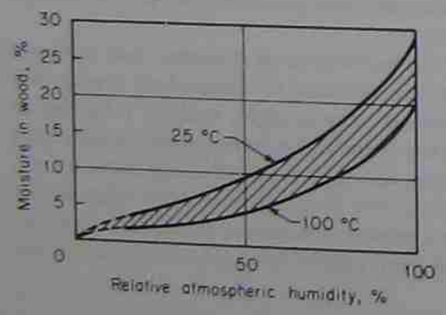


FIG. 10-1 Absorption of atmospheric moisture by wood.

Pole Classification

Pole lengths are standardized and come in increments of 5 ft and range from 20 ft to over 90 ft; for distribution lines, however, lengths are usually limited to from 25 to 55 ft.

The strength of poles depends not only on the material, but on their cross-sectional dimensions. This feature is also standardized and is denoted by "class" numbers, ranging from 00 to 10. For each standard length, the dimensions for each class are defined by standardized circumferences at the top of the pole and at a point 6 ft from the butt or bottom (approximately at the ground line). The top circumference for poles of all of the kinds of wood of the same class is the same; the lower circumference is different for different kinds of wood and determines the taper of the pole. American Standards Association (ASA) standard dimensions are given in Table 10-1 for southern pine, western red cedar, and wallaba poles; also shown are standard depth settings for the several lengths of poles.

Pole Depth Setting

For ordinary soils, depth settings start at 4 ft for 20-ft-length poles and progress to 7½ ft for 55-ft poles; in rock, similar settings range from 3 ft to 5 ft. Pole setting depths for poles over 55 ft increase 0.5 ft for each 5 ft of incremental length, from 8 ft for 60-ft poles to 11 ft for 90-ft poles.

For less resistant soils and other media, deeper settings must be considered, as well as other methods for reinforcing the strength and stability of the pole, such as push braces, cribbing, and guying. Guying is one of the most efficient methods of relieving the pole from some or all of its horizontal load; it has been discussed in Chap. 5.

Pole Strengths

Poles of equal classes will carry equal loads at 2 ft from the top of the pole when set in the ground at standard ASA setting depths. The transverse loads which different class poles will carry are given in Table 10-2.

Some average figures regarding the characteristics of several kinds of wood are shown in Table 10-3.

Pole Framing

In preparing wood poles for use, any cutting or boring is done before the preserving process to eliminate points in which decay may occur. In older poles, a "roof" was cut either in the shape of a gable or at an angle, to prevent snow, ice, and water from accumulating on top and causing decay. Present preserving practices make this unnecessary.

For attaching cross arms, a "gain" cut into the side of the pole, in the form of a channel gouged out to the dimensions of the cross arm, at standard locations on the pole, may be found in older poles. Present practice calls for planing a flat surface on one side of the pole, referred to as a "slab" gain.

TABLE 10-1 ASA STANDARD POLE DIMENSIONS AND DEPTH SETTINGS

Pole length, ft	Depth setting, ft	Wood*	Minimum circumference at 6 ft from butt (approximate ground line), in: Class and minimum top circumference, in: 00 29	0 28	1 27	2 25	3 23	4 21	5 19	6 17	7 15
20	4	P	—	—	31.5	29.5	27.5	25.5	23.5	22.0	20.0
		C	—	—	34.5	32.0	30.0	28.0	25.5	23.5	22.0
		W	32.0	30.0	28.5	26.5	25.0	23.0	21.0	—	—
25	5	P	—	—	34.5	32.5	30.0	28.0	26.0	24.0	22.0
		C	—	—	38.0	35.5	33.0	30.5	28.5	26.0	24.5
		W	35.0	33.0	31.0	29.0	27.0	25.5	23.5	—	—
30	5½	P	—	—	37.5	35.0	32.5	30.0	28.0	26.0	24.0
		C	—	—	41.0	38.5	35.5	33.0	30.5	28.5	26.5
		W	38.0	36.0	33.5	31.5	29.5	27.5	25.5	—	—
35	6	P	45.0	42.5	40.0	37.5	35.0	32.0	30.0	27.5	25.5
		C	49.0	51.5	43.5	41.0	38.0	35.5	32.5	30.5	28.0
		W	40.5	38.0	36.0	33.5	31.5	29.0	27.0	—	—
40	6	P	47.0	44.5	42.0	39.5	37.0	34.0	31.5	29.0	27.0
		C	51.0	48.5	46.0	43.5	40.5	37.5	34.5	32.0	—
		W	42.5	40.5	38.0	35.5	33.5	31.0	28.5	—	—
45	6½	P	50.0	47.0	44.0	41.5	38.5	36.0	33.0	30.5	28.5
		C	54.0	52.0	48.5	45.5	42.5	39.5	36.5	—	—
		W	45.0	42.5	40.0	37.5	35.0	32.5	30.0	—	—
50	7	P	—	—	46.0	43.0	40.0	37.5	34.5	32.0	29.5
		C	—	—	50.5	47.5	44.5	41.0	38.0	—	—
		W	46.5	44.0	41.5	39.0	36.5	34.0	31.5	—	—
55	7½	P	—	—	47.5	44.5	41.5	39.0	36.0	33.5	—
		C	—	—	52.5	49.5	46.0	42.5	39.5	—	—
		W	48.5	46.0	43.0	40.5	38.0	35.0	32.5	—	—
60	8	P	—	—	49.5	46.0	43.0	40.0	37.0	34.5	—
		C	—	—	54.5	51.0	47.5	44.0	—	—	—
		W	50.0	47.5	44.5	42.0	39.0	36.5	33.5	—	—
65	8½	P	—	—	51.0	47.5	44.5	41.5	38.5	—	—
		C	—	—	56.0	52.5	49.0	45.5	—	—	—
70	9	P	—	—	52.5	49.0	46.0	42.5	39.5	—	—
		C	—	—	57.5	54.0	50.5	47.0	—	—	—
75	9½	P	—	—	54.0	50.5	47.0	44.0	—	—	—
		C	—	—	59.5	55.5	52.0	48.5	—	—	—
80	10	P	—	—	55.0	51.5	48.5	45.0	—	—	—
		C	—	—	61.0	57.0	53.5	49.5	—	—	—
85	10½	P	—	—	56.5	53.0	49.5	—	—	—	—
		C	—	—	62.5	58.5	54.5	—	—	—	—
90	11	P	—	—	57.5	54.0	50.5	—	—	—	—
		C	—	—	63.0	60.0	56.0	—	—	—	—

*P = yellow pine; C = western red cedar; W = wallaba.

TABLE 10-2 STANDARD MAXIMUM HORIZONTAL FORCE THAT CAN BE APPLIED TO CLASSES OF POLES*

Pole class	Load resistance 2 ft from top (approximate load that pole must withstand), lb	Increment between class numbers
10	(No specifications)	—
9	900	—
8	1000	100
7	1200	200
6	1500	300
5	1900	400
4	2400	500
3	3000	600
2	3700	700
1	4500	800
0	5400	900
00	6400	1000

*At standard depth settings.

Dielectric Value of Wood

Wood offers a marked resistance to the passage of an electric current and, at least for lower voltages, may be classed as a nonconductor. Its dielectric strength varies with the different species and is greater across the grain than along the grain; changes in temperature affect the dielectric strength substantially, approximately doubling with each decrease of 22.5°F or 12.5°C. The most significant variation, however, takes place with changes in moisture content: as wood dries from fiber saturation to the vacuumed oven-dry condition, its dielectric value approaches infinity. Preservatives, however, have great influence on the dielectric strength of the wood, especially those consisting of chlorides; older poles treated with creosote and its derivatives have been found to experience

TABLE 10-3 CHARACTERISTICS OF VARIOUS WOODS

Wood	Weight, lb/ft^3	Ultimate strength, lb/in^2
Northern white cedar	23	3,600
Redwood	24	4,400
Cypress	29	4,800
Western red cedar	23	5,600
Chestnut	41	6,000
Southern yellow pine	35	7,400
Douglas fir	32	8,000
Wallaba	—	11,000
Locust	—	12,800

little change in dielectric strength as a result of the treatment. As the wood seasons, the effect of still more aging on its dielectric strength diminishes and ceases to be serious in the period of a year or so. Although the wood of poles (and cross arms) aids in the insulation of line conductors from each other and from grounds, it is not to be relied upon where safety to the public and workers is concerned.

Life Expectancy

The life of wood poles, under "normal" conditions of soil and weather, when they are treated and maintained with reasonably effective preservatives, has been estimated to be from 25 years to over 100 years. These figures have been used in making economic studies, in establishing sinking funds for the retirement of poles (and other wood structures), and in designing pole lines calling for considerably larger and stronger poles than initially necessary. In view of the continuing changes in consumer requirements, in civic and traffic requirements, and in the materials and methods employed in providing electric service, the higher longevity considerations (100 years, or even 50 years) appear to be somewhat unrealistic.

CONCRETE AND METAL POLES

General

Concrete and metal poles are at present not used extensively for distribution purposes in the United States. They are, however, used extensively in Europe and other lands where woods suitable for poles are not readily or economically available. Concrete and metal poles are usually used where great strength and appearance are paramount requirements; concrete poles are made in several colors and finishes. Both concrete and metal poles come in cross sections that are circular, square, or polygonal (usually six- or eight-sided). Both allow electrical risers to be installed in the hollow space within them.

Access to Pole-Top Facilities

The problem of access to the facilities at the top of concrete and metal poles has been met by the use of pole steps, whether they are installed permanently, or whether means are provided for their temporary installation. The permanent installation of steps is frowned upon from considerations of safety; their temporary installation is time-consuming, as well as similarly unsafe, as such steps can be installed by unauthorized people. This contrasts with the safety provided by wood poles, where skilled and trained workers, employing climbers, essentially eliminate this unauthorized access by the general public. The widespread use of bucket-type trucks that enable access to pole-top facilities has essentially eliminated the need of climbing, as well as the need for the installation of steps on the pole. Hence, this means has become common to all types of poles.

CONCRETE POLES

Manufacture

Concrete poles are manufactured with hollow cores to reduce their weight, which has been (and still is) a disadvantage, especially when they are handled in the field. Reinforcing steel strands are installed longitudinally for the full length of the pole and prestressed before the concrete is placed; reinforcing steel strands are also installed, essentially at right angles to the longitudinal reinforcing strands, usually as special coils wrapped around and welded to them in a manner to prevent movement during concrete casting. See Fig. 10-2.

In addition to their heavier weight (compared with wood), concrete poles are relatively more expensive, another reason for their lessened usage. Representative data on the characteristics of hollow round and square reinforced concrete poles are contained in Appendix 10A at the end of this chapter.

All concrete poles are tapered, and the square ones have chamfered corners. All provide cable entrance openings and hand holes to permit the installation of electric riser cables in their hollow cores.

Advantages

Concrete poles are not adversely affected by wet or dry rot, birds (especially woodpeckers), fire, rust, or chemicals (such as fertilizers and salt spray). Besides being stronger and more rigid than wood, they are essentially maintenance-free;

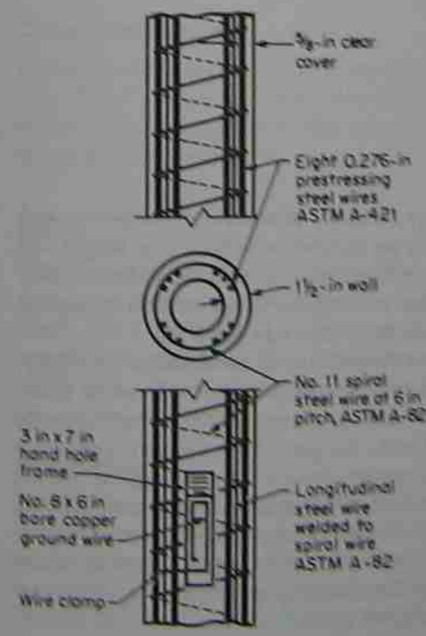


FIG. 10.2 Typical reinforced concrete hollow pole section. (Courtesy Centrecon, Inc.)

ground moisture and weather, which work against other types of poles, work in favor of concrete, hardening, toughening, and protecting its integrity. Considering the potential lifespans, concrete claims the lowest cost per year.

METAL POLES

Metal poles are manufactured according to specifications drawn up for particular uses; their length and the thickness of the metal employed depend on their use and the desired strength. They are tapered and come in the same shapes as concrete poles—round, square, and polygons. They may also include provision for pole steps. Though generally of the color of the metal of which they are made, they may be painted in specified colors. They may be buried directly in the ground, set directly in bases of concrete, or bolted to metal base plates permanently set in concrete.

CROSS ARMS

Cross arms are the most common means of supporting distribution conductors on poles. Although they are being used less frequently, their use will persist for some time.

Standard Arms

Standard cross-section dimensions for wood cross arms (width by height) are:

$3\frac{1}{4}$ in by $4\frac{1}{4}$ in

$3\frac{1}{2}$ in by $4\frac{1}{2}$ in

$3\frac{3}{4}$ in by $4\frac{3}{4}$ in

4 in by 5 in

Of these, the first two are most commonly used for distribution purposes, and usually only one of these will be stocked by an individual utility. The larger size finds greater use in the harsher northern and western climates, while the smaller finds use in the south and southwest. The rectangular cross section is slightly rounded or "roofed" on the top surface to shed rain and snow.

The length of the cross arm depends on the number of conductors it is to support and the spacing between them. Standard cross arms include two-, four-, six-, and eight-pin arms, although the four- and six-pin arms, 8 ft in length, are the more widely used. Spacing between pins for the six-pin 8-ft arm is standardized at $14\frac{1}{2}$ in, except for the space between the two center pins, the "climbing space" for the lineman's safety; for primary voltages up to 15,000 V, this climbing space is 30 in, and for voltages above that value it is 36 in (with spacing between the six pins reduced to 13 in). Spacing between pins for the four-pin 8-ft cross arm is 26 in, with a space between the two center pins of 36 in, the climbing space. See Fig. 10-3. Vertical spacing between cross arms is standardized at 2 ft.

Both Douglas fir and southern yellow pine are used for cross arms because

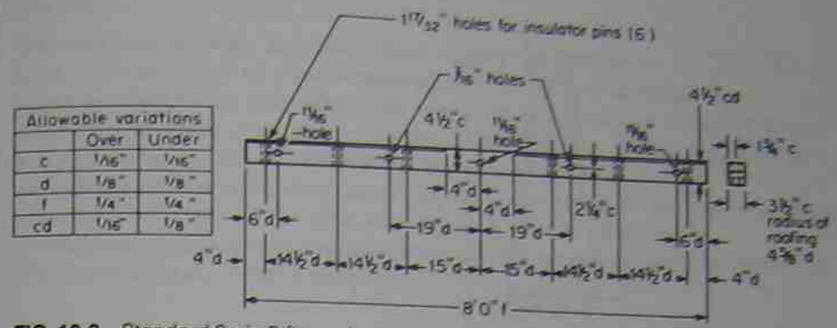


FIG. 10-3 Standard 6-pin 8-ft wood cross arm. *(From Overhead Systems Reference Book.)*

of their comparatively high bending strengths and their durability. Both are treated with preservatives after holes for pins and bolts have been bored in them. Their insulating properties are similar to those described for wood poles.

Steel Cross Arms

Cross arms made of steel are used where stresses are very large and cannot be accommodated by other means such as double arms or arm guys; they do not have the insulating property that wood cross arms have.

Cross-Arm Braces

Galvanized flat steel braces are used to provide strength and rigidity to the cross arm. They are usually attached to the cross arm by means of carriage bolts and to the pole by a lag screw. For heavier loads, a one-piece vee-shaped angle-iron brace is sometimes used.

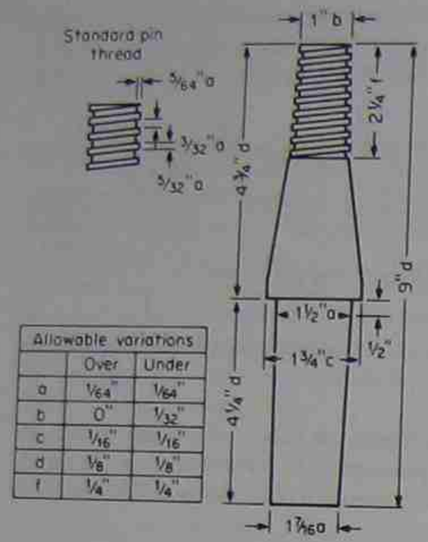
PINS

Pins are used to hold the insulators to which conductors are fastened. They may be made of wood, usually locust because of its strength and durability (refer to Table 10-3, p. 291), or of iron or steel where greater strength or extra-long lengths are required. Pins fastened to cross arms are made of wood or steel, while those fastened directly to poles are made of steel.

Wood Pins

Wood pins are generally made of yellow or black locust, having an ultimate fiber bending strength of about 10,000 lb/in^2. They are standardized in the dimensions of the pin and in the threads which accommodate the insulators. Where greater strength is required, galvanized metal pins having an ultimate fiber strength of 50,000 lb/in^2 for malleable iron and 60,000 lb/in^2 for steel are used.

Standard locust pins are 9 in. in length, with a shank $1\frac{1}{4}$ in. in diameter that



Allowable variations		
	Over	Under
a	1/64"	1/64"
b	0"	1/32"
c	1/16"	1/16"
d	1/8"	1/8"
f	1/4"	1/4"

FIG. 10-4 Standard wood pin. *(From Overhead Systems Reference Book.)*

fits into the cross-arm hole. A $1\frac{3}{4}$ in shoulder above this shank tapers to a 1-in-diameter part $2\frac{1}{4}$ in long, which is threaded to receive the insulator; refer to Fig. 10-4.

Steel Pins

Steel pins have many shapes; some are designed to be bolted through the cross arm, others to be clamped around the arm; while others are designed to be bolted directly to the top of the pole. The steel pins may vary in length, and some may also be of hollow core section. Several types of steel pins are shown in Fig. 10-5.

Long steel pins with angle bases, bolted to the side of the pole, serve to replace the cross arm in supporting conductors, making for a more streamlined, stronger, better-appearing line; refer to Fig. 5-13 in Chap. 5.

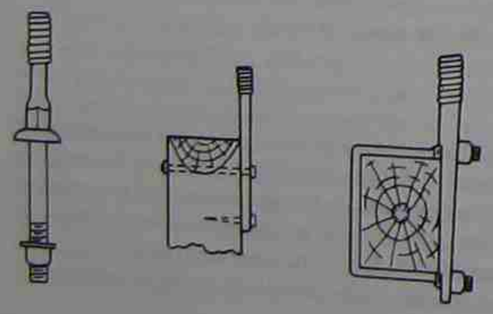


FIG. 10-5 Typical steel pins. *(Courtesy A. B. Chance Co.)*

RACKS

Secondary conductors, for many years supported horizontally on wood cross arms, were relocated to a lower position on the pole and mounted vertically on a rack attached to the pole. They make for a better appearance and are stronger and less costly than cross arms; and the wires being in a vertical plane, service wires running in different directions do not cross each other. With this design the worker on the secondary conductors and services need not approach the primary conductors on the pole, making for a safer work method.

Many secondary-service installations on cross arms and on racks still exist and will continue to do so for a long time.

Multispool Racks

Racks, made of galvanized steel, are attached to the pole by one or more through bolts, some of which may be replaced by lag screws where loadings permit. The racks support insulators, spaced 6 or 8 in apart (although some may have a 4-in spacing), to which the conductors are attached. The conductors may be attached to a number of individual single-insulator racks, or to one rack containing several insulators. The insulators may be of the spool or knob type, as shown in Fig. 10-6.

Single-Spool Racks

Single-spool racks are also manufactured; on these, each insulator is bolted individually to the pole. While spool-type insulators are the more frequently used type, knob-type insulators are also used.

Cabled Secondary Mains and Services

The rack has been supplanted in many instances by a single uninsulated clamp attached to the pole and supporting the secondary mains. Here, the conductors are cabled around a neutral wire, which also acts as a messenger wire carrying the conductors. A similar type of cabled conductor is used for services, with the

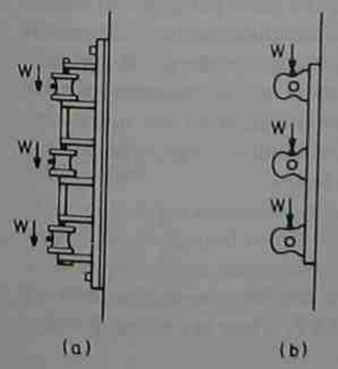


FIG. 10-6 Typical secondary rack: (*a*) spool type; (*b*) knob type. *(Courtesy McGraw Edison Co.)*

neutral-messenger supporting the conductors from the pole to the consumer's premises.

INSULATORS

Materials

Insulators, placed between energized conductors and the supporting structures, are now almost universally made of porcelain, although a great many glass insulators are still in service and will be for a long time. Fiberglass, epoxy, and other plastics are now beginning to be used in the manufacture of insulators.

Glass Glass insulators, made in a variety of shapes and sizes, are electrically and mechanically adequate and very economical. Their usage, however, has been generally limited to circuits operating at voltages under 5 kV, principally because of their relatively (compared to porcelain) low resistance to shock and high coefficient of expansion. While the dielectric properties of glass may vary considerably depending on its particular treatment, its mechanical properties are reasonably consistent. Its tensile strength is usually less than 10,000 lb/in^2; its minimum compressive strength is 50,000 lb/in^2; its modulus of elasticity is 10,000,000 lb/in^2; and its coefficient of expansion is 400 to 600 $\times$ 10^{-6} per degree Fahrenheit, or 720 to 1080 $\times$ 10^{-6} per degree centigrade.

Pyrex, a form of glass, partially overcomes the two deficiencies concerning shock and temperature changes, but its relatively high cost restricts its application generally to high-voltage transmission lines.

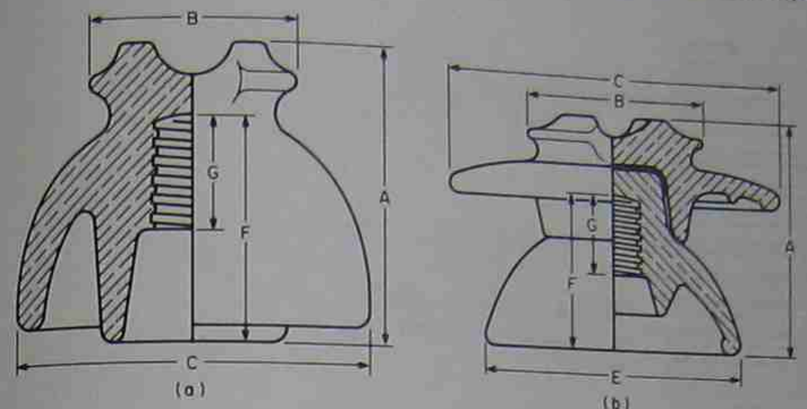
Porcelain Porcelain is made from white clay to which powdered feldspar and silica are added. The material has greater (compared to glass) ability to resist sudden changes in temperature, and an external glaze protects it from shock. Depending on how insulators are manufactured, the tensile strength of the porcelain may vary from less than 2000 lb/in^2 to as much as 9000 lb/in^2, and the corresponding minimum compressive strengths, from 15,000 to 60,000 lb/in^2; its coefficient of expansion may be as low as 16.6 $\times$ 10^{-6} per degree Fahrenheit, or 30 $\times$ 10^{-6} per degree centigrade. The dielectric strength generally exceeds 16 kV/mm (16,000 kV/m), or some 400 kV/in.

Porcelain insulators are made by two processes: the "wet process," in which the insulation is molded, and the "dry process," in which the insulation is pressed into shape in steel molds. The dry-process insulator has less electrical and mechanical strength, but is also less expensive; it is more apt to puncture under electrical stress rather than to flash over. Dry-process insulators are more economical, however, and their use is generally limited to lower-voltage applications.

The principal types of insulators are described below.

Pin-Type

Pin-type insulators may be constructed in one piece for voltages to about 35 kV and in two or three pieces from that voltage to 69 kV. They are shaped with a groove on top in which the conductor lies and is tied in place; they may also have a groove around the sides in which the conductor is placed and tied. The side groove is generally used where the line turns and the conductor imposes strains on the side. Both glass and porcelain insulators are shaped so as to provide a long path from the line conductor to the point of support where the insulator is screwed to the pin, usually considered a ground. Several ridges on the underside extend this path so that, figuratively, the insulator may be described as having an outside skirt and a number of inner petticoats; see Fig. 10-7. Though constructed in a variety of shapes, colors, and ratings, all types of pin insulators share a common standard in the diameter, shape, and number of insulator threads per inch, a standard that matches that of the pins with which they are usually associated.



	Max.	Min.
A	4 1/2	3 1/4
B	3	2 1/2
C	6 1/2	4 1/4
F	3 3/8	2 3/8
G	2	1 1/2

	Max.	Min.
A	6	5 3/8
B	5	4 1/2
C	9	9
E	7	7
F	4 1/8	3 3/4
G	2	1 7/8

FIG. 10-7 Typical pin-type porcelain insulators: (*a*) one-piece 11- to 15-kV pin insulator; (*b*) two-piece 33-kV pin insulator. *(From Overhead Systems Reference Book.)*

Post-Type

The post-type insulator is a variation of the pin-type insulator, in which the porcelain is shaped into a cylindrical block with its surface corrugated horizontally to provide a long path from the conductor to the point of support; grooves for the attachment of the conductor are provided at the top of the insulator; see Fig. 10-8.

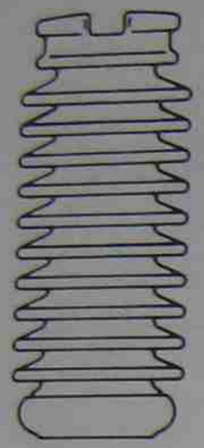


FIG. 10-8 Typical post-type porcelain insulator. *(Courtesy Ohio Brass Co.)*

Suspension- or Strain-Type

The suspension- or strain- (or string-) type insulator consists of a porcelain disk contained between a ball-and-socket (or clevis-and-pin, or other) arrangement so that the porcelain is in compression; each disk has certain electrical and mechanical characteristics. The ball-and-socket arrangement permits units to be added to each other in a string, thus accommodating higher voltages. Several such strings can be connected mechanically in "parallel" to achieve necessary strength requirements. Disks vary in diameter from about 5 to 10 in, with standard vertical distances between ball and socket (or other components) of $4\frac{3}{4}$ and $5\frac{3}{4}$ in, and are rated for an allowable tension of 12,000 lb. See Fig. 10-9.

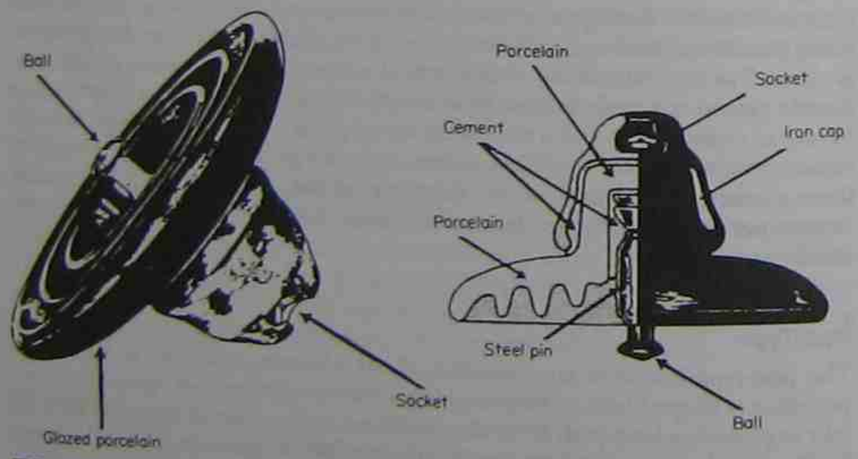


FIG. 10-9 Typical suspension or strain-type porcelain insulator. *(Courtesy Locke Insulator Co.)*

Spool-Type

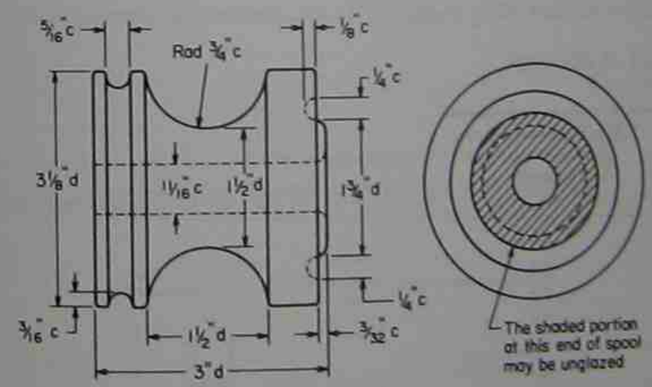
Spool-type insulators are used with secondary racks or in service brackets to support secondary mains and services; they come in two different sizes and colors for identification purposes. See Fig. 10-10.

Strain-Ball Type

The strain-ball insulator is generally employed in guys to insulate the upper part from the lower part; the lower part is insulated to protect people on the ground, while the upper part is insulated from the ground to protect the lineman on the pole. In some instances involving wye circuits with a common primary and secondary grounded neutral, this insulator is sometimes not inserted in the guy wire. The insulator consists of a ball or block of porcelain in which two transverse holes at right angles to each other contain the guy wires so arranged that the porcelain is always under compression. See Fig. 10-11. This type of insulator is also used to dead-end smaller conductors at the cross arm where the operating voltage is less than 5000 V.

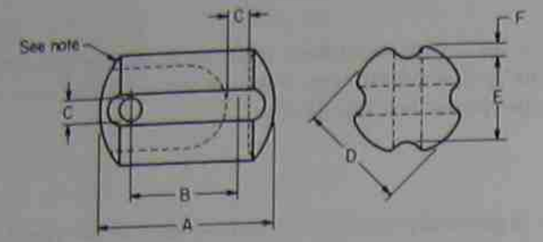
Other Types

Other insulator types include the knob types sometimes used with secondary racks, previously described; and various other shapes for use as bushings, bus and service supports, and other specific purposes. Where porcelain is used, it is always designed to be under compression.



Allowable variations		
	Over	Under
c	1/16"	1/8"
d	1/8"	1/16"

FIG. 10-10 Typical spool porcelain insulator for secondary rack. Material: porcelain. Finish: brown glazed. *(From Overhead Systems Reference Book.)*



Trade no.	A	B	C	D	E	F	Strength in compression
502	3¼" f	1¾" f	7/16" c	2½" d	1¾" f	5/16" c	10,000 lb
504	3⅜" f	2¼" f	9/16" c	2⅞" d	2⅛" f	⅜" c	12,000
506	5¼" f	3⅛" f	¾" c	3⅜" d	2⅜" f	½" c	15,000

Allowable variation		
	Over	Under
c	1/16"	1/16"
d	⅛"	⅛"
f	¼"	¼"

FIG. 10-11 Typical strain-ball-type porcelain insulator. Material: porcelain, wet process. Finish: brown glazed. *Note:* One end of insulator may be unglazed. *(From Overhead Systems Reference Book.)*

TEST VOLTAGES

Nominal ratings of insulators include not only their operating voltage, but flashover values as well. Flashover values depend in general on the leakage distances provided between the conductor and the point of attachment to the support. These values, however, may be subject to other factors, including local atmospheric and environmental conditions, types of support, maintenance programs, etc. Typical minimum flashover voltage values are contained in Table 10-4.

TABLE 10-4 TYPICAL FLASHOVER VOLTAGE REQUIREMENTS

Nominal voltage (between phases), kV	*Minimum rated dry flashover voltage of insulators, kV**
0.75	5
2.4	20
6.9	39
13.2	55
23.0	75
34.5	100
46.0	125
69.0	175

*Interpolate for intermediate values.

For current industry recommended values, refer to the latest revision of the National Electric Safety Code.

APPENDIX 10A CONCRETE DISTRIBUTION POLES: REPRESENTATIVE SPECIFICATIONS*

SCOPE

These specifications apply to the manufacture of machine-made, pretensioned, prestressed concrete distribution poles, designed in accordance with recommendations of the American National Standards Institute (ANSI).

SHAPE

The poles shall be single, hollow, round or square cross section, with a taper of 1 to 150. They shall have a uniform nominal wall thickness of 1½ in as shown in Fig. 10-12.

DIMENSIONS AND STRENGTH

Round Poles

The dimensions and strength of the round poles shall be as shown in Table 10-5. The poles shall be grouped into seven classes based on the design ultimate strength as given in Table 5-22 in Chap. 5.

Square Poles

The dimensions and strength of the square poles shall be as shown in Table 10-6.

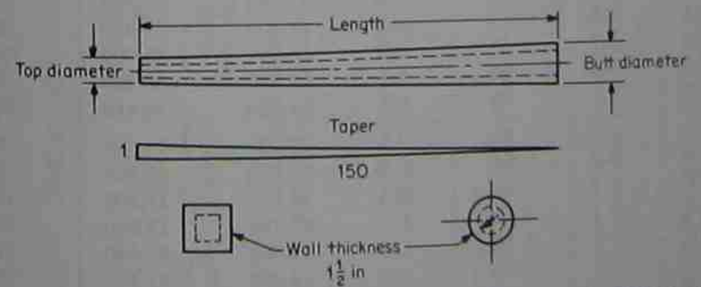


FIG. 10-12 Typical reinforced concrete hollow distribution pole. *(Adapted from Centrecon, Inc.)*

*Adapted from data furnished by Centrecon, Inc., and by Concrete Products, Inc.

TABLE 10-5 DIMENSIONS AND STRENGTHS—ROUND HOLLOW CONCRETE POLES

Overall length		Class	Setting depth,	Top diameter,	Butt diameter,	Design ultimate moment,	Allowable moment—SF = 2,	Nominal weight,
m	ft-in		ft-in	in	in	ft · lb	ft · lb	lb
12	39-4	A	5-11	7½	13½	100,530	50,260	2540
13	42-8	A	6-3	7½	14⅛	110,130	55,060	2830
14	45-11	A	6-7	7½	14½	119,470	59,730	3130
15	49-2	A	6-11	7½	15⅛	128,800	64,400	3470
16	52-6	A	7-3	7½	15½	138,400	69,200	3800
12	39-4	B	5-11	7½	13½	84,830	42,410	2480
13	42-8	B	6-3	7½	14⅛	92,930	46,460	2760
14	45-11	B	6-7	7½	14½	100,800	50,400	3060
15	49-2	B	6-11	7½	15⅛	108,680	54,340	3380
16	52-6	B	7-3	7½	15½	116,780	58,390	3710
9	29-6	C	4-11	6½	11⅞	50,810	25,400	1520
10	32-10	C	5-3	6½	11½	57,560	28,780	1770
11	36-1	C	5-7	6½	12⅞	64,130	32,060	2010
12	39-4	C	5-11	7½	13½	70,690	35,340	2430
13	42-8	C	6-3	7½	14⅛	77,440	38,720	2710
14	45-11	C	6-7	7½	14½	84,000	42,000	3000
15	49-2	C	6-11	7½	15⅛	90,560	45,280	3310
16	52-6	C	7-3	7½	15½	97,310	48,650	3640
9	29-6	D	4-11	6½	11⅞	41,780	20,890	1490
10	32-10	D	5-3	6½	11½	47,330	23,660	1720
11	36-1	D	5-7	6½	12⅞	52,730	26,360	1960
12	39-4	D	5-11	7½	13½	58,120	29,060	2390
13	42-8	D	6-3	7½	14⅛	63,670	31,840	2670
14	45-11	D	6-7	7½	14½	69,070	34,540	2960
15	49-2	D	6-11	7½	15½	74,460	37,230	3260
16	52-6	D	7-3	7½	15½	80,010	40,000	3570
9	29-6	E	4-11	6½	11⅞	33,870	16,930	1470
10	32-10	E	5-3	6½	11½	38,370	19,180	1700
11	36-1	E	5-7	6½	12⅞	42,750	21,370	1930
12	39-4	E	5-11	7½	13½	47,130	23,560	2360
13	42-8	E	6-3	7½	14⅛	51,630	25,810	2640
14	45-11	E	6-7	7½	14½	56,000	28,000	2930
15	49-2	E	6-11	7½	15½	60,380	30,190	3220
16	52-6	E	7-3	7½	15½	64,880	32,440	3530
9	29-6	F	4-11	6½	11⅞	27,100	13,550	1460
10	32-10	F	5-3	6½	11½	30,700	15,350	1680
11	36-1	F	5-7	6½	12⅞	34,200	17,100	1920
12	39-4	F	5-11	6½	13	37,700	18,850	2160
13	42-8	F	6-3	6½	13½	41,300	20,650	2410
14	45-11	F	6-7	6½	14⅛	44,800	22,400	2680
15	49-2	F	6-11	6½	14½	48,300	24,150	2960
9	29-6	G	4-11	6½	11⅞	21,450	10,720	1460
10	32-10	G	5-3	6½	11½	24,300	12,150	1670
11	36-1	G	5-7	6½	12⅞	27,080	13,540	1900
12	39-4	G	5-11	6½	13	29,850	14,920	2150
13	42-8	G	6-3	6½	13½	32,700	16,350	2400
14	45-11	G	6-7	6½	14⅛	35,470	17,730	2660
15	49-2	G	6-11	6½	14½	38,240	19,120	2930

Courtesy Centricon, Inc.

TABLE 10-6 DIMENSIONS AND STRENGTHS—SQUARE HOLLOW CONCRETE POLES

Overall pole length, ft	Pole size—tip/butt, in	E.P.A., ft²		Ultimate ground-line moment, ft · lb	Breaking strength load 2 ft. below tip, lb	Deflection per 100 ft · lb, in	Deflection limitations, ft · lb	Pole weight, lb
		Concrete strength, lb/in²						
		6000, standard	7000, when specified					
25	7.6/11.65	43.3	45.3	84,000	4540	0.03	4100	2260
30	7.6/12.46	38.7	40.7	132,000	5740	0.03	5000	2880
35	7.6/13.27	33.8	36.2	147,000	5350	0.03	5900	3600
40	7.6/14.08	29.4	31.7	163,000	5090	0.03	6800	4370
45	7.6/14.89	25.7	28.1	178,000	4880	0.06	3850	5225
50	7.6/15.70	22.3	24.7	193,000	4710	0.06	4300	6160
55	7.6/16.51	19.1	21.7	209,000	4590	0.06	4750	7270

Glossary of Terms

E.P.A. Effective projected area, in square feet of transformers, capacitors, streetlight fixtures, and other permanently attached items which are subject to wind loads.

Concrete strength This is a reference to the compressive strength of the concrete in pounds per square inch as measured by testing representative samples 28 days after casting.

Ultimate ground-line bending moment This is the bending moment applied to the pole which will cause structural failure of the pole. This is the result of multiplying the load indicated in the column Breaking Strength by a distance 2 ft less than the pole height (i.e., 2 ft less than the length of pole above ground). Figures under Ultimate Ground-Line Moment assume embedment of 10 percent of the pole length plus 2 ft. The figures in this column on technical charts are maximum moments expected to be applied to the pole. Appropriate safety factors should be used by the designer.

Breaking strength This is the approximate load which, when applied at a point 2 ft below the tip of the pole, will cause structural failure of the pole.

Ground line The point at which an embedded pole enters the ground or is otherwise restrained.

Deflection The variation at the tip of the pole from a vertical line resulting from the application of loads such as equipment, wind, ice, etc.

Ground-line bending moment The product of any load applied at any point on the pole multiplied by its height above ground line.

Dead loads This refers to the load on a pole resulting from the attachment of transformers and other equipment permanently.

Live loads These are loads applied to the pole as a result of wind, ice, or other loads of a temporary nature.

Ultimate Strength

The design ultimate strengths are determined to meet the working strength requirement of wood poles in accordance with the ASA *Specifications and Dimensions for Wood Poles*. The factor of safety of 2 shall be used for prestressed concrete poles.

COLORS AND FINISHES

The poles shall be furnished in colors and finishes specified by the buyer. Colors shall be white, gray, buff, green, brown, and black. Finishes shall be Mold Finish; Natural Aggregate, exposed or polished; or Terrazzo Aggregate, exposed or polished. Other finishes will be furnished on request.

MATERIALS

Cement

The cement used for the concrete shall be portland cement, type I, II, or III, conforming to ASTM designation C-150.

Aggregates

The concrete shall be made with fine and coarse aggregates conforming to ASTM designation C-33.

The fine aggregates shall be graded from $\frac{3}{8}$ in to no. 100 sieve, with 100 percent passing the $\frac{3}{8}$-in sieve and not more than 10 percent passing the no. 100 sieve.

The maximum-size coarse aggregate shall not exceed one-fifth of the minimum dimension of the member nor three-fourths of the clear spacing between the prestressed wires. The maximum size of coarse aggregate to be used shall conform to the smaller of the two limitations mentioned above.

Water

The water used for mixing concrete shall be clean and free of injurious quantities of substances (acid, alkalines, oil, and vegetable matter) deleterious to concrete or to prestressing steel.

Admixture

The admixture used for the concrete shall conform to ASTM C-494, and shall not contain more than a trace of calcium chloride.

Reinforcement

The prestressing steel wire shall conform to ASTM A-421 with the strengths as noted in the following table.

Diameter	*Yield strength*	*Tensile strength*
9 mm (0.354 in)	192,000 lb/in^2	220,500 lb/in^2
7 mm (0.276 in)	177,000 lb/in^2	206,200 lb/in^2

The reinforcing steel wire used for main reinforcement and spiral reinforcement shall conform to ASTM A-82.

Embedded Materials

The embedded materials, such as sleeves for through holes, sockets for step bolts, and other inserts, will be corrosion-resistant and weatherproof.

GENERAL REQUIREMENTS

Design Ultimate Strength

The design ultimate strength for each class of pole shall be as given in Table 5-22 (in Chap. 5) for round poles and in Table 10-6 for square poles.

Through Holes

The through-hole spacing and sizes for framing shall be as shown in Fig. 10-13*a*, *b*, and *c* for round poles and Fig. 10-14 for square poles.

Step Bolts

Each pole may have provisions (if specified) for installing step bolts to gain access to, and perform work on, the poles as shown in Fig. 10-13*a*, *b*, and *c* as well as Fig. 10-14.

Grounding Wire Exits

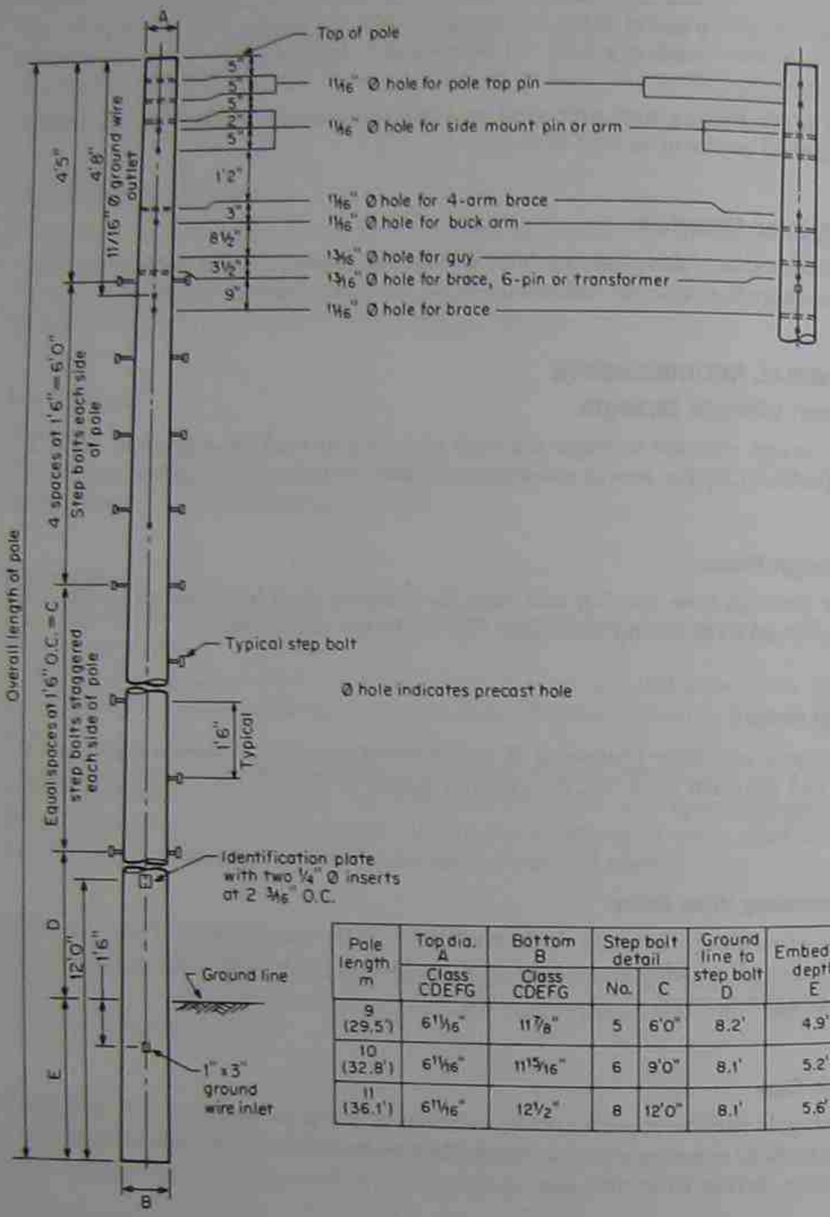
The grounding wire exits shall be as shown in the specifications. Fish wire shall be attached to poles at the time of manufacture to facilitate ease in installation of grounding wire.

Pole Cap

Each pole shall have permanently attached to its top an insulating pole cap. This cap shall be constructed of a nonconductive material that will not become conductive during its service life.

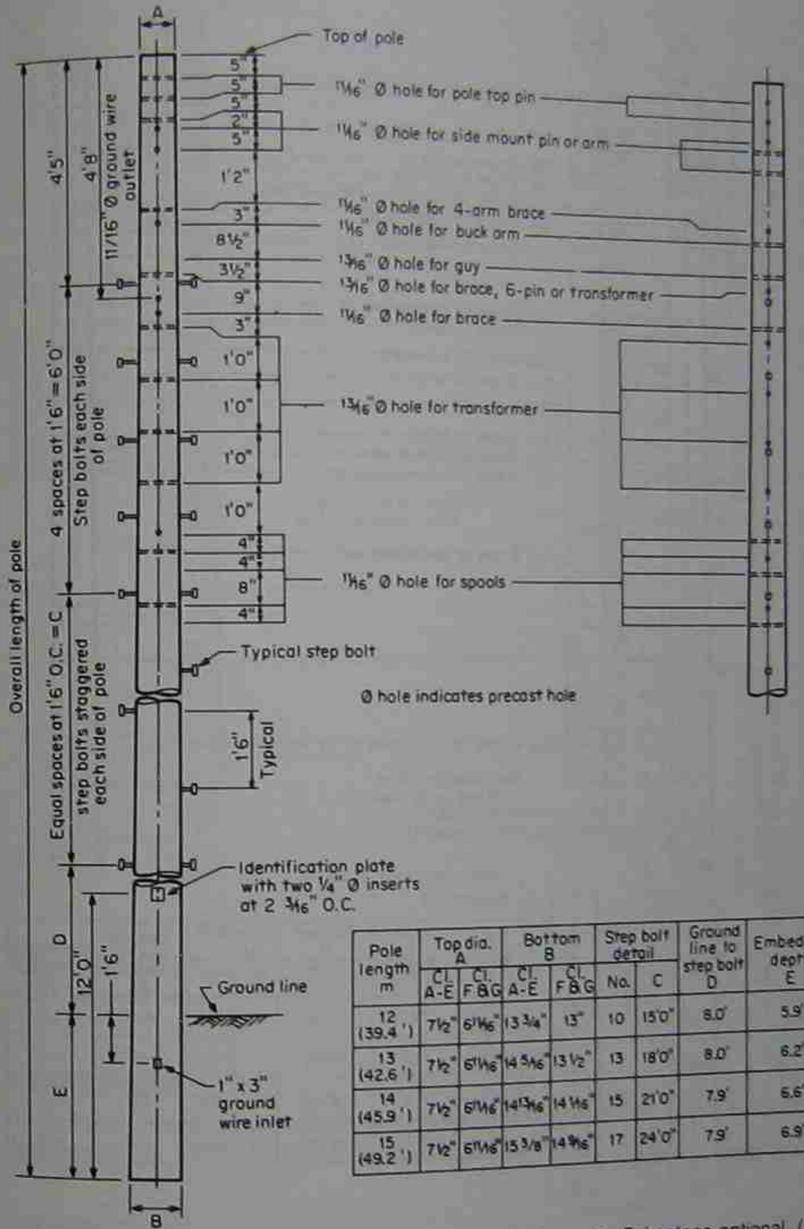
Butt Cap

Each pole manufactured under this specification shall have permanently attached thereto a concrete butt cap.



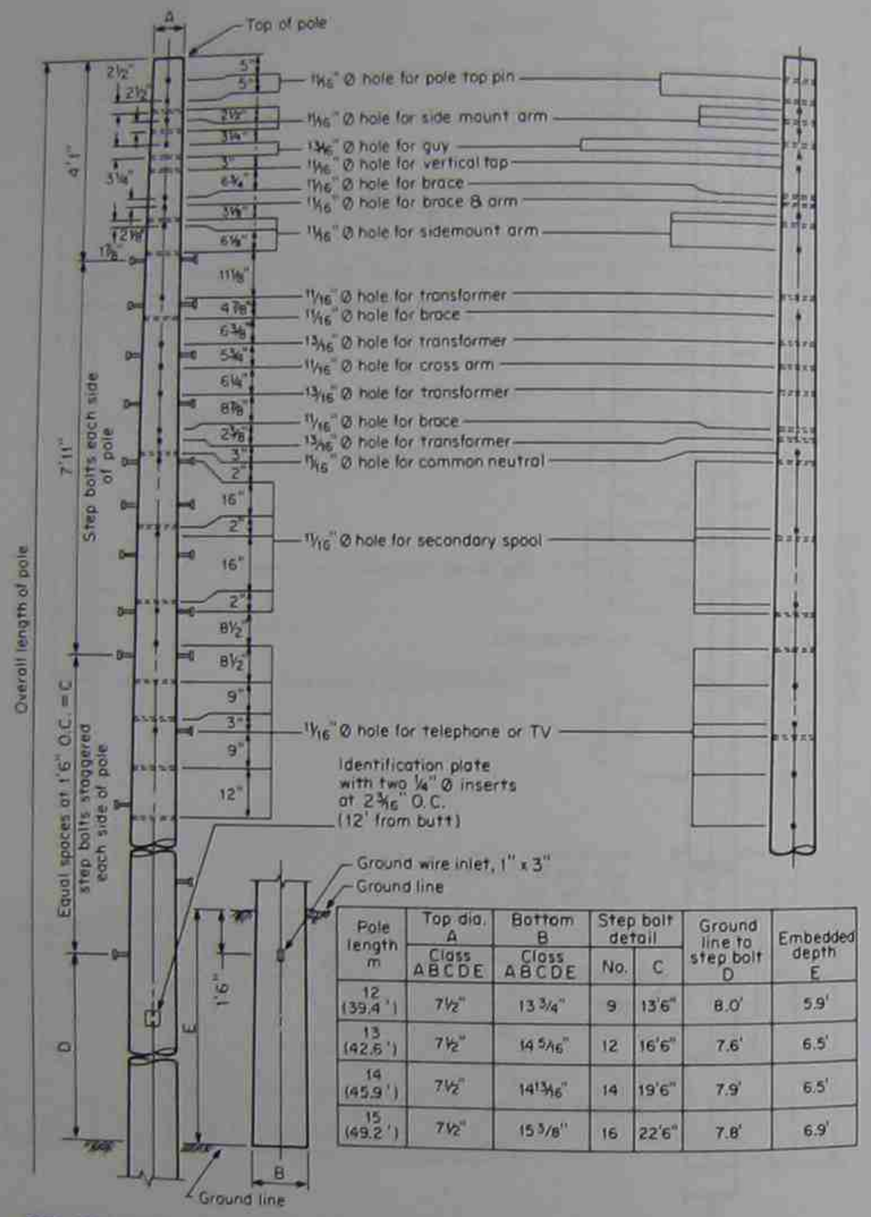
Pole length m	Top dia. A	Bottom B	Step bolt detail		Ground line to step bolt D	Embedded depth E
	Class CDEFG	Class CDEFG	No.	C		
9 (29.5')	6 1/16"	11 7/8"	5	6'0"	8.2'	4.9'
10 (32.8')	6 1/16"	11 15/16"	6	9'0"	8.1'	5.2'
11 (36.1')	6 1/16"	12½"	8	12'0"	8.1'	5.6'

FIG. 10-13 Reinforced concrete round hollow distribution pole. Pole steps optional. (*a*) Use of top third of upper part of pole. *(Courtesy Centrecon, Inc.)*



Pole length m	Top dia. A		Bottom B		Step bolt detail		Ground line to step bolt D	Embedded depth E
	Cl. A-E	Cl. F & G	Cl. A-E	Cl. F & G	No.	C		
12 (39.4')	7½"	6 1/16"	13 3/4"	13"	10	15'0"	8.0'	5.9'
13 (42.6')	7½"	6 1/16"	14 5/16"	13½"	13	18'0"	8.0'	6.2'
14 (45.9')	7½"	6 1/16"	14 13/16"	14 1/16"	15	21'0"	7.9'	6.6'
15 (49.2')	7½"	6 1/16"	15 3/8"	14 9/16"	17	24'0"	7.9'	6.9'

FIG. 10-13 Reinforced concrete round hollow distribution pole. Pole steps optional. (*b*) Use of top two-thirds upper part of pole. *(Courtesy Centrecon, Inc.)*



Pole length m	Top dia. A Class A B C D E	Bottom B Class A B C D E	Step bolt detail No.	Step bolt detail C	Ground line to step bolt D	Embedded depth E
12 (39.4')	7½"	13 3/4"	9	13'6"	8.0'	5.9'
13 (42.6')	7½"	14 5/16"	12	16'6"	7.6'	6.5'
14 (45.9')	7½"	14 13/16"	14	19'6"	7.9'	6.5'
15 (49.2')	7½"	15 3/8"	16	22'6"	7.8'	6.9'

FIG. 10-13 Reinforced concrete round hollow distribution pole. Pole steps optional. (c) Use of top full upper part of pole. *(Courtesy Centrecon, Inc.)*

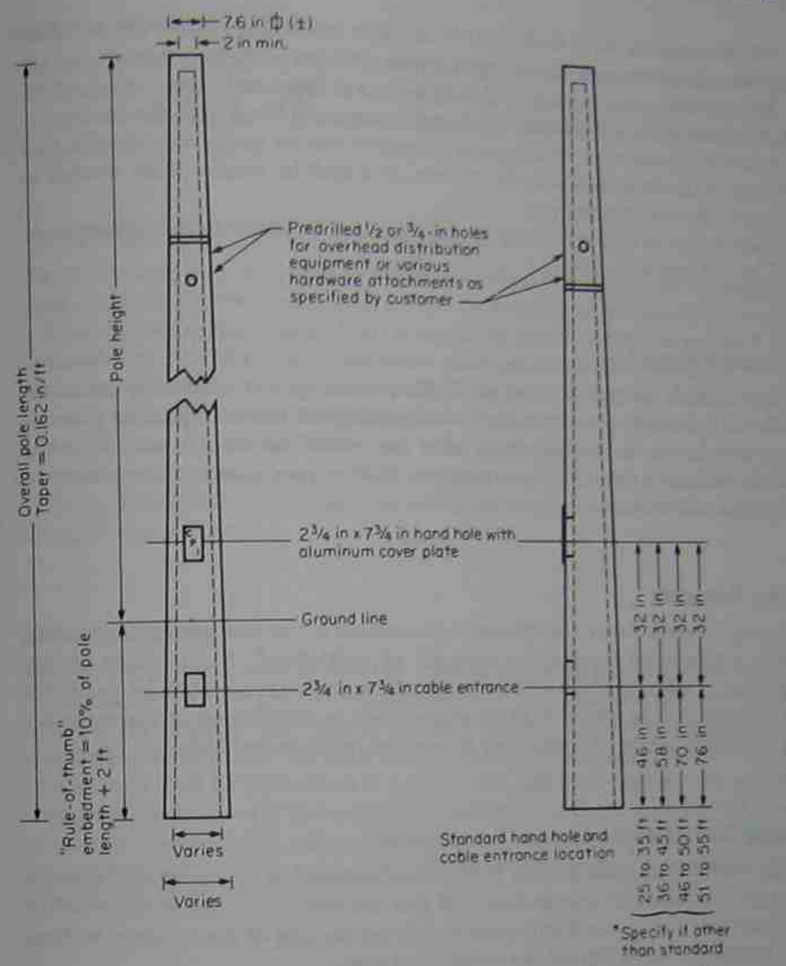


FIG. 10-14 Reinforced concrete square hollow distribution pole. *(Courtesy Concrete Products, Inc.)*

Cable Entrance

These poles shall be furnished with cable entrance opening, hand hole, and hollow core or PVC raceway for use with underground wiring.

MANUFACTURE

Placement of Steel Reinforcement

All prestressing steel and reinforcing steel shall be accurately positioned and satisfactorily protected against the formation of rust or other corrosion prior to placement to the concrete.

All prestressing steel shall be free of loose rust, dirt, grease, oil, or other lubricants or substances which might impair its bond with the concrete.

All unstressed reinforcing steel shall be free of loose rust, dirt, grease, oil, or other lubricants or substances which might impair its bond with the concrete.

Spiral reinforcement shall have a minimum size of gauge no. 11 with 6-in pitch, or equivalent steel ratio in volume, and shall be mechanically welded to the unstressed reinforcement.

The amount of concrete cover on the outside of the major steel reinforcement shall be not less than $\frac{3}{4}$ in.

Embedded Items

Sleeves, sockets, inserts, or other embedded items shall be accurately set in the molds and secured to prevent movement during the concrete placing process. They shall be cast in the concrete so that the axis of the insert is normal to the outside surface of the pole. Particular care shall be used to insure proper cover on all embedded items.

Mixing Concrete

The proportions of water to cement shall produce a concrete after steam curing having a minimum compressive strength of 3500 lb/in^2. A minimum 28-day compressive strength of 6000 lb/in^2 after atmospheric curing shall be required.

Concrete shall be mixed until there is a uniform distribution of the materials and shall be discharged completely before the mixer is recharged.

Placing Concrete

Round Poles The poles shall be formed and compacted by centrifugal force in a machine of suitable type so designed that the molds may be revolved at the required speed to insure distribution and dense packing of the concrete without the creation of voids behind the reinforcing steel.

Metal molds shall be used which shall be adequately braced and stiffened against deformation under pressure of the wet concrete during spinning. They shall also be sufficiently rigid to take the prestressing force without allowing deformation, which will reduce the spinning speed.

Filling the mold and spinning shall be a continuous operation and the spinning shall take place before any of the concrete in the mold has taken an initial set. Excess water forced to the center of the mold during the spinning cycle must be drained in a suitable manner.

Square Poles Square poles shall be cast in steel molds which are true to shape and line.

Concrete shall be poured in one continuous operation while being vibrated with high-frequency vibration to achieve consolidation and insure high density.

Applying Prestressing Force

The intial prestressing force shall be the smaller of 70 percent of tensile strength or 80 percent of yield strength. Tensioning shall be carried out in such a manner that the initial prestressing force shall vary no more than ±5 percent from design value.

Concrete Curing

The poles shall be cured with low-pressure steam for as long as necessary to reach the strength required by the design for transfer of prestressing force.

Prior to the application of heat, a minimum initial setting period of 2 h is required. The rate of rise of temperature shall not exceed 20°F per hour during the second 2 h of the curing cycle nor 60°F per hour during the third 2 h. The maximum temperature shall not exceed 175°F. Fresh concrete shall be protected so as to be free from rain, hot sun, or wind and rapid loss of moisture prior to the start of the steam-curing cycle. Temperature and moisture for each steam-curing cycle shall be continuously controlled and recorded to ensure the adequate curing of the concrete.

Concrete Testing

Samples for strength tests of concrete shall be taken not less than once each day in accordance with ASTM C-172. Standard 4- × 8-in test cylinders shall be used to insure the required strength of products. Standard cylinders for acceptance tests shall be molded and laboratory-cured in accordance with ASTM A-39. Each strength test shall be performed at 1, 7, and 28 days after casting. The strength level of the concrete will be considered satisfactory if the averages of all sets of two consecutive strength test results equal or exceed the required strength and if no individual strength test result falls below the required strength by more than 500 lb/in^2.

Bending Test

A bending strength test of a pole shall be performed in order to assure that the pole meets the minimum structural strength requirements in accordance with specifications.

Manufacturing Tolerance

1. Length: $\pm\frac{3}{8}$ in per 10 ft of length
2. Outer dimension: $+\frac{3}{16}$ in, $-\frac{1}{8}$ in
3. Wall thickness: $-\frac{1}{8}$ in
4. Deviation from straight line: not more than $\frac{1}{8}$ in per 10 ft of length

5. Location of reinforcement: main reinforcement cover, $\pm\frac{1}{4}$ in; spacing of spiral, $+\frac{1}{4}$ in
6. Location of embedded items: $\pm\frac{1}{4}$ in

Workmanship

All poles shall be unpolished but free of burrs, chips, holes, excess cement, and other surface irregularities. All poles shall present a straight and symmetrical appearance after erection. Crooks, curvatures, and twisting edges shall be prohibited. All raceway openings to cable entrance and hand holes shall be free of burrs, cement, or aggregate. Any surface roughness or obstructions that would injure or harm the insulation of electrical cables under normal installation or operating procedures will be prohibited.

Quality Control

Manufacturing procedures and quality control shall follow the recommendations of the Prestressed Concrete Institute.

CHAPTER 11

TRANSFORMERS, CUTOUTS, AND SURGE ARRESTERS

TRANSFORMERS

The transformer, one of the most efficient pieces of electrical apparatus (usually better than 98.5 percent efficient), having no moving parts, transfers electric power from one circuit to another magnetically; in the process, it enables changes to be made in the voltage (and current) output. It is this latter characteristic that has enabled the development of economically feasible ac systems.

While output voltage values may thus be stepped up (at power plants and transmission substations), they can also be stepped down to values suitable for distribution purposes. The first such transformation takes place at the distribution substation, where incoming transmission line voltages are stepped down to primary feeder voltage values. A second transformation takes place at the distribution transformer connected to the primary feeder; here, the voltage is further reduced to values suitable for utilization at the consumer's premises.

Main Parts

Transformers consist essentially of two windings, insulated from each other, wound around a common core usually made of steel and having excellent magnetic properties. The assembly is contained in a steel tank and submerged in an insulating coolant, usually an oil of high dielectric strength. The electric leads connecting the coils to their respective circuits are passed through the tank by bushings made of porcelain or plastics. The dielectric values of the insulations of the several components are deliberately so scaled between them that voltage surges which may cause damage will cause failure to occur at the bushings, a point which can be readily discovered and repaired or replaced at relatively

minor cost. More detailed discussion of this insulation coordination is contained in Chap. 4.

Core Types Cores may be of the *shell* type or *core* type. In the first, the steel core surrounds the windings; though providing a better magnetic circuit, the units become larger and heavier, and are usually restricted to the larger-size transformers generally found in substations and in underground network units; they are usually polyphase units.

In the core type, the windings surround the steel core, resulting in a more compact, smaller unit, generally more suitable for the sizes of transformers associated with overhead and radial primary distribution systems; these are almost always single-phase units.

Windings Windings are usually designed to have the requisite number of turns take up the minimum amount of space, to sustain the forces set up when large or short-circuit currents flow in them, and to allow space for the cooling medium to transfer the heat created to the tank and atmosphere. They are also designed electrically to produce an optimum combination of I^2R losses and IZ impedance drops (IR resistance and IX reactance voltage drops).

In core-type transformers, the low-voltage winding is usually placed next to the core and the primary winding outside and next to the secondary winding, requiring only one high-voltage insulation between the two windings and the core. In shell-type transformers, the primary and secondary windings consist of a number of pancake-shaped coils connected in series, but the primary and secondary "pancake coils" are placed alternately around the core; the arrangement reduces the reactance between windings and provides better cooling paths for heat dissipation.

Polarity In a transformer, the vector relationship between the primary and secondary voltages depends on the way the windings are wound in relation to each other. To identify this relationship, if both windings are connected in series, as in an autotransformer, the voltage in the secondary can add to or subtract from the primary voltage. Where the primary and secondary voltage vectors are in opposite directions, the transformer is said to have *additive* polarity; where the vectors are in the same direction, the transformer is said to have *negative* or *subtractive* polarity. These polarities are shown in Fig. 11-1.

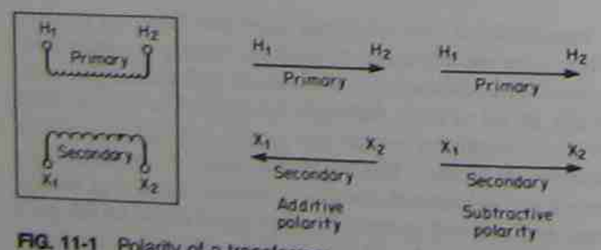


FIG. 11-1 Polarity of a transformer.

Since transformers are connected in parallel with each other, or in polyphase banks, it is essential that the terminals be connected so that the proper voltage relationships ensue. The polarity marks or designations provide the means of accomplishing this. Primary terminals are marked H_1, H_2, H_3, etc., while the secondary terminals are marked X_1, X_2, X_3, etc. See Fig. 4-6*a* through *k* in Chap. 4 for transformer connections using these markings. In these standardized designations, the H_1 (primary) and X_1 (secondary) terminals in a transformer having subtractive polarity will be on the *left* when the observer faces the low-voltage bushings; for an additive-polarity transformer, the X_1 (secondary) terminal only will be on the *right* when the observer faces the low-voltage bushings. Standards of the ASA call for distribution transformers rated up to 200 kVA and voltages below 8600 V to have additive polarity, and those above these values to have subtractive polarity; the polarity is usually specified on the transformer nameplate.

DISTRIBUTION TRANSFORMERS

Distribution transformers may be installed on poles, on the ground on pads, and under the ground directly or in manholes and vaults. The transformers used in these types of installations differ mainly in their packaging, as the internal operating features are very much the same.

Overhead Transformers

The overhead type of distribution transformer is mounted directly on a pole by means of two lugs, welded to the transformer tank, that engage two bolts on the pole, as shown in Fig. 11-2*a*; this is known as *direct mounting*, in contrast to older methods in which the transformer was bolted to a pair of hanger irons that were hung over a cross arm. Where more than one transformer is required, as in power banks, the transformer lugs engage studs on a bracket which is bolted, like a collar, around the pole; the units form a cluster around the pole, from which the term *cluster mounting* is derived; see Fig. 11-2*b*.

Where the load (weight) of the transformer or transformers may be too great for the pole, they may be placed on a platform erected between two or more poles in a structure, or they may be placed on a protected ground-level pad.

Pad-Mounted Transformers

Transformers may be mounted on concrete pads at, or slightly below, ground level within an enclosure or compartment that may be locked for protection. These are generally installed as part of so-called underground residential distribution (URD) systems, where appearance is a major consideration; refer to Fig. 6-19 in Chap. 6.

The transformers may have their energized terminals exposed when the compartment is open, or the terminals may be mounted behind an insulating barrier and connections from the cables made through bayonet-type connections on insulated elbows which are plugged into jacks connected to the terminals;

these units are referrred to as *dead-front* units and provide an additional margin of safety. Refer to Figs. 6-18 and 6-19 in Chap. 6.

Underground Transformers

In the underground type of transformer, also called the subway type, the tank is not only hermetically sealed for water tightness, but its walls, bottom, and cover are made thicker to withstand higher internal and external pressures; the cover is bolted to the tank (with intervening gaskets) by a relatively large number of bolts, and in some instances, welding is used. These units are designed to operate completely submerged in water.

In larger units, where cooling of the tank itself is not sufficient, radiator fins are welded to the tank to provide additional cooling surface, or pipes are welded to the tank for the circulation of oil through them; in the latter case, the additional surface of the pipes as well as the circulating oil is useful for cooling.

Connections to the supply cables are made by means of watertight wiped joints between a fluid-tight bushing and the cable sheath. Another means provides for the making of connections in a chamber attached to the transformer tank in which the primary-voltage transformer windings are brought out in fluid-tight bushings. In some units, this chamber also houses high-voltage disconnecting and grounding switches.

Where these units supply low-voltage secondary networks, they also house the network protector in another watertight compartment, usually situated at the opposite end of the transformer tank from the primary connection and switch chamber. Refer to Fig. 6-4 in Chap. 6.

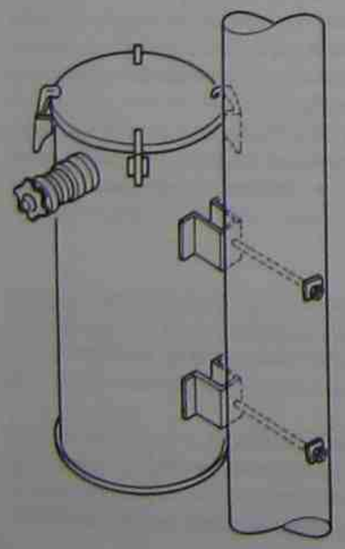


FIG. 11-2 (*a*) Direct pole mounting of a transformer *(Courtesy Westinghouse Electric Co.)*

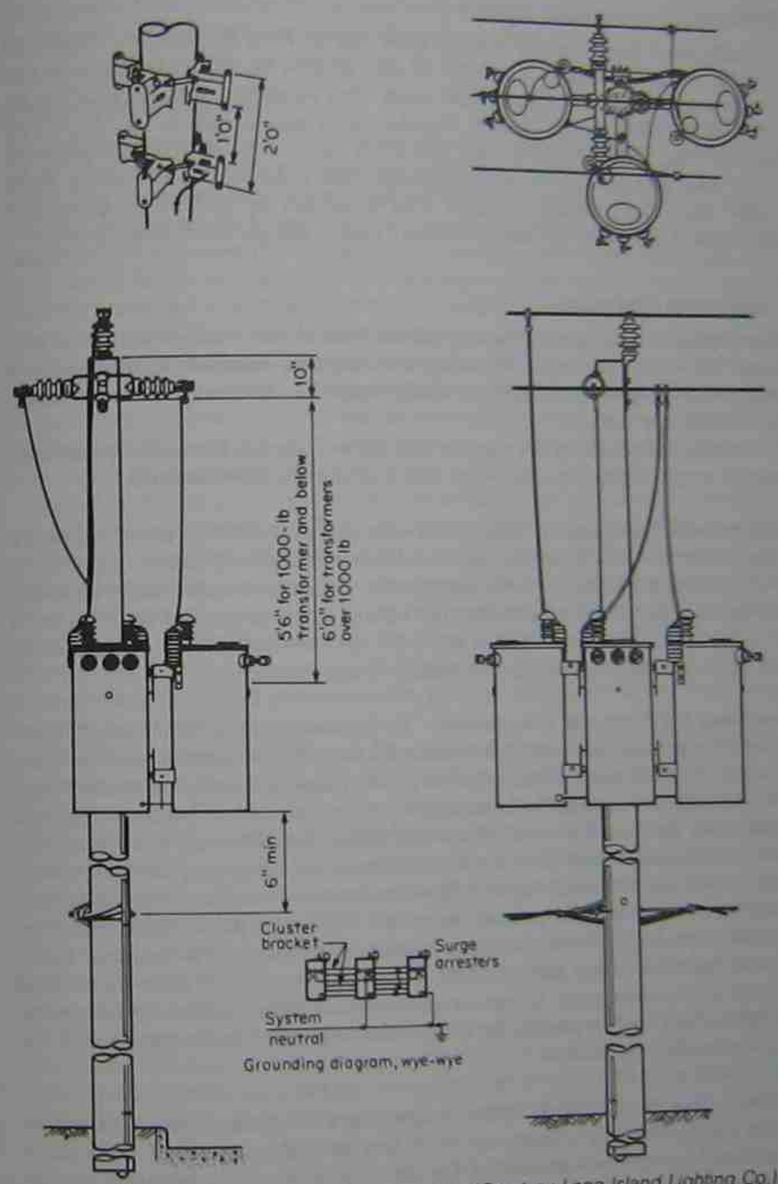


FIG. 11-2 (*b*) Cluster mounting of transformers. *(Courtesy Long Island Lighting Co.)*

Ratings

Transformers are rated by voltage class and in kVA for capacity. Standard voltage classes are 2400, 4160, 7620, 13,200, 23,000, 34,500, 46,000, and 69,000 V for single-phase and three-phase units, with secondary voltages of 120/240, 120/208, 240/480, and 277/480 V. Standard sizes may include 5, 10, 15, 25, 37½, 50, 75, 100, 167, 250, 333, and 500 kVA for overhead and pad-mounted units, and in addition to these, underground units may also include 667-, 1000-, 1500-, and 3000-kVA units. The units may be both single-phase and three-phase, although the larger sizes are almost always three-phase units.

Transformer Protection

Distribution transformers generally fall into two broad classifications: "conventional," in which the protective devices are mounted externally to the unit; and completely self-protected (CSP), in which protection devices are included inside the transformer tank.

Protection is provided the transformer against overload or failure, and from voltage surges (lightning, switching) that may damage the insulation.

Conventional Transformers Associated with the conventional transformer are a fused cutout which separates the transformer from the primary in the event of overload or the failure of some component of the transformer, and a lightning or surge arrester which bleeds the high-voltage surge to ground before it has a chance to damage the insulation or other parts of the transformer. Fused cutouts and surge arresters will be discussed later in this chapter.

Completely Self-Protected Transformers In the completely self-protected transformer, the primary fuse is situated within the case, and because its characteristics are different from those of the external primary fuse, it is referred to as a "weak link." Additional protection from overloads is provided by means of circuit breakers on the secondary side, which coordinate with the weak link; i.e., in the event of overload or fault on the secondary main, the secondary circuit breakers open before the weak link blows. The surge arrester is mounted outside the tank, but connected to its primary terminal. For single-phase units on a wye-grounded system, therefore, only one connection is required to be made to the primary line; this makes for a simpler, neater-appearing, and more economical mounting of transformers. Moreover, these units are also equipped with a warning light which may be seen from the ground and which indicates the unit has been thermally overloaded.

Grounds In a grounded wye system employing a common neutral for both the primary and secondary systems, the secondary neutral is connected to the transformer tank and the tank grounded. For safety purposes, a second visible ground conductor is connected between the neutral terminal and the neutral conductor of the secondary mains.

Similar protection is provided for ground-level or pad-mounted transformers. Surge protection is usually not required for transformers installed underground, although exceptions are made where such transformers are installed close to

underground risers connected to overhead systems; surge arresters may then be installed at the transformer or at the pole, or both.

Single-Phase Transformers

Most of the distribution transformers in service are single-phase units supplying single-phase loads directly or supplying polyphase loads in banks of two or three units. The secondary winding is usually divided into two equal parts, each part having a voltage of 120 V between its terminals. The two parts may be connected in parallel for two-wire 120-V operation, in series for two-wire 240-V operation, or in series for three-wire 120/240 V operation; refer to Fig. 4-6*a* in Chap. 4. In older units, the four leads from the two parts of the secondary winding were brought outside the tank through insulated bushings, and connections were made outside the tank; in more recent construction, the connections of the parts are made inside the tank and only those leads are brought out that the circuit requires. In many cases, the middle or neutral lead is not brought out through an insulated bushing, but is connected to a stud on the tank which also serves as a means of grounding the transformer tank.

Leads from the primary winding are brought out of the tank through insulated bushings usually made of porcelain of sufficient dimensions to accommodate the intended primary supply voltage. Where the primary supply is a delta-connected or ungrounded wye circuit, the leads employ two bushings. Where the primary supply is a grounded wye circuit, only one lead is brought out through a porcelain bushing; the other lead is connected to the tank and brought out by means of a stud, which may also be connected to the secondary neutral lead, and which also serves for making connection to the distribution-circuit neutral conductor.

(It is most important that care be exercised when connecting or energizing single-bushing transformers, or any transformer with one end of the primary coil connected to the transformer tank, to make *absolutely* certain that the ground connections on the tank of the transformer are made to the system neutral *first*. Failure to do so could lead to energizing the transformer tank at line voltage, jeopardizing the safety of anyone working at or near that transformer.)

Single-phase units may also be used to supply two-phase and three-phase loads from a polyphase primary supply; they may also be used as boosting or bucking transformers in single-phase primary supply circuits; connections are shown in Fig. 4-6*a* through *k* in Chap. 4.

The primary windings may also be furnished with taps which permit changes in the transformation ratio to accommodate the need for a fixed raising or lowering of the secondary voltage, or to provide for phase transformation from three-phase to two-phase (or vice versa) as noted previously.

Polyphase Transformers

In polyphase (usually three-phase) transformers, the connections between the phase windings on both the primary and secondary sides are made within the tank of the transformer, and the leads are brought out through porcelain bushings. Whether connected for delta or wye and whether on the primary or sec-

ondary side, three leads are brought out on each side. In most instances where a grounded wye circuit is involved, the neutral is brought out through a stud connected to the transformer tank, as mentioned previously for single-phase units. In the relatively few instances where ungrounded wye circuits are involved, the "neutral" or common junction point is brought out through a fourth porcelain bushing.

Taps on the primary side are also furnished to permit the same changes in ratio of transformation as were described for single-phase transformers.

Transformer Cooling

Most distribution transformers, whether overhead, pad-mounted, or subway types, have their cores and coils submerged in insulating oil. The heat produced by the iron and copper losses is carried by convection currents in the oil to the tank and there dissipated into the atmosphere. Excessive temperatures and the formation of hot spots are thus prevented, avoiding damage to the insulation and conductors.

Moisture and sludge formed from the effect of the oxygen in the air on hot oil tend to reduce the dielectric quality of the oil.

Where the use of oil is undesirable, principally because of fire hazard, air-cooled or askarel-cooled units may be employed, although these are generally limited to larger sizes and to transformers installed in vaults. Askarels, although nonflammable, are heavier, less effective coolants, and more expensive than oil; they are also environmentally undesirable, containing carcinogenic PCB compounds, and are extremely irritating to eyes and skin.

Transformer Impedance

Transformer nameplate data also include the impedance of the transformer expressed as a percentage of its nominal rated voltage. This information is important when transformers are connected in parallel, or in polyphase banks, as units of different impedances will not share the load equitably and will cause circulating currents producing unnecessary heating when connected in banks; refer to Chap. 4 for additional discussion.

FUSE CUTOUTS

Distribution transformers (of the conventional type) are usually connected to the primary supply lines through a fuse cutout. The cutout contains a fusible element (a link) whose melting automatically disconnects the transformer from the primary to prevent damage from overloads; it also disconnects the line from the transformer in the event of a fault in the transformer, not only preventing spread of damage in the faulted transformer, but also preventing interruption to the primary supply circuit that would affect other transformers and consumers served from that circuit.

Fuse cutouts are also used to disconnect faulted or overloaded parts of a primary circuit from the remaining unfaulted portion of the circuit.

The size of the fuse is generally based on the size of the transformer or load on the primary section it is to protect.

For voltages of 5000 V or lower, the fuse element, enclosed in a fiber tube, is mounted inside a porcelain box, engaging the two contacts at the top and bottom of the box. The fuse is usually mounted on the door of this box, which is hinged at the bottom; in some models, the melting of the fuse causes the door to drop open as an indication that the fuse has blown. See Fig. 11-3*a*.

For voltages above 5000 V, the fuse element is mounted in the open between two contacts at either end of an insulating porcelain support, as shown in Fig. 11-3*b*. The tube containing the fuse drops when the fuse melts, indicating that the fuse has blown. For obvious reasons, this type is known as an open-type cutout.

The design of fuse cutouts should take into consideration the voltages which will be applied to them and the currents that will flow through them. As the currents that may flow under fault conditions may be of rather large magnitude, the fuse cutouts should be strong enough to withstand the resultant forces without damage to themselves or to surrounding objects.

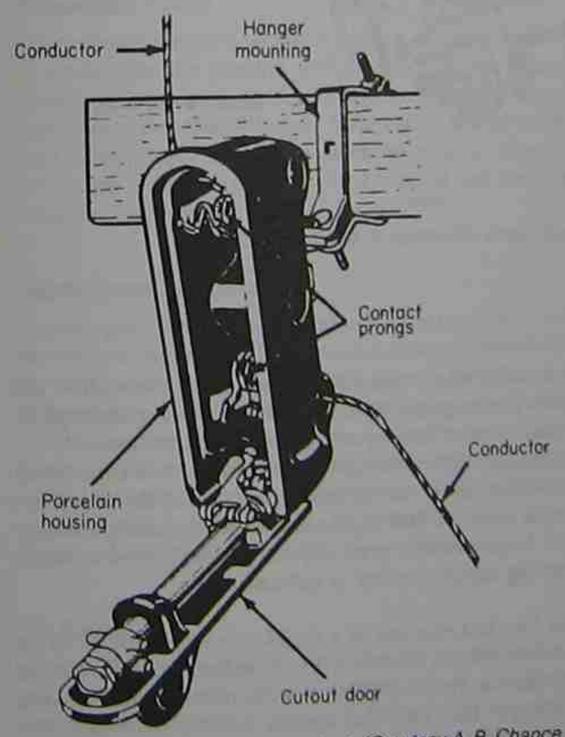


FIG. 11-3 (a) Door-type fuse cutout. *(Courtesy A. B. Chance Co.)*

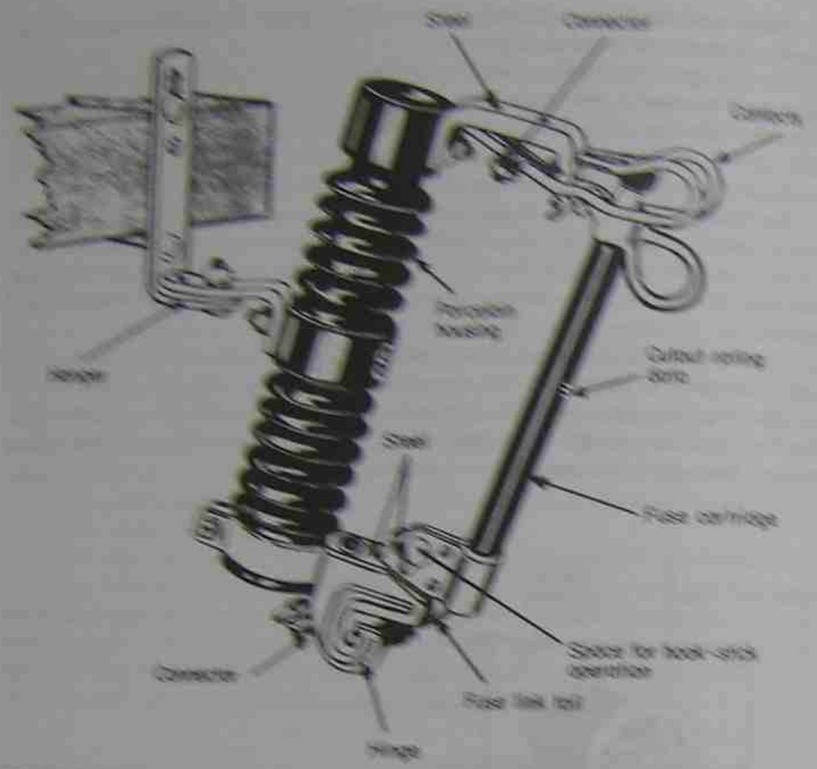


FIG. 17-3 (b) Open-type fuse cutout. (Courtesy A. B. Chance Co.)

Fuses

A fuse is a fusible link that melts when excessive current flows through it, the time of melting varying with the magnitude of the current flowing through it. Further description and discussion of fuse operation are given in Chap. 4.

Fuses for different applications are of several types; those used in connection with the primaries of distribution feeders and transformers are of the expulsion type. These contrast with the open or link types used with secondary voltages and the filled-type fuses of large capacity generally used with higher voltages such as are found on incoming supply feeders at substations.

Expulsion-Type Fuses The fuse link consists of a fusible element with a cap on one end and a flexible stranded cable on the other. The fuse fits into an insulating tube, usually of fiber, with the cap holding it in place on one end and making contact with the nut or fitting at that end; the flexible cable is held taut by a spring or by being wound around a stud and held in place by a knurled nut. The assembly is fitted between the stationary terminals of the cutout.

The minimum time required to melt the link is determined by the composition and dimensions of the link. As the primary voltages involved, however, an arc will persist between the ends of the melted link. The rapid expansion of the surrounding air confined in the tube will tend to blow out the arc; the heat arising on the fiber will also produce a gas under pressure, aiding in extinguishing the arc. The mounting or enclosure of the fuse, therefore, will determine the length of time to extinguish the arc. The clearing time of the fuse will be the sum of these two times, the melting time and the arc-extinguishing time. Hence, the fuses are rated on their voltage class, their normal current-carrying capacity, and a time-current relationship expressed as fast or slow (e.g., type K, type T, etc; refer to Chap. 4).

In the open-type cutout, the expulsion tube may be made to vent at both ends by having the cap at the top made deliberately weak to blow off when high currents produce high gas pressures. Thus, this type of cutout permits the expulsion tube to vent at only one end when fault currents are low, and to "double-vent" when fault currents are high, allowing a higher interrupting rating for the fuse and cutout.

Three-Shot Fuses

When fuses are used to sectionalize a primary feeder, it is sometimes desirable to reenergize the portion disconnected by the blowing of a fuse, e.g., after a fault of a temporary nature. Three fuses are mounted in parallel, but only one fuse is connected in the line. When that fuse blows, as it swings open it trips a latch that places the second fuse in service. Should this fuse also blow, the operation is repeated for a third fuse. If the third fuse should blow, the line remains deenergized.

Safety Considerations

Besides providing adequately for normal and fault currents and for the voltage at which a cutout is to be operated, designs provide for the mounting or cutout to withstand severe climatic conditions, including snow, ice, rain, and severe temperature differences. Protection is also provided against decay, insects, birds, rodents, snakes, etc. Metal parts are made noncorrosive, not only from rust but from corrosive atmospheres. All nonenergized metal parts are bonded together and connected to one or more grounds. The cutouts are also installed out of reach of the general public and are operated with auxiliary devices such as an insulated switch stick handled from the ground.

Oil Fuses

Where very large interrupting capacity is required in a fuse, it is submerged in oil in a hermetically sealed steel tank. Here, the hot gases are not expelled, but are allowed to expand into sealed explosion chambers at the top of the cutout; the remnants of the fuse remain under the relatively cool oil. The magnetic field the remnants of the fuse remain under the relatively cool oil. The magnetic field set up by the large current flowing through the fuse in turn sets up magnetic

fields within the tank that aid in snuffing out the arc that forms, the insulating lining of the tank preventing the arc from contacting the tank.

The fuse link is fitted on an insulating frame that fits between the contacts inside the tank. The assembly is so shaped that it can only be inserted into an open position, preventing a premature blowing of the fuse before the assembly is locked in the closed position. Stationary contacts inside the tank are brought out by means of porcelain bushings.

The relatively high cost of oil fuses generally restricts their use to transformers in vaults or underground manholes, and to where voltages are less than 15 kV.

SURGE ARRESTERS

Lightning or surge arresters serve to bleed a high-voltage surge to ground before it reaches the line or equipment which they are to protect. They do this by presenting a lower-impedance path to ground than that presented by the line or equipment. The voltage surge breaks down the insulation of the arrester momentarily, allowing the surge to go to ground and dissipate itself; the insulation of the arrester then recovers its properties, preventing further current from flowing to ground, and returning the arrester to a state ready for another operation.

Types of Arresters

Lightning or surge arresters consist basically of an air gap in series with another element which has the special characteristic of providing a relatively low resistance or impedance to the current produced by a high-voltage surge, and a high resistance or impedance to the flow of power current at the relatively low operating voltage of the distribution line to which it is connected. In some later units, the air gap may be omitted.

Pellet Type In the pellet type of arrester, the second element is made up of a tube full of lead pellets. The lead pellets are actually lead peroxide coated with

TABLE 11-1 STANDARD RATINGS OF SURGE ARRESTERS FOR DISTRIBUTION VOLTAGES

Voltage reference class, kV	*Crest voltage, kV**	*Voltage reference class, kV*	*Crest voltage, kV**
1.2	30	15	110
2.5	45	23	150
5.0	60	34.5	200
8.7	75	46	250
12.0	95	69	350

*Basic insulation level (BIL) in kilovolts with a standard 1.5- by 40-μs wave.

Courtesy McGraw Edison Co.

lead oxide. The pellets normally act as insulation preventing current from flowing to ground. When a high-voltage surge is impressed on them, a current will flow that heats them and turns the lead oxide (a poor conductor) into lead peroxide (a good conductor). After the surge is discharged to ground, the surface of the pellets is changed by the discharge current back to lead oxide and restores the arrester to its original condition. Although rapidly becoming obsolete, a great many of this type of arrester exist and will for a long time.

Valve Type In the valve type of arrester, the second element may be made of some particular substance such as ceramic material containing conducting particles, such as metal oxides (Thyrite and Granulon are commercial names), or other substances having characteristics under surge-voltage conditions similar to those described above. Many of these are built in modular units, several connected in series to accommodate the line voltage impressed on them.

Expulsion Type The expulsion type of arrester may or may not employ a second air gap enclosed in a tube made of fiber in series with a fixed air gap. As with fuse holders made of fiber, when a high voltage occurs creating an arc across the gap, the heat acting on the fiber gives off a nonconducting gas under pressure that blows out the arc, interrupting the flow of surge current and restoring the arrester to its original condition.

Installation

Surge arresters are installed as close as possible to the equipment or line to be protected so that the resistance of the connection to ground may be held to a minimum. The ground is of the utmost importance, as the arrester will not operate without one. If possible, the arrester should have its own ground, in addition to connections to other grounds.

Since the arrester is to protect the insulation of the line or equipment associated with it, its insulation should be coordinated with that of the line or equipment. This is discussed in some detail in Chap. 4.

Rating

Standard arresters are rated not only on the nominal voltage class of the line to which they are to be connected, but also as to the crest voltage (the basic impulse insulation level) they can withstand; refer to Chap. 4 for more detail. Table 11-1 lists some standard ratings for surge arresters associated with distribution circuits of various voltage classes.

CHAPTER 12

REGULATORS, CAPACITORS, SWITCHES, AND RECLOSERS

VOLTAGE REGULATORS

A voltage regulator is used to hold the voltage of a circuit at a predetermined value, within a band which the control equipment is capable of maintaining and within accepted tolerance values for distribution purposes. Regulators may be installed at substations or out on distribution feeders on poles, pads, or platforms or in vaults.

Voltage regulators are essentially autotransformers, with the secondary (or series) portion of the coil arranged so that all or part of its induced voltage can be added to or subtracted from the line or incoming primary voltage (across which the primary or exciting portion of the winding is connected). The voltage variations are accomplished by changing the ratio of transformation automatically without deenergizing the unit.

Types

There are two types of voltage regulators in use in distribution systems: the induction regulator and the tap-changing-under-load (TCUL), or step-type, regulator. The first is usually limited to circuits operating at 5000 V or less and is being rapidly replaced by the latter, employed where relatively larger amounts of power and higher voltages are involved.

Induction Regulator In the induction type of voltage regulator, the primary (high-voltage) winding and the secondary (or series) windings are so arranged that they rotate with respect to one another (Fig. 12-1). The primary coil is usually the stator and the secondary coil the rotor, the direction of rotation

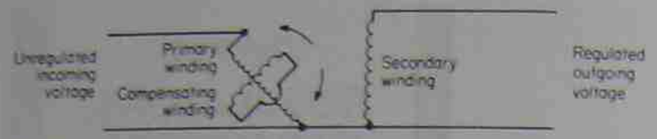


FIG. 12-1 Induction regulator windings.

generally depending on whether the incoming voltage is to be raised or lowered. The voltage induced in the secondary or series winding will depend on the position in relation to the primary winding. Depending on the position, the induced voltage can add to or subtract from the input voltage to obtain the outgoing voltage.

During the rotation of the primary coil, the moving magnetic field can cause a large reactance voltage drop in the secondary. To dampen (or cancel) this effect, a third coil is mounted at right angles to the primary coil on the movable core and short-circuited on itself. The moving primary coil will induce a voltage in the third coil which will, in turn, set up a moving magnetic field of its own, which will tend to oppose that set up by the motion of the primary coil. The reactance of the regulator unit is thus kept essentially constant.

Step-Type (or TCUL) Regulator The TCUL, or step-type, regulator is also essentially an autotransformer, and is connected in the circuit in the same manner as the induction regulator. This type does not employ rotation of one of the coils, but changes voltages by means of taps in the primary coil, as shown schematically in Fig. 12-2. The portion of the coil with taps is a separate part of the primary coil with arrangements included for a reversal in its connection so that the voltage within that portion of the primary coil can be added to or subtracted from the voltage in the rest of the primary coil.

Each tap is changed by the opening and closing of an associated "selector" switch. To avoid disconnecting the transformer from the line each time a tap is changed, the taps are so arranged that two adjacent taps are connected through a small autotransformer each time the tap change is in progress. The midpoint of this "preventive" autotransformer is connected to the primary coil, as illustrated in Fig. 12-3. A small air gap is inserted in the core of the autotransformer to reduce the size of the magnetic field, which could cause an excessive voltage drop in the coil.

Small circuit breakers, known as *transfer switches*, make and break the circuit under oil. The selector switches are always closed while the corresponding transfer switch is open, and opened while the transfer switch is closed. In this design,

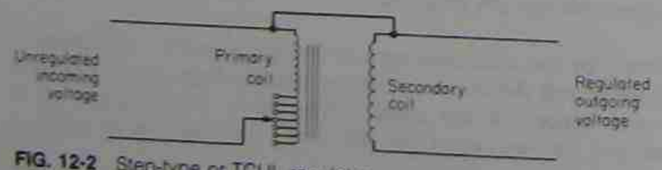


FIG. 12-2 Step-type or TCUL regulator.

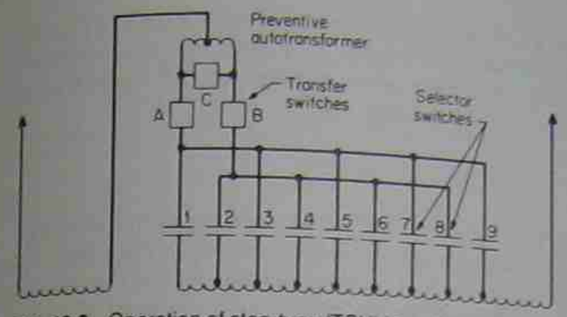


FIG. 12-3 Operation of step-type (TCUL) regulator. *(Courtesy Westinghouse Electric Co.)*

three transfer switches and one selector switch for each tap are required for operation. The transfer switches are often contained in a separate compartment attached to the main tank of the regulator so that they may be maintained without the necessity of draining the oil from the entire regulator unit. The oil in this compartment may be more readily contaminated because of the frequency of the switches' operation.

The sequence of operation of both the selector and transfer switches is shown in Table 12-1. The switches are operated in proper sequence by a motor-operated mechanism which may be controlled manually or automatically. A time-delay device prevents short-duration dips from operating the control relays.

Control

The rotation of the primary coil in the induction regulator and the tap changing in the step-type (TCUL) regulator are controlled by a voltage-regulating relay (earlier known as a *contact-making voltmeter*) connected to the output side of the

TABLE 12-1 SEQUENCE OF OPERATION OF TCUL REGULATOR SWITCHES

	Position								
Switch	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Transfer switch A	X X		X X X		X X X		X X X		X X
B	X	X X X		X X X		X X X		X X X	
C	X	X	X	X	X	X	X	X	X
Selector switch 1	X X								
2	X	X X X							
3		X	X X X						
4			X	X X X					
5				X	X X X				
6					X	X X X			
7						X	X X X		
8							X	X X X	
9								X	X

Courtesy Westinghouse Electric Co.

regulator. Associated with it is a *line-drop compensator*, which is essentially a miniature reproduction of the electric circuit to be regulated and determines the voltage applied to the voltage-regulating relay. A more detailed description of these devices' operation is contained in Chap. 4.

Rating

Both induction and step-type regulators are rated on their nominal voltage classification and their plus-minus percent of voltage regulation. Their capacity, or kVA rating, as a percentage of the volt-amperes transformed is the same as the percent voltage transformed using the incoming primary voltage as a base. This is the same rating used for autotransformers.

For example, if the regulator boosts (or bucks) the voltage 10 percent, it transforms only 10 percent of the load in kVA. If the load to be served is 1000 kVA, the size of regulator required is 100 kVA.

CAPACITORS

Capacitors are also used to improve voltage regulation on distribution circuits, but their operation differs from that of induction and step-type regulators. By introducing capacitive reactance in the circuit, they effectively counteract the inductive reactance of the circuit, affecting its impedance. This, in turn, may cause a voltage drop or rise. It will also tend to improve the circuit power factor, thereby decreasing the current required for a given load and reducing losses in the circuit.

Construction

Capacitors are usually constructed of sheets of aluminum foil separated by liquid-insulating-impregnated paper or other material, wrapped in bundles. The bundles are connected together electrically in series-parallel circuits, and the number of such bundles determines the voltage and capacitance rating of the units. The bundles are contained in a steel tank through which the leads are brought out by means of porcelain bushings.

Operation

Sufficient numbers of units are assembled in a bank of capacitors to provide the required capacitance or reactive power. Capacitors should be installed as close as possible to the inductive load (equipment) so that the current supplied over the circuit will be as nearly as possible in phase with the voltage (unity power factor).

In utility practice, however, capacitors are installed at intervals on the circuit to counter the effect of the inductance of the circuit itself as well as that of the inductive loads connected to it. Capacitor banks may be installed outdoors on poles in racks, on platforms, or on pads. They may also be installed indoors in vaults or other enclosures, and in substations.

Since the loads on a circuit change almost continuously, means are sometimes

provided to switch on or off some or all of the units in a capacitor bank, so that the capacitance (approximately) cancels out the inductance of the system. This may be accomplished by time clocks, overvoltage or undervoltage relays, or remote-control devices.

Protection When installed outdoors, capacitor banks are usually protected by fuse cutouts and surge arresters, somewhat in the way transformer installations are protected. In indoor installations, the banks may be protected by switches or fuse cutouts. Large banks of capacitors, such as may be found connected to substation buses, are usually connected by means of circuit breakers of ample capacity and short-circuit duty to accommodate the switching on and off of such banks, either in their entirety or in part. The employment of capacitors is discussed in greater detail in Chap. 4.

To protect against the failure of one unit in a bank affecting the entire bank, each capacitor unit in the bank is usually fused individually.

Discharge of Capacitors Some arrangement of resistors or reactors connected to the terminals of the capacitors is often provided for discharging the potentially dangerous energy that remains in a capacitor that has been charged, even after it is disconnected from the line. This phenomenon is known as *dielectric absorption*. Where the capacitors are connected between a phase of the primary feeder to which distribution transformers are connected and ground, discharge facilities may not be required, since the charge in the capacitor will drain off through the transformer winding. The rapidity at which this occurs will depend on the distance and the size and configuration of the conductors between the capacitor and the transformer.

Series Capacitors

Capacitors may be connected in series with the line to compensate for reactive voltage drop in the circuit and provide an instantaneous and almost perfect voltage regulation. Their use is generally limited to low-voltage heavy-current application, such as welders and furnaces. The units so employed may be the same as those used for shunt operation.

Rating

Capacitor units are rated according to their nominal voltage class (e.g., 2400 or 7620 V) and their kVA rating: 15, 25, 50, 100, 150, 200, and 300 kVA. Banks of such units, both for single-phase and three-phase operation, are assembled to provide the required capacitance.

Maintenance

Capacitors require little maintenance beyond occasional inspection for blown fuses, cracked bushings, leaking tanks, and the accumulation of dirt or other pollutants (severe smoke, salt fog, chemical fumes, etc.) on insulating surfaces. Maintenance is often accomplished by replacing only the unit in the bank requiring attention.

SWITCHES

In addition to the fuse cutouts and potheads mentioned in Chap. 9 and 11, other devices are used for connecting or disconnecting circuits or portions of them.

Disconnects

Disconnects are switches designed *not* to be opened when any amount of load current flows through them. Their use is generally limited to places where no load current or only a small charging current is to be interrupted. They are usually installed in a circuit so as to enable a line or a piece of equipment to be isolated from the energized portion of the circuit; they provide a visual break in the circuit as a positive safety measure for the worker. On the other hand, when used as normally open devices, they may be closed to energize a line or piece of equipment where only charging current will flow; in some instances, some relatively large load current may also flow when the disconnect is closed. In either case, the disconnect should be closed firmly to prevent the possibility of arcs forming between the blade and terminal clip as the blade approaches the (energized) clip.

Disconnect switches, air-break switches, and oil switches are sometimes gang-operated; i.e., the three single-pole disconnects (for a three-phase system) are mechanically connected and operated together.

Air-Break Switches

Air-break switches are generally used to interrupt relatively small amounts of load current, such as in sectionalizing primary feeders or interrupting the exciting current of large transformers or a group of smaller transformers. The switches may be closed to pick up loads, but extreme care must be used in opening a circuit carrying load.

Air-break switches are essentially disconnect switches equipped with so-called arcing horns. These are metal rods attached at an angle to the stationary terminal of the switch. As the blade of the switch is opened under load, the arcing horns remain in contact with the blade until after the main contacts have separated. As the blade continues to travel, an arc will form between it and the arcing horn. The arc will lengthen as the blade continues to travel, until it can no longer sustain itself and becomes extinguished. Pitting or burning from the arc occurs on the horn and part of the switch blade, where it can be tolerated.

Auxiliary devices are sometimes employed to increase the load-interrupting capability of such switches. One scheme interposes a low-capacity high-interrupting-duty fuse between the stationary contact and the moving element or blade; the fuse interrupts the circuit safely while the switch blade is still in place.

Construction Air-break switches are built rather ruggedly not only because they may have large fault currents flowing through them, but also because they are exposed to the weather. They are designed to operate under severe weather variations, with special attention paid to prevent contacts and hinges from "freezing" in position in cold, snowy, and icy weather.

Oil Switches

Operation Where load currents are to be interrupted relatively often, oil switches not designed to interrupt fault currents are used. Here, the switch is opened under oil, the oil serving to quench the arc that forms. Usually, however, a fuse is connected in series with the switch to clear the circuit should the switch fail to interrupt the circuit. Oil switches of this type, such as double-throw switches, are often used to transfer a primary service from one feeder to another and may be operated manually or automatically.

While the oil switch is more dependable than the air-break switch, it is more costly and its use is generally limited to those applications where other means are unsatisfactory.

Rating Like disconnects and air-break switches, oil switches are rated on their voltage classification and their normal current-carrying capacities. Inasmuch as fault current may flow through them, their fault-current-carrying capabilities are often included in their specifications.

CIRCUIT BREAKERS

Types

A circuit breaker generally is an oil switch but is built more ruggedly to enable it to interrupt not only the relatively large load currents but also the much larger fault currents which may occur on a circuit. Some circuit breakers, however, are designed to open in air, with special provisions for handling the arc that follows when the contacts are opened. These are known as air circuit breakers, and their interrupting capability is usually much lower than that for oil circuit breakers. Other circuit breakers are designed to have their contacts open in a vacuum or in an ambient of inert gas such as sulfur hexafluoride (SF_6), with improved interrupting capability claimed for these latter types.

Operation

All types of circuit breakers are designed to operate automatically in opening the circuit under fault conditions, or to be opened or closed manually when desired.

Circuit breakers are generally installed at substations on the ends of primary feeders. They may be used elsewhere, however, where heavy short-circuit currents must be interrupted and cannot be handled by other means such as fuses. Such locations, for example, are at-large consumers served at primary voltages.

Circuit breakers are usually actuated by overcurrent- or fault-sensing relays which serve to open them. This is done by tripping a compressed spring. Opening may be achieved in from 2 to 60 or more cycles, including the extinguishing of the arc, from the time the relay contacts are made. Relays also control their reclosure, which is accomplished by means of solenoids or electric motors. Circuit breakers may be set for a single operation, or for multiple reclosing operations before "locking out."

To insure their operation, the operating power source for the operation of

the relays and the circuit breakers may be storage batteries floated on the line through a rectifier so that they are continuously fully charged.

Further discussion of circuit breakers may be found in Chaps. 4, 7, and 13.

Rating

In addition to their voltage classification and current-carrying capacity, the interrupting capability is a most important part of the circuit breaker rating.

RECLOSERS

Reclosers are essentially circuit breakers of relatively lower normal current- and short-circuit current-carrying capability. Their overcurrent- and fault-sensing devices and reclosing controls are a part of the unit and are contained within it.

Operation

The coils operating the closing mechanism obtain their power from the source side of the recloser. These coils also operate a mechanism that compresses the springs, which, when tripped, open the circuit breaker contacts rapidly. Another coil, in series with the coil operating the closing mechanism, trips a latch that releases the compressed springs to open the circuit breaker. A relay reenergizes the coil operating the closing mechanisms, which automatically close the circuit breaker. A time delay inserted in the relay circuit permits the reclosing of the breaker a number of times (usually three) before locking it open. The reclosing feature may be switched out of operation when only a single operation is desired (e.g., when workers may be working on the circuit). The unit may also be operated manually.

Reclosers may be installed out on one or more branches of a circuit so that a fault on those branches need not affect the entire circuit. Temporary faults (such as a tree limb falling on the line) will not cause a lengthy outage to service on the branch, but only a momentary interruption.

Reclosers may sometimes be installed at substations as circuit breakers on distribution feeders where loads are relatively small and likely short-circuit or fault current low enough not to exceed the rating of the recloser. Such conditions may often be found in rural areas.

Rating

Recloser units may be single-phase or polyphase, and are rated according to voltage class, normal carrying current, and fault-current interrupting capability. Additional discussion may be found in Chap. 4.

CHAPTER 13

DISTRIBUTION SUBSTATION EQUIPMENT

EQUIPMENT

The principal equipment usually found in a distribution substation includes power transformers; circuit breakers and their associated protective relays and control devices; high-voltage fuses; air-break and disconnect switches; surge or lightning arresters; voltage regulators; storage batteries; measuring instruments; and, in some instances, capacitors and street lighting equipment. Associated with all of these are cables and buses and their supports.

Many of these items have been discussed previously in connection with their functions in the planning and design of distribution systems and in their construction and installation; this discussion may generally be found in Chaps. 2, 4, 5, 6, 7, 11, and 12. Discussion in this chapter will focus on those characteristics of these same items which were not discussed previously but which are associated with the activities of the distribution engineer.

TRANSFORMERS

Substation transformers function in a manner similar to distribution transformers, but have significant differences in their construction and operation. Features shared by both categories include the usual employment of oil (sometimes air or askarels) for insulating and cooling purposes, taps for changing the ratio of transformation, and insulation coordination together with basic insulation levels. Transformers may be of the single-phase or three-phase types.

Core

Substation transformers, and especially the polyphase units, are usually constructed with shell-type cores which surround the windings, as compared with the usual distribution transformer, in which the windings surround the core.

Polarity

Substation transformers are usually wound for additive polarity, in accordance with EEI, NEMA, and other standards, as contrasted with the subtractive polarity of distribution transformers.

Bushings

The bushings of substation transformers on the low-voltage side are usually made of porcelain and are similar to the primary bushings found on distribution transformers, but of greater current-carrying capacity. The high-voltage-side bushing, however, in addition to the greater current-carrying capability, depending on the magnitude of the voltage, may consist of a solid porcelain cylinder (with petticoats) as insulation for voltages up to about 35 kV, or an oil-filled hollow porcelain cylinder for values up to about 69 kV; for 69 kV and higher voltages, the hollow porcelain cylinder may contain layers of oil-impregnated paper insulation with metal foil inserted at several locations among the layers, forming a series of capacitors which serve to even out and equalize the electrostatic stresses set up within the bushing; see Fig. 13-1. Other high-voltage bushings may be filled with an inert gas such as sulfur hexafluoride (SF_6).

Like distribution transformers designed for line-to-ground operation, single-phase transformers may have only one bushing on both the high- and low-voltage sides; three-phase transformers may have only three high- and three low-voltage bushings, with a neutral stud as a common terminal for both high- and low-voltage windings.

Oil

Substation transformers may also show evidence of greater precaution taken in keeping air and moisture from the oil. In some units, an inert gas, such as nitrogen, fills the space above the oil, and the transformer tank is sealed. A "relief diaphragm" is sometimes installed in a vent in the sealed transformer which ruptures when the internal pressure exceeds some predetermined value, indicating possible deterioration of the insulation. In some units, a pressure relay is installed to give an indication of pressure rise in the tank.

Some outdoor units are equipped with a tank on top of the transformer, called a *conservator*, in which the expansion and contraction of the oil takes place. The tank is sometimes open to the atmosphere through a breathing device. The condensation of moisture and the formation of sludge take place in the tank, which is also provided with a sump from which the condensation and sludge may be drawn off. See Fig. 13-2.

Cooling

Substation transformers may be equipped with fins or radiators to enhance the ability of the transformers to dissipate the heat generated by their copper and iron losses. Both the fins and the radiators increase the surface area transferring heat to the atmosphere. The radiator, in addition, increases the natural circulation of oil by the convection currents set up within the unit.

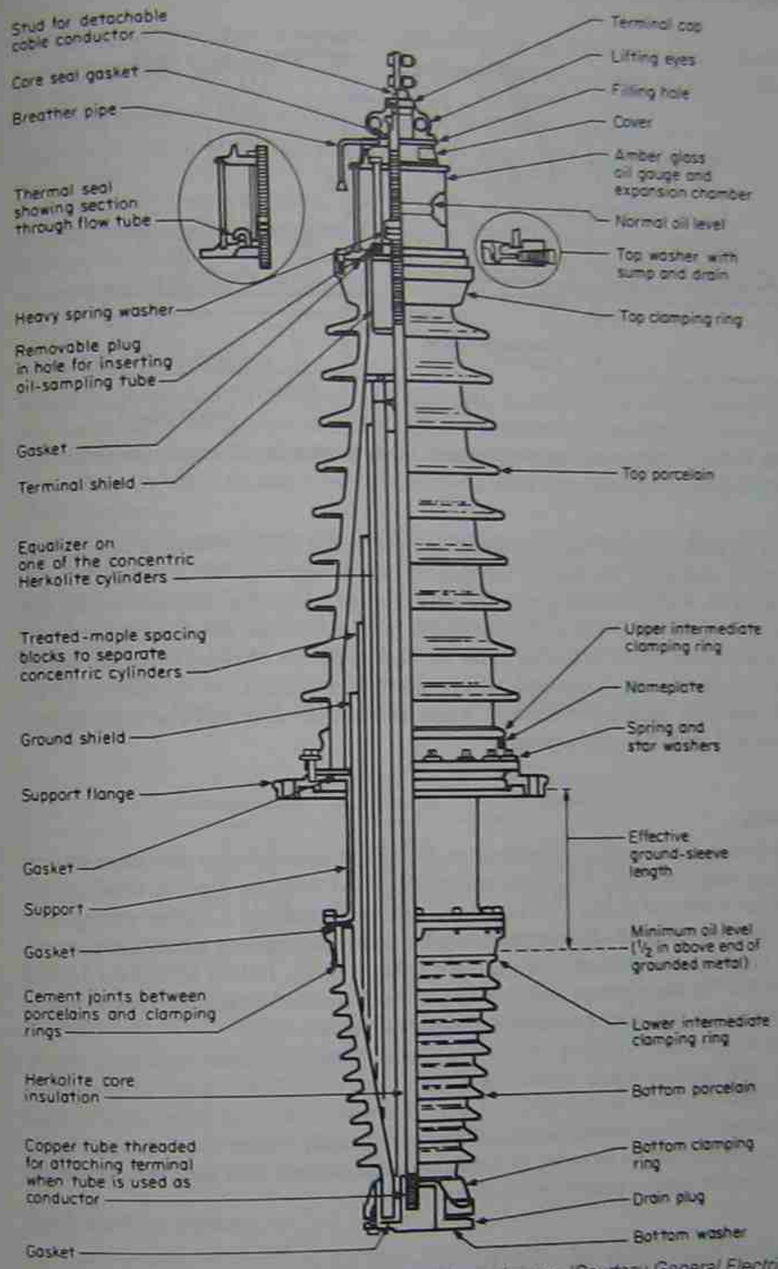


FIG. 13-1 Typical oil-filled bushing for a 69-kV transformer. *(Courtesy General Electric Co.)*

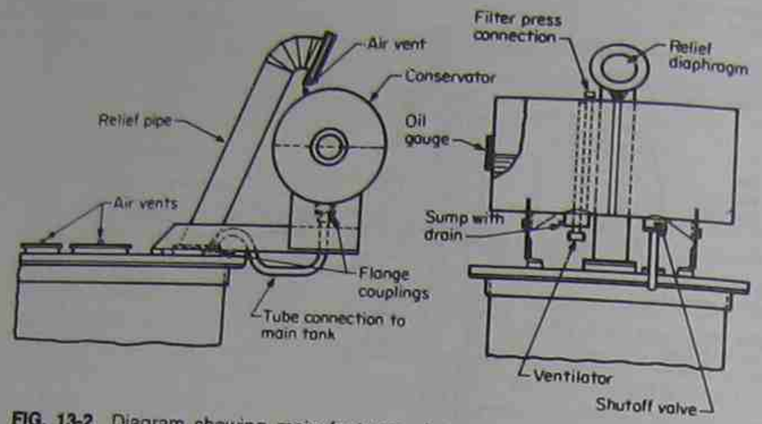


FIG. 13-2 Diagram showing main features of a conservator. *(Courtesy General Electric Co.)*

This cooling capability may be further increased by fans blowing against the fins and radiators, increasing the rate of heat transfer to the surrounding atmosphere. Further cooling may be obtained by pumps forcibly increasing the rate of circulation of oil in the radiators. Both means are often used together. In some cases, resort is had to water cooling by means of pipes installed within the transformer tank through which water is circulated, or by means of an external heat exchanger through which the hot oil and water are separately circulated with the aid of pumps.

Rating

In addition to the voltage classification, substation transformers may have several ratings expressed in kVA, each rating associated with the type of cooling employed: a normal rating with no added means of cooling; a higher rating with forced air or forced oil circulation; and a still higher rating when both means are used in combination; for example, 10,000 kVA; 12,000 kVA-FA; 15,000 kVA-FA/FO. Ratings may also include permissible noise levels at maximum loads, expressed in decibels at standard distances from the unit.

Impedance

The impedance of substation transformers is usually higher than that of distribution transformers in order to hold down the current that may flow during a fault on the system connected to its low side.

CIRCUIT BREAKERS AND PROTECTIVE RELAYING

Protective devices have been described in Chaps. 4, 7, and 12. The same considerations that apply to the types of bushings for the several levels of voltage

for transformers on their high-voltage side also apply to circuit breakers. Current transformers for relaying, metering, or other purposes may also be included in the bushing.

Circuit breakers may be single-phase or three-phase; these may consist of a single pole within an individual tank, or the three poles may be contained in a single tank.

Ratings of circuit breakers include their voltage classification in kV, their normal current-carrying capacity in amperes, their short-circuit- or fault-current interrupting capability in amperes or kVA, and, in some instances, their speed of opening, in cycles.

Metal-Clad Switch Gear

Modular metal-clad switch gear is constructed to incorporate circuit breakers, disconnecting devices, interlocks, measuring instruments, current and potential transformers, relays, and buses into a single, compact, factory-assembled unit or module for each circuit; a number of these units are capable of being assembled together.

Beside the compactness, the modular construction provides for flexibility in switching arrangements and for ready, inexpensive future expansion. With no live parts exposed and with interlocks to prevent energized switch gear from being drawn out, protection for both worker and equipment is enhanced. Connections into and out of this type of switch gear can be made via underground cables, making for neat appearance.

Ratings of metal-clad switch gear are determined by its current-breaking capability:

Voltage classification	*Normal current capacity*	*Fault-current interrupting duty*
5 kV	2000 A	50,000 kVA
15 kV	2000 A	500,000 kVA
34.5 kV	2000 A	1,500,000 kVA

Units above these ratings may be tailor-made for specific installations.

FUSES

Fuses associated with distribution transformers and primary circuits have been described in Chaps. 4, 5, and 11. Their time-current characteristics and their coordination with each other and with reclosers and circuit breakers have been discussed.

High-Voltage Fuses

In some smaller or rural substations, where possible short-circuit currents may be limited to relatively low values, a high-voltage fuse may be substituted for the incoming circuit breaker. While its operation, including coordination with other protective devices on the same circuit, is the same as for distribution fuses,

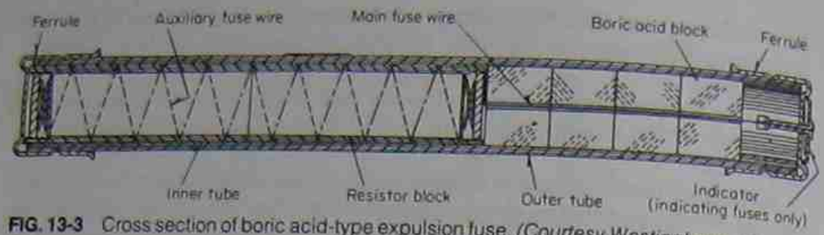


FIG. 13-3 Cross section of boric acid-type expulsion fuse. *(Courtesy Westinghouse Electric Co.)*

its construction is greatly different from that associated with door- and expulsion-type cutouts. The high-voltage fuse links are usually enclosed in a container, which tends to suppress and confine the arc and vaporizing metal, making the fuse capable of interrupting moderate short-circuit currents at the higher voltages.

Liquid-Filled Fuses In liquid-filled construction, the fuse link is enclosed in a tube that is filled with a fire-extinguishing fluid such as carbon tetrachloride. A spring holds the fuse under tension so that, when it blows, the resultant arc is quickly lengthened and quenched in the fluid; the gas formed is inert and aids in blowing out the arc. If the pressure becomes excessive, provision is made to have the cap on the "outgoing" side of the fuse blow off, preventing the rupture of the tube and confining damage to the fuse itself.

Solid-Filled Fuses In solid-filled construction, the material surrounding the fuse element may be sand or powdered boric acid. In the sand-filled type, the heat and gases generated when the fuse melts are absorbed by the sand, which tends to squelch the arc. In the boric acid type, the heat produced decomposes the boric acid, which forms steam under pressure that acts to squelch the arc. See Fig. 13-3.

Ratings

High-voltage fuses for this type of application are rated not only for their voltage classification and normal current-carrying capacity, but also as to their short-circuit-current interrupting capability.

DISCONNECT AND AIR-BREAK SWITCHES

Disconnects are rated by voltage classification in kV and normal current-carrying capacity in amperes. They are not rated to interrupt any current. These have been discussed in Chaps. 4, 5, 7, and 12.

Also discussed in these chapters have been air-break switches. They may be single-pole or three-pole gang-operated. They are also rated by their voltage

classification and normal current-carrying ability, but, in addition, have a current-interrupting capability expressed in amperes.

SURGE OR LIGHTNING ARRESTERS

Surge arresters may be of the valve or expulsion type and have been described in Chap. 6. They are rated not only on their normal voltage classification in kV, but also on their crest voltage capability in kV at a standard 1.5 × 40-μs wave (or other specified wave), and their discharge-current capability in amperes or thousands of amperes (kA). For high-voltage application, surge arresters may consist of a number of unit-value valve arresters connected in series in one overall unit, as shown in Fig. 13-4 for a 69-kV arrester.

VOLTAGE REGULATORS

Voltage regulators may be of the induction type or the TCUL or step type, and have been described in Chaps. 4, 7, and 12. A cross section of an induction regulator is shown in Fig. 13-5. Regulators are rated by voltage classification in kV and the plus-minus percent voltage-regulation capability. In step-type regulators, the percent voltage of each step and the number of steps is often also

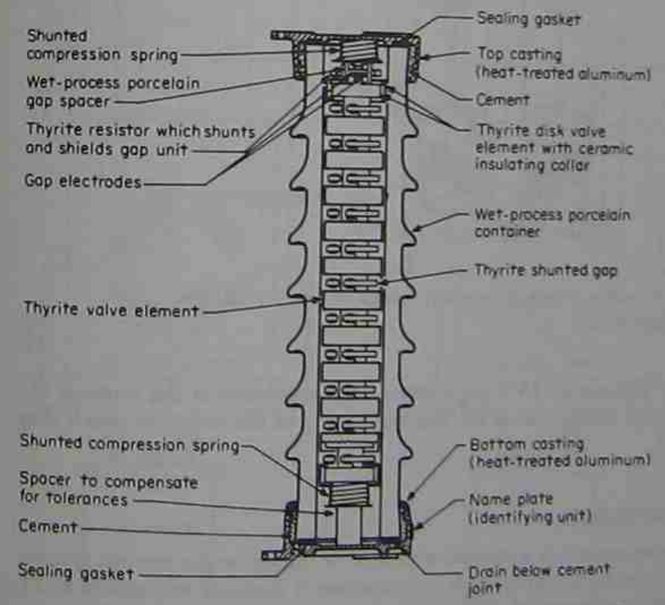


FIG. 13-4 Cross section of a 69-kV Thyrite (valve) surge arrester. *(Courtesy General Electric Co.)*

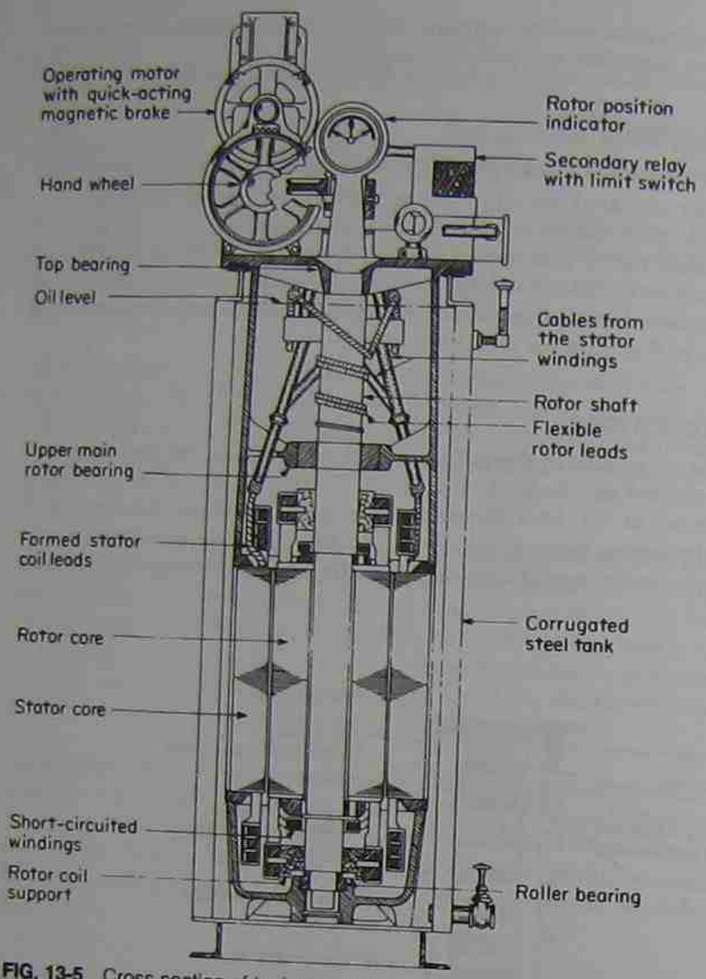


FIG. 13-5 Cross section of typical induction voltage regulator. *(Courtesy Westinghouse Electric Co.)*

specified. The current or kVA capability of the regulators is the same as the maximum voltage change times the full load rating of the circuit in which they are connected.

STORAGE BATTERIES

Storage batteries constitute a reliable source of dc energy to the control systems in substations. Such control systems may operate at nominal voltages of 6, 12, 24, 48, or 120 V, although the latter three are the preferred values. Since the batteries are made up of a number of individual cells, each producing approximately 2 V, a number of them are connected in series-parallel circuits to provide

the required voltage and capacity. These have been mentioned in Chap. 7 in connection with the operation of circuit breakers and their associated relays.

The most frequently used batteries are the so-called lead-acid type and the nickel-alkaline type (sometimes also called the Edison battery). The first type employs plates made of lead and sulfuric acid as the electrolyte; the second, plates made of nickel oxide and iron or cadmium, with potassium hydroxide as the electrolyte. Separators are made of treated wood, glass wool, porous rubber, or plastic material. Containers for the lead-acid cells are usually made of glass, rubber, plastic, or asphaltic compositions, with ports or vents for exhausting of gases and renewal of water or acid. Containers for the nickel-cadmium alkaline cells are nickel-plated sheet steel, hermetically sealed, but with valves to allow the venting of gases; the electrolyte needs no replacement.

Storage batteries are usually rated in ampere-hours and their capacity on the basis of an 8-h rate. Battery efficiencies run from 85 to 90 percent, with the lower efficiencies experienced at the more rapid rates of discharge and charge.

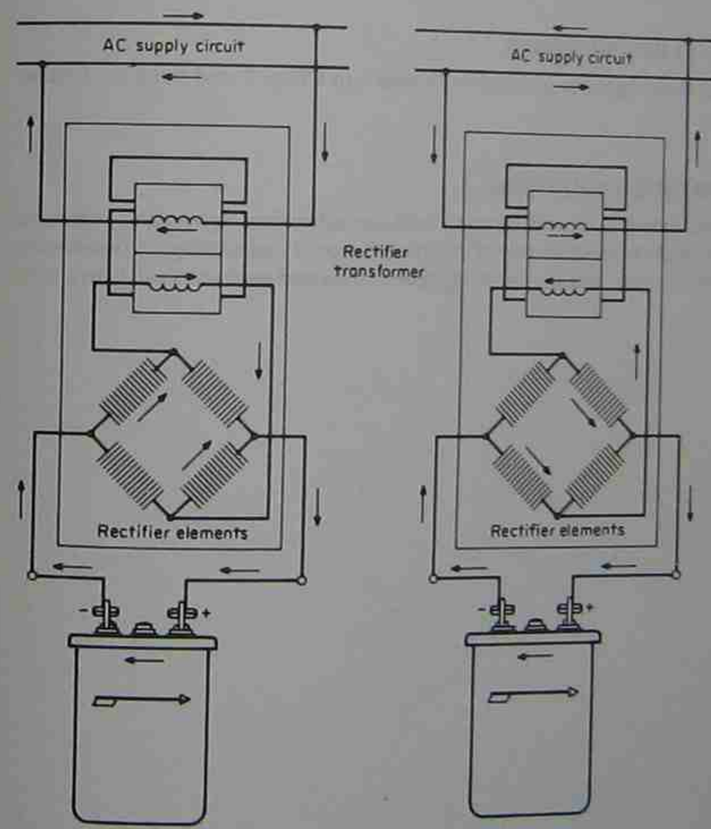


FIG. 13-6 Basic rectifier connections for battery charging.

Batteries are permanently connected to a dc source usually supplied through small copper oxide or selenium rectifiers from an ac supply, and connected as shown in Fig. 13-6.

MEASURING INSTRUMENTS

Measuring instruments usually include ammeters, voltmeters, watthour meters, and kilowatt demand meters; wattmeters, reactive volt-ampere, and power factor meters may also be found in some installations. These have been generally discussed in Chap. 8, and as they are universal types of instruments they will not be described further. Associated current and potential transformers have been described elsewhere.

CAPACITORS AND STREET LIGHTING EQUIPMENT

Capacitors and lighting equipment have been described in Chaps. 4, 5, and 12 and need no further discussion.

BUSES AND BUS SUPPORTS

Buses and their supports have been discussed in Chap. 7 and need no further discussion.

ALL SUBSTATION EQUIPMENT

For current information and further details on substation equipment, reference should be made to manufacturers' instruction books and catalogs. Consultation with manufacturers' and suppliers' representatives and engineers will prove most valuable.

PART FOUR

OTHER DESIGN CONSIDERATIONS

CHAPTER 14

NONTECHNICAL CONSIDERATIONS

INTRODUCTION

The maintenance of good employee, consumer, and community relations cannot be divorced from the planning and design of distribution systems. Indeed, along with the other functions connected with the utility's business, these must be considered an integral part of the distribution engineer's responsibility. The distribution system involves not only the utility's employees, but contact with every consumer at some stage in the process of providing and maintaining electric service. Moreover, electricity is intimately connected with the life of a community as a whole. The distribution engineer, therefore, must be ever conscious not only of the obligations of a fellow employee and a good neighbor, but also those of a good citizen.

The technology and expertise which the distribution engineer brings to the problems of safety, quality of service, and economy must also be extended to include those involving nontechnical considerations. While the previous chapters deal with the resolution of technical questions employing the natural laws of science and mathematics, the solution to nontechnical problems requires the employment of heavy dollops of common sense.

SAFETY

Safety to the employees and the public (who are, after all, the distribution engineer's neighbors) has been previously discussed in terms of electrical and mechanical technical considerations (e.g., selection of utilization voltages, adequate strength of poles and conductors, etc.). In addition, however, several other considerations should be taken into account.

Accessibility

As much as practical, the utility's facilities have to be both accessible (to the workers) and inaccessible (to the public). For example, a distribution pole line should be so located that free and easy access to the facilities is available at all times, yet it should not interfere with pedestrian and vehicular traffic, nor intrude into areas (such as playgrounds) where its presence may constitute a particular hazard. This accessibility and inaccessibility should prevail even under adverse or contingency conditions.

Moreover, the conductors and equipment on the poles should be so situated that they can be handled safely by the people working on them. This not only implies providing sufficient working space, but includes considerations of how the work may be performed safely. Safe methods include the use of protective equipment (such as rubber gloves and sleeves, line hose, etc.), the use of live-line tools and equipment, and the deenergization and grounding of the facilities on which work is to be performed. This last, in turn, may include the design of additional facilities to maintain service, as much as practical, to the consumers involved.

The continual development of new and better tools and equipment is also reflected in the design of distribution lines. For example, the development of bucket trucks and plastic insulation resulted in "armless" construction wherein cross arms are eliminated and insulated conductors are spaced closer together chiefly to obtain a more desirable appearance.

Horizontal and vertical clearances between the power line and adjacent structures must take into account the possibility of contact with television and radio antennas, flagpoles, and other encumbrances that may exist on, or may later be added to the structures rather than being limited only by technical or code requirements.

Clearances are specified in the National Electric Safety Code, and in local rules and regulations. These, it must always be remembered, are only recommendations for minimum values. The judgment of the distribution engineer can, and must, supersede them when other factors make exceeding these values desirable, if not imperative.

Maintainability

Each item selected, and its place in the distribution system, must be viewed in light of its possible failure or malfunction for whatever reason. Provision, therefore, must be made in the design for adjustment, repair, revamping, or even replacement, should that occasion arise. The design of the distribution system, therefore, should take into consideration the method of maintaining each of the several elements making up the distribution system.

The Distribution System In general, the safest means is to be able to deenergize and ground the particular item requiring maintenance, preferably without affecting the remainder of the circuit. Circuits, both primary and secondary, are arranged so that small sections may be deenergized by interconnecting the remaining portions to other sources, by means of some sort of switches. Smaller pieces may be deenergized by means of hot-line or live-line clamps.

Where deenergization is not practical, work may be carried out by insulating the worker. This is accomplished by protective gear, such as rubber gloves, sleeves, blankets, line hose, insulator hoods, and other, similar devices. Another method insulates workers from ground by having them work from insulated platforms or insulated buckets mounted on line trucks. Still another means involves the handling of the energized facilities by tools having sufficient insulation properties which, properly handled, enable the worker to accomplish required maintenance by essentially a remote operation of the tools; this is referred to as live-line, or hot-line, maintenance. To facilitate such operations, appropriate details and modifications are included in the design of distribution systems, e.g., wider spacing of conductors; hot-line ties that hold conductors to the insulators; "unnecessary" extensions of primary and secondary mains so that mains butt each other, permitting their temporary connection during contingencies by means of jumpers; the arrangement of terminals at substations to accommodate portable substations; and the limitation of buried cables in URD systems to enable their bypass by an emergency length of cable laid on the ground during cable failures.

Equipment Design for maintainability also extends to individual pieces of equipment installed on the distribution system. For example, in both substation and distribution transformers, provision is made so that taps can be changed through a hand hole in the cover of the transformer (while it is deenergized), bushings can be repaired or replaced, or oil changed, without the necessity of removing the transformer to the shop for dismantling.

QUALITY OF SERVICE

There is more to the quality of electric service to the consumer than the electrical and mechanical considerations described in previous chapters. The selection and maintenance of proper voltage, of materials and equipment of ample capacity, and the maintenance of frequency within very rigid limits all contribute to the quality of electric service rendered the consumer. Equally, if not more, important, however, are service continuity and environmental considerations, which also play a large part in the high standard of quality established by the power suppliers in this country.

Continuity of service may be affected by the nature of the area served. For example, if the facilities are to be installed in a heavily treed area, initial and periodic tree trimming may be required, and armless design with insulated conductors, or the installation of an overhead sheathed cable, may also be specified in order to have a minimal effect on the trees. Indeed, if the aesthetic value of the trees is prized by the consumers in the area, good consumer and community relations may dictate consideration of underground construction.

Similarly, areas exposed to severe storm or wind conditions, or to lightning displays, may require additional considerations, as will areas of atmospheric

pollution such as concentrations of salt spray or chemical contamination. Also, the proximity of airports and military bases may introduce additional sources of hazard that may require relocation or undergrounding of facilities.

Occasionally, underground installations may also require remedial or preventive considerations. For example, chemical action from minerals in the soil, and from electrolytic action caused by stray direct currents from railroad return circuits or by those generated by the presence of dissimilar elements (usually metals) either in contact with each other or immersed in soil chemicals acting as electrolytes, may be such as to require special considerations. Some have been mentioned in the previous chapters, but relocation of facilities or their installation overhead may be the individual solutions to such problems.

Moreover, both overhead and underground systems in particular areas may be subject to the effects of hurricanes, tornadoes, floods, earthquakes, landslides, and other destructive acts of nature. The incidence of their occurrence may substantially affect the planning and design of distribution systems in those areas.

In addition to the environmental problems brought about by nature, other environmental problems, usually concerning appearance, may affect final plans and designs. These may arise from the desires of single consumers, from groups of consumers, or from the community as a whole. In areas where property values may be adversely affected by the appearance of utility facilities, alternate plans and designs may need to be considered. For example, installation of overhead facilities along rear-lot property lines to improve appearance is sometimes considered, although access to the facilities, while not restricted, may be hampered. Armless construction has also been discussed. Other measures may include the substitution of concrete or metal poles for wood poles, and the coloring of poles (wood, concrete, or metal) and visible equipment (transformer and capacitor tanks, insulators, etc.) to blend with the surroundings, or with the sky.

Community pride in government buildings, civic centers, historical structures, and landmarks may call for special attention and treatment, which the distribution engineer must recognize; the engineer might also seek to participate in the determination of preservation measures.

The interests and desires of members of a community are often reflected in ordinances and regulations promulgated by their representatives on appropriate boards and councils of authority. In many cases, the statutes specify the community's relationship with the electric utility serving it and, more specifically, the design of facilities to be installed. Revenues from the community may or may not justify their demands, but the distribution engineer has little choice but to modify the designs to meet the requirements.

ECONOMY

Operating Modifications

In the planning and design of distribution systems, the economics of the cost of installation (including materials, equipment, labor, engineering, and overhead) to serve a given load are generally determined by Kelvin's law; i.e., that combination of designs and equipment whose annual carrying charge is equal to the

annual cost of losses sustained therein usually indicates the economic preference among the several designs under consideration. The designs are often modified by the distribution engineer to provide spare capacity to serve future load growth. The amount of additional expenditures that can be justified may be calculated by determining the future worth of present expenditures (or vice versa). This, however, may be based on many assumptions of which the distribution engineer may be unaware; therefore the engineer must use discretion and experience in selecting the proper ones for study.

As indicated above, the conclusions reached from economic considerations may be substantially modified because of special conditions that interpose themselves for geographic, seasonal, or environmental reasons.

Standardization

Even after all of these factors have been taken into account, the use of standardized sizes, kinds, and types of materials and equipment again skews the economics and may seriously affect the cost-effectiveness of the final design and construction.

Standardization, however, permits substantial economies to be realized. It enables quantity purchase of materials at lower unit costs as well as the purchase of fewer items and smaller overall amounts to be stocked; it also allows fewer and more specialized tools to be employed. It makes for the interchangeability of materials, equipment, and tools; and because such standardization leads to standardized construction and maintenance practices, it also permits the interchangeability of personnel.

Indeed, such standardization of materials and work practices also tends to result in greater safety to and productivity from the work force. Training can be more effective if concentrated on fewer and more repetitive tasks. In addition to humanitarian considerations, these contribute to more efficient and economical operations.

The utilization of such standards may disturb the economic optimization sought, as its effect on cost-effectiveness may be negative for an individual project. On overall balance, however, such standardization results in positive improvement in the economics of distribution design.

Civic Improvement

Another instance in which the discretion of the distribution engineer is exercised is that in which projects of reinforcement, rebuilding, or modernization of distribution facilities cannot be ordinarily justified economically. Advantage is taken, however, of other activities, usually associated with civic improvements such as road widenings, sewer, water-line, and subway construction, beautification programs, and similar projects, which may necessitate the handling, making safe, or temporary relocation of the distribution facilities. Here, logic would indicate the undertaking of changes that would otherwise not have been justified from a strictly economic viewpoint.

CONCLUSION

These are only a few examples in which recommendations based solely on tangible technical considerations may be overridden by nontechnical considerations influencing the design of the distribution finally selected.

The distribution engineer, therefore, must not only be aware of new and improved materials and equipment, but must be cognizant of changes in codes, regulations, and construction and maintenance standards and practices. Many of these are brought about by the development of new methods as well as new materials and equipment; many are also influenced by the changing public expectations resulting from changing social values and economic conditions. Indeed, the engineer must not only keep abreast of such changes, but should be an active contributor to them.

In selecting each item and designating its place in the distribution system, the engineer must examine step by step its impact on safety, service quality, and economic results before making a final determination and issuing orders to the field.

CHAPTER 15

OPERATING CONSIDERATIONS

INTRODUCTION

There are yet other requirements which the design of distribution systems must meet, other than those of meeting the consumer's and community's needs and desires. The additional requirements, in the main, have arisen from the changing national economic and energy situations. Collected under the general subject of operating requirements are the installation and arrangement of facilities to achieve a better quality of service, but also a more efficient distribution system and a more economical overall electric system from the generating plant to the consumer's premises.

The operations may be classified into four specific functions and may be listed under simplified headings:

1. Quality of service
2. Load shedding
3. Cogeneration
4. Demand control (or peak suppression)

These are somewhat interrelated, and all involve the distribution system.

QUALITY OF SERVICE

Operations involving the improvement of quality of service to the consumer have been discussed in previous chapters, and include measures to:

1. Isolate faults and restore service to the unfaulted portion of the distribution system

2. Transfer loads between phases or between circuits to relieve overloads or potential overloads, and improve voltage conditions
3. Switch on and off capacitors installed out on the distribution feeders (and in the substations) to improve power factor, reducing the value of current flowing and releasing capacity of distribution facilities, with resultant voltage improvement
4. Enable portions of the distribution system, including the substation portion, to be deenergized for construction and maintenance purposes without affecting the remaining portion of the circuit

Designs of distribution systems include provisions for carrying out these operations by means of suitable circuit extensions and switches. With the development of electronic and miniaturized systems of control and communication, many of these operations, generally performed manually and sometimes with a significant lapse of time, may now be performed automatically almost instantaneously.

LOAD SHEDDING

Why

The need for load shedding stems from two general causes, usually unforeseen:

1. Lack of sufficient power supply
2. Lack of sufficient transmission or distribution load-carrying ability

These conditions may come about from:

1. Load growth faster than the construction of new facilities can be accomplished
2. Abnormally high unforeseen demands that are created by unusual seasonal changes or by some special events that cause a significant loss in diversity of consumers' loads
3. Failure or overload in some element or elements of the supply facilities; e.g., transmission line failure, substation transformer failure, etc., for a prolonged period.

How

In this context, load shedding implies decreasing the load on the substation bus, substation transformer, or incoming transmission line. This may be accomplished in two basic ways:

1. Voltage reduction
2. "Brownout," or periodic disconnecting of feeders for relatively short periods of time on a predetermined schedule

In rare instances is resort had to the employment of both of these methods at the same time.

Voltage Reduction Voltage reduction may be accomplished by manipulating voltage regulators at the substation on individual feeders, or on the substation bus, where the substation's voltage is so regulated. Voltages may be reduced by steps according to the amount of load shedding required. In circuits that supply essentially lighting or unity power factor loads, a 1 percent voltage drop results in almost a 1 percent drop in load.

Steps may be 1 or 2 percentage points each to a maximum of about 8 percent; more often, however, voltage is lowered in two steps, (say) 5 percent and 8 percent.

Lowering voltage beyond this 8 percent value may prove self-defeating as light output from incandescent lamps decreases to the point where additional lighting may be turned on. Fluorescent lighting is also affected as maintenance of the electron flow in the fluorescent tube becomes tenuous. Power loads usually continue to operate satisfactorily at the lower voltage, drawing more current, so that they have little effect on load reduction. This increase in current, however, may cause overheating, loss of torque, and other undesirable conditions to take place.

In some instances, the lowering of voltage may take place on the transmission or subtransmission incoming supply circuit or circuits when they are equipped with voltage regulators at the sending ends. In this event, the voltage regulators on the distribution feeders (or on the distribution feeder bus) at the substation may have to be blocked in a fixed or neutral position so as not to negate the effect of the reduced voltage on the incoming supply.

Regulators installed in the field on portions of primary circuits, for practical reasons, are usually left alone and allowed to travel to their maximum position if necessary. The relatively small amounts of load that can be shed by attending to these units is often not worth the effort necessary to adjust them to nonautomatic operation at the start and to return them to automatic operation at the end of a usually short period of time.

Distribution System Problems Where distribution feeders are deliberately designed to accommodate such lowering of voltage below normal values, it may be necessary to reinforce or provide for some consumers, usually at the ends of primary circuits. These may have a sufficiently low normal voltage that the additional drop may cause damage to some of their connected loads. In most cases, provision involves the shortening of secondary mains and the more closely spaced installation of transformers; also, taps may be set for a lower (or the lowest) ratio of transformation. Sometimes, the installation of a booster transformer in those farthest sections of the primary circuit will accomplish the purpose. In any event, this feature requires investigation and the taking of necessary measures preferably before the need for such voltage reduction to shed load is placed in effect.

Where the need for voltage reduction stems only from some deficiency in the distribution system, that deficiency should be identified and removed as quickly as possible; such a need might occur in the case of overloads in an outgoing underground cable supplying a feeder where the cable carries too

great a load under normal conditions, or under contingency conditions where it may be called upon to carry the load of an additional circuit or circuits, or parts of them.

Low-Voltage Network Where the feeders supply a low-voltage secondary network, extreme care must be exercised in lowering the voltage on the supply primary feeders. Operation of the regulators must be coordinated so that the voltage on each of the feeders is lowered as simultaneously as practical to prevent opening of network protectors on the feeder if its voltage alone is lowered. In turn, the additional load picked up by the feeder or feeders whose voltage is not lowered may cause "hunting" between the protectors of the several feeders, or may cause feeders to trip from overloads in a cascading effect that would shut down the network. In some instances, the overcurrent relays on the feeder circuit breakers may be blocked to prevent feeders from tripping from temporary overloads until all the regulators have been adjusted and locked in at the desired lowered voltage level. If the voltage lowering operation is to be a relatively frequent occurrence, relay settings on the network protectors in the field may be made sufficiently insensitive to keep the protectors from hunting and the feeders from cascading out.

Brownout

Brownout is a procedure in which feeders are taken out of service for a relatively short period of time on a predetermined basis, usually one at a time, to reduce the demand on the substation supply transformers or on the facilities back to the generating station. Critical loads, such as hospitals and military bases, are usually supplied from two sources with double-throw facilities to accomplish a switchover to an energized source, either manually or automatically. Where this arrangement does not exist, it may be necessary to sectionalize that portion of a feeder supplying such critical loads, connecting it to an energized feeder when its normal supply feeder is deenergized. In some instances, where more than one critical load may exist on a feeder, that feeder may be exempt from the brownout procedure. Feeders supplying low-voltage networks are usually exempt as the load dropped by them in such an operation would be picked up by the others supplying the network, and the net reduction in load would be very nearly zero.

COGENERATION

Why

Basically, cogeneration involves the interconnection of consumers' generation to the utility's distribution system. Changing energy and economic conditions have made such interconnections feasible in many instances, and, in some areas, mandated by law (e.g., Texas). Large users of steam and hot water have found it economically desirable to generate electricity and use the "waste" heat to meet their steam and hot water requirements. The electricity so produced that they do not use themselves is sold to the utility, usually at an advantageous rate. This

is because regulatory guidelines tend to favor a rate paid for power purchased by a utility (the avoidable cost to produce power) to be based on the utility's *least* efficient power plant, whereas the cost of power to a utility consumer is usually based on an *average* cost to produce power.

Paralleling the Systems

Paralleling the consumer's generation facilities with those of the utility requires that additional protection equipment be installed at the cogenerator's facilities. The principal features of this additional protection include:

1. Automatic synchronizing of the generator output with the utility
2. Relaying to prevent the closing of the circuit breaker to the utility system until the cogenerator's generator is open, for protection of that generator
3. Relaying to open the circuit breaker to the utility system on loss of power in the utility system
4. Relaying to open the circuit breaker to the utility system on a ground fault on the utility system
5. Relaying to control the cogenerator's generator circuit breaker to provide generator overcurrent protection, phase current balance protection, reverse power protection, under- and over-frequency protection, and under- and overvoltage protection
6. Control of engine governor equipment for speed, generator phase match, and generator load

The electrical connections and indicated protection are shown on the one-line diagram in Fig. 15-1.

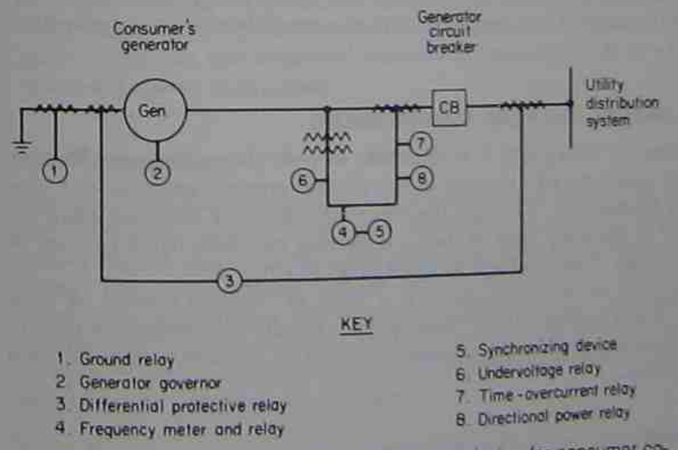


FIG. 15-1 One-line diagram showing protection relaying for consumer cogeneration unit.

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Modes of Operation

There are several load relationships that may exist between the cogenerator and the utility:

1. The cogenerator always supplying power at a constant rate; i.e., the cogenerator supplying a part of the utility's base load
2. The cogenerator always supplying power in variable amounts, fluctuating with the consumer's needs; i.e., the cogenerator supplying only a marginal part of the utility's load
3. The cogenerator and the utility both supplying the consumer's requirements on a normal or contingency basis
4. The utility supplying all of the consumer's requirements on a contingency basis

The Distribution System

The variation in the modes of operation not only may affect the settings applied to the protective relays, but may influence the design of the utility's distribution system. Obviously, the distribution facilities required will vary with the mode of operation, and the problem of maintaining voltage within acceptable limits as conditions change (e.g., from mode 1 to mode 4 above) may tax the engineer's ingenuity.

The wide variations that may take place in voltage profiles and current distribution in the distribution circuit to which the cogenerator is connected may require rearrangement of the circuit configuration to maintain safe and acceptable standards of electricity supply. These may require the installation of additional switching facilities to achieve desired sectionalization and rearrangement; preferably the switches should be automatically operated. Moreover, as generators are usually under control of one operating group while the distribution system is controlled by a separate group, some difficulties in coordination may arise.

DEMAND CONTROL (OR PEAK SUPPRESSION)

From an economic viewpoint, it is desirable to hold down the peak load or maximum demands on all the parts of the electric system—generation, transmission, and distribution. This has the desirable effects of reducing plant investment and at the same time reducing operating expenses (fuel) because of reduced I^2R losses. This has been touched upon in Chap. 8.

Load shedding as described above is a form of demand control or peak suppression, but is associated with contingencies usually of a temporary nature; demand control applies to a permanent reduction in maximum demands as a normal condition.

Basic Concept

For a utility, the most efficient use of its facilities, from an investment point of view, is to use them throughout their lifetimes at maximum loads. By definition,

if this were done, the load factor for the facilities would be 100 percent. This does not occur, because some consumer loads are not always required and are turned off. The closer the utility can approach 100 percent load factor, however, the better the investment can be utilized, and the lower a unit of output can be priced.

The load factor concept in supplying a given load applies equally well whether it is applied to the utility itself or to a single consumer. For example, it is not unusual for a utility to have an annual load factor of 50 to 60 percent because of seasonal air-conditioning loads; this implies that a great part of the facilities used to meet summer peak demands will remain idle the rest of the year.

Typical load factors range from less than 20 percent for some residences to over 90 percent for some industrial plants (like some manufacturing plants having large air-filtering installations). In between, office buildings typically may have load factors of 20 to 30 percent and large, three-shift manufacturing plants 70 to 80 percent. Small to medium industries may have load factors ranging from 20 to 70 percent.

Conservation

Demand control is also a conservation measure, as it will substantially reduce losses, in both the utility's and the consumer's facilities. These reductions will be reflected in fuel consumption at the utility's generating plants and in both demand and energy charges (including fuel adjustment charges) in the consumer's bill.

Although the total overall consumption by a consumer may remain the same, the leveling of demands will decrease the *maximum* current flow, though the *reduced* current flow may continue for a longer period of time. As losses (I^2R) vary as the square of the current, the lower current should result in a substantial reduction in the total energy requirements of the consumer.

Experience has also indicated that reviews for reducing demand often discover unnecessary operation of some equipment, and result in elimination of some operations and improved methods of operation—all of which result in decreased energy consumption.

Load Management

Basically, to reduce the demand on its facilities, the utility must seek to reduce the individual consumers' demands. Preferably, the individual consumers' demands should also be coordinated so as to achieve a minimum coincident demand. This latter feature is more difficult of attainment than the first, as it involves cooperation not only between the utility and the consumer, but among a number of consumers as well. Methods for reducing demands differ for large consumers, such as industrial plants, and for small consumers, such as residences; both, however, employ rate incentives.

Large Consumers For large consumers this subject was touched upon in Chap. 8, in connection with the demand metering of large consumers and their role in schemes employed for reducing consumer demands. This is important to the

consumer, as utility rates include demand charges based on the registered maximum demand. The timing impulses from the demand meter are used in several schemes to hold down demands to predetermined values.

To reduce demand requires that nonessential load peaks be reduced or eliminated. Loads are analyzed into several categories:

1. Those that are essential, that cannot be turned off without affecting safety and operations.
2. Those that may be curtailed or turned off for relatively short periods of time without being noticed (e.g., 10 min out of each hour); they may be programmed to be shut off sequentially for predetermined periods of time.
3. Those that may be deferred, put off to some random off-peak time which may differ from day to day (or other period).
4. Those which may be conveniently rescheduled regularly to off-peak periods.

Typical examples of such categories for large industrial consumers are shown in Table 15-1.

Load Cycling Cycling involves the turning off and on of individual loads or groups of loads. How long they can be turned off and how often is predetermined, and the off-on times are staggered so that a minimum number of such loads are on at any one time to achieve the smallest practical maximum demand.

TABLE 15-1 TYPICAL CATEGORIES OF LARGE CONSUMER LOADS

Category	*Examples*
Essential	Lighting (some)
	Elevators
	Production equipment (some)
	Ventilators (some)
	Pumps (some)
Curtailable	Air conditioners
	Heaters
	Ventilators
	Refrigerators
	Water pumps
	Ovens
Deferable	Coolers
	Air compressors
	Water heaters
	Equipment testing
Reschedulable	Electric furnace
	Process ovens
	Incinerators
	Trash compactors
	Battery chargers

Most automatic demand-control systems employ load cycling and involve some technique of demand forecasting to determine when loads should be turned off and on. All are based on the consumer's actual consumption, and its rate compared to some predetermined ideal rate. Several methods of obtaining the comparison have been devised yielding different degrees of accuracy and precision; these will not be further detailed as they are not within the scope of this book. Almost all employ pulses obtained from the utility's demand meter for matching the demand under consideration with that being recorded by the demand meter. Demand-control equipment also acts to control "average" maximum demands, leaving the utility still needing to meet the actual or peak maximum demand.

Demand control usually leads to increased off-on switching of equipment. Care must be taken, therefore, to ensure that thermal overloads and mechanical failure of switching devices do not occur because of short cycling of equipment.

Small Consumers Most small consumers are residential consumers whose demand is not usually metered. Efforts by the utility to hold down their demands are limited almost to promotional rates which, for practical purposes, cannot be policed. More and more, however, utilities are installing demand meters or clocking devices connected to the larger loads, such as hot water heaters, dish and clothes washers, etc. Consumers are thereby encouraged to install small computer-actuated devices for controlling the turning off and on of such loads; these include supplementary time delays so that the initial inrush currents on the various appliances will not (because of possible loss of diversity) all occur simultaneously, causing service interruption and possible damage to the appliance.

Thermal devices have been developed for storing cold and heat during off-peak periods to be used during periods of electrical peaks. Such devices are also beyond the scope of this book.

Load Management Control

A number of utilities have assumed control of devices that will switch off loads on their system automatically when undesirable demand levels are being reached. This involves the identification of noncritical loads that can be placed under the control of the utility with agreed-upon constraints regarding maximum time to be left off. Agreements with consumers include favorable "interruptible" rate schedules. These may be controlled by means of signals transmitted by radio, carrier, or telephone communication. (Similar means of communication are also employed in small residential consumers, mentioned earlier.)

Costs for such demand-control installations are sometimes shared with the (large) consumer, where the same equipment is also used to control the consumer's maximum demand. This demands an almost continuous review to assure certain that a target value set up by the consumer will not run afoul of that set up by the utility.

Utility Problems

The utility generally must meet seasonal and daily load peaks, peaks of relatively short duration. Generation, transmission, and distribution facilities must be provided to meet these demands.

Generation Utilities generally have three levels of power generation equipment, base load units, usually the newest and most highly efficient (as well as the most expensive); midrange units, which are less efficient and are perhaps the next newest of older generation facilities; and units generally operated as peak units, the least efficient and usually the oldest, but sometimes new units specifically designed for this short-term purpose. Controlling system demands, therefore, results in lowered cost to operate the least efficient units and, in the long term, defers the addition of the most expensive newest units.

Transmission Transmission lines are the bulk carriers of electrical energy, and fall into the same category as generators as far as investment is concerned. Here, too, the older and less efficient transmission lines, usually those operating at lower voltages than the newest lines, constitute part of the transmission network, including those facilities needed to ensure continuity of adequate service in contingencies. Controlling system demands will not only result in lowered I^2R losses, as indicated previously, but will also defer, if not make unnecessary, the installation of new and expensive transmission lines.

Distribution The same general observations concerning transmission lines also apply to distribution circuits. Additional distribution facilities (including substations) and conversions or construction at higher voltages can be deferred if the system demands can be controlled.

In the case of distribution facilities, however, a problem arises as to the rating of equipment, particularly transformers. The rating of such equipment, though nominally predicated on its current-carrying ability, is actually based on the allowable temperature at which insulation may be subject to failure. This temperature is a function not only of the heat caused by the losses (copper and iron) developed within the unit, but also of the duration of the developed heat. The control of demands on the distribution system will, on the one hand, reduce the maximum values of heat applied (as noted previously), but on the other, may reduce the thermal margin of safety resulting from the duration of the heating cycles. In some instances, no doubt, the net overall effect may be negligible; in others, especially during periods of prolonged hot ambient temperatures, such as exist in summertime, the net overall effect may be appreciable. Units so affected should, therefore, be closely monitored.

CONCLUSION

The need for conservation of investment capital and use of energy resources indicates the desirability of operating practices that no longer separate the distribution system from other parts of electrical system operations. Moreover,

electronic and miniaturization advances make practical the integration and automatic management of such operations. These may be listed as

1. Load management for conservation and improved overall system efficiency. This may include the direct control of consumer loads and energy storage where practical), and other means to alter the shape of the utility system load curve.
2. Alternative energy resource management to control utility- or consumer-owned generation which will integrate with the distribution system.
3. Distribution system management during normal and contingency operation, including reporting of interruptions, relocating and reconfiguration of circuits, remote operation of equipment, load monitoring and reactive power (VAR and capacitors) control, and even remote meter reading for revenue billing purposes.
4. Integrated systemwide control to provide for overall system operation during periods of widespread emergencies.

The distribution engineer, to a greater degree, must take into account the impact of these integrated operations on planning and design practices.

APPENDIXES

APPENDIX A

CIRCUIT ANALYSIS METHODS

INTRODUCTION

In the analysis of circuits to determine current distribution and voltage drops in the individual parts of the circuits, several basic principles are employed. These call for the reduction of the circuitry into successively simpler forms until a single loop circuit results. Computation of current and voltage values can then be made, essentially reversing the order of simplification, until all the individual parts of the circuit have been analyzed. These procedures are especially applicable to network-type circuits.

Kirchhoff's Laws

Kirchhoff's laws encompass two fundamental simple laws which apply to both dc and ac circuits, no matter how complex they may be:

1. The current flowing away from a point in the circuit (where three or more branches come together) is equal to the amount flowing to that point. Expressed another way, the vector or algebraic sum of all the currents entering (and leaving, a negative entry) a point is zero.
2. The voltage acting between two points in a circuit acts equally on all the paths connected between the two points. Expressed another way, the vector or algebraic sum of all the voltage drops (or rises, negative drops) around a closed loop is zero.

Applying Kirchhoff's laws to the parts of a circuit, a number of equations between the unknowns can be drawn. The number of independent equations which can be written from the first law is 1 less than the number of junction points; from the second law, the number is equal to the number of branches

less the number of junction point equations. The equations can be algebraically solved for all the unknowns. In practice, however, these laws are more often used to check results obtained by other means.

CIRCUIT TRANSFORMATIONS

Wye to Delta

Refer to Fig. A-1.

$$I_a + I_b + I_c = 0$$

$$I_a = I_B - I_C$$

$$I_b = I_C - I_A$$

$$I_c = I_A - I_B$$

$$\Delta = Z_aZ_b + Z_bZ_c + Z_cZ_a$$

and

$$Z_A = \frac{\Delta}{Z_a} = Z_b + Z_c + \frac{Z_bZ_c}{Z_a} \qquad Z_B = \frac{\Delta}{Z_b} = Z_c + Z_a + \frac{Z_cZ_a}{Z_b}$$

$$Z_C = \frac{\Delta}{Z_c} = Z_a + Z_b + \frac{Z_aZ_b}{Z_c}$$

Delta to Wye

Refer to Fig. A-1.

$$I_A = \frac{I_cZ_B - I_bZ_C}{Z_A + Z_B + Z_C} = \frac{(I_cZ_c - I_bZ_b)Z_a}{\Delta'} \qquad Z_a = \frac{Z_BZ_C}{Z_A + Z_B + Z_C}$$

$$I_B = \frac{I_aZ_C - I_cZ_A}{Z_A + Z_B + Z_C} = \frac{(I_aZ_a - I_cZ_c)Z_b}{\Delta'} \qquad Z_b = \frac{Z_CZ_A}{Z_A + Z_B + Z_C}$$

$$I_C = \frac{I_bZ_A - I_aZ_B}{Z_A + Z_B + Z_C} = \frac{(I_bZ_b - I_aZ_a)Z_c}{\Delta'} \qquad Z_c = \frac{Z_AZ_B}{Z_A + Z_B + Z_C}$$

where $\Delta' = Z_AZ_B + Z_BZ_C + Z_CZ_A$.

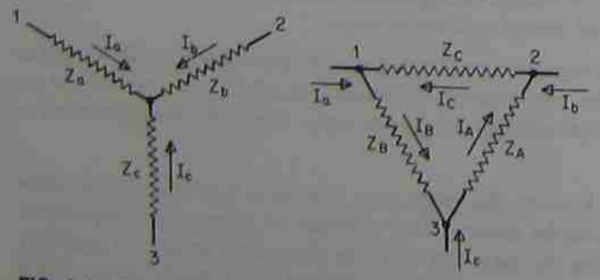


FIG. A-1 Delta-wye transformations.

Changing Bases

To convert Z in ohms at a voltage E to Z′, the equivalent value on a voltage base E',

$$Z' = Z\left(\frac{E'}{E}\right)^2$$

To convert Z in percent on a kVA base U to Z′, the equivalent value on a kVA base U',

$$Z' = Z\frac{U'}{U}$$

To convert Z_p in percent on a kVA base U to Z_z in ohms on a voltage base E,

$$Z_z = \frac{3Z_pE^2}{U \times 10^5}$$

and, conversely

$$Z_p = \frac{U \times 10^5}{3E^2}$$

where E = line-to-neutral voltage and U = total three-phase kVA.

Paralleling Two Impedances

Refer to Fig. A-2.

$$Z = \frac{Z_aZ_b}{Z_a + Z_b}$$

where Z is the equivalent impedance; and

$$I_a = I\frac{Z_b}{Z_a + Z_b} \qquad I_b = I\frac{Z_a}{Z_a + Z_b}$$

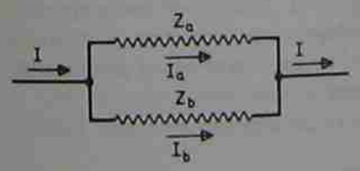


FIG. A-2 Paralleling two impedances.

SUPERPOSITION THEOREM

In a network containing several voltage sources, the current in the several branches may be found by replacing all but one of the voltage sources by their particular resistances (dc) or impedances (ac) and determining the current contributed by

the one source in each of the branches. The process is repeated with each of the other voltage sources, and separate current distribution in the several branches from each of the voltage sources is again determined. The vector or algebraic sum of all of the currents in each branch (as determined above) gives the value of the current in that branch with all of the voltage sources in place.

SYMMETRICAL COMPONENTS

General

The method of symmetrical components is essential to the analysis of unbalances between phases of a polyphase circuit.

A balanced three-phase system is represented by three vectors of equal magnitude with a phase displacement of 120°. Normal current and voltage conditions assume balanced phases, allowing the magnitude of the current or voltage of one phase to represent each of the three phases. Calculation of the three-phase performance then involves the analysis of one phase by a single-phase calculation with the result rotated through 120° and 240° to complete the three phases.

The unbalanced three-phase system is represented by vectors whose magnitude and phase displacement are not equal. The equivalent single-phase circuit represented by one phase cannot be used for calculations, as it does not include a measure of the conditions on the other two phases.

For ease of calculation, the method of symmetrical components can be used to separate the unbalanced three-phase system into three components, two being balanced three-phase components, the third a uniphase component. Each of these component systems can be represented by an equivalent single-phase system. Thus, the solution of the component systems separately by an equivalent single-phase calculation and then the addition of the three components in proper phase relation simulates the unbalanced system, the solution of which is desired.

Symmetrical Component Systems

The unbalanced system of vectors can be divided into three components called the positive-phase sequence components, negative-phase sequence components, and zero-phase sequence components (see Fig. A-3). Positive-phase sequence components are balanced three-phase vectors, whose time sequence of maxima occur in the order E_a, E_b, E_c. Being balanced, the vectors have equal amplitudes and are displaced 120° relative to each other; and

$$\begin{aligned} E_{a1} &= E_{a1} \\ E_{b1} &= e^{j240}E_{a1} = a^2E_{a1} \\ E_{c1} &= e^{j120}E_{a1} = aE_{a1} \end{aligned} \tag{1}$$

in which a is the unit vector, $e^{j120} = -0.5 + j0.866$, that is, an operator which indicates that a vector to which it is attached has been rotated through 120° in a positive or counterclockwise direction; and a^2 is the unit vector $e^{j240} = -0.5 - j0.866$, that is, an operator which indicates that a vector to which it is attached has been rotated through 120° twice or 240° in a positive direction; see Fig. A-4 and Table A-1.

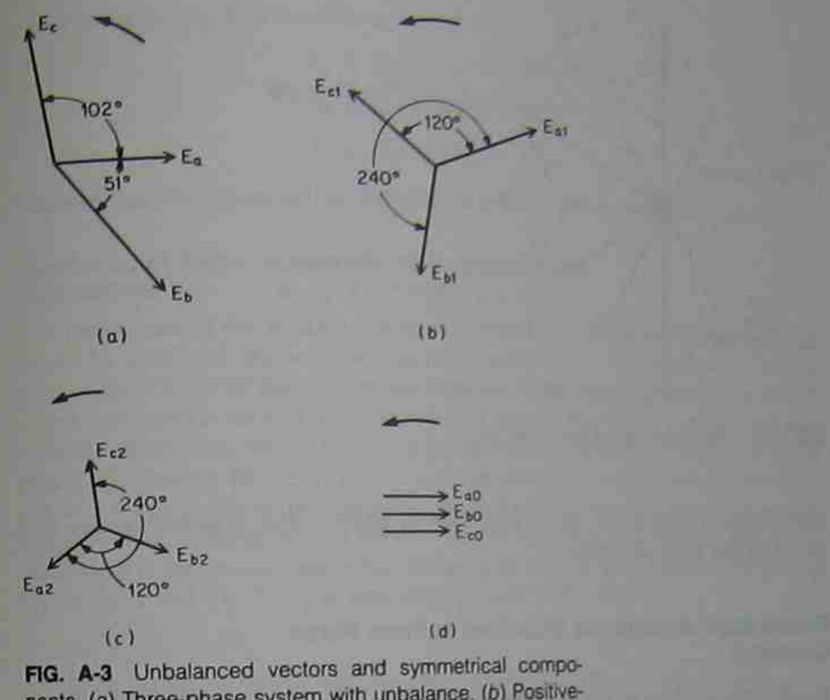


FIG. A-3 Unbalanced vectors and symmetrical components. (*a*) Three-phase system with unbalance. (*b*) Positive-phase sequence component. (c) Negative-phase sequence component. (*d*) Zero-phase sequence component.

The negative-phase sequence components are balanced three-phase vectors whose time sequence of maxima occur in the order E_{a2}, E_{c2}, E_{b2}, as shown in Fig. A-3*c*.

$$\begin{aligned} E_{a2} &= E_{a2} \\ E_{b2} &= e^{j120}E_{a2} = aE_{a2} \\ E_{c2} &= e^{j240}E_{a2} = a^2E_{a2} \end{aligned} \tag{2}$$

The zero-sequence components are three-phase vectors of equal magnitude without phase displacement, as shown in Fig. A-3*d*.

$$\begin{aligned} E_{a0} &= E_{a0} \\ E_{b0} &= E_{a0} \\ E_{c0} &= E_{a0} \end{aligned} \tag{3}$$

In each of the three systems, fixing the phase position and magnitude of one vector immediately determines the other two vectors. Phase sequence should not be confused with the rotation of the vectors. Standard convention calls for coun-

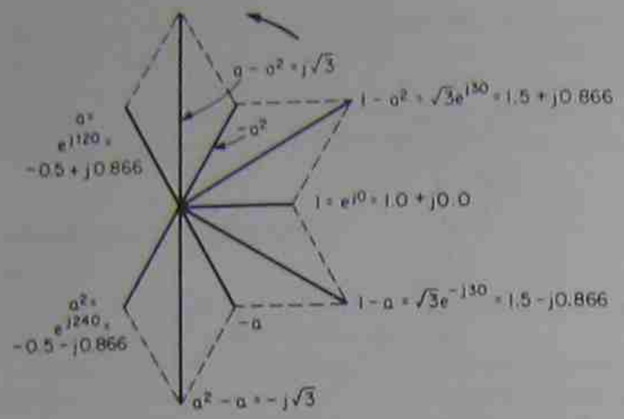


FIG. A-4 The properties of the vector *a*.

terclockwise rotation for all vectors; hence, positive and negative vectors will rotate in the same direction.

Combination of Sequence Quantities to Form Phase Quantities

In all three systems of the symmetrical components, the subscripts denote the components in the different phases. The total voltage is then equal to the sum of the corresponding components of the different sequences in that phase. The three unbalanced vectors in Fig. A-3*a* may be equated:

$$E_a = E_{a0} + E_{a1} + E_{a2} \tag{4}$$

$$E_b = E_{b0} + E_{b1} + E_{b2} \tag{5}$$

$$E_c = E_{c0} + E_{c1} + E_{c2} \tag{6}$$

TABLE A-1 PROPERTIES OF THE VECTOR *a*

$1 = e^{j0} = 1.0 + j0.0$
$a = e^{j120} = -0.5 + j0.866$
$a^2 = e^{j240} = -0.5 - j0.866$
$a^3 = e^{j360} = 1.0$
$a^4 = e^{j480} = a$
$1 + a + a^2 = 0$
$1 - a = \sqrt{3}e^{-j30} = 1.5 - j0.866$
$1 - a^2 = \sqrt{3}e^{j30} = 1.5 + j0.866$
$a - a^2 = \sqrt{3}e^{j90} = j\sqrt{3}$
$a^2 - a = \sqrt{3}e^{-j90} = -j\sqrt{3}$

or, by substituting their equivalent values:

$$E_a = E_{a0} + E_{a1} + E_{a2} \tag{7}$$

$$E_b = E_{a0} + a^2E_{a1} + aE_{a2} \tag{8}$$

$$E_c = E_{a0} + aE_{a1} + a^2E_{a2} \tag{9}$$

The unbalanced system is thus defined in terms of three balanced systems.

Resolution of Three Vectors into Their Symmetrical Components

The magnitude of the symmetrical components in an unbalanced system can be found by graphical methods, by analytical methods, or by meters with suitable connections. Each of these solutions depends upon the addition of the unbalanced three-phase vectors in a manner that cancels two of the components and adds the third component. Graphically, the positive-sequence component E_{a1} is found by rotating phase B $+120°$ with respect to phase A, rotating phase C $-120°$ $(+240°)$ with respect to phase A, and adding the two rotated phases to phase A and dividing by 3 to correct for the addition, as shown in Fig. A-3*b*. Analytically, the positive-sequence component may be obtained by multiplying Eq. (8) by a and Eq. (9) by a^2 and adding them to Eq. (7):

$$\begin{aligned} &E_a + aE_b + a^2E_c \\ &= E_{a0} + E_{a1} + E_{a2} + aE_{a0} + a^3E_{a1} + a^2E_{a2} + a^2E_{a0} + a^3E_{a1} + a^4E_{a2} \\ &= (1 + a + a^2)E_{a0} + 3E_{a1} + (1 + a^2 + a)E_{a2} \end{aligned}$$

Solving for E_{a1} and recalling that $1 + a^2 + a = 0$,

$$E_{a1} = \frac{E_a + aE_b + a^2E_c}{3} \tag{10}$$

This is the procedure, outlined under the graphical solution, above, expressed as an equation.

Either of these operations (graphical or analytical) eliminates the negative and zero components from the resultant.

The negative-sequence component is found graphically by rotating phase B $+240°$ $(-120°)$ in respect to phase A, rotating phase C $+120°$ in respect to phase A, and adding the two rotated phases to phase A and dividing by 3 to correct for the addition; refer to Fig. A-5*c*.

Analytically, the negative-sequence component may be found by multiplying Eq. (8) by a^2 and Eq. (9) by a, and adding the results to Eq. (7):

$$\begin{aligned} &E_a + a^2E_b + aE_c \\ &= E_{a0} + E_{a1} + E_{a2} + a^2E_{a0} + a^4E_{a1} + a^3E_{a2} + aE_{a0} + a^2E_{a1} + a^3E_{a2} \\ &= (1 + a^2 + a)E_{a0} + (1 + a + a^2)E_{a1} + 3E_{a2} \end{aligned}$$

Solving for E_{a2},

$$E_{a2} = \frac{E_a + a^2E_b + aE_c}{3} \tag{11}$$

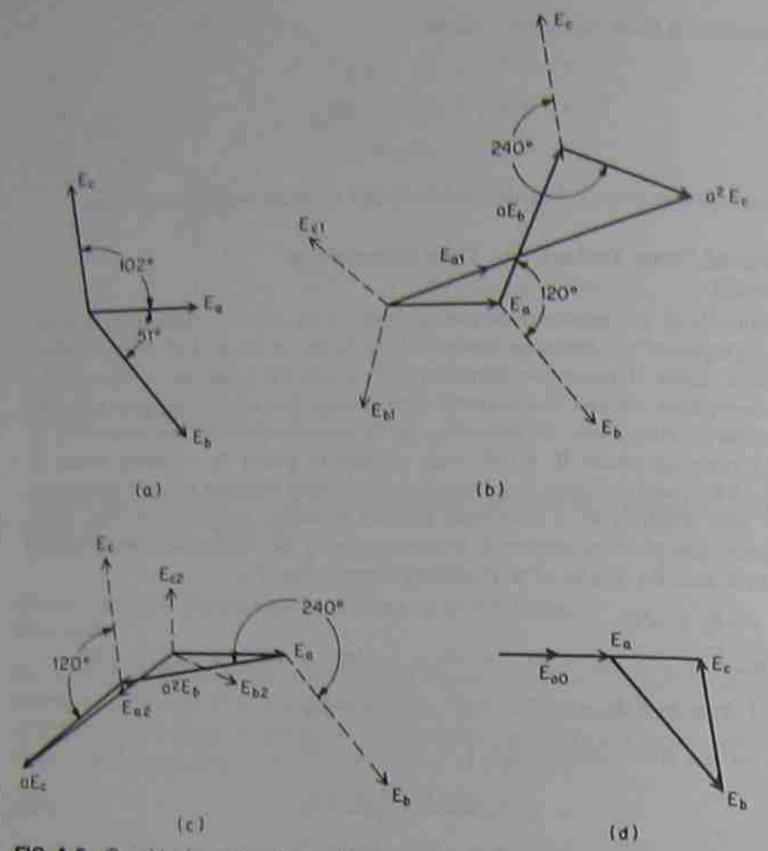


FIG. A-5 Graphical construction for the determination of sequence components. (*a*) Original vectors. (*b*) Positive sequence. (*c*) Negative sequence. (*d*) Zero sequence.

These operations eliminate the positive- and zero-sequence components from the resultant.

The zero-sequence component is found graphically by adding the phase B and phase C vectors to phase A without rotation, then dividing by 3 to correct for the addition; refer to Fig. A-5*d*. Analytically, the zero-sequence component may be found by adding the three equations, Eqs. (7), (8), and (9):

$$E_a + E_b + E_c$$
$$= E_{a0} + E_{a1} + E_{a2} + E_{a0} + a^2E_{a1} + aE_{a2} + E_{a0} + aE_{a1} + a^2E_{a2}$$
$$= 3E_{a0} + (1 + a^2 + a)E_{a1} + (1 + a + a^2)E_{a2}$$

Solving for E_{a0},

$$E_{a0} = \frac{E_a + E_b + E_c}{3} \tag{12}$$

Suppose the given voltages are balanced; e.g.,

$$E_a = E_a \quad \text{and} \quad E_b = a^2E_a \quad \text{and} \quad E_c = aE_a$$

Then

$$E_{a0} = \frac{E_a + a^2E_a + aE_a}{3} = \frac{1 + a^2 + a}{3}E_a = 0$$
$$E_{a1} = \frac{E_a + a^3E_a + a^3E_a}{3} = \frac{1 + a^3 + a^3}{3}E_a = E_a$$
$$E_{a2} = \frac{E_a + a^4E_a + a^2E_a}{3} = \frac{1 + a + a^2}{3}E_a = 0$$

In a balanced three-phase system, therefore, the zero- and negative-sequence components disappear, leaving only the positive-sequence components; i.e., the three voltages E_a, E_b, and E_c, as measured, are the positive-sequence components. While the above equations have been stated in terms of voltage, they apply equally well to currents.

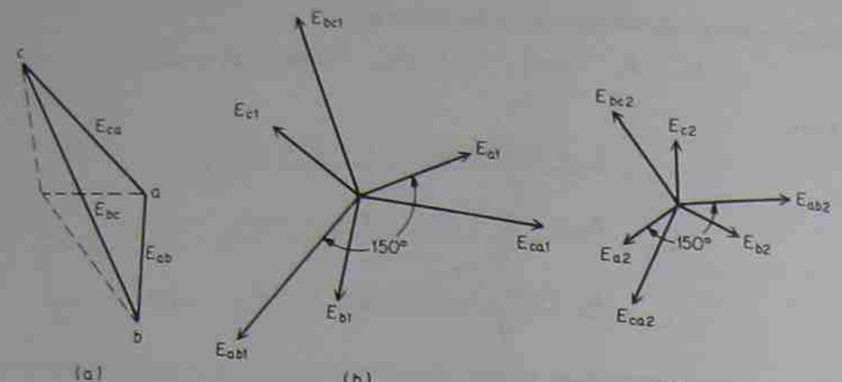
The zero-sequence component, being a uniphase component, can exist in a three-phase system only when a path to ground exists which allows the flow of ground current (zero-sequence current times 3) or the establishment of a definite potential in relation to ground. It is apparent, therefore, that in three-phase three-wire systems and in lines feeding delta connections, where the currents and voltages must add to zero, the zero-sequence component is not present. The negative-sequence component, not being present in balanced systems, indicates an unbalance whenever it is present in a system.

SEQUENCE FILTERS

If a device is obtained which will perform the rotations and additions for a particular component, the resultant can be applied on a meter which will indicate the magnitude of the component desired. The measurement of sequence components requires that a current flow through the measuring device which is directly proportional, but not necessarily equal, to the component being sought, and therefore that the effects of the other two components be eliminated. If the rotation of vectors were performed exactly in accordance with Eq. (10) or (11), the measuring device would be more complicated than necessary. Refer to Fig. A-6, which shows the positive- and negative-sequence components for both the wye and delta voltages of the unbalanced three-phase voltages (Fig. A-6*a*).

It will be noted that the positive- and negative-sequence components of the delta voltages bear definite relations to the positive- and negative-sequence components, respectively, of the wye voltages, and the zero-sequence component of the delta voltages is always zero. These relations follow:

$$E_{a1} = \frac{E_{ab1}}{\sqrt{3}}e^{j150} \qquad E_{ab1} = \sqrt{3}E_{a1}e^{-j150}$$
$$E_{a2} = \frac{E_{ab2}}{\sqrt{3}}e^{-j150} \qquad E_{ab2} = \sqrt{3}E_{a2}e^{j150} \tag{13}$$
$$E_{a0} = \text{indeterminate} \qquad E_{ab0} = 0$$



$$E_{a1} = \frac{E_{ab1}}{\sqrt{3}} e^{j150} \qquad E_{ab1} = \sqrt{3}\, E_{a1} e^{-j150}$$

$$E_{a2} = \frac{E_{ab2}}{\sqrt{3}} e^{-j150} \qquad E_{ab2} = \sqrt{3}\, E_{a2} e^{j150}$$

$$E_{a0} = \text{indeterminate} \qquad E_{ab} = 0$$

FIG. A-6 Positive- and negative-sequence components: (*a*) unbalanced voltages; (*b*) positive-sequence components; (*c*) negative-sequence components.

It is obvious that if the delta voltages are used in metering positive- or negative-sequence components, the zero-sequence component is automatically eliminated, and it is only necessary to eliminate the effect of one component.

Positive-Sequence Voltage Filter

Assume that it is desired to measure the positive-sequence voltage of a three-phase four-wire system. Using phase *a* as a reference, then:

$$E_{a1} = \frac{E_{ab1}}{\sqrt{3}} e^{j150} = \frac{\sqrt{3}}{9} (E_{ab} + aE_{bc} + a^2E_{ca}) e^{j150} \tag{14}$$

and

$$E_{ab0} = \frac{E_{ab} + E_{bc} + E_{ca}}{3} = 0 \tag{15}$$

From Eq. (15),

$$E_{bc} = -E_{ca} - E_{ab} \tag{16}$$

Substituting Eq. (16) in Eq. (14) gives

$$E_{a1} = \frac{\sqrt{3}}{9}(1 - a)E_{ab} + (a^2 - a)E_{ca}e^{j150} \tag{17}$$

Recalling that $1 - a = \sqrt{3}e^{-j30}$ and $a^2 - a = \sqrt{3}e^{-j90}$, then

$$E_{a1} = \frac{\sqrt{3}}{9}(\sqrt{3}\, E_{ab}\, e^{-j30} + \sqrt{3}\, E_{ca}\, e^{-j90}) e^{j150}$$

$$= \frac{E_{ab}}{3} e^{j120} + \frac{E_{ca}}{3} e^{j0} \tag{18}$$

Recalling that $e^{j120} = a$ and $e^{j0} = -a^2$, then

$$E_{a1} = \frac{aE_{ab} - a^2E_{ca}}{3} \tag{19}$$

The coefficient of E_{ab}, namely, a, indicates a rotation through 120°. Likewise $-a^2$ indicates a rotation of E_{ca} through 60°. The difference in angle is 60°, so that the current through a measuring device will be proportional to the positive-sequence voltage, if it consists of a component proportional to E_{ab} and another bearing the same relation to E_{ca} except lagging 60°; refer to Fig. A-7*a*. The current I_m is therefore proportional to the positive-sequence voltage E_{a1} but lags it by 120°. If the impedance of the measuring coil is negligible, such a current will obviously be obtained by the connection shown in Fig. A-8*a*. The resistor R across the voltage E_{ab} allows the current I_r proportional to E_{ab} to flow through the measuring device; while the reactor, which has a phase angle of 60° or equals Re^{j0}, across the voltage E_{ca} allows the current I_x, which is proportional to E_{ca} and lagging it by 60°, to flow through the metering device. The total current through the metering device is, therefore, proportional to the positive-sequence voltage E_{a1}. That the current is proportional to the positive-sequence voltage, even when the impedance of the metering device is not negligible, can be shown from Fig. A-8*a*.

$$E_{ab} = I_r(R + Z_m) + I_xZ_m \tag{20}$$

$$E_{ca} = I_x(Re^{j0} + Z_m) + I_rZ_m \tag{21}$$

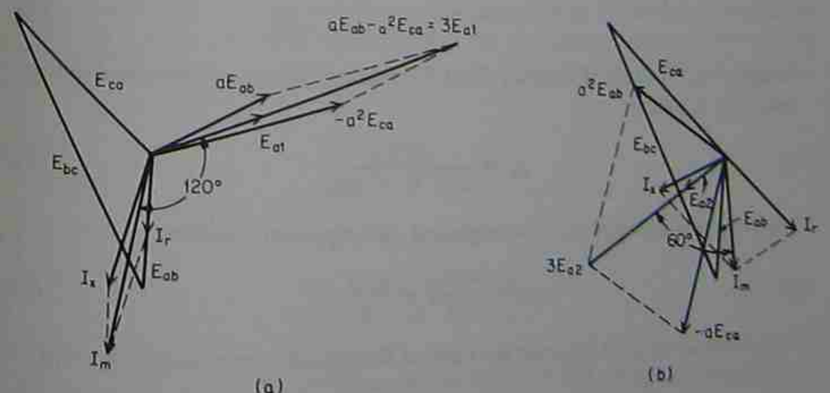


FIG. A-7 (*a*) Positive- and (*b*) negative-sequence voltages from line voltages.

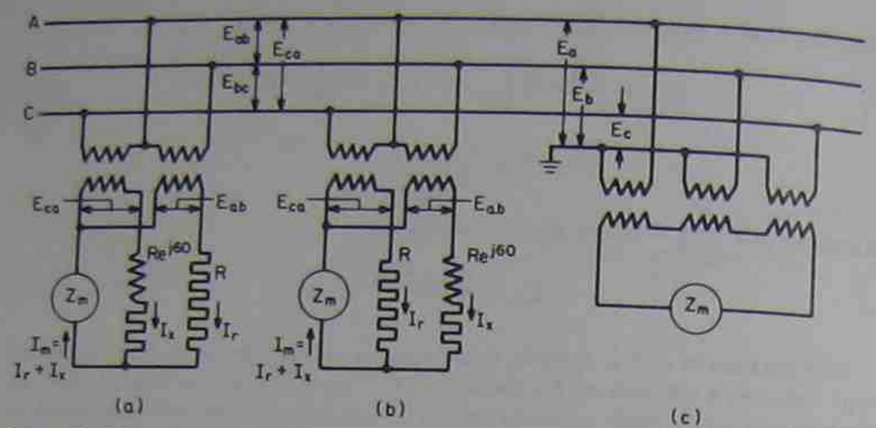


FIG. A-8 Sequence voltage filters: (*a*) positive sequence; (*b*) negative sequence; (*c*) zero sequence.

Multiplying Eq. (20) by a and Eq. (21) by $-a^2$ and adding, remembering that $e^{j60} = -a^2$,

$$aE_{ab} - a^2E_{ca} = 3E_{a1}$$
$$= aI_rR + aI_rZ_m + aI_xZ_m + a^4I_xR - a^2I_xZ_m - a^2I_rZ_m$$
$$= I_r(aR + aZ_m - a^2Z_m) + I_x(aZ_m + a^4R - a^2Z_m)$$
$$= I_r[aR + (a - a^2)Z_m] + I_x[a^4R + (a - a^2)Z_m]$$

Remembering that $a^4 = a$,

$$3E_{a1} = (I_r + I_x)[aR + (a - a^2)Z_m]$$

Therefore

$$I_m = I_r + I_x = \frac{3E_{a1}}{aR + (a - a^2)Z_m} \tag{22}$$

Writing this equation in another form by dividing both numerator and denominator by a, giving:

$$I_m = \frac{3a^2E_{a1}}{R + (1 - a)Z_m} \tag{23}$$

when Z_m is small enough to be neglected, this equation becomes:

$$I_m = \frac{3a^2E_{a1}}{R} = \frac{3E_{a1}}{R}e^{-j120} \tag{24}$$

which shows that for this case the current through the metering device lags the reference voltage by 120°.

When the connection (Fig. A-8*a*) is desired for voltage measuring purposes, it will often happen that Z_m is quite small. Hence the external impedance, which usually forms a large portion of the total impedance of the voltmeter, may be replaced by the impedances R and Re^{j60}.

The combination of impedances R and Re^{j60} was originally known as a *sequence network*. Owing to the possibility of confusing it with the term *network* as applied to the low-voltage ac network system, the combination of impedances R and Re^{j60} is now designated a *sequence filter*.

Other combinations of impedances may be used as well, as long as they fulfill the fundamental condition that the impedance in the phase which leads by 120° has a phase angle 60° greater than the other impedance. For example, in Fig. A-8*a*, the impedance Re^{j60} could be replaced by a resistance, and the resistance R by a capacitive impedance Re^{-j60}. This change, of course, changes the phase angle of the resultant current. Unless the phase angle of I_m meets certain requirements, as for example in the measurement of power, the impedances shown in Fig. A-8*a* are used.

Negative-Sequence Voltage Filter

Negative-sequence voltage can be measured in the same manner as positive-sequence voltage, except that the resistance branch and the impedance branch of the filter must be interchanged. In vector representation, negative-sequence voltages are represented with the same direction of rotation, but with two phases interchanged from their positive-sequence positions. From the physical standpoint this is equivalent to reversal of phase rotation.

Interchanging two phase leads in the positive-sequence filter will cause the network to indicate the voltage of opposite phase rotation, which is then the negative-sequence voltage. This may be accomplished on the line side of the potential transformers by interchanging any two leads. On the measuring side, the common connection is a return or neutral wire instead of a phase wire, so that the change on this side may be made only by interchanging the two impedances (refer to Fig. A-8*b*). To check these observations the analytical derivation may be made in a manner similar to that for the positive-sequence filter. It will be found that the negative-sequence voltage in terms of line voltage E_{ab} and E_{ca} is:

$$E_{a2} = \frac{a^2E_{ab} - aE_{ca}}{3} \tag{25}$$

and

$$I_m = \frac{-3a^2E_{a2}}{R} = \frac{3E_{a2}}{R}e^{j60} \tag{26}$$

If Z_m is negligible, the solution may be found in Fig. A-7*b*.

Zero-Sequence Voltage Filter

Since the zero-sequence component does not appear in the line-to-line voltages, the line-to-neutral voltages must be used. By definition, the zero-sequence voltage is given by the equation:

$$E_0 = \frac{E_a + E_b + E_c}{3}$$

The connection of Fig. A-8*c* obviously gives across a high-resistance meter $E_a + E_b + E_n$, which is $3E_0$.

Sequence Current Filters

As in the case of voltage filters, the determination of each of the three sequence current components requires the elimination of the other two components. In a three-phase three-wire system, without any neutral or ground connections, no zero-sequence current can flow, and the problem is somewhat simplified. Mathematically, this requires that:

$$I_{a0} = \frac{I_a + I_b + I_c}{3} = 0 \tag{27}$$

By definition,

$$I_{a1} = \frac{I_a + aI_b + a^2I_c}{3} \tag{28}$$

Substituting for I_b from Eq. (27),

$$I_{a1} = \frac{1}{3}[(1 - a)I_a - (a - a^2)I_c] \tag{29}$$

Remembering that $1 - a = \sqrt{3}\, e^{-j30}$ and $a - a^2 = \sqrt{3}\, e^{j90}$, then

$$I_{a1} = \frac{1}{3}(\sqrt{3}I_a e^{-j30} - \sqrt{3}I_c e^{j90}) \tag{30}$$

Factoring out $j\sqrt{3}$,

$$\begin{aligned} I_{a1} &= \frac{j\sqrt{3}}{3}(I_a e^{-j120} - I_c) \\ &= \frac{j\sqrt{3}}{3}(a^2 I_a - I_c) \end{aligned} \tag{31}$$

As would be expected, these equations are similar to the voltage equations and show that when the zero-sequence component is not present, the positive-sequence current can be expressed in terms of two line currents. Similarly, the negative-sequence current may be expressed in terms of two line currents. In the case of voltage networks, it was possible to obtain the required phase shift

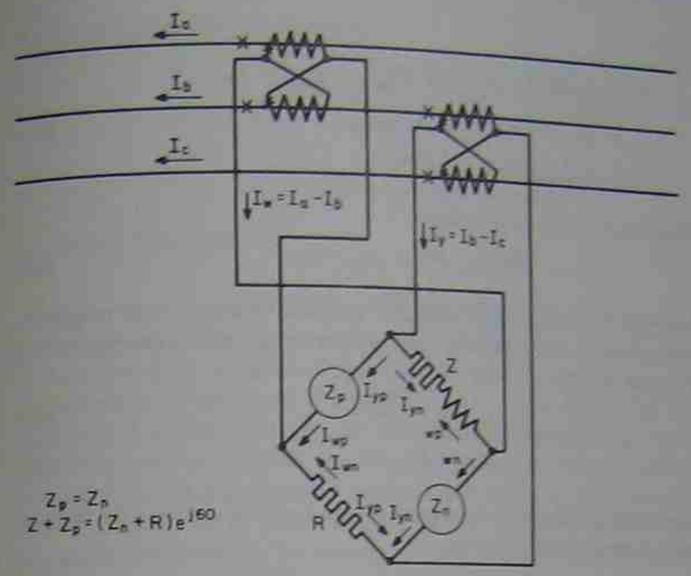


FIG. A-9 Sequence current filter.

by means of series impedance. In the current case this is not possible, since the current throughout the current-transformer series circuit is everywhere the same. Hence, parallel combinations of impedance must be used with the measuring coil in series with one branch.

When the system is grounded or provided with a neutral conductor, zero-sequence currents may flow in the phase conductors, which will affect the measuring currents. Hence, some means must be provided to remove the zero-sequence components. One of the most convenient means is to use pairs of current transformers connected in opposition instead of single-current transformers; see Fig. A-9.

From the figure,

$$I_w = I_a - I_b$$

By definition

$$I_a = I_{a1} + I_{a2} + I_{a0}$$
$$I_b = I_{b1} + I_{b2} + I_{b0}$$

and

$$I_w = I_{a1} + I_{a2} + I_{a0} - I_{b1} - I_{b2} - I_{b0}$$

From Eqs. (1), (2), and (3):

$$I_{b1} = a^2 I_{a1} \quad \text{and} \quad I_{b2} = aI_{a2} \quad \text{and} \quad I_{b0} = I_{a0}$$

Thus

$$\begin{aligned} I_w &= I_{a1} + I_{a2} + I_{a0} - a^2 I_{a1} - a I_{a2} - I_{a0} \\ &= (1 - a^2) I_{a1} + (1 - a) I_{a2} \\ &= \sqrt{3}(I_{a1} e^{j30} + I_{a2} e^{-j30}) \end{aligned} \tag{32}$$

In a similar manner it may be shown that:

$$I_y = \sqrt{3}(a^2 I_{a1} e^{j30} + a I_{a2} e^{-j30}) \tag{33}$$

It will be observed from Eqs. (32) and (33) that the positive- and negative-sequence components of I_w and I_y are directly proportional to the corresponding components of I_a and I_b; i.e.,

$$I_{w1} = \sqrt{3}\, I_{a1} e^{j30} \tag{34}$$

$$I_{w2} = \sqrt{3}\, I_{a2} e^{-j30} \tag{35}$$

With the elimination of the zero-sequence component of current by the use of cross-connected current transformers,

$$I_{w0} = \frac{I_w + I_y + I_z}{3} = 0 \tag{36}$$

where

$$I_z = I_c - I_a = -I_w - I_y \tag{37}$$

By definition

$$I_{w1} = \frac{1}{3}(I_w + a I_y + a^2 I_z) \tag{38}$$

Substituting Eq. (37) in Eq. (38),

$$\begin{aligned} I_{w1} &= \frac{1}{3}(I_w + a I_y - a^2 I_w - a^2 I_y) \\ &= \frac{1}{3}(1 - a^2) I_w + (a - a^2) I_y \\ &= \frac{1}{3}(\sqrt{3} I_w e^{j30} + \sqrt{3} I_y e^{j90}) \end{aligned}$$

Factoring out e^{j60},

$$I_{w1} = e^{j60}\left(\frac{\sqrt{3}}{3} I_w e^{-j30} + \frac{\sqrt{3}}{3} I_y e^{j30}\right) \tag{39}$$

From Eq. (34),

$$I_{a1} = \frac{I_{w1}}{\sqrt{3} e^{j30}} = \frac{1}{\sqrt{3}} I_{w1} e^{-j30} \tag{40}$$

Substituting Eq. (39) in Eq. (40),

$$\begin{aligned} I_{a1} &= \frac{1}{\sqrt{3}} e^{j30}\left(\frac{\sqrt{3}}{3} I_w e^{-j30} \pm \frac{\sqrt{3}}{3} I_y e^{j30}\right) \\ &= \frac{1}{\sqrt{3}} e^{j30}\left(\frac{I_w}{\sqrt{3}} e^{-j30} + \frac{I_y}{\sqrt{3}} e^{j30}\right) \end{aligned} \tag{41}$$

By similar development,

$$I_a = \frac{1}{\sqrt{3}} e^{-j30}\left(\frac{I_w}{\sqrt{3}} e^{j30} + \frac{I_y}{\sqrt{3}} e^{-j30}\right) \tag{42}$$

Equation (41) indicates that a current proportional to the positive-sequence current may be obtained if a portion of I_w which lags I_w by 30° and a similar portion of I_y which leads I_y by 30° are taken through a measuring device. Likewise a current proportional to the negative-sequence current may be obtained by passing through a measuring device a portion of I_w which leads I_w by 30° and a similar portion of I_y which lags I_y by 30°. I_w and I_y may be divided into the necessary components by means of two impedances of equal magnitude but differing in phase by 60°, connected in parallel. Separate filters may be used to obtain the currents proportional to the positive- and negative-sequence currents or to allow simultaneous measurements of both currents. The most-used filter in the sequence network is shown in Fig. A-9; it must be designed with the following relation between the impedances to meet the requirements outlined above:

$$Z_p = Z_n \qquad \text{and} \qquad Z + Z_p = (Z_n + R)e^{j60}$$

The current I_w passing through the filter divides into two parts I_{wp} and I_{wn} equal in magnitude but differing in phase by 60°. I_{wp} lags I_w by 30° and I_{wn} leads

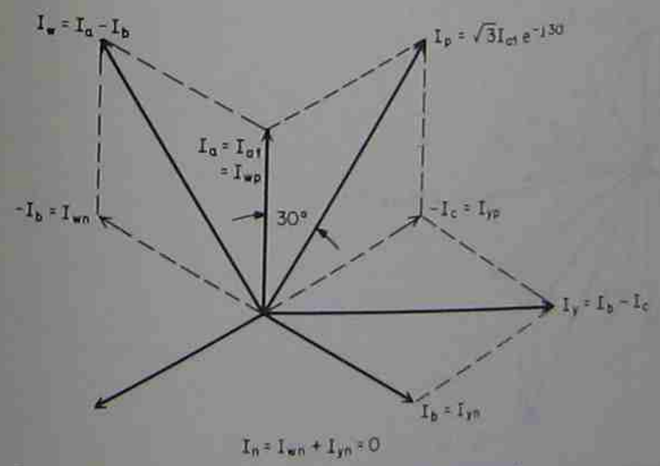


FIG. A-10 Sequence current filter—balanced currents.

I_a by 30°. Similarly the current I_y divides into two parts I_{yp} and I_{yn} equal in magnitude but differing in phase by 60°. I_{yp} leads I_y by 30° and I_{yn} lags I_y by 30°.

The current through Z_p is $I_{ap} + I_{yp} = I_p$. From Eq. (41):

$$I_{ap} = \frac{I_a}{\sqrt{3}} e^{-j30} \quad \text{and} \quad I_{yp} = \frac{I_y}{\sqrt{3}} e^{j30}$$

Therefore

$$I_p = \frac{I_{a1}}{\frac{1}{\sqrt{3}} e^{j30}} = \sqrt{3} I_{a1} e^{-j30} \tag{43}$$

The current through Z_n is $I_{an} + I_{yn} = I_n$. From Eq. (42)

$$I_{an} = \frac{I_a}{\sqrt{3}} e^{j30} \quad \text{and} \quad I_{yn} = \frac{I_y}{\sqrt{3}} e^{-j30}$$

Therefore

$$I_n = \frac{I_{a2}}{\frac{1}{\sqrt{3}} e^{-j30}} = \sqrt{3} I_{a2} e^{j30} \tag{44}$$

Referring to Fig. A-10, which is a vector diagram of the currents through the filter when the line currents are balanced, the currents through the positive-sequence measuring coil (I_{ap} and I_{yp}) add to give a current I_p equal to $\sqrt{3}$ times the positive-sequence current and lagging it by 30°. The currents through the negative-sequence measuring coil (I_{an} and I_{yn}) are equal and opposite and therefore cancel. It will be remembered that for balanced currents the negative-sequence current is zero.

Inspection of Fig. A-11, which is a vector diagram of the currents through the current filter when the line currents are unbalanced, will show that the current through the positive-sequence measuring coil again is equal to $\sqrt{3}$ times the positive-sequence current and lagging it by 30°. The currents through the negative-sequence measuring coil do not add to zero in this case but add up to equal $\sqrt{3}$ times the negative-sequence current and to lead it by 30°.

Thus the filter of Fig. A-9 produces, under balanced or unbalanced conditions alike, currents proportional to the positive- and negative-sequence currents existing in the system from which it is energized.

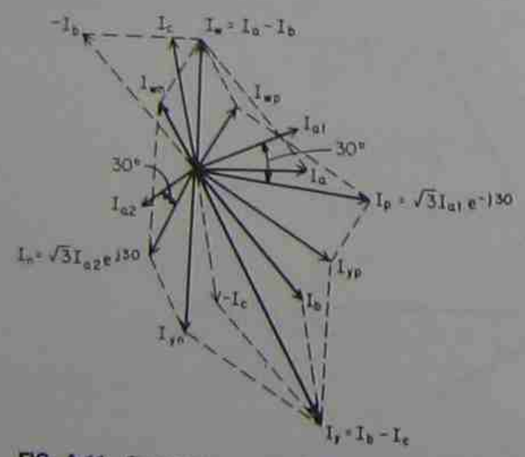


FIG. A-11 Sequence current filter—unbalanced currents.

APPENDIX B

ECONOMIC STUDIES*

INTRODUCTION

Purpose

Economic studies are the means of evaluating the economic consequences of a particular proposal or of a number of alternate proposals for meeting a problem. Basic questions which continually face the management of any business are:

1. Will a venture be sufficiently profitable to justify the risk assumed in its undertaking?
2. Which of several ways of undertaking the venture will maximize the profits?

Scope

Economic studies may range from the extremely simple to the extremely complicated. In some cases, they may appear to be no more than the application of good common sense. The most important thing is the orientation which motivates a person to apply common sense or perform a more complicated evaluation of a situation.

Characteristics

No matter how complicated, economic studies all have certain definite characteristics:

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1. Money to carry out every plan represents either:
   a. Annual Expense—Obtained from operating revenue; or
   b. Capital expenditure—Obtained from financing, reinvested depreciation reserve, reinvested earnings. In general, capital costs represent the initial purchase price of installed plant; or
   c. Both annual expense and capital expenditure.
2. Capital expenditures incur future annual expense.
3. The source usually available to a company to meet its annual expenses of operation, including taxes and obligations on its securities, is the revenue it receives from its consumers. Mathematically, therefore, the most economical of a number of plans (the one which will maximize profits) is the one which will require the minimum amount of additional revenue. A convenient way to conduct an economic study is to evaluate the effect of alternate proposals on the revenue requirements of the company.
4. Expenditures may take place (and thus affect revenue requirements) at different intervals over a period of time. The economic study must compare such expenditures on a consistent common basis.
5. The economics of alternate plans will generally be only one factor, although a major one, in the final selection of the most advantageous plan. Any differences in the non-tangible items of comparison, however, must be recognized and considered with economic differentials among the several plans. The assignment of a value for the effect of inflation may be arbitrary and best omitted from the calculations and considered a judgmental factor in the final recommendations. (The effects of inflation at several rates are contained in Table B-1; other rates may be interpolated.) The differences in the various plans should be pointed out so that the phases of each alternative may be fully evaluated.

ANNUAL CHARGES

The overall revenue requirement of a project, or the cost of doing business, is the sum of annual charges for:

1. Return on investment (stockholder, bondholder, etc.)
2. Depreciation (sinking fund, etc.)
3. Insurance expense
4. Property tax expense
5. Income tax expense
6. Operating and maintenance expense
7. Other taxes (e.g., on gross revenue)

The first five of these charges can usually, for convenience, be estimated as a percentage of original investment. The operating and maintenance charges should be separately estimated for each project. The tax (if any) on gross revenue must be calculated after all other charges are determined.

TABLE B-1 INFLATION FACTORS (COMPOUND INTEREST): $(1 + i)^n$

	Inflation rate—i in percent								
n	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
1	1.020	1.030	1.040	1.050	1.060	1.070	1.080	1.090	1.100
2	1.040	1.061	1.082	1.103	1.124	1.145	1.166	1.188	1.210
3	1.061	1.093	1.125	1.158	1.191	1.225	1.260	1.295	1.331
4	1.082	1.126	1.170	1.216	1.262	1.311	1.360	1.412	1.461
5	1.104	1.159	1.217	1.276	1.338	1.403	1.469	1.539	1.611
6	1.126	1.194	1.265	1.340	1.419	1.501	1.587	1.677	1.772
7	1.149	1.230	1.316	1.407	1.504	1.606	1.714	1.828	1.949
8	1.172	1.267	1.369	1.477	1.594	1.718	1.851	1.993	2.144
9	1.195	1.305	1.423	1.551	1.689	1.838	1.999	2.172	2.358
10	1.219	1.344	1.480	1.629	1.791	1.967	2.159	2.367	2.594
11	1.243	1.384	1.539	1.710	1.898	2.105	2.332	2.580	2.853
12	1.268	1.426	1.601	1.796	2.012	2.252	2.518	2.813	3.138
13	1.294	1.469	1.665	1.886	2.133	2.410	2.720	3.066	3.452
14	1.319	1.513	1.732	1.980	2.261	2.579	2.937	3.342	3.797
15	1.346	1.558	1.801	2.079	2.397	2.759	3.172	3.642	4.177
16	1.373	1.605	1.873	2.183	2.540	2.952	3.451	3.970	4.595
17	1.400	1.653	1.948	2.292	2.693	3.159	3.727	4.328	5.054
18	1.428	1.702	2.026	2.407	2.854	3.380	4.026	4.717	5.560
19	1.457	1.754	2.107	2.527	3.026	3.617	4.348	5.142	6.116
20	1.486	1.806	2.191	2.653	3.207	3.870	4.635	5.604	6.727
21	1.516	1.860	2.279	2.786	3.400	4.141	5.071	6.109	7.400
22	1.546	1.916	2.370	2.925	3.604	4.430	5.477	6.659	8.140
23	1.577	1.974	2.465	3.072	3.820	4.741	5.915	7.258	8.954
24	1.608	2.033	2.563	3.225	4.049	5.072	6.388	7.911	9.850
25	1.641	2.094	2.666	3.386	4.292	5.427	6.899	8.623	10.83
26	1.673	2.157	2.772	3.556	4.549	5.807	7.451	9.399	11.92
27	1.707	2.221	2.883	3.733	4.822	6.214	8.047	10.25	13.11
28	1.741	2.288	2.999	3.920	5.112	6.649	8.691	11.17	14.42
29	1.776	2.357	3.119	4.116	5.418	7.114	9.386	12.17	15.86
30	1.811	2.427	3.243	4.322	5.743	7.612	10.14	13.27	17.45
31	1.848	2.500	3.373	4.538	6.088	8.145	10.95	14.46	19.19
32	1.885	2.575	3.508	4.765	6.453	8.715	11.82	15.76	21.11
33	1.922	2.652	3.648	5.003	6.841	9.325	12.77	17.18	23.23
34	1.961	2.732	3.794	5.253	7.251	9.978	13.79	18.73	25.55
35	2.000	2.814	3.946	5.516	7.686	10.68	14.90	20.41	28.10

Return on Investment

A growing company must continually provide money for capital construction. In many cases, a large proportion of such funds are realized by sale of securities.

bonds, debentures and stocks. These securities are purchased by people who believe that the future earnings of the company will provide a return on their investment commensurate with the hazards of the business and the nature of the security purchased. If the return provided is not sufficient to meet the expectations of investors when they analyze the risk involved, they will not invest in that firm. It is axiomatic then, that if a company is to be able to attract the necessary capital for continued expansion, it must maintain an adequate return on its invested capital.

Depreciation

The purpose of a depreciation allowance is to set aside a sufficient amount periodically (usually each year) to accumulate, over the life of the equipment, the original capital investment less net salvage.

There are a number of ways of taking account of depreciation; among the many types are two aptly named Straight Line Depreciation and Annuity Depreciation.

Straight Line Depreciation The straight line method of calculating depreciation means that a fixed percentage is applied to surviving plant each year (usually monthly) to determine the accrual. The accrual rate is determined from the reciprocal of the average service life adjusted for salvage. This may be expressed by the equation:

$$D = \frac{1}{S}(1 - \text{SAL})$$

where

D = straight line depreciation rate

S = average service life

SAL = salvage ratio

Annuity Depreciation It is also possible to express the annual charge for depreciation as an equivalent uniform annual charge. In cases where there is no salvage or dispersion (Iowa SQ dispersion), the annuity may be found in the future worth-to-annuity column in the compound interest table. This factor is determined from the equation:

$$\text{AA} = \frac{i}{(1 + i)^n - 1}$$

where

AA = annuity depreciation rate

i = return as a percent of investment

n = number of years

Dispersion is a factor to be considered in depreciable plant accounts. From actuarial studies, the nearest (Iowa) dispersion curve for each plant account has

been previously determined. Thus to determine the annuity depreciation for a dispersed plant, the above equation is modified:

$$\text{AA} = \left(\frac{1}{\sum_{n=1}^{n} \frac{R_n}{(1 + i)^n}} - 1 \right) \times (1 - \text{SAL})$$

where, in addition to above:

n = maximum or total life

R_n = mean annual survivor ratio

SAL = salvage ratio

The annuity depreciation factors for a dispersed plant have been calculated for every (Iowa) curve; please refer to Fig. B-1. An elementary treatment of Depreciation, for illustrative purposes, is given in Table B-2.

There are many other ways of considering depreciation, and reference should be made to appropriate treatises on this subject.

Insurance

Unless specifically known, a value of 0.1% of original investment generally is sufficient to be used for insurance.

The four major forms of insurance carried to provide protection against damage to property are:

1. Fire insurance.
2. Boiler and machinery insurance covering accidental damage to such objects.
3. Coverage against damages due to motor vehicle collision, falling aircraft, storms, etc.
4. Insurance for general liability in excess of some value (e.g., $50,000).

The premium expense of such insurance, expressed as a percentage of total investment, is usually very small, and the value of 0.1% as an average annual charge adequately covers premiums on the insurance carried. In any special case where items of insurance make up a substantial portion of operating expense, they should be considered separately in the estimation of operating expense.

Property Taxes

Taxes on property fall into two classes: Special franchise or business taxes (applied to facilities on public property and to certain businesses); and, Real estate taxes (applied to facilities on private property). Plant classified as "Land Rights" (easements) or "Personal Property" such as tools, furniture and vehicles is not usually taxable. Depreciation is theoretically allowed on property, but in practice it is often not considered in computing taxes.

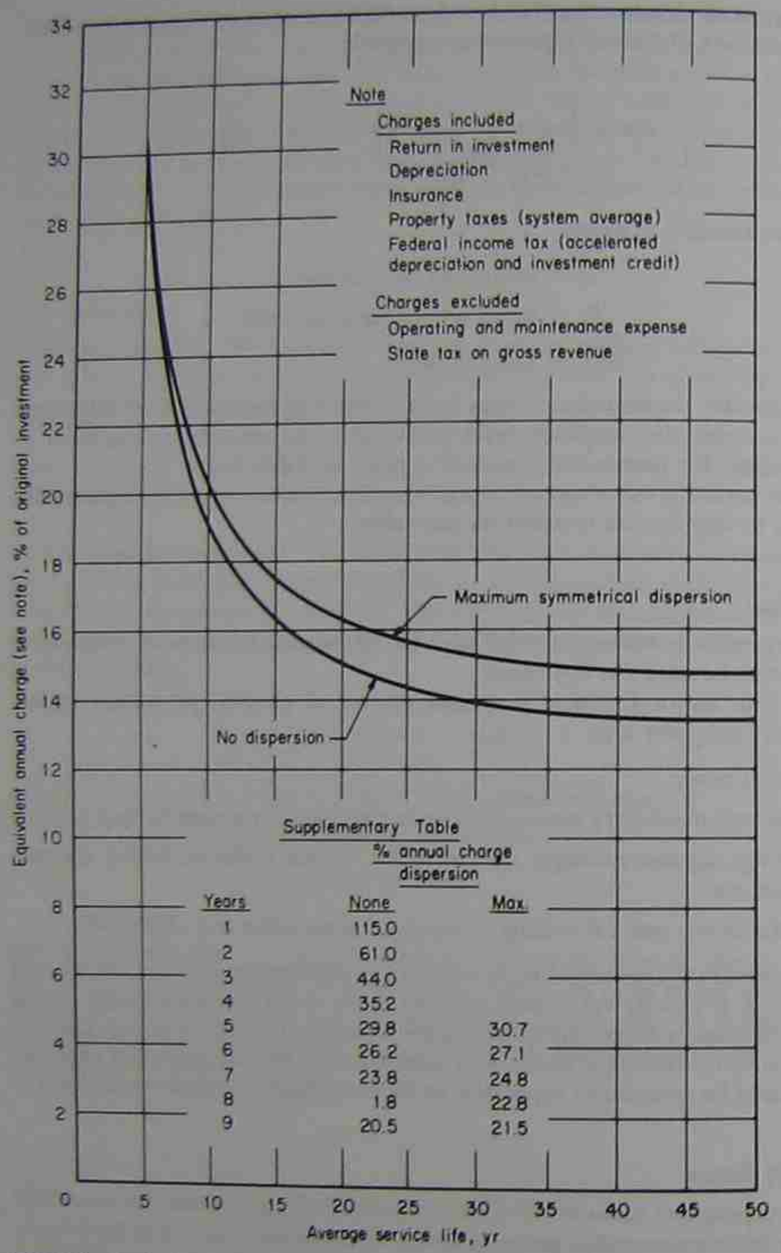


FIG. B-1 Equivalent annual charges as a percentage of original investment, assuming no salvage on project and 7 percent return on investment.

TABLE B-2 TREATMENT OF DEPRECIATION
$1000 capital investment—5 year life

Year	Investment at beginning	Depreciation	7% return	Total annual cost	Present worth Factor	Present worth Amount
A. Straight line depreciation						
1	$1,000	$200	$70	$270	0.935	$252
2	800	200	56	256	0.873	224
3	600	200	42	242	0.816	198
4	400	200	28	228	0.763	174
5	200	200	14	214	0.713	152
						1000
B. Very slow depreciation						
1	$1,000	0	70	70	0.935	65
2	1,000	0	70	70	0.873	61
3	1,000	0	70	70	0.816	57
4	1,000	0	70	70	0.763	54
5	1,000	1000	70	1070	0.713	763
						1000
C. Very fast depreciation						
1	$1,000	1000	70	1070	0.953	1000
2	0	0	0	0	0.873	0
3	0	0	0	0	0.816	0
4	0	0	0	0	0.763	0
5	0	0	0	0	0.713	0
						1000
D. Sinking fund depreciation (sinking fund factor from interest table)						
1	$1,000	174	70	244	0.935	228
2	—	174	70	244	0.873	213
3	—	174	70	244	0.816	199
4	—	174	70	244	0.763	186
5	—	174	70	244	0.713	174
						1000

Federal Income Tax

Federal income taxes are levied on taxable income as defined in applicable laws. The relationship of taxable income to revenue and to return on investment is illustrated by Fig. B-2*a* and *b*. Since rate of return on a project is the ratio of income available from the project to the net (depreciated) investment in the project, income tax must be calculated on the same basis of income or return.

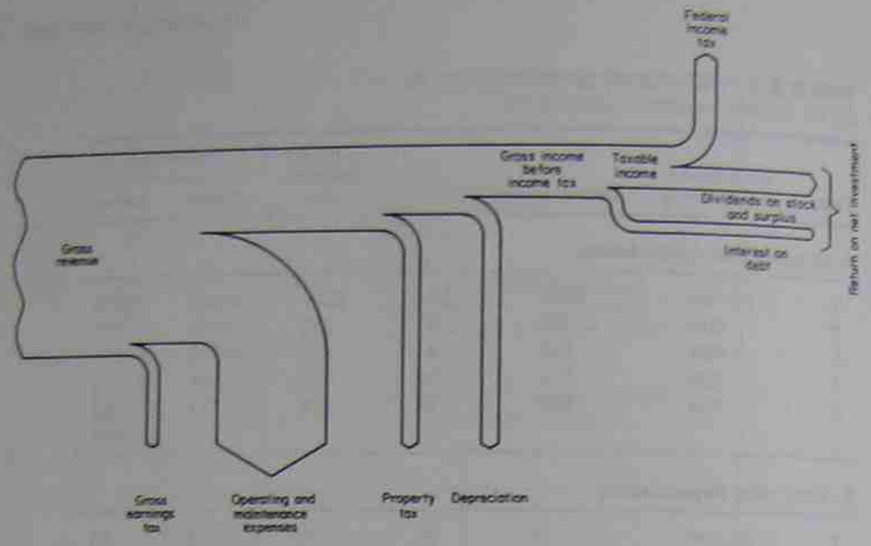


FIG. B-2 (a) Revenue and expense flow diagram.

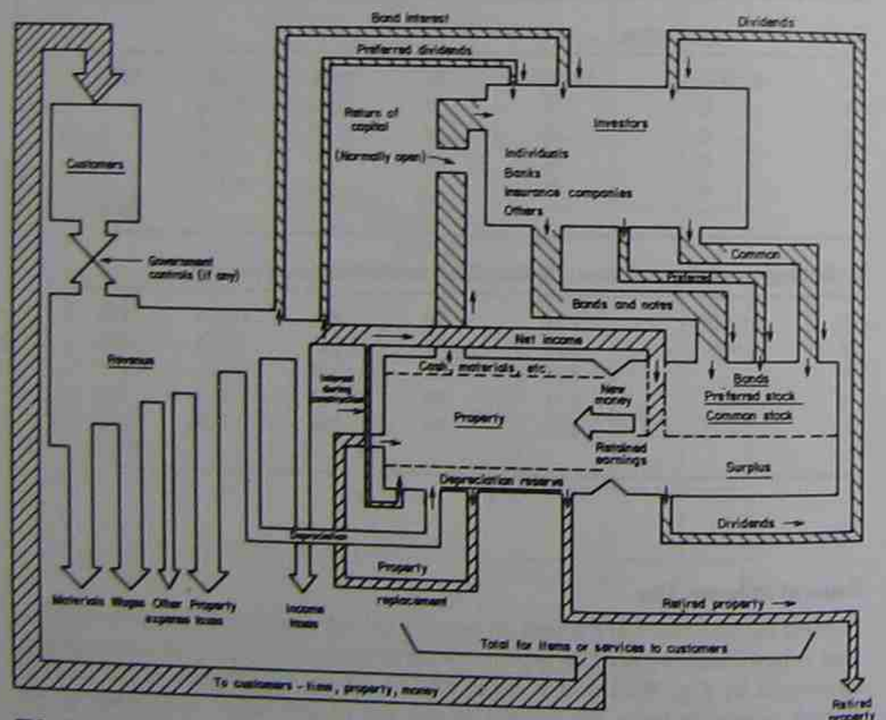


FIG. B-2 (b) Financial flowchart.

Operating and Maintenance Expenses

Operating and maintenance expenses are constituent parts of the total annual charge. As a general rule, operating and maintenance expenses cannot be expressed as a percent of the plant or unit of property investment since they do not vary directly with the investment cost. Expenses must be specifically estimated based on the individual project and must include applicable loadings as well as direct charges. In the comparison of alternate plans, costs common to the plans in the same year may be eliminated since their difference will be zero. Large non-recurring expenses must be evaluated on a present worth basis in the year of their occurrence.

Gross Earnings Tax

Some States (e.g., New York) levy earning taxes which are based on gross revenues. In evaluating alternate plans, the variation in this charge among plans will not affect the relative conclusions, and its consideration may be omitted unless total revenue requirements are desired.

BROAD ANNUAL CHARGE

For a complete study, it is necessary to evaluate the annual charges as discussed above applicable to a particular project. For many comparisons, enough accuracy can be obtained by using a more practical method employing broad annual charges. When the average service life exceeds twenty-five years, a broad annual charge of 15% of original investment may be used as a rough estimate of all charges exclusive of operating and maintenance expenses and gross earnings taxes. Figure B-1 shows the variation in total annual charge with service life and indicates the approximate basis for the 15% value.

This overall charge of 15% of original investment should not be applied to projects with a service life of less than 25 years. The annual charges on projects with a service life of less than 25 years increase rapidly as service life shortens, as shown in Fig. B-1. For such projects, a value determined from the upper curve of Fig. B-1 for the service life of the particular project will provide a reasonable first approximation of the annual charge.

TIME VALUE OF MONEY

Earning Power

Money has earning power. A dollar today is worth more than a dollar a year from now because of this earning power available through investment. The precise value of today's dollar in the future will depend upon the rate of interest earned on the invested dollar. Thus, one dollar today, invested at a 7% interest rate, will be worth $1.07 one year in the future. Conversely, $1.07 available a year from now has a present worth of $1.00. By using this concept, that money has an increasing value over a period of time, any expenditure in the future may be expressed in its equivalent "present worth" today. This principle is used

to convert expenditures made at varying times to an equivalent value at any one given instant.

Conversions

Such conversions may be made by converting values to:

1. Present worth—the value today.
2. Future worth—value at any specified time in the future.
3. Annuity—a uniform series of payments over a period of time.

The result of spending capital money is a series of annual charges extending over the service life of the property in which the capital is invested. Some of these annual charges will be uniform every year and may be considered an annuity. Other annual charges will vary from year to year resulting in a non-uniform series; these can be converted to a uniform series.

Conversion factors at 7% interest for all these manipulations are provided in Table B-3.

There are a number of different ways of developing the conversion factors. The convention used in Table B-3 is that annuity payments and future worth values are evaluated at the end of periods (years) and present worth values are evaluated at the beginning of periods. Developed in this way, Table B-3 is in its most directly usable form since all payments are assumed to be made at the end of a year (December 31) throughout this study.

EXAMPLES

Eight conversions cover all cases and are summarized and illustrated in the following examples and worth-time diagrams.*

EXAMPLE B-1 Present worth to future worth (single amount at any date to single amount at any subsequent date)

You have just won $5,000, tax free. How much money will you have at the end of 10 years, if you invest it at 7% compounded annually?

Solution

See Fig. B-3*a*. The $5,000 is a present worth, the value 10 years hence is a future worth. The future worth is obtained by multiplying the present worth by the conversion factor "Present Worth to Future Worth" for 10 years from Table B-3:

$$\text{Future worth in 10 years} = \$5{,}000 \times 1.967 = \$9{,}835$$

*Courtesy Long Island Lighting Co.

TABLE B-3 COMPOUND INTEREST TABLE

$i = 7\%$

	Lump sum		Uniform annual series			
n	Present worth to future worth, $(1+i)^n$	Future worth to present worth, $\frac{1}{(1+i)^n}$	Annuity to future worth $\frac{(1+i)^n-1}{i}$	Future worth to annuity $\frac{i}{(1+i)^n-1}$	Annuity to present worth $\frac{(1+i)^n-1}{i(1+i)^n}$	Present worth to annuity $\frac{i(1+i)^n}{(1+i)^n-1}$
1	1.070	0.9346	1.000	1.00000	0.935	1.07000
2	1.145	0.8734	2.070	0.48309	1.808	0.55309
3	1.225	0.8163	3.215	0.31105	2.624	0.38105
4	1.311	0.7629	4.440	0.22523	3.387	0.29523
5	1.403	0.7130	5.751	0.17389	4.100	0.24389
6	1.501	0.6663	7.153	0.13980	4.767	0.20980
7	1.606	0.6227	8.654	0.11555	5.389	0.18555
8	1.718	0.5820	10.260	0.09747	5.971	0.16747
9	1.838	0.5439	11.978	0.08349	6.515	0.15349
10	1.967	0.5083	13.816	0.07238	7.024	0.14238
11	2.105	0.4751	15.784	0.06336	7.499	0.13336
12	2.252	0.4440	17.888	0.05590	7.943	0.12590
13	2.410	0.4150	20.141	0.04965	8.358	0.11965
14	2.579	0.3878	22.550	0.04434	8.745	0.11434
15	2.759	0.3624	25.129	0.03979	9.108	0.10979
16	2.952	0.3387	27.888	0.03586	9.447	0.10586
17	3.159	0.3166	30.840	0.03243	9.763	0.10243
18	3.380	0.2959	33.999	0.02941	10.059	0.09941
19	3.617	0.2765	37.379	0.02675	10.336	0.09675
20	3.870	0.2584	40.995	0.02439	10.594	0.09439
21	4.141	0.2415	44.865	0.02229	10.836	0.09229
22	4.430	0.2257	49.006	0.02041	11.061	0.09041
23	4.741	0.2109	53.436	0.01871	11.272	0.08871
24	5.072	0.1971	58.177	0.01719	11.469	0.08719
25	5.427	0.1842	63.249	0.01581	11.654	0.08581
26	5.807	0.1722	68.676	0.01456	11.826	0.08456
27	6.214	0.1609	74.484	0.01343	11.987	0.08343
28	6.649	0.1504	80.698	0.01239	12.137	0.08239
29	7.114	0.1406	87.347	0.01145	12.278	0.08145
30	7.612	0.1314	94.461	0.01059	12.409	0.08059

EXAMPLE B-2 Future worth to present worth (single amount at any date to single amount at any previous date)

You have estimated that 10 years from now the unpaid mortgage on your house will be $9,835. How much money do you have to invest today at 7% interest to just accumulate $9,835 in 10 years?

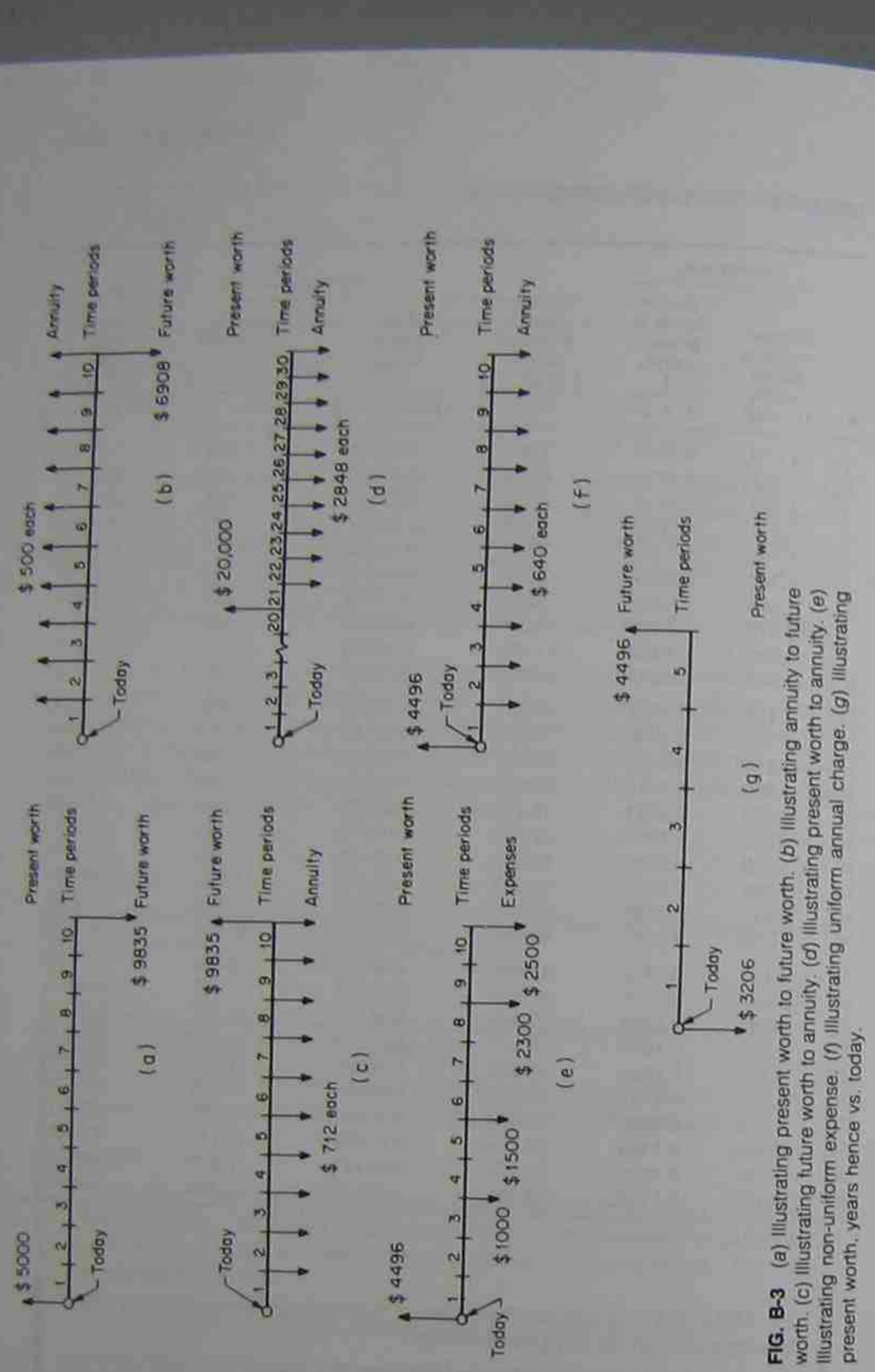


FIG. B-3 (a) Illustrating present worth to future worth. (*b*) Illustrating annuity to future worth. (c) Illustrating future worth to annuity. (*d*) Illustrating present worth to annuity. (*e*) Illustrating non-uniform expense. (*f*) Illustrating uniform annual charge. (*g*) Illustrating present worth, years hence vs. today.

Solution

The $9,835 is a future worth; the present worth of that amount is desired. From Table B-3, the conversion factor is 0.5083:

$$\text{Present worth} = \$9{,}835 \times 0.5083 = \$5{,}000$$

This is the reverse of Example B-1. The conversion factor for future worth to present worth is simply the reciprocal of the present worth to future worth factor. The worth-time diagram is the same as for Example B-1.

EXAMPLE B-3 Annuity to future worth (annuity over any period to single amount at end of period)

You plan to save $500 of your earnings each year for the next 10 years. How much money will you have at the end of the 10th year if you invest your savings at 7% per year?

Solution

The $500 each year is an annuity since it is a uniform amount each year. You wish to know the future worth. From Table B-3, the annuity to future worth factor, 10 years, is 13.816:

$$\text{Future worth of the annuity} = \$500 \times 13.816 = \$6{,}908$$

Note from Fig. B-3*b* that annuity payments are assumed to be made at the end of each time period. The conversion factor evaluates future worth at the same time that the last annuity payment is made.

EXAMPLE B-4 Future worth to annuity (single amount at any given date to annuity over any previous period ending at the given date)

If the unpaid mortgage on your house in 10 years will be $9,835, how much money do you have to invest annually at 7% interest to have just this amount on hand at the end of the 10th year?

Solution

See Fig. B-3*c*. The $9,835 is a future worth; the uniform amount (annuity) to set aside annually is desired. From Table B-3, the future worth to annuity factor, 10 years, is 0.07238:

$$\text{Annuity} = \$9{,}835 \times 0.07328 = \$712$$

EXAMPLE B-5 Present worth to annuity (single amount at any given date to annuity over any subsequent period starting at the given date)

You hold an endowment type insurance policy which will pay you a lump sum of $20,000 when you reach age 65. If you invest this money at 7% interest, how much money can you withdraw from your account each year so that at the end of 10 years, there will be nothing left?

Solution

See Fig. B-3*d*. The $20,000 can be considered the present worth at the end of the 10th year. From Table B-3, the present worth to annuity factor, 10 years, is 0.14238:

$$\text{Annuity which may be withdrawn for 10 years} = \$20{,}000 \times 0.14238 = \$2{,}848$$

Note that direct use of the conversion factor assumes the first withdrawal to take place one period after the lump sum of $20,000 is received.

EXAMPLE B-6 Annuity to present worth (annuity over any period to single amount at start of the period)

You have estimated that for the first 10 years after you retire you will require an annual income of $2,848. How much money must you have invested at 7% at age 65 to realize just this annual income?

Solution

The present worth of an annuity for 10 years is desired. From Table B-3, the annuity to present worth factor, 10 years, is 7.024:

$$\text{Present worth} = \$2{,}848 \times 7.024 = \$20{,}000$$

The worth-time diagram is the same as for Example B-5.

EXAMPLE B-7 Present worth non-uniform expenses to equivalent uniform annual charge

The maintenance expenses for the next 10 years on a piece of equipment are estimated as follows:

Year	*Amount*
3	$1,000
5	1,500
8	2,300
10	2,500

What is the present worth of these expenses? What is the uniform annual payment for 10 years equivalent to this non-uniform series? What does this mean?

Solution

See Fig. B-3*e*. The expense amounts are future worths in the year indicated. The present worth is desired. Future worth to present worth factors from Table B-3:

Year	*Amount*	*Factor future worth to present worth*	*Present worth*
3	$1,000	0.8163	$ 816
5	1,500	0.7130	1,070
8	2,300	0.5820	1,339
10	2,500	0.5083	1,271
Total			$4,496

The total present worth of these non-uniform series of expenses is $4,496.

The equivalent uniform annual series is obtained by applying the present worth to annuity factor for 10 years to the present worth. From Table B-3, present worth to annuity factor, 10 years, is 0.14238:

$$\text{Equivalent uniform annual charge} = \$4{,}496 \times 0.14238 = \$640$$

(See Fig. B-3*f*.) This means that if you had $4,496 and invested it at 7%, you could withdraw the required amounts to meet exactly either the non-uniform series of expenses or pay out an equivalent amount of $640.

EXAMPLE B-8 Present worth some years hence to present worth today

Assume the expenses given in Example B-7 were to be associated with a piece of equipment to be installed 5 years from now. What is the present worth of the non-uniform expenses in that case?

Solution

See Fig. B-3*g*. The present worth previously obtained was the present worth for the expenses incurred in the 10 years following installation of the project. This is a present worth 5 years from now. In terms of today's present worth, it is a future worth 5 years away. The present worth today is obtained simply by converting the future worth in 5 years to a present worth. From Table B-3, the future worth to present worth factor, 5 years, is 0.7130:

$$\text{Present worth today} = \$4{,}496 \times 0.7130 = \$3{,}206$$

PROCEDURE FOR ECONOMIC STUDIES

The procedures for commencing an Economic Study may be laid out in a sequence of steps:

1. The facts concerning the different plans that could be used to meet the requirements of the problem should be set down. The plans should be made as comparable as possible.
2. The capital expenditures which will be incurred under each of the plans and the timing of these expenditures should be determined. The amounts and

timing of operating and maintenance expenses must be estimated; allocations of cost to capital and expense must be adhered to.

3. A study period must be selected during which the revenue requirements incurred by the plans will be evaluated. In economic studies, it is seldom possible to find a study period which will precisely reflect the timing inherent in each of the plans under study. It will often be helpful to draw a diagram of the timing of capital and expense dollars for each of the plans in determining the study period. The study period chosen must be one determined on the basis of judgment. In every case, it must be sufficiently long to approximate the overall effects, over a long period of time, of the money reasonably to be spent for both capital and operating expenses.
4. The annual charges resulting from the capital expenditures in each phase must be calculated if broad annual charges cannot be applied. In considering alternate plans, items common to the several plans may be omitted from the calculations. The effect of temporary installations, salvage, and of the removal of equipment which can be used elsewhere on the system must be taken into account.
5. When annual revenue requirements are non-uniform, the present worth of the revenue requirements for each plan must be calculated. The most economical plan will have the lowest present worth of revenue requirements. In the case where annual revenue requirements are uniform throughout the study period, the plan with the lowest annual requirements will be the most economical.
6. The comparison of the economic differences among the plans may be made on the dollar differences among the present worths of the revenue requirements. If percentage difference is considered, the dollar differences may be misleading as, in conducting the study, charges which are the same in the several plans are generally omitted; this will distort the base upon which a percentage difference is derived.
7. A recommendation of the most advantageous plan must be made. The plan with the minimum revenue requirements would be recommended from an economic point of view. Other considerations may indicate the recommendation of one of the other plans despite higher revenue requirements.

CONCLUSION

Economic studies constitute perhaps the most important ingredient in the implementation of a project. In sum, the consideration of any undertaking must answer satisfactorily three basic requirements or questions:

1. Why do it at all?
2. Why do it now?
3. Why do it this way?

The answers to these can, in large part, be supplied by the results of economic studies.

APPENDIX C

THE GRID COORDINATE SYSTEM: TYING MAPS TO COMPUTERS*

by
Anthony J. Pansini EE, PE
Engineering & Management Consultant
Waco, Texas

INTRODUCTION

The grid coordinate system is the key that ties together two important tools, maps and computers. Maps are a necessity for the better operation of many enterprises, especially of utility systems. Their effectiveness can be increased manyfold by adding to their information data contained in other files. Much of the latter data are now organized and stored in computer-oriented files—on punched cards and on magnetic tapes, drums, disks, and cells. Generally, these data can be retrieved almost instantly by CRTs (cathode ray tubes) or printouts. The link that makes the correlation of data contained on the maps and in the files practical is the grid coordinate system.

Essentially, the grid coordinate system divides any particular area served into any number of small areas in a grid pattern. By superimposing on a map a system of grid lines, and assigning numbers to each of the vertical and horizontal spacings, it is possible to define any of the small areas by two simple numbers. These numbers are not selected at random, but have some meaning. Like any graph, these two coordinates represent measurements from a reference point; in this respect they are similar to navigation's latitude and longitude measurements.

Further subdivision of the basic grid areas into a series of smaller grids is possible, each having a decimal relation with the previous one (i.e., by dividing each horizontal and vertical space into tenths, each resultant area will be one-

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hundredth of the area considered). By using more detailed maps of smaller scale, it is possible to define smaller and smaller areas simply by carrying out the coordinate numbers to further decimals. For practical purposes, each of these grid areas should measure perhaps not more than 25 ft by 25 ft (preferably less, say, 10 ft by 10 ft) and should be identified by a numeral of some 6 to 12 digits.

For example, by dividing by 10, an area of 1,000,000 ft by 1,000,000 ft (equivalent to some 190 miles square) can be divided into 10 smaller areas of 100,000 ft by 100,000 ft each, identified by two digits, one horizontal and one vertical. This smaller area can again be subdivided into 10 smaller areas of 10,000 ft by 10,000 ft each, identified by two more digits, or a total of four with reference to the basic 1,000,000-ft square area. Breaking down further into 1000- by 1000-ft squares and repeating the process allows these new grids to be identified by two more digits, or a total of six. Again dividing by 10 into units of 100 ft by 100 ft, and adding two more digits, produces a total of eight digits to identify this grid size. One more division produces grids of 10 ft by 10 ft and two more digits in the identifying number—for a total of 10 digits, not an excessive number to be handled for the grid size under consideration; see Fig. C-1.

This process may be carried further where applications requiring smaller areas are desirable; however, each further breakdown not only reduces the accuracy of the measurements, but also adds to the number of digits, which soon becomes unmanageable. Experience indicates that a "comfortable" system should contain 10 digits or fewer for normal usages.

While the decimal relation has been mentioned, other relations can be used, such as sixths, eighths, etc., or combinations, such as eighths and tenths, and others.

Standard References

To give these numerals some actual physical or geographical significance, they may be tied in with existing local maps, U.S. Geological Survey maps, coast and geodetic survey maps, state plane coordinate systems, standard metropolitan statistical areas, or latitude and longitude bearings. They may also be tied in with maps independent of all of these.

While reference to state and federal government systems lends some geographical significance, it produces identifying grid numbers with several additional digits. It is not necessary for any grid coordinate system to have this reference to a government system, but if it is desired, it is a relatively simple procedure to develop a computerized look-up program that can translate such coordinates.

Basic grid coordinate maps may be developed from the conversion of existing maps to a usable scale, if such maps are reasonably accurate and complete, both as to their geography and content. They may also be developed from exact land surveys, from aerial surveys, or from combinations of all of these.

Excellent maps are also available for most of the country. U.S. Geological Survey maps show latitude and longitude lines every few miles; they also show numerous triangulation stations with the latitude and longitude for each station

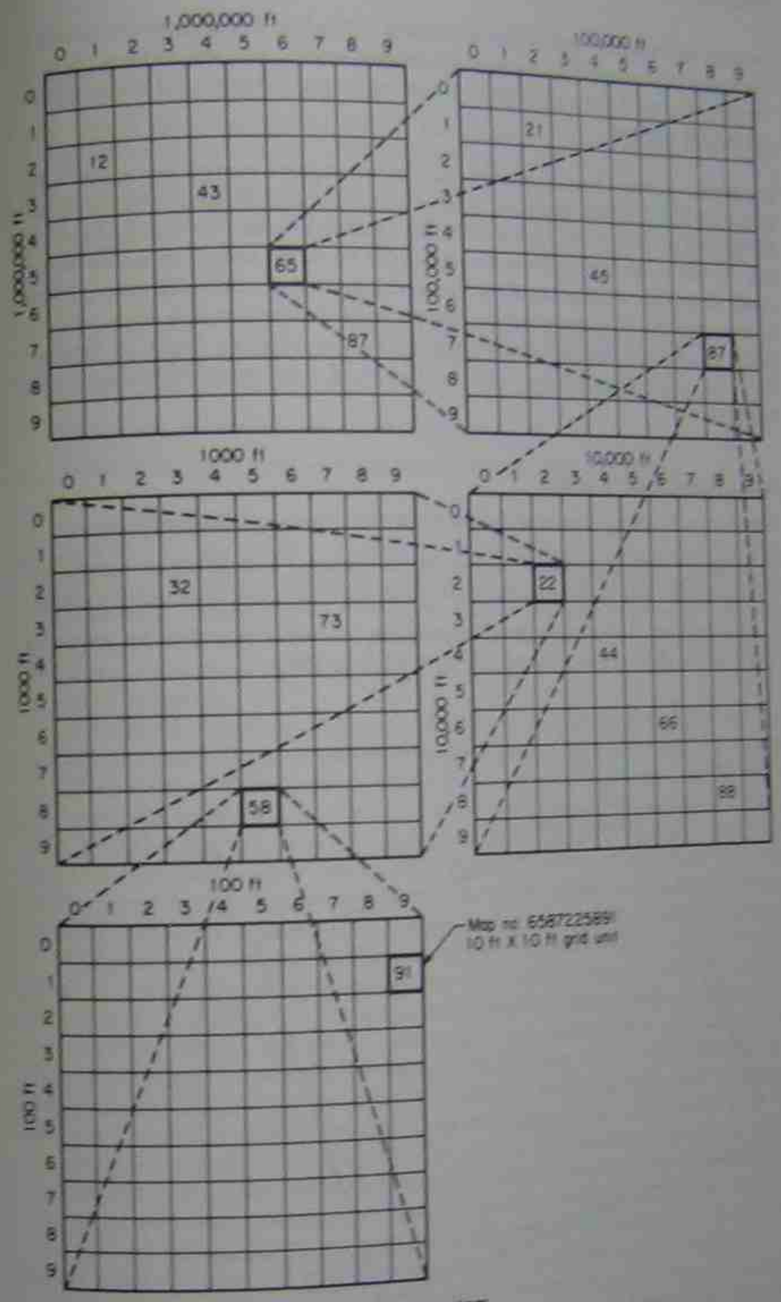


FIG. C-1 Development of grid coordinate system.

determined to an extreme degree of accuracy. Further, detail maps are available for practically every city and township, showing streets, houses, and lots. Despite the fine degree of accuracy of these maps, minor inaccuracies and discrepancies are bound to occur.

Earth's Curvature Errors occur in mapping the earth's curved surface on a flat map; see Fig. C-2. For example, in the case of the approximate 190-mi square mentioned previously, in the continental United States, the error introduced by this curvature, measuring from the center (95 mi in the longitudinal, or north-south direction) would probably not exceed 2 percent, a tolerable error. These errors need not be of great import, except in establishing match lines between maps. No gaps or overlaps should appear between adjacent maps, or between property or lot lines within a map. Tolerances of a few percent ordinarily are acceptable.

GRID COORDINATE MAPS

A grid coordinate map system should meet the following requirements:

1. It should include a simple and easily understood system of numerals for locating the data under consideration (numerals only; the x and y coordinates).
2. The grid areas should be small enough to be consistent with the purposes for which they are to be used (25 ft by 25 ft or less).

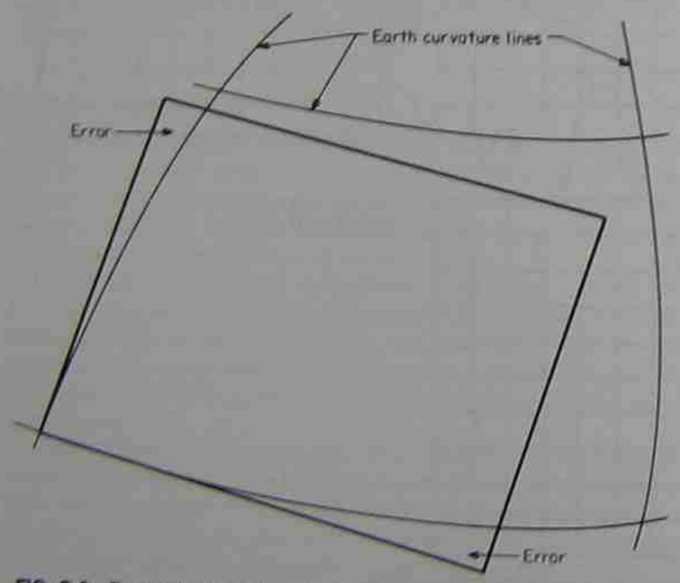


FIG. C-2 Error introduced in grid coordinate system by earth curvature.

3. The number of digits in the grid number should be held to a practical number so as not to become cumbersome and unwieldy (normally not more than about 10).
4. It should be designed to allow for expansion so that it will not have to be radically revised if unforeseeable expansion should occur.
5. It must provide reasonable accuracy (tolerances of a few percent), and it may or may not be tied in with some government or other established coordinate system.
6. Map sizes should be manageable (say, 24 or 36-in square).
7. Maps of different scales should be included in the system to accommodate different kinds of data (for circuit data, say 1000 or 500 ft; for details of facilities, say, 100 ft for overhead and 50 or 25 ft for underground).
8. A key map must show the entire grid area.
9. Optional is a grid atlas showing street locations with grid overlay.

In attempting to design a grid coordinate system for a very large area, it may be difficult to meet these requirements. In such instances it may be desirable and practical to divide the entire area into two or more convenient districts, establishing a separate grid coordinate system in each district and tying the separate systems together with match lines at the borders. A prefix letter or number may be used to identify districts, though this may not prove necessary in actual operation.

The size of individual maps should be large enough to encompass an area suitable for the purpose but small enough not to be unwieldy; sizes of 24 or 36 in square have proven practical. Maps of different scales are used for different purposes; for example, a 50- or 100-ft scale is used for dense or crowded areas; 300- or 500-ft for less dense or rural areas; and 500- or 1000-ft or even larger for district or overall area viewing. The series of scales used should be such that the larger-scale maps fit into those of smaller scale completely and evenly. Match lines of each sheet should fall on corresponding match lines of adjacent sheets.

The grid pattern applicable to each of the several scale maps may be printed directly on each map as light background lines, perhaps even in a different color, or printed on the back of the maps when they are reproduced. Alternately, a grid overlay can be applied to each map to be used when it is necessary to determine a grid coordinate for an item on the map. The actual grid number need not be printed on every item on every map unless desired. Such numbers assigned to key locations on each map normally suffice; the others may be determined from the grid background or overlay. To maintain their permanence and to minimize distortion from expansion and contraction because of changing humidity and temperature, the maps should be printed on a material such as Mylar, a translucent polyester-base plastic film; this is especially true of the base maps from which others of different scales and purposes are derived.

As much as practical, the data on the maps should be uncluttered and as legible as possible. It may be desirable in some instances to provide two or more

maps (of the same scale) for several purposes; marks for coordinating these several maps, should it be necessary, may be included on each of the maps.

Maps may be further uncluttered by deliberately removing as much of the information on them as appears desirable and practical and consigning such information to files readily accessible by computer. In many instances, this information already is included or duplicated in such files, but may need to be labeled with the appropriate grid coordinate number. The use of CRTs and printouts makes this information available at will.

Application of Grid Coordinate Numbers

The grid coordinate number may be applied to each item of information contained in the computer-operated files by location. This may be done in several ways: manually, by machine, or a combination of the two.

The manual method is to superimpose or overlay the grid pattern on existing maps and manually assign numbers to each item to be processed. As mentioned previously, the grid pattern may be transferred to the master or original maps, and reproduced (or microfilmed) on the maps for the user; here numbers can be assigned directly from the map.

The machine method of grid number assignment employs an electronic scanning device called a *digitizer*. This machine includes a drafting table for map display and a cursor or pointer. The postal address and other fixed data are inserted on a punch card. For a particular map, the grid numbers of the map are set on the digitizer console. The digitizer assigns the x and y coordinates when the cursor is placed on a selected point and activated. These data are fed to a keypunch, which produces a punched card. In this method of producing the grid coordinate numbers, the digitizer enables additional refinement to be achieved, producing additional decimal numbers for the x and y coordinates. Hence, the ultimate grid area that can be measured can be one-tenth or one-hundredth, etc., of the basic unit area (1 ft by 1 ft, or 0.1 ft by 0.1 ft, for a 10-by 10-ft base area).

When numbers are assigned manually from maps, this degree of accuracy is not possible, nor is it necessary if the principal purpose of the grid coordinate system is to identify an item rather than a precise point. While the actual accuracy of such additional digits can be questioned, they provide a method of further subdividing a map for closer location of an item, but more important, they make possible a system of automatic mapping using the computer.

The grid coordinate number corresponding to the location of an item in question is added to its record and now becomes its computer *address*. In assigning these numbers to existing files, the digitizer generally can properly identify the location from a suitable map. As a practical matter, however, there will be some locations or descriptions that cannot be identified using the digitizer, and these may require manual processing and actual checking in the field; fortunately these usually constitute only a small percentage of the total records.

In the maintenance of such files, the grid coordinate numbers associated with changes in, or with the introduction of new items into, the records can be assigned manually by the originator of the record.

COORDINATE DATA HANDLING

As implied earlier, the grid coordinate system provides an easy and simple but, more important, a very rapid means of obtaining data from files through the use of the computer. In some respects, it assigns addresses to data in the same way as the ZIP code system in use by the postal service. The manner in which the grid number may be used is illustrated in the following examples; for convenience they refer to electric utility systems, although obviously they apply equally well to other endeavors employing maps and records.

Data contained on maps and records generally apply to the consumers served and the facilities installed to serve them. While maps depict (by area) the geographic and functional (electrical) interrelationship between these several components, the records supply a continuing history (by location) of each component item (consumers and facilities).

In the case of consumers, such data may include, in addition to the grid coordinate number, the name and post office address. Also a history of electric consumption (and demand where applicable), billing, and other pertinent data over a continuing period, usually 18 or 24 months. There may also be data on the consumer's major appliances; also the date and work order number of original connection and subsequent changes. The grid coordinate number of the transformer from which the consumer is supplied is included, as well as that for the pole or underground facility from which the service to the consumer is taken. Sometimes interruption data may be included. Other data may include telephone number, tax district, access details, hazards (including animals), dates of connection or reconnection, insurance claims, easements, meter data, meter reading route, test data, credit rating, and other pertinent information. Only a small portion of these data are shown on maps, usually in the form of symbols or code letters and numerals. In the case of facilities, such data may include, in addition to the grid coordinate number, location information, size and kind of facility (e.g., pole, wire, transformer, etc.), date installed or changed, repairs or replacements made (including reason therefor, usually coded), original cost, work order numbers, crew or personnel doing work, construction standard reference, accident reports, insurance claims, operating record, test data, tax district, and other pertinent information. Similarly, only a small portion of these data are shown on maps, usually in the form of symbols or code letters and numerals.

Data from other sources also may be filed by grid number for correlation with consumer and facility information for a variety of purposes. Such data may include government census data; police records of crime, accidents, and vandalism; fire and health records; pollution measurements; public planning; construction and rehabilitation plans; zoning restrictions; rights-of-way and easement locations; legal data; plat and survey data; tax district; and much other information that may affect or be useful in carrying out utility operations.

Obviously, all these data, whether pertaining to the consumer or to the utility's facilities, are not necessarily contained on one map or in one record only; indeed, there may be several maps and records involved, each containing certain amounts of specialized or functionally related data. All, however, may be correlated through the grid coordinate system.

Data Retrieval

Data contained in the files may be retrieved by means of the computer and may be presented visually by means of CRTs for one-time instant use, or by printouts and automatic plotting for repeated use over an indefinite time period. Data presented may be the exact original data as contained in one or more files, or extracted data obtained as a result of correlating data residing in one or more files, or a combination of both; such extracted data may or may not be retained in separate files for future use.

These data may be retrieved for an individual consumer or an individual item of plant facilities, or may be other data for a particular location. They may be retrieved for a group of individual locations, or for a particular area, small or large. The various specific purposes determine what data are to be retrieved and how they are to be presented. They also determine the programs and equipment required. Data thus retrieved then are used with data contained on the map to help in forming the decisions required. The decisions may include new data that can be reentered in the files as updating material, that can be plotted or printed for exhibit purposes, or that can be reentered on maps for updating or expanding the material thereon; all of these may be done by means of the computer.

The grid coordinate number is applied to utility facilities for ease of location and positive identification in the field. In the case of electric utilities, these may include services, meters, poles, towers, manholes, pull boxes, transformers, transformer enclosures, switches, disconnects, fuses, lightning arresters, capacitors, regulators, boosters, streetlights, air pollution analyzers, and other equipment and apparatus; also the location of laterals on transmission and distribution circuits.

OTHER APPLICATIONS

Similarly, for gas utilities, the applications of grid coordinate numbers may include mains, services, meters, regulators, valves, sumps, test pits, and other equipment; also the location of boosters, laterals, and nodes on the gas systems. For water systems, they may include mains, services, meters, valves, dams, weirs, pumps, irrigation channels, and other facilities. For telephone and telegraph communication systems, including CATV circuits, they may include mains, services, terminals, repeaters, microwave reflectors, and other items including poles, manholes, and special items.

Grid coordinate numbers also may find application in many other lines of endeavor: highway systems, railway systems, oil fields, social surveys (police, health, income, population distribution, etc.), market surveys (banks and industries), municipal planning and land use studies, nonclassical archeology, geophysical studies, and others where such means of location identification may prove practical.

The use of grid coordinates facilitates positive identification in the field; the numbers are posted systematically on facilities, such as streetlight or traffic standards, poles, and structures, and at corners or other prominent locations.

An atlas, consisting of a grid overlay on a geographical map, aids the field

forces in locating consumers and plant facilities and provides a common basis for communication between office and field operating personnel.

The grid pattern permits the classical manipulation of data by individual grid sections or areas comprising several grid sections. In addition to the simple presentation of such data by means of CRT displays and typed printouts, data may be presented in the form of plotting in various graphical forms, in patterns indicating the distribution of data, the density of particular data, the accumulation of data within fixed boundaries, the determination of area boundaries for predetermined data content (the analysis of data within a given polygon), the calculation of lengths and distances between grid locations, and the mapping of facilities in acceptable detail—and all of these operations may be performed automatically by means of the computer.

Further, summaries and analyses employing the grid coordinate system may be more readily made and are susceptible to combination and consolidation, resulting in perhaps fewer and more comprehensive reports (eliminating the duplication of much needless data and the presentation of more complete and meaningful conclusions in one place).

In all of the foregoing discussion, the point must be made that all of the handling of data using the grid system may also be accomplished without the use of the grid system. It is apparent, however, that this latter method will in the vast majority of cases employ more effort in terms of work hours and will be more time-consuming, so as to render many applications impractical, even though their desirability may be great; in short, the grid coordinate system enhances the economics of data handling.

ECONOMICS

It is not to be denied that the introduction of the grid coordinate system will impose additional cost to the maps and records function. It is also evident that these costs will be offset by the decreased personnel requirements in the processing of data derived from the maps and records, especially when the computer may be made to take up a large part of this burden. Moreover, more refinement and a wider scope in processing of data are attainable.

The cost of implementing a grid coordinate system can be evaluated fairly accurately. Many factors will influence the final determination; these include the area of the system involved, the number of consumers and facilities, the condition of the basic and auxiliary maps and records, the number and scope of the applications desired, the extent of automation, and many other factors. A very approximate estimate may average perhaps about one day's revenue per consumer. Practical considerations associated with implementation may well dictate a period of several years, perhaps 5 years or even more, over which the expenditure will have to be made to accomplish the desired goals.

The offsetting savings from the introduction of a grid coordinate system, including those derived from the additional worth of the wider utilization, are difficult to pinpoint. It should be observed that while it is probable that a single application will not justify the adoption of the grid coordinate system, except in some unusual or special set of circumstances, it is also probable that the multi-

plicity of practical applications indicated will justify the relatively modest expenditure necessary for the conversion of present maps and records to the grid coordinate system.

The personnel requirements necessary to implement a grid coordinate system over a reasonable (short-term) period of time must be viewed together with the overall probable lessened longer-term in-house requirements. Since such a conversion is a one-time operation, it recommends itself admirably to the classical use of contractors having the special skills and experience. Further, such outside services are not apt to be diverted by crisis incidents prevalent in many enterprises.

One final observation. With the national consensus apparently pointing to an ultimate metric system for the United States to conform with world standards, the adoption of a grid coordinate system provides an excellent opportunity for its introduction with a minimum of conversion effort.

With the advent of the computer, it was inevitable that the grid coordinate system should be developed to provide a simple means of addressing the computer. The grid number provides the link between the map and the vast amount of data managed by the computer. This happy marriage of two powerful tools results not only in better operations but in improved economy as well. It is a must in the modernization of operations in many enterprises and especially in utility systems.

APPENDIX D

AUTOMATED DISTRIBUTION COMES OF AGE*

by
Thomas J. Kendrew
and
John A. Marks

INTRODUCTION

The subject of automated distribution for electric utilities is receiving widespread attention. The idea has been around for over 10 years—that is, the idea of an "expert system" designed to automatically operate and coordinate the use of all of a utility's distribution components in real time. Only recently, with advances in digital and communications technology, has its application been a real possibility.

The time for implementation has come. Consider that electric utilities are among the largest users of data of any industry and, according to some experts, are the largest users of real-time data. In today's utility industry, computer workstations are on the desks of nearly everyone from the CEO to the plant maintenance technician. At corporate headquarters, managers, engineers, clerks, and specialists of every kind process and analyze business and operational information through a host of computers big and small. From next month's revenue projection to next week's system load forecast, to the next day's customer billing run, data are the operational lifeblood of the utility industry.

Such a thumbnail sketch of utilities' data processing and communications functions could give the impression that all those computers and other electronic gear are neatly connected into very large systems encompassing the full range of utility operations. Information entered anywhere in the system would wind its way up, down, and across the organization, to be electronically filtered out to those people and systems that need it and are authorized to receive it.

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BRIDGING THE ISLANDS OF COMMUNICATION

But that is far from the case. In fact, most utilitys' computers and communications systems were designed only to perform specific functions, such as supervisory control and data acquisition (SCADA) in transmission or distribution operations or financial accounting in corporate systems. Most were put in place, piecemeal, as needs arose or as new technology opened opportunities to automate. Although such independence can be a strength in certain respects, it can become a disadvantage when different systems must work together.

Most systems were installed with no, or only limited, capability to communicate with other systems. Rarely have all of the systems' utility uses come from the same vendor, with compatible interconnections or with standard communications protocols—the procedural codes that govern how data are exchanged among systems. Therefore, islands of communication have resulted.

An integrated distribution system is a way of connecting all the components of a utility's distribution system into a single communications network. The potential benefits of automated distribution systems are striking. The Electric Power Research Institute (EPRI) has worked with several electric utilities and found that the improved productivity and the remote monitoring resulting from an automated distribution system could save as much as 10 percent of their annual operation and maintenance expenses. Other utilities may find such automation of substantial value, and appropriate evaluation studies of automation functions are recommended.

SINGLE FUNCTIONS NOW JUSTIFY INSTALLATION

Today, as utilities look more closely into the applicability of currently available automated distribution systems, economies are beginning to emerge that justify its installation on the basis of a single function.

One example is the new "smarter substation." Today's microprocessors can operate in the harsh environment of a distribution substation and, if so ordered, make operating decisions and issue commands. Automated distribution systems provide far more automation than existing SCADA systems. A SCADA system usually provides limited substation data and some operating capability but provides very little knowledge of the distribution system beyond the substation feeder breaker. Using a SCADA system, an operator may be able to open or close the feeder breaker, but that is about it.

During a persistent fault condition with a feeder lockout, a dispatch operator must make some decisions about the fault conditions based on his or her intimate knowledge of the distribution system. Before any decisions are made, the operator must analyze wall maps for feeder routing. When routing is identified, an emergency repair crew is contacted and feeder patrolling starts. After the fault is located, it is isolated and power is restored to other, unaffected areas.

Restoration of the unaffected areas, therefore, requires interaction between the dispatch operator, several data bases, and field personnel. The distribution dispatch center may have information available concerning the loading and availability of backup feeders, again through data bases, and the dispatcher will determine

if a switch can be closed to pick up load for an isolated part of the faulted feeder. After restoring service to all nonaffected zones of the faulted feeder—which takes an average of three hours—work starts on the faulted area.

The above example outlines the necessary response to a single-point utility system fault and the subsequent measures taken to restore customer service. During a major storm, this condition could multiply by one or two orders of magnitude, depending on the size of the storm area or the size of the utility itself. Under these conditions, the system operator must prioritize outage reports for a step-by-step investigation of feeders, which will inevitably result in longer outages for some customers.

An automated distribution system ties numerous data management and processing systems scattered throughout utility operations into a central control system. This lets a utility centrally automate more than 100 distinct functions and subfunctions. Centralized communications has the potential of becoming a data highway for all of a utility's data functions.

SIMULATING AN OPERATOR'S DECISIONS

Automated distribution has the capability of opening and closing switches automatically, using the same techniques that an operator uses. The difference is that fault isolation and service restoration are done at the substation level, in a few minutes, using substation microprocessors that have been programmed to react as an operator would. The processor also calls on different data bases, just as an operator would, to clear a fault and will queue up multiple faults and also clear them on a preestablished priority base. After the fault has been cleared, the processor will call the dispatch center and report what has happened. With an automated distribution system, restoration takes minutes instead of hours.

The scenario described in the previous paragraphs only touches on one capability of an automated distribution system. It was used because it shows that an "expert" system is capable of operation through computer control without human intervention. In addition, the automated system has digital protection capability far beyond the ability of today's conventional systems. For example, if an operator enters an incorrect protection value, the system may reject it. Another example is breaker backup. If the protection unit is inoperative and no command is issued to the breaker, the data-acquisition system will sense this and issue a trip command.

Finally, an automated distribution system is adaptive, with several built-in characteristics such as time-over-current (TOC) curves, reclosing, underfrequency, backup, sync check, and diagnostics, only to mention a few subfunctions. These are implemented on a feeder rather than phase base.

LOAD MANAGEMENT TOOL

Automated distribution can also aid in load management, balancing load between substation transformers and allowing for better utilization of transformer capacity. An unattended distribution substation could be considered attended through an on-site microprocessor. With the on-site microprocessor, load can be transferred

APPLICATIONS FOR AUTOMATED DISTRIBUTION

Automatic control

Bus sectionalizing
- Fault isolation
- Service restoration
- Overload detection

Feeder deployment switching and automatic sectionalizing
- Fault location
- Fault isolation
- Service restoration
- Feeder reconfiguration

Integrated voltage and VAR control
- Bus voltage control
- Substation-transformer circulating current control
- Line-drop compensation
- Feeder remote-point voltage control
- Feeder reactive power control
- Substation reactive power control

Substation-transformer load balancing
- Transformer load loss reduction
- Minimization of overloads

Cold load pickup on feeders

Manual control

Distribution dispatch center/SCADA interface

Data acquisition and processing

Analog data freeze
Data monitoring
Data logging

Interface

Distribution communications interface
- Distribution line carrier
- Radio
- Telephone
- Others

Protection

Automatic reclosing
Bus fault protection
Instantaneous overcurrent
Time overcurrent
Substation-transformer protection
Underfrequency protection

Load Management

Load control
Remote service connection, disconnection
Pass-through commands
- Fault isolation
- Service restoration

Remote metering

Load survey
Peak demand metering
Remote meter programming
Tampering detection

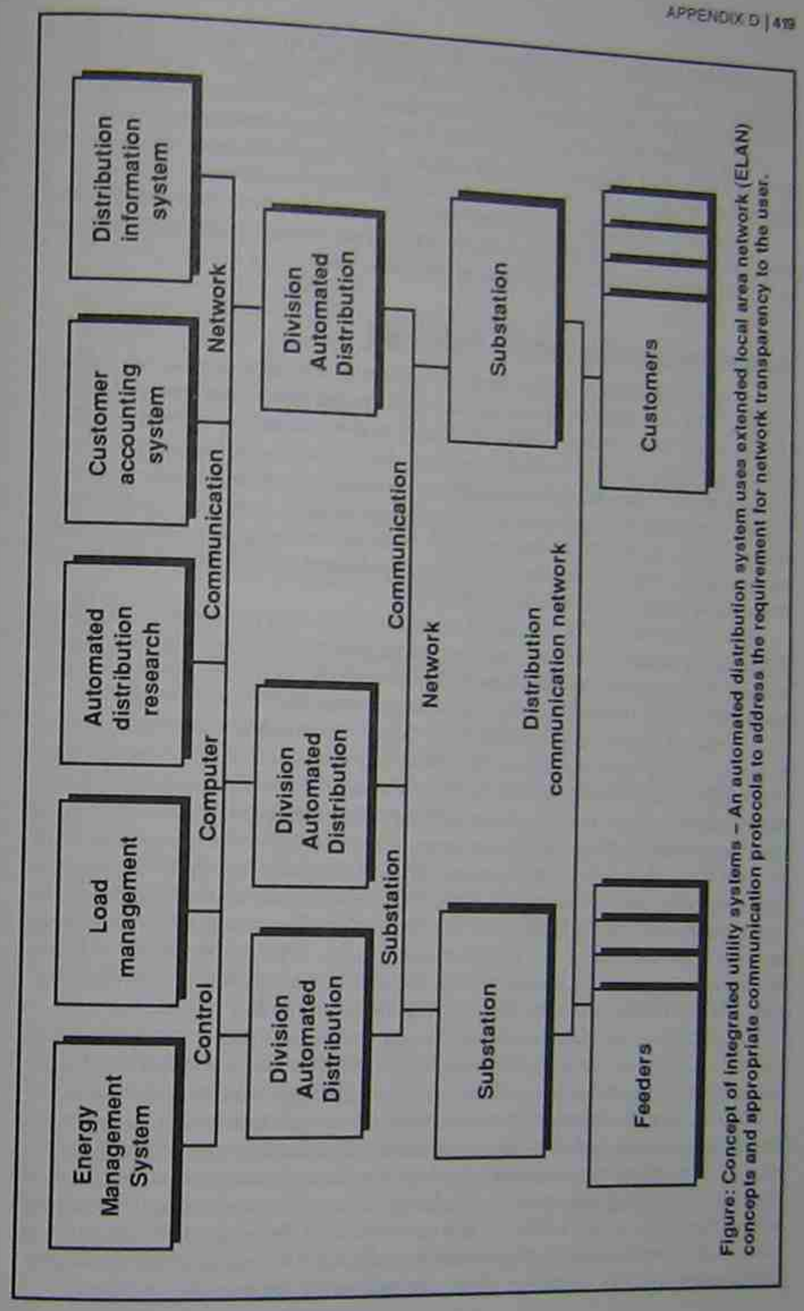


Figure: Concept of integrated utility systems – An automated distribution system uses extended local area network (ELAN) concepts and appropriate communication protocols to address the requirement for network transparency to the user.

within minutes, power transformers can be loaded to a full rating (not 50 percent as some are) to allow for the failure of an adjacent transformer. This capability could defer capital investments for additional transformer capacity, a major savings.

An integrated volt/VAR function could produce a large savings due to the control of losses and improved voltage control. This function alone may have the capability of paying for the automated distribution system.

Remote meter reading and monitoring is also possible with automated distribution. In fact, the list of automated distribution capabilities could go on and on to describe more than 150 programmable functions.

AUTOMATED DISTRIBUTION FEATURES

The main component of automated distribution is its backbone communications system. The central processor must be able to receive input from remote sources, process data, and transmit instructions back to those sources or substations. The central processor data base must be addressable so that the software patched into the system from remote sources is indifferent to incoming data location or format. Utilities must be willing to convert information stored in a variety of forms from maps, to text, to diagrams, into readable form in the central digitized data base (as seen in the Figure). The data base then coordinates and processes information from throughout the distribution network.

The automated distribution system communicates with remote elements of the distribution network over all types of communications media. This versatility enables the central utility data base to independently control the myriad of functions performed throughout the distribution network.

Automated distribution is much more than a communications system, or load control, or a sophisticated SCADA system; it is true automation where software capability will actually replace the operator in some of the normal utility operations, thereby freeing them for other duties and improving their productivity. Automated distribution has endless capabilities because of its ability to interconnect systems or data bases that store data in many forms, acting as a translator for systems that essentially speak different languages. Utility planners are now looking at specific installations that take advantage of automation's ability to reconfigure a system in ways that can reduce the need for redundancy, defer construction of costly facilities, and maintain reliability with reduced resources. Automated distribution is as attractive from the engineering viewpoint as it is from operations.

Installation of an automated distribution system provides a second order of benefits to the innovative utility. Automated distribution establishes a valuable interface between the utility and the customer. Through this central network, the utility can receive instantaneous information from substations during potential brown-out periods and then alter load distribution accordingly. This eliminates the need to appeal to customers to reduce use during peak periods. Automated distribution offers greater service reliability for customers and a more economical use of resources to the utility. It also provides a medium by which the utilities can advise customers of rapidly changing conditions. The benefits of an automated distribution system, therefore, filter through to the entire utility system.

BENEFITS OF AUTOMATED DISTRIBUTION

Investment related

Deferred generation
Released transmission capacity
Deferred distribution substation
Deferred distribution substation transformer capacity
Deferred feeder(s) and/or feeder getaway(s)
Reduced wiring and cabling at distribution substation
Displace or reduce need for:
- Conventional SCADA master and remote terminals
- Conventional metering and recorders at substation
- Transducers (e.g., using waveform sampling)
- Conventional controls, such as capacitor bank controls
- Conventional protection

Interruption related

Increased revenue because of faster restoration
Reduced crew time to locate faults and restore service

Customer related

Reduced customer complaints because of:
- Low voltage
- Prolonged outages

Value to customer of improved reliability

Operational savings

Improved cash flow because of remote metering
Improved conservation voltage regulation
Improved engineering and planning decisions because of more accurate and timely distribution system data
Repair and maintenance savings
Generation fuels savings because of:
- Reduced substation transformer losses
- Reduced primary feeder and distribution transformer losses
- Load management
- Reduced spinning reserve requirement

Reduced travel to distribution substations and feeders to switch load and gather data
Reduced loss of revenue from theft of service

Improved system operation

Capability to change digital protection settings remotely
Improved data for distribution-system operators during emergencies
Improved detection of system equipment malfunction
More sensitive protection (adaptive changes for reconfiguration, cold load pickup, etc.)
Simplified change of substation sectionalizing routines
Capability to reassemble distribution system quicker

INSTALLING AN AUTOMATED DISTRIBUTION SYSTEM

The degree of compatibility between the automated distribution structure and a utility's organizational structure is a major factor in determining the success of the automated distribution system. Automation should be used to enhance the productivity of an operation; yet this may be difficult to accomplish if the system itself is at odds with the structure of the company. This is not to say that changes cannot or should not be made in a utility's organizational structure. Rather, the chances of successful integration of automated distribution will be greater if radical changes in the organizational structure are not required.

CONCLUSION

As utility system load grows, utility systems necessarily become more sophisticated, and control of the large amounts of data necessary to properly opreate these systems will similarly become unmanageable. Computerized distribution systems are well suited to tackle new challenges that will face utilities. Automation projects are paving a road for the future, and the need for that road is more critical with each passing day. As the need develops, the automation systems are being proven and will be ready to be incorporated into utility operations for both large and small utilities.

FOR FURTHER READING

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APPENDIX E

U.S. AND METRIC RELATIONSHIPS

Metric to U.S.		*U.S. to metric*	
Length			
1 mm	= 0.03937 in	1 in	= 25.4 mm
1 cm	= 0.3937 in	1 in	= 2.54 cm
1 m	= 39.37 in	1 in	= 0.0254 m
1 m	= 3.2808 ft	1 ft	= 0.3048 m
1 m	= 1.094 yd	1 yd	= 0.9144 m
1 km	= 0.6214 mi	1 mi	= 1.609 km
Surface			
1 mm^2	= 0.00155 in^2	1 in^2	= 645.2 mm^2
1 cm^2	= 0.155 in^2	1 in^2	= 6.452 cm^2
1 m^2	= 10.764 ft^2	1 ft^2	= 0.0929 m^2
1 m^2	= 1.196 yds^2	1 yd^2	= 0.8361 m^2
1 hectare	= 2.471 acres	1 acre	= 0.4047 hectare
1 hectare	= 0.00386 mi^2	1 mi^2	= 258.99 hectare
1 km^2	= 0.3861 mi^2	1 mi^2	= 2.59 km^2
Volume			
1 cm^3	= 0.061 in^3	1 in^3	= 16.39 cm^3
1 m^3	= 35.314 ft^3	1 ft^3	= 0.0283 m^3
1 m^3	= 1.308 yd^3	1 yd^3	= 0.7645 m^3
1 liter	= 0.0353 ft^3	1 ft^3	= 28.32 liters
1 liter	= 61.023 in^3	1 in^3	= 0.0164 liter
1 liter	= 1.0567 qt	1 qt	= 0.9463 liter
1 liter	= 0.2642 gal	1 gal	= 3.7854 liters
1 m^3	= 264.17 gal	1 gal	= 0.0038 m^3
Weight			
1 g	= 0.0353 oz	1 oz	= 28.35 g
1 kg	= 2.2046 lb*	1 lb	= 0.4536 kg
1 T metric	= 1.1023 net tons**	1 net ton	= 0.9072 T (metric)
Compound Units			
1 kg/m	= 0.6720 lb/ft	1 lb/ft	= 1.4882 kg/m
1 kg/cm^2	= 14.223 lb/in^2	1 lb/in^2	= 0.0703 kg/cm^2
1 kg/m^2	= 0.2048 lb/ft^2	1 lb/ft^2	= 4.8825 kg/m^2
1 kg/m^3	= 0.0624 lb/ft^3	1 lb/ft^3	= 16.0192 kg/m^3
1 kg·m	= 7.233 ft·lbs	1 ft·lb	= 0.1383 kg·m
1 kW	= 1.340 hp	1 hp	= 0.746 kW
1 $kg·m/cm^2$	= 46.58 $ft·lb/in^2$	1 $ft·lb/in^2$	= 0.0215 $kg·m/cm^2$

*Avoirdupois.

**1 ton = 2000 lb.

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Jan de Kock, PR Eng, PH.D, University of Potchefstroom, Potchefstroom, South Africa

Kobus Strauss, CPEng, BCom, B.Eng, SKM Engineers, Perth, Western Australia

Series editor: Steve Mackay

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Preface

This is a practical book on Power Distribution, focusing on medium voltage (1–36 kV) power considerations, switchgear, power cables, transformers, power factor correction, grounding/earthing, lightning protection and network studies. You will gain useful practical technical know-how in these areas, not always covered by university or college programs.

Typical people who will find this book useful include:

- Electrical engineers
- Design engineers
- Project engineers
- Electrical technicians
- Protection technicians
- Maintenance technicians and supervisors.

We would hope that you will gain the following from this book:

- Understand practical power distribution fundamentals
- Determine short-circuit ratings quickly and effectively
- Assess the influence of fault levels on switchgear ratings
- Select the correct type of switchgear for the right application
- Evaluate the advantages of modern state-of-the-art switchgear protection for your applications, including preventative maintenance information
- Recognise the different applications for various cable insulation types
- Know when and how to use single core cables vs three core cables
- Specify correct power cable installation methods
- Correctly utilise and protect power transformers
- Assess and specify correct grounding throughout your electrical network
- Determine the need for Power Factor Correction (PFC) for your environment
- Assess the economic justification for installing PFC equipment
- Correctly specify PFC equipment and be aware of practical consequences
- Confidently use software to solve and predict simple power network problems.

1

Introduction to power distribution

1.1 Introduction

A typical electrical power network is illustrated in Figure 1.1.

An electrical network initiates at the point of generation. Electrical power is generated by converting the potential energy available in certain materials into electrical energy. This is either done by direct conversion of kinetic energy, e.g. wind- or water turbines, or creating steam to drive the turbines, e.g. coal- or nuclear boilers.

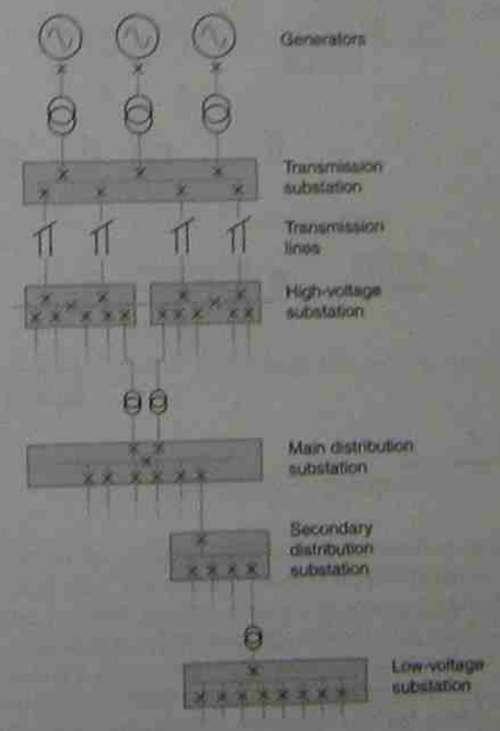


Figure 1.1
Typical electrical power network

The electrical powers generated are either transferred onto a bus to be distributed (small scale), or into a power grid for transmission purposes (larger scale). This is done either directly or through power transformers, depending on the generated voltage and the required voltage of the bus or power grid.

The next step is power transmission, whereby the generated electrical potential energy is transmitted via transmission lines, usually over long distances, to high-voltage (HV) substations. High-voltage substations will usually tap directly into the power grid, with two or more incoming supplies to improve reliability of supply to that substation's distribution network.

Electrical transmission is normally done via high to extra high voltages, in the range of 132–800 kV. Mega volt systems are now being developed and implemented in the USA. The longer the distance, the more economical higher voltages become.

Question 1.1 for course participants: Why would high-voltage transmission be more economical than lower voltages the longer the transmission distance, and be less economical for short distances?

Normally, the transmission voltage will be transformed at the HV substation to a lower voltage for distribution purposes. This is due to the fact that distribution is normally done over shorter distances via underground cables. The insulation properties of three-phase cables limit the voltage that can be utilized, and lower voltages, in the medium-voltage range, are more economical for shorter distances.

Figure 1.2 is a schematical illustration of a typical power grid.

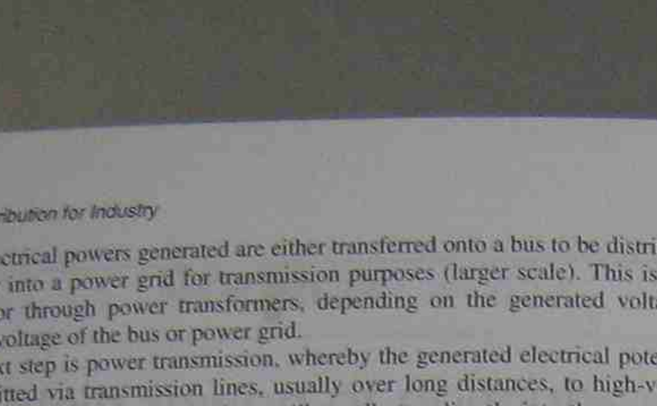


Figure 1.2
Typical power grid

Critical medium-voltage (MV) distribution substations will generally also have two or more incoming supplies from different HV substations. Main distribution substations usually supply power to a clearly defined distribution network, for example, a specific plant or factory, or for town/city reticulation purposes.

Power distribution is normally done on the medium-voltage level, in the range of 6.6–33 kV. Three-phase power is transferred, mostly via overhead lines or 3-core MV power cables buried in trenches. Single-core-insulated cables are also used, although less often.

Low-voltage distribution is also done over short distances in some localized areas.

A power distribution network will therefore typically include the following:

- HV/MV power transformer(s) (secondary side)
- MV substation and switchgear
- MV power cables (including terminations)
- MV/LV power transformer(s) (primary side).

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The distribution voltage is then transformed to low voltage (LV), either for lighting and small power applications, or for electrical motors, which is usually fed from a dedicated motor control center (MCC).

This is illustrated in Figure 1.3.

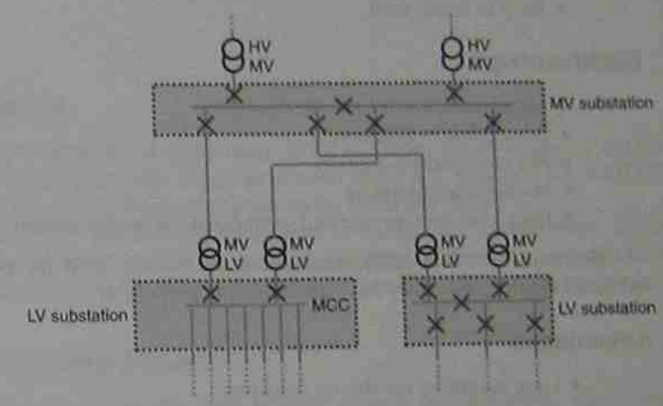


Figure 1.3
Typical power distribution network

Note: Voltage levels are defined internationally, as follows:

- *Low voltage*: up to 1000 V
- *Medium voltage*: above 1000 V up to 36 kV
- *High voltage*: above 36 kV

Supply standards variation between continents by two general standards have emerged as the dominant ones:

- In Europe
  IEC governs supply standards
  The frequency is 50 Hz and LV voltage is 230/400 V
- In North America
  IEEE/ANSI governs supply standards
  The frequency is 60 Hz and the LV voltage is 110/190 V.

Overhead lines are far cheaper than underground cables for long distances, mainly due to the fact that air is used as the insulation medium between phase conductors, and that no excavation work is required. The support masts of overhead lines are quite a significant portion of the costs, that is the reason why aluminum lines are often used instead of copper, as aluminum lines weigh less than copper, and are less expensive. However, copper has a higher current conducting capacity than aluminum per square mm, so once again the most economical line design will depend on many factors.

Overhead lines are by nature prone to lightning strikes, causing a temporary surge on the line, usually causing flashover between phases or phase to ground. The line insulators are normally designed to relay the surge to ground, causing the least disruption and/or damage. This is of short duration, and as soon as it is cleared, normal operation may be resumed. This is why sophisticated auto-reclosers are employed on an increasing number of overhead lines.

Overhead lines have the following properties:

Advantages

- Less expensive for longer distances
- Easy to locate fault.

Disadvantages

- More expensive for shorter distances
- Susceptible to lightning
- Not environment-friendly
- Maintenance intensive
- High level of expertise and specialized equipment needed for installation.

Underground (buried) cable installations are mostly used for power distribution in industrial applications. They have the following properties:

Advantages

- Less expensive for shorter distances
- Not susceptible to lightning
- Environment-friendly
- Not maintenance intensive.

Disadvantages

- Expensive for long distances
- Can be difficult to locate fault.

The focus of this manual will be on MV power distribution, specifically practical considerations regarding MV switchgear, power cables, power factor correction and computer simulation studies.

2

Medium-voltage switchgear

2.1 Standards

Standards in Europe and many other 50 Hz countries are governed by the IEC. The SA bureau of standards SABS has adopted many of the IEC standards e.g. SABS/IEC 87.

In North America, the standards are set by ANSI and the IEEE.

The standards and the way switchgear is tested vary from country to country. It is therefore important to verify what standard is being called for in a specification or is used by the manufacturer. Variations in standards also affect the price of equipment.

2.2 Switch board layout

Switch boards can be designed to have various configurations. This depends on the reliability, fault level and the flexibility required.

Examples:

- Single busbar with only one busbar section (no flexibility and low reliability)
- Single busbar with two sections (improved flexibility and reliability with highest fault level if section maker is closed)
- Single busbar with three sections (excellent flexibility and reliability)
- Double busbar with one or more sections (good flexibility and reliability). The busbar layout may require a break before transfer from one busbar to the next.

2.3 Ratings

Manufactured medium-voltage (MV) switchgear panels are rated according to the following main specifications:

Nominal voltage

This is the designed average voltage of a system, e.g. 11 kV. The actual voltage will typically fluctuate between 10.5 and 11.5 kV (95–105%).

Rated voltage

This is the voltage level at which the equipment will be expected to perform at continuously under normal operating conditions, e.g. 12 kV for a system with a nominal voltage of 11 kV.

The rated voltage will determine the insulation properties of the panel. Each main component, including individual circuit-breakers, busbars, cable terminations, etc., must be rated to this voltage, or higher. ('Main' components refer to those components that form part of the main voltage circuit of the panel, as opposed to the control circuit.) For example, if a 7.2 kV circuit-breaker is installed in a 12 kV panel, it will mean that the whole panel is rated only 7.2 kV.

The normal practice is to rate switchgear panels 10% higher than the required nominal voltage, e.g. 12 kV for an 11 kV system, 36 kV for a 33 kV system, etc.

Power frequency withstand voltage

This is the 50 or 60 Hz voltage that the switchgear can with stand for 1 min. For 12 kV related equipment, the applied test voltage is 28 kV. Switchgear manufacturers use this test to prove the insulation of their equipment after manufacture in routine testing.

Commissioning engineers also use this test to prove the integrity of the equipment before switching on the power. This test is also known as a pressure test.

Impulse voltage

This is the highest peak voltage the equipment will be able to withstand for a very short period of time, as in the case of a voltage peak associated with lightning, switching or other transients, e.g. 95 kV for 12 kV equipment.

BIL standards are set by IEC 60.

The same principle as above applies, i.e. the impulse voltage rating of the panel is equal to the rating of the lowest rated main component.

The impulse level that a panel will experience may be controlled by installing surge suppressers, which will limit the peak voltage to a certain level. This is illustrated in Figure 2.1.

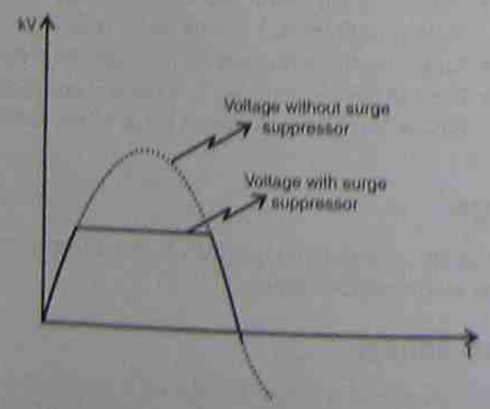


Figure 2.1
Impulse voltage

In limiting the peak voltage, e.g. 45 kV, the surge arrestor will conduct a large current, say 10 kA to earth.

Surge arrestor

Surge arrestors are installed at the transition point between e.g. an overhead line and a transformer, and as close to the transformer terminals as possible.

Surge arrestors are also installed as motor terminals and on the ends of overhead lines. They are unusually connected between phases and earth.

Three types of surge arrestors are used:

1. Rod spark gapped
2. Multiple gapped arrestors
3. Zinc (metal) oxide surge arrestors.

In applying surge arrestors the voltage rating, lighting density and the surge rating should be considered in determining the insulation coordination of the power system.

Full load current

This is the maximum load current that may pass continuously through the switchgear panel. Contrary to the voltage rating, not every main component needs to have the same current rating. Every individual circuit breaker or switch will be rated according to the maximum load current that will pass through it.

The incoming circuit-breaker/disconnector and the main busbars will usually be rated the same. This value is obtained by adding all the individual feeder ratings, multiplied by a load or diversity factor. This factor is smaller than one, and is determined by the types of loads connected to the panel. Individual loads will not run at full capacity simultaneously, hence the load factor.

This calculation can be illustrated as follows:

Feeder No.	Current Rating (A)
1	200
2	100
3	350
4	600
5	150
6	250
Total	1650
Load factor	60%
Required incomer/busbars	990 A

A good estimate of the load factor can be done by looking at the historical values recorded for the relevant feeders, if available.

Due to economy of scale, MV circuit-breakers/disconnectors are manufactured in a few standard sizes, for example 630 A, 1250 A, 1600 A, 2000 A and 2500 A according to IEC standards.

Fault current

The magnitude of fault current that a switchgear panel must withstand is not determined by the load connected to it, but by the properties of the supply to it. Usually, a MV panel will be supplied via a HV/MV transformer(s). This transformer will then determine the magnitude of the fault currents that may flow through the panel.

Electrical faults usually occur due to breakdown of the insulating media between live conductors or between a live conductor and earth. This breakdown may be caused by any one or more of several factors, e.g. mechanical damage, overheating, voltage surges (caused by lightning or switching), ingress of a conducting medium, ionization of air, deterioration of the insulating media due to an unfriendly environment or old age, or misuse of equipment.

Faults are classified into two major groups: symmetrical and unbalanced (asymmetrical). Symmetrical faults involve all three phases and cause severe fault currents and system disturbances. Unbalanced faults include phase-to-phase, phase-to-ground, and phase-to-phase-to-ground faults. They are not as severe as symmetrical faults because not all three phases are involved. The least severe fault condition is a single phase-to-ground fault with the transformer neutral earthed through a resistor or reactor. However, if not cleared quickly, unbalanced faults will usually develop into symmetrical faults. These different types of faults are illustrated in Figure 2.2.

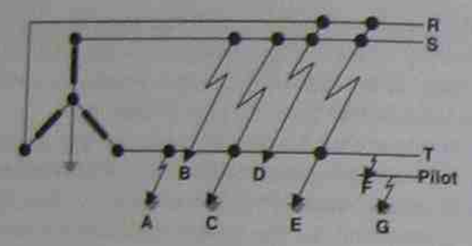


Figure 2.2
Electrical fault types

In distribution systems with Δ/λ (HV/mV) connection and the star point solidly earthed, the single-phase fault current may be higher than the three-phase symmetrical fault current due to the zero sequence reactance of the transformer being lower than the positive sequence reactance.

Switchgear needs to be rated to withstand and break the worst possible fault current, which is a solid three-phase short-circuit close to the switchgear. 'Solid' means that there is no arc resistance. Normally arc resistance will be present, but this value is unpredictable, as it will depend on where exactly the fault occurs, the actual arcing distance, the properties of the insulating medium at that exact instance (which will be changing all the time due to the heating effect of the arc), etc.

Arc resistance will decrease the fault current flowing.

Exact calculations of prospective fault currents can be quite complex, and are usually performed with the aid of computer simulation software (see Chapter 5). However, when a few allowable assumptions are made, approximate fault currents can be determined quite easily and quickly with pen and paper (plus calculator, preferably!). These approximate values will be conservative, giving the worst case, and can therefore be confidently used for the ratings of switchgear panels.

These assumptions are the following:

- Assume the fault occurs very close to the switchgear. This means that the cable impedance between the switchgear and the fault may be ignored.
- Ignore any arc resistance.
- Ignore the cable impedance between the transformer secondary and the switchgear, if the transformer is located in the vicinity of the substation. If not, the cable impedance may reduce the possible fault current quite substantially, and should be included for economic considerations (a lower-rated switchgear panel, at lower cost, may be installed).
- When adding cable impedance, assume the phase angle between the cable impedance and transformer reactance as zero, hence the values may be added without complex algebra, and values readily available from cable manufacturers' tables may be used.
- Ignore complex algebra when calculating and using transformer internal impedance.

Fault currents are then easily calculated as follows:

Example 1 (ignoring cable impedance)

Ignoring cable impedance means that the fault is actually calculated directly on the transformer's terminals. The magnitude of the fault current is then only limited by the transformer's internal impedance, which is usually indicated by a percentage value on the nameplate of the transformer. This value expresses the impedance value as a percentage of the base value. This is illustrated in the following calculation:

Calculation

Transformer ratings:

Primary voltage:	$V_p = 132$ kV
Secondary voltage:	$V_s = 11$ kV
Capacity:	$S = 20$ MVA
Impedance:	$Z = 10\%$

Calculation of base value, Z_b:

$$S = \frac{V^2}{Z}$$

$$\Rightarrow Z_b = \frac{V_s^2}{S} \text{ (referred to secondary side of transformer)}$$

$$= \frac{(11\times10^3)^2}{(20\times10^6)}$$

$$= 6.05\ \Omega$$

$$Z_{actual} = Z\% \times Z_b$$

$$= 0.1 \times 6.05\ \Omega$$

$$= 0.605\ \Omega$$

$$I_{fault} = \frac{V_s}{\left(\sqrt{3}.Z_{actual}\right)}$$

$$= \frac{11\times10^3}{1.048\ \Omega}$$

$$= 10\,496\ \text{A}$$

Manipulation of the above formulas will give a quick reference formula to determine the fault current at the secondary terminals of the transformer:

$$I_{fault} = \frac{S}{\left(\sqrt{3} \times Z\% \times V_s\right)}$$

When more than one transformer is connected in parallel, feeding a switchboard, the fault currents of the transformers are added to give the fault current at the switchboard. For example, if two transformers, with ratings as in the above example, are connected in parallel, the fault current will be 20 992 A.

The smaller the transformer, the smaller the error of this approximation.

Example 2 (with cable impedance)

When the switchgear is situated quite some distance away from the transformer(s), the cable impedance needs to be taken into account to arrive at a realistic value. The fault current will be lower with additional impedance in the circuit, therefore this may be necessary for economic reasons, so as not to overrate new equipment at additional (unnecessary) cost.

The quickest and easiest way to bring cable impedance into the calculation is to simply add the cable impedance, which is usually a Ω/km value in the cable manufacturer's data table, to the transformer reactance (adjusting for line to phase values). This is an approximate value, as complex algebra should be used to add the impedance values, but it is usually accurate enough to determine required switchgear ratings.

Calculation

Take the same transformer ratings as in the above example. Assume the cable distance between the transformer and the switchgear as 6000 m. The cable has the following properties:

Type:	Copper conductors, XLPE insulated
Size:	185 mm²
Current rating:	410 A
Impedance:	0.1548 Ω/km (see Table 3.28)

Four cables are installed in parallel between the transformer and switchgear to achieve the required current rating.

Transformer reactance (as per above example): $Z_{Tr} = 0.605\ \Omega$

Cable impedance:

$$Z_C = 0.1548\ \Omega \times 6/4$$
$$= 0.2322\ \Omega$$
$$\Rightarrow Z_{total} = 0.605\ \Omega + 0.2322\ \Omega$$
$$= 0.8372\ \Omega$$
$$I_{fault} = \frac{V_s}{\sqrt{3}.\,Z_{(total}}$$
$$= \frac{11 \times 10^3}{1.450\ \Omega}$$
$$= 7586\ \text{A}$$

Therefore, if two transformers would feed in parallel to the switchboard in this example, the total fault current would be 15 172 A, and a switchgear panel rated 20 kA would be sufficient; whereas in the previous example a higher rating than 20 kA would be required.

This fault current rating that the switchgear must withstand, is not for an indefinite time, but is normally rated for 1 s or 3 s. The reason for this is that the electrical protection should operate within this time, clearing the fault. Even if the main protection should fail, enough time should be reserved for the back-up protection to function, avoiding severe damage to the switchgear panel. Sufficient time is also allowed for the circuit breaker tripping time.

The fault current rating will then be specified as a current and time rating, e.g. 20 kA, 3 s. This means that the panel will be able to withstand a three-phase through fault current of 20 kA for a continuous period of 3 s.

The fault current rating actually refers to two properties:

1. The amount of electrical energy the panel can absorb, according to the formula, $E = I^2t$. Exceeding this energy limit will cause thermal damage to the panel, and the conductors will melt.

   Therefore, there is quite a difference between a rating of, for example, 20 kA for 1 s, and 20 kA for 3 s. A panel rated for 20 kA, 1 s will only be able to withstand 11.5 kA for 3 s, according to the following calculation:

$$I_1^2 t_1 = I_2^2 t_2$$
$$\Rightarrow 20^2 \times 1 = I_2^2 \times 3$$
$$\Rightarrow I_2 = \sqrt{(400/3)}\ \text{kA}$$
$$= 11.5\ \text{kA}$$

   However, a panel rated for 20 kA, 3 s will not necessarily be able to withstand 34.6 kA for 1 s (according to the same formula), due to the second property involved with fault currents, namely electromechanical stresses.

2. Electromechanical stresses in a switchgear panel arise due to the phenomenon that current flowing in the same direction will cause an electromagnetic field that will assert an attracting force between the current-carrying conductors. In the case of fault currents, this force between the adjacent busbars can be so large that the busbars can be torn loose of their supports, causing extensive damage to the panel.

   This force is proportional to the square of the instantaneous current flowing. Therefore, the mechanical construction of the panel (busbar supports, etc.) will impose an upper limit on its fault current rating, irrespective of the time rating. The peak asymmetrical current rating, including fall DC offset, is used to determine the maximum electromechanical stresses.

It can be seen from the examples that, for MV applications, even long cable distances make only a marginal difference to the fault current rating. This is due to the fact that MV distribution usually involves large cable sizes, with several cables often installed in parallel, with low cable impedance as a result. It is for this reason that the effect of cable impedance is often ignored in MV fault calculations for distribution purposes, except in borderline cases, or where long distances are involved, or in the case of small size cables.

When small MV cables severely reduce the fault current rating, the chances are good that the cable itself will not be able to handle the fault current. This is illustrated in the next chapter on power cables.

Each individual switch as well as the busbars of a switchgear panel must be rated to withstand the prospective fault current. Huge mechanical forces are present in the current-carrying equipment when large fault currents flow, due to electromagnetism. Therefore, the fault current rating do not only refer to the electrical properties of the equipment, but also to their ability to withstand these mechanical forces.

MV switchgear equipment is rated according to the current allowed to pass through it (load or fault current), as well as a 'making' and 'breaking' value. The 'making' current rating is the value of current that the switch may close onto, i.e. the current flowing immediately when the switch is closed. The 'breaking' rating is the value of current already flowing that the switch may interrupt.

Question 2.1 for course participants: Why a 'making' rating, as the current flowing immediately before the switch is closed must be zero (circuit is still open)?

DC offset

The phenomenon called 'DC offset' should be taken into account when rating circuit breakers. This is illustrated in Figure 2.3. This phenomenon occurs due to the presence of inductive reactance in the system.

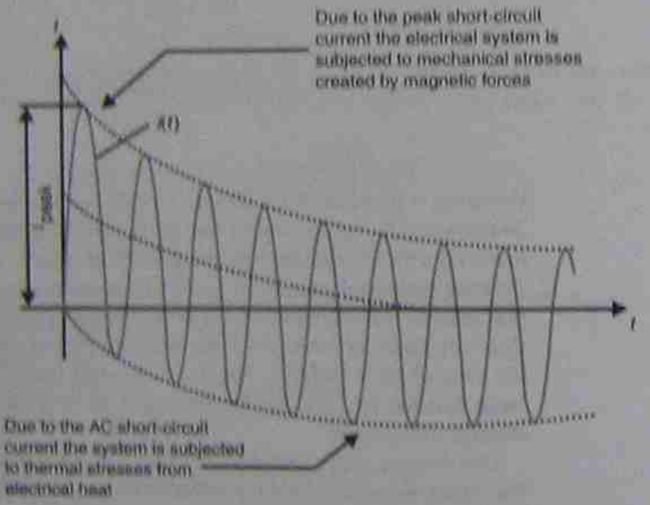


Figure 2.3
Illustration of DC offset

The peak current value will depend on the power factor of the system at the time of the fault. This maximum practical value of this peak current is 2.55 times the RMS fault current, as determined by the system impedance. This relationship is illustrated in Figure 2.4.

Although the peak currents associated with the DC offset is of relative short duration, they must be taken into consideration when rating switchgear panels, as additional mechanical stresses are caused by the electromagnetic forces associated with these high peak currents.

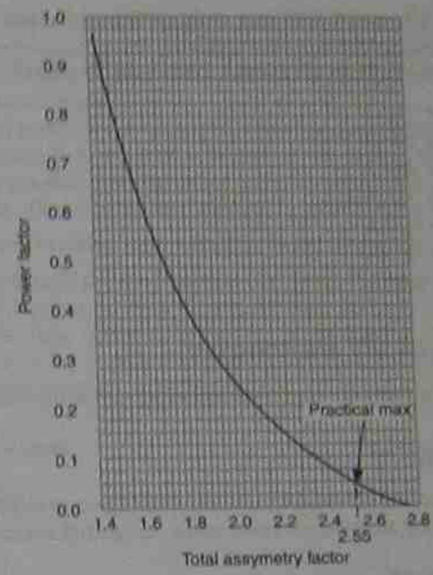


Figure 2.4
Asymmetry factor chart

The *rate of decay* of the DC offset, as illustrated in Figure 2.3, is dependent on the relationship L/R of the system. The higher the inductance, the slower the rate of decay. Normally, the DC offset will decay to zero within the first 3 to 4 cycles. Therefore, at the instant that the circuit breaker opens, these peaks have all but disappeared, and it will not be a cause for concern.

However, when a circuit breaker is installed close to high-inductive sources, like generators and large induction motors, the current waveform may still be substantially asymmetrical at the instant of the circuit breaker opening. This may cause the breaker to interrupt a higher current value than it was rated for, and the DC offset may cause an extended arcing period within the breaker. The resultant thermal energy may be higher than the breaker can withstand, with the result that the breaker may blow up.

Therefore, for these applications, a specialized generator circuit breaker should be installed, which is designed to withstand these factors.

Regulations

The SAA Wiring Rules (Australian Standard AS 3000) stipulates the following for switchgear above 1000 V (Regulation 8.7.2.2):

'The switching device shall be capable of performing at least the following operating functions:

- Make and break full-load current
- Carry the prospective fault current
- Make prospective fault current
- If fitted with protection devices, also break prospective fault current

A manually operated switch need not be capable of breaking the prospective fault current.

A switch which will not make prospective fault current may be approved where satisfactory interlocking is provided.'

Standard fault current ratings for switchgear include:

- 16 kA
- 20 kA
- 25 kA
- 31.5 kA
- 40 kA
- 50 kA
- 60 kA.

2.4 Types of MV switchgear

Switchgear types are classified according to function and method of insulation.

Function

Different terms are used to describe switchgear in different parts of the world. However, the following are most accepted terms recognized internationally.

Switch

A switch is a piece of equipment used to open an electric circuit by a mechanical action, interrupting the flow of current, without causing permanent damage to the equipment when it is used as designed for. A switch may either be a disconnector/isolator or circuit-breaker.

Disconnector/Isolator

The term disconnector or isolator is used to describe a device that is designed to open the electric circuit manually (or by manual command) under normal operating conditions. It may either be an off-load or on-load disconnector/isolator.

'Off-load' means the device is designed to open the circuit without any current flowing. The current rating of an off-load isolator will refer only to the value of current allowed to continuously pass through the device. The making- and breaking current rating will be zero.

'On-load' means the device may open the circuit with normal load current flowing, up to the full load current rating of the device. The continuous- and breaking current ratings will usually be the same, equal to the full load current rating of the device. Modern disconnectors usually have a short-circuit making rating in the region of 25 kA. However, the disconnector will not be able to handle this current for any sustained period of time; hence the current must swiftly be interrupted by a protective device, namely a fuse or a circuit breaker.

Circuit breaker

A circuit breaker (CB) is designed to open an electric circuit under overcurrent or fault conditions. This will usually occur upon a trip signal from a protection relay. A CB will have a continuous full load current rating, a fault current rating for a limited time, as well as a fault making- and breaking rating.

The CB opens its main contacts through a mechanical action. The contacts are kept closed by virtue of mechanical spring pressure. When a trip signal is received, a latch is drawn by a magnetic field set-up by the tripping coil, the spring pressure is released instantly, and the contacts separate.

Due to the mechanical actions involved, a certain fixed amount of time (in ms) elapses from the time the trip command is given until such time as the main contacts actually separate. Additional to this, there is a short period of arcing when the contacts separate, during which time current continues to flow. Therefore, the total tripping (or breaking) time is defined as follows:

CB breaking time = opening time + arcing time

'Opening Time' represents the time between the instant of application of the tripping signal to the instant of mechanical separation of the main contacts.

'Arcing Time' is the time between the instant of mechanical separation of the main circuit breaker contacts to the instant of arc extinction and hence zero current flow.

This may be illustrated as shown in Figure 2.5.

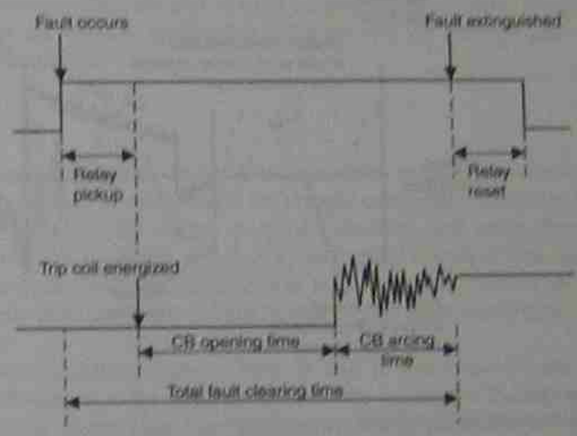


Figure 2.5
Total fault clearing time

Modern circuit breakers have total breaking times between 1 and 5 cycles (40–100 ms).

CB behavior under fault conditions

Before the occurrence of a short circuit, normal load current will be flowing through the CB. This could be regarded as zero when compared to the level of the fault current that would flow. At the instant of the fault, the current will rapidly rise to the maximum value allowed by the network properties. Due to the presence of reactance in the power network, the first few cycles be off-set from the center, oscillating around a fast-decaying axis above the zero line.

This phenomenon is called the DC off-set, or DC transient (see also Section 2.1). The magnitude of the first cycle will depend on network conditions, but may be up to 2.55 times the value of the 'sustained' fault current, i.e. the fault current that will continue to flow until it is interrupted.

The rate of decay of the DC transient will depend on the ratio L/R, i.e. the ratio of system inductance to resistance as seen at the point of the fault.

Under a short circuit or fault condition (Figure 2.6), fault current flows – that has a magnitude which is determined by the network parameters. Upon the breaker tripping, the current is interrupted at the next natural current zero (cyclic point occurring twice a cycle). The network reacts by transient oscillations that give rise to the *transient recovery voltage* (TRV) across the circuit breaker main contacts.

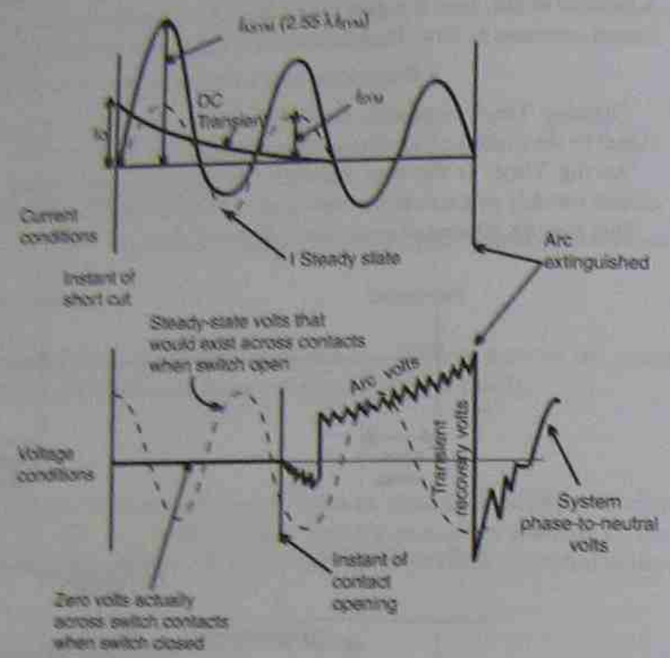


Figure 2.6
Behavior under fault conditions

The insulating medium ensures that the TRV does not cause a flash-over between the contacts and a recurrence of current flow.

The circuit breaker has been designed to withstand and interrupt very high fault currents. Fault current operation places quite high electrical and mechanical stresses on the CB components. For this reason, MV CB life is typically limited to approximately 100 short-circuit operations, depending on the specific type.

Furthermore, circuit breakers are generally limited to around 20 000 load break operations and a maximum of 100 000 mechanical operations.

Contactors

Contactors do not strictly fall under the category 'switchgear', as they are not intended to perform typical switching operations in a power distribution network. Contactors are classified as 'control gear', as their main purpose is to perform control operations, usually starting and stopping of motors, bringing capacitor banks on- and off-line for power factor correction purposes, etc. However, a brief discussion of MV contactors is appropriate here for completeness and comparison purposes.

Vacuum contactors are designed to provide a large number of operations at typical rated loads of up to 400 A per vacuum bottle at voltages of 1.25–13.8 kV. They can typically

provide 1–2 million operations at load current. Contactors can be operated in a combination of series and parallel switches to provide the required rating.

It is important to remember that contactors are designed for frequent load control operations, and NOT to interrupt fault currents. Moderate overload currents (up to approximately 120–140%) may be interrupted by a contactor, but certainly not short-circuit currents. Therefore, contactors should not be used for protection purposes, and the contactor itself should be protected against fault currents.

It should be remembered that once a contactor is used to interrupt moderate overload currents, it becomes difficult to prevent the contactor from interrupting fault currents as well, or to ensure that the fault is cleared by other protective devices. Therefore, it is good engineering practice not to use the contactor for protection purposes at all, and to use the contactor in conjunction with other protection devices, like a relay-CB combination or fuses, to clear fault currents.

Due to the fact that the contactor may be utilized for normal load switching and isolation purposes, it is usually an overkill to use a CB in conjunction with a contactor, except in applications where the use of a CB is specifically required. Normally, it is more cost-effective to use fuses to protect the contactor and the relevant part of the network against high overcurrents.

Fuses

Fuses are also not classified as 'switchgear', but rather as protection devices. However, a short discussion of fuses is warranted in the context of electrical distribution equipment.

The fuse is probably the oldest, simplest, cheapest and most-often used type of protection device. The operation of a fuse is very straightforward: The thermal energy of the excessive current causes the fuse-element to melt and the current path is interrupted. Technological developments have served to make fuses more predictable, faster and safer (not to explode).

A common misconception about a fuse, is that it will blow as soon as the current exceeds its rated value (i.e. the value stamped on the cartridge). This is far from the truth. A fuse has a typical inverse time–current characteristic as illustrated in Figure 2.7 and the higher the current, the faster the fuse will blow.

(The curve is typically exponential, due to the equation $e = i^2t$.)

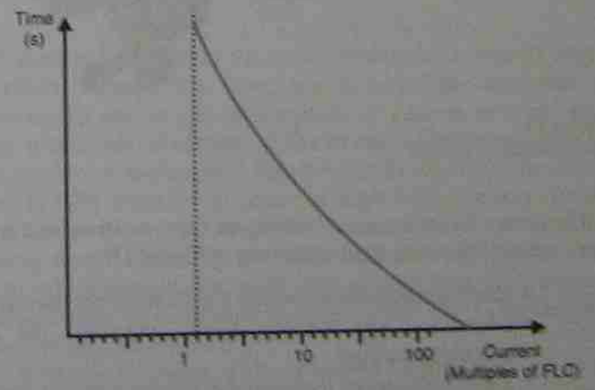


Figure 2.7
Typical fuse characteristic

By nature, fuses can only detect faults associated with excess current. Therefore, a fuse will only blow in earth fault conditions once the current in the faulty phase has increased beyond the overcurrent value. Therefore, fuses do not offer adequate earth fault protection. A fuse has only a single time–current characteristic, and cannot be adjusted. In addition, fuses need to be replaced after every operation. Finally, fuses cannot be given an external command to trip.

Fuses are inexpensive. Therefore, they are suitable to use solely on less critical circuits, in conjunction with contactors or as back-up protection should the main protection fail. They offer very reliable current-limiting features by nature.

Another advantage of fuses is the fact that they can operate totally independently, i.e. they do not need a relay with instrument transformers to tell them when to blow. This makes them especially suitable in applications like remote Ring Main Units, etc.

I_s-limiter

A very 'special' type of fuse is the I_s-limiter, originally developed by the company ABB. The device consists of two main current-conducting parts, namely the main conductor and the fuse, as illustrated in Figure 2.8.

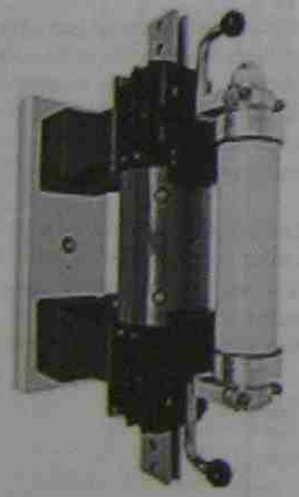


Figure 2.8
Construction of I_s-limiter

The device functions as an 'intelligent fuse', as illustrated in Figure 2.9. The functional parts are the following (with reference to Figure 2.9):

- Current transformer (detects the short-circuit current)
- Measuring and tripping device (measures the current and provides the triggering energy)
- Pulse transformer (converts the tripping pulse to busbar potential)
- Insert holder with insert (conducts the operating current and limits the short-circuit current).

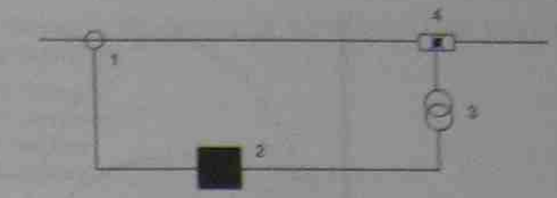


Figure 2.9
Functional diagram of I_s-limiter

The I_s-limiter is intended to interrupt very high short-circuit currents very quickly, in order to protect the system against these high currents. Currents of up to 210 kA (11 kV) can be interrupted in 1 ms. This means that the fault current is interrupted very early in the first cycle, as illustrated in Figure 2.10.

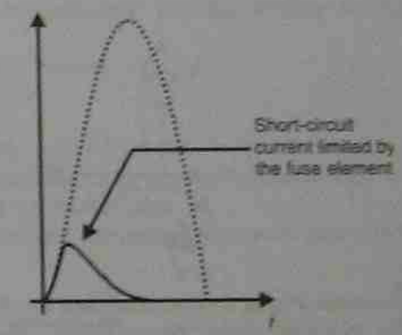


Figure 2.10
Fault current cycle

When a fault current is detected, the main conductor is opened very swiftly. The current then flows through the fuse, which interrupts the fault current. The overvoltage occurring due to the interruption of current is relatively low due to the fact that the magnitude of current on the instant of interruption is still relatively low. The main conductor and parallel fuse have to be replaced after each operation.

The I_s-limiter is only intended to interrupt high fault currents, leaving the lower fault currents to be interrupted by the circuit breakers in the system. This is achieved by the measuring device detecting the instantaneous current level and the rate of current rise. The rate of current rise (di/dt) is high with high fault currents, and lower with lower fault currents, as illustrated in Figure 2.11. The I_s-limiter only trips when both set response values are reached.

A practical use of the I_s-limiter is illustrated in Figure 2.12, where the combined fault current supplied by two transformers in parallel would be too high for the switchgear panel to withstand.

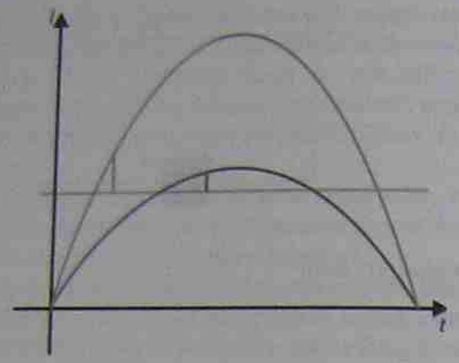


Figure 2.11
Rate of current rise

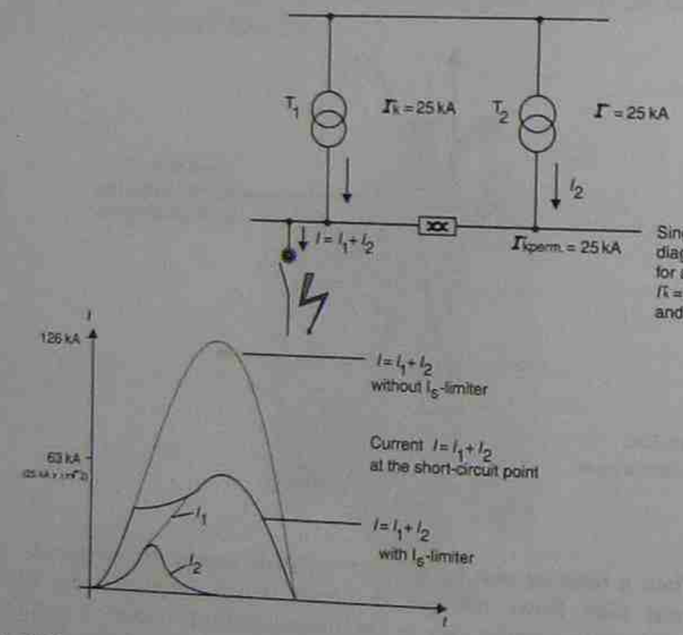


Figure 2.12
Practical use of I_s-limiter

2.5 Insulation methods

Oil circuit breakers

In this design, the main contacts of the circuit breaker are immersed in oil.

Oil in CB has two functions i.e. cooling the arc and providing insulation of the live parts.

The energy inherent in the electrical arc has the effect of decomposing the switch oil into four component parts:

1. 70% hydrogen
2. 22% acetylene
3. 5% methane
4. 3% ethylene.

Due to this decomposition into gas components, the arc effectively lives in a bubble of gases, this being surrounded by the oil.

The formation of gas and carbon during arcing reduces the insulation properties of the oils. This requires the oil to be charged on a regular basis.

Oil has the following advantages

- Ability of cool oil to flow into the space after current zero and therefore extinguishing the filament arc that is still in existence
- A cooling surface is presented by oil to the contact surfaces
- Absorption of arc-energy by decomposition of oil from liquid to gas
- Oil acts as an additional insulator lending to more compact designs of switchgear.

Disadvantages

- Inflammability, especially if there is any O2 near the generated gasses
- Additional maintenance is required to ensure that the oil is kept in a suitable and adequate operational state
- Additional fire and environmental hazard with possible leakage of oil out of switchgear.

Oil circuit breakers are not manufactured on a large scale anymore by the world's leading switchgear manufacturers. This is mainly due to the major disadvantages as mentioned above, namely fire and environmental hazard, and high maintenance requirements.

Air break switchgear

Air break switchgear can be divided into two major divisions, namely air circuit breakers (ACBs), mainly utilized for low-voltage applications, and high-voltage air disconnectors and breakers utilized in high-voltage switchyards. The latter falls outside the scope of this manual. The ACB is discussed briefly.

Air circuit breaker (ACB)

The interrupting contacts are situated in free air, and as such use this medium for arc suppression and cooling. This is illustrated in Figure 2.13. The ACB normally uses an electronic tripping device, as an integral part of the equipment, to provide the tripping signal.

The resultant arc is chopped into a number of smaller arcs by the arc-chute as it rises due to the generated heat and associated magnetic forces. In some cases air puffers are used to aid the upward movement of the arc. In other cases air under high pressure is used to 'blast' the arc away. This type of breaker is relatively large, due to the distance needed between phases with only air as insulating medium. New air breakers are very seldom used for voltages exceeding 3,3 kV nowadays.

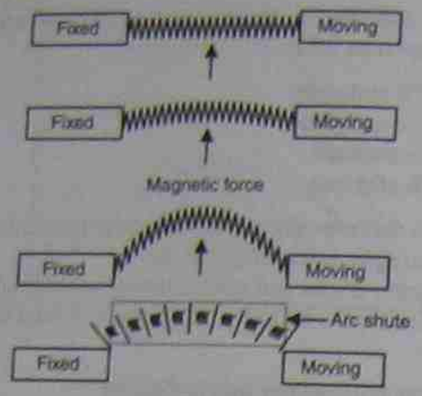


Figure 2.13
Illustration of ACB contacts

The following are the advantages and disadvantages of air breakers.

Advantages

- Economical choice for voltages up to 1000 V
- Simple construction
- No fire or health hazard
- 'Soft' break of current, due to the fact that the ionization of air will support current flow during the early stages of contact separation
- High short-circuit withstand and breaking capability.

Disadvantages

- Not economical for voltages exceeding 3.3 kV (too big)
- Requires regular maintenance in mV application's.

Sulphur-hexaflouride (SF_6)

Sulphur-hexaflouride (SF_6) is an inert insulating gas that is becoming more and more popular in modern switchgear designs both as an insulating as well as an arc-quenching medium.

The pressure of the SF_6 gas is generally maintained at a pressure between 2 and 10 bar. So good sealing of the gas chambers is vitally important. Leaks will cause loss of insulating medium and it has to be remembered that contact clearances are not designed for operation in air. Certain types of switchgear are rated to be able to break normal load current in the absence of SF_6, i.e. with only air as insulating medium, *but not fault current*. Opening of the contacts in air under short-circuit conditions will have catastrophic consequences.

The SF_6 switchgear can have the facility to continuously monitor the gas pressure in the contact chambers. Modern relays have the capability to automatically raise an alarm the instant this pressure falls below a specified limit, trip or lock-out the CB in its current position when a second predefined pressure limit has been reached, and/or continuously send through gas pressure information to a SCADA control station (see Chapter 6).

Even though the risk of gas leaks is very low with modern switchgear, the monitoring of SF_6 gas pressure is strongly recommended, either automatically or as part of a manual maintenance procedure.

Practical tip

A common concern regarding the use of SF_6 gas pressure monitors are that the monitor itself posses the highest risk of causing a leakage. This very seldom occurs when switchgear is manufactured under tight quality control measures, as it should be. However, it can be seen as an additional point of risk. But even if a gas leakage develops at the pressure monitor, at least an alarm will be raised, and the responsible personnel will know about it, and corrective measures can be taken in advance.

With no monitor installed, no one will know about a gas leakage until it is too late, with possible disastrous consequences. Therefore, having pressure monitors on the switchgear can be regarded as the lesser of two evils by far.

SF_6 gas

SF_6 gas is an inert gas, colorless and odorless. It is not poisonous or flammable. It is heavier than air, hence in case of a leakage, SF_6 gas will collect in the lowest regions of the substation, which are normally the cable trenches, and replace all the air. Therefore, it may pose a health risk to human beings in that it may cause suffocation to unaware workers.

Question 2.2 for course participants: How would you prevent a possible build-up of SF_6 *gas when using* SF_6 *type switchgear?*

GIS switchgear

Gas-Insulated switchgear (GIS) also uses SF_6 gas to insulate not only the switch contacts, but most of the switchgear panel, including the busbars. The GIS has been used at the higher-voltage levels, namely 66 kV and above, but is also becoming a viable option for medium-voltage applications in special circumstances. The switchgear manufacturers ABB, for example, has used this technology very successfully in designing efficient, compact and safe Ring Main Units.

The main advantage of GIS is the reduced clearance distances required due to the superior insulating properties of SF_6 gas, resulting in compact, space-saving switchgear. Therefore, the higher the voltage level, the more the space-saving benefits obtained.

The following are the advantages and disadvantages of SF_6.

Advantages

- 'Softer' switching than, for example, vacuum breakers, meaning that less pronounced voltage peaks are caused when interrupting large currents
- Suitable for voltages up to 66 kV for metal-clad switchgear and 800 kV for GIS
- SF6 gas pressure can be easily monitored
- Insulating medium present no fire/explosion hazard.

Disadvantages

- Depositories formed during switching limit the number of achievable operations before maintenance/refurbishment is required
- More expensive than other types of switchgear
- Decomposed SF6 products are toxic and should be handled with care.

Vacuum breakers

Vacuum switchgear applies the principle that it is virtually impossible for electrical current to flow in a vacuum. Therefore, the main contacts separate inside a vacuum bottle.

The typical contact material comprises a tungsten matrix impregnated with a copper and antimony alloy to provide a low melting point material to ensure continuation of the arc until nearly current zero.

The early designs of vacuum breakers displayed the phenomenon of current chopping i.e. switching off the current at a point on the cycle other than current zero. This sudden instantaneous collapse of the current generated extremely high-voltage spikes and surges into the system, causing failure of equipment (Remember the formula $V = L\,di/dt$?).

Another phenomenon was prestrike at switch on. Due to their superior rate of dielectric recovery, a characteristic of all vacuum switches was the production of a train of pulses during the closing operation. Although of modest magnitude, the high rate of rise of voltage in prestrike transients can, under certain conditions, produce high insulation stresses in motor line end coils.

Subsequent developments attempted to alleviate these shortcomings by the use of 'softer' contact materials, in order to maintain metal vapor in the arc plasma so that current continues to flow until point zero. Unfortunately, this led to many instances of contacts welding on closing.

Re-strike transients produced under conditions of stalled motor switch-off were also a problem in vacuum contactors. When switching off a stalled induction motor, or one rotating at only a fraction of synchronous speed, there is little or no machine back emf, and a high voltage appears across the gap of the contactor immediately after extinction. If at this point in time the gap is very small, there is the change that the gap will break down and initiate a re-strike transient, puncturing the motor's insulation.

Modern designs have all but overcome these problems. In vacuum contactors higher operating speeds coupled with switch contact material have chosen to ensure high gap breakdown strength, produce significantly shorter trains of pulses.

In vacuum circuit breakers, operating speeds are also much higher which, together with contact materials that ensure high dielectric strength at a small gap, have ensured that prestrike transients have ceased to become a significant phenomenon.

However, by nature of their design, vacuum switchgear do cause higher-voltage peaks when breaking high currents, compared to other types of switchgear. With the use of special surge arrestors, e.g. ZORCo* and wave-slowing capacitors, the transient overvoltages can be prevented from damaging the motor's insulation. (*a registered trademark of Strike Technologies).

The following are the advantages and disadvantages of vacuum switchgear.

Advantages

- Due to virtually no depositories being formed during the breaking operation, vacuum switchgear support a large number of operations
- More compact than the other types
- Vacuum bottles are relatively inexpensive and easy to replace
- Very little maintenance needed.

Disadvantages

- Tendency to cause voltage 'spikes' when interrupting large currents
- No practical method available at this stage to monitor the vacuum inside the bottle
- Generally limited to voltages of up to 36 kV.

Figures 2.14 and 2.15 illustrate the typical construction of a vacuum circuit breaker.

Comparison of insulating methods for CBs

Property	Air	Oil	SF_6	Vacuum
Number of operations	Medium	Low	Medium	High
'Soft' break ability	Good	Good	Good	Fair
Monitoring of medium	N/A	Manual test	Automatic	Not possible
Fire hazard risk	None	High	None	None
Health hazard risk	None	Low	Low	None
Economical voltage range	Up to 1 kV	3.3–400 kV	3.3–800 kV	3.3–36 kV

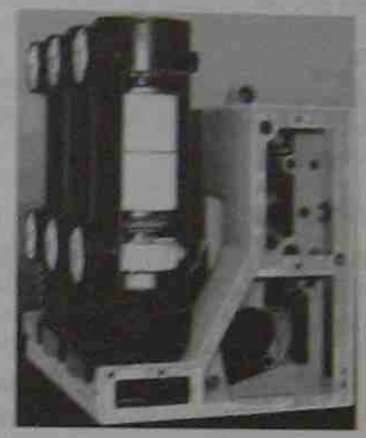
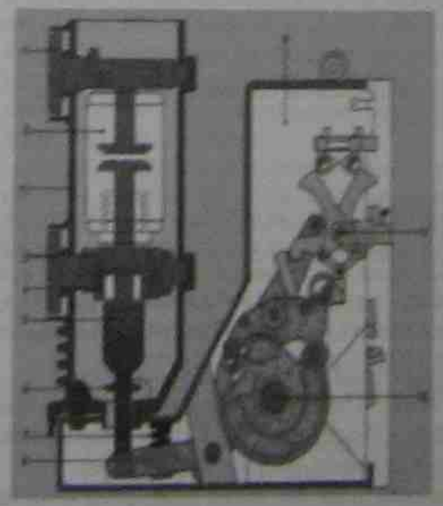


Figure 2.14
Typical vacuum circuit breaker



1 Upper connection
2 Vacuum interrupter
3 Lower connection
4 Roller contact (swivel contact for 630 A)
5 Contact pressure spring
6 Insulated coupling rod
7 Opening spring
8 Shaft lever
9 Mechanism housing with spring operating mechanism
10 Drive shaft
11 Pole tube
12 Release mechanism

Figure 2.15
Internal construction of a vacuum circuit breaker

2.6 Types of closing mechanisms

Hand operated

A cheap version but is losing popularity as the operating speed depends entirely on the operator's dexterity. Additionally it is only used at ratings of 150 MVA and less, and up to a maximum of 11 kV.

Hand operated and spring assisted

Hand actuator compresses a cam-spring arrangement over top dead center (>90°). The spring is under compression and, once past T.D.C, completes the cycle to 180° and closes the breaker.

Quick make

A variance on the device described in version (2) above. A spring is compressed and latched by a hand-operated system. The spring is then released by operation of the latch to operate mechanism.

Motor wound spring

Versions (2) and (3) above can have a motor replacing the manual function as described. Motor-driven systems have gearboxes, and are used for larger systems (high MVA ratings).

Solenoid

Versions (2) and (3) above can have a solenoid replacing the manual function as described: this is more common on the smaller ranges of switchgear.

Pneumatic

Used at 69 kV and above. Convenient, but a supply of dry air is required.

Hydraulic

Hydraulic pressure is increasingly being used on modern circuit breakers.

2.7 Internal arc proofing

Internal arc proofing refers to the certified ability of switchgear to withstand an internal short circuit, typically a busbar fault, for a specified period of time without causing injury to persons standing directly in front of the switchgear panel. Internal arc proofing need to be certified by an authorized testing authority, and will state a current and time rating, e.g. 25 kA, 1 s.

The following will typically be features of an internal arc proof panel for 200 ms:

- Mild steel of at least 3 mm thickness for panel construction
- Secured, bolted front doors. The door to the CB enclosure cannot be opened while the CB is racked in. CB needs to be racked out with the door closed
- No easy access to busbar chambers, only via bolted covers
- Arc energy will be directed to the top of the panel away from the front door and 'blown out' at the top via false covers.

It is theoretically safe to stand in front of a panel that is being faulted.

Because the internal arc proofing is short time rated, bus zone protection is required to reduce the fault clearing time. Examples of bus zone protection include:

- High- and low-impedance differential protection schemes (operates in less than 10 ms)
- Busbar blocking schemes (operates in 100 ms or more)
- Arc detection schemes (operates in less than 20 ms).

2.8 Modern protection relays used with switchgear

Although this is not a text on electrical protection, a short discussion on modern protection relays are justified, as modern relays are changing the way electrical engineers think, not only about protection, but regarding a much wider scope, including switchgear applications and maintenance issues.

The most advanced protection relays available today are termed IEDs (intelligent electronic devices), as they offer much more than only the protection functions of the traditional relay.

Functions of an IED

The functions of a typical protection IED can be classified into five main areas, namely protection, control, monitoring, metering and communications. Some IEDs may be more advanced than others, and some may emphasize certain functional aspects over others, but these main functionalities should be incorporated to a greater or lesser degree.

Protection

The protection functions of the IED evolved from the basic overcurrent and earth fault protection functions of the feeder protection relay (hence certain manufacturers named their IEDs 'feeder terminals'). This is due to the fact that a feeder protection relay is used on almost all cubicles of a typical distribution switchboard, and the fact that more demanding protection functions are not required enable the relay's microprocessor to be used for control functions. The IED is also meant to be as versatile as possible, and is not intended to be a specialized protection relay, for example generator protection. This also makes the IED affordable.

The following is a guideline of protection-related functions that may be expected from the most advanced IEDs (the list is not all-inclusive, and some IEDs may not have all the functions). The protection functions are typically provided in discrete function blocks, which are activated and programed independently.

- Non-directional three-phase overcurrent [low-set, high-set and instantaneous function blocks, with low-set selectable as long time-, normal-, very-, or extremely inverse, or definite time]
- Non-directional earth fault protection [low-set, high-set and instantaneous function blocks]
- Directional three-phase overcurrent [low-set, high-set and instantaneous function blocks, with low-set selectable as long time-, normal-, very-, or extremely inverse, or definite time]
- Directional earth fault protection [low-set, high-set and instantaneous function blocks]

- Phase discontinuity protection
- Three-phase overvoltage protection
- Residual overvoltage protection
- Three-phase undervoltage protection
- Three-phase transformer inrush/motor start-up current detector
- Auto-reclosure function
- Underfrequency protection
- Overfrequency protection
- Synchro-check function
- Three-phase thermal overload protection.

Control

Control functions include local and remote control, and are fully programmable.

- Local and remote control of up to six switching objects (open/close commands for circuit-breakers, isolators, etc.)
- Control sequencing
- Bay level interlocking of the controlled devices
- Status information
- Information of alarm channels
- HMI panel on device.

Monitoring

Monitoring includes the following functions:

- Circuit-breaker condition monitoring, including operation time counter, electric wear, breaker travel time, scheduled maintenance
- Trip circuit supervision
- Internal self-supervision
- Gas density monitoring (for SF6 switchgear)
- Event recording
- Other monitoring functions, like auxiliary power and relay temperature.

Metering

Metering functions include:

- Three-phase currents
- Neutral current
- Three-phase voltages
- Residual voltage
- Frequency
- Active power
- Reactive power
- Power factor
- Energy
- Harmonics
- Transient disturbance recorder (up to 16 analog channels)
- Up to twelve analog channels.

Communications

Communication capability of an IED is one of the most important aspects of the device today and is the one aspect that clearly separates the different manufacturers' devices from one another regarding their level of functionality.

IEDs are normally able to communicate directly to a SCADA system, i.e. upper level communications. Different manufacturers use different communication protocols, and this will determine certain critical aspects, e.g. response times, possibility of direct relay-to-relay communications, etc.

An IED will, in addition to upper level communications, also have a serial port or optical interface to communicate directly to substation PC or laptop for configuration and data downloading purposes, should the SCADA link not be available or desirable in that instance.

Comparison of electromechanical relays and digital relays

No.	Feature	Electromechanical	Digital
1	Reliability	Moderate	High
2	Stability	High	High
3	Sensitivity/accuracy	Low	High
4	Speed of operation	Moderate	High
5	Discrimination capability	Moderate	High
6	Multi-function	No	Yes
7	Versatile (can be used for different applications)		Yes
8	Flexible (multiple curves, selectable setting groups)	No	Yes
9	Maintenance intensive	High	Low
10	Self-diagnostics	No	Yes
11	Trip circuit supervision	No	Yes
12	Condition monitoring	No	Yes
13	Data communications	No	Yes
14	Control functions	No	Yes
15	Metering	No	Yes
16	Disturbance recordings	No	Yes
17	Remote operation	No	Yes
18	CT Burden	High	Very low
19	Cost	Low	See Note 1

Note 1

The cost will depend on the application. If a multi-function relay, like an intelligent feeder terminal, is used for only overcurrent protection, the cost for that function will be high. However, if a digital relay is fully utilized, for example a generator protection relay, the cost per function will be low.

Note 2

Not all digital relays will comply with the features as in the table, depending on the type of relay. However, the table is an overview of what is possible with digital relays in general, compared to what could be achieved with electromechanical relays.

3

Power cables

3.1 Introduction

The following types of power cable are mainly used for distribution purposes in the medium-voltage (MV) range and will be the focus of discussion in this chapter:

- Paper-insulated lead covered (PILC) cables
- Cross-linked polyethylene (XLPE) cables.

PVC cables are used mainly in the low-voltage (LV) range, and will be briefly discussed as well as elastomeric trailing cables, which are used for specialized applications, for example the mining industry.

Overhead lines are mainly used for transmission purposes and will only be briefly mentioned.

IDC acknowledges the contribution of Aberdare cables and in particular the efforts of Dick Hardy.

3.2 Paper-insulated lead-covered (PILC) cables

The PILC cables are manufactured by using layers of paper impregnated with a compound mineral oil as insulating medium, both as individual core and overall insulation. A lead sheath is constructed as an outer core layer to mainly provide a seal for the compound in the paper layers, and also for excellent corrosion protective properties as well as to provide additional mechanical protection.

A steel tape layer (often a double layer) or steel wires are used for the main mechanical protection and it may also be used as a return path for earth currents. The outer sheath may be a PVC layer or other type of insulating and waterproof material.

DSTA = Double steel tape armored

SWA = Steel wire armored

Earlier PILC cables displayed the phenomenon of compound migration, meaning the compound tended to drain toward the lower part of the cable when installed vertically or against slopes. Non-draining compound are used in modern manufacturing techniques, eliminating this phenomenon.

PILC cables are generally used for 66 kV up to 33 kV applications. The designation 6.35/11 kV, for example, means that the cable has an insulation level of 6.35 kV between each core and earth, and 11 kV between phases. Cables rated 6.35/11 kV may be used for earthed systems (transformer neutral earthed), whereas 11/11 kV

rated cables should be used for unearthed systems. The same applies for other voltage levels.

Detail specifications of PILC cables are given in Section 3.8 and Table 3.27.

3.3 Cross-linked polyethylene (XLPE) cables

XLPE, PEX and PVC are used as conductor insulating materials in these cables. XLPE is a semiconductor, and provide partial insulation as well as electrical stress relieving. The conductors, with their XLPE layers, are embedded in PVC to provide total insulation. Steel wires are used for mechanical strength, and may also be used to provide the return path (or part thereof) for earth fault currents. The outer sheath is normally a PVC sheath (Figure 3.6), to provide insulation and waterproofing.

XLPE cables are used from low voltage (600/1000 V) to 132 kV applications. Pure PVC cables, in which PVC replaces the XLPE as conductor layer, are used up to a maximum of 6.6 kV.

Detail specifications of XLPE and PVC cables are given in Section 3.8 and Table 3.28.

3.4 Elastomeric cables

These types of cables use a rubber-type elastomeric material for insulation to provide mainly greater flexibility as well as high corrosion resistance against harsh environmental conditions and ultraviolet radiation. The outer sheath is usually reinforced with a mesh braiding.

Elastomeric cables are mainly used as trailing cables in mining operations and other specialized applications.

3.5 Aerial bundled conductors (ABC)

This type of cable is used for LV distribution of power in residential areas. The three insulated conductors are rapped around a steel rope and strung between overhead live poles. This reduces the risk of open conductors touching, and trees causing faults.

3.6 Overhead aluminum conductors

Aluminum conductors have gained wide acceptance all over the world for use in overhead transmission and distribution lines. Generally a steel core is used with the aluminum to give the conductor mechanical strength, termed aluminum conductor steel reinforced (ACSR).

Aluminum is preferred as conducting medium in overhead lines above copper, mainly based on economic considerations. Aluminum is considerably lighter than copper, even when allowing for less current density of aluminum compared to copper. This has a considerable economic advantage when designing overhead lines, as span lengths can be greater and support masts lighter.

Aluminum also has superior corrosion-resistant properties, which is a great benefit for overhead lines, as no insulating material is present to protect the conductors against corrosion, as is the case in cables.

The design and application of overhead lines are very specialized, and they are nowadays used mainly for transmission purposes. Therefore, a detail discussion of overhead lines falls outside the scope of this manual.

3.7 Cable selection

When selecting a cable for your specific application, a number of variables require attention. These are:

- Application
- Size and type of load to be supplied
- Permissible voltage drop
- Prospective fault current
- Circuit protection
- Installation conditions.

Application

Low-voltage distribution

For LV distribution purposes, the choice is basically between XLPE and PVC-insulated cables. The XLPE cables have higher current ratings than PVC cables for the same conductor size, as can be seen from Tables 3.25 and 3.26. Normally XLPE cables tend to be slightly more expensive than PVC cables.

The choice between these two types for LV applications will normally be determined by economic considerations (the relative prices at that stage) and availability. Bear in mind that a slightly smaller XLPE cable can be chosen for the same current requirement, which have other spin-offs, for example space-saving on cable racks or in trenches, slightly reduced labor costs for installation, etc.

Medium-voltage distribution

For MV applications, the choice is more involved. First of all, the choice lies between overhead lines and underground cables. Nowadays, the tendency is to move toward underground cables for distribution purposes, the motivation mainly being the following:

- Distribution is mainly done in industrial and/or populated areas, where overhead lines pose an environmental hazard.
- Overhead lines are very maintenance intensive, due to required protection against corrosion, pollution and fires.
- Overhead lines are very susceptible to lightning strikes.

Due to the above considerations, overhead lines are mainly considered for applications over relatively large distances, where they are very economic compared to underground cables.

The next choice is then between aluminum or copper conductors. Aluminum conductors are larger than copper conductors for the same current-carrying capacity, which may add to installation costs. The choice will mainly be an economic one, influenced by availability and the relative prices of the two metals at that stage. Aluminum conductors may be considered in high corrosive areas.

The third choice is the question of cable insulation type. For normal distribution purposes, the choice lies between PILC- or XLPE-insulated cables. The choice will be influenced by taking the following factors into account:

- PILC cables tend to be more expensive than XLPE cables for the same conductor size.
- XLPE cables have a higher current rating for the same conductor size.

- XLPE cables have a larger overall diameter for the same conductor size.
- PILC cables provide better corrosion resistance than XLPE cables.
- PILC cables have a higher average life span, 40 years compared to 25 years of XLPE cables.
- XLPE cables are better suited to be moved frequently after installation, making them better suited for use in an continuously changing environment, for example mining applications.

Single-core cables may also offer an economical choice, especially in high-current applications, where the installation of three single-core cables (one per phase) might be preferred to the option of installing a number of 3-core cables in parallel.

The outer 'PVC' sheath is available in finishes, e.g:

- No stripe – plain PVC
- Red stripe – fire retardant
- Blue stripe – low halogen
- White stripe – zero halogen.

All 'PVC' covering are also UV resistant.

Once a choice is made, companies tend to stick to a specific type of cable, in order to prevent confusion, eliminate the need for re-training of personnel, and reduce stock levels.

Load to be supplied

In order to select the appropriate cable, it is necessary to know the voltage and the load current, as the first step in the selection process.

The following formulae apply:

$$I_{FL} = \frac{kW \times 1000}{\sqrt{3} \times V \times \cos\phi} \text{ A if we know kW, voltage, and power factor}$$

$$= \frac{kVA \times 1000}{\sqrt{3} \times V} \text{ A if we know the kVA rating and voltage}$$

Use this value of current to determine the cable size by reference to the relevant manufacturer's tables for copper or aluminum conductors.

A slightly larger conductor size may be chosen for safety aspects, and to provide for the higher than usual current, which may be experienced during starting of electric motors.

Example of cable selection for low voltage

(*Note*: The tables used in this manual are for illustrative purposes only. They are based on data supplied by the cable manufacturer Aberdare Power Cables. The user should use the corresponding tables supplied by the specific manufacturer of the cable he is using, as each manufacturer's specifications will vary.)

Suppose it is required to supply a three phase, 400 V, 100 kW motor, over a distance of 50 m, the motor load is known to have a power factor of 0.9 lagging. The full load line current, I_{FL} can be calculated as follows:

$$I_{FL} = \frac{100 \times 1000}{\sqrt{3} \times 400 \times 0.9}$$

$$= 161 \text{ A}$$

Full load current ratings can usually be obtained easily from the equipment nameplate.

We now refer to Table 3.25 (example table for LV cables) and note that the smallest copper conductor, PVC-insulated cable, that can supply a current of 161 A in air, is a 50 mm² two area cable. This cable can carry 167 A continuously if installed under standard conditions.

Permissible voltage drop

Calculate the highest current drawn by the load, by multiplying the current as calculated in Section 3.7 by an appropriate factor. If a Star/Delta motor starter is used on a motor this factor is 3. If the motor is started direct on line, then use a factor of 6. A factor of 4 may be used for most electronic soft-starters. Where the load is resistive heating, lighting or a transformer, it is not necessary to increase the current as calculated in Section 3.7.

Calculate the volt drop that will be experienced at the load terminals. The maximum volt drop allowed by the Australian Standard for Electrical Installations (Standard AS 3000; known as the SAA Wiring Rules) is 5%.

The volt drop may be calculated in two different ways:

1. Multiplying the current by the impedance of the length of cable. Calculate the percentage volt drop by reference to the phase-to-earth voltage.
2. Multiply the current by the length of cable, and then multiply the result by the volt drop per amp per meter figure as given in Table 3.25.

Previous example using method (a)

$$\text{Starting current} = 3 \times \text{running current}$$
$$= 3 \times 161\,\text{A}$$
$$= 483\,\text{A}$$

$$\text{Impedance of 50 m of 50 mm}^2\text{ cable (Table 3.25)} = \frac{0.4718}{1000} \times 50$$
$$= 0.02359\,\Omega$$

$$\text{Volt drop} = 483 \times 0.02359$$
$$= 11.394\,\text{V}$$

$$\text{Percentage volt drop} = \frac{11.394}{230} \times \frac{100}{1}$$
$$= 4.95\%\ \text{(acceptable)}$$

Previous example using method (b)

$$\text{Starting current} = 3 \times 161\,\text{A}$$
$$= 483\,\text{A}$$

$$\text{Volt drop per amp per meter} = 0.817\ \text{mV/A/m (Table 3.25)}$$

$$\text{Volt drop} = 0.817 \times 10^{-3} \times 483 \times 50$$
$$= 19.73\,\text{V}$$

$$\text{Percentage volt drop} = \frac{19.73}{400} \times \frac{100}{1}$$
$$= 4.93\%\ \text{(acceptable)}$$

Note: It often happens on long runs of electric cable that a larger conductor than that calculated in 3.7 is required for volt drop reasons.

It must be noted that the calculation as per the above example is an approximation. However, it is accurate enough for cable selection purposes. (In fact, it is accurate enough for most practical purposes.)

Question 3.1 for course participants: Why is the method as illustrated above only an approximation? What is the correct method to calculate the exact volt drop?

Example of cable selection for MV (11 kV)

We wish to supply a 2 MVA 11 kV transformer from a utility supply which is 3 km away. Underground paper-insulated, copper conductor cable is to be used.

The depth of burial of the cable is 1.25 m. Ground thermal resistance is 2 Km/W. The ground temperature is 25 °C and there are no other cables in the trench.

Short-circuit level may be assumed to be 250 MVA, and the earth fault level 100 MVA, and it may be assumed that a fault will be cleared in half a second.

Using the previous formulae:

$$I_{FL} = \frac{2\,000\,000}{\sqrt{3} \times 11\,000}$$
$$= 105\,\text{A before derating for non-standard conditions}$$

De-rating factor for depth of burial at 1.25 m is 0.96 (see Section 3.8).
De-rating factor for soil thermal resistivity at 2 Km/W is 0.84.
De-rating factor for ground temperature of 25 °C is 1.00.

$$\text{Total derating} = 0.96 \times 0.84 \times 1.00$$
$$= 0.806$$

$$I_{\text{standard}} = 105/0.806$$
$$= 130\,\text{A}$$

Table 3.27 shows that a 35 mm² copper conductor cable would be capable of carrying this load (130 A).

Checking for volt drop

$$V_{drop} = \frac{\sqrt{3} \times Z \times I \times \text{distance}}{1000}$$
$$= \frac{0.6371 \times 1.73 \times 105 \times 3000}{1000}$$
$$= 347.2\,\text{V (3.2\% of 11 kV)}$$

Volt drop is seldom a problem at MV, even for long runs of small conductor size as shown above.

Question 3.2 for course participants: Why would volt drop seldom be a problem at higher voltages?

Prospective fault current

Electric cables are designed to operate below a certain maximum temperature, this being dependent on the conductor material and the type and the thickness of the insulation.

Cable selection for a particular installation must therefore be made on the basis of not exceeding these temperature limits.

Suppose the 400 V distribution board from which a cable is fed has a fault level of 5 MVA. This translates to a fault current of 7.22 kA, and the cable must be capable of carrying this current without damage until the fault is cleared. Fault current ratings for cables are given in the manufacturers' specifications and tables and must be modified by taking into account the fault duration.

The smallest cable that can safely handle the above fault current for a 1 s fault, is a 70 mm^2 copper conductor cable, or a 95 mm^2 aluminum conductor cable. Suppose now that the fault clearance time (including any mechanical delays on the tripping mechanism) is closer to 2 s, then the smallest cable would be a 95 mm^2 copper conductor ($11.52/\sqrt{2}$ = 8.13 kA for 2 s) or a 150 mm^2 aluminum conductor ($10.80/\sqrt{2}$ = 7.64 kA for 2 s).

Likewise, a fault duration less than 1 s will allow the use of smaller conductors than were calculated for the 1 s rating.

Continuing with the example in Section 3.7:

Prospective symmetrical (short-circuit) current:

$$= \frac{250\,000\,000}{\sqrt{3} \times 11\,000}$$

$$= 13.137 \text{ kA}$$

Cable short-circuit current withstand is:

$$I_{sc} = \frac{\text{Cross-section} \times K}{\sqrt{t}}$$

K is 115 for copper conductors, paper insulated

The half second rating is thus:

$$= \frac{35 \times 115}{\sqrt{0.5}}$$

$$= 5.692 \text{ kA}$$

This cable will not survive the prospective short-circuit current. Conductor size required is thus:

$$\frac{x \times 115}{\sqrt{0.5}} = 13.137 \text{ kA}$$

$$\therefore x = 80 \text{ mm}^2$$

The nearest standard size is a 95 mm^2 copper conductor. This has a current rating of 235 A under standard conditions.

Earth fault current for half a second

Lead area for a 95 mm^2 × 3-core PILC cable is 198.2 mm^2.

Cable earth fault current withstand is $= \frac{198.2 \times 0.024}{\sqrt{0.5}}$

$= 6.7$ kA for half a second

Required earth fault current, $I_{ef} = \frac{100 \times 10^6}{\sqrt{3} \times 11\,000}$

$= 5.25$ kA for half a second

In many cases, the cable conductor size is larger than dictated by the full load current, and is chosen in order to survive the prospective short-circuit current.

The use of large conductors can be avoided by improving the speed of protection (fuses for example) and in the case of earth fault current, by the use of sensitive earth fault protection.

Another example is shown in Figure 3.1.

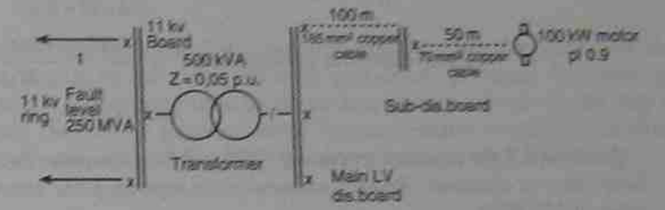


Figure 3.1
Distribution example

We are required to calculate the fault current at the sub-distribution board.

P.U. system:

$$\text{p.u. source impedance} = \frac{\text{Base MVA}}{\text{Fault level MVA}} \quad (1)$$

$$\text{p.u. transformer impedance} = \frac{\text{Base MVA} \times \text{transformers \% impedance}}{\text{Transformers MVA}} \quad (2)$$

$$\text{p.u. cable impedance} = \frac{Z \text{ (ohms)} \times \text{Base MVA}}{V^2 \text{(kV)}} \quad (3)$$

$$\text{p.u. total impedance} = (1) + (2) + (3)$$

$$\text{Fault level} = \frac{\text{Base MVA}}{\text{p.u. impedance}}$$

$$\text{Fault current} = \frac{\text{Fault level (MVA)} \times 1\,000\,000}{\sqrt{3} \times V}$$

Example 1

Using a base of 100 MVA and the per unit method, the impedance of the system at the sub-dist board can be determined:

$$\text{Source: } \frac{100}{250} = 0.4 \text{ p.u.}$$

$$\text{Transformer: } \frac{100}{0.5} \times 0.05 = 10 \text{ p.u.}$$

From Table 3.25, the impedance of 185 mm^2 cable = 0.1445 Ω/km.

Thus the impedance of 100 m = 0.01445 Ω

$$\text{Z p.u.} = \frac{\text{Z (ohms)} \times \text{MVA}}{V^2\ (\text{kV})}$$

$$= \frac{0.01\,445 \times 100}{(0.400)^2}$$

$$= 9.03 \text{ p.u.}$$

The fault level at the sub-dist board is then found by dividing the base MVA by the total per unit impedance.

$$\text{Fault level at sub board} = \frac{100}{0.4+10+9.03}$$

$$\text{Fault current at sub-dist Board} = \frac{5.147 \times 1\,000\,000}{\sqrt{3} \times 400}$$

$$= 7.429 \text{ kA}$$

Question 3.3 for course participants: Will a different answer be obtained if a different base value is obtained? Prove your answer by repeating the above example for a base value of 250 MVA.

Reference to Table 3.25 shows that a 70 mm² copper cable can withstand a short-circuit current of 8.05 kA for 1 s. This is below the potential fault level of the system.

However, the duration of the fault or the time taken by the protective device to operate has to be considered. The circuit supplying the motor would very likely be protected by a 200 A fuse or a circuit breaker. Both these devices would operate well within 1 s, the actual time being read from the curves showing short-circuit current/tripping time relationships supplied by the protective equipment manufacturer. Suppose the fault is cleared after 0.2 s. We need to determine what short-circuit current the cable can withstand for this time. This can be found from the expression:

$$I_{sc} = \frac{A \times K}{\sqrt{t}}$$

Where:

K = 115 for PVC/copper cables of 1000 V rating

K = 143 for XLPE/copper cables of 1000 V rating

K = 76 for PVC/aluminum (solid or stranded) cables of 1000 V rating

K = 92 for XLPE/aluminum (solid or stranded) cables of 1000

and where:

A = the conductor cross-sectional area in mm²

t = the duration of the fault in seconds

So in our example:

$$I_{sc} = \frac{70 \times 115}{\sqrt{0.2}} = 18 \text{ kA}$$

This is well in excess of the system potential fault level and below the bursting capacity of the cable so it can be concluded that a 70 mm² cable is suitable for this example. Bursting is not a real threat in the majority of cases where armored cable is used since the armoring gives a measure of reinforcement. However, with larger sizes, in excess of

300 mm², particularly when these cables are unarmored, cognisance should be taken of possible bursting effects.

When the short-circuit current rating for a certain time is known, the formula $E = I^2t$ can also be used to obtain the current rating for a different time. In the above example:

$$I_1^2 t_1 = I_2^2 t_2$$

$$\Rightarrow I_2 = \sqrt{I_1^2 t_1 / t_2}$$

$$I_2 = \sqrt{(8.05^2 \times 1)/0.2}$$

$$= 18 \text{ kA}$$

Note: In electrical protection, engineers usually cater for failure of the primary protective device by providing back-up protection. It makes for good engineering practice to use the tripping time of the back-up device, which should only be slightly longer than that of the primary device in short-circuit conditions, to determine the short-circuit rating of the cable. This then has a built-in safety margin.

Environmental conditions of installation

The data used for determining the current ratings given in this manual are based on calculations according to IEC 287. Ratings for multicore cables are given for a single cable run; where groups of cables run in a common route, the appropriate derating factors are given in the appropriate sections depending on the type of cable being used.

Similarly when the installation conditions differ from standard, the derating factors in the appropriate sections must be used.

A qualitative assessment of the conditions immediately surrounding the cable should be made. Factors such as the need for a fire-retardant sheath, additional mechanical protection, safeguards against chemical attack and corrosion should be considered in this category. These influences affect mainly the external finish of the cable, the armoring and serving.

Cables are sometimes specified with a termite-repellent sheath. It is worth mentioning that no sheath will repel insects since sheath material has to be ingested by the termite to be fatal. Thus, the statement 'cable with a termite repellent sheath' is somewhat erroneous. The PVC sheath is coated with Teflon that makes it difficult bite into the PVC.

In the case of paper, lead cables there are several alternative sheath metals available, pure lead is prone to fatigue when subjected to vibration. An alloy sheath can be supplied which will resist deterioration through fatigue.

The foregoing notes are by no means an exhaustive treatment of the points to consider when choosing a cable for a particular application but are rather guidelines to the salient points that need consideration.

Cables laid directly in the ground

The ratings given are based on a ground thermal resistivity (g) of 1.2 Km/W. The factor (g) varies considerably with differing ground conditions and has a pronounced effect on a cable's current-carrying capacity. The only sure way to determine (g) is to measure it along the cable route. This practice is normally reserved for supertension cables, but there could be other applications where soil thermal resistivity is critical.

Suitability of soils for bedding and backfill

Clay

Clay is a dense, compact material, greasy to the touch when wet and which has a low thermal resistivity even in the fully dried-out condition. Most types of clay however, shrink when drying and can thus not be used as a bedding for the cable. They can be used as backfill and should be consolidated by rolling rather than stamping.

Sand

Sand is a crumbly material with particle grains easily distinguished and gritty to the touch even when wet. Particle sizes larger than 2 mm are known as gravel. Sea sand or sand obtained from a river bed usually consists of spherical particles and has a very high thermal resistivity when dry. Therefore, it should not be used as cable bedding in its pure form.

Some quarried sands and man-made sands as used for making concrete, have irregularly shaped particles of varying size and can be compacted to a high density. These can be used as a bedding material especially when 5–10% clay is added and will have a satisfactorily low thermal resistivity in the dried-out state. Sand/gravel mixes should be used with care as sharp particles can damage the cable serving.

Sand Clay

Sand clay is, as its name implies, a mixture of sand and clay. It is an ideal material for use as bedding and backfill and is best compacted by rolling. It rarely dries out to lower than 6% moisture content.

Loam

Loam can vary in color from reddish brown to dark brown and may contain quantities of organic matter. It crumbles well, even when dry, and can be well compacted to achieve satisfactory values of thermal resistivity. It is very suitable as a bedding material.

Chalk

Chalk is a soft white or gray porous material having a lower thermal resistivity when wet, but dry out to very high values and is unsuitable for use as bedding or backfill in any area where drying out is likely.

Peat

Peat or humus is composed mainly of organic material and is black or dark brown in color. It should not be used as bedding or backfill as dried-out thermal resistivity values of over 4 Km/W are usually obtained. It should be removed and alternative material used for both bedding the cables and backfilling the trench.

Make-up soil

This is a general term for the soil in any area, the level of which has been raised artificially using imported fill which may consist of bricks, concrete, cinders, ash, slag, stones, other refuse or any of the material considered above. This should only be used for backfill and never for cable bedding. If any doubt exists as to suitability, it is best removed completely and a suitable material imported.

Mine sand

Mine sand is thermally very satisfactory, but is highly corrosive and should therefore not be used.

The thermal resistivity of a substance is greatly influenced by the moisture content at a given time (Table 3.1). The higher the quantity of retained moisture, the lower will be the thermal resistivity. A heavily loaded cable will dry out the soil around the cable and cause an increase in (g). This process is cumulative and damage could be done to the cable insulation through overheating.

Material	Thermal Resistivity (g) Km/W
Sandy soil	1.20
Clay	1.60
Chalky soil	1.80
Concrete	0.90
Water-logged ground	0.50
Gravel	1.00

Table 3.1
Typical values of thermal resistivity of substances encountered in cable installations

Impurities such as slag, ash and the like increase the value of (g), as does intense vegetation on the cable route, by drawing moisture from the ground.

Cables installed in air

Multicore cables should be installed with a space of ≥0, 3 × overall diameter and single-core cables with a space of ≥0, 5 × overall diameter between themselves and the vertical wall or surface supporting them as per IEC 287. If they are installed in direct contact with the wall then the current rating given should be reduced by 5% as a rough guideline provided there is a space of 150 mm or six times the overall diameter of the cable, whichever is the greater between adjacent cables or cable groups in the case of single-core cables. If the installation fails to comply with this requirement then the derating factors in the relevant sections should be applied.

Where the ambient temperature along a route varies, the highest value should be taken to select the cable size.

Question 3.4 for course participants: Why should cables be de-rated when they are installed close to each other or against a wall?

Cables installed in ducts

The air within a pipe or duct will increase the thermal resistance of the heat dissipation path. Consequently, the current rating for a cable run in a duct or pipe is lower than that for an equivalent cable in the ground or in free air. The ratings given can be applied to cables laid in concrete, asbestos, pitch fiber, PVC, earthenware or cast iron pipes which are the more common materials encountered. It should be noted that single-core cables forming a part of an AC system should not be individually installed in cast iron pipes due to the heavy losses incurred by eddy current induction.

Generally, the size of the duct or pipe chosen should depend upon the ease of pulling in, or out, the cable. It should be borne in mind that a larger cable may be required in the future to cater for increased load growth. Common pipe sizes used are 100 mm and 150 mm internal diameters. When groups of cables are run in pipes along the same route, they should be de-rated according to the factors given in the relevant tables.

Composite cable routes

It frequently happens that a cable run is made partly in air, partly direct in the ground and partly in ducts. The latter conditions lead to the lowest rating and it is here that attention must be focused. Very little heat travels longitudinally along the cable, the main dissipation being vertically through the duct wall and surrounding ground. Any rating where the route is part ground, part duct must therefore be treated with care.

Where the length of ducting does not exceed 5 m per 100 m of route length, the cable rating may be assumed to be that for direct burial in the ground.

Intermittent operation

Certain types of loads have an intermittent characteristic where the load is switched on and off before the cable has time to cool completely. Depending upon the load cycle it may be possible to select a smaller cable for intermittent operation than would be the case if the load were continuously applied. When a current in excess of the normal rated current is applied, the heating of the cable will be a correspondingly quicker operation than the cooling.

Generally:

I = Equivalent RMS current
I_n = Current flowing during nth period (including periods of zero current)
t_n = Duration of nth period
N = Number of periods, (includes periods of zero current)
Thus:

$$I = \sqrt{\frac{\sum_{n=1}^{n=N}\left[(I_n)^2 t_n\right]}{\sum_{n=1}^{n=N}(t_n)}}$$

Example:
Suppose a process cycle is as follows:
150 A for 1 min
50 A for 2 min
100 A for 3 min
0 A for 4 min
then applying the expression for RMS current

$$I = \sqrt{(57\,500/10)}$$
$$= 75.83\ \text{A}$$

Thus a continuous current of 76 A flowing over the 10 min cycle time would produce the same heating effect as the individual cyclic currents, and the size of cable could be selected based on 76 A.

Solar heating

When cables are installed in direct sunlight, an appreciable heating due to solar absorption takes place. This result in a significant reduction in the cables' current-carrying capacity and for this reason it is strongly recommended that cables be protected from direct sunlight. The maximum intensity of solar radiation measured in Australia varies between 100 and 115 mW/cm^2 depending upon location.

3.8 Transport, handling and installation of electric cables

Cables on wooden drums

- The cable drum is manufactured from carefully selected wood with a low moisture content (typical not more than 15%). If they are required to be treated it shall be done with a preservative or with chromate copper arsenate. Certain types of hardwood do not require treatment.
- Marking on drum flanges should be clear, stencilled or burned into the wood and should include the following information (this will depend on the specific manufacturer, but may be requested by the client):
  - Manufacturer's name or trade mark
  - Rated voltage, rated area, number of cores and specification
  - Length of the cable in meters
  - Year of manufacture
  - Gross mass in kilograms
  - The instruction 'not to be laid flat'
  - Serial number or other identification
  - On each flange an arrow with the words 'roll this way'
  - The standard to which the cable is manufactured.
- Both ends of the cable on the drum should be sealed and the inner end fixed to the flange of the cable drum to prevent loose coiling. The outer end is fixed to the flange as well, for the same reason.
- Cable drums should stand on firm, well-drained surfaces.
- In the past, it was common practice to rotate stored cable drums through 180° to redistribute the impregnation oil through the dielectric. The use of MIND cables has obviated this reason for rotating drums. However, it is still recommended that wooden cable drums that are stored in the open, irrespective of the type of cable contained, should be periodically rotated to avoid the drum timber rotting through rising damp.

Cable transportation

Preparation

- The truck must match the drum size
- Do not overload the trucks
- Cable ends must be sealed, secured and protected
- Use special cable trailers for transportation from depot to site if possible (see Figure 3.2).



Figure 3.2
Cable trailer

Loading

- Check drums for correct cable and size, serial number, mass and possible damage
- Select correct forklift/crane
- Select correct slings and spindle and check sling condition
- If a crane is to be used, ensure that a spreader is incorporated to prevent damage to drum flanges
- If the drum is to be rolled, observe correct rolling direction by referring to arrows on flanges
- Ensure that the drum bolts are tight
- Ensure that truck surface is clear of obstructions, nails, etc.
- Do not drop drums onto truck loading bed.

Securing

- Secure drums to the truck bed to prevent sliding and rolling, using adequate steel chains and chocks
- Always try to pack drums flange-to-flange
- Do not lay drums flat
- Stop the vehicle during transportation and check that the load is secure.

Off-loading

- Check for damage to cable drums
- Select correct spindle slings for the drum size and mass and ensure that same are in good order, ensure that a spreader is used
- Do not drop drums but lower gently onto firm and relatively level surfaces
- Off-load drums in such a way that they are easily accessible
- If using a fork-truck, ensure that it is of adequate size relative to the task at hand
- Ensure that the fork-truck tines lateral spacing is correct
- Take care that the protruding tines do not damage other equipment or drums
- There are two methods of rolling drums from loading beds if cranes are not available (see Figure 3.3).

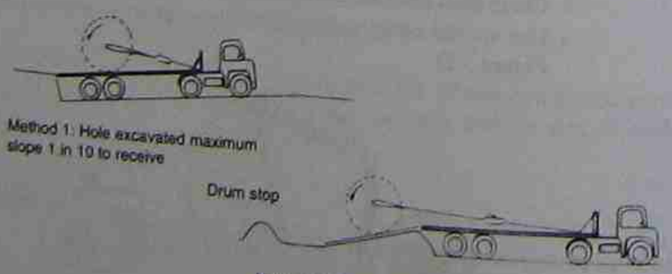


Figure 3.3
Unloading cable drums

Cable storage

Indoors

- Stack flange-to-flange and preferably not one on top of the other
- Stack so that drums are easily accessible
- Observe fire prevention rules
- Cable ends must be sealed at all times
- Dispatch on 'first in-first out' basis
- Rotate paper-insulated cable drums one complete revolution per annum.

Outdoors

- Drums should be stored on a hard surface at a slight angle and the area should have a drainage system
- Drums should be released on a 'first in-first out' basis
- Cable ends should be sealed at all times
- Stack flange-to-flange but if this is not possible, limit vertical stacking practice to smaller drums only
- Stack in such a way that drums are easily accessible
- Observe fire protection rules
- Cable racks are ideal for storage but take care not to overload
- Cables must be identifiable at all times
- If drums are expected to be stored for a long time they must be specially treated or made of hard wood
- Rotate paper-insulated cable drums one complete revolution per annum.

Mechanical forces on cables during installation

Any cable has a maximum pulling force, which should not be exceeded during installation. The cable construction imposes the limitation on the pulling-in force. When a cable stocking is used, the maximum force can be related to overall cable diameter in mm as follows:

Steel wire armored cables:	$F = 0.94\ d^4 \times 10^{-6}$ kN
Steel tape armored or unarmored cable:	$F = 0.39\ d^4 \times 10^{-6}$ kN
Control and communication cables:	$F = 0.26\ d^4 \times 10^{-6}$ kN

Attempts should be made to limit the pulling force required to a minimum to avoid stretching the outer layers of the cable. This is particularly relevant where control and communication cables are concerned since instances are known where the cores have finished 2–3 m inside the sheath and insufficient overlap at straight joint positions has necessitated relaying some lengths.

An increase in the pulling force is permissible when the cable is laid by means of a pulling eye attached to the conductors. As a rule of thumb, the following forces may be applied to a conductor:

Copper:	4.9×10^{-2} kN/mm^2
Aluminum:	2.94×10^{-2} kN/mm^2

Then, for example the maximum force that should be applied via a pulling eye to a 70 mm^2, 3-core copper cable is:

$$70 \times 3 \times 4.9 \times 10^{-2} = 10.29 \text{ kN}$$

Generally when cables are installed using well-oiled rollers and jacks, the following forces can be expected:

Straight route: 15–20% of cable weight
90° bends: 10–20% of cable weight per bend

Example

Calculate whether it would be permissible to pull in a 300 m length of 6.35/11 kV, 185 mm² × 3 core, PILC cable with a winch in one go. The route has two 90° bends along the 300 m distance, and well-maintained cable rollers are used.

Taking the worst case initially, from Table 3.27:

$$\begin{aligned}\text{Cable mass} &= 12\,290\ \text{kg/km} \times 0.3\ \text{km}\\ &= 3\,687\ \text{kg}\\ \text{Force on cable} &= (0.2 \times 3\,687 \times 9.8) + (2 \times 0.2 \times 3\,687 \times 9.8)\\ &= 21.68\ \text{kN}\end{aligned}$$

The maximum permissible pulling force (using a cable stocking):

$$\begin{aligned}F &= 0.39 \times 47.42^4 \times 10^{-6}\ \text{kN}\\ &= 1.97\ \text{kN}\end{aligned}$$

Therefore, the actual force on the cable would exceed the maximum permissible value. This cable may be pulled in by means of a pulling eye attached to the conductors. (Prove this as an exercise.)

Cables laid in open trenches should be left slightly 'snaked' so that any longitudinal expansion or contraction can be accommodated. Similarly, when cables are installed in cleats or on hangers, a slight sag between fixing points is recommended.

Pulling cables through pipes or ducts

When a cable is pulled through a pipe, friction between the cable serving and the pipe material increases the longitudinal force requirements. Representative values for the coefficient of friction (m) between the more common cable servings and pipe materials are given below (Table 3.2).

Serving Material	Pipe Material	μ
PVC	Asbestos	0.65
PVC	Metal (steel)	0.48
PVC	Pitch fiber	0.55
PVC	PVC	0.35
Bitumenized	Asbestos	0.97
Hessian, or	Metal (steel)	0.76
Jute	Pitch fiber	0.86
	PVC	0.55

Table 3.2
Friction coefficients

This information can readily be used to determine the maximum length of cable that can be pulled through a given pipe without exceeding the maximum permissible pulling force. Take for example the 70 mm² × 3 core cable previously quoted. If this is a low-voltage

cable with a PVC sheath and it is desired to know the maximum length of PVC pipe it can be pulled through then:

Maximum force = 10.29 kN (by pulling eye)
for PVC to PVC, m = 0.35

$$\begin{aligned}\text{Force} &= \mu \times \text{reactive force}\\ &= \mu \times \text{cable weight}\\ &= \frac{\mu \times \text{cable mass}}{102}\end{aligned}$$

$$\begin{aligned}\text{Cable mass} &= \frac{10.29 \times 102}{0.35}\\ &= 2\,998\ \text{kg}\\ (1\ \text{kN} &= 102\ \text{kg})\end{aligned}$$

From Table 3.25 the mass of 70 mm² × 3 Core copper cable is 3.85 kg/m. Thus the maximum length of cable that can be pulled through a PVC pipe is:

$$\frac{2\,998}{3.85} = 778\ \text{m}$$

If there are any bends in the route then these will create additional loading and reduce the theoretical length of cable that can be installed.

In certain instances when long runs in pipes or ducts are encountered it may be beneficial to grease the cable with petroleum jelly or some other non-aggressive compound to facilitate the pulling-in.

Considerable damage can be done to cable serving at the mouth of a pipe and precautions should be exercised at such points. This point is achieving more importance with the present day trend toward impermeable anti-corrosive sheaths which have to withstand periodic pressure tests. Included among the protective measures that can be adopted are the fitting of a rubber grommet to the mouth of the pipe and inserting a reasonable thickness of rag.

When unarmored cables are pulled into pipes it will be beneficial to ensure that there is no foreign matter present which could cause damage to the sheath before pulling. Pushing a draw rod through the pipe will usually clear any obstruction.

Preparation for cable laying

Planning

When planning a cable route there are several factors to be considered, among the most important of these are:

- Ground thermal resistivity (TR) tests
- Position of joint bays
- Provision to indicate on the 'as laid' drawings, the serial or drum number of the cable installed
- The use of mass or pre-impregnated non-draining paper-insulated cables, XLPE and PVC dielectrics has all but eliminated the need for special precautions when laying cables on steep slopes in shafts.

Drum handling

- Always use the best hoisting equipment available.
- Do not drop drums of cable onto the ground as this not only damages the drum but will damage the cable as well (especially paper-insulated cable).
- It is most important that a minimum of rolling of the drums on the ground is allowed and then only in the direction of the arrows painted on the flanges.
- When rolling a drum of cable, to change direction use two steel plates with grease between them, and by standing one flange on these plates the cable drum may then be swivelled in the desired direction.
- Position the drum prior to cable-pulling so that the cable is pulled from the top of the drum.
- Note that a drum of power cable can weigh up to 10 tons so make sure that adequate cable drum jacks are used, that the spindle is strong enough to hold the drum and that the jacks stand on firm ground and that they hold the spindle horizontal.
- Site the drum at the most convenient place for cable-pulling, usually at the start of a reasonably straight section near the commencement of the trench work.
- Allow for drum braking.

Ground thermal resistivity

- This often governs the rating of a power cable buried directly, as does the temperature of the soil. Losses for cables running at the maximum temperature at which the dielectric system can faithfully operate for a maximum life of say, 25 years, are considerable, ranging from 15 W/m for normal distribution cables. Cable conductor temperature and the soil surrounding the cable must be able to dissipate this heat effectively or thermal instability (runway) will result. For example an XLPE-insulated 11 kV cable with conductors running at 90 °C could end up with a surface temperature of about 80 °C resulting in drying-out of the soil. Depth of burial plays an important factor here and has been set at 800 mm. Most MV cable current ratings are calculated with ground temperatures at 25 °C at depths of burial of 800 mm.

  LV cables are normally buried at 500 mm. Soil thermal resistivity (the ability of the soil to conduct or dissipate heat) is standard at 1.2 Km/W.
- The actual soil thermal resistivity along the proposed route should be measured by means of an ERA needle probe, but these are outside the scope of this paper. suffice it to say that different soil compositions along the route will have different rates of heat dissipation and could result in 'hot spots'.
- To overcome this, bedding and backfill soils may have to be 'imported'.

Positioning of joint bays

Ensure that there is sufficient working space, consider passing traffic and other obstructions. If it is not possible to position the joint bays at standard cable length distances, remember that the cable can be ordered in specific lengths. Consider drainage for large bays and try to construct the bays prior to cable pulling to prevent any damage to the cable at a later stage.

Recording cable drum serial numbers

Cable drum serial numbers should be recorded on 'as laid' drawings. In the unlikely event of a cable failure in the future, quoting the cable drum serial number will assist the cable

manufacturer in his quality control, as this serial number is related to the manufacturing and raw material management in the factory.

Preparing for cable laying

The following 'vital actions' must be observed prior to a cable pull:

- Cable rollers must be placed between 2 and 3 m apart in the trench (depending on size of cable) (see Figure 3.4)
- Ensure that graphite lubricants have been applied where necessary
- Ensure that each member of the pulling gang knows exactly what he is to do and that communication signals between members are clear
- The trench floor must be clear of stones and other obstructions and the cable bedding correctly dispersed.

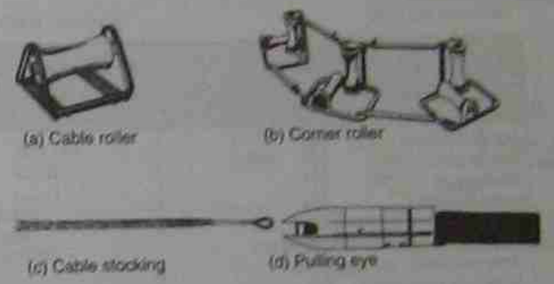


Figure 3.4
Cable pulling

Ensure that:

- Cable covers are available at convenient points.
- Any objects that may fall into the trench and damage the cable during the pull and prior to backfilling have been removed.
- If the ambient temperature is below 10 °C or has been so for the past 24 h, the cable on the drum will have to be covered with a tarpaulin and heated with suitable lamps or heaters for at least 24 h under close supervision. Ensure that sufficient ventilation exists, and pay the cable off the drum slowly and carefully. The drum should be lagged with only a few of the bottom lags removed during the heating process (This is necessary only for oil impregnated cables).

Question 3.5 for course participants: Why is this necessary?

- Place the drum at a convenient point prior to the pull on strong jacks and on sound footing (as mentioned earlier) with the arrow on the drum flanges *pointing in the opposite direction* to the rotation when the cable is being pulled.
- Before pulling, cut the inner end of the cable free.
- Remove the drum battens carefully and from the bottom.
- Inspect the cable ends for any sign of leakage (oil impregnated cables). If a leak is suspected, it can be proved by heating the cap until just too hot to touch and if

insulating oil exudes out, the cap should be removed and the extent of the damage assessed, by means of a dielectric test. Cables with extruded dielectrics should be sealed and free from moisture.

- The cable must be paid off from the top of the drum, but take care not to bend it too sharply.
- Cable pulling stockings should be examined and placed over the nose of the cable with care (see Figure 3.4). The pulling rope or wire must be attached to the stocking in such a way that the cable cap will not be damaged during the pull.
- The use of swivels is recommended to prevent twisting of the stocking. The use of stockings is preferable to tying a rope directly to the cable for pulling in.
- For permissible mechanical forces see Section 3.7.
- Bending radius of cables as recommended by the manufacturer should not be exceeded. These are given in Table 3.3.

Cable Type	Bending Radius Up to and Including 11 kV	22 and 33 kV
Paper-insulated cables		
Single core	$20\times d$	$25\times d$
Multicore	$12\times d$	$15\times d$
PVC-insulated cables 1000 V		
Multi- and single core 16–50 sq mm	$8\times d$	
Armored multi- and single core 70 sq mm and greater	$10\times d$	
XLPE-insulated cables		
Single core	$17\times d$	$17\times d$
Multicore	$15\times d$	$15\times d$

Table 3.3
Recommended bending radii

- Cable should be pulled to its final position in a continuous manner.
- If a winch is being used to pull the cable and unavoidable sharp bends are encountered, a snatch block could be used to assist the pulling tension at the bend.

Once the cable pull is completed, the nose-end of the cable is carefully lifted off the rollers and placed on the bottom of the trench, leaving enough slack to terminate the cable and observing the minimum bending radius. Immediately after cutting, the cable should be suitably sealed on both ends of the cut to prevent the ingress of moisture. Examine the nose cap and make good any damage that may have occurred during pulling.

Bond pulling

These techniques are applied when heavy cables are to be laid or the trench undergoes many changes of direction or very long lengths of cable have to be laid, or a combination of these.

As in the previously mentioned methods of cable pulling, the trench would have been prepared with cable rollers, corner rollers and skid plates. Snatch blocks would have been anchored to the sides of the trench at bends and a winch placed at the far end of the section. At the near end a mobile bond carrier is placed conveniently adjacent to the cable drum, ensuring that its braking system is adequate and that it has rewinding facilities. A steel rope, more than twice the length of the cable to be pulled, is wound onto the bond carrier drum and its end fed over the rollers and through the snatch blocks and then secured to the drum of the winch.

The cable end is manhandled onto the first rollers and tied to the steel rope at intervals of about 2 m (see Figure 3.5). Start the winch and as the nose of the cable arrives at the snatch block untie it from the steel cable, take it around the corner roller and retie on the straight.

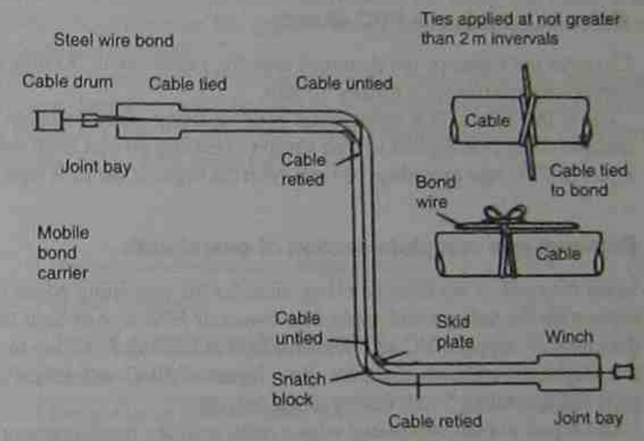


Figure 3.5
Bond pulling

Once the nose has reached the winch end, and allowing the necessary slack, the cable can be untied, the steel rope rewound onto the bond carrier. Further preparation for backfilling may then be commenced.

Backfilling and reinstatement

Once the cables have been laid, and before commencing with backfilling carry out a visual inspection of the installation to ensure that:

- The cables are properly bedded
- Correct spacing between cables if there is more than one in the trench
- Cable entrances at ducts are suitably protected against the possibility of vermin gaining entrance
- Laying and pulling equipment has been removed
- That there is no obvious damage to cable sheaths. Up to 90% of the service failures experienced in any cable system can be avoided if appropriate action is taken at this stage.

Repairs to PVC oversheaths

As mentioned above PVC sheaths damaged 'during pulling' should be repaired, applying the following procedures:

Superficial damage

Generally the local area damaged should be removed, the remaining sheath chamfered for 25 mm at the edges. An EPR self-amalgamating tape is then applied after cleaning the affected area thoroughly with a suitable solvent. The PVC tape should be approximately 30 mm wide and is applied under tension with a 50% overlap continuing up the chamfer until the top is reached plus four layers extending 75 mm beyond the chamfer.

Holes or slits in the PVC sheath

Chamfer the edges of the damaged area for a distance of 30 mm and abrade the area with carborundum strip for a further 20 mm.

Clean the area with a solvent and apply a filling putty followed by a layer of EPR self-amalgamating tape applied at high tension extending 50 mm from the patch, followed by three layers of PVC tape extending 100 mm from the edges of the EPR tape.

Removal of a complete section of oversheath

Upon removal of the damaged ring, chamfer the remaining edges for a distance of 30 mm, clean with the solvent and apply four layers of EPR tape at high tension to 50 mm beyond the chamfer. Apply PVC self-adhesive tape at one-third overlap to a level corresponding to the original oversheath diameter. Five layers of PVC self-adhesive tape are then applied, each one extending 5 mm further along the cable.

The repair is then completed with a resin poultice reinforcement consisting of six layers of ribbon gage or bandage, impregnated and painted with an approved grade of freshly mixed epoxy resin. Allow 12 h to cure.

3.9 Paper-insulated and lead-covered (PILC) 6.35/11 kV cables

The following section generally covers 6.35/11 kV PILC cables.

Notes on impregnating compound

Present day paper-insulated cables are mass impregnated with non-draining compound (MIND). This poly iso butylene compound remains in a solid state at normal operating temperatures and melts at approximately 100 °C.

Compound migration, as was experienced in earlier rosin oil-impregnated cables installed vertically or on inclines, has thus been eliminated by the use of this non-draining compound.

Moisture in paper cables

If a cable is damaged and the lead sheath or end cap is punctured, moisture almost invariably penetrates into the insulation and, if not detected immediately and removed,

may cause trouble at a later date. In every such case, therefore, a moisture test should be carried out and the cable cut back until all traces of dampness are removed. The following simple, but reliable test is recommended:

Moisture test

Heat about 1 liter of oil compound (or melted paraffin wax) in a saucepan to a temperature of 150 °C (check by thermometer). Remove individual paper tapes from the cable under test and immerse them in the hot compound. If any moisture is present, it will boil out of the paper and form bubbles or froth, which will rise to the surface of the liquid. If no moisture is present, the hot compound will be undisturbed.

When carrying out the above test do not handle the portion of the paper tapes to be immersed in the compound with bare hands, as moisture from the hands may give rise to false conclusions. As moisture is most likely to travel along the cable under the lead sheath or along the conductors, the papers next to the sheath and conductors are those most likely to contain moisture.

To minimize the penetration of moisture into the cable from the atmosphere or other sources, the cores should be moisture-blocked at each end, by sweating them solid or using solid center ferrules. Table 3.4 shows the design ambient/installation conditions applicable for PILC-insulated 6.35/11 kV grade cables.

Maximum sustained conductor temperature	70 °C
Ground temperature	25 °C
Ambient air temperature (free air-shaded)	30 °C
Ground thermal resistivity	1.2 Km/W
Depth of laying to top of cable or duct	800 mm

Table 3.4
Current rating parameters – base values

Derating factors for non-standard conditions

Tables 3.5–3.9 show the de-rating factors to be used for calculating the current-carrying capacity when the cables are used under non-standard conditions.

Depth of Laying (mm)	Direct in Ground	In Single Way Ducts
800	1.00	1.00
1000	0.98	0.99
1250	0.96	0.97
1500	0.95	0.96
2000	0.92	0.94

Table 3.5
Depth of laying – multicore PILC cables (up to 300 mm²)

Thermal Resistivity (Km/W)	Direct in Ground	In Single Way Ducts
1.0	1.07	1.04
1.5	0.92	0.95
2.0	0.82	0.88
2.5	0.75	0.82

Table 3.6
Ground thermal resistivity (multicore PILC cables)

No. of Cables in Ground	Direct in Ground					In Single Way Ducts			
	Axial Spacing (mm)					Axial Spacing (mm)			
	Touching	150	300	450	600	Touching	300	450	
2	0.80	0.85	0.89	0.90	0.92	0.88	0.91	0.93	
3	0.69	0.75	0.80	0.84	0.86	0.80	0.84	0.87	
4	0.63	0.70	0.77	0.80	0.84	0.75	0.81	0.84	
5	0.57	0.66	0.73	0.78	0.81	0.71	0.77	0.82	
6	0.55	0.63	0.71	0.76	0.80	0.69	0.75	0.80	

Table 3.7
Grouping of PILC cables in horizontal formation at standard soil conditions (multicore cables)

Maximum conductor temperature: 70 °C

Ground Temp (°C)	25	30	35	40	45
De-rating Factor	1.00	0.95	0.9	0.85	0.80

Table 3.8
Ground temperature de-rating factors

Maximum conductor temperature: 70 °C

Air Temperatures (°C)				
25	30	35	40	45
1.10	1.00	0.94	0.87	0.79

Table 3.9
Air temperature de-rating factors

Note: PILC Cables may be grouped in air without derating provided that the cables are installed on cable ladders, and that for:

- *Horizontal formation:* The clearance between cables is not less than 6 × the overall diameter of the largest cable (or 150 mm) whichever is the least.
- *Vertical formation:* The clearance from a supporting wall is greater than 20 mm, and the vertical clearance between cables is greater than 150 mm.

Note: If the number of cables > 4, they are to be installed in a horizontal plane.
Question 3.6 for course participants: Why should more than four cables be installed in a horizontal plane, otherwise de-rating factors would apply?

Short-circuit ratings for PILC cables

Short-circuit ratings do not lend themselves to rigid treatment due to unknown variables, and wherever possible conservative values should be applied.

With the continued growth of power system fault capacity, attention must be given, when selecting a cable, to its short-circuit capacity as well as to the continuous current rating.

Other limiting effects in avoiding damage during subsequent short-circuit conditions are as follows:

- Weakening of joints due to softening of solder at conductor temperatures above 160 °C
- If crimped or welded ferrules and lugs are used, temperatures of 250 °C can be tolerated
- Bursting effects are only of concern with unarmored screened cables larger than 150 mm^2. Multicore wire armored cables are only likely to burst at currents in excess of 33 kA for cable sizes below 70 mm^2, in excess of 39 kA for cables below 150 mm^2 and in excess of 22 kA for cables below 300 mm^2.

Cable short-circuit ratings are based on the adiabatic performance of the conductors and may thus be regarded as 'internal ratings' which are not affected by external factors as in the case of current ratings. Therefore, no derating factors are needed.

Formula for cable short-circuit current rating:

$$I = \frac{K \times A}{\sqrt{t}} \text{ A}$$

Where

I = short-circuit rating in amps

K = constant combining temperature limits and conductor material properties

A = area of conductor

t = duration of short circuit in seconds

The values of K for copper and aluminum conductors of 6.35/11 kV PILC cables are 154 and 101 A/mm^2 respectively, for a conductor temperature rise from 70 to 250 °C.

Table 3.27 provides 1 s short-circuit ratings. For other periods, apply the following formula.

$$I_{SC} = \frac{\text{1 s short-circuit rating (kA)}}{\sqrt{t}}$$

Earth fault ratings

Some systems make provision for reducing earth fault currents by the inclusion of a neutral electromagnetic coupler (NEC) at the star point of the distribution transformer.

Where this is not the case, the resultant high earth fault current under a fault condition will be carried by the lead sheath and by the galvanized steel wire armor. The bituminized steel tape armor is expected to rust in time and should not be included in any calculation to carry fault current.

The value of K for lead sheaths and galvanized steel wire armor is 24 and 44 A/mm² respectively. The following formula must be applied:

$$I = \frac{K \times A}{\sqrt{t}} \text{A}$$

The area of the lead sheath and the armor wires of the cable must be obtained.

3.10 Medium-voltage XLPE-Insulated, PVC-Bedded, SWA, PVC-sheathed cables

(XLPE = Cross-linked polyethylene; SWA = Steel-wired armored)

The following section generally covers 6.35/11 kV XLPE cables.

For XLPE-insulated conductors, continuous conductor temperatures of 90 °C are permissible with overload excursions up to 130 °C for a maximum of 8 h continuous per event with a maximum total of 125 h per annum. In the case of short circuits, the insulation can withstand conductor temperatures of up to 250 °C for 1 s. Table 3.10 shows the design ambient/installation conditions applicable for XLPE-insulated 6.35/11 kV cables.

Maximum sustained conductor temperature	90 °C
Ground temperature	25 °C
Ambient air temperature (free air-shaded)	30 °C
Ground thermal resistivity	1.2 Km/W
Depth of laying to top of cable or duct	800 mm

Table 3.10
Current ratings are based on these parameters

De-rating factors for non-standard conditions

Tables 3.11–3.15 show the de-rating factors to be used for calculating the current-carrying capacity when these cables are used under non-standard conditions.

Depth of Laying (mm)	Direct in Ground	In Single Way Ducts
500–800	1.00	1.00
850–1000	0.97	0.96
1050–1200	0.95	0.95
1250–1400	0.93	0.95
1450–1600	0.92	0.94

Table 3.11
Depth of layers – multicore XLPE cables (up to 300 mm²)

Thermal Resistivity (Km/W)	Direct in Ground	In Single Way Ducts
0.7	1.23	1.28
1.0	1.08	1.12
1.2	1.00	1.00
1.5	0.90	0.93
2.0	0.80	0.85
2.5	0.72	0.80
3.0	0.66	0.74

Table 3.12
Ground thermal resistivity – multicore XLPE cables (up to 300 mm²)

No. of Cables in Group	Direct in Ground			In Single Way Ducts		
	Axial Spacing (mm)			Axial Spacing (mm)		
	Touching	250	700	Touching	250	700
2	0.79	0.85	0.87	0.87	0.91	0.93
3	0.69	0.75	0.79	0.80	0.86	0.91
4	0.63	0.68	0.75	0.75	0.80	0.87
5	0.58	0.64	0.72	0.72	0.78	0.86
6	0.55	0.60	0.69	0.69	0.74	0.83

Table 3.13
Group of XLPE cables in horizontal formation at standard depths of laying and in standard soil conditions (multicore cables)

Maximum conductor temperature: 90 °C

Ground Temperature (°C)				
25	30	35	40	45
1.0	0.96	0.92	0.88	0.84

Table 3.14
Ground temperature de-rating factors

Maximum conductor temperature (90 °C)

Air Temperatures (°C)				
30	35	40	45	50
1.0	0.95	0.89	0.84	0.78

Table 3.15
Air temperature de-rating factors

Note: Cables may be grouped in air without de-rating provided that the cables are installed on cable ladders, and that for:

- *Horizontal formation:* The clearance between cables is not less than 6 × the overall diameter of the largest cable (or 150 mm) whichever is the least.
- *Vertical formation:* The clearance from a supporting wall is greater than 2 mm, and the vertical clearance between cables is greater than 150 mm.

Note: If the number of cables >4, they are to be installed in a horizontal plane.

Short-circuit ratings for XLPE-insulated 6.35/11 kV cables

Short-circuit ratings do not lend themselves readily to rigid treatment due to unknown variables. Wherever possible conservative values should be applied. As the growth of a power system increases so do the system fault levels. When selecting a cable, attention must be given to its short-circuit capability, as well as to the continuous current rating.

Other limiting effects in avoiding damage during short-circuit conditions are as follows:

- Weakening of joints due to softening of the solder at a conductor temperature of 160 °C and above, although most conductor joining nowadays is done by compression fittings, particularly on XLPE-insulated cables.
- Bucking of the conductors in joint boxes due to longitudinal expansion of cables laid directly in ground.

Cable short-circuit ratings are based on the adiabatic performance of the conductors. This assumes no heat loss from the cable during the period of the fault. No derating factors are necessary with regard to soil temperature, depth of burial, etc.

Ratings are derived from temperature limits as follows:

$$I = \frac{K \times A}{\sqrt{t}} \text{A}$$

Where

I = short-circuit rating in amps
K = constant combining temperature limits and conductor material properties
A = area of conductor
t = duration of short circuit in seconds

The value of K for copper and aluminum conductors of 6.35/11 kV XLPE cables is 143 and 92 A/mm^2 respectively, for a conductor temperature rising from 90 to 250 °C

Table 3.28 provides 1 s short-circuit ratings; for other time periods the following formula should be applied.

$$I = \frac{\text{1 s short-circuit rating (kA)}}{\sqrt{t}}$$

Earth fault current

Some systems provide for reducing earth fault currents by the inclusion of a neutral electromagnetic coupler (NEC) at the star point of the distribution transformer, typically 300 A.

Where this is not the case, the resistance of the copper tapes and steel wire armor should be included in the calculation.

Typical 1 s earth fault ratings for XLPE-insulated 6.35/11 kV are shown in Table 3.16.

Cable Size (mm^2)	Earth Fault Rating (kA/s)
25	10.4
35	12.2
50	13.1
70	17.6
95	18.7
120	19.7
150	20.8
185	25.0
240	26.8
300	28.6

Table 3.16
Earth fault ratings

3.11 Low-voltage PVC- and XLPE-insulated 600/1000 V power cables

Note on PVC insulation

For PVC insulation continuous conductor temperatures up to 70 °C are permissible. Care must be exercised in matching the cable to the circuit protection. Under short-circuit conditions, a maximum conductor temperature of 160 °C is allowed for a maximum period of 1 s.

Note on XLPE insulation

For XLPE insulation, continuous conductor temperatures up to 90 °C are permissible with excursions of up to 130 °C for a maximum of 8 h continuous per event, with a maximum total of 125 h per annum. Table 3.17 shows the design ambient/installation conditions applicable for XLPE-insulated LV (600/1000 V) cables.

	PVC	XLPE
Maximum sustained conductor temperature	70 °C	90 °C
Ground temperature	25 °C	25 °C
Ambient air temperature (free air shaded)	30 °C	30 °C
Ground thermal resistivity	1.2 Km/W	1.2 Km/W
Depth of laying to top of cable or duct	500 mm	500 mm

Table 3.17
Current rating parameters

De-rating factors for non-standard conditions

Tables 3.18–3.23 show the de-rating factors to be used for calculating the current-carrying capacity when these cables are used under non-standard conditions. These de-rating factors are applicable for both XLPE and PVC-insulated LV cables.

Depth of Laying (mm)	Direct in Ground	In Single Way Ducts
500	1.00	1.00
800	0.97	0.97
1000	0.95	0.96
1250	0.94	0.95
1500	0.93	0.94
2000	0.92	0.93

Table 3.18
De-rating factors for depth of laying – multicore cables (up to 300 mm²)

Thermal Resistivity (Km/W)	Direct in Ground	In Single Way Ducts
1.0	1.08	1.04
1.5	0.93	0.96
2.0	0.83	0.88
2.5	0.78	0.87

Table 3.19
De-rating factors for ground thermal resistivity (multicore cables)

	Direct in Ground					In Single Way Ducts			
	Axial Spacing (mm)					Axial Spacing (mm)			
No.of Cables in Group	Touching	150	300	450	600	Touching	300	450	
2	0.81	0.87	0.91	0.93	0.94	0.90	0.93	0.95	
3	0.70	0.78	0.84	0.87	0.90	0.82	0.87	0.90	
4	0.63	0.74	0.81	0.86	0.89	0.78	0.85	0.89	
5	0.59	0.70	0.78	0.83	0.87	0.75	0.82	0.87	
6	0.55	0.67	0.76	0.82	0.86	0.72	0.81	0.86	

Table 3.20
De-rating factors for grouping of cables in horizontal formation, at standard depths of laying and in standard soil conditions.

Maximum Conductor Temperature (°C)	Ground Temperatures (°C)					
	25	30	35	40	45	50
70 (PVC)	1.00	0.95	0.90	0.85	0.80	0.70
90 (XLPE)	1.00	0.96	0.92	0.88	0.82	0.76

Multicore Cables (up to 300 mm²)

Table 3.21
Ground temperature de-rating factors.

Maximum Conductor Temperature (°C)	Air Temperatures (°C)			
	30	35	40	45
70 (PVC)	1.00	0.94	0.87	0.79
90 (XLPE)	1.00	0.95	0.89	0.84

Multicore Cables (up to 300 mm²)

Table 3.22
Air temperature de-rating factors

No. of cables	1	2	3	6	9
Cable touching	1	0.9	0.84	0.80	0.75
Clearance D^* between cables	1	0.95	0.9	0.88	0.85

D^* is the overall diameter of one cable.

Table 3.23
De-rating factors for grouping of multicore cable installed horizontally in air

Note: Cables may be grouped in air without derating, provided that the cables are installed on ladders, and that for:

- *Horizontal formation*: The clearance is greater than 6 × the cable overall diameter (or 150 mm², which- ever is the least).
- *Vertical formation*: The clearance from a vertical wall is greater than 20 mm, and the vertical clearance between cables is greater than 150 mm.

Note: If the number of cables > 4, they should be installed in the horizontal plane.

Short-circuit ratings for PVC and for XLPE-insulated 600/1000 V cables

With PVC and with XLPE-insulated cables, care must be taken to limit the conductor temperatures for continuous operation and for short-circuit conditions as indicated in Table 3.24.

Short-circuit ratings are regarded as internal ratings. Their calculation is based on an adiabatic equation and is not affected by external consideration. Due to unknown variables, short-circuit ratings do not lend themselves readily to rigid treatment, so whenever possible conservative values should be applied.

$$I_{SC} = \frac{K \times A}{\sqrt{t}} \text{ A}$$

Where

I_{SC} = short-circuit rating in amps

K = a constant combining temperature limits and properties of conductor materials

A = area of conductor

t = duration of short circuit in seconds

Insulation Material	Conductor Material	Operating Temperature (°C)	Short Circuit Temperature (°C)	K Factor
PVC	Copper	70	160	
PVC	Aluminum	70	160	
XLPE	Copper	90	250	
XLPE	Aluminum	90	250	

Table 3.24
Values of conductor/temperature constant K

Copper conductors

Tables 3.25–3.30 show the electrical and physical properties of different types of cables for use in cable-sizing calculations. Diameters *D1*, *D2* and *d* referred in these tables are as per the legend of Figure 3.6 which shows the typical constructional details of a PVC-insulated 3-core armored cable. The types of cables for which the physical and electrical properties are shown in these tables as follows.

D1 = diameter over bedding
d = diameter of armor wires
D2 = diameter over outer sheath

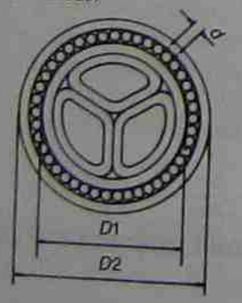


Figure 3.6
Cross-sectional view of a PVC 3-core cable

Physical Properties																
		Nominal Diameters							Approx. Mass							
Cable Size (mm^2)	Ground (A)	$d-3c$ (mm)	$d-4c$ (mm)	$D2-3c$ (mm)	$D2-4c$ (mm)	3c (kg/km)	4c (kg/km)	$D1-3c$ (mm)	$D1-4c$ (mm)							
1.5	23	1.25	1.25	14.13	14.95	448	501	8.51	9.33							
2.5	30	1.25	1.25	15.23	16.18	522	597	9.61	10.56							
4	38	1.25	1.25	17.02	18.39	667	762	11.40	12.57							
6	48	1.25	1.25	18.4	19.72	790	910	12.58	13.90							
10	64	1.25	1.25	20.41	21.96	996	1169	14.59	16.14							
16	82	1.25	1.60	22.37	25.92	1295	1768	16.55	19.18							
25	126	1.60	1.60	26.46	28.34	1838	2196	19.46	21.34							
35	147	1.60	1.60	27.89	31.17	2215	2732	20.89	23.97							
50	176	1.60	2.00	31.46	36.84	2871	3893	24.26	28.14							
70	215	2.00	2.00	35.47	40.09	3617	4837	27.07	31.29							
95	257	2.00	2.00	39.99	44.62	4901	6115	31.19	35.82							
120	292	2.00	2.00	42.18	47.40	5720	7269	33.38	38.10							
150	328	2.00	2.50	45.98	52.65	6908	9250	36.68	42.05							
185	369	2.50	2.50	51.12	57.45	8690	11039	40.82	46.75							
240	422	2.50	2.50	57.13	64.16	10767	13726	46.43	53.06							
300	472	2.50	2.50	62.20	70.13	12950	16544	51.10	58.53							

Electrical Properties																
	Current Ratings				Impedance (Ω/km)	Volt Drop (mV/A/m)	1 Short-Circuit Rating (kA)									
Cable Size (mm^2)	Ground (A)	Ducts (A)	Air (A)													
1.5	23	18	18		14.48	25.080	0.17									
2.5	30	24	24		8.87	15.363	0.28									
4	38	31	32		5.52	9.561	0.46									
6	48	39	40		3.69	6.391	0.69									
10	64	52	54		2.19	3.793	1.15									
16	82	67	72		1.38	2.390	1.84									
25	126	101	113		0.8749	1.515	2.87									
35	147	120	136		0.6335	1.097	4.02									
50	176	144	167		0.4718	0.817	5.75									
70	215	175	207		0.3325	0.576	8.05									
95	257	210	253		0.2460	0.427	10.92									
120	292	239	293		0.2012	0.348	13.80									
150	328	269	336		0.1698	0.294	17.25									
185	369	303	384		0.1445	0.250	21.27									
240	422	348	447		0.1220	0.211	27.60									
300	472	397	509		0.1090	0.189	34.50									

Table 3.25
3- and 4-core PVC-insulated, 600/1000 V copper cable

Electrical Properties							Physical Properties							
Cable Size (mm^2)	Ground	Ducts	Air	Impedance (Ω/km)	Volt drop (mV/A/m)	1 Short-Circuit Rating (kA)	*D*1 – 3c	*D*1 – 4c	*d* – 3c	*d* – 4c	*D*2 – 3c	*D*2 – 4c	3c (kg/km)	4c (kg/km)
1.5	27	22	22	15.43	26.726	0.21	8.08	8.85	1.25	1.25	13.70	14.47	416	453
2.5	35	30	29	9.45	16.368	0.35	9.18	10.08	1.25	1.25	14.80	15.70	487	521
4	46	39	37	5.88	10.184	0.57	10.06	11.07	1.25	1.25	15.68	16.69	566	650
6	57	49	46	3.93	6.807	0.85	11.25	12.40	1.25	1.25	16.87	18.02	683	778
10	76	67	61	2.34	4.053	1.43	13.25	14.64	1.25	1.25	19.07	20.46	890	1033
16	99	92	80	1.47	2.546	2.28	15.21	17.68	1.25	1.25	21.03	24.42	1191	1544
25	147	119	138	0.9313	1.613	3.57	18.13	19.86	1.60	1.60	25.13	26.86	1693	2018
35	175	142	168	0.6738	1.167	5.00	19.56	22.32	1.60	1.60	26.56	29.52	2025	2511
50	207	169	204	0.5009	0.868	7.15	22.49	25.76	1.60	1.60	29.69	32.96	2606	3242
70	253	207	256	0.3521	0.610	10.01	25.74	29.81	2.00	2.00	32.94	38.21	3323	4503
95	302	248	312	0.2589	0.448	13.58	28.76	33.1	2.00	2.00	37.16	41.90	4442	5650
120	344	282	362	0.2109	0.365	17.16	31.39	35.87	2.00	2.00	40.19	44.67	5335	6731
150	387	318	416	0.1775	0.307	21.45	34.69	40.12	2.50	2.50	43.49	50.42	6403	8708
185	435	359	478	0.1500	0.260	26.45	39.05	44.77	2.50	2.50	49.35	55.07	8184	10343
240	498	413	557	0.1247	0.216	34.32	44.22	50.58	2.50	2.50	54.52	61.68	10073	12932
300	558	471	634	0.1099	0.190	42.90	48.45	55.56	2.50	2.50	58.35	67.16	12076	15575

Table 3.26
3- and 4-core XLPE-insulated 600/1000 V copper cable

Copper Conductors						Aluminum Conductors				
Electrical Properties				Physical Properties		Electrical Properties			Physical Properties	
Cable Size (mm^2)	Ground Current Rating (A)	Impedance (Ω/km)	1s Short-Circuit Rating (kA)	Diameter Over Lead (mm)	Approximate Cable Mass (kg/km)	Ground Current Rating (A)	Impedance (Ω/km)	1s Short-Circuit Rating (kA)	Diameter Over Lead (mm)	Approx. CableMass (kg/km)
25	105	0.8779	3.850	31.38	4890	80	1.4421	2.525	31.38	4415
35	130	0.6371	5.390	33.64	5710	100	1.0492	3.535	33.64	5055
50	160	0.4751	7.700	33.49	6020	125	0.7777	5.050	33.49	5195
70	195	0.3365	10.780	36.50	7080	155	0.5423	7.070	36.50	5790
95	235	0.2499	14.630	39.33	8260	185	0.3972	9.595	39.33	6505
120	265	0.2053	18.480	41.73	9440	210	0.3183	12.120	41.73	7225
150	295	0.1739	23.100	44.36	10770	235	0.2640	15.150	44.36	7980
185	335	0.1481	28.490	47.42	12290	265	0.2166	18.685	47.42	8870
240	380	0.1245	36.960	52.14	14480	305	0.1734	24.240	52.14	10050
300	425	0.1106	46.200	56.15	16940	340	0.1472	30.300	56.15	11415

(Short-circuit ratings based on temperature rise of 70°C – 250°C)

Table 3.27
3-core 6.35/11 kV PILC-insulated copper and aluminum cables

Copper Conductors						Stranded Aluminum Conductors				
Cable Size (mm^2)	Current Rating (Ground) (A)	Impedance (Ω/km)	1 s Short-Circuit Rating (kA)	Diameter Overall (mm)	Approx. Cable Mass (kg/km)	Current Rating (ground) (A)	Impedance (Ω/km)	1 s Short-Circuit Rating (kA)	Diameter Overall (mm)	Approx. Cable Mass (kg/km)
35	170	0.6769	5.008	53.9	5600					
50	200	0.5044	7.154	56.4	6225	155	0.8284	4.724	56.4	5340
70	240	0.3561	10.016	61.7	8050	190	0.5767	6.614	61.7	6685
95	290	0.2641	13.593	65.9	9240	225	0.4213	8.976	65.9	7400
120	325	0.2163	17.170	68.9	10330	255	0.3375	11.338	68.9	8010
150	360	0.1826	21.463	72.4	11695	285	0.2795	14.173	72.4	8795
185	410	0.1548	26.470	76.5	13165	320	0.2285	17.479	76.5	9560
240	470	0.1293	34.340	82.6	14740	370	0.1821	22.676	82.6	10110
300	520	0.1139	42.925	88.9	18050	420	0.1535	28.345	88.9	12225

Table 3.28

3-core XLPE-insulated 6.35/11 kV copper and aluminum cables

	Nominal Diameters				Current Ratings 1 Phase Ac or Dc			Current Ratings 3 Phase Trefoil Formation			
Rated Area (mm2)	D1 (mm)	D2 (mm)	Nominal Mass (kg/km)	Impedance (Ω/km)	Ground	Air	Volt Drop (mV/A/m)	Ground	Duct	Air	Volt Drop (mV/A/m)
25	5.95	11.91	366	0.8767	129	139	1.75	127	111	109	1.52
35	7.00	12.96	469	0.6356	171	169	1.27	153	132	133	1.10
50	8.15	15.15	632	0.4745	204	207	0.95	180	155	164	0.82
70	9.79	16.57	880	0.3356	254	262	0.67	221	190	207	0.58
95	11.54	19.04	1160	0.2500	308	325	0.50	265	226	256	0.43
120	12.96	20.24	1413	0.2054	353	379	0.41	301	256	298	0.36
150	14.39	22.07	1734	0.1734	402	435	0.35	338	287	341	0.30
185	16.10	24.80	2145	0.1499	461	504	0.30	381	323	396	0.26
240	18.71	27.81	2725	0.1268	545	602	0.25	442	372	473	0.22
300	21.45	30.75	3375	0.1131	627	697	0.23	499	419	550	0.20
400	24.30	34.10	4395	0.1028	735	815	0.21	565	472	640	0.18
500	26.51	37.13	5299	0.0963	856	948	0.19	634	532	732	0.17
630	33.15	43.62	6965	0.0890	996	1108	0.18	718	603	867	0.15
800	37.70	49.00	9118	0.0852	1131	1258	0.17	792	689	984	0.15
1000	42.25	53.45	11050	0.0819	1241	1386	0.16	856	741	1084	0.14

Note: (1) D1 is the diameter over the conductor
(2) D2 is the diameter over the PVC sheath.

Table 3.29

Single-core PVC- insulated cables with stranded copper conductors

Rated Area	Nominal Diameters				Current Ratings 1 Phase Ac or Dc			Current Ratings 3 Phase Trefoil Formation			
	D1(mm)	D2 (mm)	Nominal Mass (kg/km)	Impedance (Ω/km)	Ground	Air	Volt Drop (mV/A/m)	Ground	Duct	Air	Volt Drop (mV/A/m)
25	5.95	11.81	328	0.9332	169	174	1.866	151	137	137	1.616
35	7.00	12.86	426	0.6760	205	211	1.352	181	164	167	1.171
50	8.15	14.38	567	0.5036	245	257	1.007	213	192	203	0.872
70	9.79	16.22	824	0.3552	302	326	0.71	260	235	257	0.615
95	11.54	17.97	1071	0.2631	366	404	0.526	312	281	318	0.456
120	12.96	19.82	1304	0.2154	422	475	0.431	355	319	372	0.373
150	14.39	21.42	1628	0.1818	480	542	0.363	397	356	426	0.315
185	16.10	23.63	1995	0.1545	554	629	0.309	449	402	494	0.268
240	18.71	26.69	2461	0.1295	656	753	0.259	522	466	594	0.224
300	21.45	30.05	3182	0.1149	766	881	0.229	589	524	692	0.199
400	24.30	33.30	4117	0.1035	902	1045	0.207	668	592	807	0.179
500	26.51	36.33	5032	0.0963	1040	1182	0.192	750	664	925	0.167
630	33.15	42.79	6641	0.0889	1229	1417	0.178	848	746	1094	0.154
800	37.70	48.84	8535	0.0856	1366	1603	0.171	942	823	1254	0.148
1000	42.25	54.21	10676	0.0831	1486	1790	0.166	1025	892	1400	0.144

Note: (1) D1 is the diameter over the conductor
(2) D2 is the diameter over the PVC sheath.

Tablep 3.30

Single-core XLPE-insulated cables with stranded copper conductors

4

Compensation

4.1 Introduction

The term compensation is used to describe the intentional insertion of reactive power devices, capactive or inductive, into a power network to achieve a desired effect. This may include improved voltage profiles, improved power factor, enhanced stability performance, and improved transmission capacity. The reactive devices are connected either in series or in parallel (shunt).

Figure 4.1 illustrates the flow of power in an electric circuit. The link has an impedance of $R + jX$, and we assume that $V_1 > V_2$ and that V_1 leads V_2. In most power networks, $X >> R$, and reactive power flows from A to B. The direction of reactive power flow can be reversed by making $V_2 > V_1$. The magnitude of reactive power flow is determined by the voltage difference between point A and B. When R is ignored, the reactive power flow, Q is given by

$$Q = \frac{V_2(V_1 - V_2)}{X} \tag{4.1}$$

The ideal situation is when $V_1 = V_2$, and reactive power flow is zero.

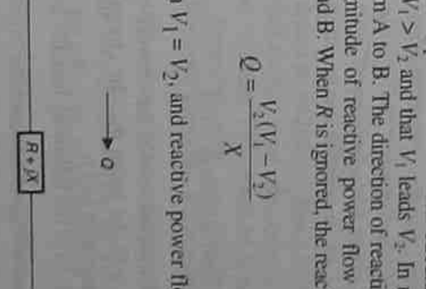


Figure 4.1

Typical power flows in electric circuits

The maximum possible active power transfer, P_{max} is given by

$$P_{max} = \frac{V_1 V_2}{X} \tag{4.2}$$

It is clear from the above formula that active power transfer capacity is improved if V_2 is increased.

4.2 Series capacitors

Series capacitors are utilized to neutralize part of the inductive reactance of a power network. This is illustrated in Figure 4.2. From the phasor diagram in Figure 4.3 we can see that the load voltage is higher when the capacitor is inserted in the circuit.



Figure 4.2
Use of series capacitors to neutralize inductor reactors

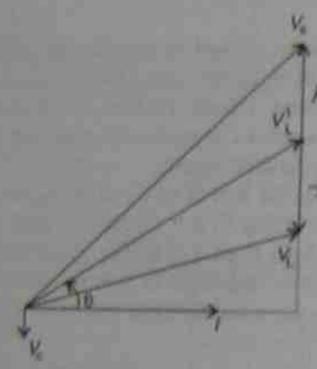


Figure 4.3
Phasor diagram with series capacitor in circuit

Introducing series capacitance in the network reduces the net reactance X, and increases the load voltage, with the result that the circuit's transmission capacity is increased, as can be seen from equation (4.1).

Series capacitors have the following benefits to the network:

- Improved voltage conditions
- Enhanced stability performance
- Controlling reactive power balances
- Aid in load distribution and control of overall transmission losses.

Due to the added transmission capacity, series-capacitor compensation may delay investments in additional overhead lines and transmission equipment, which can have capital investment benefits to the utility company as well as environmental impact advantages.

The first series-capacitor installation in the world was a 33 kV, 1.25 MVAr capacitor bank on the New York Power and Light system in 1928. Many higher-rated systems have since been installed all over the world.

Question 4.1 for course participants: Reducing the net reactance in a system has another direct consequence, which must be taken into account. What is it and what care should be taken?

The installation of series-capacitance in an AC transmission system can result in the phenomenon of subsynchronous resonance (SSR), due to the interaction between the compensated electrical system (in electrical resonance) and a turbine-generator mechanical system (in mechanical resonance). Energy is then exchanged between the electrical and mechanical systems at one or more natural frequencies of the combined system below the synchronous frequency of the system. Increasing mechanical oscillations can occur resulting in eventual mechanical failure of the turbine-generator system.

The following are techniques to counteract SSR:

- *Supplementary excitation control*: The subsynchronous current and/or voltage is detected and the excitation current is modulated using high-gain feedback to vary the generator output voltage, which counters the subsynchronous oscillations.
- *Static filters*: These are tuned to correspond to the power system frequency to filter out the oscillation mode frequencies. They are normally connected in series with each phase of the generator(s).
- *Dynamic filters*: In a manner similar to that of excitation control, the subsynchronous oscillations are detected, a counter emf is generated and injected into the power network through a series transformer to neutralize the unwanted oscillations.
- *Bypassing series capacitors*: To limit transient torque build-up.
- Amortisseur windings on the pole faces of the generator rotors can be employed to improve damping.
- A passive SSR countermeasure scheme involves using three different combinations of inductive and capacitive elements on the three phases. The combinations will have the required equal degree of capacitive compensation in the three phases at the power frequency. At any other frequency, the three combinations will appear as unequal reactance in the three phases. In this manner, asynchronous oscillations will drive unsymmetrical three-phase currents in the generator's armature windings. This creates an mmf with a circular component of a lower magnitude, compared with the corresponding if the currents were symmetrical. The developed interacting electromagnetic torque will be lower.

The following points are worth noting when considering the merits of series capacitors:

- Series capacitors are very effective when the total line reactance is high.
- Series capacitors are effective to compensate for voltage drop and voltage fluctuations.
- Series capacitors are of little value when the reactive power requirements of the load are small.
- In cases where thermal considerations limit the line current, series capacitors are of little value since the reduction in line current associated with them is relatively small.

In the last two points mentioned above, shunt capacitors may be considered instead of series capacitors.

4.3 Shunt capacitors

Shunt capacitors supply capacitive reactive power to the system at the point where they are connected, mainly to counteract the out-of-phase component of current required by an inductive load. They may either be energized continuously or switched on and off during load cycles.

Figure 4.4 illustrates a circuit with shunt capacitor compensation applied at the load side.

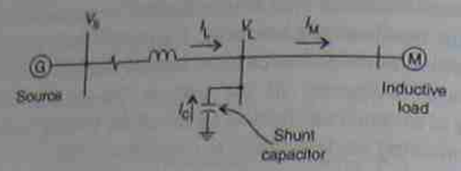


Figure 4.4
Use of shunt capacitors to counteract out-of-phase current component

Referring to the phasor diagram of Figure 4.5, the line current I_L is the sum of the motor load current I_M and the capacitor current I_C.

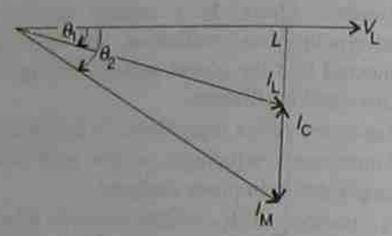


Figure 4.5
Current phasor diagram

It can be seen that the line current is decreased by adding the shunt capacitor. The angle between the load voltage and current is decreased from ϕ_2 to ϕ_1.

Figure 4.6 displays the corresponding voltage phasors. The result of adding the shunt capacitance is to decrease the source voltage from V_{s1} to V_{s2}.

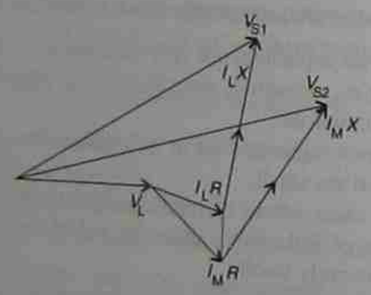


Figure 4.6
Voltage phasor diagram

It can be seen from the above that the application of shunt capacitors in a network with a lagging power factor has the following benefits:

- Increase voltage level at the load
- Improve voltage regulation (if the capacitors are switched in and out of the network correctly)

- Reduce I^2R active power loss and I^2X reactive power loss due to the reduction in current
- Increase power factor
- Decrease kVA (or mVA) loading on the source generators and network to relieve an overload condition or make capacity available for additional load growth
- Reduce demand kVA where power is purchased
- Reduce investment in system facilities per kW of load supplied.

A capacitor starting system may be employed to reduce high inrush currents with the starting of large motors. This aids in maintaining the voltage level in the system. The high inductive component of the starting current is reduced by the addition of capacitance during the starting period only. In this, it differs from applying capacitors for power factor correction.

Note that in determining the amount of shunt capacitance required, some additional capacitive kVAr above that based on initial conditions without capacitors may be required. This is due to the fact that a voltage rise increases the lagging kVAr in the exciting currents of transformers and motors.

Caution

Increased harmonics on the power system and/or a harmonic resonance condition may result with applying capacitors, especially when using harmonic-generating apparatus, such as thyristor controllers. Either a shunt or series resonance condition, or a combination of both, may occur if the resonant point happens to be close to one of the frequencies generated by harmonic sources in the system.

This can result in excessive harmonic currents flowing or harmonic overvoltages, or both, causing possible operation of the capacitor protection equipment (such as fuses), capacitor failure, overheating of other electrical equipment and electrical system interference.

4.4 Shunt reactors

Shunt reactor compensation is usually required under conditions that are the opposite of those requiring shunt capacitor compensation. This is illustrated in Figure 4.7.

Shunt reactors may be installed in the following conditions:

- To compensate for overvoltages occurring at substations served by long lines during low-load periods, as a result of the line's capacitance (Ferranti effect as voltage tip up)
- To compensate for leading power factors at generating plants, resulting in lower transient and steady-state stability limits
- To reduce open-circuit line charging kVA requirements in extra high-voltage (EHV) systems.

The effect of shunt reactance on the current phasor diagram is shown in Figure 4.8.

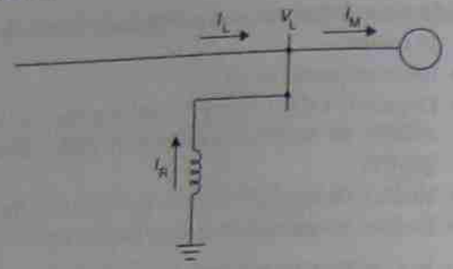


Figure 4.7
Shunt reactor compensation

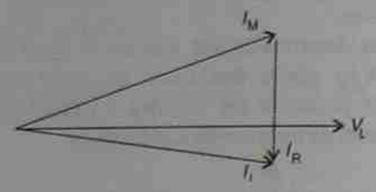


Figure 4.8
Effect of shunt reactors

4.5 Synchronous compensators

A synchronous compensator is a synchronous motor running without a mechanical load. It can absorb or generate reactive power, depending on the level of excitation. When used with a voltage regulator, the motor can run automatically over-excited at high-load current and under-excited at low-load current.

The cost of installation of synchronous compensators is high compared to capacitors, and the electrical losses are considerable relative to capacitors.

Question 4.2 for course participants: Why would the losses of a synchronous motor, utilized as a reactive compensator, be high compared to capacitors?

Synchronous condensers can also be used as dip mitigation devices to support the voltage during drops.

4.6 Static VAR compensators

Static VAR compensators (SVCs) contain shunt capacitors and reactors, which are controlled by thyristors.

They provide solutions to two types of compensation problems normally encountered in practical power systems:

- The first is load compensation, where the requirements usually are to reduce the reactive power demand of large and fluctuating industrial loads, and to balance the real power drawn from the supply lines.
- The second type of compensation is related to voltage support of transmission lines at a certain point in response to disturbances of both load and generation.

The main objectives of dynamic VAR compensation are to increase the stability limit of the power system, to decrease voltage fluctuations during load variations and to limit overvoltages due to large disturbances.

The two fundamental thyristor-controlled reactive power device configurations are:

1. *Thyristor-switched shunt capacitors*: The capacitor bank is split into small capacitor steps and those steps are switched on and off individually. It offers stepwise control, virtually no transients and very little harmonic generation. The average delay for executing a command from the regulator is half a cycle. Figure 4.9 (a) shows this arrangement.
2. *Thyristor-switched shunt reactors*: The fundamental frequency current component through the reactor is controlled by delaying the closing of the thyristor switch with respect to the natural zero crossings of the current. Figure 4.9 (b) illustrates this concept.

Harmonic currents are generated from the phase-angle-controlled reactor. There are two methods to reduce the magnitude of the generated harmonics. The first method consists of splitting the reactor into smaller steps, with only one thyristor-controlled step while the other reactor steps are either on or off.

The second method involves the 12-pulse arrangement, where two identically connected thyristor-controlled reactors are used, one operated from wye-connected secondary winding, and the other from a delta-connected winding of a step-up transformer.

Thyristor-switched reactors are characterized by continuous control, and there is a maximum of one half-cycle delay for executing a command from the regulator.

In many practical applications, a combination of these two thyristor-controlled devices are used, with the SVC consisting of a few steps of thyristor-controlled capacitance and one or two thyristor-controlled reactors, as shown in Figure 4.9 (c).

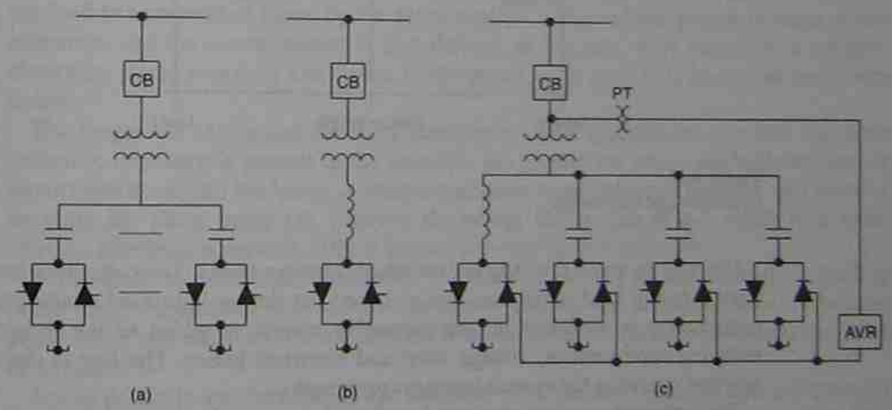


Figure 4.9
Basic static VAR compensator configurations

It is important to note that applying static VAR compensators to series-compensated AC transmission lines results in three distinct resonant modes:

1. Shunt capacitance resonance involves energy exchange between the shunt capacitance (line charging plus any power factor correction and SVCs) and the series inductance of the lines and the generator.
2. Series-line resonance involves energy exchange between the series capacitor and the series inductance of the lines, transformers and generators.
3. Shunt-reactor resonance involves energy exchange between shunt reactors at the intermediate substations of the line and the series capacitors.

Due to the above, it is crucial to represent any compensators in transient electrical simulation programs.

4.7 Distribution applications – shunt capacitors

Shunt capacitors are used more frequently in power distribution systems than any other electrical compensation device. They are used mostly for voltage regulation and power factor correction; hence, these two specific applications will be briefly discussed.

Voltage regulation

Voltage drop can be reduced by the application of a shunt capacitor. A correct selected and located shunt capacitor assures that the voltage at the load will be within the allowable limit at the heavy load condition. However, at light loading, the same capacitor will increase the voltage to above the allowable limit, as illustrated in Figure 4.10.

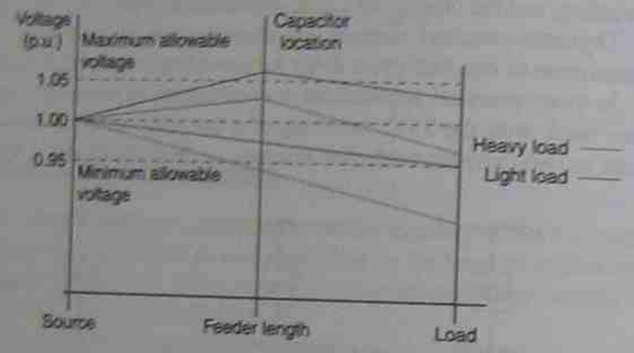


Figure 4.10
Capacitor effect on voltage

The way to avoid this is to use switched capacitor banks. The capacitors are switched in during heavy load conditions and switched out during light load conditions. When the capacitor(s) is switched in, the capacitive current is added to the inductive current, reducing total current, voltage drop and electrical losses. The last is due to reducing reactive power in the system (see next paragraph).

The optimum number, size and location of capacitor banks on a feeder are determined by detailed computer analysis, also taking into consideration minimization of the operation, installation and investment costs. The most important factors that affects the selection is the voltage levels, total loading, distribution factor and power factor of loads.

Power factor correction

Power and power factor

Power in a three-phase distribution system consisting of two components, namely active or real power (P) and reactive power (Q). The complex sum of the two gives apparent power (S). Hence, $S = P + jQ$. This is illustrated in the well-known power triangle in Figure 4.11.

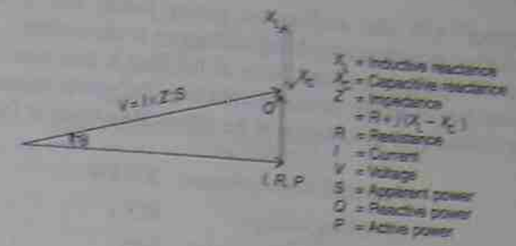


Figure 4.11
Power triangle

Apparent power (S) in a three-phase system is calculated by the formula, $S = \sqrt{3}VI$. This is expressed in VA, kVA or MVA, and is the unit used for the ratings of transformers.

Power cables and transformers add reactance to a power network, which is mainly inductive (a lesser amount of capacitance is also added). The inductive and capacitive reactances are frequency dependent (hence are only present in AC systems), oppose each other and are at right angles to the pure (dc) resistance. The net reactance, which is usually inductive, opposes the flow of current, and the power required to overcome this reactance is called reactive power (Q). This is wasted power, which is of no benefit to the user. Reactive power is calculated by the formula, $Q = \sqrt{3}VI\sin\phi$, and is expressed in VAr, kVAr or MVAr.

The presence of reactance in the network causes the voltage and the current phasors at the load to move out of phase by the phase angle ϕ. (The voltage phasor is taken as the reference, and the current phasor is then defined as 'lagging' with respect to a counter-clockwise phase rotation.) The cosine of the phase angle ($\cos\phi$) is known as the *power factor*.

The longer the cables and the more transformers in a distribution network, the more inductive reactance is present in the network, the greater the phase angle (lower power factor) and the higher the losses. Adding capacitance to an inductive network will serve to decrease the phase angle (ϕ), improve the power factor ($\cos\phi$) and result in a more efficient distribution network. This is known as *power factor correction*.

When more capacitive than inductive reactance is present in the network, a leading phase angle may result, with the current phasor leading the voltage phasor. A leading phase angle will have detrimental effects on the operation of induction motors, and must be avoided.

Active power is the electrical power available to be utilized usefully, and is expressed in W, kW or MW. This is the unit in which electric motors, lights, heaters, etc. are rated.

Active power is expressed by the formula

$$P = \sqrt{3} \times V \times I \times PF_{(load)}, \quad \text{where } PF = \cos\phi$$

Causes and effects

Any equipment with inductive properties will worsen the power factor, as reactive power is used to overcome the inductive reactance. Therefore, induction motors, transformers and cables will all add to increase ϕ. In addition, variable speed drives that use waveform

'chopping' will also worsen the power factor due to the distortion of the current waveforms, in addition to adding harmonics to the system.

The effect of a low-power factor at the load is that more current is required to achieve the same power output, as can be seen from the power formulae.

The following is an example of the effect of low-power factor:

Required active power: 200 kW

Operating voltage: 415 V

Case 1: $PF = 0.85$

$$I = 200\,000 / (1.732 \times 415 \times 0.85)$$

$$= 327 \text{ A}$$

Case 2: $PF = 0.55$

$$I = 200\,000 / (1.732 \times 415 \times 0.55)$$

$$= 506 \text{ A}$$

It can be seen from the above example that power factor has a substantial effect on the magnitude of current flowing in the network.

A sustained low-power factor may have the following effects:

- Overheating of equipment due to the excess current flowing
- Equipment being over-rated to compensate for higher currents flowing due to low-power factor
- Higher electricity consumption when measured in VA
- Necessitate additional investment in system facilities to obtain the required kW
- Lower voltage level at the load (see Section 4.7)
- Increased power losses (resistive and reactive) throughout the system due to higher currents flowing.

Tariff example

Many countries' electricity utilities introduced a penalty charge for customers with low-power factor. Several countries have changed from a kW tariff to a kVA tariff for maximum demand. A low-power factor will have a direct influence on the amount of total kVA a company will use to obtain a certain amount of active kW power (kVA = kW + jkVAr [complex values]). The lower the power factor, the more VARs are consumed.

Therefore, a low-power factor will result in inefficient energy usage and an excessive energy bill. Some utilities penalize consumers if their pf is below 0.96 and others if below 0.80.

The client is then billed for a kVA maximum demand instead of a kW maximum demand.

Let us look at an example:

To simplify the calculation for illustration purposes, we assume average values.

A factory's average monthly maximum demand is 100 MW at a power factor of 0.65.

The power triangle for this situation is shown in Figure 4.12 (a).

For a power factor of 0.65 and real power (P) of 100 MW, the apparent power (S) is 153.846 MVA and reactive power (Q) is 116.913 MVAR [$P = S \cos \phi$; $Q = S \sin \phi$]. As can be noted, the reactive power in the network is of a higher value than the real power!

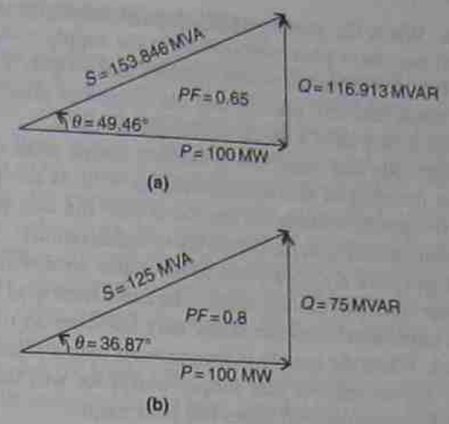


Figure 4.12
Example power triangle

Question 4.3 for course participants: The power factor needs to be higher than what value for the reactive power to be less than the real (active) power?

Referring to figure 4.12 (b), to increase the power factor to 0.8 would need 41 913 kVAR. Therefore, the factory would be charged $0.3757 × 30 × 41 913 = $472 401.42 over a month period, which could be avoided by increasing the power factor to 0.8! This should be more than enough economic justification to install power factor correction (PFC) equipment.

As a very rough approximation, the capital investment for PFC equipment can be taken as $250/kVAR on 11 kV. Therefore, to add –42 MVAR capacitive would mean a capital investment of $10.5 million, which would be paid back in approximately 22 months.

Approving power factor also have added benefits, like reduced active and reactive losses due to the reduction in the magnitude of currents flowing.

4.8 Caution: effect of shunt capacitors on induction motors

Capacitors installed close to induction motors can have the following effects:

- Increasing undesirable torque transients on the rotor
- Self-excitation and capacitive braking.

Torque transients

A short voltage interruption can cause severe torque peaks in the rotor of an induction motor. In the worst case, this can be more than 20 times the full load torque, and in the direction opposite to the rotation of the rotor. Under loaded conditions, this 'reverse torque' can easily cause severe mechanical damage to the rotor shaft.

The presence of capacitance in the system, especially power factor correction capacitors directly on the motor terminals, will worsen the condition substantially.

Explanation of 'reverse torque'

When a running motor is disconnected from the power supply, a trapped or 'frozen' flux is carried round with the rotor. This flux decays, but induces a rotational emf in the stator

windings. When the power supply returns while the rotor is still turning, the induced stator emf may have phase-opposition to the supply voltage at the instant of reconnection. This will cause severe transients currents and torque, depending on the magnitude of the induced stator emf still present and the degree of phase-opposition. The transient torque so developed may have a negative (retarding) peak.

The magnitude and direction of the first torque peak are closely dependent on the rotor speed and duration of the interruption, as well as the phase-angle between the induced emf and re-applied voltage. In the worst case the first peak may reach 15 times full load torque (without taking capacitance into consideration).

When capacitors are connected to the stator terminals for e.g. power factor correction, more severe transient effects occur. The capacitors tend to maintain the gap flux when the supply is interrupted, and the stator may build up an overvoltage in spite of the drop in rotor speed. When the supply is reconnected with a phase-opposition to the induced stator emf, very severe current and torque transients will occur. The resultant first transient torque peak may exceed 20 times full load torque.

Normally, the control voltage for the main contactor feeding an induction motor is transformed directly from the main supply voltage. The capacitors connected to the stator terminals will tend to keep the voltage level up during a power interruption, which will in turn keep the contactor coil energized, preventing the contactor from opening. Therefore, when the supply voltage comes back after a short period of time, it is directly applied to the stator, possibly opposing the induced emf already there.

To prevent connected shunt capacitors from worsening the torque transients during voltage interruptions, the capacitor(s) can be disconnected automatically during a severe voltage interruption.

The following is a graphical illustration of the transient torque occurrence (Figure 4.13):

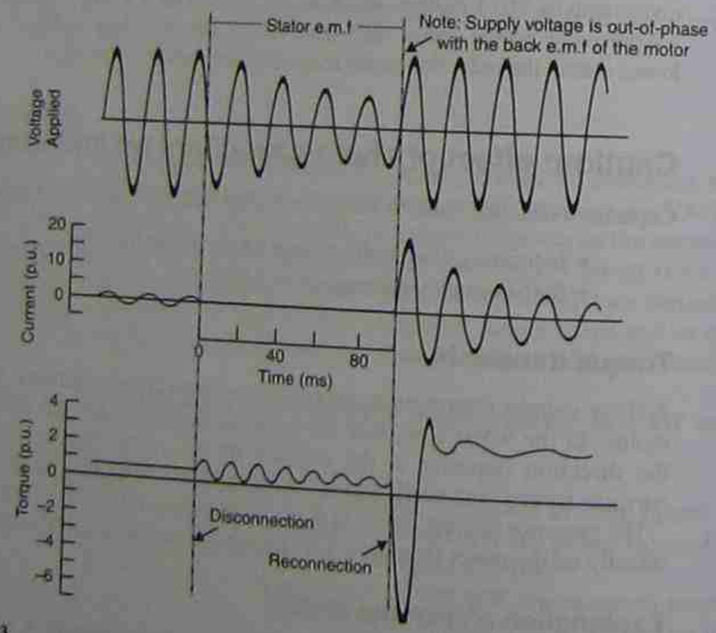


Figure 4.13
Transient torque

Self-excitation and capacitive braking

With the magnetizing reactive power provided by a capacitor bank, provided that the rotor has an adequate remnant field, an induction motor may self-excite upon the loss of stator supply. This results in the motor functioning as an induction generator, and stator overvoltages may occur. The capacitance value of power factor correction capacitors may have to be limited to prevent self-excitation.

Self-excitation may be purposely used under controlled conditions for braking. On disconnection of the stator from the supply and its subsequent connection to a capacitor bank, the stator voltages are self-excited to develop a travelling-wave field, and for a generating mode the 'synchronous' speed of the field must be lower than the speed of rotor rotation. The drive power is drawn from the inertia energy and the speed consequently falls rapidly.

However, for high-inertia loads that stay mechanically connected to the rotor shaft, forced braking may be undesirable and may even lead to rotor shaft damage.

5

Transformer theory

5.1 Transformer theory

Transformer is an essential device in electrical AC power distribution system, which is used to transform AC voltage magnitudes of any value obtained from a source to any desired value for the purpose of distribution and/or consumption. The development of power transformer dates back to 19th century. The main feature of a transformer is its constant *VA* rating whether referred to its primary side or the secondary side. With *VA* being constant (*V* refers to the voltage magnitude and *A* refers to the current magnitude in a transformer winding), it is possible to get a higher *V* with lower *A* or a lower *V* with a higher *A*, by choosing suitable ratio for the transformer.

The major benefit of such a device is its ability to take in the high current produced at relatively low voltage from the electrical generators and transform this power at a higher voltage level with lower current. This ensures that the power generated in the order of several megavolt amperes (MVA) is being transmitted at low current magnitudes in a cable of practical dimensions over very long distances. Today's transmission and distribution systems are heavily dependent upon this technology and transformers are used extensively throughout the world.

The standard transformer

A standard transformer typically consists of a pair of windings, primary and secondary linked together by a magnetic core. The windings can be connected in any of the following types, which in turn decides to which category a transformer belongs. There are two basic types of the transformer viz., (a) shell type and (b) core type. These are illustrated in Figure 5.1.

In Figure 5.1, the windings are the concentric portions and the white solid portions refer to the metallic part of a transformer (laminations), which either surround the windings (shell type) or where the windings surround the core (core type). The windings are normally made of electrolytic grade copper and the metallic parts are made of steel (usually special steel called lamination steel). The metallic part linking the windings is referred to as the magnetic core of a transformer. In these transformers the source will be connected to just one winding only, which is termed as the primary winding. The voltage will be induced magnetically through the magnetic core linking the flux in the core with the other winding (called the secondary winding), since it derives its power from the primary winding.



Figure 5.1
Transformer types

When an alternating current is applied to the primary winding, an alternating magneto motive force (mmf) is induced into the magnetic core and subsequently sets up an alternating flux passing through its body. This alternating flux in the core that links both the primary and secondary windings induces an electro motive force (emf) in both the windings. In the primary winding this emf is referred to as the back-emf and in an ideal situation, it would oppose the applied voltage to the primary windings such that there would be no flow of current (according to Lenz's law). However the impedance in the windings causes a low current to pass in the primary winding and the current that flows in the primary winding is termed as the transformer magnetizing current. In the open secondary winding, this induced emf is referred to as the secondary open-circuit voltage, which basically refers to the voltage measured between the two ends of the winding. Figure 5.2 depicts the vectorial representation of the voltages, flux and currents that flow in a simple single phase transformer neglecting its impedances. The descriptions of the parameters are identified on the left hand side, which will give a clear idea on the phase angle differences between the voltages, currents and flux in a typical single phase transformer windings and its core.

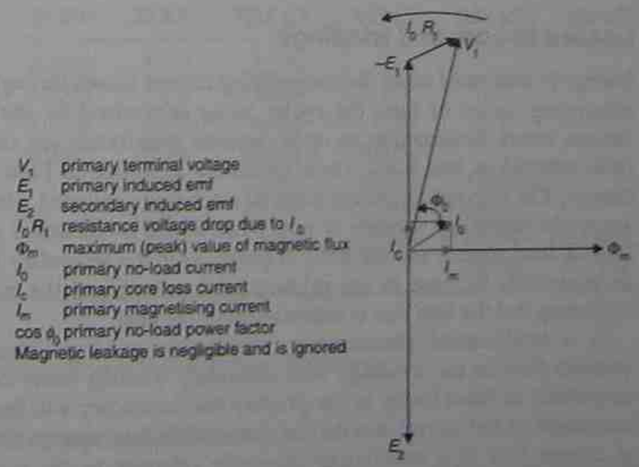


Figure 5.2
Phasor diagram for a single-phase transformer on open circuit

If a load is connected to the secondary winding across its two ends it will result in flow of current through the load, value of which depends upon the open circuit voltage across the secondary winding and the load impedance. This load current creates a demagnetizing mmf in the magnetic core upsetting the balance between the primary applied voltage and the already induced back-emf. To re-establish this equilibrium an additional current must be drawn from the primary supply source to provide an exactly equivalent mmf. Figure 5.3 shows the phasor diagram for a single-phase transformer supplying a pure resistive load, where the current I_2 in the secondary winding is in phase with its induced emf E_2 (unity power factor).

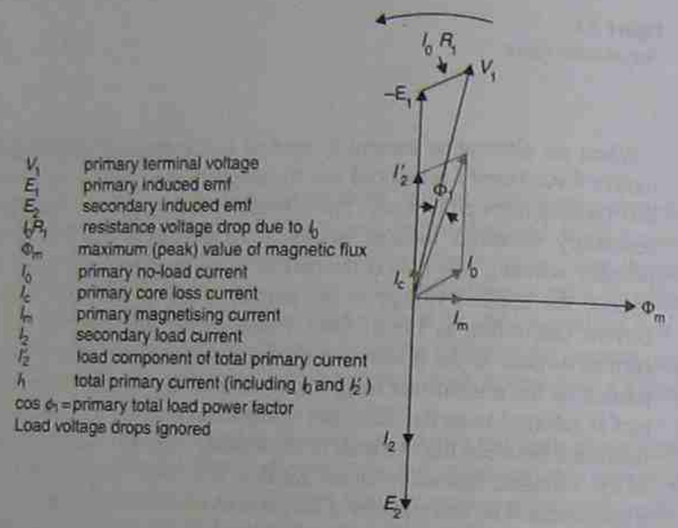


Figure 5.3
Phasor diagram for a single-phase transformer supplying a unity power factor load

Losses in core and windings

Energy is dissipated when the magnetizing current passes through the core in the form of alternating cycles of flux, the cycles being determined by the system frequency. The various losses dissipated in an open circuited transformer are core loss and no-load loss (also referred as iron loss). These losses are identified in Figure 5.3 above in terms of current. The iron loss is always constant since it is dissipated whether a load is connected across the secondary winding or not. When a load is connected across the secondary, the flow of load current and the mmf. It produces in the secondary winding are balanced by an equivalent increase in the primary load current and the mmf it produces, thereby indicating that the iron loss is independent of the load.

As a fundamental phenomenon, transformer windings also dissipate losses when currents flow in the windings with secondary winding being connected to a load. The magnitude of these losses in the primary and secondary windings will depend upon the magnitude of the current and the resistance of the total system. This is termed as load loss or copper loss of a transformer (basically referring to the losses in copper windings, though modern day transformer windings adopt materials other than copper).

As a fundamental electrical law, the losses in a conductor having resistance value R is I^2R where I is the current flowing through the conductor. In the same way, the total load loss in a transformer is found to be proportional to the square of the load current since the no-load current produces very negligible resistive loss in the windings.

Leakage reactance

It is not practically possible to ensure that all of the flux produced by the primary winding source is linked to the secondary winding. Due to limitations in the materials used and in the design of transformer cores some flux 'leaks' out of the core and flows through the air – this is termed leakage flux. It is convention to allocate half the leakage flux to both the windings, as it is difficult to quantify exactly the leakage flux contribution to the primary and the secondary windings.

So the transformer can be said to possess leakage reactance due to imperfect transformation between primary and secondary windings. Practically this is expressed as transformer impedance, since transformer windings also have resistance and this impedance is normally expressed as a percentage voltage drop in the transformer at full load current. Expressed mathematically this is:

$$V_z = \%Z = \left[\{I_{FL}\ Z\}/E\right] \times 100$$

Where:

I_{FL} is the full load current (either primary or secondary)

E = open-circuit voltage (either primary or secondary)

$Z = \sqrt{(R^2 + X^2)}$, R and X being the transformer resistance and leakage reactance respectively.

Typical impedance values for a medium-sized power transformer are about 9–10%. Occasionally transformers are deliberately designed to have impedances as high as 22.5%.

Table 5.1 lists typical impedance values for a range of standard transformer ratings, normally found in transmission and distribution systems.

Size MVA	Voltage Rating kV						
MVA	12 kV	33 kV	72.5 kV	145 kV	250 kV	300 kV	420 kV
0.5	4.75%	5.0%	5.5%				
0.8	4.75%	5.0%	6.0%				
5	4.75%	5.0%	6.0%	7.0%			
10	9.0%	9.0%	10.0%	10.0%			
20		10.0%	10.0%	15.0%	13.0%		
30		15.0%	15.0%	12.0%	13.0%		
60		12.0%	12.5%	12.5%	15.0%	15.0%	16.0%
100					16.0%	17.5%	18.0%

Table 5.1
Typical percentage impedance of 50 Hz three-phase transformers

Basic transformer equations

It is observed that the magnetic flux in a transformer core induces voltage in both the primary and secondary windings. Assuming a case where both primary and secondary winding have just one turn each with identical material it is simple logic that there can be no difference between

the voltage induced in both of these turns, whether it belongs to the primary or secondary winding. Hence it follows simply that the total voltage induced in each of the windings by the common flux must be proportional to the number of turns used in the respective windings. Thus, this establishes the well-known following relationship in a transformer:

$$E_1/E_2 = N_1/N_2 \tag{5.1}$$

and expressed in terms of power balance:

$$E_1 I_1 = E_2 I_2 \tag{5.2}$$

In terms of current balance,

$$I_1 N_1 = I_2 N_2 \tag{5.3}$$

Where E, I and N are the induced voltages, the currents and number of turns, respectively in the two windings, with suffix 1 denoting the primary winding parameters and suffix 2 denoting the secondary winding parameters. The other known term for IN is ampere turns of a transformer which is a constant factor for a transformer of a particular capacity.

Thus the voltage is transformed in proportion to the number of turns in the respective windings and the currents are in inverse proportion.

Faraday's law establishes that the magnitude of the induced voltage in a winding is proportional to the rate of change of flux linkage associated to the winding. Further Lenz's law proves that the polarity of the induced voltage is such as to *oppose* that flux linkage change if current were allowed to flow, and this is expressed as:

$$e = -N\left(\frac{\mathrm{d}\Phi}{\mathrm{d}t}\right)$$

In practical terms it can be shown that the voltage induced per turn of a winding is:

$$\frac{\mathrm{E}}{\mathrm{N}} = K\Phi_{\mathrm{m}} f \tag{5.4}$$

Where, K is a constant, Φ_m is the maximum value of total flux in Webers linking that turn and f is the supply frequency in hertz.

If the voltage is sinusoidal, K is 4.44 and equation (5.4) becomes:

$$\frac{E}{N} = 4.44 f \Phi$$

For design calculations, the same can be expressed in terms of volts per turn and flux density in the core:

$$\frac{E}{N} = 4.44\, B_{\mathrm{m}}\, A f \times 10^{-6} \tag{5.5}$$

Where

E/N = volts per turn, which is the same in both the windings (equation (5.1))
B_m = maximum value of flux density in the core, tesla
A = net cross-sectional area of the core, mm^2
f = frequency of supply, Hz

The above equation is basically used to decide the transformer construction parameters, voltages, number of turns, core area, etc.

Equivalent circuit

The above equations prove that there is a simple relationship between the primary and secondary windings in terms of voltage, current, etc. The above equations can be used to relate the impedance parameters to a common side, so that the whole transformer can be converted to a simple inductive circuit with an applied voltage, internal impedance and the current flow being determined by the load connected to the secondary side. In simple terms the circuit will look as shown in Figure 5.4.

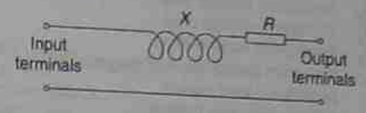


Figure 5.4
Simplified equivalent circuit of leakage impedance of two winding transformer

The transfer of primary impedance on to the secondary is done as follows:

Let Z_S = total impedance of the secondary circuit including leakage and load characteristics

Z'_S = equivalent value of Z_S when referred to the primary winding

Then

$$I'_2 = \left(\frac{N_2}{N_1}\right)(I_2) = \left(\frac{N_2}{N_1}\right)\left(\frac{E_2}{Z_s}\right) \text{ and } \quad E_2 = \left(\frac{N_2}{N_1}\right)(E_1)$$

So

$$I'_2 = \left(\frac{N_2}{N_1}\right)^2 \frac{E_1}{Z_S} \tag{5.6}$$

Also,

$$V_1 = E_1 + I'_2 Z_1$$

Where

$$E_1 = I'_2 Z'_S$$

Therefore

$$I'_2 = E_1 Z'_S \tag{5.7}$$

Comparing equations (5.6) and (5.7) it will be seen that $Z'_s = Z_s\ (N1/N2)^2$.

Transformers connected to load

The earlier clauses referred to characteristics of a transformer with a simple resistive load connected to the secondary resulting in secondary current to be in phase with its voltage. However in practical terms, the loads connected to a transformer are inductive in nature. Assume a transformer connected to a load of Z_2 across its secondary. In vectorial representation, Figure 5.5 shows the various parameters of a transformer, which is connected with an inductive load consisting both resistive and reactive components (*R* and *X*). The primary parameters are identified with suffix 1 while the secondary winding parameters are suffixed with 2.

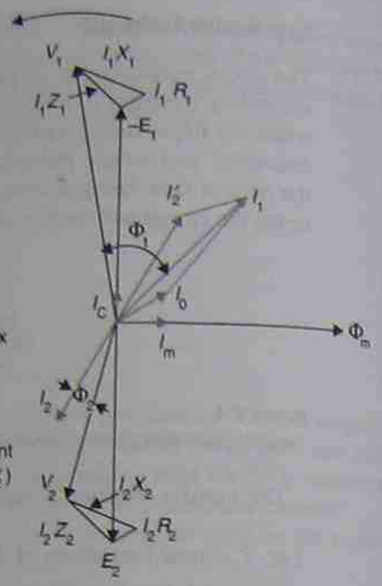


Figure 5.5
Phasor diagram for a single-phase transformer supplying an inductive load of lagging power factor cos Φ_2. Voltage drops divided between primary and secondary sides

It is to be noted that the basic phasor diagram still looks the same except for the lagging power factor introduced in the currents of both primary and secondary windings. In fact, the sum total effect is a reduction in the secondary terminal voltage. The drops due to primary resistance and leakage reactance can be converted in terms of the secondary voltage using the transformer equations. Figure 5.6 shows the phasor conditions where the resistance and leakage reactance drops are shown as occurring on the secondary side with all parameters transferred to secondary side adopting the transformer equations.

What happens when the load on the secondary is capacitive in nature? In fact, there will be a rise in the voltage as can be seen in Figure 5.7. This happens when a leading current passes through an inductive reactance (which is the transformer itself).

Preceding phasor diagrams have illustrated the relationship between the various voltages and currents and the phase angles between them for a single-phase transformer. These phasor diagrams are applicable for polyphase transformers too, except that there will be an angular difference between the parameters (phase difference of 120° between the phasewise parameters in a three-phase transformer). In all other respects, the individual phases emulate almost same type of characteristics as single-phase ones.

Rated quantities

As described in the initial paragraph, the transformer rating is specified in voltamperes indicating the amperes A can handle at a rated voltage V. Depending on the magnitude of power being transferred or handled, the transformer rating or output

can be expressed in MVA or in kilovoltamperes (kVA), and are determined by the following equations:

Single-phase transformers

Output = $E_2 \times I_2$ in VA
or $= (4.44 f \Phi_m N) \times I$
with the multiplier 10^{-3} for kVA and 10^{-6} for MVA.

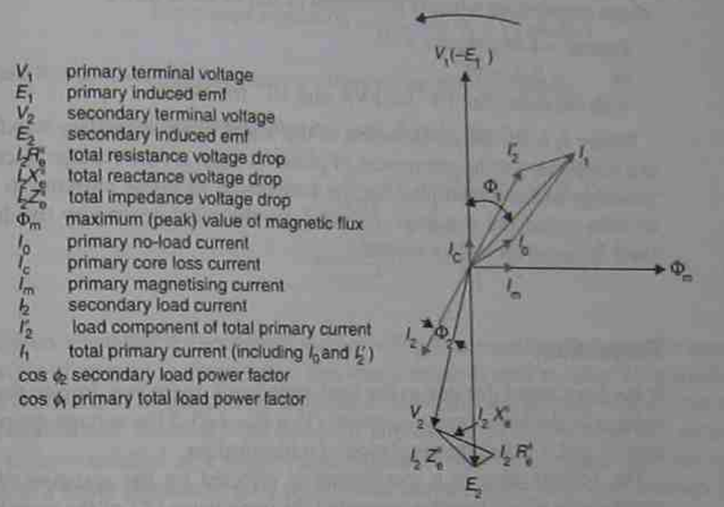


Figure 5.6
Phasor diagram for a single-phase transformer supplying an inductive load of lagging power factor cos Φ_2. Voltage drops transferred to secondary side

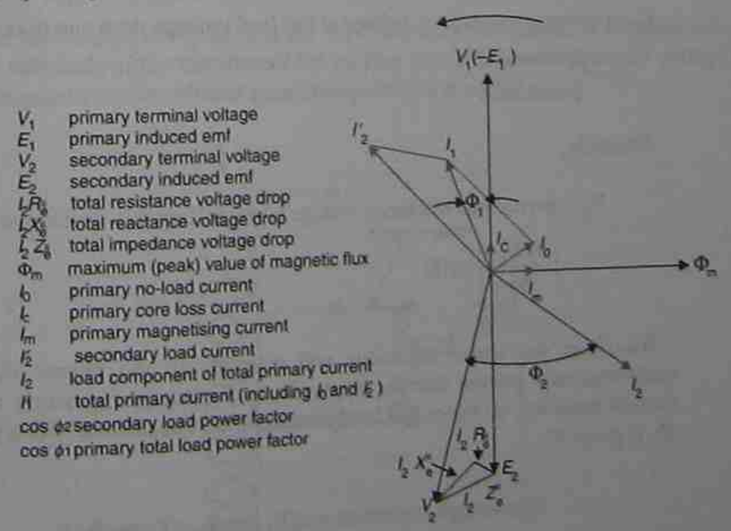


Figure 5.7
Phasor diagram for a single-phase transformer supplying a capacitive load of leading power factor cos Φ_2. Voltage drops on primary are transferred to secondary side

Three-phase transformers

A three phase transformer basically consists of three windings and is used to transmit the three-phase power produced by a generator. The three-phase transformer also has primary and secondary windings, same as a single-phase transformer, but the windings of each phase are separately wound and brought out for both primary and secondary with the primary terminals connected to the three-phase source. The three windings of the primary and secondary can be connected in the form of either star or delta. However in a three-phase transformer whether connected in star or delta form,

Output $= 4.44 f \Phi_m N I \times \sqrt{3}$

or $= E_2 I_2 \times \sqrt{3}$

with the multiplier 10^{-3} for kVA and 10^{-6} for MVA.

Where I_2 is the full-load current in the transformer secondary winding. The constant $\sqrt{3}$ is a multiplier for the conversion of phase voltage to line voltage in case of star-connected windings and is a multiplier for the conversion of phase currents to line currents in case of delta-connected windings. E_2 and I_2 are the rated secondary (no-load) voltage and the rated full-load secondary current.

Regulation

It has been noted that due to the load impedance, there is a drop in the secondary terminal voltage as the load current increases ($V_2 = E_2 - I_2 Z$). This voltage drop varies with the load current and is called the regulation of a transformer.

The voltage drop in a transformer is effected by the resistive (R) and reactive (X) components which together are called the impedance (Z) of the transformer.

The copper loss in a transformer is due to the resistive component when a load current passes through the windings. Hence,

V_R = percentage resistance voltage at full load (voltage drop due to resistive component)

$$= \frac{\text{copper loss} \times 100}{\text{Rated kVA}}$$

Similarly,

V_X = percentage reactance voltage (voltage drop due to reactive component)

$$= \left(\frac{I_2 X_e'}{V_2} \right) \times 100$$

Based on the above equations and referring to the phasor diagrams, it can be mathematically proven that the approximate percentage regulation at a particular load current equalling 'a' times full load current of the transformer with a power factor of $\cos \Phi_2$ is given by:

$$\text{Percentage regulation} = a(V_R \cos \Phi_2 + V_X \sin \Phi_2) + \frac{a^2}{200}(V_X \cos \Phi_2 - V_R \sin \Phi_2)^2 \quad (5.8)$$

The percentage regulation that occurs at the secondary terminals, at unity power factor load ($\cos \Phi_2 = 1$ and $\sin \Phi_2 = 0$ may be calculated by simplifying the above equations as below:

$$\frac{\text{Copper loss} \times 100}{\text{output}} + \frac{(\text{percentage reactance})^2}{200}$$

This value is always positive and indicates a voltage drop with load.
For transformers having low reactance values up to about 4%, this can simplify to:

$$\text{Percentage regulation} = a(V_R \cos \Phi_2 + V_X \sin \Phi_2) \quad (5.9)$$

For transformers with high reactance values about 20% and above:

$$\text{Percentage regulation} = a(V_R \cos \Phi_2 + V_X \sin \Phi_2) + \frac{a^2}{2 \times 10^2}(V_X \cos \Phi_2 - V_R \sin \Phi_2)^2 + \frac{a^4}{8 \times 10^8}(V_X \cos \Phi_2 - V_R \sin \Phi_2)^4 \quad (5.10)$$

It had been noted that the secondary voltage will get increased by increasing its number of turns ratio with respect to the primary. This characteristic is used to offset the regulation in a loaded transformer. The transformer is provided with additional winding with suitable taps for external connection. Normally this provision is made on the high-voltage side to keep the current to be controlled at a lower value. Whenever there is a voltage drop, the taps are changed to a lower position to get a proportional increase in the turns ratio between primary and secondary so that a higher voltage can be obtained on the secondary side.

On-load tap changers

On-load tap changers (Figure 5.8) are very necessary to maintain a constant voltage on the LV terminals of the transformer for varying load conditions where the voltage had to be maintained constant without interrupting the power supply.

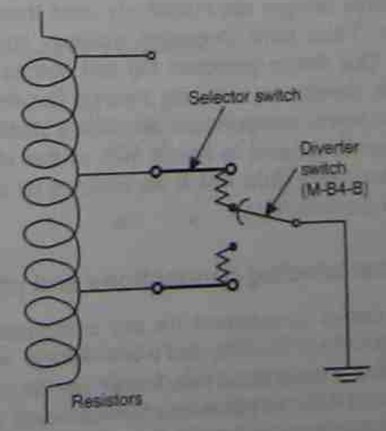


Figure 5.8
On-load tap changer

This is achieved by providing taps as shown below on the HV winding. The diverter switch is controlled by a motor which ensures that the switch is stepped up or down from one tap to the next taps until the desired secondary voltage is obtained.

The ranges are normally chosen depending upon the input supply conditions also. A typical range of taps could be +15% to –5% giving an overall range of 20% as shown in Figure 5.9.

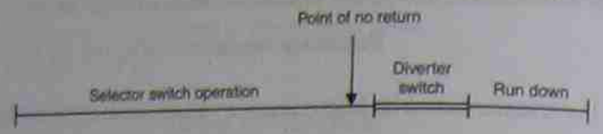


Figure 5.9
Tap changer range of operations

The tap changer is usually mounted on a separate tank to the main tank.

The tap changing can also be done by disconnecting the source (or load) by using off-circuit tap switch, which necessarily requires an interruption in power supply to the load. The off-circuit tap switch is manually changed from one step to another depending on the input conditions. It is a well-accepted practice to provide off-circuit taps from –5% to +5% in steps of 2.5% (total five steps).

The on-load changer which is comparatively costlier is adopted in case of larger and important transformers mostly in continuous process industries, whereas off-circuit change is adopted in the case of almost all smaller distribution or auxiliary transformers.

5.2 Transformer design applications

In shell-type transformers, the flux-return paths of the core are external to, and enclose the windings (refer Figure 5.1 for a three-phase shell-type transformer). The shell-type arrangement provides intrinsically better magnetic shielding that is well suited for supplying power at low voltages and heavy currents. This design is widely used in arc furnace transformers.

The core-type designs are extensively used throughout the world for other types of transformers. These have concentric windings around the various limbs as shown in Figure 5.1. This design possesses top and bottom yokes of cross-section equal to the wound limbs, thereby not requiring separate flux-return paths. In the event of very large transformers, where transportation becomes a problem, the cross-section of the top and bottom yokes are reduced to almost 50% of that of the wound limbs. This necessitates additional flux-return paths which are achieved by adopting five-limb transformer design illustrated in the same figure.

Transformer winding connections and phasor relationships

The most common arrangement for any transformer is to have only two windings per phase, a high-voltage winding and a low-voltage winding (primary and secondary). As already noticed, a three-phase transformer can have its windings connected either in star or in delta with 120° displacement between each phase supply (see Figures 5.10 and 5.11). The following paragraphs explain the different characteristics of transformers depending upon the connection method adopted.

Depending on the method chosen for the primary and the secondary connections, a phase-shift can take place through the transformer from primary to secondary (Figure 5.12).

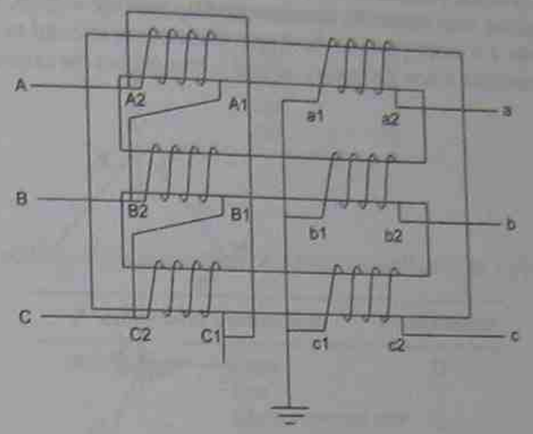


Figure 5.10
Physical connection of delta (D) or star (Y) configuration

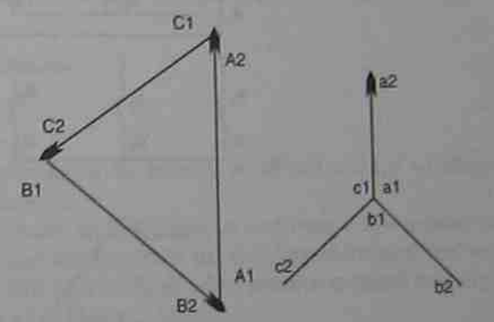


Figure 5.11
Vectorial representation of delta and star configuration

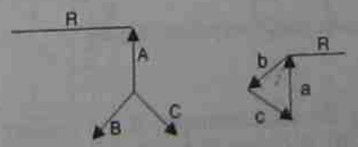


Figure 5.12
30° phase shift of transformer

Figure 5.13 shows the consolidated phase shift phenomenon of a two-winding three-phase transformer, when one winding is delta connected and the other is star connected (A-B-C refer to primary terminals and a-b-c refer to secondary terminals).

In the example shown, the phase shift of secondary winding is 30° with respect to the corresponding primary winding, i.e. the a-n voltage lags A-N by 30°, b-n voltage lags

B-N by 30° and so on. The vector diagram is considered analogous to a clock whose hour hands also rotates 360° same as the full cycle of a vector. Considering a clock with 12+1 positions, each hour position corresponds to 30° shift when you start looking after the 12 o'clock position. Hence the above connections achieve an equivalent of 1 o'clock position with respect to its corresponding primary voltage. This connection is referred to as the 1 o'clock position. In simple terms this is referred to as Dyn1 (small n represents connection where secondary neutral is brought out for external connection).

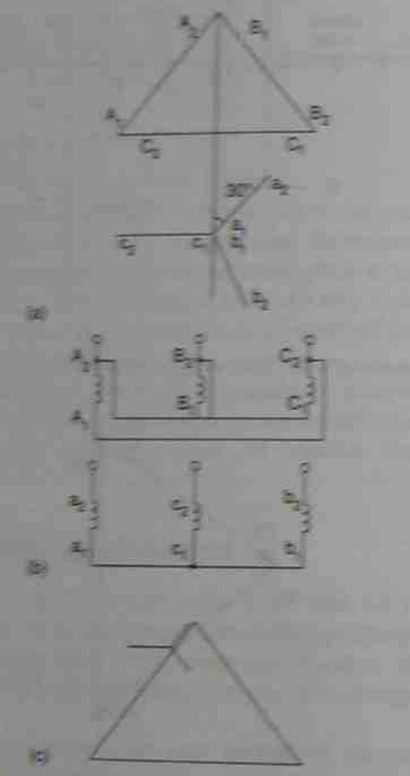


Figure 5.13
Winding connections, phasor and polarity diagram

Considering the same example, if the primary delta connection had been made by connecting A_1B_2, B_1C_2 and C_1A_2 this would have resulted in a phase displacement of 30° anticlockwise on the secondary side, i.e. the 11 o'clock position. This type of connection is termed as Dy11 (or Dyn11).

In a similar way the transformer winding connections can be expressed in different ways. For example:

YNd1 = HV winding connected in star with primary neutral (capital N) brought out.

LV winding connected in delta.

Phase shift 30° from 12 to 1o'clock.

Table 5.2 lists the various group numbers that transformer phasors can be categorised, representing the induced emfs and the counter clockwise direction of rotations.

Group Number	Phase Displacement	Clock Hour Number
I	0°	0
II	180°	6
III	−30°	1
IV	+30°	11

Table 5.2
Group numbers

Inter-phase connections of the HV and LV windings are indicated in Table 5.3.

Winding Connection		Designation
High voltage	Delta	D
	Star	Y
	Interconnected star	Z
Low voltage	Delta	d
	Star	y
	Interconnected star	z

Table 5.3
Winding connection destinations

Winding polarity

International standards define the polarity of the HV and LV windings sharing the same magnetic circuit as follows.

If the core flux induces an instantaneous emf from a low-number terminal to a high-number terminal in one winding, then the direction of induced emf in all other windings linked by that flux will also be from a low-number terminal to a high-number terminal (A1 to A2 and a1 to a2 in Figure 5.14).

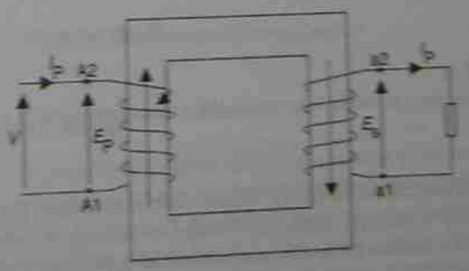
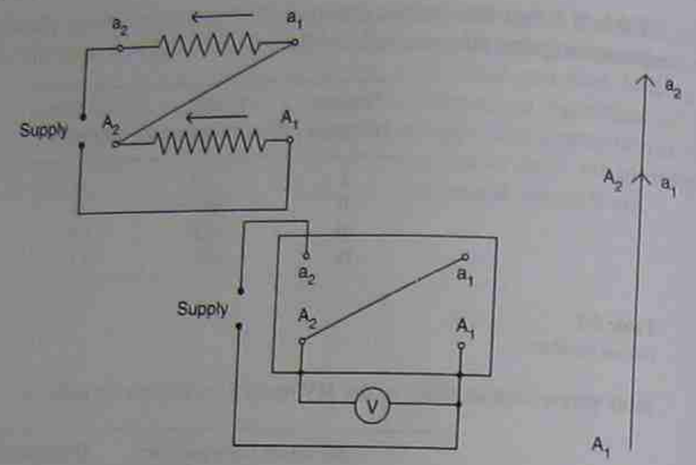


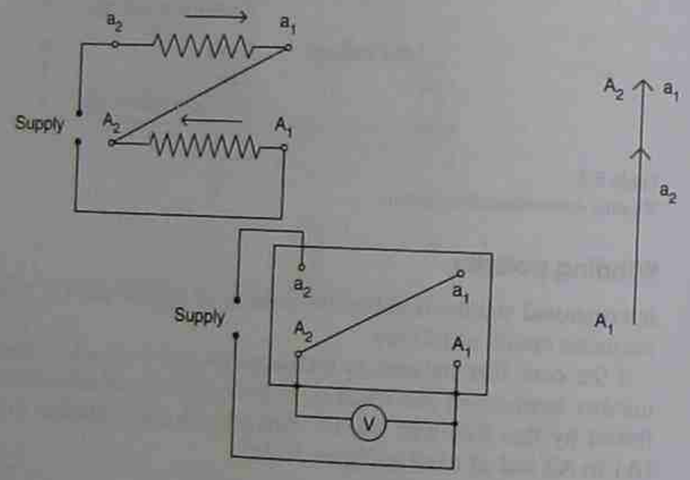
Figure 5.14
Principle of operation of a transformer

From the laws of induction, it will be seen that the current flow in the windings is in the opposite direction.

Figure 5.15 illustrates the testing connections and method to determine the polarity of a transformer.



(a) Subtractive polarity



(b) Additive polarity

Figure 5.15
Test connections for determining single-phase transformer winding polarity

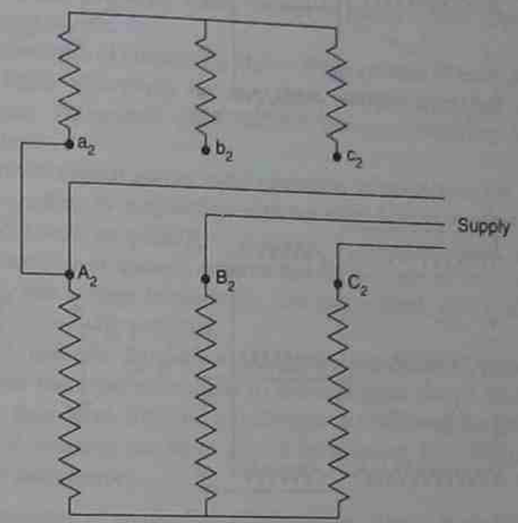
The connections basically require interconnecting the phase terminals of primary and secondary windings, applying voltage to one set of winding and measuring the voltage across the various terminals caused by the induction phenomenon. As is evident from the diagrams, if the voltage measured across A_1–A_2 is less than the voltage measures across A_1–a_2 then the polarity is said to be subtractive, and if it is greater than, then the polarity is additive.

Figure 5.16 illustrates the test connections for a three-phase star/star-connected transformer with subtractive polarity.

Polarity forms an important requirement for connecting the current transformers in the transformer windings to ensure that the current is sensed in the correct direction of flow

before deciding the fault conditions for tripping purposes. Figure 5.17 shows how the phase relationships and the polarities can undergo changes depending upon the phase sequence followed in the primary connections and changing the star point on the secondary side.

These changes can have different effects on the relays being connected and their operation.



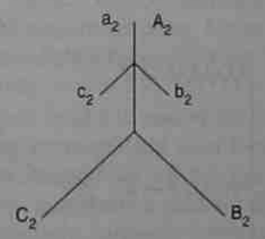


Figure 5.16
Test connections for determining three-phase transformer winding polarity

Transformer grounding

Earthing is a major requirement in most electrical systems to limit the fault currents, and transformers being the prime source of power distribution, the earthing of transformers takes utmost priority in a system. It is obvious that the transformers shall have a neutral reference point for the three phases so that this point can be connected to earth. As a consequence, it is convenient to have most three-phase transformer windings in a star-connection that provides a neutral that could be connected to earth. This connection to earth could be direct or through a current limiting resistor, or other similar devices. Earthing of system neutrals primarily falls in to three categories:

1. Solidly earthed neutral
2. Earthing via an impedance
3. Isolated neutral (unearthed).

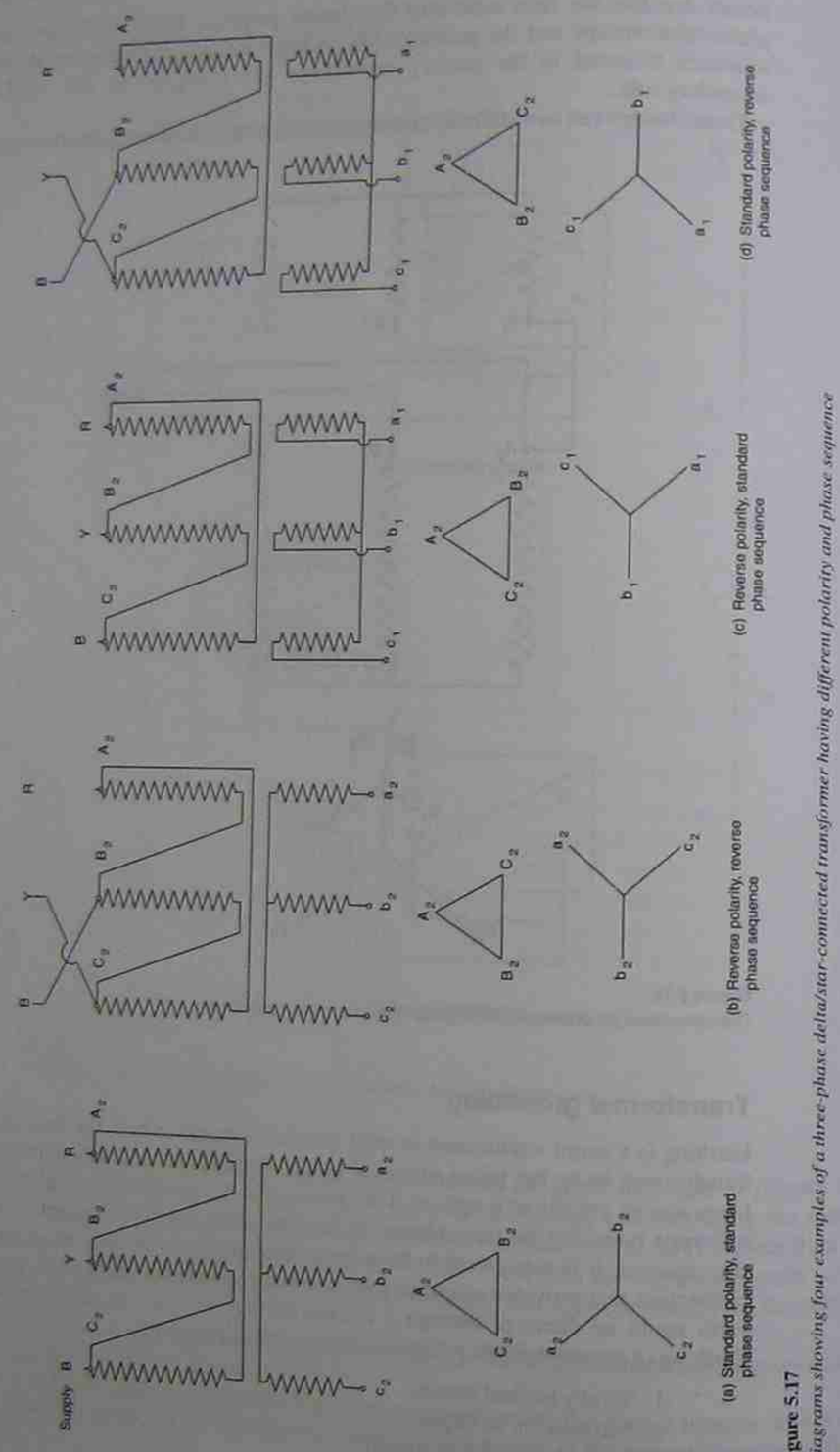


Figure 5.17
Diagrams showing four examples of a three-phase delta/star-connected transformer having different polarity and phase sequence

The third alternative is rarely seen due to the problems and disadvantages associated with an isolated earth. The method of earthing low-voltage and high-voltage electrical systems differ. The definitions of high voltage and low voltages would differ from country to country and even region to region, but in practice, usually any system over 50 V but not exceeding 1000 V is considered a low-voltage system. The low-voltage systems' neutrals are required to be solidly connected to earth and no impedance shall be inserted in any connection with earth, except in cases where they are required for operation of switchgear, etc.

Some of the advantages of connecting high-voltage systems to earth are:

- Earth faults effectively become short circuits from line to neutral thereby protecting equipment from serious damage occurring from high-voltage oscillations.
- An earthed neutral allows rapid operation of protection the instant earth faults occur, working in conjunction with sensitive fault protection devices, to isolate the faulty sections quickly.
- Solid earthing of neutrals ensures that the voltage of any live conductor never exceeds the voltage between the line and neutral, effectively maintaining the neutral at zero volt potential.
- Earthed neutrals provide added protection against capacitance effects on overhead lines that are subject to induced static charge from adjacent charged clouds, dust, sleet, fog, rain and changes in altitude of the lines.
- The HV winding can have graded installation; thus making the transformer smaller and cheaper.

The only disadvantage of connecting a high-voltage system to earth is that it introduces susceptibility to earth faults. This is particularly inconvenient for long overhead transmission lines in lightning prone areas, but as this phenomenon is only transient in nature, and is cleared immediately following a trip, this disadvantage is far outweighed by the advantages listed above.

An earth fault condition is also a reason for flow of third harmonic currents in an electrical system and higher magnitude third harmonics are undesirable. However the third harmonics can be eliminated if a separate path could be created for the flow of third harmonic currents. Hence to provide a path for the third harmonic currents in order to eliminate or attenuate the third harmonic voltages, it is also desirable to have a delta-connected three-phase system. Considering the need for grounding and the need to eliminate third harmonics, in most three-phase step down transformers it is convenient to have the high-voltage (HV) winding delta-connected and the low-voltage (LV) winding star-connected, with the neutral earthed.

Different methods of earthing neutrals

It is important that the neutral of a power system be earthed; otherwise, this could 'float' all over with respect to true ground, thereby stressing the insulation above its design capability.

On HV systems (i.e. 6 kV and above) it is common practice to effectively earth the neutral by means of a solid bar of copper (Figure 5.18).

This has the advantage that when an earth fault occurs on one phase, the two healthy phases remain at phase-to-neutral voltage above earth. This allows insulation of the transformer windings to be graded toward the neutral point, resulting in a significant saving in cost. In addition, all other primary plant need only have phase-to-neutral insulation and surge arrestors in particular need only be rated for 80% line-to-line voltage. This provides an enormous saving in capital expenditure and explains why utilities HV system is invariably solidly earthed.

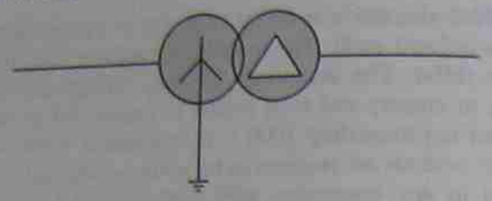


Figure 5.18
Earthing of the neutral

The disadvantage is that when an earth fault occurs, an extremely high current flows (approximately equal to three-phase fault current), stressing the HV windings both electromagnetically and thermally, the forces and heat being proportional to the current squared.

Earthing of the LV system can be achieved as in Figure 5.19.

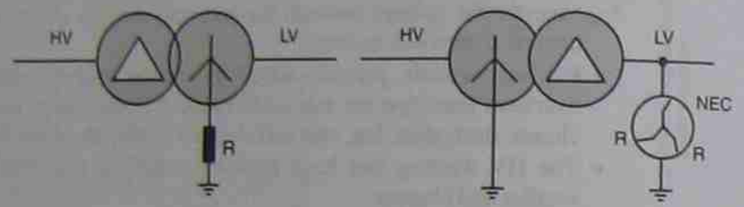


Figure 5.19
Earthing of the LV system

It will be noted that the LV system is impedance and/or resistance earthed. This allows the earth fault current to be controlled to manageable levels, normally of the order of the transformer full load current, typically 300 A.

Here, the transformer does not get a shock on the occurrence of each earth fault, however, the phase conductors now rise to line potential above earth during the period of the earth fault (Figure 5.20). It is recommended to use neutral earthing resistor (NEC/R) to limit severe overvoltages in the healthy phases of a single phase faulted system by damping the oscillations. The idea is supported and encouraged by SABS 0200 and IEEE standard 142.

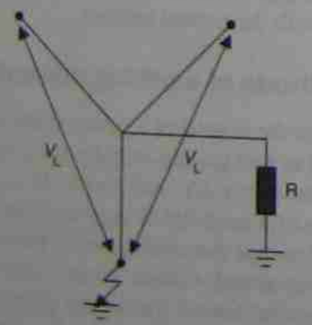


Figure 5.20
Phasor diagram illustrating phase conductors rising to phase voltage on fault

Phase-to-earth insulation of all items of primary plant must therefore withstand line-to-line voltage.

There is a case where the secondary of a transformer is delta connected without neutral. These types of transformers can be connected in the following way (Figure 5.21) as shown in Figure 5.13 for earthing purposes.

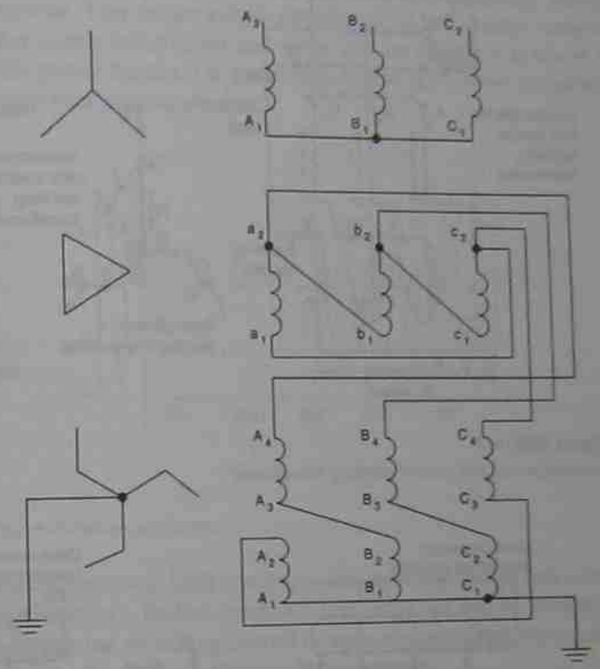


Figure 5.21
Transformer with delta secondary and interconnected star earthing transformer with a neutral connected to earth

The criterion that is to be considered is to decide whether to have a solid connection of the system neutral to earth or to introduce impedance in the circuit to earth. The value of the impedance must be such that the total current flow to earth is limited thereby limiting the amount of damage caused at the point of the earth fault. In keeping with this, Figures 5.22 and 5.23 illustrate two different methods of providing an earthed neutral to a star/delta transformer. Each offers two possibilities of providing earthing resistors and an artificial neutral for the delta windings that normally do not possess one.

In one case only one resistor is required that is designed to carry the total fault current to earth, while being insulated for the total phase voltage of the system. On the other hand, in the event of a fault, the neutral of the transformer will rise above the earth potential, equal to the potential drop across the earthing resistor, and the transformer windings will have to be insulated for the full line voltage above earth.

Alternatively in order to avoid sudden high-voltage changes in the insulated windings which is the most vulnerable component of the equipment, the second option should be chosen of installing suitably sized resistors between the lines and the earthing transformer

rather than between the neutral and earth. In doing so the purpose of current limiting is achieved and in addition the neutral of the earthing transformer remains at earth potential and the windings are not subjected to any high voltages.

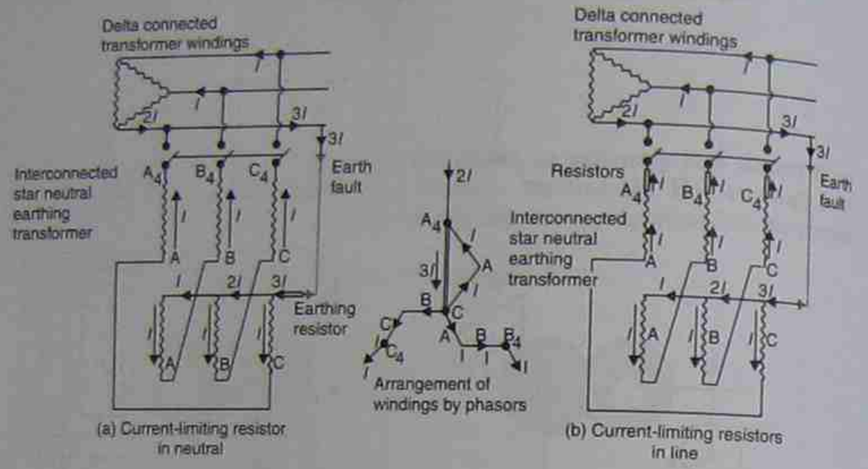


Figure 5.22
Interconnected star neutral earthing transformer

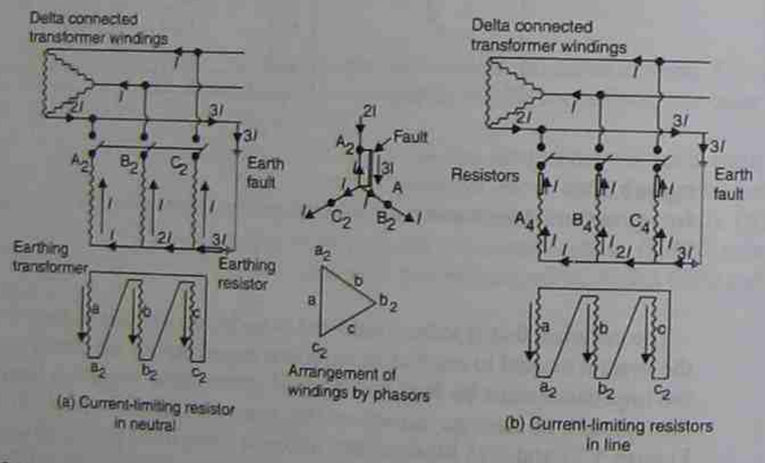


Figure 5.23
Three-phase, star/delta neutral earthing transformer

The value of these earthing resistors may be calculated simply by applying Ohm's law:

$$I = \frac{V\sqrt{3}}{Z_N}$$

$$Z_N = \frac{V\sqrt{3}}{I}$$

Frequently used devices for earthing high-voltage neutrals are the liquid neutral earthing resistor (LNER), and are capable of withstanding currents up to 1500 A for about 30 s. This type of resistor required regular maintenance like topping up of the electrolyte and maintaining its strength and fluidity in extreme winters by employing heaters, etc. To overcome this shortcoming, solid metal resistors may be used: of course this flexibility does come with additional costs.

As an alternative to earthing resistors and the associated problems, many substations use an arc suppressor. This device called a Petersen coil is a reactor connected between the neutral of the supply transformer and earth, and its reactance is tuned to match the capacitance of the power system it is protecting. Figure 5.24 shows a typical oscillogram of voltage recovery after arc suppression.

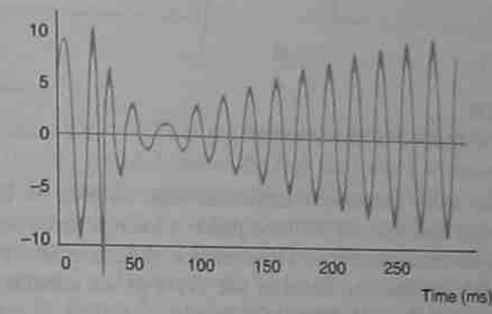


Figure 5.24
Recovery voltage after initial arc extinction

In the event of a sustained fault condition, the arc suppression coil allows the power system to be operated in a faulted condition until the fault can be located and removed. Nowadays solid-state tap switching control devices are employed in conjunction with arc suppression coils to achieve more efficient compensation.

In some instances when the high-voltage winding is common with the low-voltage winding for economic advantages, such a type of transformer is known as an autotransformer. These are most exclusively used to interconnect very high-voltage systems. Three-phase autotransformers are invariably star/star-connected and their use requires that the systems that they interconnect are able to share a common earthing arrangement (Figure 5.25).

Transformers with tertiary windings

It is most common to come across transformers with a third winding called tertiary winding in addition to primary and secondary windings. This is adopted in large size transformers in power stations and large switching substations. The most common reason for the additional third set of windings to a three-phase transformer is for the provision of a delta-connected tertiary winding to provide path for the third harmonics. Other reasons are:

- To limit the fault level on the LV system by subdividing the infeed – i.e. double secondary transformers
- The interconnection of several power systems operating at different supply voltages
- The regulation of system voltage and of reactive power by means of a synchronous capacitor connected to the terminals of one winding.

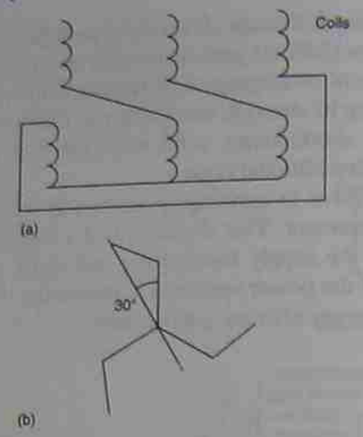


Figure 5.25
Interconnected star winding arrangement

As has been mentioned earlier in this chapter, it is desirable that a three-phase transformer has one set of three-phase windings delta-connected, thus providing a path for third harmonic currents. The presence of delta-connected windings also allows current to circulate around the delta in the event of an unbalance in the loading between the phases, so that this unbalance is reduced.

If the neutral of the supply and the star-connected winding are both earthed, then although the transformer output wave form will be undistorted, the circulating third-order harmonic currents flowing in the neutral can cause interference with telecommunications circuits and other electronic equipment. Further it can cause unacceptable heating in any neutral earthing resistors, so this provides an added reason for the use of a delta-connected tertiary winding.

If the neutral of the star-connected winding is unearthed then, without the use of a delta tertiary, this neutral point can oscillate above and below earth at a voltage equal in magnitude to the third-order harmonic component. Because the use of a delta tertiary prevents this, it is sometimes referred to as a stabilization winding.

The load currents in the primary phases corresponding to a single-phase load on the secondary of a star/star transformer with a delta tertiary are typically as shown in Figure 5.26 assuming a one-to-one turns ratio for all windings.

This leads to an ampere-turns rating of the tertiary approximately equal to one-third that of the primary and secondary windings and provides a rule-of-thumb method for rating the tertiary in the absence of any more specific rating basis.

Double secondary transformers

This is another type of multiwinding transformers where it is required to split the number of supplies from a HV feeder to economize on the quantity of HV switchgear and at the same time limit the fault level of the feeds to the LV switchgear.

In designing the double secondary transformer, it is necessary that both LV windings are disposed symmetrically with respect to the HV winding so that both have identical impedances to the HV. The two possible arrangements to achieve this, is as shown in Figure 5.27 (both instances there is a crossover between the two LV windings half way up the limb).

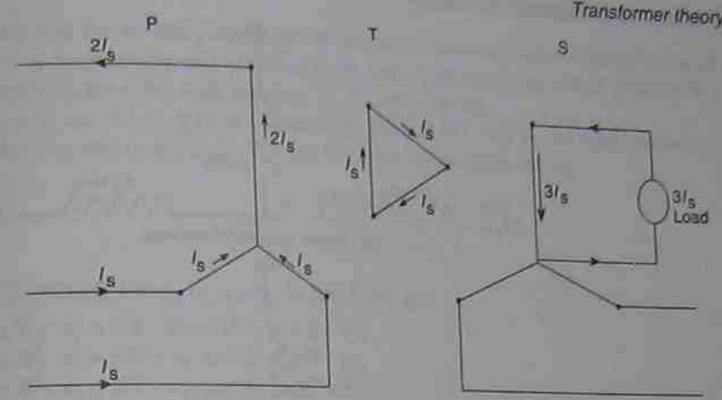


Figure 5.26
Single-phase load to neutral

The leakage reactance LV_1 to LV_2 in the first case would be high as the LV windings of Figure 5.27(a) are loosely coupled due to the fact the inner LV upper half crosses to the outer upper half and the inner lower half crosses to the outer lower half.

The leakage reactance LV_1 to LV_2 in the second case would be low as the LV windings of Figure 5.27(b) are closely coupled due to the fact the upper inner crosses to lower outer and upper outer crosses to lower inner. Thus, the equivalent circuits for these two arrangements are as in Figure 5.28 wherein the transformer is represented by a three-terminal network and typical values of impedance (leakage reactance) are marked.

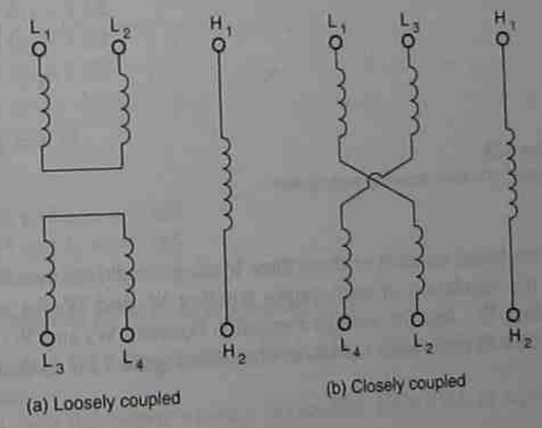


Figure 5.27
Transformers with two secondary windings

General case of three-winding transformer

The basic voltage for each winding and any combination of loading is the no-load voltage obtained from its turns ratio. In considering the case of two output windings W_2 and W_3, and one input winding W_1 as shown in Figure 5.29, there are three possibilities of loading conditions:

W_2 only loaded
W_3 only loaded
W_2 and W_3 both loaded

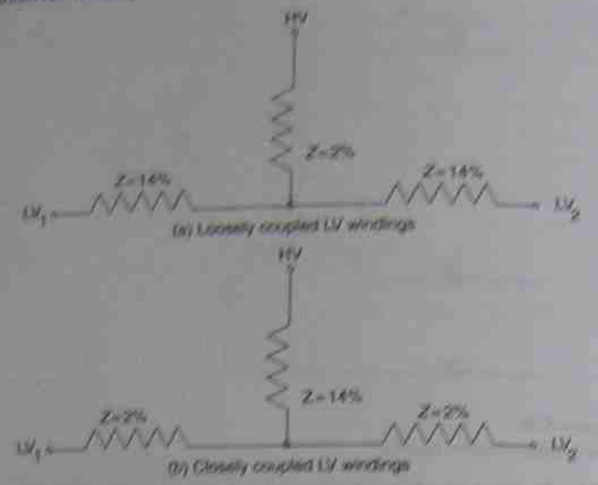


Figure 5.28
Equivalent circuits for loosely coupled and closely coupled double secondary transformers



Figure 5.29
Diagram of a three-winding transformer

Now based on each of these three loading conditions two separate values are calculated viz. the regulation of each output winding W_2 and W_3 for a constant voltage applied to winding W_1, and the voltage regulation between W_2 and W_3 relative to each other. From this data an equivalent circuit, as shown in Figure 5.30, is derived as follows:

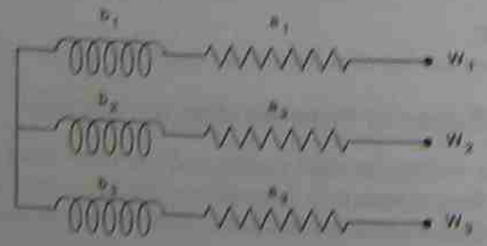


Figure 5.30
Equivalent circuit of a three-winding transformer

Let a_{12} and b_{12} be the percentage of resistance and reactance voltage referred to the basic kVA respectively and obtained from test, short circuiting either winding W_1 or W_2 and supplying the other with winding W_3 on open circuit.

Similarly, a_{23} and b_{23} by test to windings W_2 and W_3 with W_1 on open circuit, similarly, a_{31} and b_{31} by test to windings W_3 and W_1 with W_2 on open circuit.

$$d = (a_{12} + a_{23} + a_{31}), \text{ and}$$

$$g = (b_{12} + b_{23} + b_{31})$$

Then calculating for a_1, a_2, a_3, b_1, b_2 and b_3 we get:

Arm W_1: $a_1 = d/2 - a_{23}$ and $b_1 = g/2 - b_{23}$
Arm W_2: $a_2 = d/2 - a_{31}$ and $b_2 = g/2 - b_{31}$
Arm W_3: $a_3 = d/2 - a_{12}$ and $b_3 = g/2 - b_{12}$

The regulation with respect to the terminals of any pair of windings is the algebraic sum of the regulations of the corresponding two arms of the equivalent circuit.

Following is an example calculation of voltage regulation of a three-winding transformer given:

W_1 is a 66 000 V primary winding

W_2 is a 33 000 V output winding loaded at 2000 kVA and having a power factor $\cos \Phi_2 = 0.8$ lagging.

W_3 is an 11 000 V output winding loaded at 1000 kVA and having a power factor $\cos \Phi_3 = 0.6$ lagging.

In addition, the following test data is also available, related to a basic loading of 1000 kVA.

$a_{12} = 0.26$ and $b_{12} = 3.12$
$a_{23} = 0.33$ and $b_{23} = 5.59$
$a_{31} = 0.32$ and $b_{31} = 5.08$

Hence
$d = 0.91$ and $g = 9.79$

Then for

W_1: $a_1 = 0.125$ and $b_1 = +3.305$
W_2: $a_2 = 0.135$ and $b_2 = -0.185$
W_3: $a_3 = 0.195$ and $b_3 = +5.775$

The effective full-load kVA input to winding W_1 is:

1. With only the output winding W_2 loaded, 2000 kVA at a power factor of 0.8 lagging
2. With only the output winding W_3 loaded, 1000 kVA at a power factor of 0.6 lagging
3. With both the output windings W_2 and W_3 loaded, 2980 kVA at a power factor of 0.74 lagging.

Applying expressions (5.9) or (5.10) separately to each arm of the equivalent circuit, the individual regulations have, in

W_1 under condition	(i)	where $n_1 = 2.0$, the value of 4.23%
W_1 under condition	(ii)	where $n_1 = 5.0$, the value of 2.72%
W_1 under condition	(iii)	where $n_1 = 2.98$, the value of 7.15%
W_2		where $n_2 = 2.0$, the value of –0.02%
W_3		where $n_3 = 5.0$, the value of 5.53%

Summarizing these calculations, therefore the total transformer voltage regulation has:

1. With output winding W_2 fully loaded and W_3 unloaded
   At the terminals of winding W_2, the value of $4.23 - 0.02 = 4.21\%$
   At the terminals of winding W_3, the value of $4.23 + 0 = 4.23\%$
2. With output winding W_2 unloaded and W_3 fully loaded
   At the terminals of winding W_2, the value of $2.72 + 0 = 2.72\%$
   At the terminals of winding W_3, the value of $2.72 + 5.53 = 4.25\%$
3. With both output windings W_2 and W_3 fully loaded
   At the terminals of winding W_2, the value of $7.15 - 0.02 = 7.13\%$
   At the terminals of winding W_3, the value of $7.15 + 5.53 = 8.68\%$.

Terminal markings of transformers

To ensure proper design and installation, individual phase windings are given descriptive letters and the same letter in combination with suffix numbers is then used for all windings of one phase. The HV windings are given upper case letters and the LV windings are given lower case letters for corresponding phases.

Thus for single-phase transformers:

A : for the HV winding
3A : for the third winding (if any)
a : for the LV winding

For two-phase windings on a common core or separate cores in a common tank:

AB : for the HV windings
ab : for the LV winding

For three-phase transformers:

ABC: for the HV winding
abc : for the LV winding

Figure 5.31 shows the standard markings of a single-phase transformer.

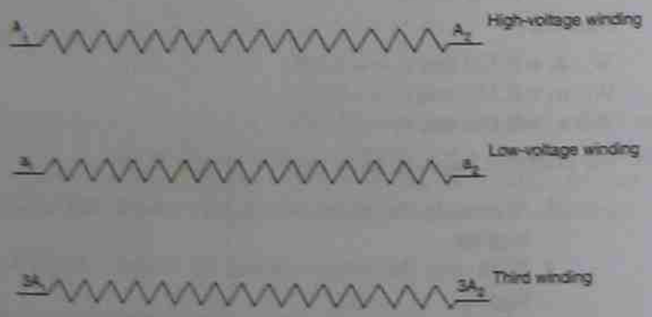


Figure 5.31
Terminal marking of a single-phase transformer having a third winding

Figure 5.32 shows the relative mar kings of a two winding transformers.

In addition to the letters marking the terminals, suffix numbers are given in sequence, relative to the direction of the induced emf, on all the tapping points and the ends of the winding. In the case of three-phase star-connected transformers, A_1 would be connected to the star's neutral point and the A_2 would be the line terminal. Figure 5.33 illustrates typical terminal markings of tappings.

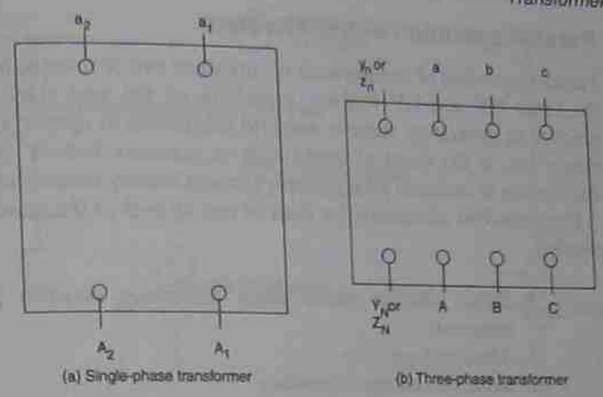


Figure 5.32
Relative position of terminals of two-winding transformers

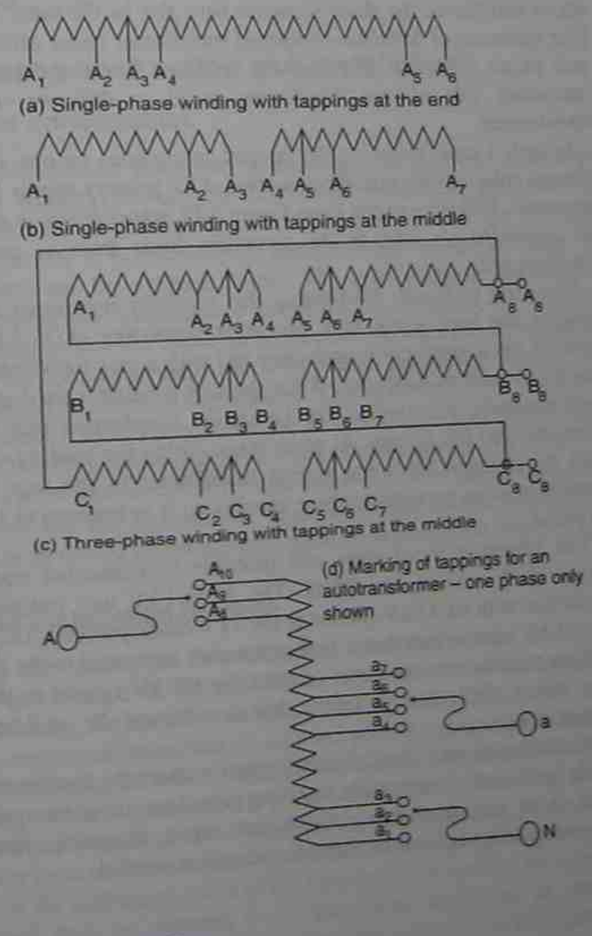


Figure 5.33
Marking of tappings on phase windings

Parallel operation of transformers

Parallel operation of transformers occurs when two or more transformers are connected to the same HV and LV busbars, especially on the load side. This is a most common practice in generating stations and grid substations to operate transformers in parallel to ensure that in the event of transformer or generator failures, redundancy is built in the distribution to maintain power supply through healthy transformers.

Five principal characteristics shall be met by each of the transformers to be operated in parallel:

1. Same inherent phase angle difference between primary and secondary terminals
2. Same voltage ratio
3. Same percentage impedance
4. Same polarity
5. Same phase sequence.

For two transformers to operate in parallel it is imperative that in addition to all of the above conditions, the phase sequence must also be the same. Figure 5.17 earlier showed four instances of delta/star-connected transformer under different conditions of polarity and phase sequence. There could be cases where the phase sequence required in secondary side of one transformer could be different with respect to the other transformer.

In such a case, reversing the internal connections on one side of the transformer can change polarities but interchanging two of the primary supply leads can reverse the phase sequence. Referring to the same Figure 5.17, transformers in diagrams in (a) and (d) can be paralleled so long as the secondary leads from a_1 and c_1 to the busbars are interchanged.

Referring to Figure 5.34 below that typically represents a power station auxiliary system, we have a 660 MW generator generating at 23.5 kV that is stepped up to 400 kV via a generator transformer and with a unit transformer providing a supply to the 11 kV unit switchboard. While the unit is being started up, the 11 kV switchboard will normally be supplied via the station transformer that takes its supply directly from the 400 kV system. At some stage during the loading of the generator, supplies will be changed from the station transformer to the unit transformer, which will briefly involve paralleling these sources so it is imperative that the supplies must be in phase.

The generator transformer will probably be connected star/delta with the 23.5 kV phasor at 1 o'clock, i.e. YNd1. The 23.5/11 kV unit transformer will be connected delta/star with its 11 kV phasor at the 11 o'clock position, i.e. Dyn11. This means that the 11 kV system now has a zero-phase shift compared to the 400 kV system. Thus, the station transformer must now connect the 400 kV system to the 11 kV system without any phase shift, and therefore this is achieved by utilizing a star/star-connected transformer.

Paralleling of two identical transformers reduces the combined impedances to half that of the individual transformers, resulting in the increase of the fault level of the LV busbar. This is to be taken into consideration while designing distribution equipment and protective relaying for transformers operated in parallel.

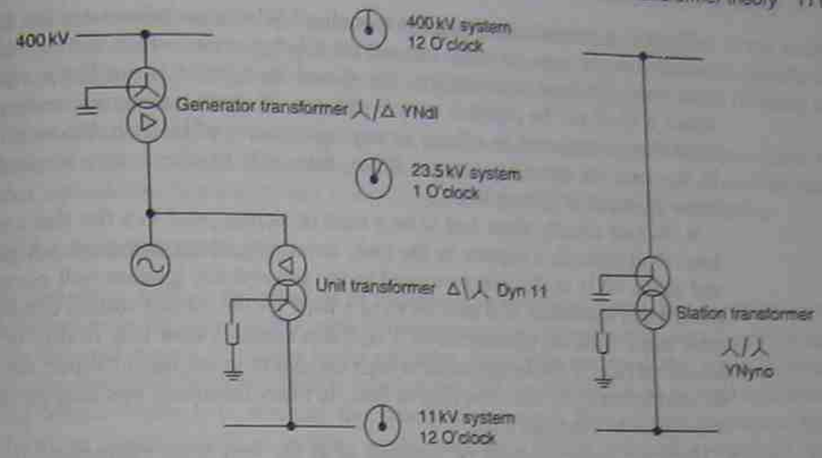


Figure 5.34
Power station auxiliary system

5.3 Transformer construction and installation

Transformer construction

Transformer construction comprises of windings and magnetic core kept in a closed tank and only windings brought out for external termination purpose. The closed tank construction is essential for safety as well as protection of the internal parts of the transformer. Further it is necessary to keep the high-voltage windings insulated from the other phases and the external surface. The most common construction is oil-filled transformer where the windings are immersed in a mineral oil having certain basic electrical characteristics like dielectric break down voltage, moisture content, etc. The oil also acts as the cooling medium which by natural circulation through the transformer radiators transfers the heat to the ambient. This construction is termed as ONAN (oil natural, air natural). Different types can be adopted to achieve higher cooling by external forced fans (ONAF) and by pumping oil using external devices (OFAF).

The other type of transformer is dry type and as the name implies this construction does not employ oil but use impregnated insulation to act as the insulating medium. The construction is air cooled by natural ventilation or with external fans.

Layout and installation practice

In designing the layout and installations of transformers, the following need to be considered: the location of the transformer whether it is to be installed outdoors or indoors, ventilation, fire hazard, transformer earthing and noise, etc.

Typically, most transformers that are oil filled present a potential fire hazard, especially if the transformer contains BS 148 oil. Therefore, it is absolutely essential to consider this factor when deciding whether a transformer is going to be installed outdoors or indoors. Invariably, most oil-filled transformers are therefore usually installed outdoors, or when essential to have the installation indoors, then adequate ventilation and physical isolation is required. This is to ensure, that in the unfortunate event of the transformer oil igniting for whatever reason, the damage caused shall be restricted to the transformer alone and its immediate ancillary equipment, and shall not interfere with any other unit assemblies in its vicinity.

There is a general misconception that all oil-filled transformers are fire hazards. This is usually not the case for most mineral oil-filled systems, which are less of a fire hazard than most. In these transformers, the closed flash point is not lower than 140 °C and hence it shall not be possible to accumulate sufficient vapor in an enclosed space to be ignited upon exposure to a flame or any other source of ignition, below this temperature. In any case, in order to sustain a flame, these oils require a wick to produce sufficient vapor to enable it to burn freely.

In the past usually there had to be a fault occurring prior to a fire that caused the rapid loss of oil through a rupture in the tank. Invariably, there will exist a high temperature, and as the oil is at this point exposed to the atmosphere, ignition will occur and then the transformer insulation will now serve as a wick for the oil and sustain combustion. On the other hand, if on the occurrence of a fault that causes a slow leak or drip of the oil onto a heated surface, if the temperature is high enough to ignite the oil/vapor, this fire could be fed continuously by the slow drip or leak. In many instances, this may go unnoticed until it escalates to a serious level.

There are many methods of avoiding or at the very least minimizing the risk of such hazards. Conventionally, it has been a general practice in many substations that employ oil-filled transformers and switchgear, to provide surfaces of chippings and a drainage sump to transport away any oil spillage that could potentially fuel a fire. This method however is not foolproof. It has been found that over a period, these chippings collect dust and grime and this grime would provide the wick for sustained combustion. Alternatively, one could explore the possibility of providing a firewater sprinkler system, which could be automatically triggered on the event of a fire around the transformer. Note that water displaces oil and any old oil spillage would be washed up from the sump. Therefore, it is imperative that this large quantity of excess oil and water be removed as quickly as possible to deluge water treatment centers before allowing the water to enter into the storm water drains, devoid of oil. Provision should be made to separate oil from water and for containment before this separation.

Additional precautions may also be considered if the above solutions are not feasible, such as separation or segregation. Separation involves locating the transformer well away from all other equipment, but this may not be convenient, as there may be space constraints. On the other hand, segregation provides for firewalls to be built around transformers such that fires, if any, would be contained within the walls. This firewall or barrier must be suitably reinforced to be capable of withstanding any explosions from the transformer.

In order to install transformers within buildings, it is a general practice that one uses dry-type resin-encapsulated units rather than using liquid-filled transformers.

In selecting the dielectric type the following must be adhered to:

- The dielectric must be non-toxic, biodegradable and must not present a hazard to the environment.
- The dielectric must have a fire point above 300 °C to be classified as a fire resistant fluid.
- The dielectric must not contribute to or increase the spread of an external fire nor must the products of combustion be toxic.
- Normal operation, electrical discharges or severe arcing within the transformer must not generate fumes or other products that are toxic or corrosive.

This does not mean that liquid-filled transformers cannot be used within buildings. They would meet all of the above criteria and in addition are cheaper and smaller than cast-resin or other dry type units. However there must be provision for a total spillage of the dielectric with suitable sumps and/or bunded catchment areas, such that in the event that spillage occurs the building drains would not be flooded with the dielectric liquids. If the transformers are installed on higher levels, then suitable precautions must be taken to prevent leakages on the lower floors.

On the other hand the building must be made totally weatherproof and care taken to ensure that there would be no deluges due to pipe leaks on the dry type of transformers after installation. Needless to say, every installation should have proper ventilation.

Noise in transformers

By definition, noise is described as an unpleasant or unwanted sound. It is inevitable that a transformer in operation emits noise. Transformer noise is continuous and it usually falls into the mid ranges of human audio spectrum. Invariably the noise that tends to irritate humans emanates from distribution transformers that are required to be located near homes and offices. Methods to attenuate this type of noise comes from employing various noise absorbing barriers such as existing walls, buildings, natural geographic topology (pits, artificial or natural), or even installing the transformer downwind from dwellings.

5.4 Transformer protection

Transformers are important in any distribution system and it is essential that they provide continuous service and are protected against faults that may keep out of service for long durations. Before proceeding with the protection methods, following paragraphs highlight the properties of transformers which shall be kept in mind while designing the protective system.

Transformer magnetizing characteristics

For efficiency reasons transformers are generally operated near to the 'knee-point' of the magnetic characteristic. Any increase above the rated terminal voltage tends to cause core saturation and therefore demands an excessive increase in magnetization current.

When a transformer is energized, it follows the classic magnetization curve as shown in Figure 5.35.

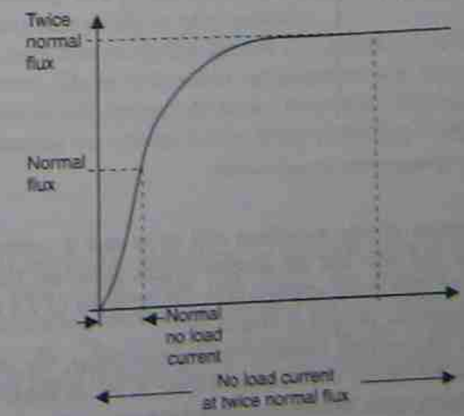


Figure 5.35
Transformer magnetizing characteristics

In-rush current

Under normal steady-state conditions, the magnetizing current, I_r required to produce the necessary flux is relatively small, usually less than 1% of full load current (Figure 5.36).

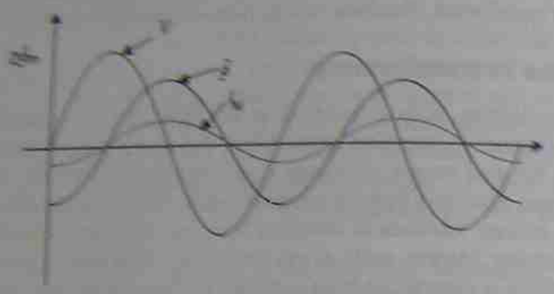


Figure 5.36
Steady-state conditions

However, if the transformer is energized at a voltage zero then the flux demand during the first half voltage cycle can be as high as twice the normal maximum flux. This causes an excessive unidirectional current to flow, referred to as the magnetizing in-rush current as shown in Figure 5.37.

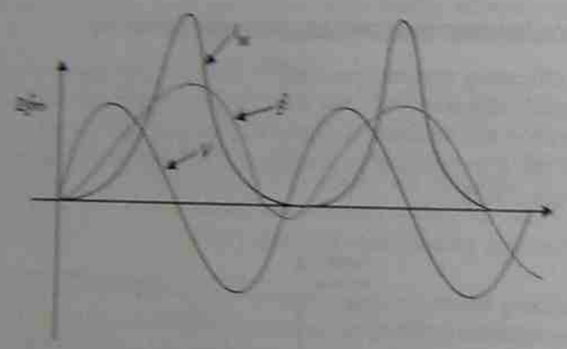


Figure 5.37
Illustration of magnetizing in-rush current

An analysis of this waveform will show that it contains a high proportion of second harmonic and will last for several cycles. Residual flux can increase the current still further, the peak value attained being of the order of 2.8 times the normal value if there is 80% permanence present at switch-on.

As the magnetizing characteristic is non-linear, the envelope of this transient in-rush current is not strictly exponential (Figure 5.38). In some cases, it has been observed to be still changing up to 30 min after switching on.

It is therefore important to be aware of these transient phenomena when considering differential protection of transformers, which will be discussed later.

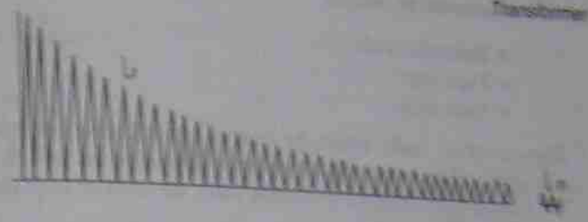


Figure 5.38
Typical transient current-rush when switching in a transformer at instant when E = 0

Mismatch of current transformers

Current transformers are provided on the HV and LV sides of a power transformer for protection purposes.

If we consider a nominal 132/11 kV 10 MVA transformer, the HV and LV full load currents would be as follows (Figure 5.39).

A ratio of 50/1 A would most likely be chosen for the HV current transformers, as it is not possible to obtain fractions of a turn. A ratio of 500/1 could be achieved comfortably for the LV current transformers.

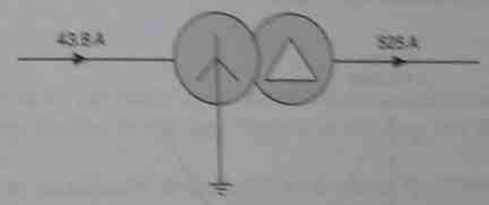


Figure 5.39
Nominal 132/11 kV 10 MVA transformer

We therefore have a mismatch of current transformer ratios with respect to the full load currents on the secondary side of the CTs (these are 0.876 A and 1.05 A). Incidentally 600/1 on the secondary side would be more suitable.

Furthermore, it is more than likely that the HV CTs and the LV CTs will be supplied by different manufacturers. There is therefore no guarantee that the magnetization curves will be the same, which will further add to the mismatch. This mismatch shall be duly considered while selecting the settings for the relays protecting the transformers.

Types of faults

A clear knowledge is required to understand the different types of faults that can occur in a transformer and their causes. This will enable the designer to adopt the correct protective system depending upon the possibilities for such faults, cost of protection vis-à-vis breakdown cost, etc. The following paragraphs briefly explain the descriptions for the following types of faults that can occur in a power transformer:

- HV and LV bushing flashovers (external to the tank)
- HV winding earth fault
- LV winding earth fault

- Inter-turn fault
- Core fault
- Tank fault.

Phase-to-phase faults within the tank of a transformer are relatively rare by virtue of its construction. They are more likely to occur external to the tank on the HV and LV bushings.

If a transformer develops a winding fault, the level of fault current will be dictated by:

- Source impedance
- Method of neutral earthing
- Leakage reactance
- Position of fault in winding (i.e. fault voltage).

Earth faults

Effectively earthed neutral

This refers to the solid connection of neutral to the earth. The fault current in this case is controlled mainly by the transformer leakage reactance, which varies in a complex manner depending on the position of the fault in the winding.

The reactance decreases toward the neutral so that the current actually rises for faults toward the neutral end (Figure 5.40).

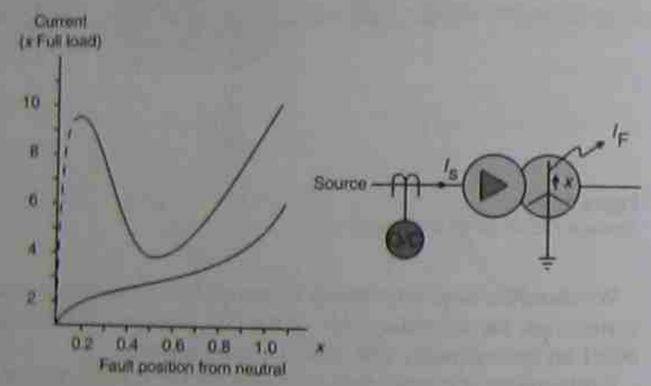


Figure 5.40
Relationship of fault current to position from neutral (earthed)

The input primary current is modified by the transformation ratio and is limited to 2 to 3 times the full load current of the transformer for fault positions over a major part of the star winding.

An overcurrent relay on the HV side will therefore not provide adequate protection for earth faults on the LV side.

Non-effectively (resistance or impedance) earthed neutral

For this application, the fault current varies linearly with the fault position, as the resistor is the dominant impedance, limiting the maximum fault current to approximately full load current (Figure 5.41).

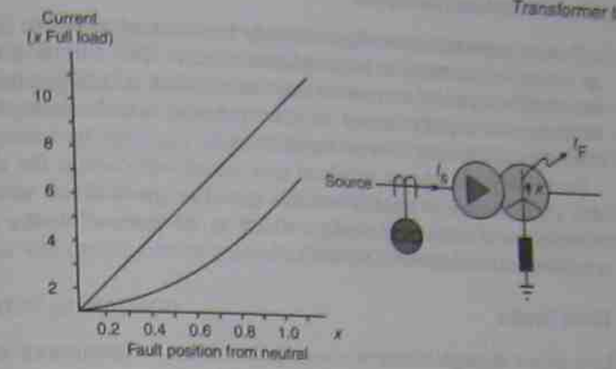


Figure 5.41
Relationship of fault current to positions from neutral (resistance earthed)

The input primary current is approximately 57% of the rated current making it impossible for the HV overcurrent relay to provide any protection for LV earth faults.

Restricted earth fault protection is therefore strongly recommended to cover winding earth faults and this will be covered in more detail in a later section.

Inter-turn faults

Insulation between turns can break down due to electro-magnetic/mechanical forces on the winding causing chafing or cracking. Ingress of moisture into the oil can also be a contributing factor.

Also an HV power transformer connected to an overhead line transmission system will be subjected to lightning surges sometimes several times rated system voltage. These steep-fronted surges will hit the end windings and may possibly puncture the insulation leading to a short-circuited turn (Figure 5.42). Very high currents flow in the shorted turn for a relatively small current flowing in the line.

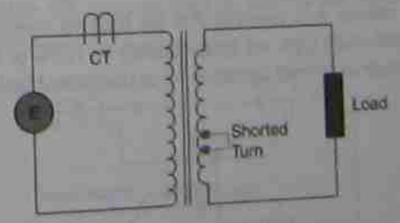


Figure 5.42
Inter-turn faults

Core faults

Heavy fault currents can cause the core laminations to move, chafe and possibly bridge causing eddy currents to flow, which can then generate serious overheating.

This additional core loss will not produce any noticeable change in the line currents and thus cannot be detected by any electrical protection system.

Power frequency overvoltage not only increases stress on the insulation but also gives an excessive increase in magnetization current. This flux is diverted from the highly saturated laminated core into the core bolts, which normally carry very little flux. These bolts may be rapidly heated to a temperature, which destroys their own insulation, consequently shorting out core laminations.

Fortunately, the intense localized heat, which will damage the winding insulation, will also cause the oil to break down into gas. This gas will rise to the conservator and be detected by the Buchholz relay, which is an external device provided in oil-filled transformers rated above 1000 kVA.

Tank faults

Loss of oil through a leak in the tank can cause a reduction of insulation and possibly overheating on normal load due to the loss of effective cooling.

Oil sludge can also block cooling ducts and pipes, contributing to overheating, as can the loss of forced cooling pumps and fans generally fitted to the larger transformer.

5.5 Relays for protection

HV overcurrent

The most common protection employed in a transformer is protection against withdrawal of currents from the source in excess of rated/design values. Also it is quite common that a ground fault or inter-phase faults in a transformer winding could be the cause for flow of fault currents many times the rated design current. The most common protection against such drawing of excess currents is by using an IDMTL (inverse definite minimum time) overcurrent and earth fault relay on the HV side of a transformer. The operating time varies inversely with respect to the current values and the operating time can be set to the desired values in these relays. The inherent time delay of the IDMTL element provides back-up for the LV side.

High-set instantaneous overcurrent is also recommended on the primary side mainly to give high-speed clearance to HV bushing flashovers. Care must be taken, however, to ensure that these elements do not pick-up and trip for faults on the LV side as discrimination is important.

For this reason, it is essential that the high-set overcurrent element should be of the low-transient over-reach type, set approximately to 125% of the maximum through-fault current of the transformer to prevent operation for asymmetrical faults on the secondary side (Figure 5.43).

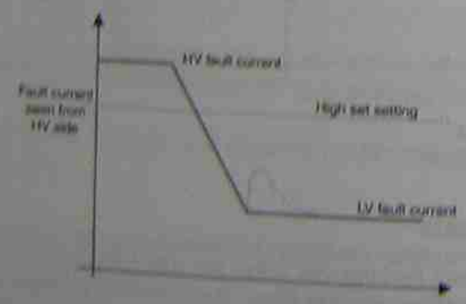


Figure 5.43
Fault current as seen from the HV side

This relay therefore looks into, but not through the transformer, protecting part of the winding, so behaving like unit protection by virtue of its setting.

When grading IDMTL overcurrent relays across a delta–star transformer it is necessary to establish the grading margin between the operating time of the star side relay at the phase-to-phase fault level and the operating time of the delta side relay at the three-phase fault level.

This is due to the fact that, under a star side phase-to-phase fault condition, which represents a fault level of 86% of the three-phase fault level, one phase of the delta side transformer will carry a current equivalent to the three-phase fault level.

Differential protection

Differential protection, as its name implies – compares currents entering and leaving the protected zone and operates when the differential current between these currents exceed a predetermined level.

The type of differential scheme normally applied to a transformer is called the current balance or circulating current scheme as shown in Figure 5.44.

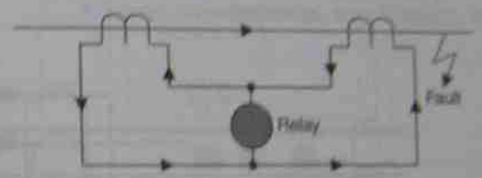


Figure 5.44
Differential protection using current balance scheme (external fault conditions)

The CTs are connected in series and the secondary current circulates between them. The relay is connected across the mid-point where the voltage is theoretically nil, therefore no current passes through the relay, hence no operation for faults outside the protected zone.

Under internal fault conditions (i.e. faults in area within the two sets of CTs) the relay operates because there is an unbalance detected by the relay within its protective zone as shown in Figure 5.45.(The CT currents tend to flow in the same direction through the relay making it to operate.)

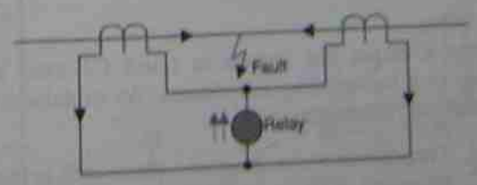


Figure 5.45
Differential protection and internal fault conditions

This protection is called UNIT protection, as it only operates for faults on the unit it is protecting, which is situated between the CTs. The relay therefore can be instantaneous in operation, as it does not have to coordinate with any other relay on the network.

This type of protection system can be readily applied to autotransformers (Figures 5.46 and 5.47) as follows.

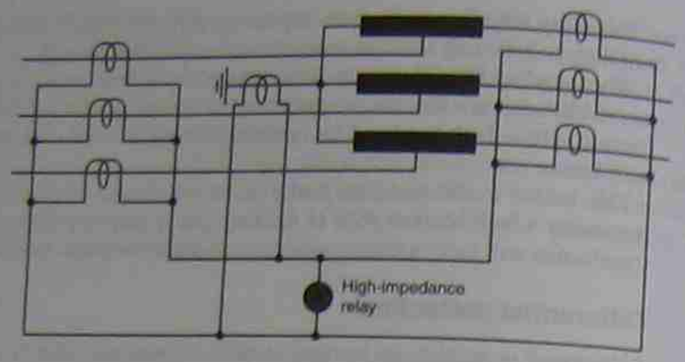


Figure 5.46
Restricted earth protection applied to autotransformers

All current transformer ratios remain the same and the relays are of the high-impedance (voltage operated) type, instantaneous in operation.

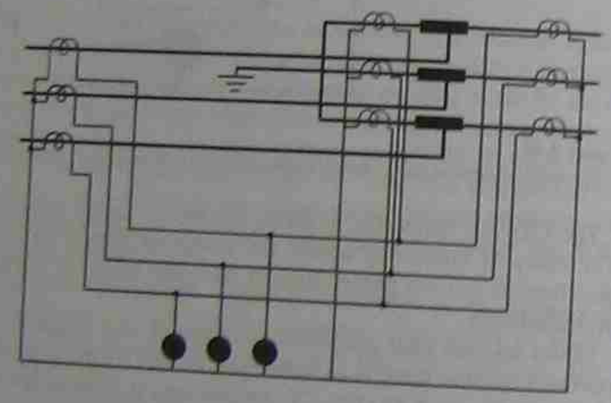


Figure 5.47
Autotransformer – phase and earth fault scheme

However it is not just enough to select CT ratio alone for adopting differential protection in a two-winding transformer. As explained earlier, there are a number of factors that need consideration:

1. Transformer vector group (i.e. phase shift between HV and LV)
2. Mismatch of HV and LV CT's characteristics
3. Varying currents due to on-load tap changer (OLTC)
4. Magnetizing in-rush currents (from one side only)
5. The possibility of zero sequence current destabilizing the differential for an external earth fault.

Factor (a) can be overcome by connecting the HV and LV CTs in star/delta respectively (or vice versa) opposite to the vector group connections of the primary windings, so counteracting the effect of the phase shift through the transformer.

The delta connection of CTs provides a path for circulating zero sequence current, thereby stabilizing the protection for an external earth fault as required by factor (e).

It is then necessary to bias the differential relay to overcome the current unbalances caused by (b) mismatch of CTs and (c) OLTC. And finally, as the magnetizing current in-rush is predominantly second harmonic, filters are utilized to stabilize the protection for this condition (d).

Most transformer differential relays have bias and slope setting of 20, 30 and 40% as shown. For OLTC-operated transformers, the operating range of the OLTC dictates the desired setting, which is responsible for the biggest current unbalance under healthy conditions.

E.g. If the OLTC range is +15 to −5% = 20% then a minimum of 20% bias setting is selected. The CT mismatch should also be taken into account.

Typical connections for a delta–star transformer would be as shown in Figure 5.48. Note that the CTs on primary are connected in star while those in secondary are connected on delta to offset the phase shift in the two windings.

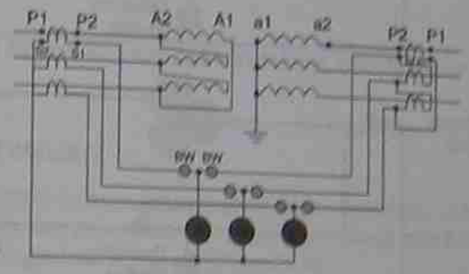


Figure 5.48
Typical connections for a delta–star transformer

Under load or through-fault conditions, the CT secondary currents circulate, passing through the bias windings to stabilize the relay, whilst only small out-of-balance spill currents will flow through the operate coil, not enough to cause operation. In fact the higher the circulating current, the higher will be the spill current required to trip the relay, as can be seen from the following characteristic in Figures 5.49 and 5.50.

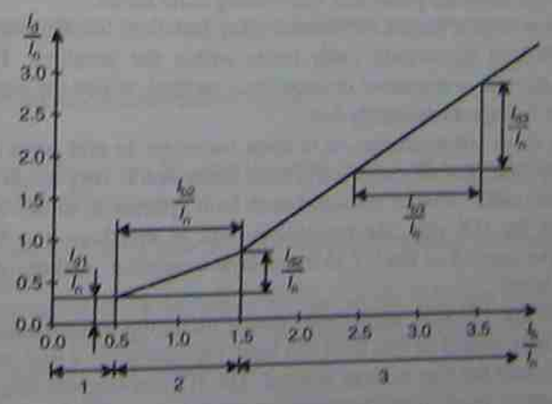


Figure 5.49
Operating current of differential relay

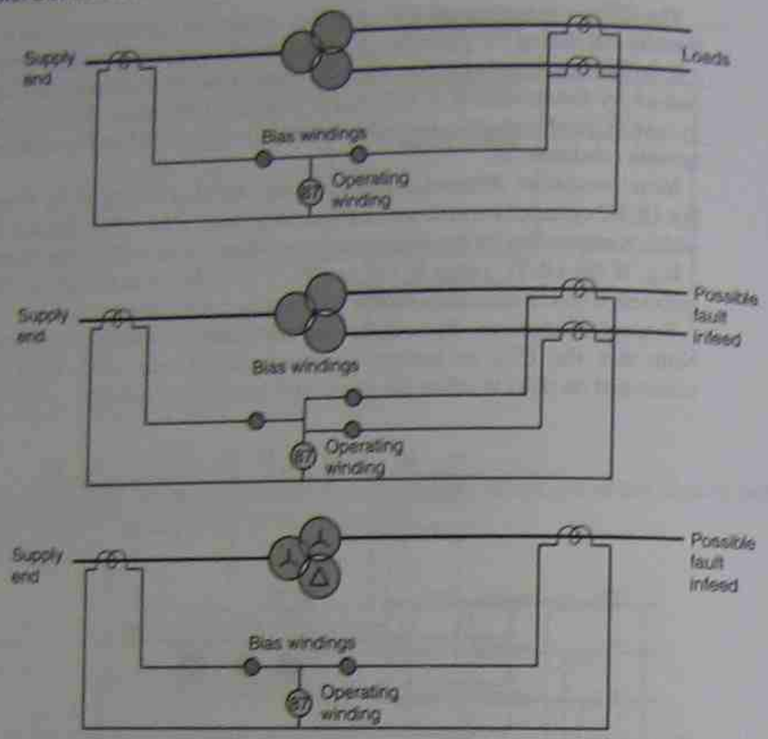


Figure 5.50
Biased differential configurations

Restricted earth fault

As demonstrated earlier in these notes, a simple overcurrent and earth fault relay will not provide adequate protection for winding earth faults.

Even with a biased differential relay installed, biasing can cause the relay to become ineffective for certain earth faults within the winding. This is especially so if the transformer is resistance or impedance earthed, where the current available on an internal fault is disproportionately low.

In these circumstances, it is often necessary to add some form of separate earth fault protection. The degree of earth fault protection is very much improved by the application of unit differential or restricted earth fault systems as shown in Figure 5.51.

On the HV side, the residual current of the three-line CTs is balanced against the output current of the CT in the neutral conductor, making it stable for all faults outside the zone.

For the LV side, earth faults occurring on the delta winding may also result in a level of fault current of less than full load, especially for a mid-winding fault which will only have half the line voltage applied. The HV overcurrent relays will therefore not provide adequate protection. A relay connected to monitor residual current will provide earth fault protection since the delta winding cannot supply zero-sequence current to the system.

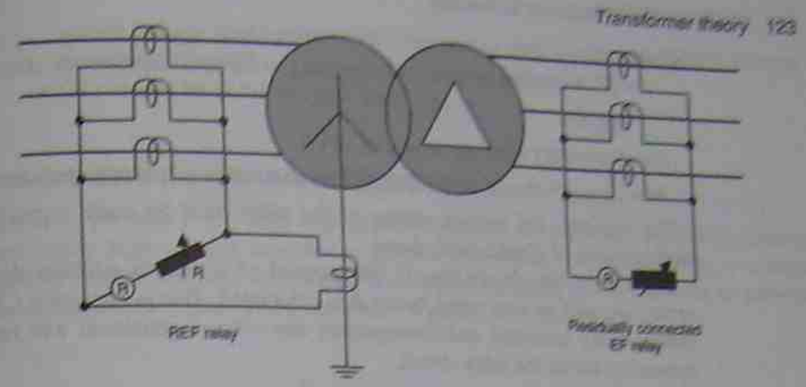


Figure 5.51
A restricted earth fault system

The relay used is an instantaneous high-impedance type, the theory of which is shown as follows:

Determination of stability

The stability of a current balance scheme using a high-impedance relay depends upon the relay voltage setting being greater than the maximum voltage which can appear across the relay for a given through-fault condition (Figure 5.52).

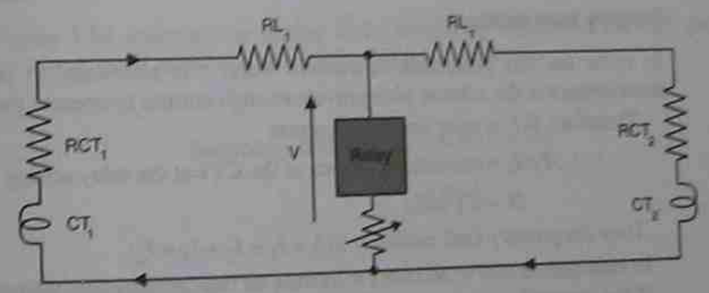


Figure 5.52
Basic circuit of high-impedance current balance scheme

This maximum voltage can be determined by means of a simple calculation, which makes the following assumptions:

- One current transformer is fully saturated, making its excitation impedance negligible.
- The resistance of the secondary winding of the saturated CT together with lead resistance constitute the only burden in parallel with the relay.
- The remaining CTs maintain their ratio.

Referring to Figure 5.52, the maximum voltage is given

$$V = I(R_{ct} + R1)$$

Where

I = CT secondary current corresponding to the maximum steady-state through-fault current

R_{ct} = Secondary winding resistance of CT

Rl = Largest value of lead resistance between relay and current transformer.

For stability, the voltage setting of the relay must be made equal to or exceed the highest value of V calculated above.

Experience has shown that if this method of setting is adopted the stability of the protection will be very much better than calculated. This is because a CT is normally not continuously saturated and consequently any voltage generated will reduce the voltage appearing across the relay circuit.

Method of establishing the value of stabilizing resistor

To give the required voltage setting the high-impedance relay operating level is adjusted by means of an external series resistor as follows:

Let v = operating voltage of relay element

Let i = operating current of relay equipment

and V = maximum voltage as defined under 'determination of stability' above.

It is sometimes the practice to limit the value of series resistor to say 1000 Ω, and to increase the operating current of the relay by means of a shunt connected resistor, in order to obtain larger values of relay operating voltage.

From the equation above $V = I(R_{ct} + Rl)$

Therefore $Rl = (V/I) - R_{ct}$

Primary fault setting

In order for this protection scheme to work it is necessary to magnetize all current transformers in the scheme plus provide enough current to operate the relay.

Therefore, if I_r = relay operating current

I_1, I_2, I_3, I_4 = excitation currents of the CT's at the relay setting voltage

N = CT ratio

Then the primary fault setting = $N(I_r + I_1 + I_2 + I_3 + I_4)$

In some cases, it may be necessary to increase the basic primary fault setting as calculated above. If the required increase is small, the relay setting voltage may be increased (if variable settings are available on the relay) which will have the effect of demanding higher magnetization currents from the CT's I_1, I_2, etc.

Alternatively, or when the required increase is large, connecting a resistor in parallel with the relay will increase the value of I_r.

Current transformer requirements

Class X CTs are preferably required for this type of protection; however experience has shown that most protection type CTs are suitable for use with high-impedance relays, provided the following basic requirements are met:

- The CTs should have identical turns ratio. Where turns error is unavoidable, it may be necessary to increase the fault setting to cater for this.
- To ensure positive operation, the relay should receive a voltage of twice its setting. The knee-point voltage of the CTs should be at least twice the relay setting voltage (knee-point = 50% increase in mag. Current gives 10% increase in output voltage).
- CTs should be of the low-reactance type.

Protection against excessively high voltages

As the relay presents a very high impedance to the CTs, the latter are required to develop an extremely high voltage. In order to contain this within acceptable limits, a voltage dependant resistor (VDR), or metrosil, is normally mounted across the relay to prevent external flashovers (Figure 5.53), especially in polluted environments.

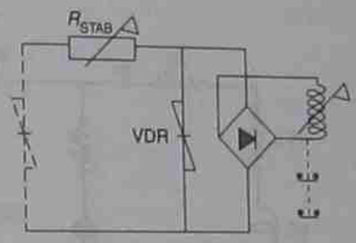


Figure 5.53
Protection against excessively high voltages

Example

Using Figure 5.54, calculate the setting of the stabilizing resistor for the REF protection. The relay is 1 A rated with 10–40% tappings, burden 1.0 VA.

$$\text{Secondary fault current} = 9000 \times \frac{1}{3000}$$
$$= 30 \text{ A}$$

Relay operating current

Choose 10% tap on the relay (10%) = 0.1 A

Relay operating voltage

$$\frac{VA}{I} = \frac{\text{burden}}{\text{current}} = \frac{1.0}{0.1} = 10 \text{ V}$$

Stabilizing voltage

$$V = I(R_{ct} + Rl) = 30(3 + 1) = 120 \text{ V}$$

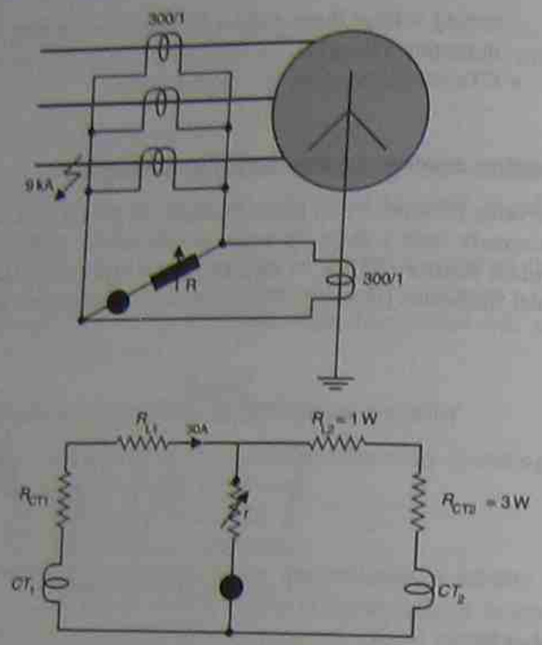


Figure 5.54
Example for calculation of setting of stabilizing resistor

Voltage across stabilizing resistor

$$\text{Stabilizing voltage} - \text{relay voltage} = 120 - 10 = 110 \text{ V}$$

$$\text{Stabilizing resistance} = \frac{\text{Voltage across resistor}}{\text{Current through resistor}}$$

$$= \frac{110}{0.1}$$

$$= 1100\ \Omega$$

Current transformer must therefore have a minimum knee-point voltage of $2 \times 120 = 240$ V to ensure positive operation of protection for an internal fault.

6

Grounding, earthing and transient overvoltage protection

6.1 Grounding devices

Solid grounding

The neutral of a power transformer is grounded solidly with a copper conductor (see Figure 6.1).

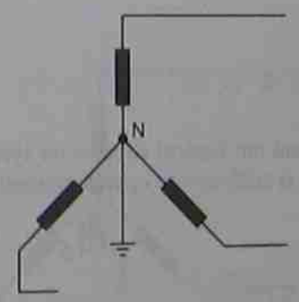


Figure 6.1
Solid grounding of power transformer

Advantages

- Neutral held effectively at ground potential
- Phase-to-ground faults of same magnitude as phase-to-phase faults so no need for special sensitive relays
- Cost of current-limiting device is eliminated
- Size and cost of transformers are reduced by grading insulation toward neutral point N.

Disadvantages

- As most system faults are phase-to-ground, severe shocks are more considerable than with resistance grounding.
- Third harmonics tend to circulate between neutrals.

Resistance grounding

A resistor is connected between the transformer neutral and earth (see Figure 6.2).

- Mainly used from 6.6 to 33 kV.
- Value is such as to limit an earth fault current to between 1 and 2 times full load rating of the transformer, typically 400 A.

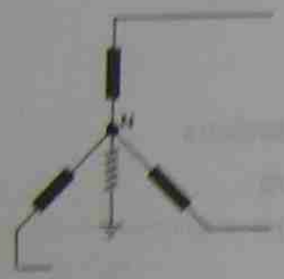


Figure 6.2
Resistance grounding

Advantages

Limits electrical and mechanical stresses on system when an earth fault occurs, but at the same time current is sufficient to operate normal protection equipment.

Disadvantages

Full line-to-line insulation required between phase and earth.

Reactance grounding

A reactor is connected between the transformer neutral and earth (see Figure 6.3).

- Values of reactance are approximately the same as used for resistance grounding.
- To achieve the same value as the resistor, the design of the reactor is smaller and thus cheaper.

However, reactance grounding can lead to severe overvoltages during arcing earth faults (see IEEE standard 142 and SABS 0200). This form of grounding is not recommended.

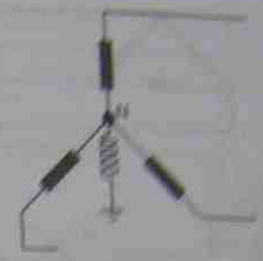


Figure 6.3
Reactance grounding

Arc suppression coil (Petersen coil)

A tuneable reactor is connected in the transformer neutral to earth (see Figure 6.4).

- Value of reactance is chosen such that reactance current neutralizes capacitance current. The current at the fault point is therefore theoretically nil and unable to maintain the arc, hence its name.
- Virtually fully insulated system, so current available to operate protective equipment is so small as to be negligible. To offset this, the faulty section can be left in service indefinitely without damage to the system as most faults are earth faults of a transient nature, the initial arc at the fault point is extinguished and does not restrike.
- Sensitive wattmetrical relays are used to detect permanent earth faults.

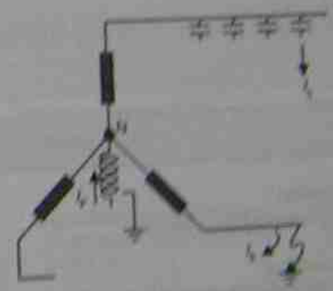


Figure 6.4
Arc suppression coil (Petersen coil)

Earthing via neutral electromagnetic coupler with resistor

This type of earthing provides an earth point for a delta system and combines the virtues of resistance and reactance grounding in limiting earth fault current to safe relayable values (see Figure 6.5).

The current should be resistive in nature to comply with IEEE standard 142 and SABS 0200. Comparisons are made in Figures 6.6 and 6.7.

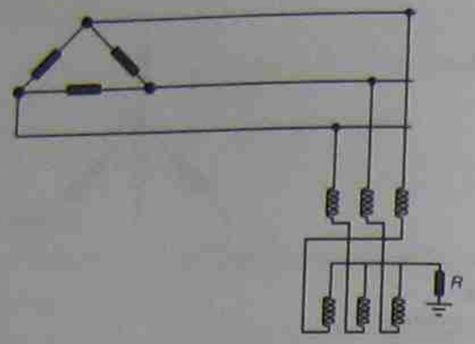


Figure 6.5
Earthing via neutral earthing compensator

Problems
Phase faults High fault currents Only limited by inherent impedance of power supply
Earth faults Solid earthing means high earth fault currents Only limited by inherent zero sequence impedance of power system
Consequences Heavy currents damage equipment extensively – danger of fire hazard This leads to long outage times – lost production, lost revenue Heavy currents in earth bonding give rise to high touch potentials – dangerous to human life Large fault currents are more hazardous in igniting gases – explosion hazard

Solutions
Phase segregation Eliminates phase-to-phase faults
Resistance earthing Means low earth fault currents – can be engineered to limit to any chosen value
Benefits Fault damage now minimal – reduces fire hazard Lower outage times – less lost production, less lost revenue Touch potentials kept within safe limits – protects human life Low fault currents reduce possibility of igniting gases – minimizes explosion hazard No magnetic or thermal stresses imposed on plant during fault Transient overvoltages limited – prevents stressing of insulation and breaker restrikes

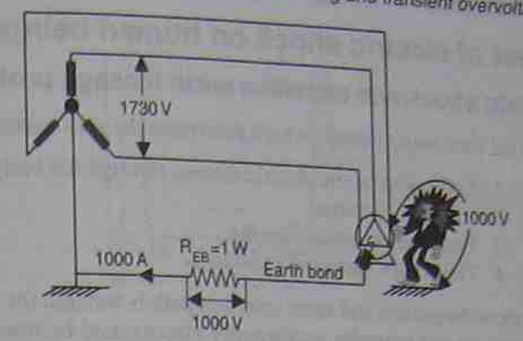


Figure 6.6
Touch potentials – solid grounding

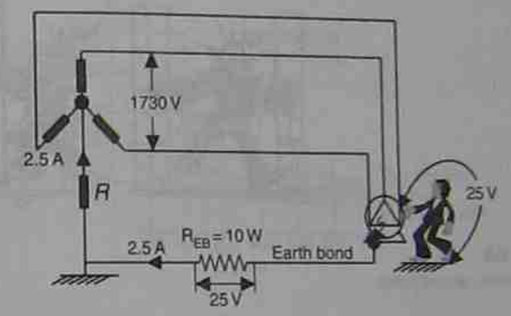


Figure 6.7
Touch potentials – resistive grounding

Evaluation of Relative Merits of Effective and Resistive Earthing
(See IEEE standard 142 and SABS 0200)

1 Subject	2 Effective Earthing	3 Resistive Earthing
Rated voltage of system components, particularly power cables and metal oxide surge arresters	Need not exceed $0.6U_m$	Must be at least $1.0U_m$ for 100 s
Earth fault current magnitude	Approximately equal to three-phase fault current (typically 2–10 kA)	Reduced earth fault current magnitude (typically 300–900A)
Degree of damage as a result of an earth fault	High degree of damage at fault point and possible damage to feeder equipment	Lesser degree of damage at fault point and usually no damage to feeder equipment
Step and touch potentials during earth fault	High step and touch potentials	Reduced step and touch potentials
Inductive interference on and possible damage to control and other lower voltage circuits	High probability	Lower probability
Relaying of fault conditions	Satisfactory	Satisfactory
Cost	Lower initial cost but higher long-term equipment repair cost	Higher initial cost but lower long-term equipment repair cost usually making resistive earthing more cost-effective

6.2 Effect of electric shock on human beings

Electric shock and sensitive earth leakage protection

There are four major factors, which determine the seriousness of an electric shock:

1. Path taken by the electric current through the body
2. Amount of current
3. Time the current is flowing
4. The bodies electrical resistance.

The most dangerous and most common path is through the heart (see Figure 6.8).

Persons are not normally accidentally electrocuted between phases or phase to neutral, almost all accidents are phase to earth.

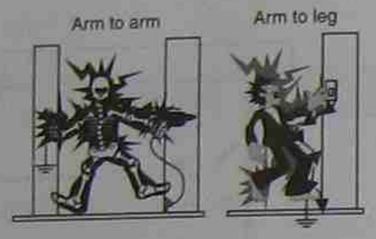


Figure 6.8
Dangerous current flows

Figure 6.9 shows the four stages of the effect of a current flow through the body:

1. Perception – tingling – about 1 mA
2. Let-go threshold level – about 10 mA
3. Non-let-go threshold level – 16 mA
4. Constriction of the therasic muscles – death by asphyxiation and ventricular fibrillation – about 70–100 mA.

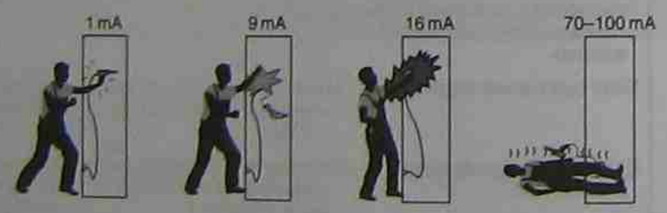


Figure 6.9
Effects of current flow through the body

Figure 6.10 shows the normal electrocardiogram – one pulse beat – at 80 bpm = 750 ms.

- QRS phase – normal pumping action
- T phase – refractory or rest phase – about 150 ms.

Death could occur if within this very short period of 150 ms a current flow was at the fibrillation level.

Figure 6.11 shows the resistance of the human body – hand to hand or hand to foot.

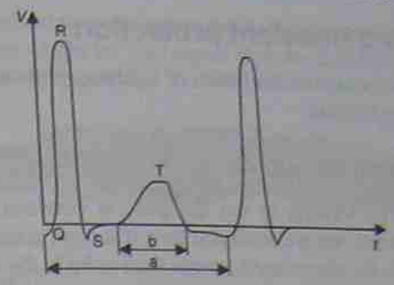


Figure 6.10
Electrocardiagram

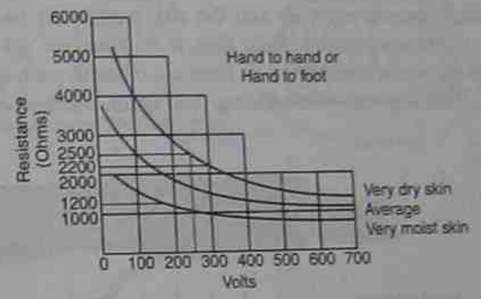


Figure 6.11
Resistance of human body

Consider an example of a man working, possibly perspiring, he touches a conductor at 300 V (525 V phase to earth).

300 V divided by 1000 Ω = 300 mA!

It is important to remember that it is current that kills, not voltage.

Sensitive earth leakage protection

Figure 6.12 illustrates the operation of the core balance leakage device.

This shows a single-phase system but would be similar for three-phase, 3w or three-phase, 4w systems.

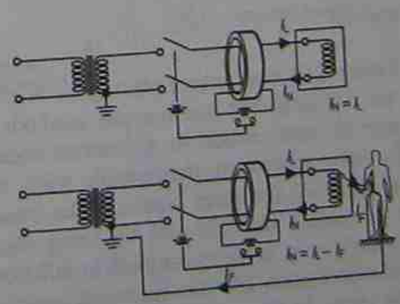


Figure 6.12
Principles of core balance protection

6.3 Surge and transient protection

This section focuses on the basics of lightning phenomenon, switching surges and typical mitigation techniques.

Earth current transients

In Figure 6.13 looking at the comparison between atmospheric transients and earth current transients, we are reminded that, if it were possible, it would do us a lot of good to be in the open air, above earth, rather than to be in the earth itself. We would much rather take our chances with a varying electrostatic field and the results that occur in an insulating medium, the air, rather than take our chances with what is taking place in a conducting medium, namely, the earth. In days gone by, we were able to suspend our telephone and data lines underbuilt below a power line. We were even able to hang our inter-plant lines in open air and the risk was much less from the direct strikes or the effects of the electrostatic field than it is when we go into the earth. We might have induced transients come to us as lines are close to each other in the construction process of underbuilding and overbuilding, but again, the end-result effects were considerably less.

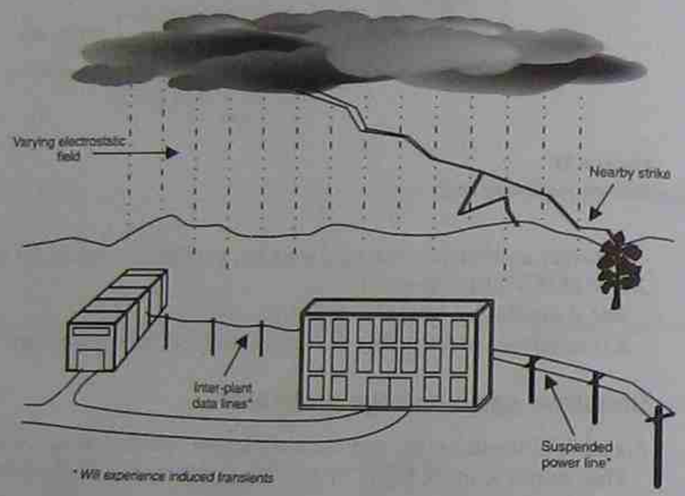


Figure 6.13
Atmospheric transients

Consider Figure 6.14 now, where placing all of our lines in the earth, we tend to no longer use the old-fashioned construction methods. The older methods consisted of bearing a piece of steel conduit in a concrete encasement and then placing wires in the center. In that construction, the metallic wires were protected, at least in part, by the shielding effect of the steel conduit. The conduit, in turn, was protected from deterioration in contact with the soil by being encased with concrete. With today's modern technology, most of the under earth installations are performed with PVC conduit with very little protection for the electromagnetic properties of the noise transients running in the earth. In Figure 6.15, we can see the impact of earth current transients running back and forth and perhaps intercepting the conductors running in the plastic conduit buried between the buildings. If there were direct lightning strikes to the earth or

if a power line with a lightning arrestor was discharging its energy into the earth, then the PVC conduit with wires might be intercepted and the metallic wires would carry these transient charges in both directions.

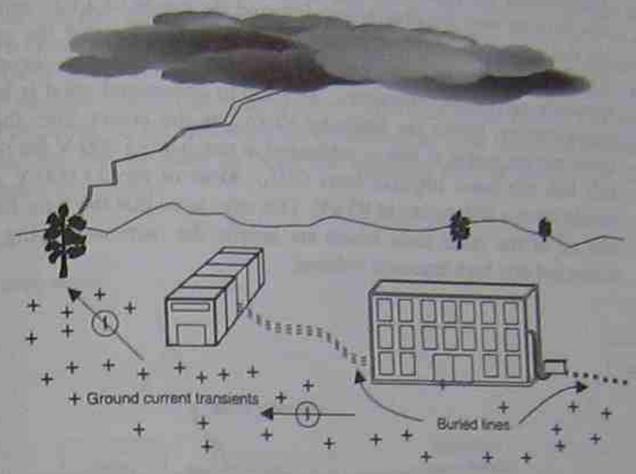


Figure 6.14
Earth current transients

The one exception to this, of course, is glass fiber installations which do not, of themselves, conduct any of these earth transients when buried in the earth directly.

Transient impact

In Figure 6.15 we see the impact of a transient phenomenon making for high field strength and dielectric stress as well as a very high rate of change of voltage with regard to time, producing a high current component. Just a reminder to us: transient phenomena can be very dangerous.

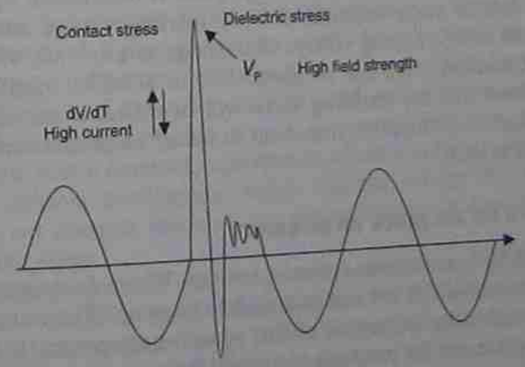


Figure 6.15
Impact of a transient

Lightning phenomenon

Let us begin by talking about what happens when a lightning strike hits an overhead distribution line. Here in Figure 6.16 we see the picture of the thunderstorm cloud discharging onto the distribution line and the points of application of a lightning arrestor by the power company at points 1 and 2. We notice that the operating voltage here is 11 000 V on the primary line and the transformer has a secondary voltage of 400 V typically serving the consumer. We need to understand what is known as traveling wave phenomenon. When the lightning strike hits the power line, the power line's inherent construction makes it able to withstand as much as 95 000 V for its insulation system. We call this the basic impulse level (BIL). Most of the 11 000 V construction equipment would have a BIL rating of 95 kV. This says to us that the wire insulation, the cross arms and all of the other parts which are nearby the current-carrying conductors are able to withstand this high transient voltage.

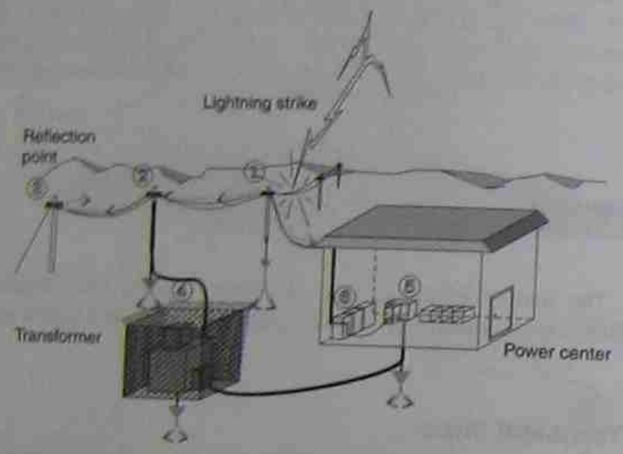


Figure 6.16
Lightning strike to an overhead distribution line

When an overhead line is struck by lightning, an overvoltage surge travels down the line. The magnitude of the voltage pulse is determined by the current of the lightning volt and the surge impedance. Upon reacting a surge arrestor the overvoltage will be limited to the clipping voltage of the range arrestor, say 45 kV for an 11 kV system. At the transition from the overhead line to a cable, transformer or at the end of the overhead line the traveling wave will be reflected and the voltage doubled by super position. It is therefore important to install surge arrestors at all transition points in a power system.

Where do we place an arrestor?

Figure 6.17 poses some serious questions. Where do we put a lightning arrestor? Do we need one at all? What is it you wish to blow up? The computer? The UPS? Or perhaps you would like to save all of that sensitive equipment. It may be a humorous type of description, but the practical, real world finds many people placing lightning arrestors and discharge devices inside of occupied spaces where the equipment and the personnel represent a heavy financial burden as well as a safety factor. Most safety standards will

advise that discharge devices do not need to be located where there are either personnel or equipment to be protected. The location of a discharge device, such as a lightning arrestor, is to be at the large service entrance earth, where the electric utility makes its service connection to the premises. Here, at this point, this discharge device which has large levels of current, then has a sufficiently large earth plane into which to discharge that current without a damaging effect on sensitive equipment. Typical lightning arrestor ratings call for 65 000 A of discharge capacity for distribution class arrestors, 100 000 A of discharge capacity for station class arrestors, and even at the 600 V and below level, 40 000 A of capability at the minimum. So we notice that these questions are not silly, but they do point out that we need to locate our lightning arrestor product as close to the service entrance as possible.

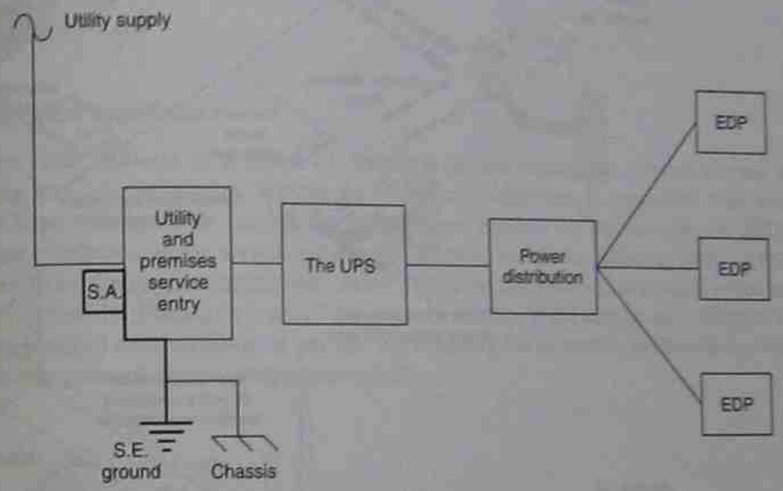


Figure 6.17
Positioning of a lightning arrestor

Arrestor and supplementary protection

From the Federal Information Processing Standards we have a picture of the combined placement of lightning arrestor products and surge protection devices called transient surge protectors. Notice that the writers of this document were very accurate in the location of the arrestor product and to make it as close to the power source as possible. In addition, they give us a picture of the use of the older style arresting products, which required capacitors to affect wavefront modification. Let us explain that. Wavefront modification means that the voltage rise is so fast that if something does not mitigate that rise, the wiring may be bridged by the extremely high voltage in the surge.

Downstream from the arrestor location, over a certain amount of distance, preferably greater than 10–15 m (30–50 ft), if possible, should be the second level of protection shown in Figure 6.18 as a transient surge protector. This device, indicated as combination suppresser and filter package made up of a variety of different types of components which will now protect against the residual energy that is flowing in the circuit. The structure that we see here is one in which the various components installed in the system,

starting at the service entrance, then to a sub-panel and then, finally, to discrete individual protectors, will now attenuate more and more of the surge energy until it is completely dissipated.

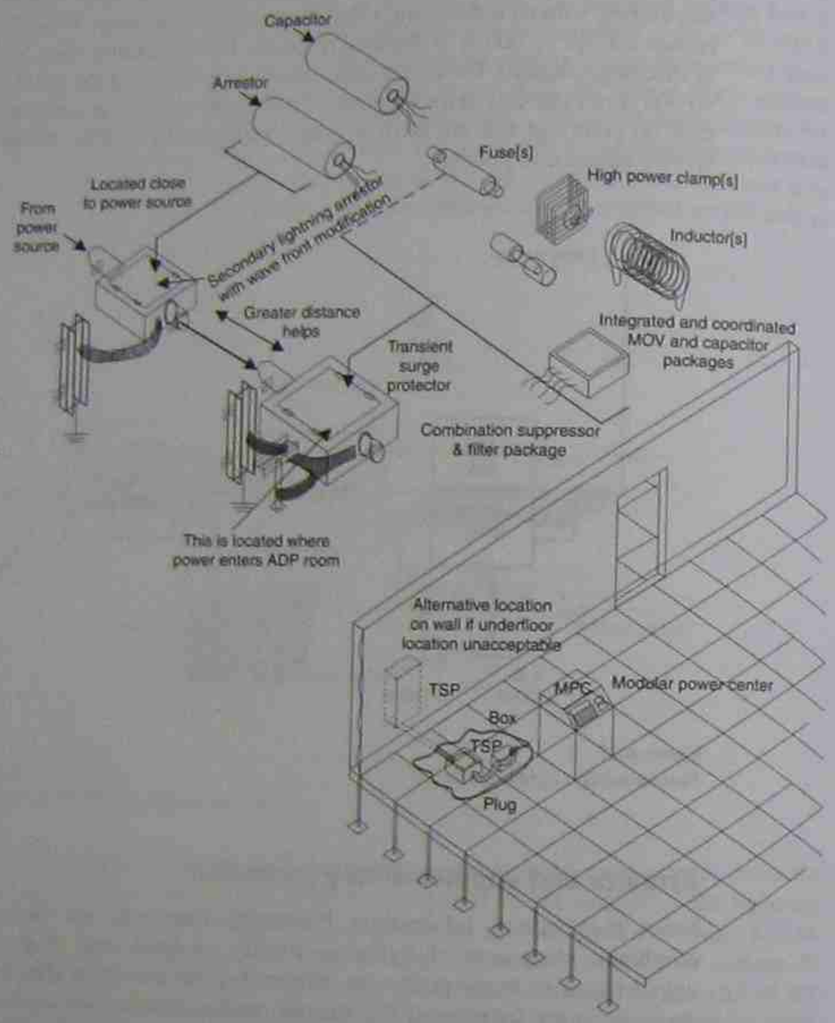


Figure 6.18
Supplementary surge protection elements

Transient clipping

In Figure 6.19, we see the onrushing surge coming into a transient voltage surge suppression device (TVSS), now becoming better known as surge protection device (SPD), and having its upper portion limited or chopped before it comes to the load. The surge protection element actually is taking off or limiting that high-transient phenomenon and sending it back into the earth path where it will do very little harm.

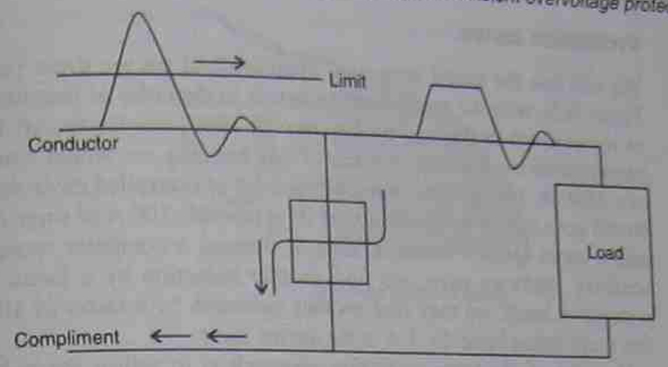


Figure 6.19
Onrushing surge

Protection locations

Figure 6.20 consists of a series of diagrams demonstrating the overall electric utility supply and internal wiring. We see the recommendation that is consistent with what we have been talking about before. The black boxes marked on our drawing as SPDs first appear connected at the service entrance equipment inside the building where it receives power from the service transformer. Next we see an SPD device at a panel board or sub-panel assembly. Finally, we may find a lower voltage style device as a discrete device either plugged in at an outlet or perhaps approaching the mounting of this device within a particular piece of sensitive equipment itself.

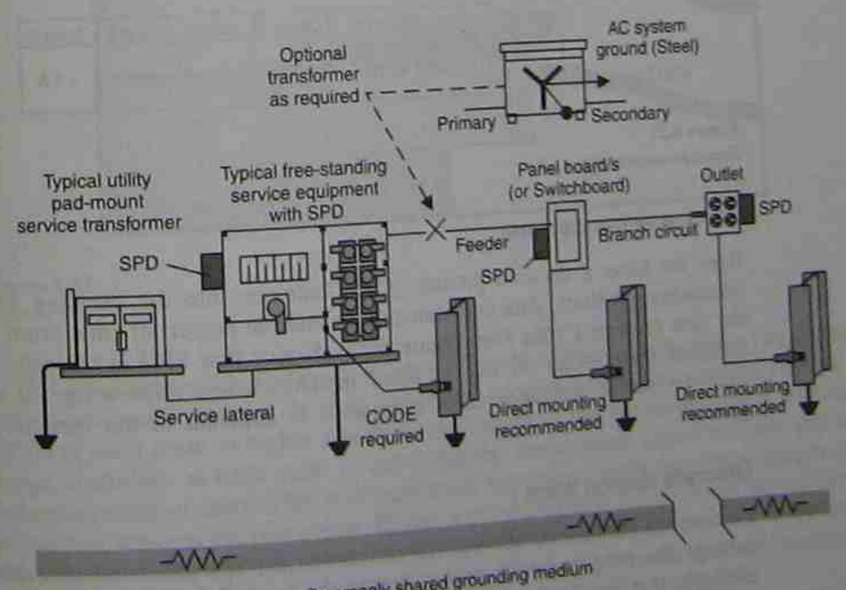
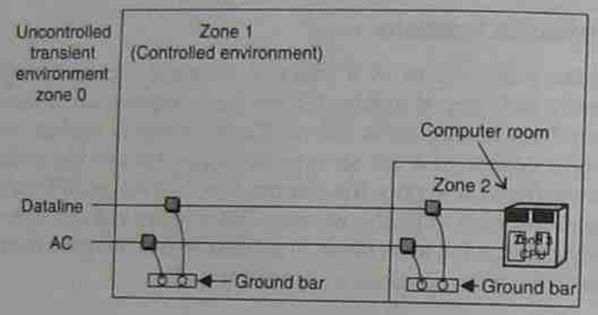


Figure 6.20
Typical location of power distribution TVSS/SPD

Protection zones

We call this the zoned protection approach and we see these various zones outlined in Figure 6.21 with the appropriate reduction in the order of magnitude of the surge current as we go down further and further into the zones, into the facility itself. Notice that in the uncontrolled environment outside of our building we would consider the amplitude of say, 1000 A. As we move into the first level of controlled environment, called zone 1, we would get a reduction by a factor of 10 to possibly 100 A of surge capability. As we move into a more specific location, zone 2, perhaps a computer room or where the various sensitive hardware exist, we find another reduction by a factor of 10. Finally, in the equipment itself, we may find another reduction by a factor of 10 of the effect of all of this surge being basically 1 A at the device itself.

The idea of the zone protection approach is to utilize the inductive capacity of the facility, namely the wiring, to help attenuate the surge current magnitude as we go further and further away from the service entrance to the facility.



	Zone 0	Zone 1	Zone 2	Zone 3
Order of magnitude of surge current	x 1000 A	x 100 A	x 10 A	x 1 A

Figure 6.21
Zoned protection approach

Service entrance zone

Here we have a detailed picture of the entrance into the building where both the telecommunications, data communications and the power all enter from the outside to the first protected zone (see Figure 6.22). Notice that SPD is basically stripping any transient phenomena on any of these metallic wires, referencing all of this to the common service entrance earth even as it is attached to the metallic water piping system.

Discrete device zone

Here as we address the discrete level between the first level of controlled zone 1 and perhaps the plug-in device taking it into the zone 2 location, we can see SPDs are available that handle the telecommunications, data and different types of physical plug connections for each, including both the RJ type of telephone plug as well as coaxial wiring (see Figure 6.23).

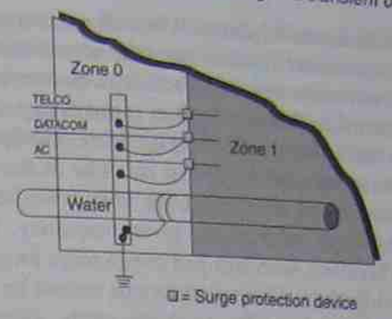


Figure 6.22
Zone 0 protection

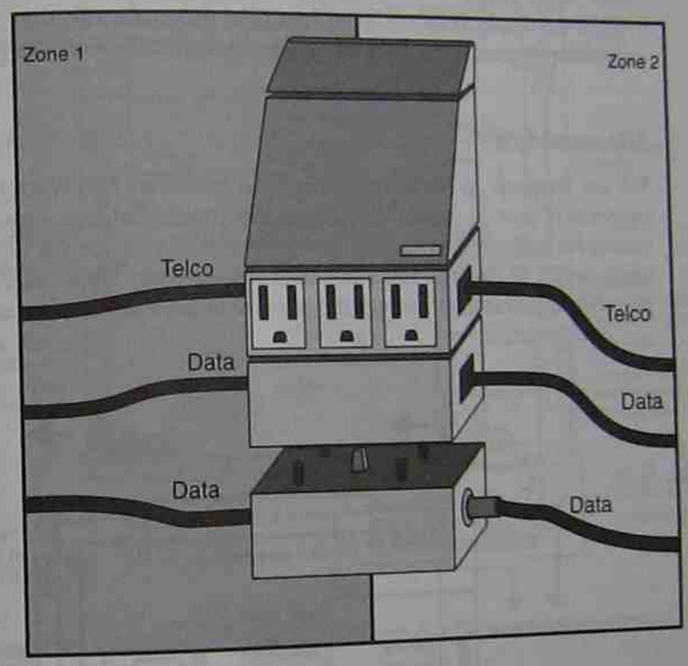


Figure 6.23
Zones 1 and 2

This is a common design error where two points of entry and therefore two earthing points are established for the AC power and telecommunications circuits. The use of SPDs at each point is highly beneficial in controlling the line-to-line and line-to-earth surge conditions at each point of entry, but the arrangement cannot perform this task between points of entry. This is of paramount importance since the victim equipment is connected between the two points. Hence, a common-mode surge current will be driven through the victim equipment between the two circuits despite the presence of the much needed SPDs. The minimal result of the above is corruption of the data and maximally, there may be fire and shock hazard involved at the equipment.

No matter what kind of SPD is used in the above arrangement nor how many and what kind of additional individual, dedicated earthing wires, etc. are used, the stated problem will

remain much as discussed above. Wires all possess self-inductance and because of $-e = L$ di/dt conditions, cannot equalize potential across themselves under normal impulse/surge conditions. Such wires may self-resonate in quarter-waves and odd-multiples thereof, and this is also harmful. This also applies to metal pipes, steel beams, etc. Earthing to these nearby items may be needed to avoid lightning side-flash, however.

Adding more earths to the above (such as at the victim equipment) is not effective since these merely act as taps into the voltage–current divider that the earth represents due to its ohms/unit value at any given frequency. This value gives up with increased frequency. Therefore, such taps just create more loops for the surge currents to flow and ring back-and-forth in. These connections cannot be implemented in any case when the equipment is located on floors above earth. Therefore, schemes based upon such connections would fall in any case due to the need to place equipment anywhere in a building and on any floor, etc. and the 'long' wires necessitated to be used to reach 'earth' floors away.

While the shown SPDs are highly beneficial (from normal-mode surge), some additional improvements must be made to cope with common-mode problems (such as lightning!).

Site overview

We are fortunate to have from consulting associate, Mr Warren Lewis, an excellent overview of how to prepare the power, telecommunications, earthing and surge current routing for protection. In our first view (Figure 6.24), we see the typical victim equipment being caught in between surge impulses coming from the service entrance of electrical power as well as coming through the entrance of the telecommunications product.

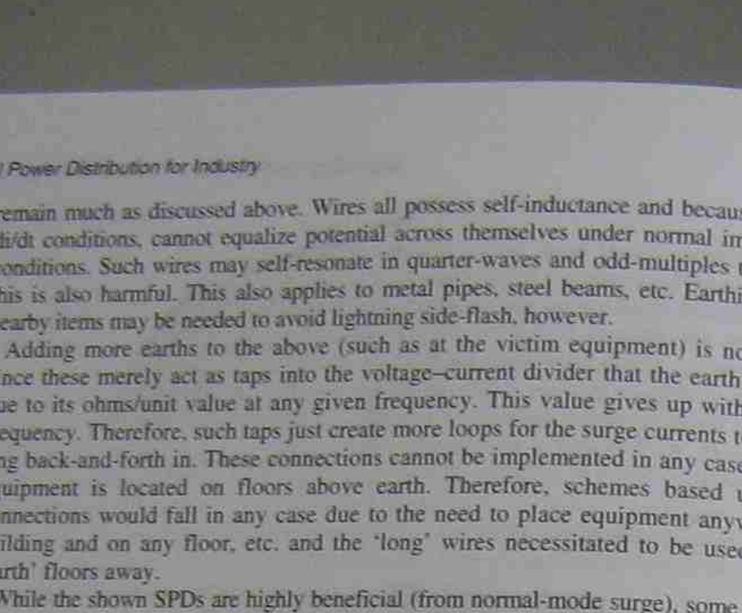


Figure 6.24
Overview of a typical site: Power and telecommunications earthing and surge current routing through victim equipment

Otherwise unchanged from the previous drawing, Figure 6.25 shows the recommended usage and location of a combination data and AC SPD unit employed for protection of the equipment connected between the AC and telecommunications systems. This practice is easy to implement on a case-by-case basis, but it is not a complete solution since the beneficial effects of the arrangement are not complete. In other words, there is always a residual surge current to deal with due to Kirchkoff's current law being operative at the junctions within the AC and data SPD unit. No SPD vendor can eliminate these phenomena.

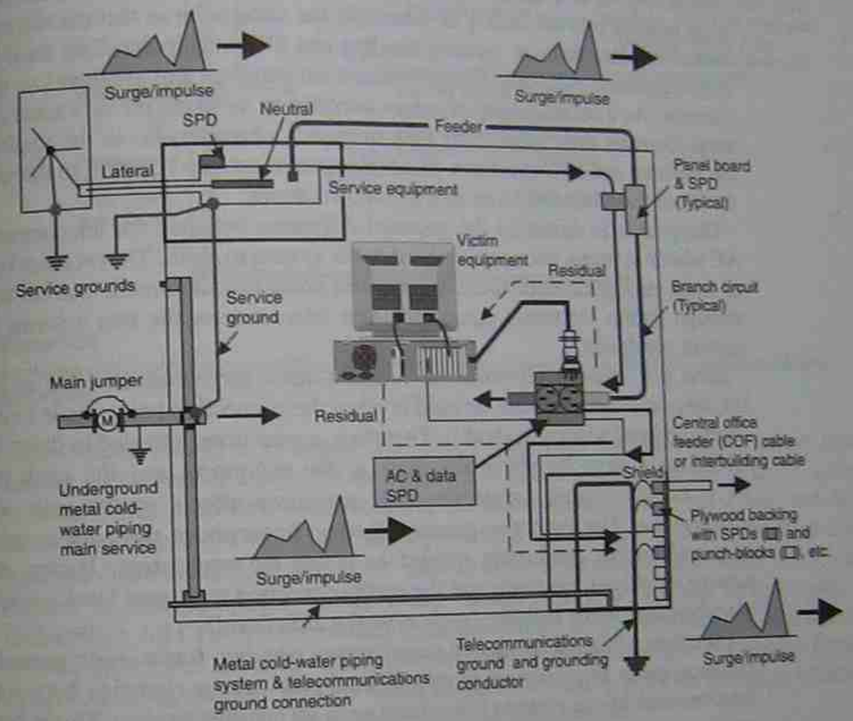


Figure 6.25
Improved protection of victim equipment connected between AC power and telecommunications circuits (localized SPD protection)

The SPD located at the service entry is beneficial in that it diverts some of the current that would otherwise enter the victim equipment's susceptibility path. The same holds true for the SPD at the telecommunications entry area. Both are important to have.

The shown solution is still flawed since the surge current is still allowed to flow largely within the facility and on the AC and telecommunications wiring. This means lots of stray coupling into other circuits along the way, and in some cases, localized arcing between items that are conductive and at different potentials. The locally installed SPD at the AC and telecommunications ports for the shown 'Victim Equipment' cannot have any practical effect on these unwanted phenomena. Therefore, something further must be done to improve matters to the level consistent with the demands of a modern, commercial establishment utilizing electronic computer/data processing and telecommunications systems that are interconnected.

Specialized 'earth' earthing at the local SPD point is not generally required of beneficial, in fact, adding another 'earth' into the circuit at this point might be an additional surge current

injection point! Local connection to local building steel, etc. are always a good practice, but not a requirement.

Improved protection

The improvement in protection for the victim equipment is shown in Figure 6.25 where the protected devices are located at the incoming power, a sub-panel board and the victim equipment itself.

Typically for new construction, the telecommunications cables and the AC power need to be brought into the facility at essentially the same point so that the two may be literally locked-together from an earthing/bonding and SPD standpoint. This must be done using high-frequency techniques. Surge currents are impulses and are therefore high-frequency currents. As a result, wiring practices intended to motivate the unwanted effects of such surge currents must reflect this high-frequency characteristic in the implementations of the earthing and SPD practices. The techniques must also conform to the requirements of the Electrical Code (NEC) as do those shown above.

The goal is to minimize the potential difference between the telecommunications and AC power systems, not necessarily of either system to earth. The problem is the exchange of surge current between these two systems under common-mode current conditions, and through victim electronic equipment, that interconnects the two systems from a surge current standpoint.

Earth is a valuable reference for common-mode surge current (such as lightning), but the only time that earth can be used is when the connection being made to it is physically short and low-inductance (both!). Therefore, connections intended to divert current in/out of the earth must be physically close to the equipment and the earth point itself or $-e = L\ di/dt$, simple impedance, and resonance effects in the path will defeat its effectiveness. This cannot be accomplished on floors above earth due to the length of the earthing/bonding conductors needed to effect the connection. Hence, the protection scheme employed must only use the earth connection at ground level – it is not effective anywhere else in the building (such as on the 25th floor!).

Therefore, all initial attacks on surge current take two forms: earth ground diversion of common-mode surge current at ground level plus voltage clamping between the AC and telecommunications systems (must be done in all possible modes). This is best done at the common point of entry for both systems to the facility. Then, secondary and tertiary attachments on the common-mode surge current to a place whenever the two systems (ac power and telecommunications) can be physically brought together and SPD interconnected in low-inductance fashion. Normal-mode protection on the AC system and the telecommunications system is generally effective wherever it is done in a path via the simple addition of a suitable SPD, since 'earth ground' is not a part of this process.

Recommended practice – joint entrance

Here in our Figure 6.26 of this sequence we find the recommended practice for installation of power and telecommunications entrances, typically, for new construction.

Two major changes are made in this figure to greatly reduce the surge current problem between the AC power and telecommunications circuit. The first is to disconnect the COAX cable from its landings on the plywood board and to reroute its end (including the gas-tube SPD assembly on it) into a metal pull-box. The cable's shields and the SPD are well-bonded to the metal box, which in turn is connected to a newly installed, driven earth ground installed just below the pull-box (this keeps wires short).

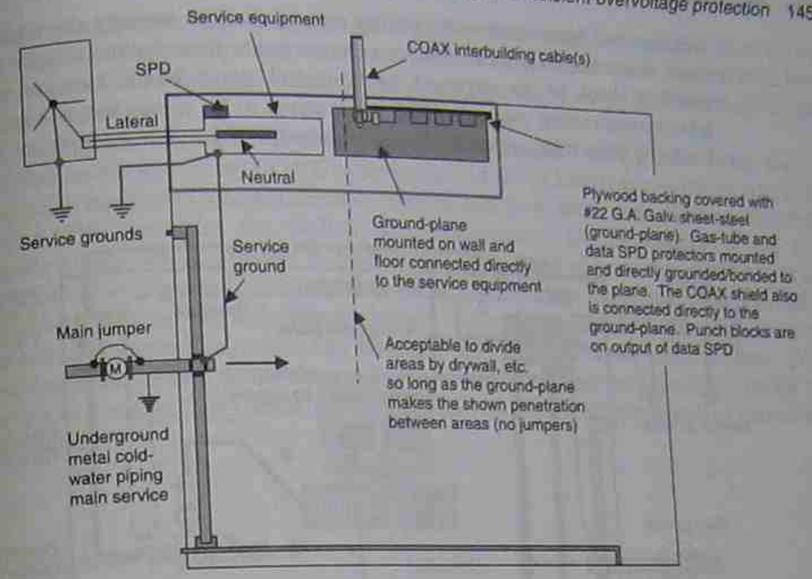


Figure 6.26
Recommended practice for installation of AC power and telecommunication lines on a facility (with SPD protection)

The second change is to reroute the COAX cable from the pull-box via ferrous metal conduit, to the service equipment area where it is landed to a high-quality SPD (i.e. a 'data protector') that is in turn earthed/bonded to the service equipment via a wall and floor mounted earth-plane. This is a #22 gage, galvanized steel arrangement that is secured to the wall, run down to the floor, bent at 90° and run to the service equipment, where it is lineally bonded to that equipment (weld, braze, solder or several screws, in that order or desirability). All COAX cable conduit is earthed/bonded to this earth-plane on both sides.

Next, the COAX cable is returned to the telecommunications area via another ferrous metal conduit as shown. Once the return is made the various pairs are landed to whatever punch-block terminals that they would have originally gone to.

The ferrous metal conduit used above is most effective if it is rigid conduit, then intermediate conduit, and finally, 'thinwall' (EMT) conduit. Do not use flexible conduits of any kind. Aluminum is acceptable, but steel is best. Also, do not make any effort to 'insulate' these conduits along the runs. Just install them in 'normal' fashion. In fact, the conduit is meant to connect multiple points of 'earth', the one at the service lateral (the power supply earth) and the other 'signal earth' at the communication entry point, into a single equipotential reference plane. When joining circuits or terminating them, use high-quality fittings and connectors. The best type is threaded, then circumferential compression ring types, and lastly, the set-screw types.

The service and telecommunications systems are SPD 'surge-locked together' in this arrangement.

Retrofitting recommendations

Here we find a recommendation for the retrofitting of a telecommunications and power system for improving the lightning and surge immunity (see Figure 6.27). You will notice that the heart of this is to correct the facility where a separate telecommunications

entrance had been made and to bring ferrous conduit carrying the telecommunications cable main runs over to the service entrance earth-plane for the electric power and then return it back to its plywood backing and punch-block location at the separate telecommunications entrance. While this seems to be somewhat of a redundant method for doing these things, it works very well in terms of providing additional protection.

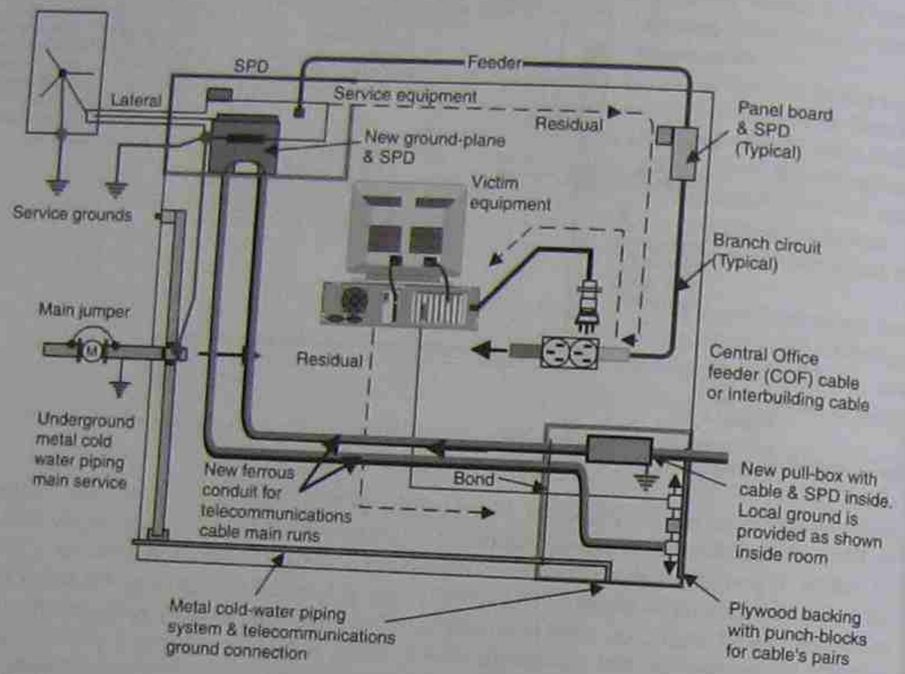


Figure 6.27
Retrofitting a telecommunication and AC power system for improved lightning and surge immunity (Recommended)

Still further improvement in surge protection is obtained once additional protection for the victim equipment is added at the local point where the equipment is installed. This is generally accomplished via the use of a combination AC and data SPD as shown and as previously discussed.

In the shown arrangement above, there is only 'residual' surge current to be controlled by the locally applied AC and data SPD as opposed to its being required to handle principal surge currents. This means that the locally applied protection becomes very much more effective since it is now acting as a second (and sometimes third) stage of surge current diversion and voltage clamping point. Less surge current is input to the local protection by the above arrangement so less escapes its effects to finally reach the victim equipment. However, something will always reach the victim equipment since no protection scheme is 'perfect'. But, if what does reach it, stays well below the point of component damage, the equipment will be 'protected' in all but the most extreme cases.

This arrangement is a form of a 'cascade' protection scheme. The idea is to progressively divert surge currents at each level – nearest the point of entry, then downstream, and finally

at the victim equipment itself. At each level of protection, destructive energy is taken out of the surge, its current and voltage level is reduced, and its waveshape is also rendered less likely to have fast transitions which are the principal cause of $-e = L\,di/dt$ problems in the current's path.

Note that the original 'Telephone Company' protector (the gas-tube SPD) that is installed on the end of the COAX cable is retained and is locally earthed/bonded to both the metal equipment conduit/raceway system and to a local earth earthing electrode system. This maintains the 'Bell System' requirements for the installation and also permits a 'first line of defense' to be provided at the point of entry for the COAX to the building. This cable-end SPD may do a lot of good and can relieve the SPD installed at the service from having to handle the highest levels of surge currents that might enter via the telecommunications cable, etc. However, this does not mean that the 'data' SPDs installed at the service do not have to be 'heavy duty', they do. Surges arriving on the AC service will trigger these SPDs, and so they must handle the large amounts of current that this implies.

Adding local protection

Hence, in summary, to the routing of the telecommunications cable in ferrous conduit, we will add, as we have seen before, the local power, sub-panel and discrete surge protection devices to improve the immunity of the product (Figure 6.28).

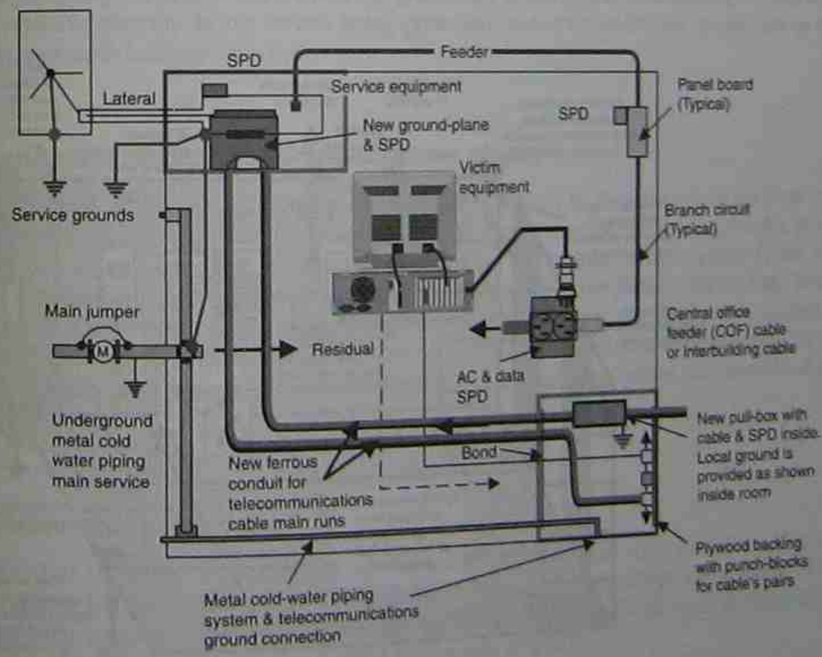


Figure 6.28
Adding local AC and data SPD protection for improved lightning and surge immunity (Recommended)

The earth-plane is now shown fully developed and covering both the wall(s) and the floor in the telecommunications equipment area. The whole area need not be covered by the earth-plane, just as shown/needed. Also, the AC power is now integrated with the same high-frequency earth system that the telecommunications system is using and all SPDs are commonly referenced to it as well.

The separately derived AC system needs to be solidly earthed as shown from one or more of the chosen AC system earthing electrodes (A, B or C). The preference is structural building steel, the made electrode system and then the metal cold-water piping, all in order of desirability. Best results are obtained when two or more of the shown electrodes are available to the earth-plane, although only one needs to be connected directly to the transformer for AC system earthing.

Cable trays/ladders must be electrically continuous so ends must be earthing/bonding jumpered together when two more sections meet or approach across a gap or other space. This is especially important to do when the tray/ladder penetrates walls, etc. Continuation of the cable into the site without tray/ladder is best done within ferrous metal conduit/raceway with it well earthed/bonded to the tray/ladder at the point of conversion.

Clamps, welds, brazing and direct soldering are all methods employed to connect items together instead of inductive means such as long earthing/bonding wires, etc. Such wires may be added to what is shown so as to allow the installer to 'see' the earthing.

Fully integrated protection

Reviewing the use of the earth-plane for a fully developed and fully integrated system, we find all of the components that we have been referring to now located and referenced to a common equipotential surface (Figure 6.29).

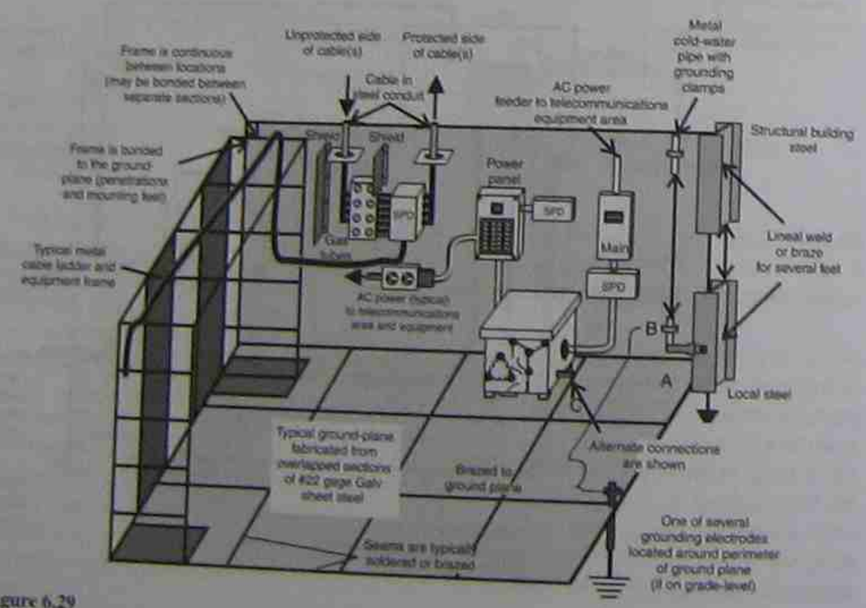


Figure 6.29
Fully integrated SPD protection and earthing for the telecommunication system

Circuit protective elements and transient phenomena

Fuses have been, until recently, the prime protective element in medium- and low-voltage circuits, with current ratings from as low as 60 mA–1000 A or more. These protective elements can carry up to 5000 times their rated current for period of <5 ms. These devices are manufactured with a wide range of characteristics that vary the speed of response (failure mode) with varying magnitudes of fault or overload currents vs time. Long-term failures can occur, caused by a continuous 20% overload, which will not become evident for hours or days. The separation of the wire element during the rupture period (clearing of the overload) can cause surges due to the arcing across the separating pieces of the element. Many fuses have the wire element surrounded in silica as a current suppressant, for 'current limiting' action, and the rapid melting of the silica as it surrounds the ruptured element leads to enormous transient voltages across the opening element. (The impedance of the wire rupture becomes nearly 'infinite' instantaneously!)

These phenomena cause stress in the associated fuses in adjoining phases of a three-phase system, and may lead to 'single phasing' in the system for indeterminate periods. The protected AC circuits tend to 'sag' just before the rupture by an amount depending on the fault current and source impedance, and the 'surge' after the complete rupture, particularly if the rupture time period is very short. The circuit will experience interference in the form of transient noise between the time of the current overload and the final clearing by the fuse element. The nominal ratings tend to show wide tolerances, as much as +/–20% is not uncommon, and thus this form of protection may not be accurate.

The general trend is to replace the fuse with a magnetic circuit breaker (MCB), capable of protecting all phases even when one phase only is effected. These devices exhibit only a resistive element in the circuit being protected, and offer additional protection in the form of earth leakage detection.

Earth leakage devices (single and three phase)

These devices operate by comparing the supply currents to the load return currents in a circuit. A difference in current, in excess of the mA rating of the device, results in the device operating to open all circuits, both phase(s) and neutral. A three-phase device can be obtained for three phase, three-wire operation or for three phase with neutral. When there is a leakage to earth, whether from any phase or neutral, the device will operate to protect the circuit, thus no connection between neutral and earth can exist downline of the unit. These units present a small series inductance on each line (phase and neutral) of the circuit.

Codes and guidelines

We find in Table 6.1 examples of various codes, standards and guidelines that are available for the understanding of standards of transient voltage surge suppression. What has been referred to by manufacturers in the United States as TVSS, now is more easily referred to throughout the international community as a SPD.

Organization	Code, Article or Standard No.	Scope
ANSI/IEEE	C62	Guides and standards on surge protection
	C62.41 – 1980	Guide for surge voltages in low voltage AC power circuits
	C62.1	IEEE standard for surge arrestors for AC power circuits
	C62.45 – 1987	Guide on surge testing for equipment connected to low voltage AC power circuits
	C62.41 – 1991	Recommended practice on surge voltages connected to low voltage AC power circuits (approved, not published)
IEEE	C74.199.6 – 1974	Monitoring of computer installations for power disturbances. International Business Machines Corp. (IBM)
UL	UL 1449	Transient Voltage Surge Suppressors (TVSS)
NEC	Article 250	Earthing
	Article 280	Surge arresters
	Article 645	Electronic data processing equipment
	Article 800	Communications circuits
NFPA	NFPA-75–1989	Protection of electronic data processing equipment
	NFPA-78 – 1989	Lightning protection code
	NFPA-20 – 1990	Centrifugal fire pumps
MIL-STD	MIL-STD-220A	50Ω insertion loss test method. Earthing, bonding & shielding for electronic equipment and facilities
	MIL-STD-419A/B	
FIPS	FIPS PUB 94	Guideline for electrical power in ADP Installations (Chapter 7)

Table 6.1
Codes, recommended practices, standards and guidelines for transient voltage surge suppression (TVSS)/(SPD)

7

Power system analysis software

Introduction

Power system analysis software ranges from basic, commercially available, generic packages to large, complex programs developed for a specific customer. The latter serves the needs of a single comprehensive electrical system and may be integrated in real time to an electrical SCADA system with real input from the field.

The former programs are usually more user-friendly, require simulated input, and are used on a wide scale by consultants, industry and utilities.

A wide variety of programs are available today to perform all sorts of electrical analyses, as will be demonstrated in this chapter. Of all these, the programs that are undoubtedly used most frequently in power distribution design and analyses are the load flow and fault analyses studies.

A load flow study determines the voltage, current, power and reactive power in various points and branches of the system under simulated conditions of normal operation. Load flow studies are essential in optimizing existing networks, ensuring an economical and efficient distribution of loads, and plan future networks or additions to existing networks.

The currents that flow into different parts of a power system immediately after the occurrence of an electrical fault differ substantially from the current flowing in steady-state conditions. These currents determine the ratings of circuit breakers and other switchgear that are installed in the system, specifically the current flowing immediately after the fault and the current which the circuit breaker must interrupt. Fault calculations consist of predicting these currents for various types of faults at various locations in the system. The data obtained from fault calculations are also used to determine relay settings.

Network studies used to be extremely time-consuming in the pre-digital computer days, and often not very accurate. However, very powerful electrical analysis software in modern times has restricted human efforts to the input of equipment data and the interpretation of the study results. Network studies can now be done in a fraction of the time it used to take, with much more accurate results. This has greatly aided in more efficient power systems being designed, implemented and maintained.

The real-time information that can be obtained from a power system automation system is a great aid to, and parallel with, network studies. Firstly, the steady-state information continuously obtained, archived and trended can tremendously assist the results of load flow studies. Secondly, the information obtained from disturbance records, as well as sequence-of-events recordings, can be used to determine the correctness of fault calculations and stability studies, as well as to verify the effectiveness of the electrical protection.

7.2 Load flow

One of the earliest programs to be developed for power system analysis was the load flow (power flow) program. It was originally developed in the late 1950s. All complete packages in use today have load flow programs as an integral part, as this is one of the cornerstones of any electrical network analysis.

Although an electrical network is linear, load flow analysis is iterative due to the interactive influences of voltages, currents, frequency and reactance on one another. The generators are scheduled to deliver a specific active power to the system and usually the voltage magnitude of the generator terminals is fixed by automatic voltage regulation. Usually, one generator busbar only has its voltage magnitude specified, as losses in the system cannot be determined before the load flow solution. This bus also has its voltage angle defined to some arbitrary value, usually zero, which is only a reference point for the rest of the network. This busbar is known as the slack bus, or utility bus in some programs. The slack bus is a mathematical requirement for the program and has no exact equivalent in reality.

The total load plus the losses are not known in operating practice, and they fluctuate continuously. When a system is not in power balance, i.e., when the input power does not equal the load power plus losses, the imbalance modifies the rotational energy stored in the system. The system frequency thus rises if the input power is too large and falls if the input power is too little. Usually a generating station with one machine is given the task of keeping the frequency constant by varying the input power.

The algorithms originally developed had the advantages of simple programing and minimum storage but were slow to converge requiring many iterations. The introduction of ordered elimination of the network matrix, and programing techniques that reduce storage requirements, allowed much better algorithms to be used. The Newton–Raphson method gave convergence to the solution in only a few iterations.

Using Newtonian methods of specifying the problem, a Jacobian matrix containing the partial derivatives of the system at each node can be constructed. The solution by this method has quadratic convergence. This method was followed quite quickly by the fast decoupled Newton–Raphson method. This exploited the fact that under normal operating conditions, and providing that the network is predominately reactive, the voltage angles are not affected by reactive power flow and voltage magnitudes are not effected by real power flow. The fast decoupled method requires more iterations to converge but each iteration uses less computational effort than the Newton–Raphson method.

The results of a load flow study can be seen as a snapshot of the system once steady-state conditions have been reached with all loads staying at constant values. The study calculates the voltage on each bus, the voltage drop on each feeder, the current, power flow and losses in all branches, as well as total system losses. Branch loads can include load diversity considerations.

7.3 Sizing study

The sizing study selects the conductor size based on the minimum conductor material and cross-sectional area necessary to meet defined feeder-current-carrying capability, and associated voltage drop criteria. Transformers are sized based on their full load kVA rating.

Feeder sizing

Feeder sizes are based on the design load value from the demand load study. The demand load study calculates the total connected demand and design load in each branch of the power system. Some loads are defined as continuous loads and, as such, the design load

value is larger than its demand load value. The NEC (USA) requires branch circuits that serve continuous loads to be rated so that not more than 80% of the feeder current rating is used. Selecting a design load value of 125% (1/80) of the demand load value meets the NEC standard. The feeder current rating is defined as the current in amperes that a conductor may carry continuously under the conditions of use without exceeding its temperature rating.

The sizing study bases its calculations on two separate criteria: the minimum conductor cross-sectional area to meet feeder rating values and a user-defined voltage drop value. If you consider parallel feeder combinations for a specified conductor type, the sizing study can select multiple feeders in parallel for that conductor. Cable sizes are usually specified in a cable library in order to be available to the sizing study. Derating factors are determined based on the temperature derating factor and duct bank design detail criterion.

The sizing study selects the cable that best meets defined current rating values and has the smallest cross-sectional area. Once the cable is selected, the voltage drop for the cable or cable pair is calculated. If the voltage drop criterion is exceeded, the sizing study selects the next larger cable size and begins the comparison of cross-sectional area, rated current and voltage drop.

The sizing study algorithm determines the feeder branch design load value in amperes, then determines the selected feeder design current rating. The feeder design rating is the product of the rated current, the temperature derating factor and the number of parallel cables. The design load value is the rated size of the load multiplied by specified demand factors and the long continuous load factor (or design factor).

Once the current rating conditions are met, the sizing study then checks the calculated voltage drop on the cable, based on the branch design load current and power factor, cable impedance, and length.

The voltage drop is calculated using the following formula:

$$\%\ \text{Voltage drop} = \frac{\sqrt{3}\left[(I\times R\times\cos\Phi)+(I\times X\times\sin\Phi)\right]}{V_{ll}}\times 100$$

If the voltage drop exceeds the specified level, the sizing study selects the next largest feeder and restarts the sizing study in order to select a cable or combination of parallel cables which meets the rating criteria of minimum cross-sectional area and acceptable voltage drop.

Transformer sizing

Transformer sizing is normally based on either the calculated branch demand or design load value, depending on user selection. The sizing algorithm compares the demand or design load value to the transformer's full load size. The transformer's full load size is:

Full load size = Nominal kVA rating × Transformer capacity factor

Typical capacity factors are:

Transformer Cooling Characteristic	Capacity Factor
Dry type (DT)	1.00
Oil/air cooled (OA)	1.15
Oil/air/forced air (OAFA)	1.25

Transformer feeders

Feeders for the primary and secondary of transformers are based on a factor (usually 125%) of the transformer's full load rating and an allowable voltage drop criteria. This factor is usually defined in the demand load study set-up dialog box.

7.4 Fault analysis

A fault analysis program derives from the need to adequately rate switchgear and other busbar equipment for the maximum possible fault current that could flow through them. Fault analysis programs were also developed in the 1950s alongside load flow programs.

Initially only three-phase faults were considered and it was assumed that all busbars were operating at nominal voltage prior to the fault occurring. The load current flowing prior to the fault was also neglected.

By using the results of a load flow prior to performing the fault analysis, the load currents can be added to the fault currents allowing a more accurate determination of the total currents flowing in the system.

Unbalanced faults can be included by using symmetrical components, mathematically dividing fault currents in negative sequence, positive sequence and zero sequence currents.

When the fault levels in an industrial plant are calculated the contributions of motors and generators should also be taken into account. Their contribution to the fault current can change the final value significantly. Modern programs also take the DC effect into account.

7.5 Transient stability

After a disturbance, due usually to a network fault, the synchronous machine's electrical loading changes and the machines speed up (under very light loading conditions they can slow down). Each machine will react differently depending on its proximity to the fault, its initial loading and its time constants. This means that the angular positions of the rotors relative to each other change. If any angle exceeds a certain threshold (usually between 100° and 140°) the machine will no longer be able to maintain synchronism. This almost always results in its removal from service.

Early work on transient stability had concentrated on the reaction of one synchronous machine coupled to a very large system through a transmission line. The large system can be assumed to be infinite with respect to the single machine and hence can be modeled as a pure voltage source. The synchronous machine is modeled by the three phase windings of the stator plus windings on the rotor representing the field winding and the eddy current paths. These are resolved into two axes, one in line with the direct axis of the rotor and the other in line with the quadrature axis situated 90° (electrical) from the direct axis. The field winding is on the direct axis. Equations can be developed which determine the voltage in any winding depending on the current flows in all the other windings. A full set of differential equations can be produced, which allows the response of the machine to various electrical disturbances to be found. The variables must include rotor angle and rotor speed. The great disadvantage with this type of analysis is that the rotor position is constantly changing as it rotates. As most of the equations involve trigonometrical functions relating to stator and rotor windings, the matrices must be constantly re-evaluated.

In the most severe cases of network faults the results, once the DC transients decay, are balanced. Further, on removal of the fault, the network is considered to be balanced. There is thus much computational effort involved in obtaining detailed information for each of the three phases, which is of little value to the power system engineer. By contrast, this type of analysis is very important to machine designers. However, programs have been written for multi-machine systems using this method.

Initially, transient stability programs all ran in the time domain. A set of differential equations is developed to describe the dynamic behavior of the synchronous machines. All the machine equations are written in the direct and quadrature axes. The network is represented in the real and imaginary axes, similar to that used by the load flow and fault analysis programs.

Modern programs also look at the response of the system, not only to major disturbances but also to the build-up of oscillations due to small disturbances (such as asynchronous resonance) and poorly set control systems. In calculating the system response for these disturbances, very long time domain solutions are not suitable, so frequency domain models of the system were developed.

Fast transients

Transient stability program considers the dynamic response of the power system in the range of 1–10 Hz. There is however also a need to calculate the system's response to faster transients from switching ranges to the propagation of steep voltage and current waves traveling down transmission lines as a result of a lightning strike. To model these effects a very detailed model is required, e.g. all the stray capacitances and inductances need to be incorporated into the model.

Many of these programs are difficult to use and take a long time to solve. For this reason only short time periods are usually studied.

7.7 Reliability

Reliability of equipment is of constant concern to the operators of power systems. In the past, reliability was ensured by providing reserve equipment, either connected in parallel with other similar devices or which could be easily connected in the event of a failure.

However, providing reserve equipment to cater for all eventualities has become very costly as systems expand.

Reliability of a system is governed by the reliability of all the parts and their configuration. Much work has been done on the determination of the reliability of power systems but work is still being done to comprehensively model power system components and integrate them into system reliability models. Much of the early work was focused on generation facilities. The reasons for this was that, first, more information was available about the generation; second, the geographical size of the problem was smaller; and, third, the emphasis of power systems was placed in generation. With the onset of deregulation (in the USA), distribution and customer requirements are considered paramount.

At the generation and transmission levels, the loss of load expectation and frequency and duration evaluation are prime reliability indicators.

The usual method for evaluating reliability indicators at the distribution level, such as the average interruption ratio per customer per year, is an analytical approach based on a failure-mode assessment.

7.8 The second generation of programs

The advent of the PC provided a universal platform on which most users and programs could come together. This process was further assisted when window-based programs reduced the need for such a high level of computer literacy on the part of users.

PCs, Macintosh computers – which has a similar capability to a PC but which is less popular with engineers – and more powerful workstations, usually based on the Unix operating system, are used for software programs. Minicomputers and mainframe computers are also still in general use in universities and industry.

Hardware and software for power system operation and control required at utility control centers are usually sold as a total package. These are usually proprietary systems and the justification for a particular configuration requires input from many diverse groups within the utility.

7.9 Graphics

Two areas of improvement that stand out in this second wave of generally available programs are both associated with the graphical capabilities of computers. A good diagram can be more easily understood than many pages of text or tables.

The ability to produce graphical output of the results of an analysis has made the use of computers in all engineering fields, not just power system analysis, much easier. Tabulated results are never easy to interpret. They are also often given to a greater degree of accuracy than the input data warrants. A graph of the results, where appropriate, can make the results very easy to interpret and if there is also an ability to graph any variable with other variables, especially if three dimensions can be utilized, then new and significant information can be quickly assimilated.

New packages became available for business and engineering which were based on either the spreadsheet or the database principle. These also had the ability to produce graphical output. It was no longer essential to know a programing language to do even quite complex engineering analysis. The programing was usually inefficient and obtaining results was more laborious, e.g. each iteration had to be started by hand. But, as engineers had to use these packages for other work, they became very convenient tools.

A word of caution: be careful that the results are graphed in an appropriate manner. Most spreadsheet packages have very limited x-axis (horizontal) manipulation. Provided the x-axis data comes in regular steps, the results are acceptable. However, we have seen instances where very distorted graphs have been presented because of this problem.

Apart from the graphical interpretation of results, there are now several good packages that allow the analyst to enter the data graphically. It is a great advantage to be able to develop a one-line diagram of a network directly with the computer. All the relevant system components can be included. Parameter data still require entry in a more orthodox manner but by merely clicking on a component, a data form for that component can be made available. The chances of omitting a component are greatly reduced with this type of data entry. Further, the same system diagram can be used to show the results of some analyses.

An extension of the network diagram input is to make the diagram relate to the actual topography. In these cases, the actual routes of transmission lines are shown and can be superimposed on computer-generated geographical maps. The lines in these cases have their lengths automatically established and, if the line characteristics are known, the line parameters can be calculated.

These topographical diagrams are an invaluable aid for power reticulation problems, for example, the minimum route length of reticulation given all the points of supply and the route constraints. Other optimization algorithms include determination of line sizes and switching operations.

The analysis techniques can be either linear or non-linear. If successful, the non-linear algorithm is more accurate but these techniques suffer from larger data storage requirements, greater computational time, and possible divergence. There are various possible optimization techniques that can and have been applied to this problem. There is no definitive answer and each type of problem may require a different choice.

The capability chart represents a method of graphically displaying power system performance. These charts are drawn on the complex power plane and define the real and reactive power that may be supplied from a point in the system during steady-state operation. The power available is depicted as a region on the plane and the boundaries of the region represent the critical operating limits of the system. The best known example of a capability chart is the operating chart of a synchronous machine. The power available from the generator is restricted by limiting values of the rotor current, stator current, turbine power (if a generator), and synchronous stability limits. Capability charts have been produced for transmission lines and HV DC converters.

7.10 Protection

The need to analyze protection schemes has resulted in the development of protection coordination programs. Protection schemes can be divided into two major groupings: unit and non-unit schemes.

The first group contains schemes that protect a specific area of the system, i.e., a transformer, transmission line, generator or busbar. The most obvious example of unit protection schemes is based on Kerchief's current law – the sum of the currents entering an area of the system must be zero. Any deviation from this must indicate an abnormal current path. In these schemes, the effects of any disturbance or operating condition outside the area of interest are totally ignored and the protection must be designed to be stable above the maximum possible fault current that could flow through the protected area. Schemes can be made to extend across all sides of a transformer to account for the different currents at different voltage levels. Any analysis of these schemes is thus of more concern to the protection equipment manufacturers.

The non-unit schemes, while also intended to protect specific areas, have no fixed boundaries. As well as protecting their own designated areas, the protective zones can overlap into other areas. While this can be very beneficial for backup purposes, there can be a tendency for too great an area to be isolated if a fault is detected by different non-unit schemes. The most simple of these schemes measures current and incorporates an inverse time characteristic into the protection operation to allow protection nearer to the fault to operate first. While this is relatively straightforward for radial schemes, in networks, where the current paths can be quite different depending on operating and maintenance strategies, protection can be difficult to set and optimum settings are probably impossible to achieve. It is in these areas where protection software has become useful to manufacturers, consultants and utilities.

The very nature of protection schemes has changed from electromechanical devices, through electronic equivalents of the old devices, to highly sophisticated system analyzers (microprocessor-based relays or IEDs). They are computers in their own right and thus can be developed almost entirely by computer analysis techniques.

7.11 Other uses for load flow analysis

It has already been demonstrated that load flow analysis is necessary in determining the economic operation of the power system and it can also be used in the production of capability charts. Many other types of analyses require load flow to be embedded in the program, e.g.

- *Unbalanced three-phase analysis:* As a follow-on from the basic load flow analysis, where significant unbalanced load or unbalanced transmission causes problems, a three-phase load flow may be required to study their effects. These programs require each phase to be represented separately and mutual coupling between phases to be taken into account. Transformer winding connections must be correctly represented and the mutual coupling between transmission lines on the same tower or on the same right-of-way must also be included.
- *Motor starting studies:* Motor starting can be evaluated using a transient stability program but in many cases this level of analysis is unnecessary. The voltage dip associated with motor start-up can be determined very precisely by a conventional load flow program with a motor starting module.
- *Optimal power flow:* Optimal power system operation requires the best use of resources subject to a number of constraints over any specified time period. The problem consists of minimizing a scalar objective function (normally a cost criterion) through the optimal control of a vector of control parameters. This is subject to the equality constraints of the load flow equations, inequality constraints on the control parameters, and inequality constraints of dependent variables and dependent functions. The programs to do this analysis are usually referred to as optimal power flow (OPF) programs.
- *Security assessment:* Often optimal operation conflicts with the security requirements of the system. Load flow studies are used to assess security (security assessment). This can be viewed as two separate functions. First, there is a need to detect any operating limit violations through continuous monitoring of the branch flows and nodal voltages. Second, there is a need to determine the effects of branch outages (contingency analysis). To reduce this to a manageable level, the list of contingencies is reduced by judicial elimination of most of the cases that are not expected to cause violations.

From this the possible overloading of equipment can be forecast. The program should be designed to accommodate the condition where generation cannot meet the load because of network islanding.

The conflicting requirements of system optimization and security require that they be considered together. The more recent versions of OPF interface with contingency analysis and the computational requirements are enormous.

7.12 Extensions to transient stability analysis

Transient stability programs have been extended to include many other system components, ...transmission systems (FACTS) and DC converters. ...either shunt or series devices. Shunt devices ...susceptance. The device

changer, which injects a direct component of voltage. Fast acting power electronics can inject either direct voltage or a combination of both direct and quadrature voltage to help maintain voltage levels and improve stability margins.

DC converters for HV DC links and rectifier loads have received much attention. The converter controls are very fast acting and therefore a quasi steady-state (QSS) model can be considered accurate. That is, the model of the converter terminals contains no dynamic equations and in effect the link behaves as if it was in steady state for every time solution of the AC system. While this may be so some time after a fault has been removed, during and just after a fault the converters may well suffer from commutation failure or fire through. These events cannot be predicted or modeled with a QSS model. In this case, an appropriate method of analysis is to combine a state variable model of the converter, which can model the firing of the individual valves, with a conventional multi-machine transient stability program containing a QSS model. During the period of maximum disturbance, the two models can operate together. Information about the overall system response is passed to the state variable model at regular intervals. Similarly, the results from the detailed converter model are passed to the multi-machine model overriding its own QSS model. As the disturbance reduces, the results from the two different converter models converge and it is then only necessary to run the computationally inexpensive QSS model within the multi-machine transient stability program.

7.13 Voltage collapse

Steady-state analyses of the problem of voltage instability and voltage collapse are often based on load flow analysis programs. However, time solutions can provide further insight into the problem.

A transient stability program can be extended to include induction machines, which are associated with many of the voltage collapse problems. In these studies, it is the stability of the motors that are examined rather than the stability of the synchronous machines. The asynchronous nature of the induction machine means that rotor angle is not a concern, but instead the capability of the machines to recover after a fault has depressed the voltage and allowed the machines to slow down. The re-accelerating machines draw more reactive current, which can hold the terminal voltage down below that necessary to allow recovery. Similarly starting a machine will depress the voltage, which affects other induction machines, which further lowers the voltage.

However, voltage collapse can also be due to longer-term problems. Transient stability programs then need to take into account controls that are usually ignored. These include automatic transformer tap adjustment and generator excitation limiters, which control the long-term reactive power output to keep the field currents within their rated values.

7.14 SCADA

Supervisory control and data acquisition (SCADA) has been an integral part of system control for many years. A control center now has much real-time information available so that human and computer decisions about system operation can be made with a high degree of confidence.

In order to achieve high-quality input data, algorithms have been developed to estimate the state of a system based on the available online data (state estimation). These methods ...e based on weighted least squares techniques to find the best state vector to fit the ...atter of data. This becomes a major problem when conflicting information is received. ...However, as more data becomes available, the reliability of the estimate can be improved.

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Transient stability programs have been extended to include many other system components, including flexible AC transmission systems (FACTS) and DC converters.

Flexible AC transmission systems may be either shunt or series devices. Shunt devices usually attempt to control busbar voltage by varying their shunt susceptance. The device is therefore relatively simple to implement in a time domain program. Series devices may be associated with transformers. Stability improvement is achieved by injecting a quadrature component of voltage derived from the other two phases rather than by a tap

changer, which injects a direct component of voltage. Fast acting power electronics can inject either direct voltage or a combination of both direct and quadrature voltage to help maintain voltage levels and improve stability margins.

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7.15 Power quality

One form of poor power quality that has received a large amount of attention is the high level of harmonics that can exist and there are numerous harmonic analysis programs now available.

Recently, the harmonic levels of both currents and voltages have increased considerably due to the increasing use of non-linear loads such as arc furnaces, HV DC converters, FACTS equipment, DC motor drives, and variable AC motor speed control. Moreover, commercial sector loads now contain often unacceptable levels of harmonics due to widespread use of equipment with rectifier-fed power supplies with capacitor output smoothing (e.g. computer power supplies and fluorescent lighting). The need to conserve energy has resulted in energy-efficient designs that exacerbate the generation of harmonics. Although each source only contributes a very small level of harmonics, due to their small power ratings, widespread use of small non-linear devices may create harmonic problems that are more difficult to remedy than one large harmonic source.

Harmonic analysis algorithms vary greatly in their algorithms and features; however, almost all use the frequency domain. The most common technique is the direct method (also known as current injection method). Spectral analysis of the current waveform of the non-linear components is performed and entered into the program. The network data is used to assemble a system admittance matrix for each frequency of interest. This set of linear equations is solved for each frequency to determine the node voltages and, hence, current flow throughout the system. This method assumes the non-linear component is an ideal harmonic current source.

The next more advanced technique is to model the relationship between the harmonic currents injected by a component to its terminal voltage waveform. This then requires an iterative algorithm, which does require excursion into the time domain for modeling this interaction. When the fundamental (load flow) is also included, thus simulating the interaction between fundamental and harmonic frequencies, it is termed a harmonic power flow. The most advanced technique, which is still only a research tool, is the harmonic domain. In this iterative technique one Jacobian is built up that represents all harmonic frequencies. This allows coupling between harmonics, which occurs, for example, in salient synchronous machines, to be represented.

There are many other features that need to be considered, such as whether the algorithm uses symmetrical components or phase co-ordinates, or whether it is single or three phase. Data entry for single phase typically requires the electrical parameters, whereas three-phase analysis normally requires the physical geometry of the overhead transmission lines and cables and conductor details so that a transmission line parameter program or cable parameter program can calculate the line or cable electrical parameters.

The communication link between the monitoring point and the control center can now be very sophisticated and can utilize satellites. This technology has led to the development of systems to analyze the power quality of a system. Harmonic measurement and analysis has now reached a high level of maturity. Many different pieces of information can be monitored and the results over time stored in a database. Algorithms based on the fast Fourier transforms can then be used to convert this data from the time domain to the frequency domain. Computing techniques coupled with fast and often parallel computing allow this information to be displayed in real time. By utilizing the time-stamping capability of the global positioning system (GPS), information gathered at remote sites can be linked together. Using the GPS time stamp, samples taken exactly simultaneously can be fed to a harmonic state estimator which can even determine the position and magnitude of harmonics entering the system as well as the harmonic voltages and currents at points not monitored (provided enough initial monitoring points exist).

One of the most important features of harmonic analysis software is the ability to display the results graphically. The refined capabilities of present three-dimensional graphics packages have simplified the analysis considerably.

7.16 Finite element analysis

Finite element analysis is not normally used by power system engineers although it is a common tool of high voltage and electrical machine engineers. It is necessary, for example, where accurate machine representation is required. For example, in a unit-connected HV DC terminal the generators are closely coupled to the rectifier bridges. The AC system at the rectifier end is isolated from all but its generator. There is no need for costly filters to reduce harmonics. Models of the synchronous machine suitable for a transient stability study can be obtained from actual machine tests. For fast transient analysis, a three-phase generator model can be used but it will not account for harmonics.

A finite element model of the generator provides the means of allowing real-time effects such as harmonics and saturation to be directly included. Any geometric irregularities in the generator can be accounted for and the studies can be done at the design stage rather than having to rely on measurements or extrapolation from manufactured machines to obtain circuit parameters. There is no reliance on estimated machine parameters.

The disadvantages are the cost and time to run a simulation and it is not suitable at present to integrate with existing transient stability programs, as it requires a high degree of expertise. As the finite element model is in this case used in a time simulation, part of the air gap is left unmeshed in the model. At each time step the rotor is placed in the desired position and the missing elements in the air gap region formed using the nodes on each side of the gap.

7.17 Earthing

The safe earthing of power system equipment is very important, especially as the short-circuit capability of power systems continues to grow. Programs have been developed to evaluate and design earthing systems in areas containing major power equipment, such as substations and to evaluate the effects of fault current on remote, separately grounded equipment.

The connection to earth potential may consist of an earth mat of buried conductors, electrodes (earth rods), or both. The shape and dimensions of the electrodes, their locations, and the layout of an earth mat, plus the resistivity of the earth at different levels must be specified in order to evaluate the earth resistance. A grid of buried conductors and electrodes is usually considered to be all at the same potential. Where grid sections are joined by buried or aerial links, these links can have resistance allowing the grid sections to have different potentials. It is usual to consider a buried link as capable of radiating current into the soil.

Various methods of representing the fault current are available. The current can be fixed or it can be determined from the short-circuit MVA and the busbar voltage. A more complex fault path may need to be constructed for faults remote from the site being analyzed.

From the analysis, the surface potential over the affected area can be evaluated and, from that, step and touch potentials calculated. Three-dimensional graphics of the surface potentials are very useful in highlighting problem areas.

7.18 Other programs

There are too many other programs available to be discussed. For example, neither automatic generator control nor load forecasting has been included. However, an example of a small program that can stand alone or fit into other programs is given here.

In order to obtain the electrical parameters of overhead transmission lines and underground cables, utility programs have been developed. Transmission line parameter programs use the physical geometry of the conductors, the conductor type, and ground resistivity to calculate the electrical parameters of the line. Cable parameter programs use the physical dimensions of the cable, its construction, and its position in the ground. The results of these programs are usually fed directly to network analysis programs such as load flow or faults. The danger of errors introduced during transfer is thus minimized. This is particularly true for three-phase analyses due to the volume of data involved.

7.19 Further development of programs

Recently there has been a shift in emphasis in the types of program being constructed. Deregulation is making financial considerations a prime operating constraint. New programs are now being developed which assist in the buying and selling of energy through the electrical system.

Following on from the solution of the economic dispatch, 'time-of-use' pricing has been introduced into some power system operations. Under this system, the price of electricity at a given time reflects the marginal cost of generation at that time. As the marginal generator changes over time, so does the price of electricity.

The next stage is to price electricity not only on time but also on the place of use (nodal pricing). Thus, the cost of transportation of the energy from the producer to the user is included in the price. This can be a serious problem at present when power is exchanged between utilities. It will become increasingly common as the individual electricity producers and users set up contractual agreements for supply and use. A major problem at present is the lack of common agreement as to whether nodal pricing is the most appropriate mechanism for a deregulated wholesale electricity market. Clarification will occur as the structure of the industry changes.

Nodal pricing also takes into account other commercial and financial factors. These include the pricing of both generation and transmission constraints, the setting of a basis for transmission constraint hedges and for the economic dispatch of generation. The programs must be designed to give both the suppliers and consumers of energy the full opportunity costs of the operation of the power system.

Inherent in nodal pricing must be such factors as marginal cost pricing, short run price, and whether the price is ex ante (before) or ex post (after) the event. Thus far, the programming effort has concentrated on real power pricing but the cost of reactive power should also eventually be included.

The changes in the operation of power systems, which are occurring throughout the world at present, will inevitably force changes to many of the programs in use today and, as shown above, new programs will emerge.

7.20 Program suites

As more users become involved with a program, its quirks become less acceptable and it must become easy to use, i.e., user friendly. Second, with the availability of many different types of program, it became important to be able to transfer the results of one

program to the input of another. If the user has access to the source code, this can often be done relatively quickly by generating an output file in a suitable format for the input of the second program. There has, therefore, been a great deal of attention devoted to creating common formats for data transfer as well as producing programs with easy data entry formats and good result processing capabilities.

Many good 'front end' programs are now available which allow the user to quickly write an analysis program and utilize the 'built-in' IO features of the package. There are also several good general mathematical packages available. Much research work can now be done using tools such as these. The researcher is freed from the chore of developing algorithms and IO routines by using these standard packages. Not only that, extra software is being developed which can turn these general packages into specialist packages. It may well be that before long all software will be made to run on sophisticated developments of these types of package and the stand-alone program will fall into oblivion.

7.21 Conclusions

There are many more programs available than can be discussed here. Those that have been discussed are not necessarily more significant than those omitted. There are programs to help you with almost every power system problem you have and new software is constantly becoming available to solve the latest problems.

Make sure that programs you use are designed to do the job you require. Some programs make assumptions that give satisfactory results in most cases but may not be adequate for your particular case. No matter how sophisticated and friendly the program may appear, it is the algorithm and processing of data that are the most important parts. As programs become more complex and integrated, new errors (regressions) can be introduced. Wherever possible check the answers and always make sure they feel right.

Last, but not least, remember the golden rule of all computer programs and simulations: GIGO – Garbage In, Garbage Out. Make absolutely sure that all information is input into the program correctly, and that it is defined in the right context and units. For example, a cable length defined as 300 miles instead of 300 m will make quite a substantial difference to the result of analyses.

8

New era of power system automation

8.1 Definition of the term

Power system automation can be defined as a system for managing, controlling and protecting an electrical power system. This is accomplished by obtaining real-time information from the system, having powerful local and remote control applications and advanced electrical protection. The core ingredients of a power system automation system are local intelligence, data communications and supervisory control and monitoring.

Note: Power system automation is also referred to as substation automation.

8.2 What is power system automation?

Power system automation may be best described by referring to Figure 8.1.

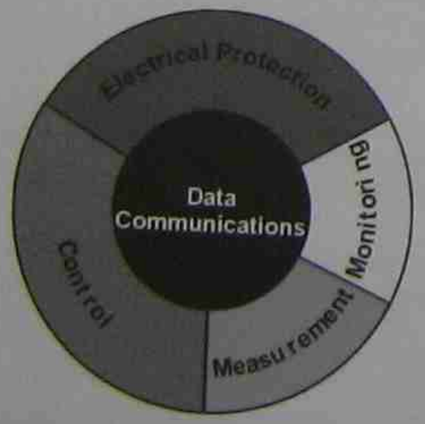


Figure 8.1
Functional structure of power system automation

Power system automation, by definition, consists of the following main components:

- Electrical protection
- Control
- Measurement
- Monitoring
- Data communications.

Electrical protection

Electrical protection is still one of the most important components of any electrical switchgear panel, in order to protect the equipment and personnel, and to limit damage in case of an electrical fault.

Electrical protection is a local function, and should be able to function independently of the power system automation system if necessary, although it is an integral part of power system automation under normal conditions. The functions of electrical protection should never be compromised or restricted in any power system automation system.

Control

Control includes local and remote control. Local control consists of actions the control device can logically take by itself, for example bay interlocking, switching sequences and synchronizing check. Human intervention is limited and the risk of human error is greatly reduced.

Local control should also continue to function even without the support of the rest of the power system automation system.

Remote control functions to control substations remotely from the SCADA master(s). Commands can be given directly to the remote-controlled devices, for example open or close a circuit breaker. Relay settings can be changed via the system, and requests for certain information can be initiated form the SCADA station(s). This eliminates the need for personnel to go to the substation to perform switching operations, and switching actions can be performed much faster, which is a tremendous advantage in emergency situations.

A safer working environment is created for personnel, and huge production losses may be prevented. In addition, the operator or engineer at the SCADA terminal has a holistic overview of what is happening in the power network throughout the plant or factory, improving the quality of decision-making.

Measurement

A wealth of real-time information about a substation or switchgear panel is collected, which is typically displayed in a central control room and/or stored in a central database.

Measurement consists of:

- Electrical measurements (including metering) – voltages, currents, power, power factor, harmonics, etc.
- Other analog measurements, e.g. transformer and motor temperatures
- Disturbance recordings for fault analyses.

This makes it unnecessary for personnel to go to a substation to collect information, again creating a safer work environment and cutting down on personnel workloads. The huge amount of real-time information collected can assist tremendously in doing network studies like load flow analyses, planning ahead and preventing major disturbances in the power network, causing huge production losses.

Note: The term 'measurement' is normally used in the electrical environment to refer to voltage, current and frequency, while 'metering' is used to refer to power, reactive power, and energy (kWh). The different terms originated due to the fact that very different instruments were historically used for measurement and metering. Nowadays the two functions are integrated in modern devices, with no real distinction between them; hence the terms 'measurement' and 'metering' are used interchangeably in the text. Accurate metering for billing purposes is still performed by dedicated instruments.

Monitoring

- Sequence-of-event recordings
- Status and condition monitoring, including maintenance information, relay settings, etc.

This information can assist in fault analyses, determining what happened when, where and in what sequence. This can be used effectively to improve the efficiency of the power system and the protection. Preventative maintenance procedures can be utilized by the condition monitoring information obtained.

Data communication

Data communication forms the core of any power system automation system, and is virtually the glue that holds the system together. Without communications, the functions of the electrical protection and local control will continue, and the local device may store some data, but there can be no complete power system automation system functioning. The form of communications will depend on the architecture used, and the architecture may, in turn, depend on the form of communication chosen.

8.3 Power system automation architecture

Different architectures exist today to implement the components of power system automation in practice. It is important to realize that not one single layout can exclusively illustrate a power system automation system. However, the most advanced systems today are developing more and more toward a common basic architecture. This architecture is illustrated in Figure 8.2.

The modern system consists of three main divisions.

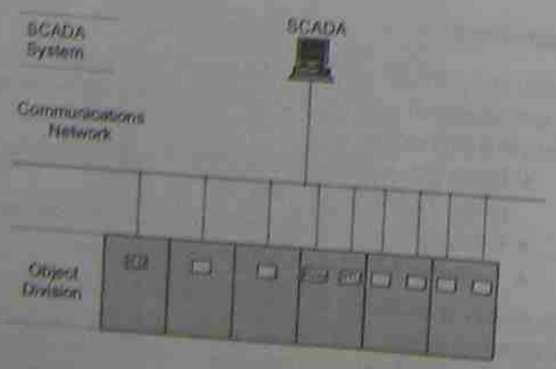


Figure 8.2
Basic architecture of power system automation

Object division

The object division of the power system automation system consists of intelligent electronic devices (IEDs), modern, third generation microprocessor-based relays and/or remote terminal units (RTUs). The PLCs continue to play an important role in some systems. They receive analog inputs from the current transformers (CTs), voltage transformers (VTs) and transducers in the various switchgear panels, as well as digital inputs from auxiliary contacts, other field devices or IEDs, or the SCADA master. They are able to perform complex logical and mathematical calculations and provide an output either to the SCADA master, other field instruments or IEDs, or back to the switchgear to perform some command, for example open a circuit breaker.

The object division consists of the process level (field information from CTs, VTs, etc.) and the bay level (local intelligence in the form of IEDs, RTUs, etc.).

The communications network

The communications network (comms network for short) is virtually the nervous system of power system automation. The comms network ensures that raw data, processed information and commands are relayed quickly, effectively and error-free among the various field instruments, IEDs and the SCADA system. The physical medium will predominantly be fiber-optic cables in modern networks, although some copper wiring will still exist between the various devices inside a substation.

The comms network need to be an 'intelligent' subsystem in its own right to perform the functions required of it, and is not merely a network of fiber-optic and copper wiring.

The communication network serves as the interface between the bay level and the SCADA station level, which might be a SCADA master station in the substation itself, or remotely in a central control room.

SCADA master

The SCADA master station(s) forms the virtual brain of the power system automation system. The SCADA master receives data and information from the field, decides what to do with it, stores it (directly or after some form of processing), and issues requests and/or commands to the remote devices. Therefore, the SCADA master is effectively in control of the complete power system automation system.

Nowadays, a SCADA master consists simply of an advanced, reliable PC or workstation (with its peripheral and support hardware) and a SCADA software package. (In contrast with a few years ago when SCADA systems used to run on big mainframe computers or some form of complex proprietary hardware.)

A SCADA master station may be installed in each substation of a power transmission network (station level), with all the substation SCADA stations forming part of a LAN or WAN (network level); or one SCADA master station may be directly in control of several substations, eliminating the station level.

Appendix

Name	P1 (kW)	Q1 (KVA)	Pf cos(theta)	S1 (kVA)	Voltage (kV)	I1 (A)	In Breaker (A)	I Fault Breaker (kA)	Cable Size Volt Drop (mm^2)	Cable Size Load Current (mm^2)	Cable Size Fault Level (mm^2)	Actual Cable Size (mm^2)
			sub #4									
P201	375.0		0.80	468.8	6.60							
P202	550.0		0.85	647.1	6.60							
P203	200.0		0.80	250.0	6.60							
tfr C			0.60	1000.0	6.60							
tfr D			0.60	1000.0	6.60							
tfr E			0.60	1000.0	6.60							
P804	320.0		0.80	400.0	6.60							
P805	1500.0		0.85	1764.7	6.60							
P806	250.0		0.80	312.5	6.60							
Total / L4 / 0 / R4 / busbars				5843.0	6.60							
			sub #3									
Cap	0.0	−2400.0	0.00		6.60							
P301	480.0		0.80		6.60							
P302	900.0		0.85		6.60							
P303	300.0		0.80		6.60							
tfr F			0.60	1250.0	6.60							
tfr I			0.60	1250.0	6.60							
P306	375.0		0.80		6.60							
P307	461.0		0.80		6.60							
P308	2000.0		0.85		6.60							
Cap	0.0	−2400.0	0.00		6.60							
L2 sub 4 feeder					6.60							
Total / L8 / 0 / R8 / busbars					6.60							

System Fault Levels

				At 132 kV	At 33 kV with 1 tfr	At 33 kV with 2 tfrs	At 33 kV without source impedance – just 2 tfrs	At 6.6 kV with 1 tfr	At 6.6 kV with 2 tfrs	At 6.6 kV without source impedance – just 2 tfrs
Base power in MVA	100.0	100.0	100.0							
Voltage level in kV	132.0	33.0	6.6							
Base impedance in ohms										
Base current in A										
Source impedance in pu										
OH Line 10 km wolf										
40 MVA tfr										
Cable (185 mm^2 × 4–5 km)										
10 MVA tfr										
Total impedance										
Fault level in p.u.										
Fault level in A at 132 kV										
Fault level in A at 33 kV										
Fault level in A at 6.6 kV										

Name	P_{nom} (kW) Nominal	Q_{nom} (kVAr) Nominal	Pf cos(theta)	Theta	S_{nom} (kVA)	Voltage (kV)	I_{actual} (A)	P_{actual} (kW)	Q_{actual} (kVAr)	S_{actual} (kVA)	Voltage (kV)	Loading (Pu)
sub #4												
P201	375.0		0.80									0.80
P202	550.0		0.85									0.80
P203	200.0		0.80									0.45
tfr C			0.80									0.45
tfr D			0.60		1000.0							0.45
tfr E			0.60		1000.0							0.80
P804	320.0		0.60		1000.0							0.80
P805	1500.0		0.80									0.80
P806	250.0		0.85									0.80
Total			0.80									0.80
sub #3						6.60					6.60	
cap	0.0	−2400.0	0.00		0.0			1.00				
P301	480.0		0.80		0.0			0.80				
P302	900.0		0.85		0.0			0.80				
P303	300.0		0.80		0.0			0.80				
tfr F			0.60		0.0			0.80				
tfr I			0.60		1250.0			0.45				
P306	375.0		0.80		1250.0			0.45				
P307	461.0		0.80		0.0			0.80				
P308	2000.0		0.85		0.0			0.80				
cap	0.0	−2400.0	0.00		0.0			0.80				
L2 sub 4 feeder					0.0			1.00				
Total						6.60					6.60	
Total (uncompensated)						6.60					6.60	

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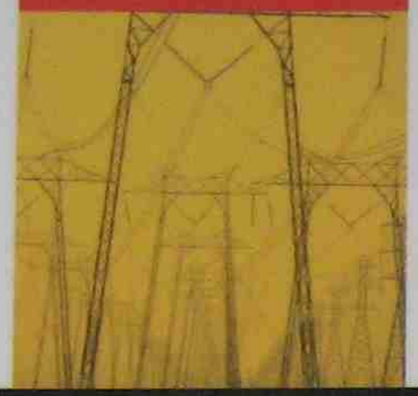


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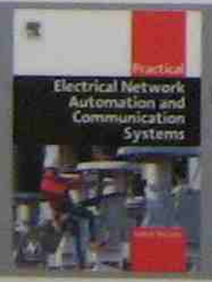
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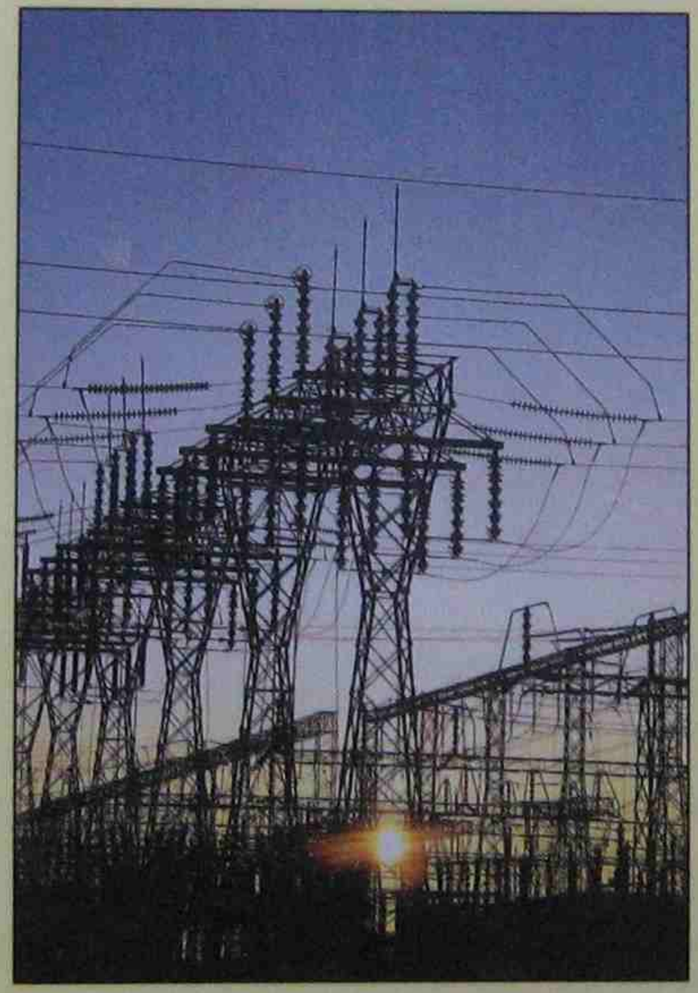


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To Luke's children
Laura and Matt Faulkenberry
and
Walter's wife
Syble Coffer
In appreciation of their patience and understanding

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Preface

This book is a practical introduction to electrical power distribution and transmission. The basic concepts of the subject are introduced in a practical, down-to-earth manner, but the subject concepts are covered in considerable depth and detail. The book is designed to be easily read by students, we hope with great interest. Although designed as a textbook for electrical power technology programs, it should also be a good reference for people already working in the power field as technicians, technologists, and engineers.

This text book is designed for a two-term course in electrical power distribution (first semester) and transmission (second semester). The order can be reversed but some information from the distribution section, such as basic transformers and circuit breakers, will have to be presented in the transmission semester. The book can also be used as a one-term course in distribution and transmission if the depth of the course or the coverage of topics is limited. The student is assumed to have had courses in ac and dc circuits, algebra, and trigonometry as minimum prerequisites to a course using this text. Basic three-phase concepts are reviewed in the text but a previous course in which basic polyphase circuits are covered is helpful, as is a course on rotating electrical machines. Some very basic calculus is used in a couple of places in the book, but a course in calculus, while nice, is not needed because the calculus elements are briefly explained where they are first used.

The book is organized in three sections. The first section is a general section that presents a brief history of the electrical power industry, the relationship of the industry with other institutions, and basic concepts including three-phase phasors and per unit. The second section, Chapters 3 through 7, focuses on electrical power distribution. This section covers basic distribution concepts and layouts, transformers, equipment, substations, distribution and substation protection, and distribution system construction. The third section, Chapters 8 through 11, covers electrical power transmission. It includes: basic system concepts including power flow, stability, and economic dispatch; types of transmission systems; transmission line parameters and equivalent circuits; fault calculations with symmetrical components; transmission line protection; grounding; and transmission line construction.

SECTION I

Introduction to the Electrical Power System

CHAPTER 1

Introduction to Electrical Power

This chapter presents a brief introductory discussion, a short history of electrical power, a discussion of the relationship of the electrical power utilities with regulatory agencies and customers, and an overview of the electrical power system.

1.1 ELECTRICAL POWER IN THE MODERN WORLD

The electrical power industry is a mature, established industry. Electrical power is the prime source of energy that supports almost all of our other technologies. Electricity is the most convenient and omnipresent energy available today. Imagine a day without it.

Electrical power is an energy transportation system. It is a safe, convenient, efficient way to transport large amounts of power long distances. The high efficiency of electrical machines—generators are over 98% efficient with efficiencies reaching over 99%, transformer efficiencies routinely reach 98% and can reach over 99.5%, and electric motors have efficiencies that are routinely over 80% and many are over 90%—makes the conversion of energy to electricity for transportation and reconversion to heat, light, and mechanical power cost effective.

The alternative to electrical energy conversion for mechanical power is thermodynamic conversion of fossil fuel, hydro, and wind power. These all have serious constraints with regard to mobility or efficiency. Thermal engines, because of temperature and pressure differences currently obtainable, are limited to thermodynamic efficiencies of 40% or less, with higher efficiencies favoring large steam turbine installations powered by fossil or nuclear fuel. Higher efficiencies can be obtained by using the exhaust of gas turbines to provide the heat to produce steam for steam turbines. This is called *combined cycle generation*, which can provide efficiencies to about 60%. Although other sources of energy can be transported, electricity is only equaled by natural gas for efficiency of transport, and it must be converted to mechanical energy at a relatively low efficiency to obtain mechanical power. Only relatively small amounts of power, ideal for remote locations, can currently be obtained from solar and wind sources. Much research is being done in pursuit of alternatives for fossil fuels for the production of electric power. Nuclear fusion appears to be the most promising long-range alternate energy source for electric power generation, but much work remains before commercial power generation can begin with nuclear fusion as the thermal energy source.

One measure of the wealth of a nation is the total production of the society of that nation. Electrical energy conveniently provides light that lengthens both work and leisure hours. Power for work, from electric motors in tools, extends human physical work output from approximately 2.8 kW to many times that amount. The human effort guides the tools that do the work. Lately, much human effort guides computers that then guide the tools. Electricity provides power for both the computers and the tools. Thus, electricity is an integral part of the daily life of the citizens of any developed country. Electricity provides power for light, tools, and entertainment. It provides power for both work and play.

1.2 A SHORT HISTORY OF ELECTRICAL POWER

In 600 B.C. Thales discovered that amber, when rubbed, attracted small objects. He had discovered static electricity. Centuries before Thales the Chinese had constructed magnetic compasses, and during the twelfth and thirteenth centuries the magnetic compass was the subject of experiments in Europe. It was not until 1600 that the first systematic discussion of electromagnetism based on experimentation was published by Englishman William Gilbert, who is called the father of modern

electromagnetism. In 1660 Otto van Guericke discovered how to generate sparks of static electricity by rotating a sulphur ball on a wooden shaft. Allessandro Volta introduced the first storage battery in 1800. In 1825 Andre Ampere discovered the attractive and repulsive force, depending on current direction, between two conductors carrying a steady current. Note that the rate of discovery started to increase rapidly around 1800.

George Ohm published his discovery that current flow in a conductor is directly proportional to the applied potential and inversely proportional to its resistance in 1827. This relationship, called "Ohm's law," is still used. Only 4 years later Michael Faraday demonstrated the basic principles of the induction generator, transformer, and electric motor.

In 1858 the South Foreland lighthouse was equipped with an arc lamp, invented in 1808 by Sir Humphry Davies, using a steam generator for power. In 1864 James Clerk Maxwell published his electromagnetic equations, which were a great leap forward in electromagnetic theory.

Around 1873 a Belgian born engineer, Zenobe Theophile Gramme, developed the first practical electric generator and motor. Earlier (1835) American Thomas Davenport had invented the electric motor using the electromagnet developed by Joseph Henry in 1823. The Davenport motor was never developed into a practical machine.

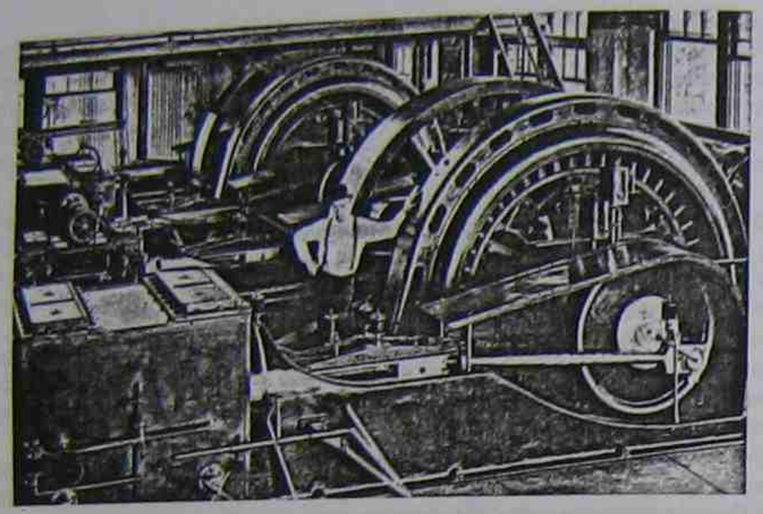
The year 1876 is known primarily for the invention of the telephone by Alexander Graham Bell. A less well known development of that year was the first practical arc lighting system by Charles Brush.

Thomas Edison perfected the incandescent lamp in 1879. That same year the first company opened for the purpose of selling electricity. The California Electric Company of San Francisco opened to sell electric service for arc lamps to commercial establishments and factories. The year 1879 was also the year that Thompson, Westinghouse, and Stanley developed a practical transformer.

In 1882 Thomas Edison's Pearl Street station opened in Manhattan. It provided direct current (dc) for incandescent lighting to an area of about one sixth square mile. Figure 1.1 shows the Gable Street power plant in Houston, Texas in 1900. This plant replaced Houston's first electric generating plant, which was opened in December 1882, just a few months after the Pearl Street plant, and destroyed by a boiler explosion in 1898. For the next 20 years small electric generating stations sprang up in every city of any size, and by 1900 there were over 3000 stations in the United States.

The quest for efficiency has been a driving force throughout the history of electrical power. The steam turbine, invented by Parsons in 1884, was to play a big role in making the generation of electricity more efficient.

In 1881 Frenchman Lucien Gaulard and Englishman John D. Gibbs patented an alternating current (ac) transmission system in England. In 1885 George Westinghouse, the American mechanical engineer who invented the air brake, bought the American patents to the system from Gaulard and Gibbs. That same year Westinghouse and his associate William Stanley perfected the transformer and developed the constant potential ac generator. The next year, 1886, Stanley



One-hundred years ago, in the summer of 1882, a group of investors formed the Houston Electric Light & Power Company. Construction began in September on a new plant and on the night of December 15, 1882, Houston entered the electrical age - as thirty crude carbon arc lights sputtered with brilliant white light.

At the turn of the century, a new plant called Gable Street, shown above, replaced the previous one which was demolished by a boiler explosion in 1898.

Since that first year, Houston Lighting & Power Company and electricity have played an indispensable role in the prosperity and growth of the Houston - Gulf Coast area.

FIGURE 1.1 The Gable Street plant in Houston, TX began operation December 15, 1902 (Courtesy of Houston Lighting and Power).

demonstrated the practicability of ac transmission in Great Barrington, Massachusetts by transmitting power 4000 feet. He used a transformer to step the generated voltage up to 3000 V for transmission and another to step the transmitted voltage down to 500 V for use. The first commercial transmission of ac in the United States was from Willamette Falls to Portland, Oregon, 13 miles at 3300 V, in 1890.

In 1888 Nicola Tesla presented a paper that was to prove extremely important to the budding electrical power industry. He introduced the polyphase ac system, as well as the polyphase induction and synchronous motor. George Westinghouse recognized the importance of Tesla's work and bought the patents from him that same year. In 1891 the first three-phase system was installed between Lauffen and Frankfurt am Main in Germany. By 1894 five polyphase generating plants were operating in the United States. Four were three-phase systems and one was a two-phase system. Three-phase electricity quickly became the ac transmission and generation standard because three-phase power was provided smoothly, rather than in the pulsating manner of one or two phases. The first hydroelectric plant was installed in Niagara Falls, New York in 1886, but ac transmission, from Niagara Falls to Buffalo 22 miles away, did not begin until 1896. Alternating current, preferably three phase, was now firmly established as the preferred method of generating and transmitting electricity.

The 1902 World Fair in St. Louis, Missouri had as its theme electric lighting, which popularized electric lighting. The first steam turbine driven generator was installed in the United States in 1903. The 5 MW unit ushered in a new, more efficient era in electric power production.

Transmission voltages rose rapidly to about 40 kV, but the pin type insulators then available limited further increases in voltage. In 1907 two U.S. electrical engineers, Edward M. Hewlett and Harold W. Buck, invented the suspension insulator that allowed higher transmission voltages. By 1920 voltages of 132 kV were common, and some systems used 150 kV. In 1934 Boulder Dam (later called Hoover) on the Colorado River sent power to Los Angeles, 270 miles away, at 287 kV. Large, hollow, copper conductors were used to prevent *corona* loss.

Corona is the discharge of static electricity from a power line. It is minimized with large diameter lines because static electricity discharges best at sharp points, corners, and along small conductors. Corona became the limiting factor in transmission voltages. Very large diameter conductors were being used, even at low currents, to avoid corona. During World War II the Germans discovered that multiconductor bundles (two or more conductors held apart by periodic spacers) acted like one very large diameter conductor as far as corona is concerned. The first multiconductor installation was after the war in Sweden using double conductor bundles (two spaced conductors per phase) at 380 kV. Transmission voltages continued to rise rapidly. In the United States the first 345 kV line began operating in 1953, the first 500 kV line in 1965, and the first 765 kV line in 1969.

To improve further operating efficiency by increasing the immediately available reserve power (called spinning reserve), reduce duplication of capital expenditures, and reduce outages the electric utilities began to interconnect their systems for mutual benefit. This allowed a utility to supply power to another utility whose

load was high at times when its own load was low, allowing both utilities to utilize their equipment more efficiently. Interconnection has been in use since the 1930s and is almost universally used today.

Although dc transmission was replaced by ac early in the history of electrical power because of the ease and efficiency with which ac voltage levels can be changed using transformers, *high voltage* transmission with dc has some advantages. There are no reactance losses on dc transmission lines, and there is no need to synchronize one user with another when using dc sources. Because the equipment required to convert the generated ac voltage to dc at the source and back to ac at the destination is expensive, dc is normally used to transmit power long distances (200 miles or more), to tie together systems for interconnection with very short lines so that the phases of the systems need not be synchronized, and when ac transmission is too lossy as with under water power cables. The Germans were the first to transmit high voltage dc. In World War II they transmitted 60 MW of dc power from the Elbe power station to Berlin at 400 kV (+ and − 200 kV). In 1954 Sweden connected the first commercial dc line, a 100 kV 20 MW submarine cable from the Swedish mainland to the Island of Gotland 60 miles away. The first U.S. dc line was finished in 1970. It was the Pacific Intertie, an overhead line that transmitted 1440 MW 825 miles from Celilo, Oregon to Sylmar, California near Los Angeles. Several dc systems were already in service in Canada, Europe, and Russia at that time. High voltage dc transmission is gaining in popularity as the conversion equipment becomes more efficient, reliable, and economical.

It is impossible in the available space to list all of the contributors to the electrical power industry. Some of the most important contributions were: Edison's dc distribution system, the ac transmission system, the large steam turbine, interconnection, and the regulated monopoly system of business for the electrical power generation and distribution companies. The last item is discussed in the next section.

By 1939 virtually all U.S. industries were powered, most by electricity. By 1945 75% of all U.S. farms had electricity (96% by 1960), and virtually all urban homes had electricity. In only a little over a century since Edison opened his Pearl Street Station in Manhattan electrical power has become an important part of the technology and the daily lives of the citizens of all developed nations.

1.3 RELATIONSHIP BETWEEN ELECTRIC UTILITIES, CUSTOMERS, AND REGULATORY AUTHORITIES

Electric generating and distribution facilities were originally owned by individuals or small groups of investors. There were thousands of very small electric companies springing up in every large or medium sized town in the late 1800s. Some people generated electric power for their own use and sold to their neighbors,

some set up small generating stations and sold to anyone who would buy (like "Mom and Pop" grocery stores), while businessmen seeking a profitable investment owned other generating stations. Each generator had to be connected to each customer it served. The many duplicate electrical distribution systems installed in many localities caused three problems. The first was danger to life and property caused by many crisscrossed, closely spaced, distribution systems. The second was the unacceptable crowding of public right of ways caused by the many distribution systems. The third was the extremely high capital cost for the many duplicate systems, which led to high rates.

The corrective step taken was to grant a franchise for an area to a single supplier of electricity. This cured all three problems but caused another one. Since the rates were no longer controlled by competition, another method of rate control had to be found. That method was regulation. By 1900 the consolidation of small, competing, electric companies into larger, investor owned, franchised systems was underway. In 1905 New York established the first public utility regulating commission. This began the transition of the electric generating and distribution industry into a set of state regulated monopolies. By 1924, 42 states had established public utility regulating commissions.

In 1920 the Water Power Act established the Federal Power Commission (FPC) to license the building and operation of hydroelectric facilities. Later its function expanded to regulating interstate commerce of power companies. It is now called the Federal Energy Regulatory Commission (FERC). During the Roosevelt administration a major push occurred to control the public utilities (investor owned utilities) through the FPC. An intense legal battle ensued. Eventually it was realized that both investor owned and government owned utilities are useful, and have a stabilizing influence on each other.

Samuel Insull, whose first job in the United States was private secretary to Thomas Edison but later became chairman of the Consolidated Edison Company that had substantial holdings in the Central United States, was very influential in shaping the electrical power industry in its early days. In two speeches, one in 1914 and another in 1916, he stated the reasons that electric utilities should be regulated monopolies. They are still valid.

The capital investment required for each dollar of revenue received is much higher in the electric generation and distribution business than it is in other industries. (Currently it is $4 or more for electric utilities, about $2 for railroads, and 30 to 50 cents for manufacturing.) Duplication of electric service in an area is costly and wasteful of both human and natural resources. Monopoly status, however, requires regulation to assure accountability to the public since the utilities have no direct competition. The regulators must assure the public of proper rate structures and business practices by the utilities, and the utilities of sufficient return on investment to make needed capital improvements and attract investors. Most cities do not have sufficient expertise and funds available to regulate large utilities effectively so the states have to shoulder the job of regulating public utilities. Insull warned of two problems associated with regulation. One is that the people appointed to regulatory commissions may not have sufficient knowledge of large

business practices to understand the power industry. Another is politicization. Regulators and other officials might be tempted to be short-term public advocates concerning power rates for political gain at the expense of long-term availability of power at reasonable prices.

Besides the high capitalization cost there are some other aspects of the electric utility business that are unique, and many are also common to other utilities.

1. The product is intangible in the common sense of the word. It cannot be driven, displayed, or handled directly (at least it shouldn't be).
2. Customers are charged for service and amount used. Service is defined as making available the correct voltage and frequency without interruption. Often good service and low rates are in conflict because of the equipment investments necessary for continued good service.
3. The product cannot be stored in large quantities. Enough equipment must be installed and ready to operate on short notice to meet the peak demand. If, as expected, the storage of electrical power in superconducting rings becomes economical, then the storage of large quantities of electrical power for use at peak loads may become practical.
4. The utility is responsible for delivering the product so the transmission and distribution systems must operate properly at all times.
5. The utility must use public right of ways for delivering the product. Thus the utility must have the right to buy, lease, and in extreme cases condemn property for right of way to assure the delivery of electricity to the public.
6. The utility is responsible for reasonable precautions to ensure the safety of its workers and the public. It must assure there is no injury to people or property because of inadequate equipment. The electric utilities take their responsibility for public safety very seriously.

The U.S. government has always considered electrical power important for its citizens. Three examples of this concern are: the Tennessee Valley Authority, the Rural Electrification Administration, and the Bonneville Power Administration.

The Tennessee Valley Authority (TVA) is a U.S. government agency formed in 1933 to provide flood control, navigation improvement, power development, and recreational area development for the Tennessee River watershed. It was also to establish power rates to compare with the rates around the country. Originally power was a secondary goal of the TVA, but it quickly became its primary purpose. Since the TVA did not have to pay interest on loans for capital investment or dividends to stock holders, its rates soon assured it no competition in the area it serves.

Concern for the farmer and the desire to "reduce farm drudgery" caused the U.S. government to form the Rural Electrification Administration (REA) in 1935. The agency encouraged the formation of "electric membership cooperatives" and provided low interest loans to build distribution systems in areas too sparsely populated to attract investor owned electric companies at that time. The REA was very successful in bringing electricity to the farm, and helping to improve agricultural productivity and rural quality of life.

The Bonneville Power Administration (BPA) is a federal agency under the Department of Interior. It markets the power produced at the federally owned hydroelectric projects in the Columbia River Basin in the Northwest United States.

Municipally owned generating and distribution facilities are operated by a number of cities. When cities began to use electric street cars and street lights many cities built their own generators instead of buying electricity. Some cities then began selling electricity to their citizens. Los Angeles, Seattle, and Takoma are examples of cities that supply all of their electric energy with municipally owned utilities.

Electric power in the United States is provided by a variety of types of organizations. Electrical power in some areas is provided by municipal systems, in some by cooperatives, in some by state or federally owned systems, however, the majority of the electrical power used in the United States is generated and distributed by investor owned companies. Although they are commonly called public utilities, they are private, investor owned, state regulated, utilities. In some cases the franchise granting municipality and the state share regulatory authority. These power supplying groups exert a stabilizing influence on each other because their rates must be competitive to attract business to their franchise area and avoid adverse public opinion. The mutually stabilizing influence of the electric power supplying groups and the regulatory authorities normally provide the public with adequate protection from unfair rates and poor service.

In contrast to the United States, in most countries the organization furnishing electric power is the government. The pricing of electrical power in many countries is a political decision dictated by political events. The regulatory and price fixing authority is either elected or appointed. In most of these countries the price of electricity is relatively high because the politicians find it easier to collect electric bills than taxes.

Another factor that is influencing the electrical power industry in the United States is cogeneration. In 1978 Congress passed the Public Utilities Regulatory Policy Act (PURPA), a section of which required power companies to buy cogenerated power (customer generated power in excess of customer needs) at the power companies avoided cost; what the power company would have spent to generate the cogenerated electricity. In the case of large cogenerators a negotiated price is now allowed. PURPA was designed to encourage private power generation in a time of energy scarcity with the expectation that smaller cogenerators using renewable resources such as wind and solar energy would save nonrenewable energy resources such as coal and oil. Within a short time industries that produced a large amount of their own electricity began cogenerating large amounts of electricity for sale to the power companies under PURPA as the market for the cogenerators primary product became depressed. If a company has a use for low temperature, low pressure steam for some process it can produce high temperature, high pressure steam, use the steam to produce electricity and the left over low pressure, low temperature steam for the process more efficiently than it can produce low pressure, low temperature steam. If a company has no use for the low pressure, low temperature steam it cannot usually produce electricity as

efficiently as a modern power company unless it uses a combined cycle unit in which gas fire turbine exhaust is used to produce steam, which is far more efficient than a stand-alone steam unit. Large cogenerators usually use nonrenewable energy resources to generate electricity so they provide no savings of these resources unless combined cycle is used.

Cogeneration of large amounts of electricity by large companies caused some problems, not all of which are resolved at this time. One problem is that cogenerators often want to sell electricity to the power companies at night when the power companies' demand is lowest and they have no need for the electricity. Thus the production of electricity by the cogenerator is out of synchronism with power company needs. A second problem is that some large cogenerators are located in areas that do not need the electricity at all, thus some power companies are forced to buy electricity they cannot resell. Often the excess electricity can be wheeled (transmitted using other power companies' transmission facilities) to areas that do need the cogenerated electricity.

Perhaps the most serious problem may occur because state Public Utility Commissions (PUCs) often consider the availability of cogenerated electricity when considering public utility applications for new generating facilities to meet future demands. New generating facilities take a long time to plan and construct (typically 5 years for a coal fired plant, not including the time required for approval by the various government agencies). Cogenerated electricity can disappear at the end of a contract, or at any time if not under contract. If adequate generating facilities are not available to handle the load served by cogenerated electricity at the end of a contract, the cogenerator(s) has a powerful bargaining position. Reliance on cogenerated electricity for a significant fraction of the electric power consumed in an area could produce a rate structure that is not under public control via the state PUC. However, the trend toward deregulation and wheeling rulings by FERC may result in a less territorial view of electricity generation. Many new business entities are being formed as electricity providers, selling their electrical power to the highest bidder, wheeling the power to the buyer.

The Department of Energy, through the FERC, has ruled that the transmission grid will remain a regulated monopoly while both generation and sales of electrical power will be regulated by the market place. Mechanisms that allow electricity to be treated as a commodity are now in place and operating, available for sale on an hour by hour basis, and delivered where it needed. Private power-related industries have formed groups to facilitate the marketing of electricity with the blessing and aid of the Department of Energy. It is now possible for an independent power producer to generate power at one location, feed it into the electric grid, have their power wheeled to a remote location, possibly across several states, and sell the power to any reasonable customer, a municipal system, an REA, an industry, or even to a shopping center. These federal initiatives have resulted in a variety of classes of owners of electrical generating facilities having access to the electrical grids and competing with utilities in electrical power generation.

Most people in the electrical power generation and distribution industry still believe in the principle Samuel Insull stated in a 1921 speech.

> In performing this task (of supplying utilities), our first duty and our first interest, an interest beyond everything else, is to square the rights of the public with those of the stockholder. Unless we can bring home to the public that our first thought and desire is to see that they get a square deal we might just as well shut up shop and go out of business and sell our plants for junk. Our income, our earning capacity, is dependent, primarily in my judgement, upon public good will, and you cannot get public good will unless you convince the public that you are treating them honestly and giving them a square deal.

In other words, the most important person associated with the power industry is the customer.

1.4 ELECTRICAL POWER SYSTEM CONSIDERATIONS

Societies must use energy resources in the form in which they appear, whether as water, wind, oil, coal, or uranium, to accomplish the tasks the societies consider desirable. The desirable tasks may be heating, cooling, lighting, manufacturing, or transportation of people and materials. Finding and converting the raw energy resources to usable energy is a vital function, as is the design, production, and use of efficient equipment to convert energy to useful work (motors, heaters, air conditioners, etc.). Both topics are beyond the scope of this book. To be useful energy must be available at the place the work is to be done. Recall that electricity is an efficient and convenient transportation system for energy that allows the raw energy resources and the equipment that converts energy to work to be separated by great distances.

Electricity does exist in nature as lightning and static electricity, but it cannot be controlled well enough to be put to practical use. Thus electricity must be generated by converting another raw energy resource. Electricity can be stored in batteries, but only in relatively small quantities. Therefore, at least for the present time, electricity must be produced at the same time it is used.

1.4.1 Reserve, diversity, and economic dispatch

Reserve is that portion of an electric utility's available generating capacity that is not producing electricity at a given time. *Spinning reserve* is the generating capacity that is being driven at the proper speed to provide proper voltage, but is not producing power. Spinning reserve can provide power to the system almost instantaneously if the system load is increased or a generator must be taken out of service. The FERC established a requirement that each electric power company construct sufficient excess capacity that it can supply its largest normal load with its largest generating plant off line. This rule has been modified for some circumstances,

as will be discussed later. Spinning reserve should be sufficient to meet any sudden load changes anticipated by the utility.

Diversity is the term used to refer to load changes during a period of time. Load varies during the day because people get up, go to work, and return in the evening using different amounts of electricity to support their various activities. Similarly, industrial and commercial power use will vary during the day. There are also weekly and seasonal variations in electricity usage. In a warm climate such as that along the Gulf Coast air conditioning results in high electricity consumption in the Summers that peaks daily in the late afternoon. Figure 1.2 shows a 24-hour diversity curve for electric power consumption. The result of diversity is that the electric utility must supply varying amounts of power depending on the time of day, day of the week, and season.

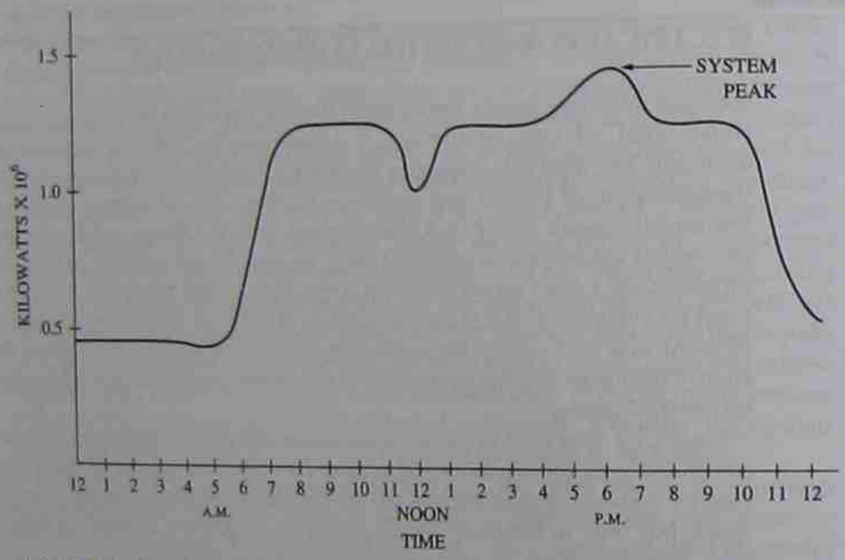


FIGURE 1.2 Load diversity

Economic dispatch refers to serving the load at all times with as little excess capacity as possible using the most efficient generating units possible. Properly sequencing the timing and size of generating units put into service can result in very large cost savings while adequately serving the load. The more efficient units are used to serve the base load and the less efficient units are used to serve the peak loads. Many factors must be considered other than just generator efficiency for economic dispatch in a large system. Line losses for various lines, fuel cost, availability and cost of interconnected capacity, and many other factors must be considered also, so economic dispatch alternatives are calculated on complicated computer programs. Figure 1.3 illustrates economic dispatch with respect to generator efficiency.

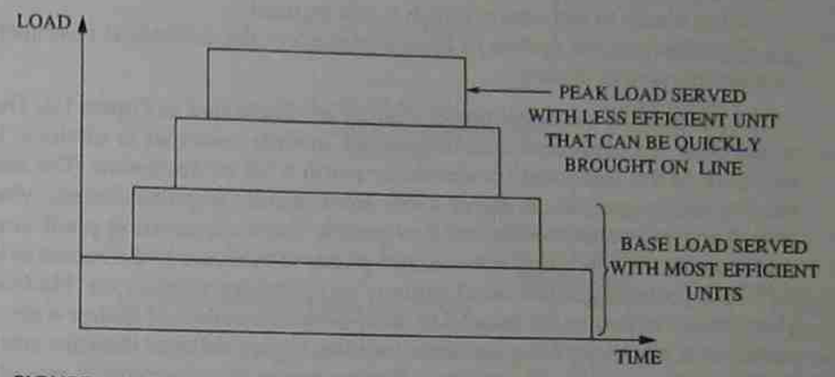


FIGURE 1.3 Economic dispatch with load diversity

Short-term power demand peaks require the use of gas turbine driven generators for the speed with which they can be started. Large boilers take a long time to come to heat, and must be brought up in a carefully controlled sequence to avoid severe damage to the boiler plates, tanks, and piping. In like manner the steam turbine and generator must be brought up to speed slowly and carefully to avoid warping the shaft. The weight of large turbines and generators and the speed they must turn (usually 3600 rpm) makes bringing them up to speed a difficult and time-consuming task. Thus the large generators must be started well ahead of the time their power is needed. The shutdown of large units is equally time consuming.

Peak power demand fluctuations cannot be predicted as accurately as normal load fluctuations. The gas turbine, essentially a jet engine adjusted to burn natural gas (jet fuel is used where natural gas is not available) and turn a mechanical load, can be put on line or removed in about 15 minutes. Thus the gas turbine is used in sizes to about 50 MVA to handle short term peak loads at a somewhat lower efficiency than the larger units.

The FERC excess capacity rule mentioned earlier was modified to allow a group of power companies with a strong interconnection system to have jointly a reserve capacity equal to the largest generating plant within the group. This has reduced the necessity for much expensive reserve generating equipment while preserving power system integrity. Transmission equipment is less expensive than generating equipment, so that a strong interconnection system now ties virtually the whole country together. The Eastern and Mid-western system was out of synchronization with the Western system, so a dc tie had to be used to tie the systems together.

1.4.2 System components

The electrical power system can be divided into three major parts:

1. Generation, the production of electricity.
2. Transmission, the system of lines that transport the electricity from the generating plants to the area in which it will be used.
3. Distribution, the system of lines that connect the individual customer to the electric power system.

The parts of the electrical power system are illustrated in Figure 1.4. That electricity must be generated and distributed to each customer is obvious, but the necessity of the transmission system is worth a bit of discussion. The trend has been to locate generation plants away from heavily populated areas when possible. Land is less expensive and few people want a generating plant next door. Additionally, remote siting often allows plants to be closer to the source of the fuel they use, providing substantial savings in electricity production. Hydroelectric plants must, of course, be located at an appropriate source of falling water. Transportation of electricity long distances requires higher voltages than are safe to connect to most customers. Electricity is then transported to the general area of use by the transmission lines and distributed to the customers at lower voltages by the distribution lines. The sites at which the power transformers used to step the transmission voltages down to the distribution voltages (which also contain switching and protection equipment) are called *distribution substations*.

1.4.3 Voltage levels

Great effort has been expended over the years, as we noted in the history section, to raise the voltage levels for each portion of the electrical power system. The major losses in transporting electricity are proportional to the current squared, thus doubling the current quadruples the loss. Power is the product of current times voltage so as voltage is increased, current is decreased, and losses are decreased for a given amount of power transfer. Thus the highest economically feasible voltage is favored for generating, transmitting, and distributing electrical power.

Rotary machines (generators and motors) have practical voltage limits set by limitations in insulation and cooling technology. Voltages allowable on rotary machines are increasing, but slowly now. Maximum generator voltages are currently about 24 kV and about 12 kV for motors.

The voltage limits for transmission voltages are set by protective devices (mainly circuit breakers) rather than transformers and insulators. Bundled conductors and shielding have removed the past limit of the breakdown of the air around the conductors. Different electric utilities have set different standard voltages, but the following voltages are common:

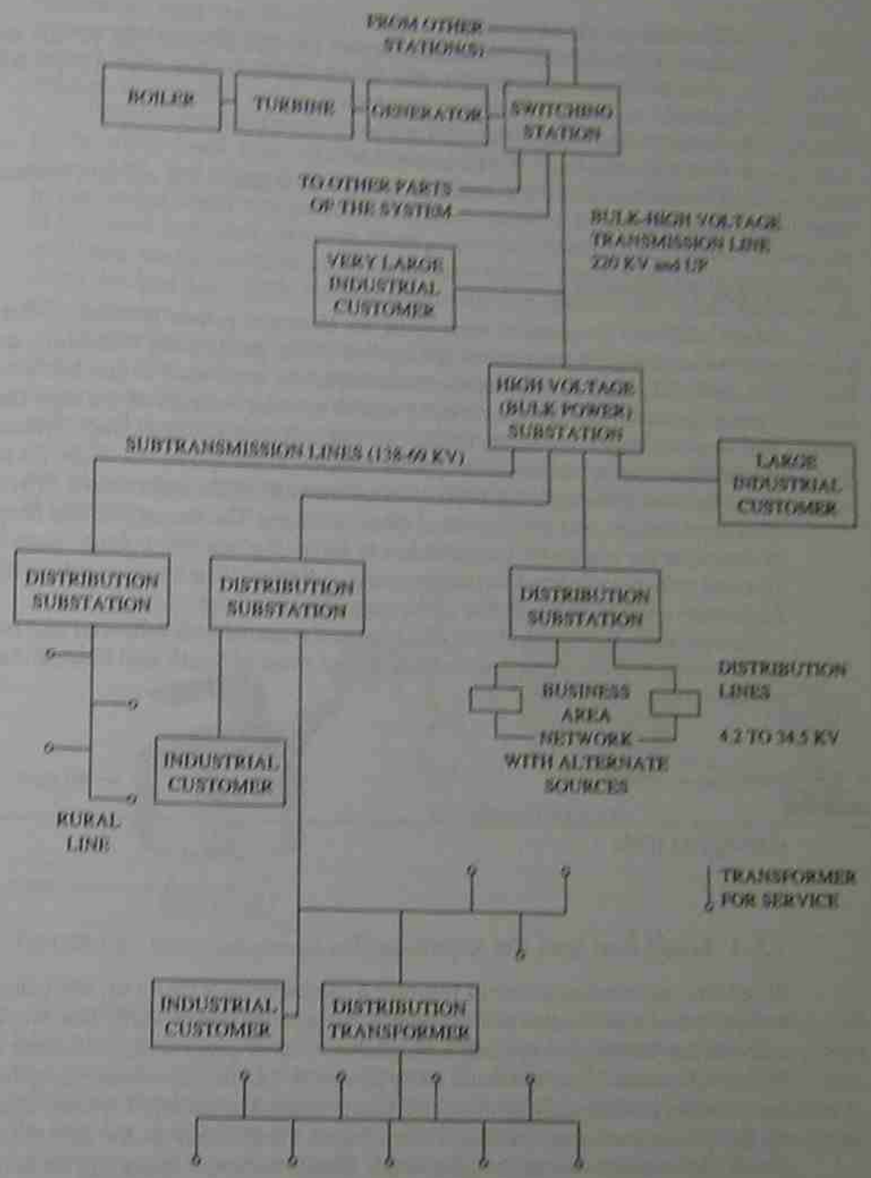


FIGURE 1.4 The electrical power system

1. Generators—11 kV to 24 kV.
2. Extra High Voltage Transmission—345 kV, 500 kV, and 765 kV for ac, and around 500 kV (± 250 kV), 800 kV (± 400 kV), and 1000 kV (± 500 kV) for dc.
3. Transmission—138 kV and 230 kV.
4. Sub-transmission—34.5 kV and 69 kV.
5. Distribution—12.5 kV and 34.5 kV (2300 V and 4 kV are still common in small towns).

1.4.4 Frequency

Many different frequencies were tried for electrical power systems in the early days of ac power. Some parts of the United States, particularly California, used 25 Hz, with fifty and 60 Hz, and some scattered dc, were used in the Midwest and Eastern parts of the U.S. Direct current was rejected because of the high line loss and large voltage drop along the line at the voltages available then. Twenty-five Hz fell from favor because incandescent lights flickered at such a low frequency. Sixty Hz was chosen in the United States because of the convenient fit with the 60-second minute, and the absence of other problems. The lowest possible frequency is desirable for electricity transmission to lower the reactive voltage drop on the line and reduce radiative loss (like antenna radiation). The lower practical limit on frequency was set by the flicker of the incandescent lamp.

Europe settled on 50 Hz. Most of Africa and some of Asia followed suit because of European colonization. Some of Africa and most of South and Central America use 60 Hz.

1.5 GENERATION

1.5.1 Fossil fuel and the steam cycle

Recall that generation involves rotating a magnetic flux (from an electromagnet) inside a set of conductors held in place by a magnetic stator. Many fine works deal with the mechanics and operation of synchronous ac generators, including *Electric Utility Systems and Practices* listed in Appendix E. Modern synchronous generators are extremely efficient. Improvements in the steam boilers and turbines that make up the prime mover system have contributed enormously to the efficiency with which electric power can be generated. Steam turbines operating at 3600 rpm (1800 rpm for nuclear plants) are the most used prime movers for generators. Steam turbines typically have efficiencies around 87%, and can be built as large as 1000 MW. The boiler efficiency contributes much to the overall efficiency of generation. Recall that maximum temperature and pressure differences currently

obtainable limit the thermodynamic efficiency to about 40%. Efficiency has improved dramatically over the years. In 1888 15 lb. of coal were required to generate 1 kWh of electricity, in 1903 7 lb. were required, in 1923 only 2.2 lb. were needed, and in 1980 0.3 lb. of coal was required to generate 1 kWh of electricity.

In 1980 the energy sources used for the production of electricity in the United States were: fossil fuel—68.9%, hydroelectric—12.6%, nuclear—9.1%, gas turbine—8.5%, and internal combustion engines—0.9%. About 78% of the electricity in the United States was generated by steam turbine driven generators, and most of the fossil fuel used was coal. Most generating plants in the United States are coal fired. Many countries generate a much higher percentage of their electricity using nuclear fuel. Both nuclear and fossil fuel plants use steam turbines as prime movers.

The process of generation is then the conversion of energy from a primary energy source such as coal by a chemical process such as burning to thermal energy, usually in the form of high pressure steam. The thermal energy is then converted to mechanical energy by a turbine, and from mechanical energy to electricity by a generator. The process is shown in its simplest form in Figure 1.5. Modern plants are a large improvement on this simple scheme, but the basic process is the same.

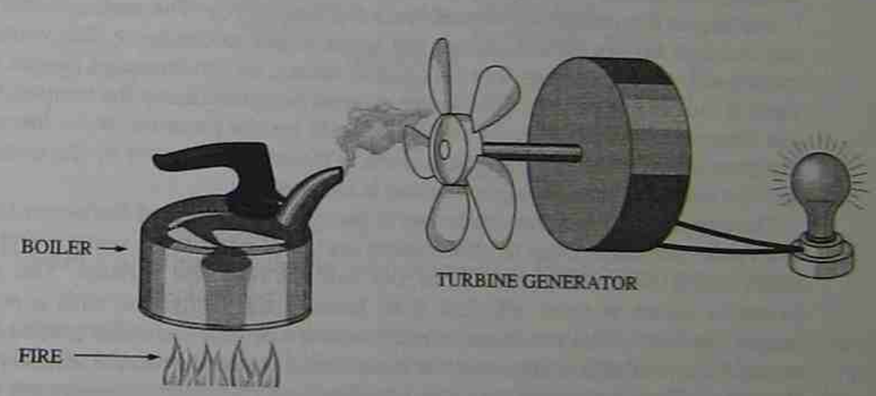


FIGURE 1.5 Simplified generation system

In modern plants fuel handling is almost fully automatic. For example, in a coal fired plant the coal will be fed automatically from hoppers to conveyers, crushed to a powder, and blown into the burning chamber by automated machinery. Preheated air (heated with exhaust air from the burning process) will be supplied to the burning chamber in the proper amount for efficient burning. The entire burning process will be automatically regulated to optimize combustion.

Many improvements have been made in every area of the electricity generation process through the years. Any small increase in efficiency that can be found in any phase of the generation process, fuel burning, steam production, turbine, or generation is important because of the immense amounts of electricity needed in

an industrial society. A small percentage gain in efficiency provides an immense saving of resources. The amount of mechanical power provided by the turbine, thus the electricity provided by the generator, depends on the volume, the temperature, and the pressure drop of the steam as it passes through the turbine. Any step that allows a higher temperature or pressure for input steam, or a lower exhaust temperature or pressure, or uses heat that remains in the steam after it has provided energy to the turbine improves efficiency.

Figure 1.6 is a simplified diagram of a fossil fuel generating plant that shows some of the major improvements that have increased efficiency. Starting at the upper left the furnace input air (forced by a fan) is preheated, using the furnace exhaust to save energy, to improve combustion efficiency. After combustion of the air and fuel mixture an induced draft fan forces the combustion byproducts out the exhaust stacks. This fan is necessary because the air heater and precipitators (for removing pollutants) constrict the exhaust flow. Motors as large as 1800 hp are needed to drive induced draft fans. The steam cycle is a closed loop except for the make up water that replaces the water lost in the inevitable small leaks. The water for the steam cycle must be de-mineralized, to prevent clogging the boiler tubes with mineral build up, and de-aerated, to remove the oxygen from the feedwater (water to be turned into steam), to reduce corrosion.

Starting at the condenser we will trace the steam cycle. The cooling water passing through the condenser causes the spent steam to condense into water. The condensed water occupies less space than steam, so condensation causes a vacuum at the turbine exhaust. The lower exhaust pressure causes the temperature of the steam (the temperature of steam depends on the pressure) to be lower. The temperature difference across the turbine is therefore increased by the condenser and the energy extracted by the turbine is increased.

The condensate from the condenser is pumped to a series of feedwater heaters. The feedwater heaters (up to about seven are used) preheat the water going to the boiler using steam extracted from the turbine near the exhaust. The use of extracted steam is more efficient than heating the feedwater with a separate heater. The preheated water reduces the amount of heat the boiler must add and reduces the mechanical stress on the boiler (cold feedwater would severely stress the boiler). The steam used to preheat the feedwater has already been used to provide energy to the generator turbine or drive turbines that power pumps, so feedwater heating is the second use of the extracted steam. The preheaters will take the steam from about 90°F at about 4 psi to about 500°F at 600 psi. The economizer uses combustion gasses that have already passed through the boiler to further preheat the incoming feedwater at little extra cost. The water then passes through the boiler where it is turned into steam at about 2400 psi at around 650°F.

Superheating steam (increasing the temperature at a fixed pressure) increases the thermal energy that can be extracted from the steam and reduces the possibility of water droplet formation in the steam as it passes through the turbine. Water droplets can corrode turbine blades very rapidly. Most high pressure turbines use input steam at about 1050°F at around 2400 psi. After the steam has passed through the high pressure turbine it is usually reheated to about 1000°F at the

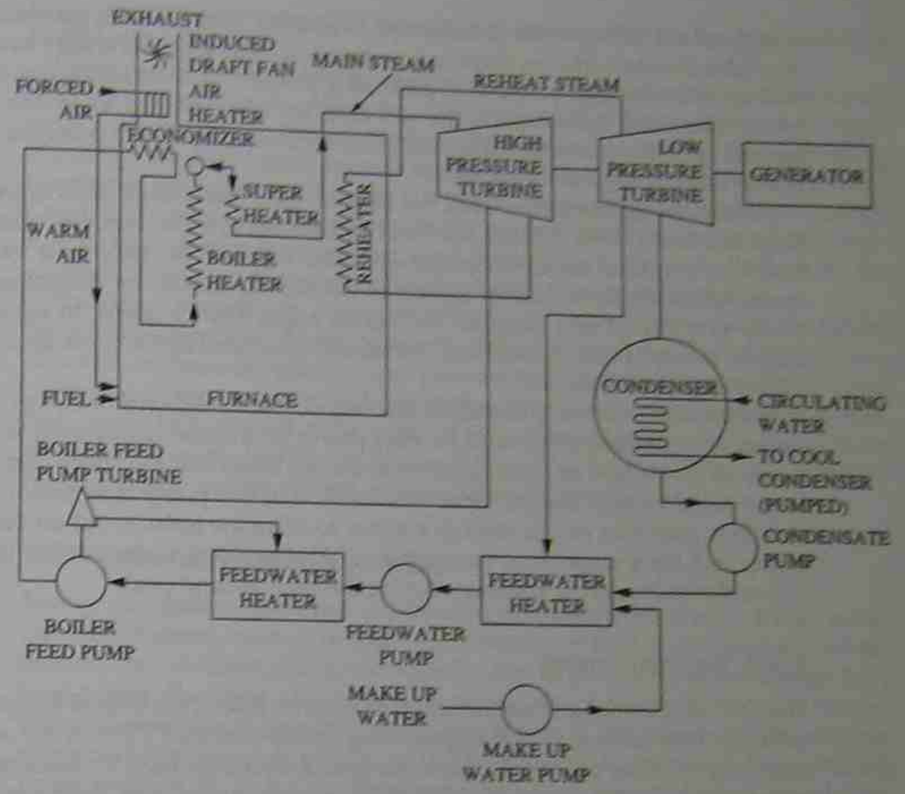


FIGURE 1.6 Diagram of the principal components of a fossil-fueled power plant

same pressure as the high pressure turbine exhaust, about 550 psi. After passing through the low pressure turbine the steam goes into the condenser and the process repeats. Most modern large generating plants use three-stage turbines (high, intermediate, and low pressure), and two reheat cycles.

Figure 1.6 does not illustrate the extreme complexity that is characteristic of a modern generating plant. The effort to improve efficiency has resulted in very complex boilers, furnaces, turbines, generators, and control systems. *Electric Utility Systems and Practices* provides a good overview of fossil fuel, hydroelectric, and nuclear generating practices.

1.5.2 Hydroelectric power

Falling water was one of the first sources of energy man exploited for work and also one of the first forms of energy used to produce electricity. The work falling water can do depends on the head (how far it falls) and the rate of flow. The

energy of the falling water is converted to rotating form to drive generators by specialized water turbines. Water is the most nearly free source of energy available that can provide large amounts of generating power. The costs are capital investment, labor, and maintenance; the fuel costs are zero. Almost all of the major sources of hydro power in the United States are in use, but much potential hydro power remains around the world.

Most of the hydroelectric work has been on high head, large units to provide large blocks of power. Smaller, low head hydro units to exploit smaller sources of hydro power have largely been ignored. Units of this type could be a valuable source of electricity in remote regions of developing nations by providing electricity to a village or a hospital. Such units might also be useful in developed nations to help conserve fossil fuel. The smaller, low head hydro units are a useful power engineering project.

Pumped storage refers to one of the few ways massive amounts of energy can be stored. A hydro unit that is used for peak power production can be used to pump water up into a lake or holding reservoir during times that electricity demand is low. A water turbine that can be reversed and used as a pump is required. A synchronous generator can be used as a motor to drive the turbine, but an auxiliary pump and electric motor is more efficient. The pumped water is then used to power the hydroelectric generator during the next demand peak.

1.5.3 Nuclear energy

The first commercial nuclear power plant went on line in the United Kingdom in 1956. By 1978 nuclear powered generating plants provided 7.5% of the world's electricity. Nuclear power promised economical electricity from an abundant fuel source. This promise may be fulfilled by nuclear fusion, but controversy has limited the acceptance of nuclear fission for electricity generation in some countries.

Nuclear power plants use controlled nuclear fission to heat water to produce steam. The nuclear decay is simply a water heating method. Nuclear fission can be an economical way to produce steam to generate electricity, but fear of the radioactive fuel and byproducts of nuclear electricity generation has resulted in an immense amount of controversy with respect to the desirability of nuclear power generation. The controversy has resulted in a complex system of regulatory procedures that make the planning, approval, construction, and commissioning of nuclear plants very time consuming and expensive in the United States. Often litigation has added to the expense. Except for the Chernobyl, USSR accident, the safety record of nuclear generating facilities world wide has been very good. The Three Mile Island accident, the worst mishap in the United States, caused no serious injuries. The good safety record has resulted partially from effective regulatory requirements and partially from the concern for safety that has been characteristic of the electrical power industry. However, the long-term storage of spent nuclear fuel and the decommissioning of old nuclear power plants are two major problems that have not yet been solved. Many countries are developing a large nuclear power generating capacity because they lack the fossil fuel reserves of the United States.

Many people in the electric power industry consider nuclear fission to be a temporary energy source for generation. Ultimately nuclear fusion is expected to provide an economical, almost inexhaustible source of energy for generating electricity. Nuclear fusion releases energy when two lighter elements are fused together to produce a heavier one; it is the source of energy for Hydrogen bombs. Controlled nuclear fusion can theoretically be obtained in a very hot plasma (mixture of high energy electrons and ions) confined in a magnetic field, or by the explosion of minute deuterium-tritium pellets in a protected enclosure.

The fusion is started by projecting several laser or particle beams on the pellets from many directions, which causes the pellets to implode. The implosion produces the extreme temperature and pressure needed for nuclear fusion to occur.

Nuclear fusion produces far fewer radioactive byproducts than nuclear fission, and cannot be sustained in the event of an equipment malfunction. It should be much safer than nuclear fission as an energy source. The possibility of commercial fusion-based generating plants in the near future is very small.

1.5.4 Alternative energy sources

Nearly any source of energy can be used to generate electricity: wind, water, chemical, thermal, nuclear, or solar. All of these have been used. The use of water, nuclear, and chemical change through burning to produce thermal energy have been briefly discussed. Direct chemical production of electricity from the electrochemical reactions in chemical power cells is now in use. Many smaller cells are connected to produce dc power up to 100 MW. The dc must then be converted, using inverters, to ac for distribution on the power system. Only a few electrochemical generating plants are in use at this time.

In the 1930s wind power was used extensively in rural America. The Delco system consisting of a wind charger and a battery was the most popular. Development is proceeding rapidly on larger, more efficient wind turbine and generator systems with control circuits that can tie them into a standard distribution system. Wind turbines to over 2.5 MW have been in operation for several years.

Geothermal energy refers to energy extracted from steam heated by the Earth's outer core in places near enough to the surface for the steam to be extracted. The geysers of Yellowstone National Park are examples of geothermal energy. The first geothermal plant was established in 1960 by the Pacific Gas and Electric Company in California. The plant capacity was 322 MW in 1972, but the field has a potential of 2000 MW. Geothermal fields such as this one with "dry" steam that can be used after being filtered, with no further processing, are rare. Geothermal steam is normally low pressure, around 100 psi, low temperature, around 350°F, and contains contaminants such as hydrogen sulfide and ammonia. Because of the contaminants the cost of the plants and maintenance is high, although the steam is virtually free. It is estimated that the worldwide potential for geothermal power is very small in comparison to total energy requirements.

Solar energy is produced two ways: by direct conversion to dc with semiconductor solar cells, which can provide as much as several kilowatts of electricity; and by using mirrors to reflect sunlight on to thermal collectors, which heat a working fluid to drive a turbine to generate up to 100 MW of electricity. Solar energy is important for providing power to remote installations, such as space stations, but it is not predicted to provide more than a small fraction of the world's energy needs.

1.6 TRANSMISSION

Large amounts of electric power must be moved from the sites where it is generated to the points where it is distributed for use. As in every other part of the electrical power system this must be done as efficiently as possible. For example, if a transmission line is to move 1000 MW at 95% efficiency and an additional investment can improve the efficiency to 96%, the additional investment must be seriously considered. The 1% saving is 10 MW. At five cents per kWh this represents a saving of 0.05 × 10,000 kW = $500 per hour. If the line has an expected life time of 40 years the total savings will be: $500/h × 24h/day × 365 days/year × 40 years = $175.2 million. Thus a lot of money is spent to obtain as much efficiency as possible in transmission lines.

The sources of loss are the same for both transmission and distribution lines, but because the distances and loads are greater for transmission lines the efficiency must be higher. The losses will be discussed in detail in the transmission section of this text, but are briefly discussed here.

1. *Resistance:* The series resistance of a conductor depends on the resistivity of the conductor material, its length, which is affected by the amount of spiralling of its strands, temperature, and the skin effect. Recall that dc resistance (R_{dc}) is directly proportional to the resistivity (ρ) and length (l) and inversely proportional to the cross-sectional area (A) as given by

$$R = \frac{\rho l}{A} \tag{1.1}$$

Stranded conductors are spiraled to improve flexibility and fatigue withstanding ability. Spiralling typically adds about 2% to the length. The area in a stranded conductor is the sum of the areas of each individual conductor. Recall conductor resistance increases almost linearly with temperature.

Skin effect refers to the fact that as frequency increases current flow shifts toward the surface of a conductor. Alternating current reverses direction periodically, and each reversal results in the magnetic flux produced by the current also reversing. The magnetic flux density is highest in the center of the conductor, causing the inductive reactance of the conductor to also be highest in the center. The higher inductive reactance at the center forces the current toward the outer surface of the conductor. The skin effect at a fixed frequency is proportional to the conductor diameter. The skin effect can result in the ac resistance of a large conductor being 20% higher than the dc resistance at 60 Hz.

Resistance losses (I^2R) are kept low by making transmission voltages as high as practical.

2. *Reactance:* The magnetic flux produced by the ac current produces series inductive reactance (X_L) because of both self inductance (which causes skin effect) along a conductor and mutual inductance between conductors. The reactance doesn't dissipate power, but results in a voltage drop ($i \times X_L$) along the line and volt-amperes-reactive (VARs) from $i^2 \times X_L$. Any reactive power on the line must be supplied by the generator in addition to the load power.
3. *Capacitance:* Conductors separated by a distance have capacitance. The capacitance of a transmission line depends on conductor size, spacing, height above the ground, and voltage. Transmission line capacitance must be charged before a line can transfer power, and even though the shunt loading of a line is low, some power is shunted to ground from the line through the capacitive reactance.
4. *Corona:* Corona is caused by the breakdown of the air around a transmission line because of high voltage. The effect is most severe around small conductors and at sharp points and corners. Corona absorbs energy from the line. Bundling of high voltage conductors, separating conductors with spacers placed periodically along the line, has dramatically reduced corona loss.

A typical high voltage transmission line is shown in Figure 1.7. The transmission line towers are a very important part of transmission lines. The tower must support the line under worst case loading with an adequate safety margin, exhibit minimal effect on the transmission line electrical characteristics, and be economical.

A new development that will effect transmission is the development of superconducting magnets for bulk power storage. The scientific investigations into superconducting magnets, which were perfected for guiding particle streams in particle accelerators, such as Super Conducting Super Collider that was planned for Texas but discontinued after construction began, and further developed into superconducting electrical energy storage devices for Star Wars rail guns, have promise in other applications. One application is as Superconducting Magnetic Energy Storage units (SMES) that promise to be useful in the management of the transmission of electricity.

The pilot program for Superconducting Magnetic Energy Storage is currently planned for San Diego Gas and Electric System (SDG&E) at Blythe, California by a consortium that includes SDG&E, Bechtel, The Department of Energy, and others. This unit will demonstrate the capability to store power, use the stored power to stabilize voltage and frequency, prevent subsynchronous reaction (low frequency power perturbations), and provide peaking power. The ability to respond to transient power needs in a few milliseconds by electronic control of electrical power stored in a superconducting magnet allows transmission lines to operate more stably. Thus they will be able to reliably transmit about 10% more power than they

can without this ability. This development will allow the more efficient operation of the North American Electrical Grid (including both Canada and Mexico), and improve the transfer of power to meet the load needs of North America following the sun East to West daily, and North to South seasonally.

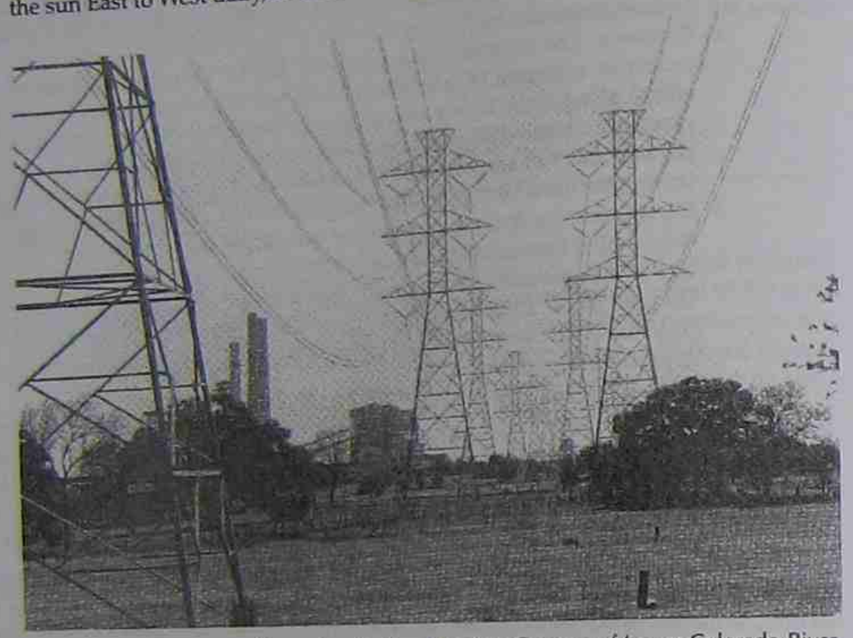


FIGURE 1.7 Transmission line at Fayette Power Project (Courtesy of Lower Colorado River Authority).

1.7 DISTRIBUTION

A distribution system is subject to all of the losses that a transmission system has, but since it carries lower voltages bundling of conductors to prevent corona is not necessary. The shorter distances and lower power per line involved in distribution allows the design emphasis to shift from maximum efficiency (it is still important) to accessibility, safety, and continuity of service. The American system of residential distribution illustrates the safety concern. The three-wire, 240/120 V system has a neutral at ground potential and hot wires at 120 V above and 120 V below neutral as illustrated in Figure 1.8. In this system, 120 V loads are fed from either hot wire to neutral and 240 V loads are connected from one hot wire to the other. This arrangement prevents voltages to ground from exceeding 120 V, provides a lower, safer voltage for low power loads, and provides a higher voltage for higher

power loads. The European system is a two-wire, 250 Volt system that works, but lacks the safety and flexibility of the U.S. system.

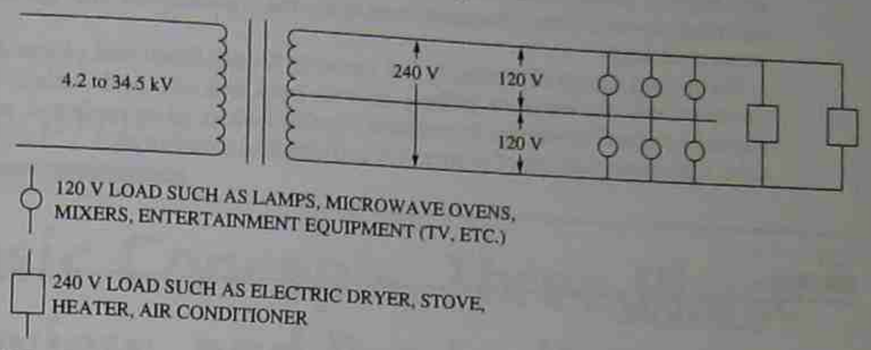


FIGURE 1.8 American 240V/120V residential distribution system

Further discussion of distribution will be delayed until Section 2, which is about electrical power distribution. Section 3 is about electrical power transmission.

1.8 SUMMARY

Electricity is a convenient form of energy to transport and the machinery used to generate, transform, and utilize electricity is efficient. This chapter provided the reader with a brief history of the development of electrical power from Thales to the present. Among the more important events were the commercial generation of electricity for street lighting, the Edison dc distribution concept with its central generating station, the invention of ac machinery by Tesla, the generation and transformation of ac by Westinghouse and Stanley, high voltage transmission, and dc transmission. The evolution of the electrical power utilities into state regulated monopolies supplying as much electricity as possible at as cheap a rate as possible (thanks to Insull's vision) was an important force in the United States. The concept of cooperative interconnection between suppliers of electricity led to the ability of electric utilities companies to provide good service at lower prices to consumers because the capital investment needed for reserve power was shared among electrical power companies. Interconnection later made the practice of wheeling cogenerated power possible.

The involvement of the U.S. government in the production and transmission of electrical power in projects such as the TVA, the REA, and BPA helped to provide a check and balance on investor owned electric utilities, electrify rural areas of the U.S. long before they would have otherwise been, and efficiently utilize the hydroelectric potential of the Pacific Northwest respectively. The U.S. government

continues to be involved in the electrical power industry via the FERC. The current trend is toward companies formed for generation supplying electricity, and electrical power utility companies managing the transmission and distribution of the electricity.

The perfect source of electricity has yet to be found. Fossil fuel plants deplete nonrenewable resources or pollute, or both (coal and oil), and nuclear fission plants leave hard to manage byproducts. Nuclear fusion, when perfected, appears to be a promising source of economical and plentiful electricity.

1.9 QUESTIONS

1. What is the function of the electrical power system?
2. Who invented the polyphase system of electricity transmission?
3. What were the major contributions of George Westinghouse and William Stanley to the electrical power industry?
4. State the conditions that led to the granting of franchises to a single supplier of electricity to an area instead of open competition.
5. State the problem that single-supplier franchising caused, and the solution to the problem that was ultimately adopted.
6. What major problem did E. M. Hewlett and H. W. Buck solve?
7. What is conductor bundling and what problem did it solve?
8. Name and state the function of the three major parts of the electrical power system.
9. List in order of magnitude the four major sources of energy used to produce electricity.
10. What are the advantages of a strong interconnect system between electric utility companies?

CHAPTER 2

Basic Concepts, Three-Phase Review, and Per Unit

This chapter reviews some basic concepts from an electrical power point of view. They are the basic circuit elements, voltage, resistance, inductance, capacitance, and their use in representing electrical loads and lines. Phasors and basic three-phase concepts are also reviewed while the per unit concept and impedance diagrams are introduced in this chapter.

2.1 BASIC CONCEPTS

2.1.1 Voltage

Voltage (electromotive force, emf) provides the electric fields that cause electron current in conductors. Electrons drift through the conductor attracted toward the more positive terminal of the voltage source and repelled by the more negative terminal. Voltage can be produced in many ways including chemical reactions in batteries, mechanical flexing of piezoelectric materials such as Barium titanate, separation of electron-hole pairs created by absorption of light in a semiconductor by the static electric field of the semiconductor junction of a photo-electric cell, and moving conductors through a magnetic field. The latter method is the one

currently used to generate voltage in the majority of the electric generating plants throughout the world.

The voltage of a generator is determined by the amount of magnetic flux produced by the field windings, the number of armature windings, and the speed at which the rotor is turned. The more of each of these three quantities that is present, the higher the voltage. The equation that describes the relationship between these three quantities, you may recall from your study of electric machines, is

$$E_{GRMS} = 4.44\,\Phi N f \cdot 10^{-8} \text{ Volts} \tag{2.1}$$

where

Φ is the number of flux lines per pole for English units, and in Webers for SI

N is the number of turns per phase

f is the frequency in Hertz (1/s where s is the number of revolutions per second)

E_G is the generator phase voltage.

The factor for SI units is 1 instead of 10^{-8}.

Generation is illustrated in Figure 2.1. If the voltage produced is to be useful the prime mover speed must be very stable to keep the frequency fixed. Recall that after an ac generator is paralleled into an infinite bus that the field excitation controls the reactive current (VARs) and the prime mover torque controls the power that the generator delivers to the bus.

A single generator connected to a load does not have a fixed voltage like a generator connected to an infinite bus. If the prime mover speed is constant, the voltage varies with field excitation, load impedance, and load power factor. Referring to Figure 2.2, as the load current increases, the voltage drop across the internal impedance of the generator causes the generator terminal voltage to drop, if the load power factor is one or less than one and lagging (as most loads are). Recall that armature reaction is the interaction of the field flux and the flux produced in the armature because of load current flow. The armature reaction flux from leading power factor loads aids the field flux, and the armature reaction flux from lagging power factor loads opposes the field flux. The amount of aid or opposition depends on the amount of lead or lag. Since the voltage produced by the armature reaction flux lags the load current by 90 ° it is in phase with the voltage drop across the armature reactance. The measured value of generator synchronous reactance includes the effect of both armature reaction and armature reactance. The generator impedance shown in Figure 2.2 is that of the armature resistance and the synchronous reactance. The terminal voltage (E_T) of a generator is

$$E_T = E_G - I_L Z_G \tag{2.2}$$

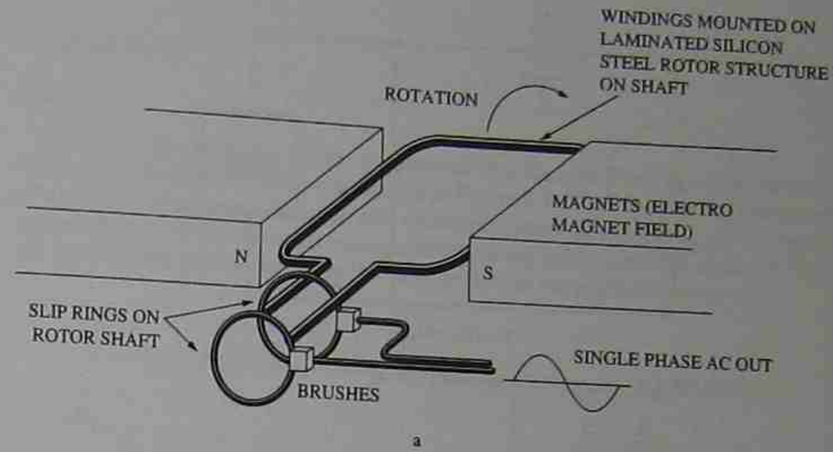


FIGURE 2.1 Generation illustration—(a) Single phase and (b) three phase.

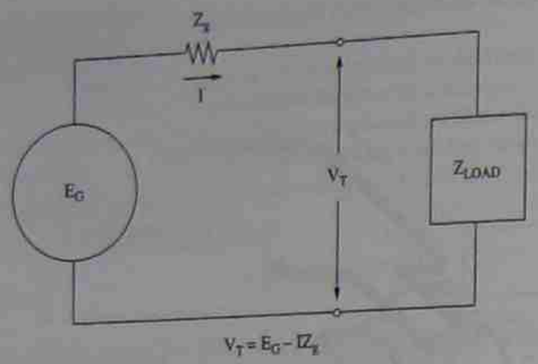


FIGURE 2.2 Generator equivalent circuit

2.1.2 Current

Current is the flow of charges under the influence of an electric field. The current we most often think of is the flow of electrons in a conductor. The direction of current flow was agreed to be from the positive terminal of a voltage source to the negative before the nature of current in a conductor was understood. After it was discovered that electrons flow from the negative terminal of a voltage source to the positive the older convention was retained as *conventional current* and the actual flow of electrons in the opposite direction was then called *electron current*. The direction of the electron current in most electrical books is opposite to the arrow depicting its direction because most authors use conventional current by tradition. Alternating current, used for most electrical power transfer, changes direction every half cycle, so current direction is for mathematical convenience if it is indicated. The current moving under the influence of the applied voltage provides the electrical power.

2.1.3 Impedance

Impedance, as you know, is the total opposition to ac current by the components of a circuit. We are interested in resistance, inductance, and capacitance.

Resistance is the property of a component that opposes dc current and the component of ac current in phase with the voltage. Resistance depends on the number of free electrons per unit volume of a material, the probability of collisions of the free electrons in the material with other electrons and atoms, and the physical dimensions of the material. The resistivity of a material (ρ) is a combination of the physical characteristics of the material that influence resistance. The resistance in ohms (Ω) is given by the equation

$$R = \rho \frac{1}{A} \text{ Ohms} \tag{2.3}$$

where

l = length and

A = area.

The units of resistance, Ohms, are named after George Ohm, the originator of Ohm's law. The circuit symbol is shown in Figure 2.3. All of the power consumed in a circuit, other than dielectric and hysteresis losses, is consumed by the resistance because of the electrons losing energy during collisions with atoms as they are forced through the circuit by the electric field of the applied voltage.

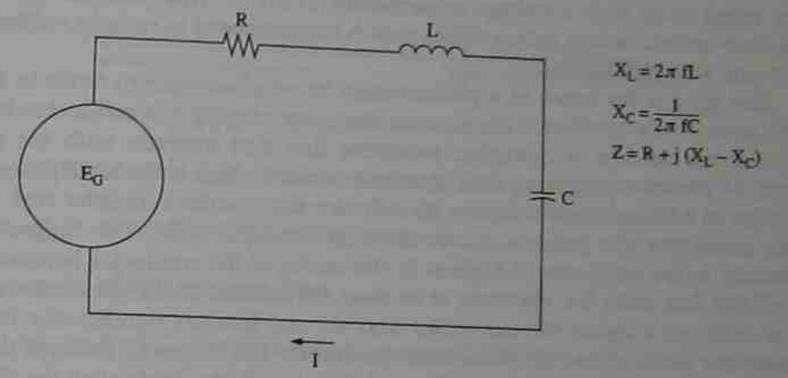


FIGURE 2.3 RLC circuit

Inductance is the property of a component that opposes any change in current through that component. Inductance is analogous to inertia in a mechanical system; the tendency of a mass in motion to remain in motion. Inductance (L) is, like R,

$$E_L = L \frac{di}{dt}$$

or

$$E_L = L \frac{\Delta I}{\Delta t} \tag{2.4}$$

a constant of proportionality between the voltage across, and the time rate of change of current through, a component.

The amount of inductance is a function of the physical construction of the component. The number of turns of wire, the permeability of the core, and the geometry determine the inductance of a component. No power is consumed by the inductance, but an inductor will consume power in its winding resistance, and its core via hysteresis and eddy currents.

The opposition to current in an inductor results because a change of current in a conductor of the inductor causes a magnetic flux change in the space surrounding the conductor that induces a counter emf in adjacent conductors. The adjacent conductor current is inducing a counter emf in the original conductor at the same time. The counter emf, because the flux is expanding when the current is rising and collapsing when the current is falling, always has a polarity that opposes the external emf, or acts as the circuit emf if the external emf is removed. The counter emf, because it opposes the circuit emf, opposes an increase in current. The emf produced by collapsing magnetic flux when the circuit emf is removed opposes a decrease in current. When the applied voltage is removed from an inductive circuit the emf produced by the collapsing flux will try to keep the current constant by rising to as high a voltage as necessary to do so. This process, often called inductive kick, causes arcing across switch contacts used to remove voltage from circuits with inductance.

Skin effect is the name of a phenomenon in which ac current tends to flow at the surface of a conductor. An electron changing velocity in a conductor, because the circuit voltage is changing, produces flux that interacts with the flux of near by electrons opposing their change in velocity. This is the same process that occurs in adjacent conductors on an inductor that results in counter emf. Within the conductor the process occurs on a microscopic scale. The magnetic flux density in the conductor is highest in the center of the conductor because about half the flux from the electrons at or near the surface of the conductor expand (or contract) outside the conductor and do not interact significantly with the magnetic fields of the electrons near the center. The magnetic fields of the electrons nearer the center of the conductor interact with the fields of all the electrons around them. Thus the magnetic flux density is higher at the center of the conductor than at the surface, the opposition to a velocity change of current carriers is higher at the center of the conductor, and the opposition to current flow is higher at the center of the conductor than at the edge. The current density is therefore highest at the surface of a conductor in which ac current is flowing. Effectively, X_L is higher in the center of a conductor carrying ac current so most of the current is forced toward the surface. As the frequency increases, the inductive reactance at the center of the conductor increases, and the current is more strongly confined to the surface (or skin) of the conductor. The current falls off exponentially going from the surface toward the center of a conductor carrying ac current as shown in Figure 2.4.

The skin depth is defined as the distance from the conductor surface at which the current has fallen to 1/e, or 36.79%, of the value at the surface. The skin depth serves the same mathematical function as the time constant in capacitor and inductor charge and discharge equations. The equation for the skin depth (δ) is

$$\delta = \sqrt{\frac{1}{\pi f \mu_r \mu_o \sigma}}$$

where

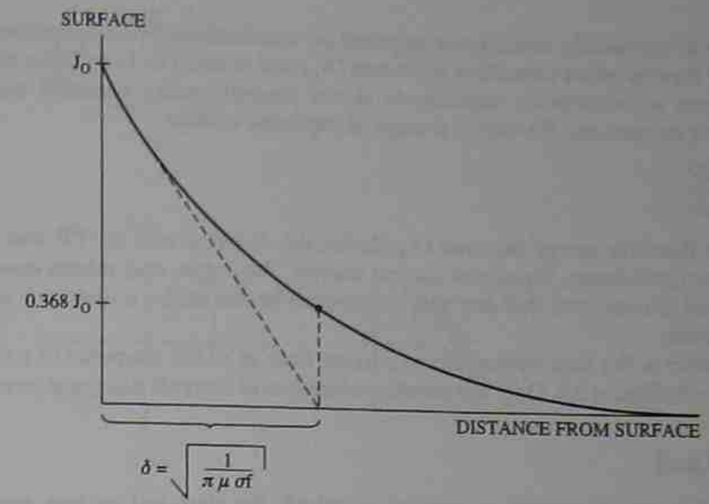


FIGURE 2.4 Skin depth vs. current density (J)

σ = conductivity in Siemens/meter

μ_r = relative permeability

$\mu_o = 4\pi 10^{-7}$ Henry/meter, the permeability of space

f = frequency in Hertz.

At 60 Hz the skin depth in copper is about 8.53 mm, or about 0.335 in. Thus current capacity cannot be increased by using thicker conductors at power line frequencies. Instead, more conductor area of conductors about 0.5 inch thickness is needed. We will see the skin effect taken into account in many areas of our study of electrical power distribution and transmission.

Capacitance results from conductors separated by an insulator, as in a parallel plate capacitor. When the conductors are at a different potential the electric field acting between them concentrates charges at the surface of the conductors that are nearest each other. If a dielectric whose molecules are easily polarized is placed between the conductors it causes the distance between the conductors to appear less than it is physically, because the polarized atoms or molecules within the dielectric transfer the electric field through the dielectric. The ease with which the dielectric can be polarized with respect to a vacuum is the dielectric constant (ϵ_r) of the dielectric, the ratio of the permittivity of the dielectric to that of a vacuum (ϵ/ϵ_o). Recall that the capacitance of a capacitor is directly proportional to the dielectric constant of the dielectric and the conductor, or plate, area, and inversely proportional to the distance between the conductors. Capacitance, because of its ability to store charge, opposes any change in the voltage across it. Because the voltage across a capacitor opposes circuit voltage at any instant that the circuit

voltage is increasing, capacitance opposes ac current flow. The opposition to ac current flow is called capacitive reactance (X_C) and is equal to $1/\omega C$. In a manner analogous to inductance, capacitance is the proportionality constant between capacitor current and the rate of change of capacitor voltage.

$$I_c = Q\frac{dV}{dt} \tag{2.6}$$

Other than the energy required to polarize the dielectric and the I^2R loss of the capacitor conductors, capacitors use no energy. They store and return energy to the circuit. Please note that any two conductors separated by a dielectric exhibit capacitance.

Impedance is the total opposition to current flow of all the elements of a circuit, as shown in Figure 2.3. Only the resistive elements of a circuit dissipate power.

2.1.4 Load

The load is the apparatus or devices to which the electrical system provides power. The electrical system loads may do work, such as electric motors or computers, provide comfort, as air conditioning and electric lighting, or entertainment and information, like television. The terminal characteristics of the load are important for the electrical system. At the rated voltage the load draws a given amount of current at a certain power factor. The current and power factor of the load may not be fixed so the electrical system must provide the maximum amount of apparent power the load will need. For example, an induction motor with a light load will draw mostly magnetizing current so its power factor will be low and lagging. At full load the motor will draw more current and the power factor will be much higher, but still lagging. A heating element or incandescent light will draw current that is in phase with the applied voltage, but draw a much higher current for a few cycles after turn on until they warm up.

Figure 2.5 shows a load that may be inductive, capacitive, or resistive depending on the relative values of reactance of L and C at the supply frequency. Figure 2.6a shows the impedance diagram and equations for a series RLC circuit, and Figure 2.6b shows the admittance diagram for a parallel RLC circuit. Recall that the j operator represents a 90° phase shift.

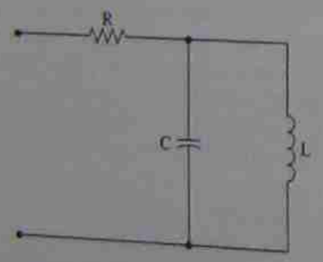
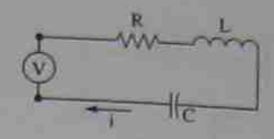
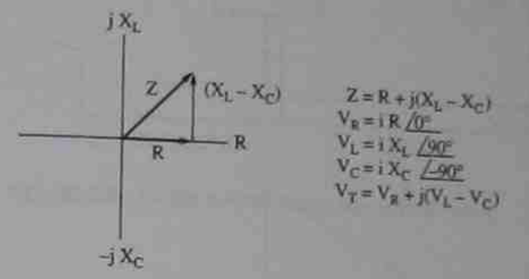


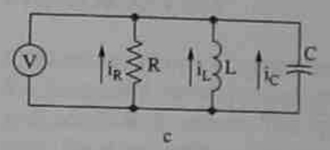
FIGURE 2.5 Example of a load equivalent circuit



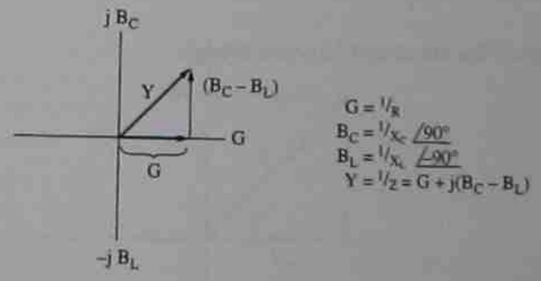
a



b



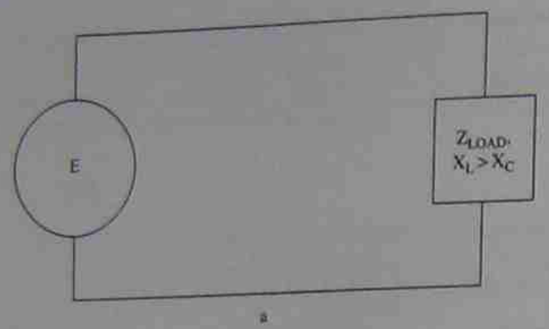
c



d

FIGURE 2.6 Impedance and admittance diagrams (a) Series RLC circuit (I common to all components) (b) impedance vector diagram (I sets reference direction) (c) parallel RLC circuit (V common to all components) and (d) admittance vector diagram (V sets reference).

The relationship between apparent, reactive, and real power (**S**, **Q**, and **P**, respectively) for an inductive load is shown in Figure 2.7. Recall that power factor (PF) is defined as the ratio of real to apparent power (**P/S**).



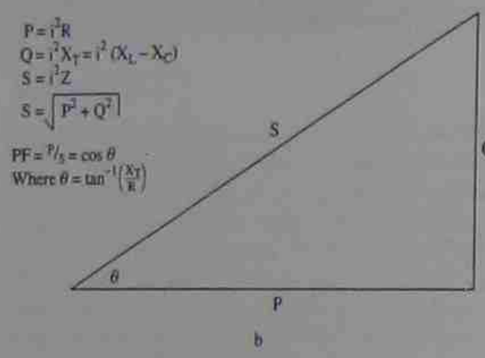


FIGURE 2.7 Power triangle (a) The circuit and (b) power triangle

2.1.5 The line

The source of electricity and the load must be connected. The transmission and distribution lines provide the connection. These lines will be a major part of our study throughout this book. The line has all of the basic circuit elements: capacitance, inductance, and resistance. The line resistance is increased by the skin effect. The length and load of the line determine the relative impact of each of the basic elements on transfer of power through the line. Figure 2.8 illustrates the equivalent circuit of a generator and a load connected by the equivalent circuit of a medium length line. The equivalent circuit of a short line would not contain the capacitor C_{LINE}. Short lines have capacitance but the effect of the capacitance on power transfer is small compared to the other line elements.

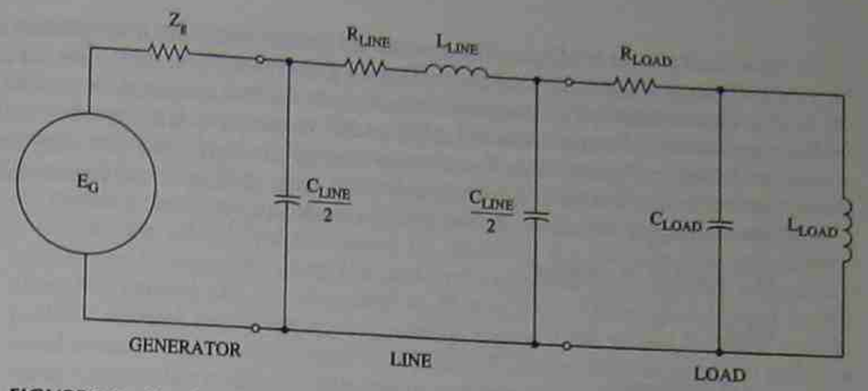


FIGURE 2.8 Simple power system equivalent circuit.

2.2 PHASOR REVIEW

Phasors are electrical quantities plotted in polar coordinates (amplitude, angle). We have used the real-imaginary plane illustrated in Figure 2.9 to plot impedance and admittance vectors. The operator j indicates a 90° shift with respect to the real axis. We now wish to use the plane to illustrate ac voltages and currents. Most

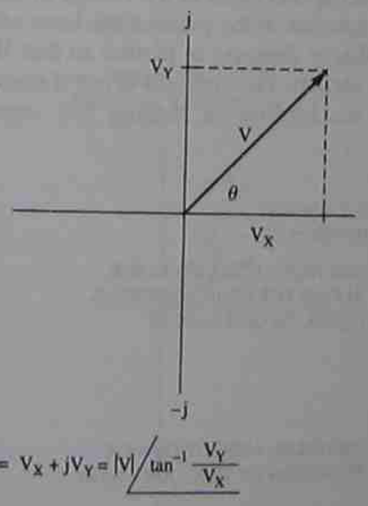


FIGURE 2.9 Coordinates

electrical power is supplied as sine waves. A vector one unit in amplitude rotated 360° traces a unit circle as shown in Figure 2.10. The vertical component of the vector on unit in amplitude is proportional to sin θ. If this amplitude is plotted on the vertical axis of a graph and the angle on the horizontal axis a sine wave will result as shown in Figure 2.11a. A sine wave may go through many 360° (2π) rotations per second so the horizontal axis may be in units of time, where time is related to the total angle in radians the vector has traveled (θ_T) by

$$\theta_T = 2\pi ft = \omega t \text{ radians} \tag{2.7}$$

where

f = frequency

t = time

$\omega = 2\pi f$

The sine waves shown in Figure 2.11a are a voltage and a current wave that are 45° out of phase with the current lagging the voltage. Because their peak values are greater than one, the sine function is multiplied by the peak value to obtain the value at a particular time, as shown in Figure 2.11a.

The relationships between voltages, voltage drops, and currents are difficult to illustrate in drawings, such as in Figure 2.11a. The relationship between the current and voltage of Figure 2.11a can be easily shown using a vectorial representation such as the one shown in Figure 2.11b. These rotating vectors are called *phasors* and have an amplitude equal to the rms value of the voltage or current. By mutual agreement, counterclockwise rotation of the phasors has been adopted as the positive rotation direction. The phasor diagram is plotted so that the phase relationships between the phasors is shown. The rotation is not shown but is a way of illustrating which phasors are leading or lagging one another. For

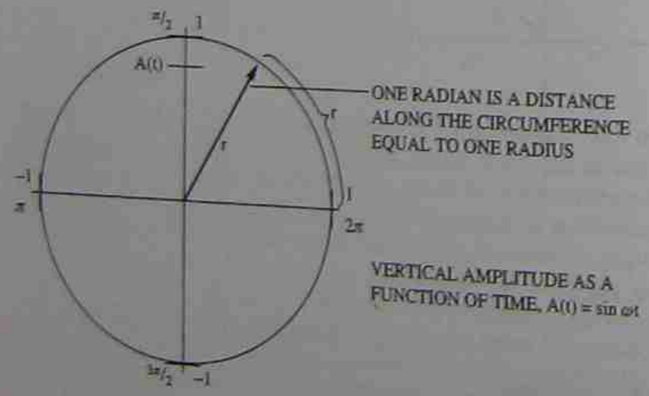
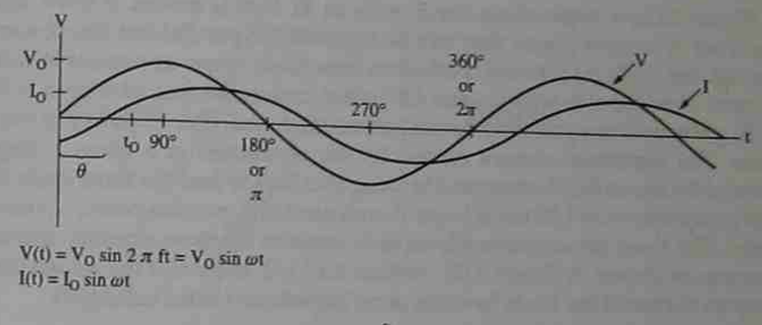


FIGURE 2.10 Unit circle

example, the voltage is leading the current in Figure 2.11a so it is drawn 45° to the ccw side of the current in Figure 2.11b. The reference phasor is frequently drawn on the zero degree axis and all other phasors drawn in their proper relationship to the reference phasor, as shown in Figure 2.11c. Phasors are vectors rotating at constant angular velocity. To calculate circuit quantities from phasors we must freeze them in time, and do calculations using normal vector mathematics. Please note that phasors are basically electrical quantities plotted in polar coordinates (amplitude, angle).

Phasors are added and subtracted by resolving the phasors into components with the real component along the horizontal axis and the imaginary component along the vertical axis, as illustrated in Figure 2.11c. The angles depend on the position selected for the reference quantity. Figure 2.11b would be more complicated to resolve into components than Figure 2.11c, but both figures will yield the same solution for problems with rms or average value (**P, Q, S**) solutions. Multiplication and division are most easily performed in polar form.



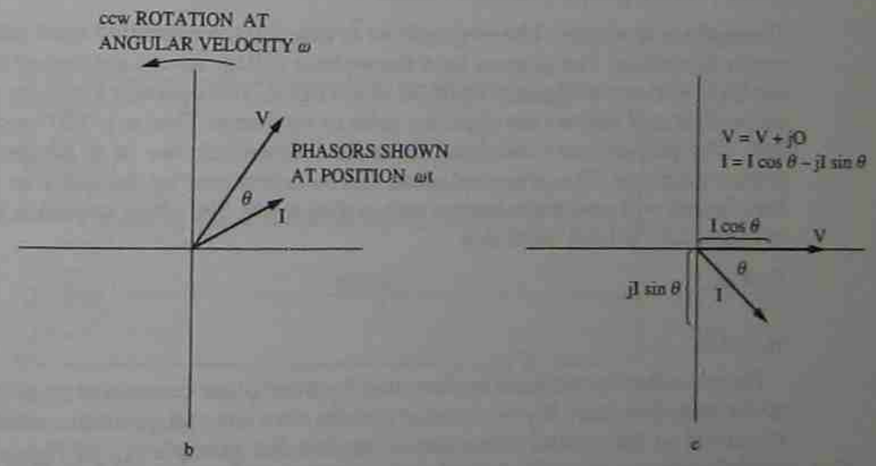


FIGURE 2.11 Phasor representation of voltage and current (a) Sinusoidal wave representation (b) phasor representation at t_0 and (c) reference chosen for convenience because θ is constant for the circuit.

2.3 THREE-PHASE REVIEW

Single-phase quantities have been discussed to this point. Most bulk electrical power is transferred as three-phase voltages and currents because the power flow is constant instead of pulsating, as it is in a single-phase or two-phase system. The constant power flow in a three-phase system is shown in Appendix A. Two- and six-phase power are occasionally used for special purposes, and single-phase power is used for the vast majority of single family dwellings, but three-phase power is used in most distribution and transmission systems.

2.3.1 Basic Three-phase Concepts

In Figure 2.12a a single-phase circuit with an RL load is shown. If three identical loads are to receive power they can be connected in parallel but the power flow through the loads pulsate and conductors three times larger are needed to carry the current. Three circuits with sources 120° offset from each other, as shown in Figure 2.12b, provide three-phase power and a smooth overall flow of power to the three loads. The maximum current carried by the conductors at a given voltage are reduced by about 42.3% compared to using two lines to feed the three loads in parallel (a capacity only 1.73 times larger than is needed to provide power to one of the loads). The three-phase source allows us to combine the three separate return lines into one, as shown in Figure 2.12c. Section 2.3.3 will show that the return line will carry no current if the loads have the same impedance (called balanced).

2.3.2 Three-phase Phasor Notation

Three-phase quantities, like single-phase ac quantities, are handled most easily as vector quantities. The phasors for a three-phase voltage source are shown in Figure 2.13. Notice the operator alpha (α) in the figure. This operator indicates a 120° phase shift and follows the algebraic rules of exponents. Thus $\alpha = 120°$ and $\alpha^2 = 240°$. The phasors are considered to rotate counterclockwise as in single-phase phasor diagrams. The phase sequence can be determined by the order in which the phasors will pass the reference axis as they rotate. The phase sequence shown in Figure 2.13 is 1-2-3. Note that

$$E_3 = \alpha E_1 \tag{2.8a}$$

$$E_2 = \alpha^2 E_1 \tag{2.8b}$$

Double subscript notation is often used for three-phase currents to avoid uncertainty as to direction. Wye-connected circuits often have all quantities referenced to neutral so the neutral connection is implied. For example V_{AN} of Figure 2.14a might be written as V_A. Double subscript notation is necessary for delta-connected circuit quantities. The first subscript, normally denotes the point of measurement

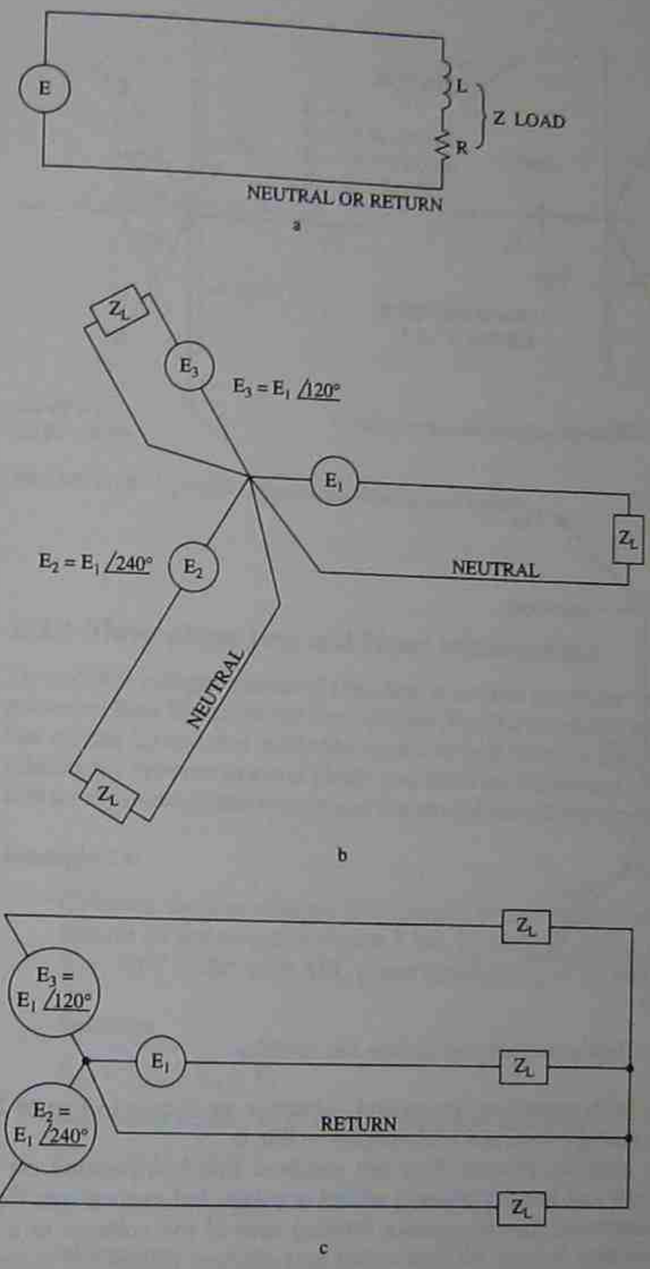


FIGURE 2.12 Three-phase system (a) Single-phase (b) three phase from single phases at 0°, 120°, 240° and (c) three neutrals replaced with a single neutral

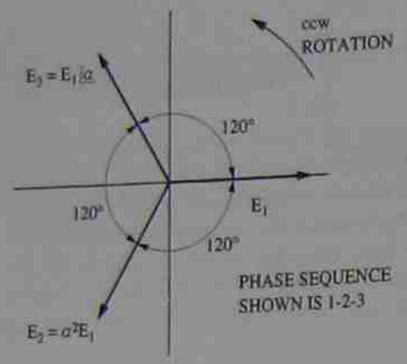
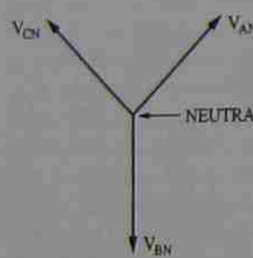


FIGURE 2.13 Three-phase phasor convention



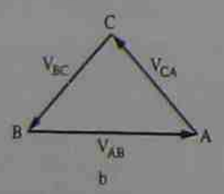


FIGURE 2.14 Three-phase notation (a) Wye and (b) delta

of a quantity with respect to the second subscript, as shown in Figure 2.14b. V_{AB} indicates the voltage on line A with respect to line B.

To add or subtract phasors they are resolved into components on the real-imaginary plane and the components added or subtracted as shown in Figure 2.15. Figure 2.15 illustrates that the phasor (vector) sum of the voltages in a balanced three-phase system is zero. Multiplication and division of phasors is most easily done with the phasors in polar form. Balanced three-phase systems can be analyzed by calculation of quantities of interest for one phase because the other two phases are behaving identically except that their phases are offset by 120° and 240°.

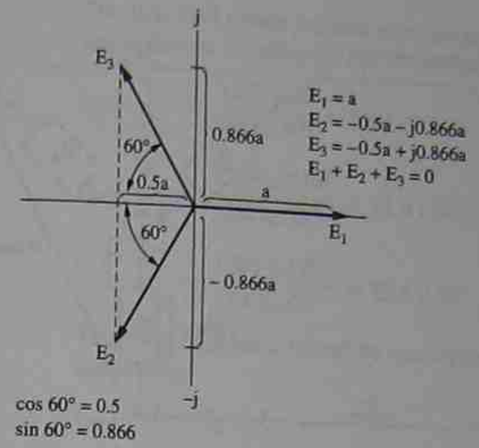


FIGURE 2.15 $V_T = 0$ in a balanced three-phase system

2.3.3 Three-phase Line and Phase relationships

Three-phase voltages measured from line to neutral are phase voltages (V_P) and those measured from line to line are line voltages (V_L). The current that flows in the line is the line current (I_L) and that inside the source or load phase is the phase current (I_P). The relationship between line and phase quantities are illustrated with two examples, the first for a wye-connected system and the second for a delta-connected system.

Example 2.1:

Calculate the line voltage, line current, phase current, and total three-phase current for the circuit of Figure 2.16a. $E_A = 120\text{V} \angle 0°$, $E_B = 120\text{V} \angle 240°$, and $E_C = 120\text{V} \angle 120°$ with ABC phase rotation. $Z_A = Z_B = Z_C = 10\angle 40°$

Solution:

$E_{\text{line}} = E_{AB} = E_A - E_B$

Expressing E_A and E_B in rectangular form we have

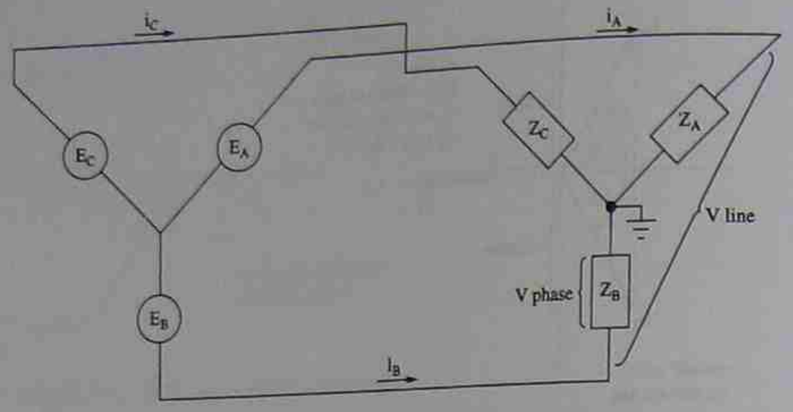
$E_A = 120\text{ V} + \text{j}0\text{ V}$

$E_B = -60\text{ V} - \text{j}103.9\text{ V}$

subtracting

$E_{AB} = 120\text{ V} + 60\text{ V} + \text{j}103.9\text{ V}$

$= 207.846\text{V} \angle 30°$

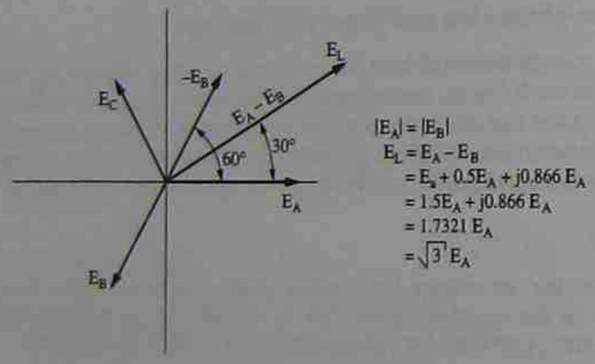


$V_l = \sqrt{3}\, V_p$ offset 30° from V_A

$I_L = I_P$

$P = \sqrt{3}\, V_l\, I_l = 3 V_p\, I_P$

a



$|E_A| = |E_B|$

$E_L = E_A - E_B$

$= E_a + 0.5E_A + j0.866\, E_A$

$= 1.5E_A + j0.866\, E_A$

$= 1.7321\, E_A$

$= \sqrt{3}\, E_A$

b

FIGURE 2.16 Wye (Y) system (a) Circuit and (b) voltage phasor diagram

which is the line voltage. The ratio of the line to phase voltage is of interest.

$$\frac{E_{AB}}{E_A} = \frac{V_l}{V_p} = \frac{207.85V}{120V} = 1.732 = \sqrt{3}$$

Thus for a wye system $V_l = \sqrt{3}\, V_p$. Figure 2.16b illustrates the relationship in vectorial form. Similarly

$E_{BC} = 207.846V\ \angle 270°$ and $E_{CA} = 207.846V\ \angle 150°$

The line and phase current must be equal because the line and phase circuits are in series. Solving for the three-line currents

$$I_A = \frac{V_A}{Z_A} = \frac{120V\angle 0°}{10\Omega\angle 40°} = 12A\angle -40°$$

$$I_B = \frac{V_B}{Z_B} = \frac{120V\angle 240°}{10\Omega\angle 40°} = 12A\angle 200°$$

$$I_C = \frac{V_C}{Z_C} = \frac{120V\angle 120°}{10\Omega\angle 40°} = 12A\angle 80°$$

The total current is found by converting the currents to rectangular form and summing

$I_{Total} = I_A + I_B + I_C$

$= 9.193\text{ A} - j7.713\text{ A} - 11.276\text{ A} - j4.104\text{ A} + 2.084\text{ A} + j11.818\text{ A}$

$= (9.193 + 2.084 - 11.276)\text{A} + j(-7.713 - 4.4104 + 11.818)\text{A}$

$= 0$

The total current, like the total voltage, in a balanced three-phase system is zero.

To calculate the power (or volt amperes) for a three-phase wye circuit we can multiply three times the phase power or use line voltage and current as follows

$$P = 3\, V_p\, I_p = 3\frac{V_l}{\sqrt{3}}\, I_l = \sqrt{3}\, V_l I_l$$

The line and phase relationships for a wye-connected circuit are summarized in Figure 2.16a.

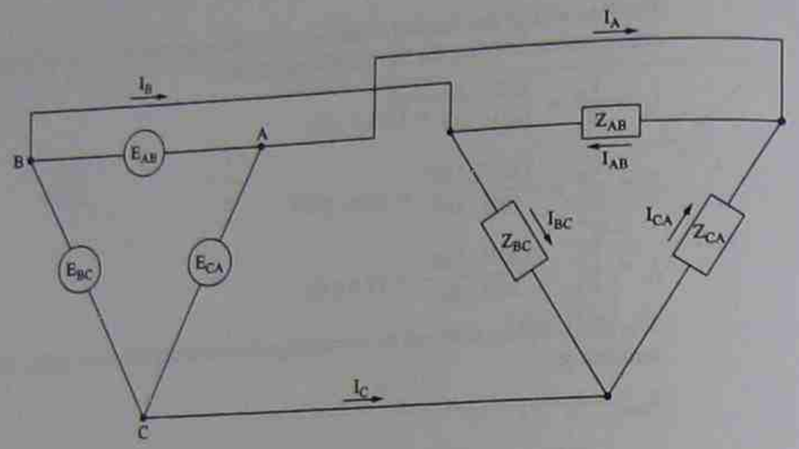
We will also examine the line and phase relationships of a delta-connected system by using an example.

Example 2.2:

For the circuit drawn in Figure 2.17a calculate the phase voltage, phase current, line current, and the relationship between the line and phase voltages and currents. The line voltages are $E_{AB} = 120V\angle 0°$, $E_{BC} = 120V\angle 120°$, and $E_{CA} = 120V\angle 240°$ for an ACB phase sequence. All three-phase impedances are the same: $Z_{AB} = Z_{BC} = Z_{CA} = 20\Omega\ \angle 50°$.

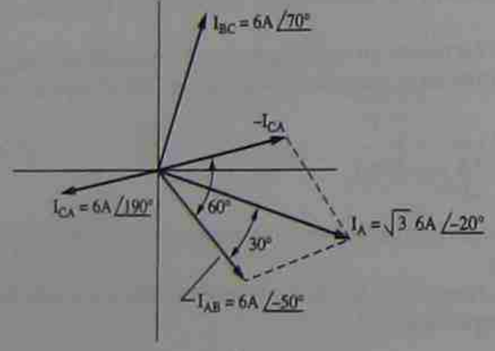
Solution:

The phase voltage is equal to the line voltage because each load is connected directly from one line to the next.



$V_L = V_P$
$I_L = \sqrt{3}\, I_p$ offset 30°
$P = \sqrt{3}\, V_L\, I_L = 3V_P\, I_P$

a



b

FIGURE 2.17 Delta (Δ) system (a) Delta connected circuit and (b) current phasor diagram

The phase currents are

$$I_{AB} = \frac{E_{AB}}{Z_{AB}} = \frac{120V\angle 0°}{20\Omega\angle 50°} = 6A\angle -50°$$

$$I_{BC} = \frac{E_{BC}}{Z_{BC}} = \frac{120V\angle 120°}{20\Omega\angle 50°} = 6A\angle 70°$$

$$I_{CA} = \frac{E_{CA}}{Z_{CA}} = \frac{120V\angle 240°}{20\Omega\angle 50°} = 6A\angle 190°$$

The system is balanced so we need calculate only one line current.
$I_A = I_{AB} - I_{CA}$

In rectangular form

$I_{AB} = 3.8\text{ A} - \text{j}4.596\text{ A}$

$I_{BC} = 2.052\text{ A} + \text{j}5.638\text{ A}$

$I_{CA} = -5.909\text{ A} - \text{j}1.419\text{ A}$

Thus

$I_A = (3.8 + 5.909)\text{A} + \text{j}(-4.596 + 1.0419)\text{A}$

$= 9.709\text{A} - \text{j}3.554\text{A}$

$= 10.339\text{A}\angle -20°$

The ratio between the line and phase current is

$$\frac{I_l}{I_p} = \frac{I_A}{I_{AB}} = \frac{10.339A\angle -20°}{6.0A\angle -50°} = 1.732\angle 30°$$

Therefore we see that in a delta system $I_l = \sqrt{3}\, I_p$ offset 30°. The relationships are summarized in Figure 2.17a, and the phasor diagram of the current is shown in Figure 2.17b.

Power is found as follows

$$P = 3V_p I_p \cos\theta = 3V_l(I_l/\sqrt{3})\cos\theta = \sqrt{3}\, V_l I_l \cos\theta$$

Up to this point in Chapter 2 we have been reviewing basic concepts from ac and three-phase circuits. If you are not familiar with an area please refer to an appropriate reference book. A list of references is provided in Appendix E.

2.4 THE PER UNIT CONCEPT

This section is about a convenient method of calculating electrical power quantities.

2.4.1 Single-phase Per Unit

A shorthand method of solving power system problems has been developed to eliminate many of the manipulations required in systems with more than one voltage, which is nearly all of them. The method is a modification of working with percentages of a base value called the *per unit system*. The system works as follows.

Suppose we have a system that supplies 50 kVA at 7.2 kV. The current must be

$$I = \frac{kVA}{kV} = \frac{50\,kVA}{7.2\,kV} = 6.94\,A$$

and the system impedance must be

$$Z = \frac{V}{I} = \frac{7.2\,kV}{6.94\,A} = 1.04\,k\Omega$$

We can now define the circuit quantities as our base units so that they are 100%.

100% voltage = 7.2 kV

100% current = 6.94 A

100% impedance = 1.04 kΩ

100% volt amperes = 50 kVA

but

100% kVA = 100% kV × 100% I ≠ 100% kVA

so a percentage system will not work. However, if we define 100% as one per unit (1 pu) in the following manner

1 pu *VA* = 50 kVA

1 pu *V* = 7.2 kV

1 pu *I* = 6.94 A

1 pu *Z* = 1.04 k Ω

then

1 pu kVA = 1 pu kV × 1 pu I

since

50 kVA = 7.2 kVA × 6.94 A

and the problems associated with using percentages are solved.

If one parameter is varied (as often occurs) the change its variance causes in other circuit parameters can be calculated in per unit proportions. If the voltage in

the previous paragraph changes to 10 kV the system current does change but the system capacity does not. The new per unit voltage is

$$V\,\text{pu} = \frac{\text{new voltage}}{\text{base voltage}} = \frac{10\,\text{kV}}{7.2\,\text{kV}} = 1.389\,\text{pu V}$$

The new current is

$$I = \frac{\text{base kVA}}{\text{new kV}} = \frac{50\,\text{kVA}}{10\,\text{kV}} = 5\,\text{A}$$

and the new impedance is

$$Z = \frac{E}{I} = \frac{10\,\text{kV}}{5\,\text{A}} = 2\text{k}\Omega$$

In per unit values these are

$$I\,\text{pu} = \frac{1\,\text{pu kVA}}{1.389\,\text{pu V}} = 0.7199\,\text{pu A}$$

which in actual amperes is

$$I = (\text{base amperes}) \times (\text{pu amperes}) = (6.94\,\text{A}) \times (0.7199\,\text{pu A}) = 5\,\text{A}$$

and

$$Z\,\text{pu} = \frac{\text{new } Z}{\text{base } Z} = \frac{2\,\text{k}\,\Omega}{1.04\,\text{k}\Omega} = 1.923\,\text{pu}\,\Omega$$

Please note that the 100% values are called the base. The two parameters of a system that are usually known are its capacity in kVA and its voltage so these are usually designated as base values and all other parameters are calculated from these two values. Thus

$$\text{base } V = \text{base } I \times \text{base } Z \tag{2.9}$$

$$\text{base } VA = \text{base} V \times \text{base } I \tag{2.10}$$

The base impedance is defined by the equation

$$\text{base } Z = \frac{\text{base } V}{\text{base } I} \tag{2.11a}$$

However, by multiplying Z by V/V we get

$$Z = \frac{V}{I} = \frac{V \times V}{VA} = \frac{V^2}{VA} \tag{2.11b}$$

Most of the time it is more convenient to express the base quantities in kV and kVA or MVA. Since

$$kV = \frac{IZ}{1000}$$

$$Z = \frac{1000 \times kV}{I}$$

Equation 2.11b can be expressed as

$$\text{base } Z = \frac{(\text{base kV})^2 \times 1000}{\text{base kVA}} \tag{2.11c}$$

and since

$$kVA = \frac{MVA}{1000}$$

$$\text{base } Z = \frac{(\text{base kV})^2}{\text{base MVA}} \tag{2.11d}$$

The base impedance must be calculated with the overall base volt amperes and the base voltage of the portion of the circuit in which the impedance of interest is located when the circuit contains transformers and has more than one voltage. It is important to note that the actual impedance of the circuit is set by the electrical properties of the components. The base impedance is not the actual impedance, but the actual system impedances can be expressed as per unit proportions of the base impedance more easily for problem solution. Upon problem solution the per unit quantities are converted back to actual values with the appropriate equation. The conversion equations are

$$Z_{ohms} = Z_{pu}\ Z_{base} \tag{2.12}$$

$$I_{amps} = I_{pu}\ I_{base} \tag{2.13}$$

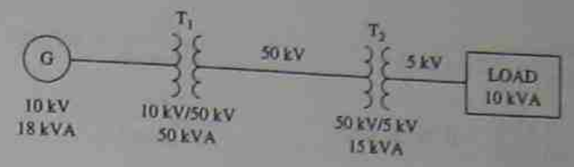
$$V_{kV} = V_{pu}\ V_{base} \tag{2.14}$$

$$VA_{volt\ amperes} = VA_{pu}\ VA_{base} \tag{2.15}$$

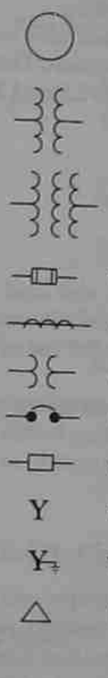
The advantages of the per unit system will become apparent after a few examples.

Example 2.3:

Refer to Figure 2.18a for the one-line diagram for this problem. We will do the problem single-phase for this example. Figure 2.18b has many of the common one-line diagram symbols. Note that the generator can provide 18 kVA at 10 kV, the load is 10 kVA at 5 kV, transformer 1 (T1) has a capacity of 50 kVA and rated voltages of 10kV/50kV (primary/secondary), and transformer 2 (T2) has a capacity of 15 kVA at 50kV/5kv. We can use any two electrical quantities of this system as the base values. Usually the largest kVA rating and the voltage is chosen as the base (though not always).



a



ROTATING MACHINE

TWO WINDING POWER TRANSFORMER

THREE WINDING POWER TRANSFORMER

FUSE

CURRENT TRANSFORMER

POTENTIAL TRANSFORMER

AIR CIRCUIT BREAKER

OIL CIRCUIT BREAKER

Y THREE-PHASE WYE, NEUTRAL UNGROUNDED

$Y_{\frac{1}{2}}$ THREE-PHASE WYE, GROUNDED NEUTRAL

△ THREE-PHASE DELTA

b

FIGURE 2.18 One-line diagram (a) For per unit discussion (b) common one-line symbols

Solution:

We will choose the 50 kVA rating of T1 as our base and the highest voltage as our base values.

50 kVA = 1 pu kVA

The remainder of the rated VA capacities are

$$T2 = \frac{15\ \text{kVA}}{50\ \text{kVA}} = 0.3\ \text{pu kVA}$$

$$\text{Load} = \frac{10\text{ kVA}}{50\text{ kVA}} = 0.2\text{ pu kVA}$$

$$\text{Generator} = \frac{18\text{ kVA}}{50\text{ kVA}} = 0.36\text{ pu kVA}$$

Now we must choose the base voltage. The generator voltage or the higher voltage is often the most convenient, so we will choose 50 kV as our base voltage. The transmission line voltage is 50 kV, 1 pu. The other voltages are multiplied by the transformer turns ratio for use in calculations.

To calculate other pu quantities on the generator and load side we must use the change of base proceedures discussed in the next section. The rest of the base parameters must now be calculated from equations 2.9 and 2.10.

$$I_{base} = \frac{50\text{ kVA}}{50\text{ kV}} = 1\text{ A} = 1\text{ pu A}$$

$$Z_{base} = \frac{50\text{ kV}}{1\text{ A}} = 50\text{ k}\Omega = 1\text{ pu Z}$$

Remember that the generator impedance, line impedance, and load impedance are expressed in terms of the per unit impedance for calculations. Later in this chapter there are example problems to demonstrate the use of the per unit system.

You may wish to note this page for future reference because the per unit equations are summarized here.

2.4.2 Per unit equation summary

$$\text{base } I = \frac{\text{base kVA}}{\text{base kV}} \qquad \text{(from Eq. 2.10)}$$

$$\text{base Z} = \frac{\text{base } V}{\text{base } I} \qquad (2.11a)$$

$$\text{base Z} = \frac{\text{base } V^2}{\text{base VA}} \qquad (2.11b)$$

$$= \frac{(\text{base kV})^2 \times 1000}{\text{base kVA}} \qquad (2.11c)$$

$$= \frac{(\text{base KV})^2}{\text{base MVA}} \qquad (2.11d)$$

$$\text{pu VA} = \frac{\text{VA}}{\text{base VA}} \qquad (2.16)$$

$$= \frac{\text{kVA}}{\text{base kVA}}$$

$$\text{pu } V = \frac{V}{\text{base } V} \qquad (2.17)$$

$$\text{pu } I = \frac{I}{\text{base } I} \qquad (2.18)$$

$$\text{pu Z} = \frac{\text{base } V}{\text{base } I} \qquad \text{(from Eq. 2.11)}$$

$$= \frac{\text{Z}}{\text{base Z}} \qquad (2.19)$$

$$= \frac{\text{Z} \times (\text{base VA})}{(\text{base } V)^2} \qquad (2.20a)$$

$$= \frac{\text{Z} \times (\text{base kVA})}{(\text{base kV})^2 \times 1000} \qquad (2.20b)$$

For the final solution
actual value = (pu value) × (base value)
as shown in Equations 2.12 through 2.15.

2.4.3 Change of base

The impedance of transformers, generators, and motors are often given in per unit or percent (pu = % ÷ 100) where the base used is the machine nominal voltage and volt-amperes. The machine base is seldom the base of the system under analysis so a convenient method of changing the base of pu impedance is needed. Consider a system in which base 2 is to be used for analysis, but base 1 is the base of a machine's pu impedance. The actual machine impedance is the same in both system bases, so

$$\text{Z} = \text{pu Z}_1 \frac{V_{B1}^{\ 2}}{\text{VA}_{B1}}$$

and

$$\text{Z} = \text{pu Z}_2 \frac{V_{B2}^{\ 2}}{\text{VA}_{B2}}$$

Since Z is the same in both systems

$$\text{pu } Z_1 \frac{V_{B1}^2}{VA_{B1}} = \text{pu } Z_2 \frac{V_{B2}^2}{VA_{B2}}$$

Solving for pu Z_1 results in

$$Z_{1pu} = Z_{2pu} \frac{V_{B2}^2}{V_{B1}^2} \frac{VA_{B1}}{VA_{B2}} \tag{2.21}$$

or in terms of old base and new base

$$\text{new base } Z_{pu} = \text{old base } Z_{pu} \frac{(\text{Old base } V)^2 \text{ (new base VA)}}{(\text{new base } V)^2 \text{ (old base VA)}}$$

2.2.4 Per unit with balanced three-phase systems

There are two methods of handling per unit calculations for balanced three-phase systems. The first is to use the three-phase line to line voltages and volt-amperes and to calculate the line current in the usual manner from $VA = \sqrt{3}\, I_L\, V_{LL}$, where subscript LL is line to line. The pu voltage is the same whether line to line or phase to neutral values of voltage are used since $V_{LL} = \sqrt{3}\, V_{LN}$, where subscript LN is line to neutral, as long as consistent values are used in the ratio. The same is true of pu VA since three-phase VA = 3 × single-phase VA. Calculated correctly the base impedance will be the same. The appropriate equations are

$$\text{base } I = \frac{\text{base three-phase kVA}}{\sqrt{3}\ \text{base kV}_{LL}} \tag{2.22}$$

$$= \frac{\text{base phase kVA}}{\text{base kV}_{LN}}$$

$$\text{base } Z = \frac{(\text{base kV}_{LL}/\sqrt{3})^2 \times 1000}{\text{base three-phase kVA}/3} \tag{2.23}$$

$$= \frac{(\text{base kV}_{LL})^2 \times 1000}{\text{base three-phase kVA}} \tag{2.24}$$

$$= \frac{(\text{base kV}_{LL})^2}{\text{three-phase base MVA}} \tag{2.25}$$

Notice that except for the subscripts these equations (2.23 through 2.25) are the same as equations 2.11 c and d. Actual impedances are given as per phase values. Additionally delta- and wye-connected impedances are not the same. If one has the pu impedance of the load this is not a problem, but if one must calculate the pu impedance of a load from its actual impedance it is easier to calculate with phase to neutral values.

The second method is to convert all circuit parameters to phase to neutral values and convert back to line to line values at the end of the problem. This method

presents fewer opportunities for confusion for beginning pu calculations, and is the method used in this chapter except for a few example steps.

Delta-connected loads must be converted to their wye equivalent impedance to obtain their pu impedance. This is simple for balanced three-phase loads. Recall from wye-delta conversion, with ABC = wye values and XYZ = delta values

$$Z_A = \frac{Z_Y Z_Z}{Z_X + Z_Y + Z_Z}$$

In a balanced system $Z_X = Z_Y = Z_Z = Z_D$, where D is for delta

$$Z_A = \frac{Z_D^2}{3\, Z_D}$$

$$= \frac{\text{delta phase } Z}{3}$$

and in similar fashion

$$Z_X = \frac{Z_A Z_B + Z_B Z_C + Z_C Z_A}{Z_A}$$

since $Z_A = Z_B = Z_C = Z_{WYE}$

$$Z_D = \frac{3 Z_{WYE}^2}{Z_{WYE}}$$

$$= 3 \times (\text{wye impedance})$$

The following example may help.

Example 2.4:

Let the circuit components of Figure 2.18 assume the following values with all values given in three-phase kVA and line to line voltage.

G—23kV at 300 kVA

T1—23kV/69kV at 350 kVA

Line—69 kV at 450 kVA capacity, Z = 10 + j150 ohms

T2—69kV/7.2kV at 120 kVA

Load—75 hp at 7.2 kV full load (assume PF = 1)

calculate the pu values of all voltages, kVAs, and impedances given using phase to neutral values.

Solution:

The base kVA for our single-phase equivalent one-line drawing is one third of the three-phase kVA

$$\text{base kVA} = \frac{450\ \text{kVA}}{3}$$

$$= 150\ \text{kVA} = 1\ \text{pu}$$

and

$$\text{base kV} = \frac{69\ \text{kV}}{\sqrt{3}}$$

$$= 39.84\ \text{kV} = 1\ \text{pu}$$

so

$$\text{base } I = \frac{\text{base kVA}}{\text{base kV}}$$

$$= \frac{150\ \text{kVA}}{39.84\ \text{kV}}$$

$$= 3.76\ \text{A} = 1\ \text{pu}$$

and the base impedance in the line section is

$$\text{base Z} = \frac{(\text{base kV})^2 \times 1000}{\text{base kVA}}$$

$$= \frac{(39.84\ \text{kV})^2 \times 1000}{150\ \text{kVA}}$$

$$= 10.58\ \text{k}\Omega = 1\ \text{pu}$$

resulting in a pu impedance of

$$\text{pu Z} = \frac{10 + \text{j}150\ \Omega}{10.58\ \text{k}\Omega}$$

$$= 0.000945 + \text{j}0.0142\ \text{pu}\ \Omega$$

The interested student will want to calculate the preceding values using line to line voltages and three-phase kVA.

The line, T1 secondary, and T2 primary voltages are all 1.0 pu because they are at the base voltage. The generator and T1 primary voltage pu voltages are the same and are

$$\text{pu } V_G = \frac{V_G}{\text{base } V}$$

$$= \frac{23\ \text{kV}/\sqrt{3}}{39.84\ \text{kV}}$$

$$= 0.331\ \text{pu V}$$

and the load is

$$\text{pu } V_L = \frac{7.2\ \text{kV}/\sqrt{3}}{39.84\ \text{kV}}$$

$$= 0.104\ \text{pu V}$$

The per unit kVA values are

$$\text{Gen. pu kVA} = \frac{\text{Gen. kVA}}{\text{base kVA}}$$

$$= \frac{100\ \text{kVA}}{150\ \text{kVA}}$$

$$= 0.667\ \text{pu kVA}$$

In similar fashion

$$\text{T1 pu kVA} = \frac{116.67\ \text{kVA}}{150\ \text{kVA}}$$

$$= 0.778\ \text{pu kVA}$$

$$\text{T2 pu kVA} = \frac{40\ \text{kVA}}{150\ \text{kVA}}$$

$$= 0.267\ \text{pu kVA}$$

$$\text{Load pu kVA} = \frac{25\ \text{hp} \times (746\ \text{W/hp})}{150\ \text{kVA}}$$

$$= 0.124\ \text{pu kVA}$$

Note: Motor power factor (one in this problem) must be taken into account in the load pu kVA calculation.

Notice also that to calculate the load pu impedance we must use the over all base kVA and the base voltage of the section of the circuit in which the load is located, in our example the secondary circuit of T2. The impedance of the load, the effective full load impedance of the motor, must be calculated from the nominal machine voltage and kVA.

$$I_L = \frac{\text{three-phase load kVA}}{\sqrt{3} \times \text{load } V_{LL}}$$

$$= \frac{75\ \text{hp}\ (746\ \text{W/hp})}{\sqrt{3}\ 7.2\ \text{kV}}$$

$$= 4.48\ \text{A}$$

$$Z_L = \frac{V_L}{I_L}$$

$$= 927\ \Omega$$

$$\text{base } Z = \frac{\left(\frac{7.2\text{ kV}}{\sqrt{3}}\right)^2 \times 1000}{150\text{ kVA}}$$

$$= 115\ \Omega$$

$$\text{load pu } Z = \frac{927\ \Omega}{345\ \Omega}$$

$$= 8.06 \text{ pu ohms}$$

The delta load impedance is 3x927 = 2.78 k Ω.

2.5 GENERATORS, TRANSFORMERS, AND PER UNIT

This section discusses the calculation of generator and transformer pu impedances by way of two examples.

Example 2.5:

Referring to the simplified generator equivalent circuit of Figure 2.19 calculate the per unit impedance of the generator.

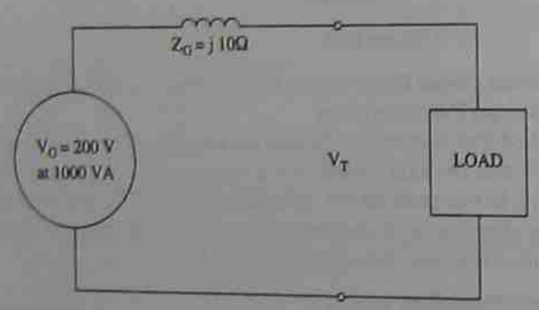


FIGURE 2.19 Generator equivalent circuit for Example 2.5

Solution:

We know the impedance of the generator so we must find the base impedance of the generator. The generator is rated at 200 V at 1000 VA. These values are our base values for calculating the base impedance.

$$\text{base } I = \text{full load } I = \frac{VA}{V}$$

$$= \frac{1000\text{ VA}}{200\text{ V}}$$

$$= 5\text{ A}$$

$$\text{base } Z = \frac{\text{base V}}{\text{base I}}$$

$$= \frac{200\text{ V}}{5\text{ A}}$$

$$= 40\ \Omega$$

and

$$\text{pu } Z = \frac{Z}{\text{base } Z}$$

$$\text{pu } Z = \frac{j10\ \Omega}{40\ \Omega}$$

$$= j0.25 \text{ pu}$$

Notice that 25% of the rated voltage will cause the rated current to flow into a short circuit connected to the generator output. Thus we can find the generator pu impedance by connecting an ammeter across the output terminals and adjusting the voltage until rated current flows. The voltage at the generator terminals with the short circuit removed divided by the rated voltage is the pu generator impedance. Note that

$$5\text{ A} \times j10 = 50\text{ V}$$

$$\frac{50\text{ V}}{200\text{ V}} = 0.25$$

Example 2.6:

Calculate PRI pu $Z = \frac{4}{20} = 2$ pu of the simplified transformer equivalent circuit shown in Figure 2.20a and b with the primary side as a base and then with the secondary side as a base.

Solution:

Using equation 2.13b we find the base impedance is

$$\text{Pri. base } Z = \frac{(\text{base } V)^2}{\text{base VA}}$$

$$= \frac{(200\text{ V})^2}{2000\text{ VA}}$$

$$= 20\ \Omega$$

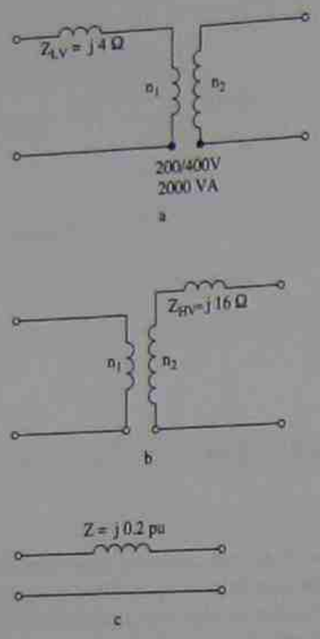


FIGURE 2.20 Simplified transformer equivalent circuit for Example 2.6 (a) Primary reference (b) secondary reference and (c) per unit equivalent circuit for impedance diagram

The base impedance on the secondary side of the transformer is

$$\text{sec. base } Z = \frac{400\ \text{V}^2}{2000\ \text{VA}}$$

$$= 80\ \Omega$$

$$\text{sec. pu } Z = \frac{16\ \Omega}{80\ \Omega}$$

$$= 0.2 \text{ pu ohms}$$

Notice that the pu impedance of the transformer is the same on both the primary and secondary side. This fact is one of the major advantages of the pu system. Properly calculated pu impedances are independent of voltage transformation so the transformer impedance can be represented in a drawing of pu impedances as a simple impedance as shown in Figure 2.20c. It is important to remember that the voltage on the primary side of the transformer must be used to calculate the primary side base impedance, and the secondary voltage must be used to calculate the secondary base impedance.

2.6 IMPEDANCE AND REACTANCE DIAGRAMS

A large system drawn with all of the three-phase and the neutral conductors shown would be very difficult to follow. The reader of the diagram would lose sight of the overall system in the detail. The one-line diagram allows one to grasp the overall system without excessive detail. The one-line drawing of Figure 2.21a is used to supply a lot of information about the system in as concise a form as possible. Recall that several common one-line diagram symbols are shown in Figure 2.18b. The one-line diagram is not useful in the calculation of system parameters under load. Because pu impedances are independent of voltage transformation the one-line circuit of Figure 2.21a can be drawn as a pu equivalent circuit, called an *impedance diagram*, as shown in Figure 2.21b. The impedance diagram is useful for such calculations. All of the circuit parameters are given in pu values. The standard network solution methods are easily applied to the impedance diagram since voltage level changes are taken care of by correctly calculating the pu quantities.

The resistance of a generator, transformer, or line is usually approximately 0.1 times the reactance, consequently the resistance can often be ignored in fault calculations for power system protection. The omission of the resistance from the impedance diagram results in the *reactance diagram* of Figure 2.21c. A computer of sufficient speed and calculating power makes such a simplification unnecessary for calculating system quantities.

2.7 PER UNIT EXAMPLES

Example 2.7:

Draw an impedance diagram of the one-line drawing of Figure 2.22a and show all of the impedances in per unit.

Solution:

First select the base VA for the entire system. We will choose the highest VA rating in the system, T1. A base VA that is not a rating of any machine or line in the system can be chosen as the base. For our problem

$$1 \text{ pu kVA} = 6 \text{ kVA}/3$$

$$= 2 \text{ kVA}$$

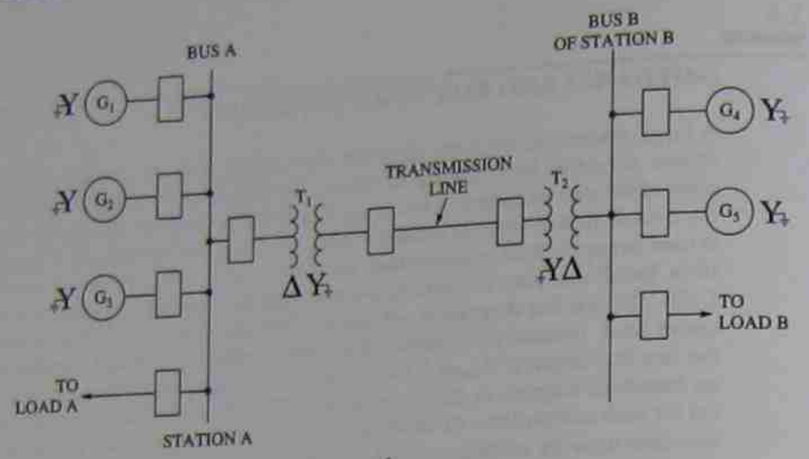


FIGURE 2.21 Reactance diagram development (a) One-line diagram (b) equivalent circuit (impedance diagram) and (c) reactance diagram

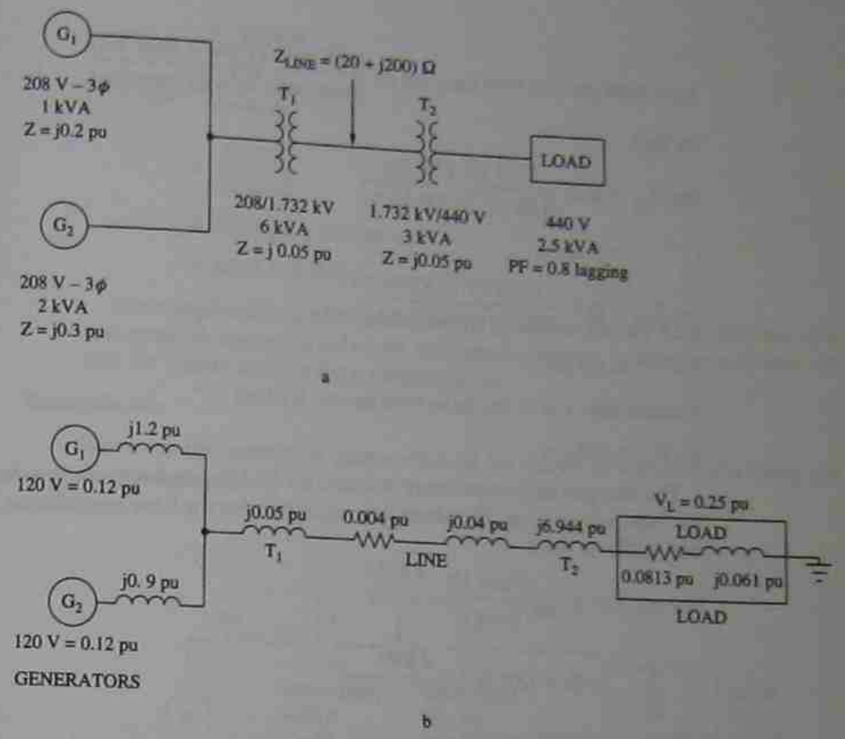


FIGURE 2.22 Example 2.7 system (a) One-line diagram and (b) impedance diagram

Since transformers are present the base voltage of each section of the system, for base impedance calculation, is set by the transformer ratios after the base voltage for the diagram is selected. It is frequently convenient to use the generator voltage as a base and we will do so for this example.

Gen. base $V = 208/\sqrt{3}$

$= 120\text{ V} = 1\text{ pu}$

Line base $V = 1732\text{ V}/\sqrt{3}$

$= 1\text{ kV}$

Load base $V = 440\text{ V}/\sqrt{3}$

$= 254\text{ V}$

Equation 2.21 will be used to transform the generator impedances to the base kVA. Recall

$$\text{new base pu } Z = (\text{old base pu } Z)\,\frac{(\text{old base } V)^2\,(\text{new base VA})}{(\text{new base } V)^2\,(\text{old base VA})}$$

so that

$$\text{pu } Z_{G1} = j0.2\,\frac{(120\ V)^2\,(2\ \text{kVA})}{(120\ V)^2\,(0.333\ \text{kVA})}$$

$$= j1.2\ \text{pu}$$

$$\text{pu } Z_{G2} = j0.3\,\frac{(120\ V)^2\,(2\ \text{kVA})}{(120\ V)^2\,(0.667\ \text{kVA})}$$

$$= 0.9\ \text{pu}$$

Transformer 1 is at the base voltage and kVA so

$$\text{pu } Z_{T1} = j0.5\ \text{pu}$$

The line per unit impedance is found by dividing the actual impedance by the base impedance. The short form equation for the base impedance, Equation 2.22b, is used.

$$\text{line pu } Z = Z_{LINE}\,\frac{\text{base } VA}{\text{base } V^2}$$

$$= (2 + j20)\ \Omega\,\frac{2\ \text{kVA}}{1\ \text{kV}^2 \times 1000}$$

$$= 0.004 + j0.04\ \text{pu}$$

Transformer 2 per unit impedance must be found with the base transformation equation.

$$\text{pu } Z_{T2} = j0.05\ \Omega\,\frac{(1\ \text{kV})^2\,(2\ \text{kVA})}{(0.12\ \text{kV})^2\,(1\ \text{kVA})}$$

$$= 6.994\ \text{pu}$$

The wye equivalent load impedance is

$$Z_{LOAD} = \frac{\left(\frac{2.5\ \text{kVA}}{3}\right)}{440/\sqrt{3}}$$

$$= 3.28\ \Omega$$

The base impedance at the load is

$$\text{base load } Z = \frac{\text{base } V_P^2}{\text{base VA}}$$

$$= \frac{254\ V^2}{2000\ \text{VA}}$$

$$= 32.26\ \Omega$$

$$\text{pu } Z_{LOAD} = \frac{Z}{\text{base } Z}$$

$$= \frac{3.28\ \Omega}{32.26\ \Omega}$$

$$= 0.102\ \text{pu} \angle \arccos 0.8$$

$$= .0813 + j0.061\ \text{pu}$$

The completed impedance diagram is shown in Figure 2.22b. We can now use network theory to solve for the circuit currents. A simpler example circuit for which to solve for current follows.

Example 2.8:

Solve for the current in each section of the circuit in Figure 2.23a using per unit values.

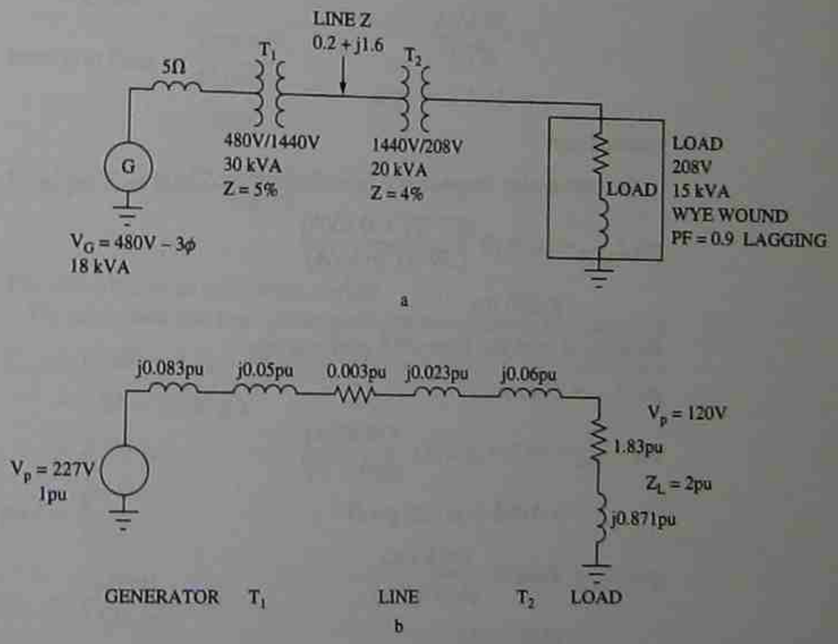


FIGURE 2.23 One-line diagram for Example 2.8 (a) Circuit and (b) impedance diagram

Solution:

The first task is to select the base kVA and voltage. The phase to neutral generator voltage is convenient for the base voltage, and the highest kVA is convenient for the base kVA.

$$\text{base voltage} = 480\ \text{V}/\sqrt{3}$$
$$= 277\ \text{V} = 1\ \text{pu}$$

$$\text{line base voltage} = 1440\ \text{V}/\sqrt{3}$$
$$= 831.4\ \text{V}$$

$$\text{load base voltage} = 208\ \text{V}/\sqrt{3}$$
$$= 120\ \text{V}$$

$$\text{base current} = \frac{\text{base VA}}{\text{base V}}$$
$$= \frac{10\ \text{kVA}}{277\ \text{V}}$$
$$= 36.1\ \text{A} = \text{pu}$$

Impedances

The generator impedance from Equation 2.21 is

$$\text{pu } Z_{GEN} = \text{j}0.05\ \Omega\ \frac{(277\ \text{V})^2\,(10\ \text{kVA})}{(277\ \text{V})^2\,(6\ \text{kVA})}$$
$$= \text{j}0.083\ \text{pu}$$

Because it is at the base kVA and voltage

$$\text{pu } Z_{T1} = \text{j}0.05\ \text{pu}$$

$$\text{pu } Z_{LINE} = (0.2 + \text{j}1.6)\ \Omega\ \frac{(10\ \text{kVA})}{(831.4\ \text{V})^2}$$
$$= 0.003 + \text{j}0.023\ \text{pu}\ \Omega$$

$$\text{pu } Z_{T2} = \text{j}0.04\ \Omega\ \frac{(10\ \text{kVA})}{(6.67\ \text{kVA})}$$
$$= \text{j}0.06\ \text{pu}\ \Omega$$

Now the load

$$Z_{LOAD} = \frac{(120\ \text{V})^2}{5000\ \text{VA}}$$

$$= 2.88\ \Omega\ \angle \arccos 0.9$$

$$\text{base } Z_{LOAD} = \frac{(120\ \text{V})^2}{10{,}000\ \text{VA}}$$
$$= 1.44$$

$$\text{pu } Z_{LOAD} = \frac{2.88}{1.44}$$
$$= 2.0\ \text{pu}\ \angle \arccos 0.9$$
$$= 1.83 + \text{j}0.871\ \text{pu}$$

The completed impedance diagram is shown in Figure 2.23b.

At this point it is instructive to calculate the pu load impedance after it has been referred to the generator circuit through the turns ratios of the transformers (Z_{RG}).

$$Z_{RG} = 2.88\,\frac{(831.4\ \text{V})^2\,(277\ \text{V})^2}{(120\ \text{V})^2\,(831.4\ \text{V})^2}$$
$$= 15.346$$

$$\text{base } Z \text{ at Gen.} = \frac{(277\ \text{V})^2}{10{,}000\ \text{V}}$$
$$= 7.6729$$

$$\text{Load pu } Z \text{ at Gen} = \frac{15.346}{7.6729}$$
$$= 2.0\ \text{pu}$$

The same value as calculated earlier.

We now need the total pu impedance to calculate the currents.

$$Z_{total} = (0.003 + 1.8) + \text{j}(0.083 + 0.05 + 0.023 + 0.06 + 0.871)\ \text{pu}$$
$$= 1.83 + \text{j}1.087\ \text{pu}$$
$$= 2.131\ \text{pu}$$

$$\text{pu } I = \frac{\text{pu } V}{\text{pu } Z}$$
$$= \frac{1.0\ \text{pu}}{2.131\ \text{pu}}$$
$$= 0.469\ \text{pu}$$

$$I = I_{pu} \times I_{base}$$
$$I_{GEN} = (0.469)\ (36.1\ \text{A})$$

$$= 16.9\text{A}$$

$$I_{LINE} = (0.469)\frac{10\text{ kVA}}{831.4\text{ V}}$$

$$= 5.647\text{ A}$$

$$I_{LOAD} = (0.4685)\frac{10\text{ kVA}}{120\text{ V}}$$

$$= 39.1\text{ A}$$

The currents are line currents.

Again the major advantage of the per unit system is the ease with which it can be used to solve problems such as these examples because the transformer pu impedance is the same on either side of the transformer. The pu system is used throughout this book.

2.8 SUMMARY

Loads, lines, and generators have impedance, and all contribute to the relative phase of the current and voltage in the system. The reference for power factor, the ratio of real to apparent power, is the load for the system or system segment. The power consumed is dissipated as work by electrical machines or heat lost in resistance. The inductive reactance is higher in the center of a conductor because the magnetic flux density is higher. For this reason alternating current is forced toward the outer portion or skin of a conductor. The effective decrease in conductor area causes the ac resistance of a conductor to be higher than the dc resistance. This phenomena is called the *skin effect*.

The selection of three-phase ac for electrical power distribution and transmission resulted because three-phase ac with 120° phase separation results in power that is constant over time. DC and six-phase electrical power is constant over time too, and both are also use for electrical power transmission. Three-phase electrical equipment can be connected in either delta or wye configurations. The line and phase voltage and current relationships of delta and wye connections are discussed in Section 2.3.3.

To ease the calculation of three-phase quantities in balanced three-phase systems, in which each phase has the same load, the per unit (pu) method of representing system quantities was devised. In the pu method one phase of the system is represented with the impedances, voltages, currents, power, VA, and VAR levels represented as a fraction of the system base. The base quantities are normally chosen to be the most significant voltage level and the VA capability of that section of the system, perhaps the generating voltage and capacity. Once the base quantities are chosen all other base quantities, such as current, are referenced to them. The

system quantities represented as pu quantities are the ratio of that quantity to the base quantity, such as current to base current. By representing each segment of the system in the base of the most significant segment complex calculation, while still complex, are far simpler than they would otherwise be. The mechanics of pu calculations are shown in Section 2.4.

2.9 QUESTIONS

1. Calculate the number of turns a generator must have to provide an rms voltage of 23 kV at a flux of 420 Mlines per pole.
2. The conductivity of copper is 5.8×10^7 Siemens/meter and the relative permeability is one. Calculate the skin depth at 400 Hz, 100 MHz, and 12 GHz.
3. Repeat problem 2 for aluminum, the conductivity of which is 3.53×10^7 S/m and $u_r = 1$.
4. If the generator of Figure 2.2 provides a full load output voltage of 16 kV at 500 kVA calculate the terminal voltage with the load removed. The generator impedance is j6 Ω.
5. Calculate the current of the circuit of Figure 2.3 at 60 Hz if $E_G = 480$ V at 60 Hz, $R = 10\ \Omega$, $L = 0.1$ H, and $C = 100\ \mu$F.
6. The load of Figure 2.5 has $R = 10\ \Omega$, $L = 0.1$ H, and $C = 100\ \mu$F. Calculate Z at 60 Hz.
7. The components of Figure 2.6a and b are $L = 0.2$ H, $C = 120\ \mu$F, and $R = 20\ \Omega$. If the voltage for both circuits is 110 V at 60 Hz calculate the total current for each circuit.
8. The load of Figure 2.7 is rated at 500 kVA with a power factor of 0.8. Calculate the load P and Q.
9. Draw the phasor representation of the voltage and current of a circuit with an rms voltage of 120 V and an rms current of 12 A and a power factor of 0.7.
10. A three-phase circuit has a 60 Hz voltage of 208 V line to line and a wye connected load of 28 Ω ∠60° per phase. If the phase rotation is ABC and phase A is at zero degrees, calculate the line current and draw the phasor diagram.
11. Repeat problem 11 for a delta-connected load of 20 Ω ∠40°.
12. The generator of Figure 2.19 has $V_G = 440$ V and $Z_G = j12\ \Omega$. Calculate the per unit impedance.
13. The single-phase transformer of Figure 2.20b has a rating of 500 kVA, voltages of 34.5kV/480V, and a high side impedance of j100 Ω. Calculate the high and low side per unit impedance.
14. A 400 V, 5 kVA load has a per unit impedance of 0.2 with its own rating as base. It is to be placed in a system with a base of 10 kVA and 800 V. Calculate the load per unit impedance in the new system.
15. The circuit components of Figure 2.18a have the following specifications: Generator—23 kV at 600 kVA

T1—23kV/138kV at 1 MVA
Line—$Z = (100 + j1500)\ \Omega$
T2—138kV/12.47kV at 300 kVA
Load—200 kVA
Calculate the per unit values of the voltages, kVAs, and line impedance using 1 MVA and 138 kV as base.

16. Repeat problem 15 with 23 kV and 600 kVA as base values.
17. The components in the one-line drawing of Figure 2.23a have the following single-phase ratings:
Generator—12.47 kV at 90 kVA, Z = 10%
T1—12.47kV/34.5kV at 120 kVA, Z = 4%
Line—$Z = (3 + j40)\ \Omega$
T2—34.5kV/480V at 75 kVA, Z = 3%
Load—60 kVA at 480 V, PF = 0.9
Use the generator kVA and voltage as the system base and calculate the per unit impedances and the current flowing through the load, line, and generator.
18. The components of the one-line drawing of Figure 2.23a have the following three-phase ratings:
Generator—23 kV at 240 kVA, Z = 8%
T1—23kV/138kV at 360 kVA, Z = 5%
Line—$Z = (50 + j600)\ \Omega$
T2—138kV/12.47kV at 180 kVA, Z = 4
Load—150 kVA at 12.47 kV, PF = 0.95
Use the generator voltage as the system base voltage and T1 kVA rating as the system base kVA. Calculate the per unit impedances and the line current flowing in the load, line, and generator.

SECTION II

Electrical Power Distribution

CHAPTER 3

Basic Considerations and Distribution System Layout

3.1 UTILITY LOAD CLASSIFICATIONS

The electrical power distribution system is that portion of the electrical system that connects the individual customer to the source of bulk power, as shown in Figure 1.4.

Loads are the reason for the electrical power system. The types of loads are: resistive, such as lighting and heating; inductive, such as motor loads; and capacitive, such as rectifier bridges with capacitor filters. Most electrical system loads are predominantly inductive. Utility loads are usually classified by the occupancy of the structures that use the power instead of the type of electrical load.

Residential loads are the combined loads of single family dwellings and apartment complexes. Most dwelling units are single-phase although most apartment complexes have three-phase service and the load to each phase is balanced among the apartment units. The types of loads are predominantly lighting, heating

(water, space, and cooking), and motors for appliances such as air conditioners, washing machines, and refrigerators. In numbers, residential loads are the largest group of electric utility customers, comprising up to 85% (about 80% typically), and require the largest investment in distribution equipment.

Commercial loads typically make up about 15% of an electric utility's customers. They consist of office buildings and complexes, schools, shopping malls, and stores. The types of loads are primarily lighting, heating, air conditioning, and office equipment such as computers, copying machines, word processors, and coffee makers.

Industrial loads seldom make up more than about 5% of an electric utility's customers but they may use up to 25 to 30% of the kilowatt hours supplied. The loads consist of the same types of loads as commercial businesses plus large motors, control panels, and production equipment.

3.2 POWER FACTOR CORRECTION

Because most commercial and industrial loads are inductive in nature the kVAs drawn from the utility are larger than the kWs, and the current lags the voltage, as shown in Figure 3.1. Only the component of the current that is in phase with the voltage provides useful work. The out of phase component increases the total current that the utility must supply so a premium may be charged to a customer with a power factor that is below a value fixed by the electric utility (usually 0.7). Utilities actually charge their customers for the kVA hours, not kW hours, that they use, although the latter term is more commonly used. Thus customers have an economic interest in improving the power factor of their facilities. The trend has been to improve power factors to between 0.9 to 0.95 or even better as the cost of electricity has risen in recent years. Figures 3.2, 3.3, and 3.4 show the impedance, current, and power diagrams, respectively, for an inductive and capacitive load. The overall power factor of a customer's internal electrical system is brought closer to one by adding capacitance across the line at various points in the customer's internal electrical distribution system. If the system is compact the capacitance may be near the service. Larger systems may require power factor correction for each major bus. In the event the system was capacitive (a rare occurrence) inductance would be added across the line for power factor correction. Automatic equipment

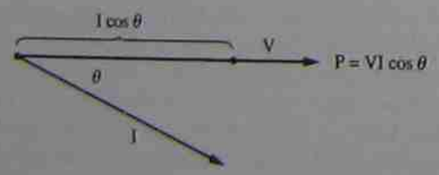
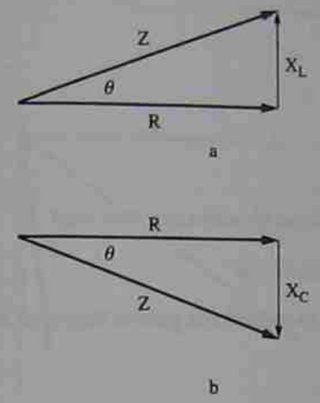


FIGURE 3.1 Power from in phase component of current

is available to sense the power factor of a system and switch more or less capacitance across the line as the load changes in nature. The automatic systems must be chosen with care because many will try to over correct the power factor when a significant part of the load is solid state motor drives, possibly causing the system voltage to rise to excessive levels (we will discuss why later). The next two examples review the calculation of reactance for power factor correction.



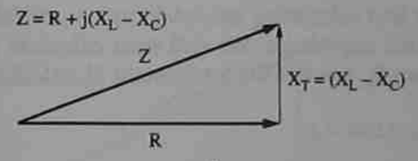


FIGURE 3.2 Impedance diagram (a) Inductive (b) capacitive and (c) general, $Z = R + j(X_L - X_C)$

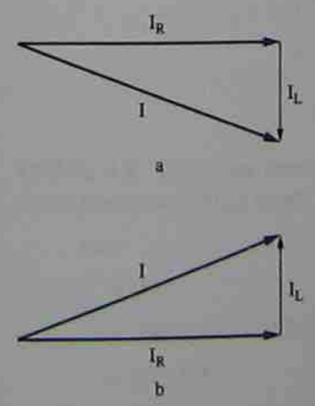


FIGURE 3.3 Current (a) Inductive—lagging and (b) capacitive—leading

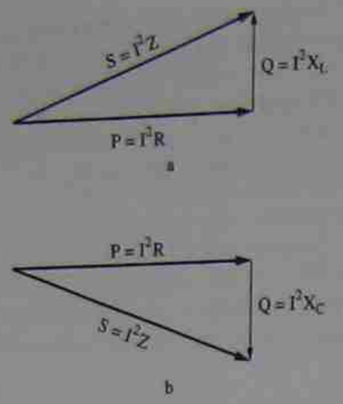


FIGURE 3.4 Power triangle (a) with inductive load and (b) with capacitive load

Example 3.1:

Calculate the value of capacitor needed to correct the power factor of the circuit of Figure 3.5 to unity.

Solution:

We will solve the problem by first calculating the total current, which will have the same angle as the total impedance. We will then calculate S, the power factor, then Q. We will set Q_C equal to the total circuit Q, calculate X_C, and then C.

$$I_1 = \frac{V}{R}$$

$$= \frac{120\ \text{V}}{100\ \Omega}$$

$$= 1.2\ \text{A}$$

$$Z_2 = (10 + j100)\ \Omega$$

$$= 100.5\ \Omega\ \angle 84.29^\circ$$

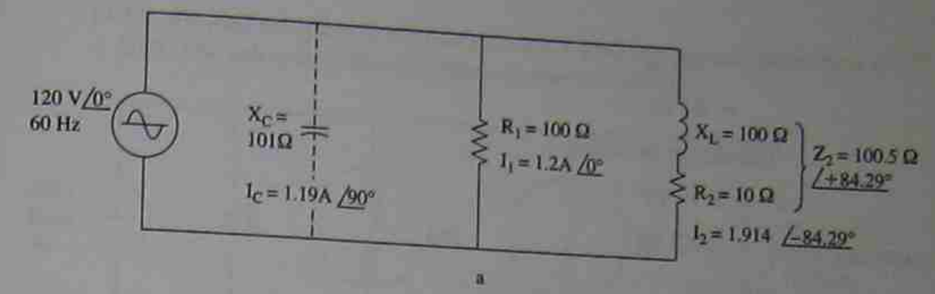
$$I_2 = \frac{120\ \text{V}}{100.5\ \Omega\ \angle 84.29^\circ}$$

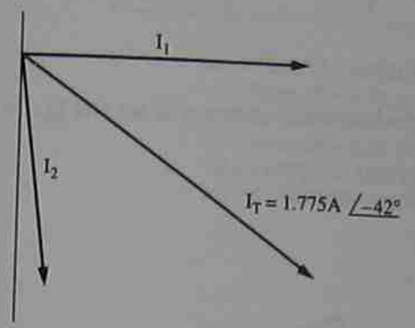
$$= 1.194\ \text{A}\ \angle -84.29^\circ$$

$$I_T = I_1 + I_2$$

$$= 1.2\ \text{A} + 0.118\ \text{A} - j1.18\ \text{A}$$

$$= 1.775\ \text{A}\ \angle -42^\circ$$





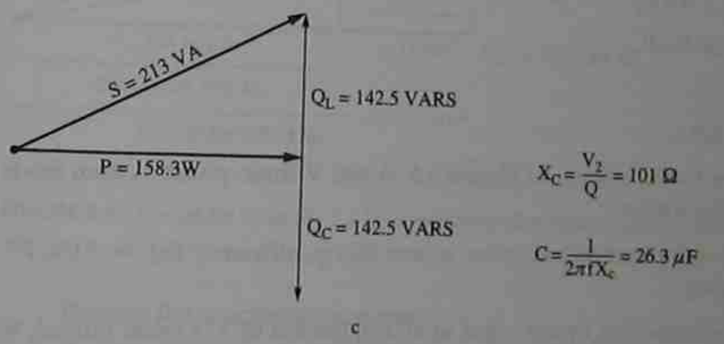


FIGURE 3.5 Circuit for Example 3.1 (a) Circuit diagram (b) phasor diagram before power factor correction and (c) power diagram

now

$$S = VI$$

$$= 120\ \text{V} \times 1.775\ \text{A}$$

$$= 213\ \text{VA}$$

and the power factor (PF) is

$$PF = \cos 42^\circ$$
$$= 0.743$$

The circuit power is

$$P = S \times PF$$
$$= 158.3\ W$$

and Q is

$$Q = S \sin 42^\circ$$
$$= 142.5\ VAR$$

The capacitive Q must cancel the inductive Q so we will set the $Q_C = 142.5$ VAR. Now we calculate X_C from

$$X_C = \frac{V^2}{Q}$$
$$= 101\ \Omega$$

and

$$C = \frac{1}{2\pi f X_C}$$
$$= 26.3\ \mu F$$

Example 3.2:

Refer to the system of Figure 3.6. A 480 V three-phase system feeds the following loads:

M1—fully loaded induction motor, 80 hp, efficiency (η) = 91%, PF = 0.86 lagging.

M2—Induction motor rated at 40 hp, loaded to 3/4 rated output, with η = 89% and PF = 0.83 lagging at actual load.

R—50 kW of lighting and heating load.

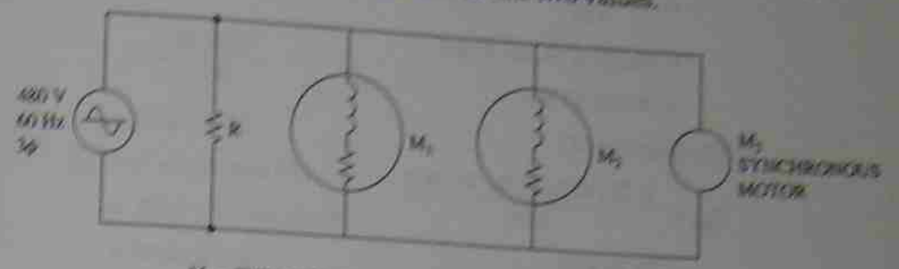
M3—a synchronous motor added to provide power factor correction and drive a 70 hp load. η = 93% at full load.

Calculate the leading kVAR that the synchronous motor must provide to correct the overall power factor to 98% lagging.

Solution:

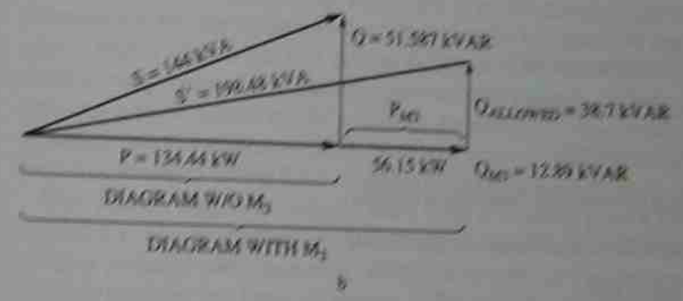
Our solution method will be to calculate first the lagging kVAR of the system without the synchronous motor. We will then calculate the lagging

kVAR allowed with the synchronous motor and the system operating at PF = 0.98. The solution is the difference in the two values.



M_1 = FULLY LOADED INDUCTION MOTOR
80 hp, PF = 0.86, η = 91%
M_2 = INDUCTION MOTOR, 3/4 LOADED
40 hp, PF = 0.83, η = 89%
R = LIGHTING AND HEATING LOADS, 50 kW
M_3 = SYNCHRONOUS MOTOR, η = 93%, LOAD = 70 hp

a



b

FIGURE 3.6 Circuit for Example 3.2 (a) Impedance diagram and (b) power diagram of system

Without the synchronous motor.

$$P_R = 50\ kW$$

$$P_{M1} = \frac{P_{OUT}}{\eta}$$
$$= \frac{80\ hp \times 746\ W/hp}{0.91}$$
$$= 65.582\ kW$$

$$Q_{M1} = S \sin\theta$$
$$= (P/PF)\sin(\arccos PF)$$

$$= \frac{644.582 \text{ kW}}{0.86} \sin(\arccos 0.86)$$

$$= 76.529 \text{ kVA} \sin 30.68°$$

$$= 38.914 \text{ kVAR}$$

Similarly for M2

$$P_{M2} = \frac{0.75 \text{ (40 hp) (746 W/hp)}}{0.89}$$

$$= 25.15 \text{ kW}$$

$$S_{M2} = \frac{P}{PF}$$

$$= \frac{18.86 \text{ kW}}{0.83}$$

$$= 30.3 \text{ kVA}$$

and

$$Q_{M2} = S \sin(\arccos PF)$$

$$= 30.3 \text{ kVA} \sin 33.9°$$

$$= 16.9 \text{ kVAR}$$

The total power and reactive kVA are

$$P_T = 50 \text{ kW} + 65.582 \text{ kW} + 25.15 \text{ kW}$$

$$= 140.5 \text{ kW}$$

$$Q_T = 38.914 \text{ kVAR} + 16.9 \text{ kVAR}$$

$$= 55.8 \text{ kVAR}$$

and if needed

$$S_T = \sqrt{P^2 + Q^2}$$

$$= 151.4 \text{ kVA}$$

With the synchronous motor (primed values)

$$P_{M3} = \frac{70 \text{ hp} \times 746 \text{ hp/W}}{0.93}$$

$$= 56.15 \text{ kW}$$

$$P'_T = 140.5 \text{ kW} + 56.151 \text{ kW}$$

$$= 196.9 \text{ kW}$$

$$S'_T = \frac{P'_T}{PF}$$

$$= \frac{196.9 \text{ kW}}{0.98}$$

$$= 200.9 \text{ kVA}$$

$$Q' = S' \sin(\arccos PF)$$

$$= 200.9 \text{ kVA} \sin 11.48°$$

$$= 39.98 \text{ kVAR}$$

synchronous motor $Q = Q_T - Q'$

$$= 55.80 \text{ kVAR} - 39.98 \text{ kVAR}$$

$$= 15.82 \text{ kVAR}$$

We may not always choose to correct the power factor to one for one of two main reasons. The cost of correcting the power factor to one as opposed to a more modest correction between 0.95 and 0.99 may be much higher, and the return on investment for the optimal correction may be too small to justify. The second reason is that a correction to a power factor of unity under one set of operating conditions may result in a leading power factor under differing load conditions. A leading power factor could result in an excessive line voltage increase in many systems. Such systems would need automated equipment to change the power factor correction as the load changes to operate well at unity power factor.

The reason that line voltage rises with a leading power factor is illustrated in Figure 3.7. The secondary circuit of any transformer contains the transformer secondary leakage reactance and resistance as well as the reactance and resistance of the line feeding the load, as shown in Figure 3.7a. Current drawn from the source causes an in phase voltage drop across the resistances and a voltage drop across the reactances that leads the current 90°, as shown in Figure 3.7b. If the source voltage is held constant, then as the power factor becomes less lagging the voltage drops across the reactance and resistance of the transformer secondary and line will rotate in the direction of the arrows in Figure 3.7b and c. The algebraic sum of the voltages around a closed loop must equal zero so the load voltage will rise, as shown in Figure 3.7d.

3.3 UTILITY FACTOR

Utility factor is a measure of how much of the total capacity of a utility is in use. If all of the power a utility can generate is being used the utility factor is 100%. The requirement for reserve power, and the load diversity (illustrated in Figures 1.2

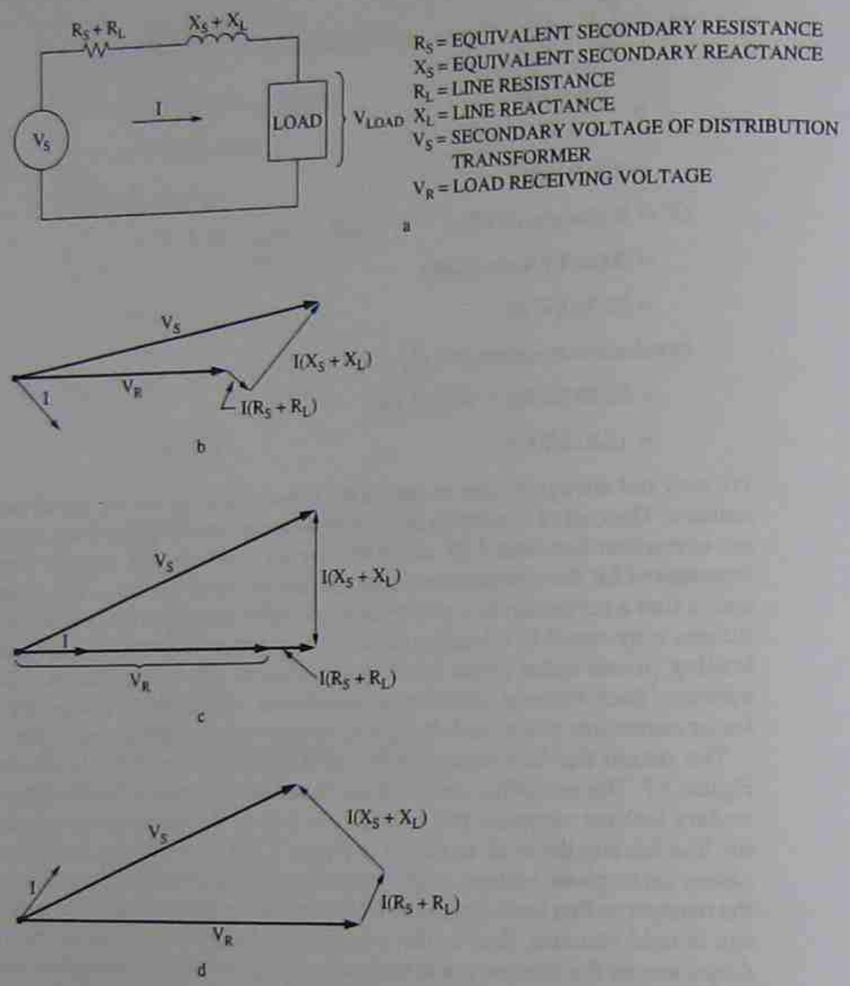


FIGURE 3.7 Voltage rise with PF < 1 and leading (a) Equivalent circuit of source (b) load PF < 1 and lagging (c) load PF = 1 and (d) load PF < 1 and leading

and 3.8) keep the utility factor less than one. Both the desire to provide reliable service and the Federal Energy Regulatory Commission (FERC) requirements dictate that reserve capacity be available in case of failure by some generating equipment.

The reserve requirements are for both spinning reserve and stand-by reserve. Spinning reserve refers to reserve power available from generators that are spinning but are not producing full rated output power. Spinning reserve is available almost immediately. Spinning reserve must be available to meet historically expected immediate load demand changes whether planned or unexpected. The

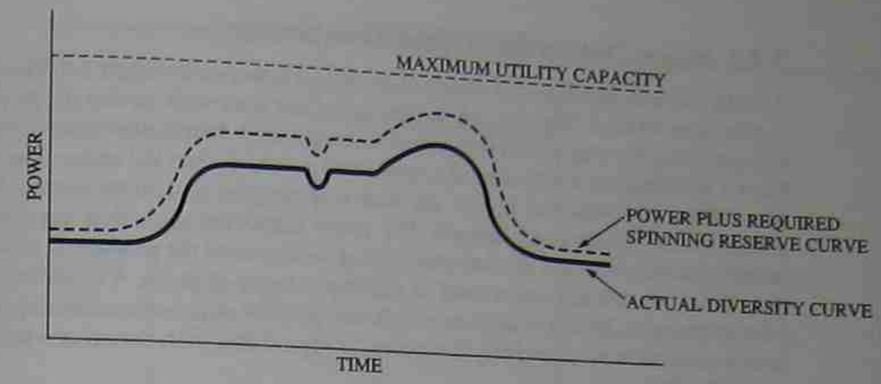


FIGURE 3.8 Diversity diagram

spinning reserve requirement is typically 10% of the anticipated or actual load, whichever is greater, at a given time. The increased use of large natural gas fueled turbines that start rapidly has resulted in the spinning reserve being reduced to 70% in many areas. Records of electricity usage are kept so that the anticipated power requirement for a given time is fairly accurately known. A stand-by reserve equal to the largest single unit in the system is required. The stand-by reserve requirement does not include the spinning reserve. The system is defined for standby reserve as all solidly interconnected utilities so interconnected area utility companies can can share stand-by reserve. The interconnection of electric utility systems provides more reliable service to customers, and saves the duplication of investment on stand-by reserve capability by interconnected utilities.

Service factor refers to the amount of time a load can be fed by the system. A service factor of 100% means the system feeding a particular load (or set of loads) was never out of service. Lightning storms, other weather events, and scheduled maintenance cause some portion of the system to be out of service for some period of time, thus, some portion of the system will experience a service factor of less than 100%.

3.4 DISTRIBUTION SYSTEM LAYOUT

Recall that the transmission line system carries bulk power at high voltages to the general areas of usage. Subtransmission lines carry large amounts of power from the bulk power substations to the immediate area of use at intermediate voltages, typically 138 or 69 kV. The distribution system carries electrical power from the distribution substation to the individual customer at voltages that range between 34.5 kV and about 4.2 kV. The distribution layout refers to the physical arrangement of the distribution lines.

3.4.1 Major Distribution Layout Classifications

A *radial* subtransmission and distribution layout is shown in Figure 3.9. The distribution lines extend from the substation to the last load with service drops to customers along the way. Often the system is shown with distribution lines extending from a distribution substation like spokes on a wheel, thus the name. The major advantages of the radial layout are that it is simpler and more economical to install than other types of layouts. The major disadvantage is that any problem usually leaves a number of customers out of service until the problem is solved. In fact, radial layouts are never used in subtransmission systems. A modified radial subtransmission layout is used in which two parallel radial subtransmission lines have a provision for switching the load to the good line in the event of a failure of one of the lines.

The *loop* arrangement is shown in Figure 3.10. The loop connection is more expensive than the radial because it requires more equipment, but any point on the line has service from two directions. If one is out, the customer can be fed from the other direction. Switches must be placed periodically around the loop so that a malfunctioning section can be repaired without removing much of the line from service. The loop layout is very reliable and expensive.

A *combination* of loop and radial, shown in Figure 3.11, is often used to provide the most reliable service to critical customers, such as business and industrial, by a loop, and reasonably economical service to residential neighborhoods. The radial part of the system is arranged so that only a few residential customers will be out of service at one time for any foreseeable fault condition.

Networks are designed to provide very reliable service to areas with dense loads such as downtown and suburban business districts containing many multi-story buildings. The network consists of underground secondary lines connected (phase A to phase A, B to B, etc.) at corners with transformers feeding the network every one to two blocks. The network equipment is contained in underground vaults with access through man holes in streets and alleys. Figure 3.12a shows a segment, two blocks on a side, of a larger network. Although networks can be very large, *network sections* are seldom larger than four square blocks. The network is fed from two or more feeders and no two adjacent network transformers are fed by the same feeder. The idea is that if one feeder is down the network can be fed by the other feeders. The primary feeders are typically between 12.5 kV and 34.5 kV. The network secondary lines are at 208/120 V wye for older networks, and 480/277 V wye for newer networks.

The network vaults contain a network unit that consists of a primary switch, a transformer, and a network protector. A network unit one-line diagram is shown in Figure 3.12c. The primary switch is a three-position primary switch with positions to connect the transformer primary to the feeder, open the line between the primary and the feeder, or ground the feeder line for testing. The transformer is usually rated between 1000 and 3000 KVA. The network protector is usually an air circuit breaker with a fuse back up. The circuit breaker is operated by relays, which are electro-mechanical or electronic sensing systems that detect, via current and potential transformers, unacceptable electrical conditions on the lines they

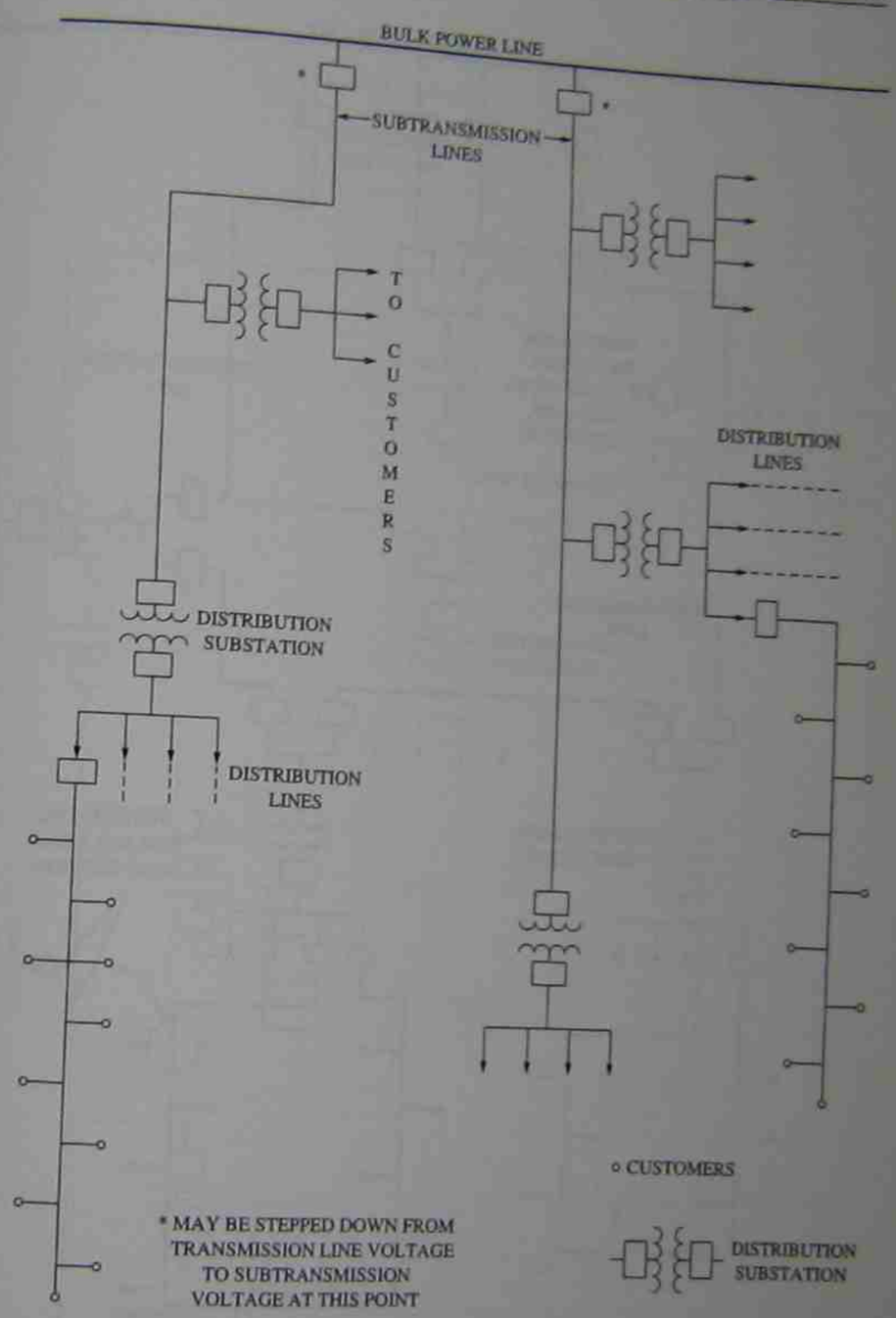


FIGURE 3.9 Radial distribution and subtransmission

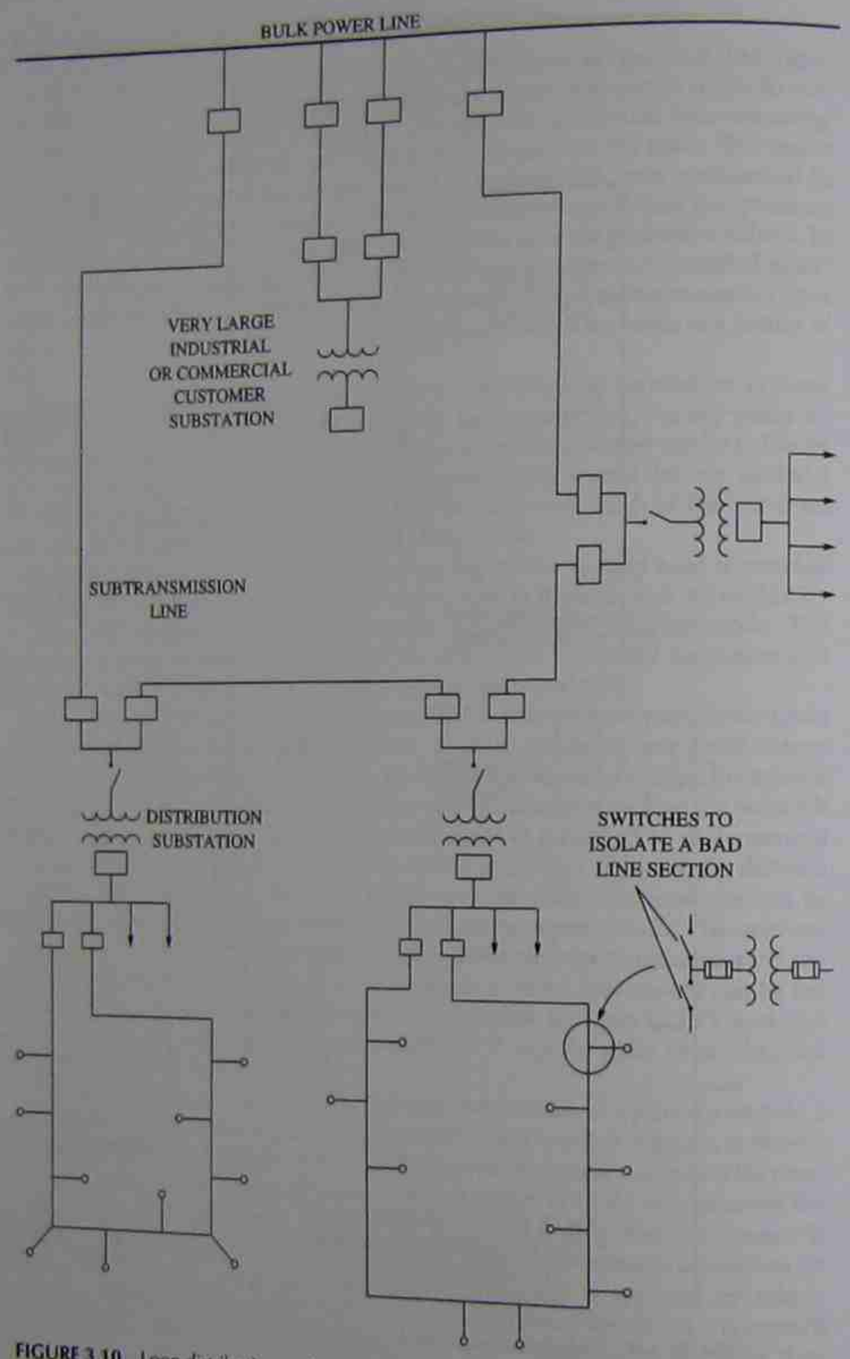


FIGURE 3.10 Loop distribution and subtransmission

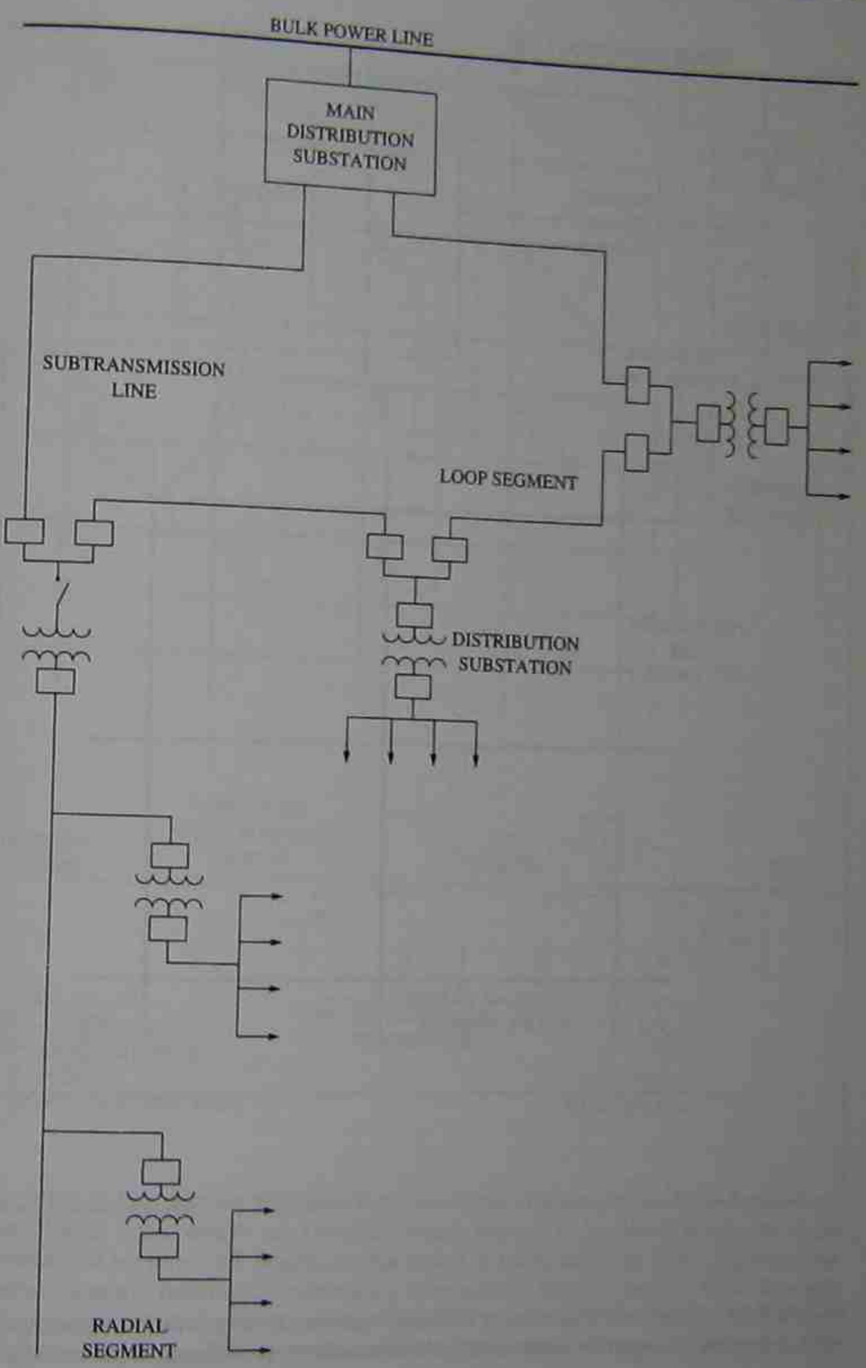


FIGURE 3.11 Combination

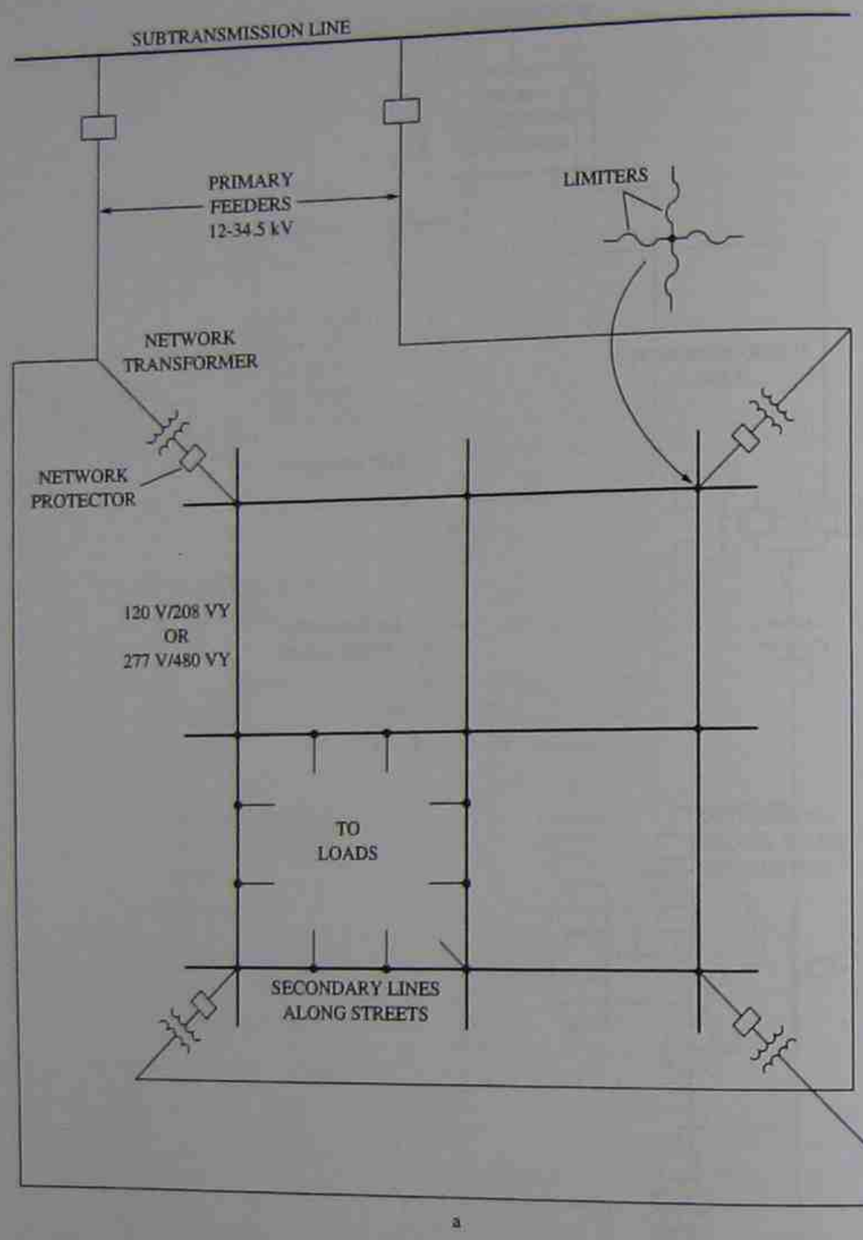
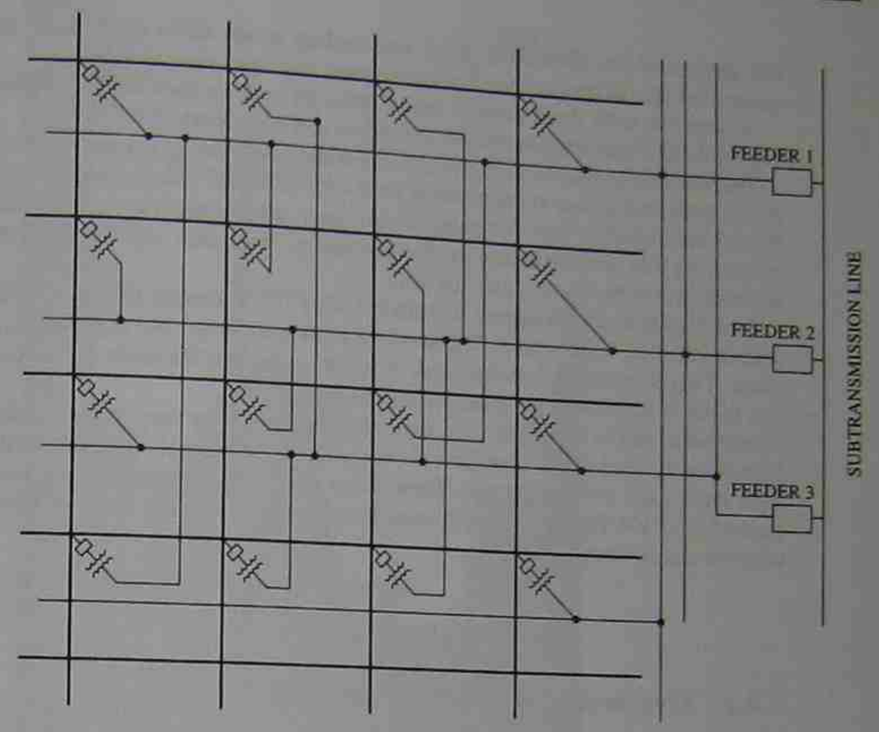
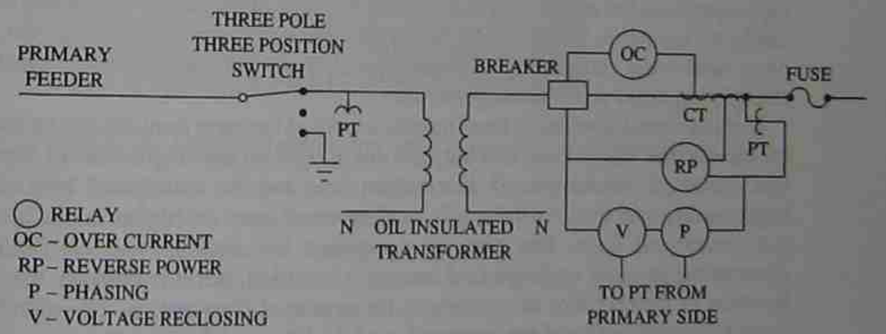


FIGURE 3.12 Network for high density loads (a) Single network section for four square blocks (b) Network grid, single block connections (note feeder alternation in each direction) and (c) Network unit





monitor. Relays provide trip signals to the circuit breakers when they detect fault conditions. Some relays can provide reclose signals to breakers when the fault conditions are removed. Relays are discussed in more detail in later chapters. The network relays monitor for secondary overcurrent, reverse power flow through the transformer, and primary voltage loss. They will open the breaker under any of these conditions. The relays also monitor the primary voltage for restoration at

the proper phase after they open, and reclose when those conditions are met unless the circuit breaker has been prevented from reclosing manually.

A network with three feeders and a network unit on each corner is shown in Figure 3.12b. Note the alternation of feeders to the network units.

The limiters indicated in Figure 3.12a are short sections of copper connected in series with each phase at each corner with a transformer. The copper sections contain a constricted section designed to burn open when supplying substantial fault current so that the insulation on the secondary conductor will not be damaged between the network unit and the fault.

Spot Networks are designed to provide 480/277 V service to larger buildings within 208/120 V networks. The network units are similar but are located in one place. Two or more feeders are used, as in networks, but the loads are served by a bus (a set of high capacity lines) instead of a grid.

Individual feeders are often used for critical loads. Many very large buildings in high density load areas, hospitals, as well as large industrial customers will have their own high voltage service. These large customers are usually connected at around 12.5 kV. Figure 3.10 illustrates loop service to a very large industrial or commercial customer.

3.4.2 Overhead and Underground

Overhead distribution, such as the line shown in Figure 3.13, is used because of the low initial cost and good reliability. The equipment for overhead distribution costs less than the equipment required for underground distribution, and it is less costly to maintain. Overhead distribution lines are more subject to storm, lightning, and wind damage than underground lines, but they are more easily and cheaply repaired when damage occurs.

Underground lines have been readily accepted because they are not as vulnerable to weather conditions, and they are out of sight so the neighborhood sky line is less cluttered. Underground distribution lines require waterproof insulation of high quality and cost. Additionally, underground lines are higher in electrical loss than overhead lines. The price of equipment for underground distribution is decreasing as more underground service is installed, but it is unlikely that it will become as inexpensive as equipment for overhead distribution. The distribution lines to a neighborhood are overhead, and the laterals (the lines that feed the padmount transformers for the houses) are underground, as are the lines that provide service to the individual houses. The utility company will charge the developer the difference in cost between overhead and underground service, which the developer then includes in the price of the property. A padmount transformer for underground distribution is shown in Figure 3.14.



FIGURE 3.13 Overhead distribution line (Courtesy of Gulf States Utilities Co.).



FIGURE 3.14 Pad mount transformer for underground distribution Primary connections (left) and secondary connections (right) shown (Courtesy of Houston Lighting & Power).

3.4.3 Line Losses

Line losses are discussed in greater detail in the transmission section of this book. At this point please note that the primary losses on the relatively short distribution lines are the resistive I^2R losses, and the voltage drop across the line inductive reactance. Capacitive effects are usually negligible on distribution lines because they are not very long. The resistance increases with length, as does inductive reactance. The magnetic flux cancellation between lines increases as their spacing

decreases, so close spacing of lines decreases the voltage drop across the line reactance. (We will calculate the line inductance and capacitance in the transmission section.) Underground lines are spaced more closely than overhead lines, and their insulation has a higher dielectric constant and loss than air. Underground distribution has higher losses than overhead distribution, because of increased dielectric losses.

3.5 VOLTAGE LEVELS

Distribution voltage levels have standardized at a nominal 12 kV with variations from 11.6 to 13.2 kV depending on the utility's preference and history, with the wye phase voltages ranging from 6.7 to 7.6 kV. The most common distribution voltage is 12.5/7.2 kV. Early in the development of electrical distribution 2300 V delta systems were common, but it was quickly found that a 4160/2300 V wye system provided a higher distribution voltage (with lower I^2R losses) with little change in equipment.

Electric utilities are now in the process of increasing the distribution voltages to 34.5/19.9kV. The change will provide more efficient distribution of electricity with lower losses. Better, less expensive insulating devices and materials have made possible the switch to higher voltages for distribution.

3.6 SUMMARY

The loads that electrical power utilities service are classified by customer type. Residential customers comprise the most numerous group, about 80%, commercial customers the next most numerous, about 15%, and industrial customers comprise about 5% of the total number of customers. The industrial customers typically use about 30% of the electrical power supplied. Often commercial and industrial customers correct power factor within their facilities to reduce the demand penalty that many electrical power providers charge for providing VAR capacity in excess of the power used.

Electrical power must be distributed to customers that a utility serves. The major distribution substations layouts are:

1. Radial, in which all users are fed by lines connected directly to a central supply. It is an inexpensive layout to build.
2. Loop, in which any user within the system is fed from two directions or sources. Loop systems are very reliable but more expensive.
3. Combination, in which critical users are supplied by a loop and noncritical users by radial feeds. It is a compromise between reliability and economy.

4. Networks, in which high density users such as business districts and downtown areas are fed by a grid of interconnected lines with well protected multiple service points. Networks are reliable but expensive.
5. Spot networks, in which a small high density load areas are fed by a small networks, with similar protection capabilities as larger networks, which have two or more feeds.
6. Individual feeders are used for large customers who then distribute the power to their loads from the feeder. The distribution layouts used by an electrical power utility are similar to those used by large industrial and multibuilding commercial customers to distribute electricity from their service to the various sections of their businesses.

Overhead distribution is less inexpensive and lower in loss than underground distribution. However, esthetic and reliability considerations make underground distribution attractive in many areas.

3.7 QUESTIONS

1. How are loads classified by electric utilities?
2. Define power factor correction.
3. What situation has made the improvement of power factor to 0.95 or better a trend?
4. Why must the power factor of a system not become leading?
5. A circuit with a 120 V, 60 Hz, single-phase source has a 7.5 hp capacitor start motor running at full load. The motor full load efficiency is 78%, and the power factor is 0.75. Calculate the value of capacitor required to correct the full load motor power factor to unity.
6. A 277/480 V three-phase wye system has the following load:
   M1—Induction motor, 50 hp, $\eta = 0.91$, PF = 0.89 at full load.
   M2—Induction motor, 25 hp, $\eta = 0.9$, PF = 0.9 at full load.
   R—Heater load, PF = 1.
   M3—A synchronous motor to drive a second 25 hp load.
   Calculate the leading kVARs the synchronous motor must provide to correct the system power factor to unity. The synchronous motor will run at full load, 25 hp, with $\eta = 0.94$.
7. Calculate the kVA and kVAR of the system of problem 6 if M3 is an induction motor of the same type as M2 instead of a synchronous motor.
8. Calculate the difference in electricity cost between the systems of problems 6 and 7 if they run 16 hours a day for 10 years and electricity costs eight cents per kVA hour (normally called kW hour).
9. If the synchronous motor of problem 6 costs $500 more than the induction motor of problem 7, how long will it take to pay for the difference in cost if the system of problem 6 is used instead of the system of problem 7?

10. List the major advantage and disadvantage of each of the following distribution layouts: radial, loop, and combination.
11. State the primary purpose of the network distribution layout.
12. State the function of spot networks.
13. Why must network protectors sense reverse power flow through the transformer?
14. List two advantages and two disadvantages for each: overhead and underground distribution.
15. State the development that is chiefly responsible for higher distribution voltages.

CHAPTER 4

Distribution Transformers

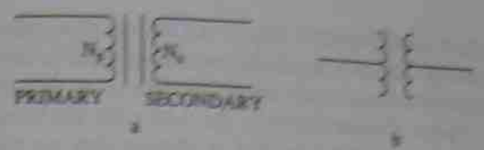
4.1 NEED FOR TRANSFORMERS

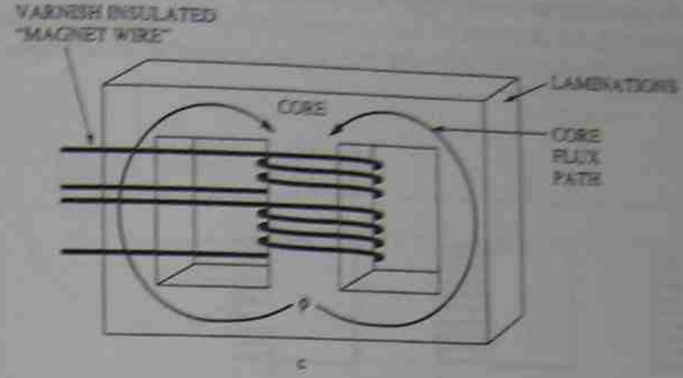
Transformers, as you know, are electrical machines that use magnetic induction to change alternating current (ac) voltage levels. Without high transmission and distribution voltages the power losses and voltage drops associated with line resistance would make electrical power transfer very inefficient. Currently the highest practical generating voltage is around 25 kV, so transformers are needed to step up voltage for economical transmission, and step down voltage to levels that are safe for the customer to use. Transformers are also a key element in the equipment used for high voltage direct current (dc) transmission. The transformer is the machine that made ac transmission and distribution the standard early in the history of the electrical power industry.

Although the student is already familiar with basic transformer theory, this chapter briefly reviews some basics, and then discusses topics of interest relating to transformers for distribution.

4.1.1 Description

Transformers, whose schematic and one line symbols are shown in Figures 4.1a and b, are essentially two sets of windings of insulated wire called magnet wire (transformer wire in larger sizes) wound around a high permeability silicon steel





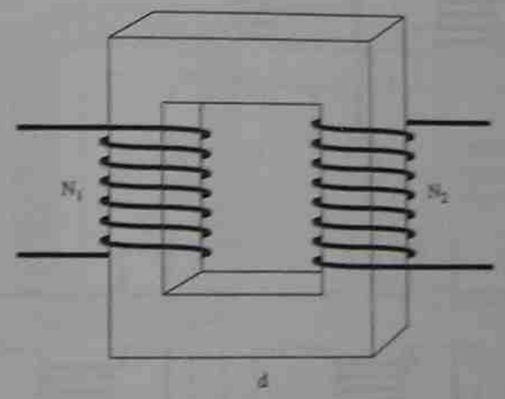
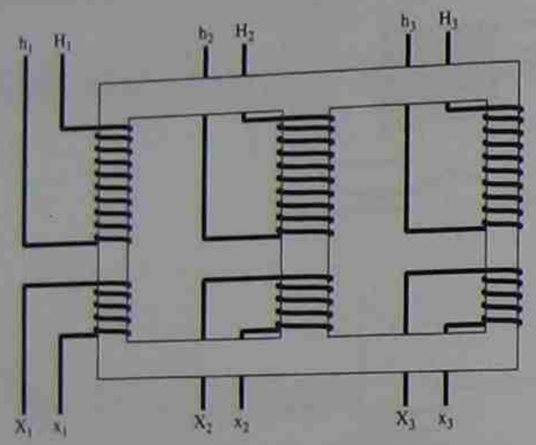


FIGURE 4.1 Transformer (a) Schematic symbol (b) one-line symbol (c) shell constructed single-phase transformer and (d) core constructed single-phase transformer

core, assembled from thin laminations, as shown in Figure 4.1c. The wire is insulated with a thin coat of high quality plastic varnish, and the core laminations are made of silicon steel with good magnetic properties (low loss, high μ) that are between 0.009 and 0.014 inches thick for 60 Hz. The transformers are usually constructed in shell or core form. Figures 4.1c and d show shell and core constructed single-phase transformers respectively. The shell type has less magnetic flux leakage than the core type but requires more core material. Shell constructed three-phase transformers are less frequently used because of their added cost, and the good

performance of core constructed transformers. Figure 4.2 shows three-phase core and shell constructed transformers. The core laminations are supplied in two forms, flat and ribbon. The flat laminations are stamped out of thin sheets, as shown in Figure 4.3a, that are stacked like sheets of paper to form the core with the laminations cut to overlap at joints. Laminations are also supplied in ribbons that are rolled out and are put together like the layers of an onion skin as shown in Figure 4.3b (again the ends overlap). All laminations have a very thin layer of insulating material on their surface so that they are not in electrical contact with other laminations.



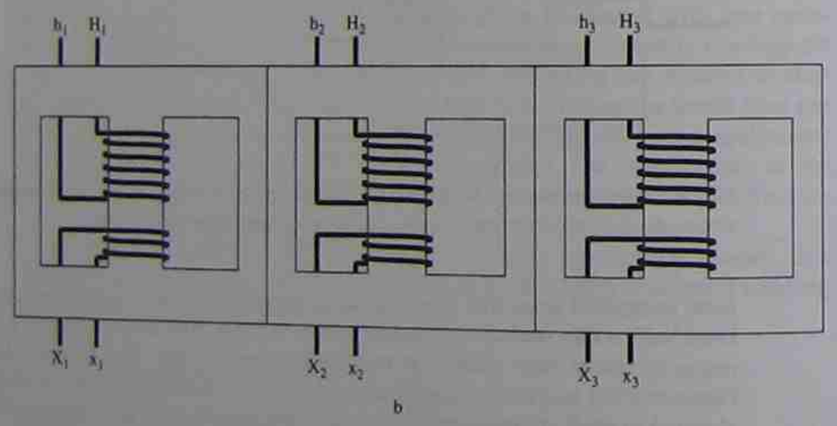


FIGURE 4.2 Three-phase transformer (a) core-constructed transformer and (b) shell-constructed transformer

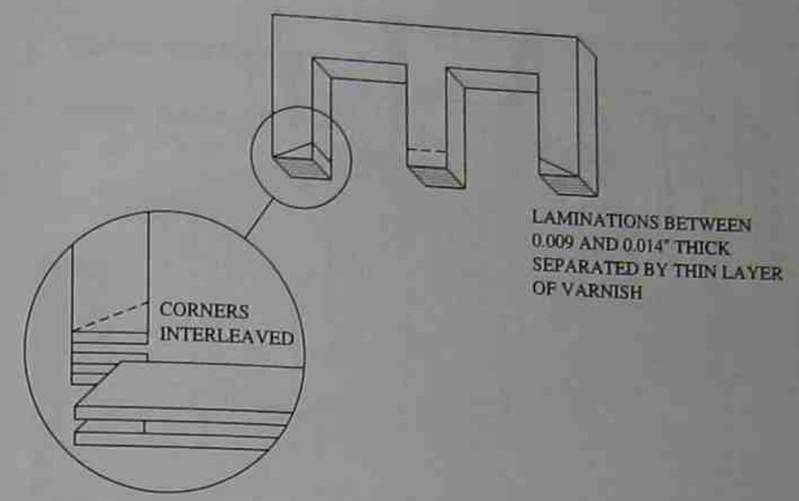


FIGURE 4.3 Core laminations (a) Stacked laminations and (b) ribbon, also called form core and wrap core laminations

The windings are helical, as in Figure 4.1c and d, with insulation between the core and windings and each layer of windings, for low voltage transformers. Higher voltage transformers are wound with either layer or disk type windings for greater separation (Figure 4.4), with disk favored for very high voltages. The entire core and winding is placed in a support structure and the winding leads brought out to terminations. A sketch of an oil immersed transformer is shown in Figure 4.20 later in the chapter.

Transformers are classified by their function such as unit, transformers used in generating stations to step up the generated voltage; power transformers, used in

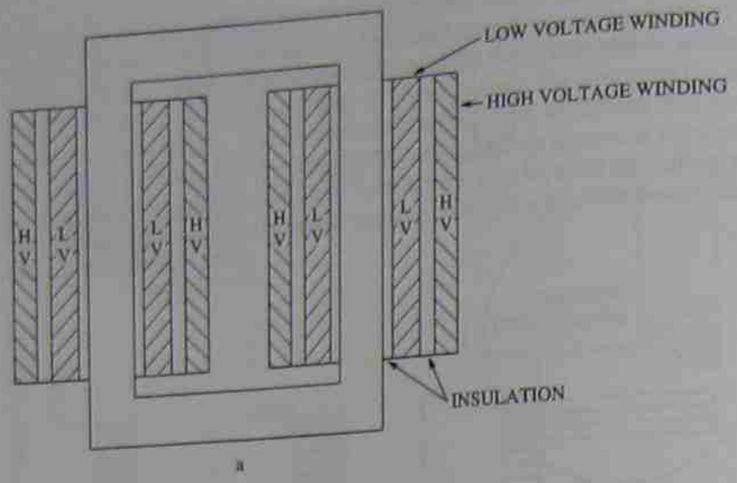


FIGURE 4.4 Winding types (a) layer and (b) disk

substations and large customer service; and distribution, generally the last transformer between the customer and the power system. The lines of classification by use are often fuzzy since the same transformer may be suitable for more than one job. For example, the distribution transformer for a very large industrial customer may be identical to a substation power transformer. Transformers are also classified by cooling. Dry types are air cooled, primarily by convection. Oil immersed transformers, in which the windings and core are immersed in oil, are both cooled and helped in insulation by the oil. Almost all utility power and distribution transformers are oil. Dry types are used primarily where minimum cost is a factor and the transformer is supplied by the customer such as in apartment house and building distribution systems. Because the cooling of dry transformers is by convection they are very intolerant of overloads. Dry types must be in an enclosure for safety. Figure 4.5 is a photograph of an oil immersed transformer.

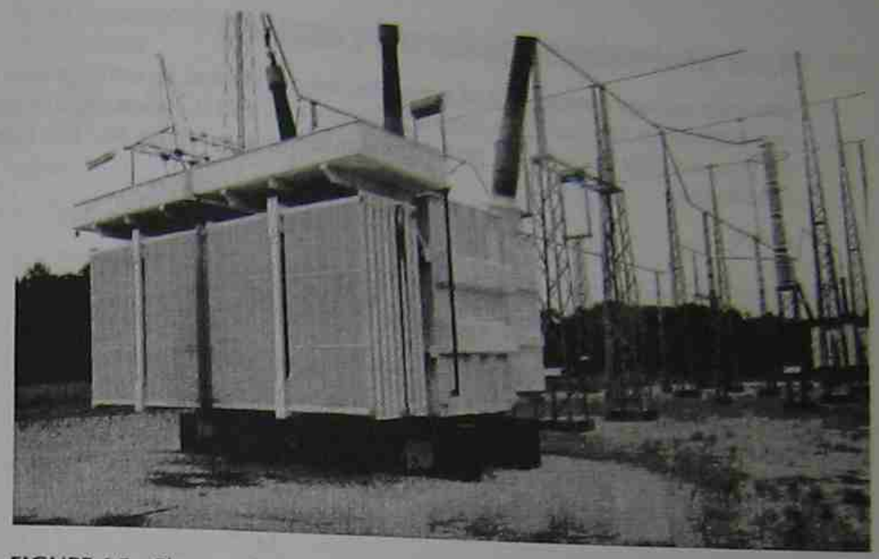


FIGURE 4.5 Photograph of a power transformer (Courtesy of Houston Lighting & Power).

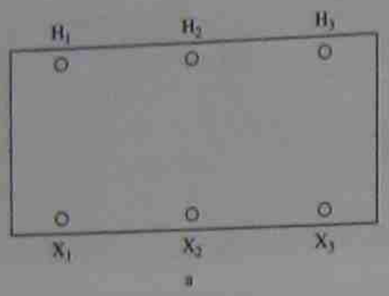
Oil immersed transformers are inside tanks of steel. Great effort is expended to assure the oil in the tanks remains free of water and impurities to ensure the insulating property of the oil, and if a transformer is opened for maintenance the oil is tested for impurities, and cleaned or replaced if necessary. The oil is in intimate contact with the transformer core and coil and removes heat from them. The oil circulates by convection and loses its heat to the environment through the steel transformer tank. External fins through which the oil can flow improves the cooling, as does forcing air across the cooling fins with fans (called forced air, FA). Pumping the oil through the fins (called forced oil, FO) improves it more and doing both even more (FOA). Each cooling improvement increases the capacity of the transformer. Power transformer ratings often follow the following pattern: MVA-25/33/42, which means the capacity is 25 MVA with convection circulated oil (OA), 33 MVA with forced air added (FA), and 42 MVA with both forced oil and air (FOA). The rating ratio is 1/1.33/1.67 for OA/FA/FOA. Many transformers are rated for only one type of cooling, such as FOA and all systems are expected to be used while it operates. Very high power transformers may have heat exchangers in which heat from the oil is transferred to water and the water is then cooled. Oil transformers are much more tolerant of overloads than dry types. Overloads that result in excessive heating of either type shortens the transformer life by degrading the insulation (and oil in oil types).

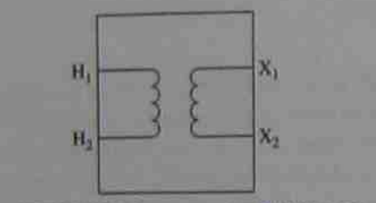
Dry type transformers are available in voltages to 15 kV and power ratings to around 150 kVA, and oil immersed transformers are available in sizes over 1000 MVA and 1000 kV. Both are available in single and three-phase systems.

4.1.2 Ideal Relationships and Dot Convention

The high voltage connections of a transformer are labeled H, and the low voltage connections are labeled X, as shown in Figure 4.6a and b. Referring to Figure 4.6c the primary side turns are N_1 and the secondary side turns are N_2. The turns ratio is defined as

$$a = N_1/N_2 \tag{4.1}$$





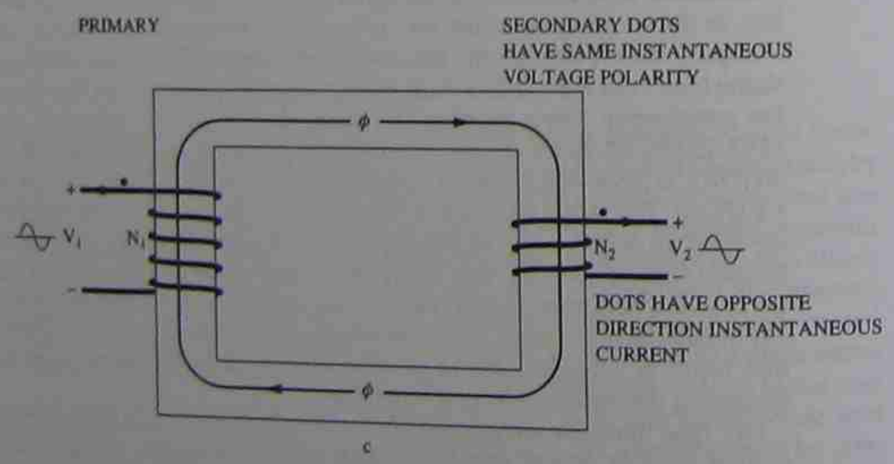


FIGURE 4.6 Nomenclature conventions (a) single phase (b) three phase and (c) dot convention

From Faraday's law we know that the voltage induced on a conductor in a magnetic field is

$$e = \frac{\Delta\phi}{\Delta t} = \frac{d\phi}{dt} \tag{4.2}$$

where

e = instantaneous conductor voltage

ϕ = magnetic flux lines linking the conductor

Δ = change in time, labeled dt as Δt becomes small

$d\phi/dt$ = time rate of change of flux linking the conductor

If the conductor is a loop then it is called a turn, and the conductor voltage is the number of turns, N, times $(d\phi/dt)$. If the same $d\phi/dt$ links two sets of turns then the ratio of the voltage induced on the two sets of turns is

$$\frac{V_1}{V_2} = \frac{N_1\,(d\phi/dt)}{N_2\,(d\phi/dt)} = \frac{N_1}{N_2}$$

The flux linking the two sets of turns is very nearly equal when the two windings are on the same core because the high permeability of the core confines the magnetic flux to the vicinity of the windings. By the conservation of energy principle the VA out of the transformer cannot exceed the VA in. If the transformer losses are assumed to be zero,

$$VA_{out} = VA_{in}$$

$$I_2V_2 = I_1V_1$$

$$\frac{I_2}{I_1} = \frac{V_1}{V_2} = a \tag{4.3}$$

Which is the inverse of the voltage ratio.

The agreed upon convention is for the dots on a transformer to indicate terminals with the same instantaneous polarity. If in Figure 4.6 the dot on the primary is at the peak of the positive half cycle, the secondary terminal is at the same voltage. The current is flowing into the primary terminal because it is a voltage drop in the primary circuit. The secondary of the transformer is a source in the secondary circuit so it must supply current, thus current is flowing out of the dotted secondary terminal, as shown in Figure 4.6.

4.1.3 Losses in Transformers

There are three sources of loss in a transformer: copper, hysteresis, and eddy current. They use real power and reduce transformer efficiency.

Copper losses are the power losses caused by current flowing through the winding resistance, I^2R losses. Skin effect causes the ac resistance of the transformer

windings to increase with frequency, so copper losses increase with frequency if the winding current remains constant. Proper sizing of the winding wire and proper cooling for the transformer minimize copper losses.

Hysteresis losses are the result of the energy needed to magnetize the core first in one direction and then the other as the applied ac voltage reverses in polarity. The magnetic domains must form in one direction, and then in the other. Hysteresis losses increase with frequency because the domains must be reversed more frequently. These losses are minimized by the proper choice of magnetic material. A new magnetic material has been developed that is amorphous in structure instead of having the small crystalline grain structure of most current magnetic materials. This means the magnetic domains are almost atomic in size and require very little energy to reverse. The amorphous magnetic materials have very low hysteresis losses, but currently can be manufactured only in ribbon form. For this reason, and their relatively high cost, they are not currently in wide use.

Eddy current is current induced in metal near a magnetic field. If the field surrounds the metal object, the induced current will be a loop at a right angle to the flux. The core of a transformer is ideally positioned with respect to the windings for eddy current to be induced in it. The laminations break the core into many small thin pieces of metal, thereby reducing the voltage that is induced to drive eddy currents in the core (the conductor length is reduced within the flux linkages), and increasing the resistance through which eddy currents must flow because the cross-sectional area of each lamination is small. Additionally the silicon steel is higher in resistance than non-silicon steel, which also helps to reduce eddy current. Any reduction in eddy current reduces the losses by the square of the reduction. These losses can be less than 0.5% of the total power transferred by a transformer.

4.1.4 Transformer Efficiency

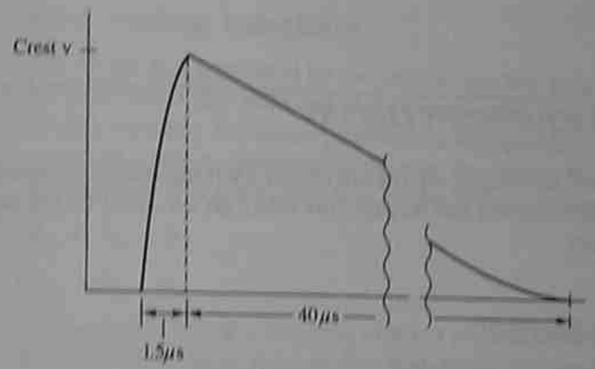
Transformers are among the most efficient machines ever invented. A transformer that is properly designed, built, and cooled can be more than 99% efficient. The following efficiency values are average measured values for three-phase power transformers operating at full load with a unity load power factor: 2000 kVA—15 kV, 98.97%; 34.5 kV, 98.89%; 69 kV, 98.83%; 138 kV, 98.57%; 10,000 kVA—15 kV, 99.23%; 34.5 kV, 99.27%; 69 kV, 99.17%; and 138 kV, 99.12%. Maximum efficiency occurs when the copper loss is equal to the core loss. If amorphous magnetic metals can be made suitable for large power transformers efficiencies may someday routinely be greater than 99.5%.

4.1.5 BIL (Basic Insulation Level)

A transformer BIL is the peak transient voltage level that the transformer can withstand for a specified time. The insulation class of a transformer is the maximum rms working voltage of the transformer. The BIL is between 5 and 30 times the insulation class. The lower ratio is for higher voltage transformers, with only

1.2 kV and 5 kV insulation class transformers being tested to a BIL of more than 8.6 times their insulation class. The high voltage withstanding capability is necessary because of lightning and switching transients. Lightning strikes impress very high voltage transients of short duration on transmission and distribution lines that propagate down the lines to the transformers. If the BIL levels were lower the reliability of the electrical power system would be lower.

The transient test waveforms for BIL tests are shown in Figure 4.7a. The full wave, rising to its crest voltage in 1.5 μs and decaying in 40 μs, is modeled after a "typical" lightning strike. The waveform of Figure 4.7a is called the full wave, and the waveform of Figure 4.7b is called the chopped wave. It has a crest about 15% higher than the full wave and is interrupted by a spark-gap breakdown between one and three us after the wave begins. The BIL transient test consists of one reduced full wave (full wave of 50 to 70% full wave crest voltage), two chopped waves, and one full wave. The full wave crest voltage is specified as 95 kV for a



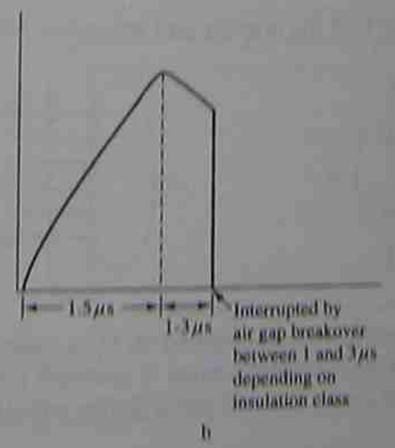


FIGURE 4.7 Basic insulation level (BIL) test waveforms (a) full wave and (b) chopped wave

15 kV oil transformer under 500 kVA, and 110 kV for one over 500 kVA. A 69 kV oil transformer would be tested to a full wave crest voltage of 350 kV regardless of its kVA rating. A 1.2 kV transformer is tested to a crest voltage of 30 kV. Test specifications are established for every standard insulation class.

Other insulation tests are performed. A low frequency *applied potential* test is run that consists of applying a low frequency voltage between each winding and ground for 1 minute. Example values used for this test are (insulation class, test voltage): 1.2 kV, 10 kVrms; 15 kV, 34 kVrms; 34.5 kV, 70 kVrms; and 69 kV, 140 kVrms. An *induced potential* test is one in which twice the rated voltage is applied at 120 Hz (to reduce core excitation) to one of the windings for one minute.

Dry type transformers are tested to lower BIL crest voltages and applied potential voltages than equivalently rated oil transformers. The oil improves the ability of the transformer to withstand high voltage. For example, a 1.2 kV dry type is tested to a low frequency applied potential of 4 kV.

4.2 TRANSFORMER EQUIVALENT CIRCUIT

In this section we will develop an equivalent circuit for transformers. We will also consider the excitation current and leakage flux effect on the ideal transformer in the equivalent circuit.

4.2.1 Excitation Current

Let $\mathcal{F}$ be the magnetomotive force (MMF) in ampere turns

$$\mathcal{F} = NI \tag{4.4}$$

The mutual flux is the result of both the primary and secondary MMFs, so

$$\begin{aligned}\mathcal{F}_T &= \mathcal{F}_p + \mathcal{F}_s \\ &= N_p I_p + N_s(-I_s) \\ &= N_p I_p - N_s I_s\end{aligned}$$

solving for I_p we find

$$I_p = \frac{\mathcal{F}}{N_p} + \frac{N_s}{N_p} I_s$$

That portion of the primary current represented by $\mathcal{F}/N_p$ is called the excitation current, that portion of the primary current needed to establish the magnetic flux and supply power for the core losses. Thus we can write the equation for primary current as

$$I_p = I_{ex} + I_s/a \tag{4.5}$$

At no load the primary current is all excitation current, except for the $I_{ex}^2 R_p$ loss (resistive power dissipated in the transformer windings is called copper loss) in the primary winding. At loads over 1/2 the rated load $I_{ex} << I_p$. Because the excitation current supplies both magnetization current and core loss current we can express the excitation current as

$$I_{ex} = I_m + I_{h+e} \tag{4.6}$$

where

I_m = magnetization current component of the excitation current which lags the primary voltage by 90°.

I_{h+e} = current to supply core losses that is in phase with the primary voltage.

The core losses consist of hysteresis and eddy current loss.

4.2.2 Leakage Inductance

Not all the flux generated by the primary winding links the secondary winding via the core. Some flux leaks out of the core coupling only the primary or only the secondary winding. The actual pattern of the leakage flux is quite complex and depends on the physical configuration of the core. The leakage flux is shown as Φ_{1P} and Φ_{1S} in Figure 4.8. If Φ is the mutual flux linking both the primary and secondary windings

$$\Phi_{1P} = \Phi_P - \Phi \tag{4.7}$$

$$\Phi_{1S} = \Phi_S - \Phi \tag{4.8}$$

In general $\Phi_l << \Phi$, consisting of only 1 to 7% of the total flux. High voltage transformers have more leakage flux than lower voltage transformers because their windings must be further apart to provide proper insulation for the high voltage.

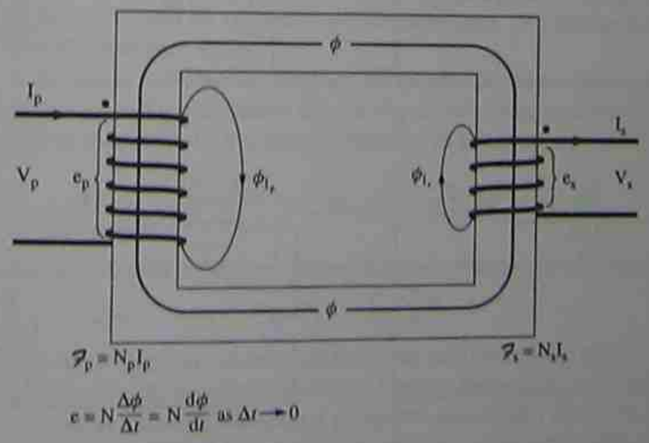


FIGURE 4.8 Transformer flux paths

The medium of the leakage flux, which has leaked out of the core, is air so the leakage flux paths do not saturate. Leakage flux is linear with current. The leakage flux changes at the same rate as the mutual flux so it induces a voltage in the winding with which it is associated. Let e be the induced voltage, then

$$e_{1P} = N_P \frac{d\Phi_{1P}}{dt}$$

$$e_{1S} = N_S \frac{d\Phi_{1S}}{dt}$$

These induced voltages are shown in Figure 4.9a. Recall that flux expressed in terms of permeance ($\mathcal{P}$) is

$$\Phi = \mathcal{P}\, NI$$

We now substitute this expression into the preceding instantaneous voltage equations and move the constants out of the portion that changes with time to obtain

$$e = N^2 \mathcal{P}(dI/dt)$$

but $L = N^2\mathcal{P}$, so the expression becomes

$$e_{1P} = L_{1P} \frac{dI_P}{dt} \qquad (4.9)$$

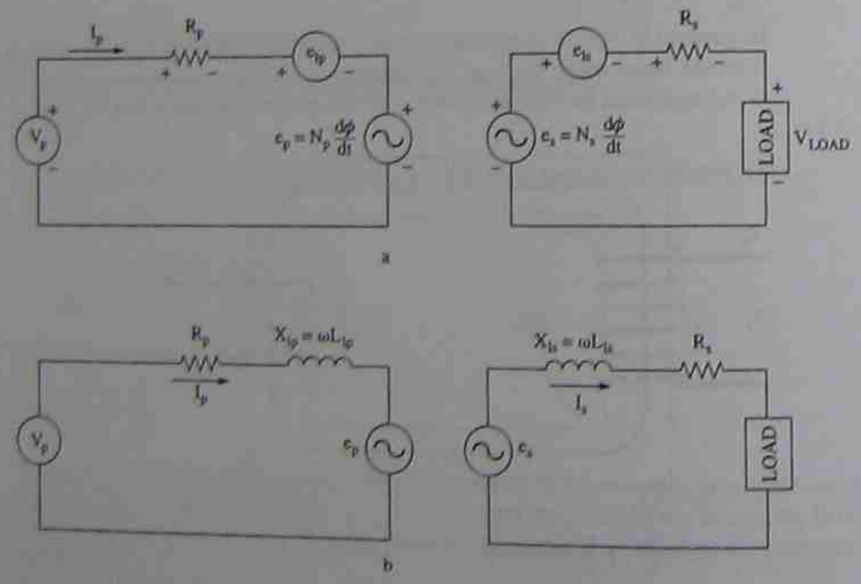


FIGURE 4.9 Transformer equivalent circuit with leakage flux (a) as voltage drop and (b) as inductive reactance

$$e_{1S} = L_{1S} \frac{dI_S}{dt} \qquad (4.10)$$

This means that the leakage flux cutting the windings of the primary and secondary must generate a voltage across them, and that the voltage is proportional to the change of current per unit time through the windings, which acts as leakage inductances because of the leakage flux. The reactance of the leakage inductance is included in the transformer equivalent circuit, as shown in Figure 4.9b.

The primary voltage induced on the secondary is reduced by two factors, the primary resistance and the primary leakage reactance. Similarly the voltage across the secondary terminals is reduced from the induced secondary voltage by the secondary winding resistance and leakage reactance. The following equations summarize this.

$$e_p = V_p - I_p R_p - e_{1P}$$
$$= V_p - I_p R_p - L_{1P}(dI_p/dt) \qquad (4.11)$$

and similarly

$$V_S = e_S - I_S R_S - L_{1S}(dI_S/dt) \qquad (4.12)$$

4.2.3 Equivalent Circuit

Only two more items remain to complete the equivalent circuit. The magnetizing current can be represented by an inductive reactance (X_m) across the primary because the magnetizing current lags the applied voltage by 90° and is drawn from the primary. The current drawn from the primary to supply the hysteresis and eddy current losses is in phase with the primary voltage (these are real power losses) and can be modeled with a resistance (R_c) across the primary. These are shown in Figure 4.10a.

In use in a reactance diagram all of the elements will be referred to either the primary or the secondary side of the transformer to simplify calculations. Recall that any secondary impedance referred to the primary side Z_{rp} is

$$Z_{rP} = \frac{V_p}{I_p} = \frac{V_S(N_P/N_S)}{I_S(N_S/N_P)} = Z_S(N_P/N_S)^2 = Z_S a^2$$

and conversely a primary impedance referred to the secondary is

$$Z_{rS} = Z_p/a^2$$

The equivalent circuit with all elements referred to the primary is shown in Figure 4.10b and with all elements referred to the secondary is shown in Figure 4.10c.

In most calculations such a complete equivalent circuit is not necessary so the circuit is simplified by omitting R_C and X_m, and combining all of the series resistors into one equivalent and all of the series inductive reactances into one, as shown in Figures 4.10d and e. In Figure 4.10d, referred to the primary

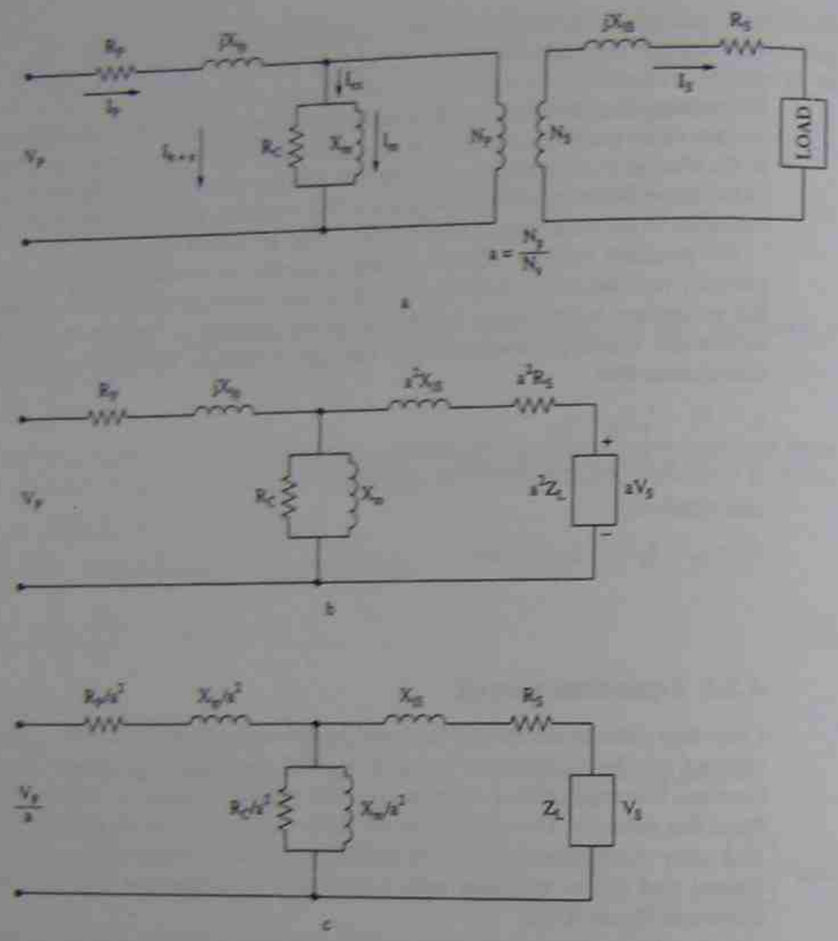
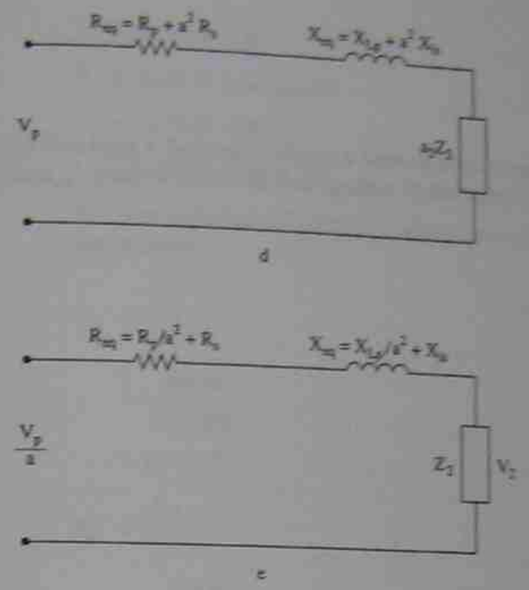


FIGURE 4.10 Transformer equivalent circuits (a) Complete equivalent circuit (b) all elements referred to the primary (c) all elements referred to the secondary (d) approximate equivalent circuit referred to the primary and (e) approximate equivalent circuit referred to the secondary



$$R_{eq} = R_p + a^2 R_s \tag{4.13}$$

$$X_{eq} = X_p + a^2 X_s \tag{4.14}$$

therefore

$$Z_{eq\,rP} = R_{eq\,rP} + X_{eq\,rP} \tag{4.15}$$

In Figure 4.10e, referred to the secondary

$$R_{eq} = R_p/a^2 + R_s \tag{4.16}$$

$$X_{eq} = X_p/a^2 + X_s \tag{4.17}$$

$$Z_{eq\,rS} = R_{eq\,rS} + X_{eq\,rS} \tag{4.18}$$

Typical values of I_m range from 0.01 (per unit) pu to 0.05 pu, but can be as high as 0.1 pu in extremely high voltage transformers. I_{h+e} is normally about 0.03 pu in a good transformer. Thus X_m is around 20 to 100 pu, and R_c around 33 pu. Transformer impedance runs between 0.01 pu to 0.05 pu in distribution transformers, but it can be as high as 0.15 pu in high voltage power transformers. These values are only approximate to give the reader a feel for the values expected. A good transformer may vary markedly from these values depending on the transformer design.

4.2.4 Examples

Example 4.1:

An ideal transformer is used to feed a single-phase 240 V load of 5 kVA with a PF = 0.8 lagging. The primary voltage is 4160 V. Calculate a, I_S, and I_P.

Solution:

$$a = \frac{V_P}{V_S}$$

$$= \frac{4160\ \text{V}}{240\ \text{V}}$$

$$= 17.333$$

$$I_S = \frac{\text{kVA}}{\text{V}}$$

$$= \frac{5\ \text{kVA}}{240\ \text{V}}$$

$$= 20.83\ \text{A}$$

$$I_P = \frac{I_S}{a}$$

$$= \frac{20.83\ \text{A}}{17.333}$$

$$= 1.2\ \text{A}$$

Example 4.2:

The transformer of Example 4.1 has: $X_P = j46\ \Omega$, $R_P = 3.7\ \Omega$, $X_S = j0.15\ \Omega$, and $R_S = 0.012\ \Omega$. Reference the equivalent circuit of Figure 4.10*e* to the secondary and use it to calculate the actual voltage across the load.

Solution:

First calculate Z_L

$$Z_L = \frac{\text{rated V}}{\text{I at rated V}}$$

$$= \frac{240\ \text{V}}{20.83\ \text{A}}$$

$$= 11.52\ \Omega$$

In polar form it is

$$Z_L = 11.52\ \Omega \angle \arccos 0.8$$

$$= 11.52\ \Omega \angle 36.87°$$

$$= 9.216\ \Omega + j6.912\ \Omega$$

We now calculate all primary values referred to the secondary. These values are primed.

$$X_P' = \frac{X_P}{a^2}$$

$$= \frac{j46\ \Omega}{(17.333)^2}$$

$$= j0.153\ \Omega$$

$$R_P' = \frac{R_P}{a^2}$$

$$= \frac{3.7\ \Omega}{(17.3333)^2}$$

$$= 0.012\ \Omega$$

$$V_S' = \frac{4160\ \text{V}}{17.333}$$

$$= 240\ \text{V}$$

The equivalent values are now

$$X_{eq} = X_P' + X_S$$

$$= j0.153\ \Omega + j0.15\ \Omega$$

$$= j0.303\ \Omega$$

$$R_{eq} = R_P' + R_S$$

$$= 0.012\ \Omega + 0.012\ \Omega$$

$$= 0.024\ \Omega$$

$$Z_{eq} = 0.024\ \Omega + j0.303\ \Omega$$

Now we calculate the total impedance

$$Z_T = Z_{eq} + Z_L$$

$$= 9.24\ \Omega + j7.215\ \Omega$$

$$= 11.72\ \Omega \angle 37.98°$$

$$I = \frac{V_S'}{Z_T}$$

$$= \frac{240\ \text{V}}{11.72\ \Omega}$$

$$= 20.47\ \text{A}$$

Finally

$$V_L = IZ_L$$

$$= 20.47\ \text{A} \times 11.52\ \Omega$$

$$= 235.84\ \text{V}$$

In this case the more accurate equivalent circuit made little difference with respect to the ideal transformer, about 1.8%.

Actually X_m and R_c would have caused the primary current to be higher than I_S/a. Assuming $I_m = 0.05$ pu and $I_{h+e} = 0.01$ pu we will calculate the approximate difference.

$$\text{primary base } I = \frac{\text{rated kVA}}{\text{rated V}}$$

$$= \frac{5\ \text{kVA}}{4160\ \text{V}}$$

$$= 1.2\ \text{A}$$

$$I_{h+e} = 0.01\ (1.2\ \text{A})$$

$$= 12\ \text{mA}$$

$$I_m = 0.05\ (1.2\ \text{A})$$

$$= 60\ \text{mA}$$

$$I_m = \sqrt{I_{h+e} + I_m}$$

$$= \sqrt{(12\text{ma})^2 + (60\text{ma})^2}$$

$$= 61\ \text{mA} \angle 78.7°$$

Therefore the primary current would have been 1.2 A ∠39.6° + 0.061 A ∠78.7° = 1.248 A ∠41.37°, an error of 4% and 1.77°.

4.3 HARMONICS AND INRUSH CURRENT

Transformer core material is not linear and requires initial magnetization upon energization. Therefore transformers generate harmonics in operation, and draw more current when energized than in normal operation. These characteristics are discussed in this section.

4.3.1 Harmonics

The nonlinear nature of transformer core material is evident in the B-H curve in Figure 4.11, in which magnetic flux density (B), in flux lines per unit area, is plotted against magnetic field intensity (H), in ampere turns per unit length. One might ask why the transformer cannot be operated around the origin of the curve where the curve is almost linear, and far away from saturation where the curve is very nonlinear. The reason is that the amount of core material needed for a distribution transformer to provide a reasonable power transfer would be so much as to make the transformers prohibitively expensive. To make power transformers reasonable in cost the operation along the B-H curve has to be close enough to saturation that nonlinearity is inevitable. Not only is the B-H curve nonlinear, but it also exhibits hysteresis; that is, the position of a point on the curve depends on the direction of approach. The area inside the curve is a measure of the losses to hysteresis and eddy current in the core. Recall that the excitation current of the core provides the magnetizing current and the core loss current.

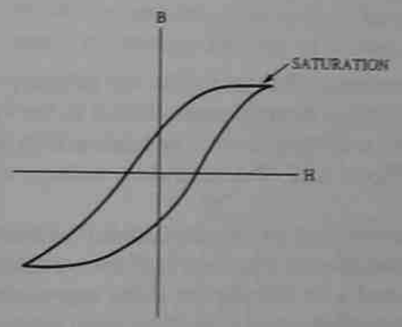


FIGURE 4.11 B-H curve of core material

Voltage and Flux Relationship

Referring to the primary induced voltage recall that

$$e_p = N_p(d\Phi/dt)$$

Solving for Φ we find

$$d\Phi = (1/N_p)e_p dt$$

The flux can be found by summing e_p over all of the small dts. The process of summing the dts, which are infinitesimally small Δts, is called integration. An integral can be thought of as the area under a curve between two points. The symbol for integration is $\int$. Thus the total flux is the sum, or integral, of the area of each

$dt \times e_p$ within the dt. The turns are fixed so they can be multiplied by the integral after it is found. The flux is then

$$\Phi = \frac{1}{N}\int e_p dt$$

Let $e_p = (\sqrt{2})\, E_p \sin(\omega t + \alpha)$, then

$$\Phi = \frac{(\sqrt{2})E_p}{N_p}\int \sin(\omega t + \alpha)dt$$

From memory or from a table of integral solutions we find that

$$\sin(\omega t + \alpha) = -(1/\omega)\cos(\omega t + \alpha) + \text{constant}$$

therefore

$$\Phi = -\frac{(\sqrt{2})E_p}{\omega N_p}\cos(t + \alpha) + \Phi_c \qquad (4.19)$$

where Φ_c is a constant that depends on the conditions at $t = 0$, a transient flux that dies away quickly. The maximum flux will occur when $\cos(\omega t + \alpha) = 1$, or at 90° from the voltage maximum

$$\Phi_{MAX} = \frac{(\sqrt{2})E_p}{\omega N_p} = \frac{V_p}{(\sqrt{2})\,\pi f N_p} \qquad (4.20)$$

From equation 4.20 we see that the maximum flux looks like the primary voltage except that it lags the voltage by 90°, that it is directly proportional to the volts per turn on the primary, and that it reduces with frequency. The relationship between the voltage and the flux is shown in Figure 4.12. The secondary voltage will look like the flux from which it is induced.

A mathematician named Fourier showed that any nonsinusoidal waveform was made of harmonics (multiples of the fundamental frequency) of the waveform with varying amplitude, the fundamental, and a dc component if the waveform is not symmetrical around the time axis. His mathematical equations were subsequently

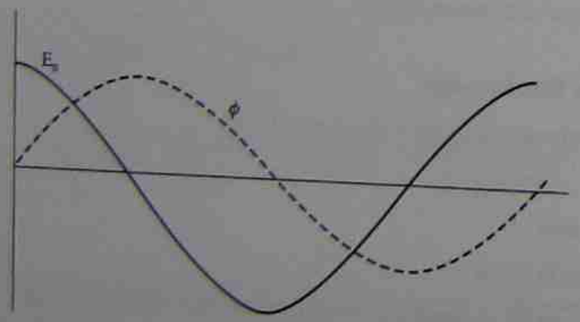


FIGURE 4.12 Magnetic flux and primary winding voltlage

proven correct by experimentation. The fundamental frequency amplitude, the harmonic amplitudes, and the dc component if there is one, is called the *Fourier series*. By calculating the Fourier series one can discover all of the harmonics that make up a waveform and their amplitude. The series is of the form, where f(t) is the equation of the waveform with time

$$f(t) = a_0 + \Sigma_{n=1}^{\infty}[a_n\cos(n\omega t) + b_n\sin(n\omega t)]$$

where

a_0 = dc amplitude of the waveform

a_n = amplitude of the sine terms

b_n = amplitude of the cosine terms

Many excellent books go into the details of how to calculate the amplitude of the terms in the Fourier series. It turns out that certain waveforms do not contain all possible harmonics. Square waves, for example, contain only odd harmonics of the fundamental. Sharply peaked, triangular shaped waves also contain only odd harmonics.

Consider Figure 4.13. In this figure the primary voltage and the resulting flux are plotted against the *B-H* curve. The magnetizing force is shown in ampere turns instead of ampere turns per unit length to make the drawing clearer (in other words the unit length is unity). The magnetizing current that is drawn by the primary to produce the flux is drawn below the B–N_pI_p curve. Several points are

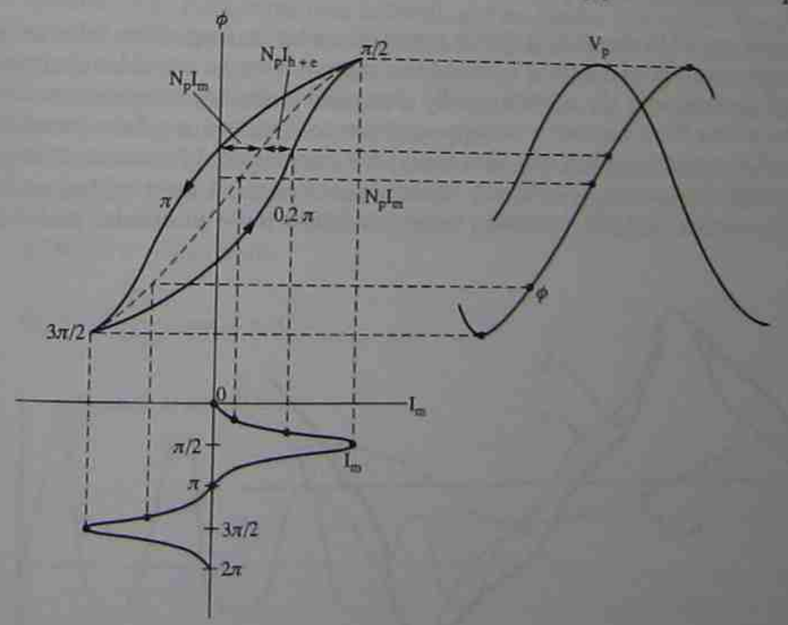


FIGURE 4.13 Magnetizing current

plotted on the curve. Notice that the resulting magnetizing current is sharply peaked. A Fourier analysis of the waveform reveals that it contains, in addition to the fundamental (about 90% of the energy), harmonic energy divided as follows: third harmonic (about 45%), fifth harmonic (about 15%), seventh (about 3%), and lesser amounts of higher harmonics. These values are typical at normal transformer load ranges. If I_{h+e} were plotted from the outer perimeter of the B–$N_P I_p$ curve a flat topped sinusoidal wave as shown in Figure 4.14 would result. Little error results from considering I_{h+e} sinusoidal and this is normally done. Figure 4.14 illustrates the excitation current waveform that results from its two components, magnetization and core loss currents.

In a three-phase system the fundamental waves are 120° out of phase so the current sums to zero at the neutral and the three-phase voltages sums to zero, as we noted in Chapter 2. Let the three-phase voltages of a system be

$$E_1 = E\sin(\omega t)$$

$$E_2 = E\sin(\omega t + 120°)$$

$$E_3 = E\sin(\omega t - 120°)$$

then the third harmonic voltages (primed values) will be

$$E_1' = E\sin(3\omega t)$$

$$E_2' = E\sin(3\omega t + 360°)$$

$$E_3' = E\sin(3\omega t - 360°)$$

which are all in phase, and do not cancel. However, as long as the third harmonic currents can flow the third harmonic voltages will not be a problem because in a wye system with the neutral solidly connected to the source system neutral the line to line third harmonic voltages will sum to zero, and in a delta (in which the third harmonic current can flow easily) the internal third harmonic voltage and voltage drop across Z_{eq} will sum to zero in each phase. If the third harmonic current cannot flow the excitation current is forced to be sinusoidal and the core

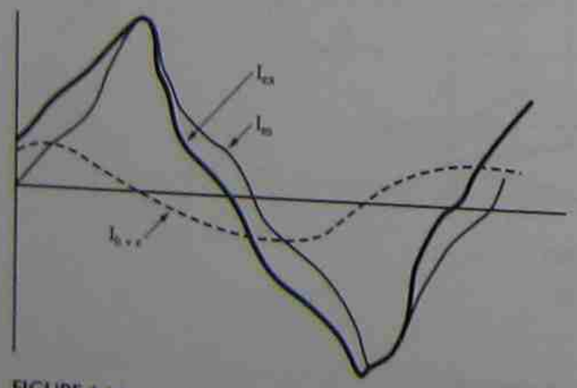


FIGURE 4.14 Excitation current, $I_{ex} = I_m + I_{h+e}$

nonlinear characteristics will be exhibited in the secondary voltage; it will become very nonsinusoidal. The secondary voltage will then have a waveshape similar to the normal excitation current waveshape, and will have a peak voltage nearly twice the normal fundamental voltage. A wye-wye transformer without a grounded neutral has no path for third harmonic current, thus it has a large third harmonic voltage on the secondary.

A transformer with a delta winding has a third harmonic current path and no third harmonic voltage on the line terminals. Because of third harmonic flux cancellation in the core, three leg core constructed three-phase transformers have only a little third harmonic (about 5%) even when connected wye-wye. Wye-wye transformers to be used in applications where third harmonic content is not desirable (this includes most) have a delta connected tertiary sized about one third of the transformer VA rating. The tertiary allows the third harmonic current to flow, and is often used to provide auxiliary power for other substation equipment.

4.3.2 Inrush Current

When a transformer is first energized the initial current is usually much higher (up to 16 times) than the full load current. The initial current surge, which lasts only a few cycles, is the initial magnetization current of the transformer, and is called the inrush current. The inrush current is normally high enough to saturate the core, which is the reason the inrush current is so high. Shell constructed transformers normally have lower inrush current than core constructed transformers because they have more core material, and are harder to saturate. The inrush current of shell constructed transformers is approximately the same whether energized from the high or the low voltage side, but may be twice as high in a core constructed transformer when it is energized from the low side. The inrush current waveform is illustrated in Figure 4.15.

The constant of equation 4.19 is the mathematical expression for the initial magnetic flux required by the transformer. Before energization the only flux is the small amount of residual flux left from previous operation. Evaluating equation 4.19 at $t = 0$ we obtain

$$\Phi_R = -\frac{(\sqrt{2})E_P}{N_P\omega}\cos\alpha + \Phi_c$$

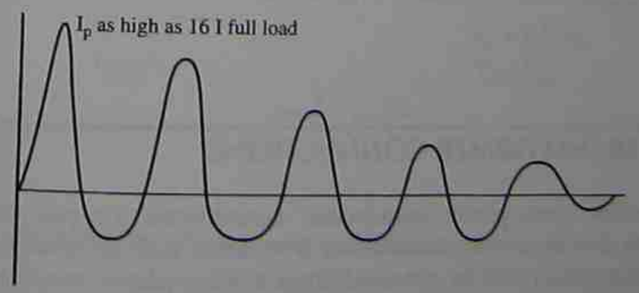


FIGURE 4.15 Inrush current waveform

where

Φ_R is the residual flux

Φ_C is the initial condition flux

α is the angle of e_p at $t = 0$

We may now write

$$\Phi_c = \Phi_{MAX} \cos\alpha + \Phi_R$$

If at $t = 0$, $e_p = 0$, and $\alpha = 0$, then

$$\Phi_c = \Phi_{MAX}(1) + \Phi_R$$

causing the initial total flux to be from equation 4.19

$$\Phi = \Phi_{MAX} \cos(\omega t) + \Phi_{MAX} + \Phi_R$$
$$= 2\Phi_{MAX}$$

Thus the flux required at $t = 0$ is about twice the flux required for normal operation. This much flux saturates the core, causing the reactance of the transformer to be lower than normal. The abnormally low reactance causes the inrush current to be high. The initial flux level is higher than required for normal operation and decays in a few cycles. The abnormally high primary current causes the internal voltage drops across the primary winding reactance and resistance, the first holding the e_p induced on the secondary down and the second dissipating the transient energy. The highest inrush current results when the transformer is energized as the line voltage passes through zero.

If the transformer is magnetized when the line voltage is maximum, $\alpha = 90°$, cos $\alpha = 0$, then we find

$$\Phi_c = \Phi_R$$

which is very small and from equation 4.19 $\Phi = -\Phi_{MAX} + \Phi_R$, which does not saturate the transformer core, so the inrush current is almost zero, allowing $I_P = aI_S$.

It is difficult to time transformer energization to coincide with the peak of the energizing voltage, and the three phases peak 120° apart. Transformer protective devices are designed to recognize and ignore the inrush current since it is inevitable.

4.4 THREE-PHASE TRANSFORMER CONNECTIONS

There are four major three-phase transformer connections for two winding transformers. They are wye-wye, delta-delta, wye-delta, and delta-wye. Additionally each configuration can be obtained from a three-phase transformer or

three single-phase transformers. Figure 4.16 illustrates these four configurations, their line to phase relationships, and their turns ratio.

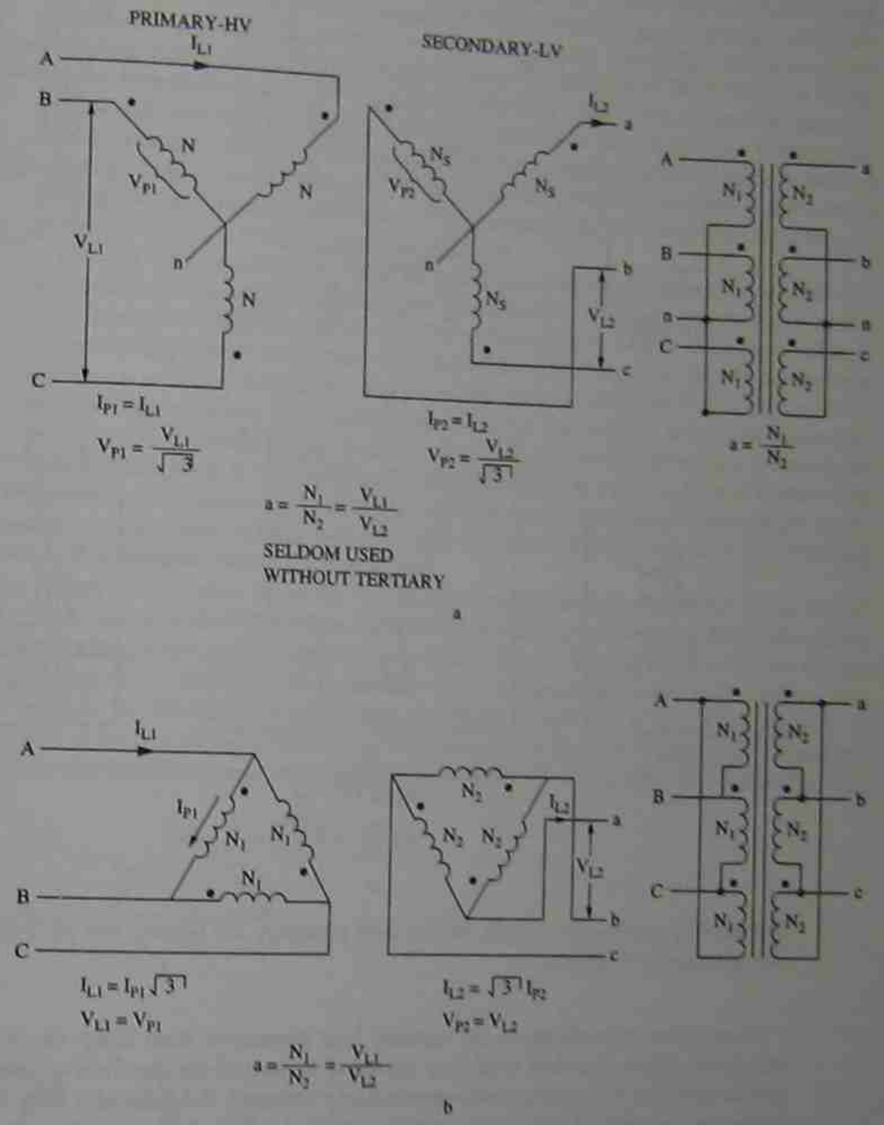


FIGURE 4.16 Three-phase transformer connections include: (a) Y-Y, (b) Δ-Δ

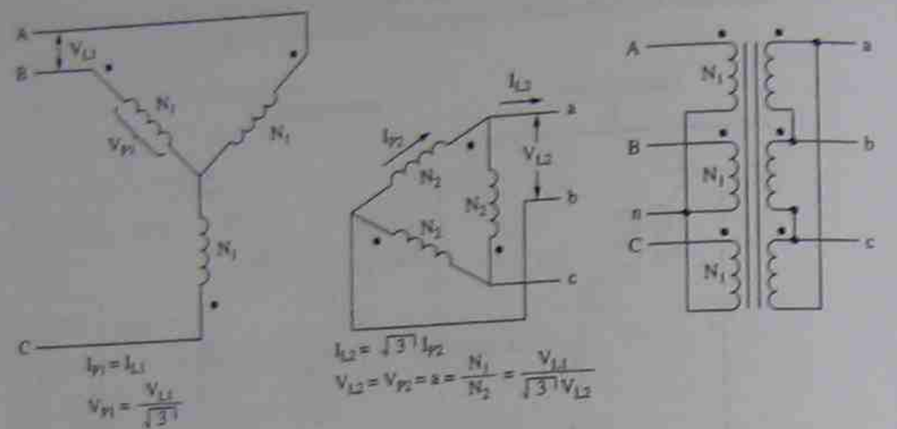


FIGURE 4.16 (continued) (c) Y-Δ, shown with secondary 30° lagging, and (d) Δ-Y, shown with secondary 30° lagging.

Three-phase transformers are usually less expensive than three single-phase transformers because less total core material is needed for the three-phase transformer and the packaging costs are similarly reduced. Additionally they take up less space, are lighter, require less on site external wiring for installation, and are a bit more efficient than three single-phase transformers. When the initial kVA required by an installation is substantially less than the subsequent kVA requirement the initial capital investment can be lowered substantially by using two single-phase transformers connected in an open delta. Recall that an open delta can

supply only 57% of the kVA that three transformers of the size used for the open delta can supply without line voltage imbalance.

Figure 4.16a shows the wye-wye (Y-Y) connection. Recall that this connection has significant third harmonic content on the secondary lines (almost twice the normal peak line voltage) unless the neutral is solidly grounded, and the source neutral is solidly grounded, or a delta connected tertiary is built into the transformer. Even with solid neutral grounding the third harmonic current in the neutral can interfere with signal and telephone lines that run parallel to the neutral. The Y-Y configuration is seldom used without a delta connected tertiary with a capacity of about one third that of the transformer. Recall the tertiary is often used for auxiliary power at the substation. There is no phase shift between the primary and secondary of a Y-Y connected transformer.

The Δ-Δ connection has no harmonic problem and no phase shift from primary to secondary. The only disadvantage with respect to a wye connection is that the delta insulation class must be for the line to line instead of line to neutral voltage. When closing a delta secondary care must be taken to assure proper connection because a wrong connection causes a large fault current to flow (Figure 4.17). Before making the last delta connection measure the voltage across the open connection. If the voltage is less than the line voltage (third harmonics prevent the voltage being zero if the primary is wye connected) the connection is correct and the connection can be made after the power is removed. If the connection is incorrect the measured voltage will be larger than the line voltage and the winding must be reversed before it is connected.

Figures 4.16b and c show the Y-Δ and Δ-Y connections respectively. There is a 30° phase shift in both connections. United States industry convention is to connect the secondary so it lags the high voltage primary by 30°. Figure 4.16 shows the V_2 side lagging the V_1 side 30°. When possible the Y is connected to the high voltage side because the insulation requirements are lower (recall that Y phase voltage is $1/\sqrt{3}$ that of the line voltage). The Y may be necessary on the low voltage side because of the distribution system requirements as in 480/277 V and 208/120 V installations.

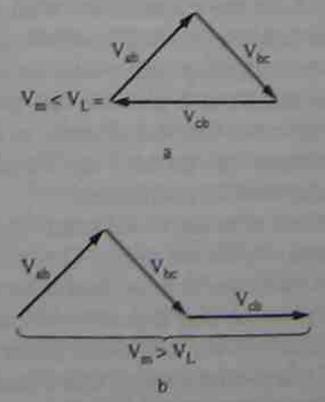


FIGURE 4.17 Delta secondary connection (a) properly connected and (b) incorrectly connected

4.5 NEED FOR TRANSFORMER PROTECTION

Transformers, especially power transformers, are expensive. The investment in a transformer needs to be protected. The transformer must be protected from overcurrent due to faults on its secondary circuit, and from over voltage, which is usually caused by lightning. The protective devices are discussed in detail in a later chapter, but they are briefly introduced here.

Lightning protection is provided by lightning arresters. At one time these were spark gaps of controlled gap length, the voltage being set by the gap length. Bulk metal oxide semiconductors are now popular because they can absorb large amounts of power with a modest terminal voltage rise. Zinc oxide lightning arresters are the most popular now. The voltage at which the lightning arrester begins conducting, absorbing power, and preventing further voltage rise on the line is set at a voltage below the maximum insulating voltage of the transformer and above the maximum operating voltage of the transformer. Notice in Figure 4.18 that lightning arresters are used on both the primary and secondary side of larger power transformers because lightning can strike on either side. Only the primary side of pole top transformers for buildings will have lightning arresters.

Overcurrent protection is provided by circuit breakers and their associated protective relays, and fuses. A fuse opens on overcurrent. Higher voltage fuses are expulsion type, which means that they contain a means of blowing out the arc caused by their operation to interrupt a fault current. Circuit breakers open electrical contacts when they receive a trip signal from one of their associated relays. The opening is done by driving the contacts apart with powerful springs (which are compressed with an air driven piston in large power breakers) or, on smaller circuit breakers, with springs compressed with a motor or a manual ratchet. The arc across the contacts is extinguished by oil in oil circuit breakers, pressurized air blown across the contacts in air breakers, and sulfur hexaflouride in SF_6 breakers. Circuit breakers are used on the secondary side of the transformer with a fuse back up on the primary side in case the breaker fails to operate (a secondary overcurrent will cause a primary overcurrent), or on both the primary and secondary sides of power transformers. The primary protection also protects the primary feeder if something should fail inside the transformer. The transformer in Figure 4.18 uses a secondary circuit breaker with a primary fuse for back up. Residential distribution transformers usually have a primary fuse for protection.

Current transformers and potential transformers, to be discussed more later, provide line current and voltage information respectively for the relays. The relays are electromechanical or microprocessor controlled electronic systems that detect overcurrent, over voltage, and other fault conditions on the line. If fault conditions are detected the relays send a trip signal to the circuit breaker to open it. Some relays can send a reclose signal to properly equipped relays after sensing that a fault condition has been removed. Protective relaying equipment is very expensive and is usually used only on larger, more expensive substation and network transformers.

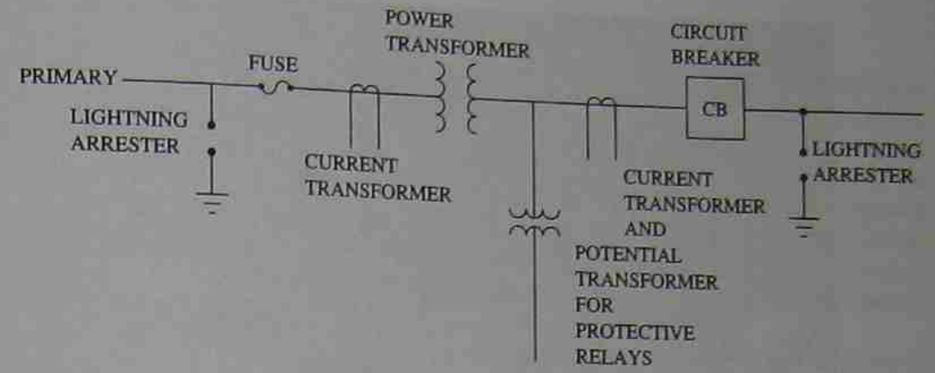


FIGURE 4.18 Power transformer one-line drawing with protection

4.6 TYPES OF DISTRIBUTION TRANSFORMERS

Transformers used in distribution include: power transformers; autotransformers, which may also be power transformers; distribution transformers; and instrument transformers. We will now examine each type.

4.6.1 Power Transformers

Power transformers are normally oil immersed transformers used for substations and connection to large commercial and industrial customers. Smaller power transformers may be dry types used primarily for connection to commercial customers who purchase their own transformers. Figure 4.19 is a photograph of a power transformer for a distribution substation. Figure 4.20 is a diagram of the same general type of transformer. Note the high and low voltage bushings for connection, the cooling fins, and the location of the current transformers in the bushings (usually two per bushing).

Power transformer capacities vary over a wide range. A smaller distribution substation may have a power transformer rated at 1000 kVA, and a large one may have a power transformer rated at 30,000 kVA. Subtransmission substations will have even larger power transformers. Power transformers are made with capacities to over 1000 MVA. Impedances will range from 1 to 3% at around 2.5 kV at 3 kVA, around 4% at 15 kV and intermediate kVA ratings, to as high as 20% at 230 kV and high kVA ratings. Lower voltage transformers typically have lower impedances. Power transformers are designed for very high efficiency, and are routinely maintained. As noted in the last section, power transformers are well protected both for safety and economy. Almost all larger power transformers are three-phase as opposed to three single-phase units.

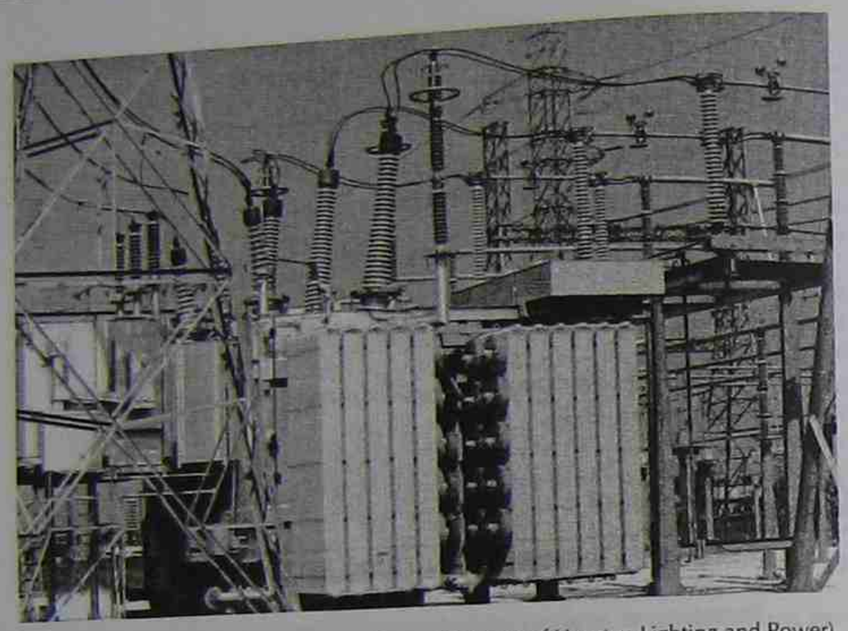


FIGURE 4.19 Photograph of power transformer (Courtesy of Houston Lighting and Power)

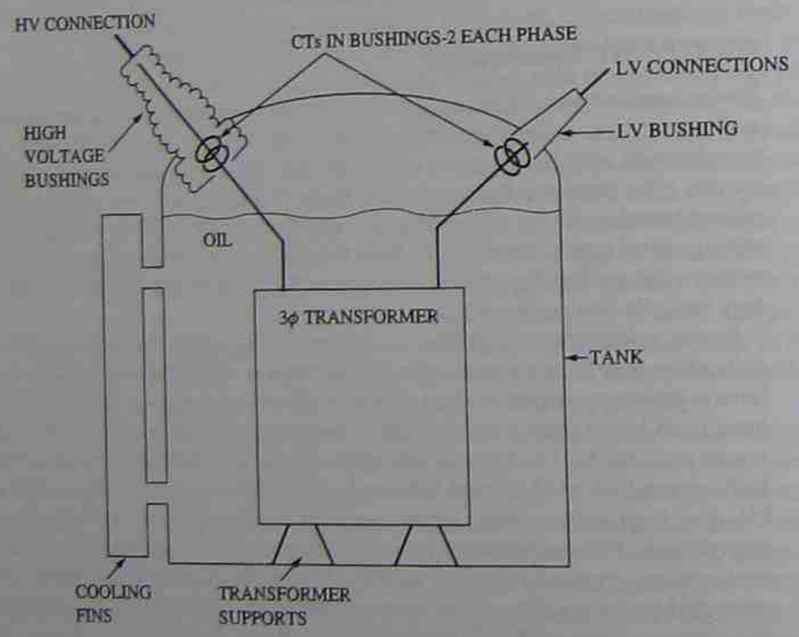


FIGURE 4.20 Power transformer diagram

4.6.2 Autotransformers

Autotransformers are one winding transformers that are often used in transmission and subtransmission substations. Figure 4.21a shows an autotransformer schematic symbol. Notice that the primary and secondary sides are not isolated from each other. This means that if the secondary neutral, which is common to the primary neutral, is opened for any reason the full primary voltage could appear on the secondary side, as shown in Figure 4.21b, with disastrous results. Unsafe conditions would result for people as well as damage to the low voltage side protective devices and equipment. For this reason autotransformers are never used as the final transformer in distribution substations.

From Figure 4.21a we see that the primary and secondary kVA must be equal in a lossless transformer, so if the turns ratio is

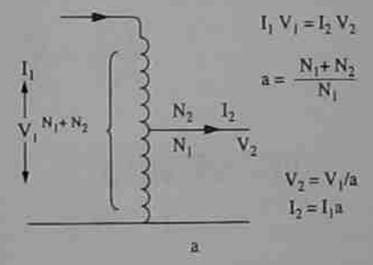
$$a = \frac{N_1 + N_2}{N_1}$$

and the same $d\Phi/dt$ is cutting both windings

$$V_2 = V_1/a$$

$$I_2 = I_1 a$$

In other words the ideal transformer relationships are approximately true for autotransformers as well as isolation (conventional) transformers.



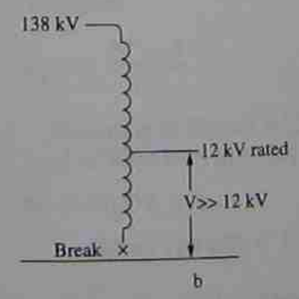


FIGURE 4.21 Autotransformer (a) Schematic diagram, step down and (b) Safety consideration

Autotransformers differ from isolation transformers in that the lack of isolation between the primary and secondary sides allows some of the transferred power to be conducted to the secondary side instead of being transferred by magnetic induction. The relative amounts of power transferred by conduction and induction vary, as we shall see, with the turns ratio. Because some of the transferred power is conducted autotransformers need less core material for each kVA transferred than do isolation transformers. Thus autotransformers are smaller, lighter, more efficient, and less costly for a given kVA rating than isolation transformers. For this reason they are used in transmission and subtransmission substations where their lack of isolation poses no safety hazard to the public.

The *Autotransformer Rating Advantage* is because of the reduced core loss. Refer to Figure 4.22a. Let N_1 be the common turns and N_2 be the series turns. Then

$$\frac{V_2}{V_1} = \frac{V_1 + (N_2/N_1)\,V_1}{V_1}$$
$$= 1 + (N_2/N_1)$$
$$= N'$$

giving

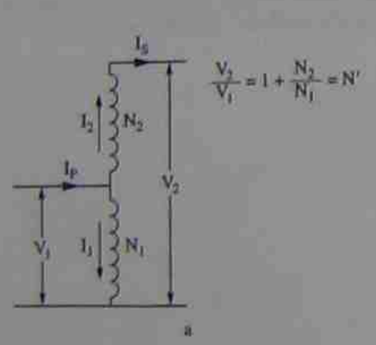


FIGURE 4.22 Autotransformer diagram for discussion of (a) ratio and (b) rating

$$\frac{N_2}{N_1} = N' - 1$$

The ampere turns must be equal in each winding, so

$$I_1 N_1 = I_2 N_2$$

therefore

$$I_2 = I_1 \frac{N_1}{N_2}$$

$$I_P = I_1 + I_2 = I_1 + I_1(N_1/N_2)$$
$$= I_1[1 + (N_1/N_2)]$$
$$= I_1\left(1 + \frac{1}{N' - 1}\right)$$
$$= I_1\left(\frac{N' - 1}{N' - 1} + \frac{1}{N' - 1}\right)$$
$$= I_1 \frac{N'}{N' - 1}$$

Let

S_I = VA rating as an isolation transformer = $I_P V_1$

S_A = VA rating as an autotransformer = $I_1 V_1$

$$\frac{S_A}{S_I} = \frac{V_1 I_1}{V_1 I_P}$$

$$= \frac{V_1 I_1}{V_1 I_1[N'/(N' - 1)]}$$

$$= \frac{N' - 1}{N'}$$

Therefore

$$S_A = S_I \frac{N' - 1}{N'} \tag{4.21}$$

Referring to Figure 4.22b we find the induced kVA of the autotransformer for a load of 2000 kVA at 69 kV is

$$N' = N_2/N_1 + 1$$
$$= (69\text{ kV}/69\text{ kV}) + 1$$
$$= 2$$

and

$$S_A = 2000\ \text{kVA}\frac{2-1}{2}$$

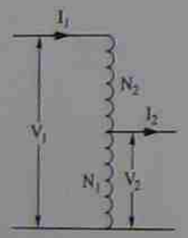
$$= 2000\ \text{kVA}\ (0.5)$$

$$= 1000\ \text{kVA}$$

Thus the autotransformer needs only the core to induce 1000 kVA to supply a load of 2000 kVA. As N′ gets larger (larger step-up or step-down ratio) the advantage becomes less favorable. For example if $N' = 5$, $S_A = 0.8S_I$. Notice that N_1 is the winding shared by the primary and secondary circuits. Figure 4.23 shows the kVA transferred by conduction and by induction in both the step-up and step-down connections.

The impedance of an autotransformer is handled like that of an isolation transformer if it is in percent or per unit. The impedance of autotransformers is lower than that of isolation transformers, often as low as 4% for high voltage transformers. Therefore autotransformers tend to have good voltage regulation but allow high fault current.

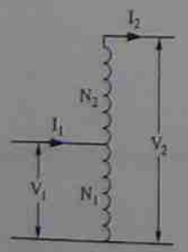
Autotransformers are usually wye connected with a built-in tertiary with a capacity of about 30% of the autotransformer kVA rating.



$|V_1 - V_2|\ I_1$ TRANSFORMED

$V_2 I_1$ CONDUCTED

a



$|V_2 - V_1|\ I_2$ TRANSFORMED

$V_1 I_2$ CONDUCTED

b

FIGURE 4.23 Transformed and conducted VA (a) step down and (b) step up

Example 4.3:

What is the required rating of an autotransformer to be used to step 900 kVA down from 69 kV to 46 kV?

Solution:

Using equation 4.20

$S_A = S_I[(N' - 1)/N']$

where

$$N' = V_1/V_2$$

$$= \frac{69\ \text{kV}}{46\ \text{kV}}$$

$$= 1.5$$

$$S_A = 900\ \text{kVA}\frac{1.5-1}{1.5}$$

$$= 300\ \text{kVA}$$

4.6.3 Distribution Transformers

Distribution transformers are those that are used to provide the final link with the customer. The distribution voltage is brought down to a level that is safe to use on the customer's premises. The primary voltage is between 34.5 kV and 2.3 kV, single or three phase depending on the customer size, and the secondary is normally either 480Y/277 V, 208Y/120 V three phase or 240/120 V single phase. A second transformer or a tertiary winding always provides 120 V for a building. Very large commercial and industrial customers may be fed at 12.5 kV or even higher voltages, and have a distribution substation of their own on their property. Transformers for services of this size are referred to, and are, power transformers.

Distribution transformers may be dry type, in which the windings are *not* immersed in oil. These are usually used in moderate to small commercial installations where cost is the primary consideration.

The most familiar distribution transformer is the pole top, shown in Figure 4.24. These are normally in the 15 to 100 kVA range. Three-phase service with pole top transformers is usually provided by a bank of three transformers, although three-phase pole top transformers are also used. Pole types are oil immersed, sealed, and seldom have any auxiliary cooling other than raised fins on the case. They are built with enough excess cooling capacity to sustain 200% overloads for hours. A typical high quality pole top transformer has a life expectancy of up to 40 years. They are protected with a minimum of a primary fuse, and a lightning arrester at or near the transformer primary.

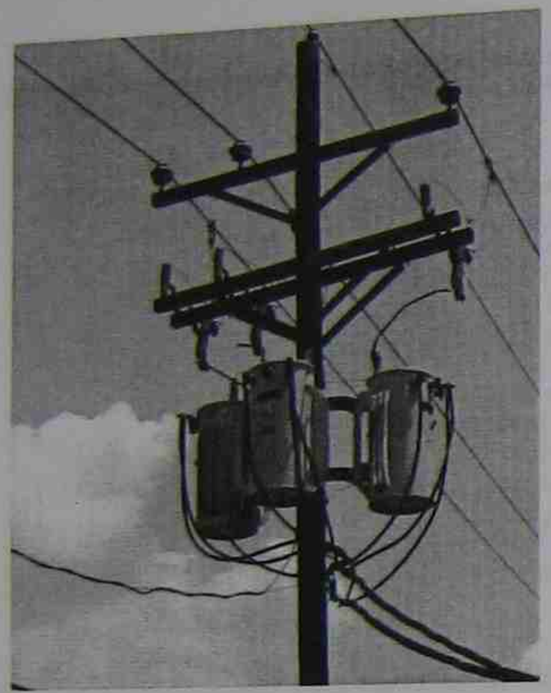


FIGURE 4.24 Photograph of pole top distribution transformer. Three-phase cluster on single pole (Courtesy of Gulf States Utilities Corp.)

The growth of underground service has made the pad-mount transformer almost as familiar a sight as the pole top. Pad-mount transformers are oil immersed, mounted in a steel case with a front that closes to prevent injury, and installed on a concrete pad. A photograph of a pad-mount transformer with the front open is shown in Figure 4.25. Residential pad-mount transformers are usually single phase, primary with two or more secondaries, each providing power for three or four residences (each pad-mount transformer feeds eight to 12 houses). Commercial pad-mount transformers have a three-phase primary. The minimum protection is primary fusing. Elbow connections have been very important in making underground service economical. A cable with a conductor-insulator-concentric neutral-insulated sheath construction can be directly buried (no conduit), brought up from underground, and connected to the mating concentric connection on the transformer in a fairly small space with an elbow connector. The primary connections are completely insulated outside of the transformer (called dead front primary) with the access door open. Elbows rated at below 200 A are usually load break.

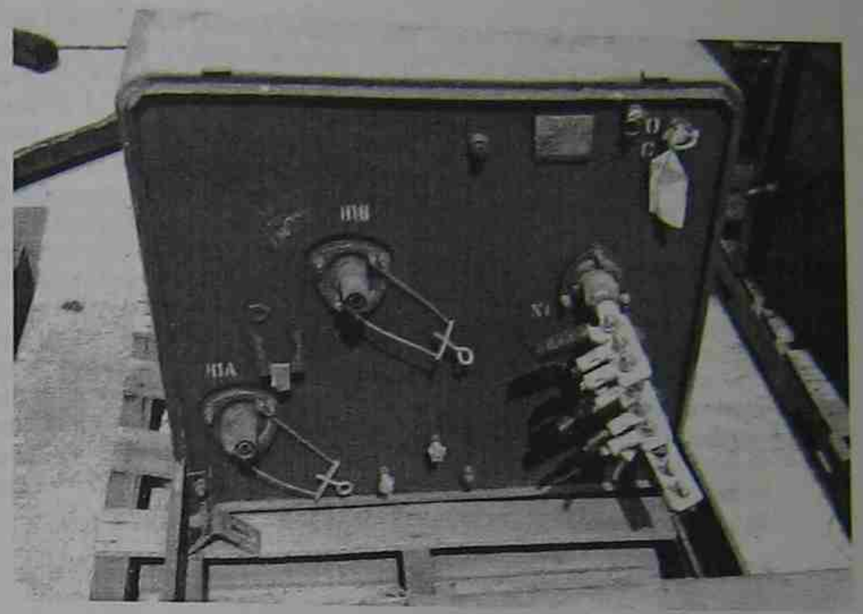


FIGURE 4.25 Photograph of pad-mount transformer with the front open (Courtesy of Houston Lighting and Power).

4.6.4 Instrument Transformers

Instrument transformers provide line current and voltage information to protective relays and control systems at low power levels. Two types of transformers are in this class: current transformers and potential transformers.

Figure 4.26 is a diagram of a *current transformer* (*CT*), it is a secondary winding of many turns wound on a torroid core. The primary is the conductor on which current is to be measured. The cores need not be torroids, but torroids provide the

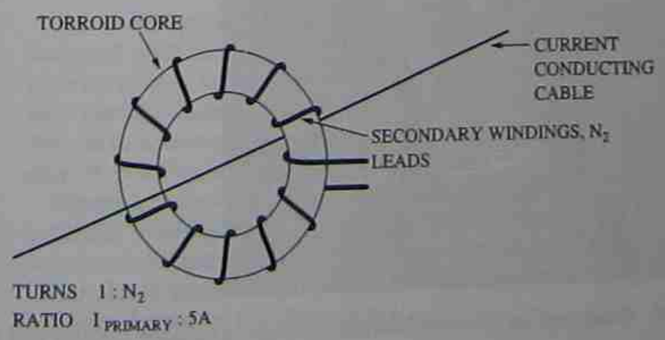


FIGURE 4.26 Current transformer

lowest leakage for better mutual flux coupling. Current transformers are wound for a secondary current of 5 A at the maximum current they are to measure because the instruments to which they provide information are 5 A full scale (or range). Thus the CT ratios are expressed as *primary amperes:5 A* or sometimes primary current as a ratio:1, where the 1 is taken as 5 A. Therefore, a 100:1 CT is read as 500 A:5 A. CTs must be very well insulated between the primary and secondary because the primary line may be at an extremely high voltage. For this reason high voltage CTs are quite large. Current transformers are designed for use with low impedance current sensors and coils. When they are not attached to the instrument their secondary leads are shorted together to prevent induced secondary turn-to-turn voltage from exceeding the insulation rating of the secondary wire.

Burden refers to the load imposed on an instrument transformer, usually in VA. The accuracy is specified with a specific range of burden. The voltage drop across the internal impedance of a CT causes the accuracy to decrease with increased burden. The CT secondary current is offset from the primary current in phase by a small amount because of the excitation current drawn by the CT. The angular error introduced by the CT magnetizing current is usually less than 1°. Figure 4.27 is a photograph of a current transformer.

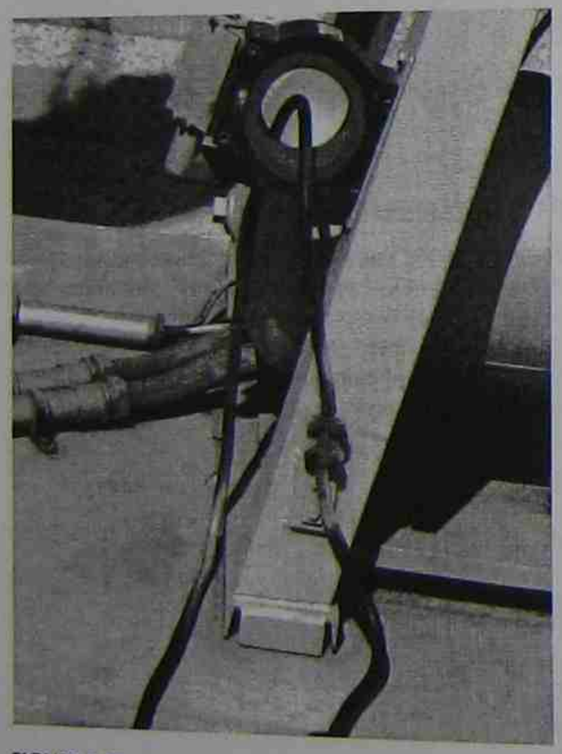


FIGURE 4.27 Photograph of current transformer (Courtesy of Houston Lighting and Power).

Potential transformers step line voltage down to the 0-150 V range for which most instruments are designed. Like CTs, potential transformers (PTs) are very large for their VA rating because of the amount of insulation required for the high voltage side. A photograph of a PT is shown in Figure 4.28.

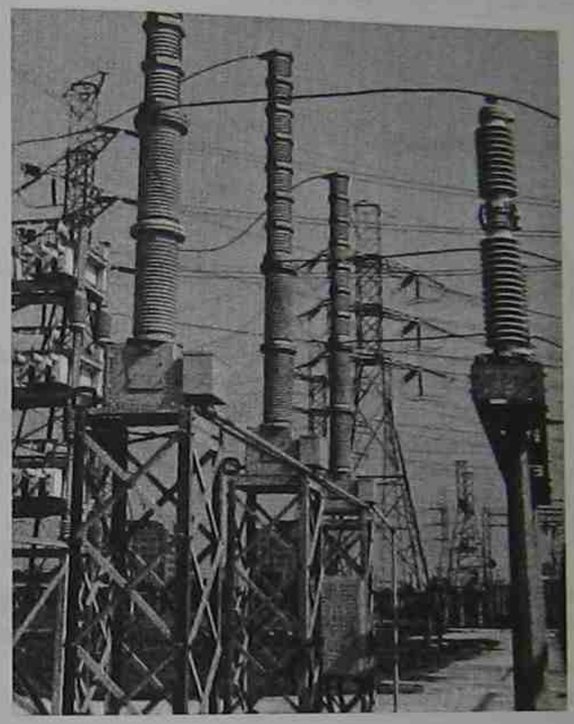


FIGURE 4.28 Photograph of potential transformers (Courtesy of Gulf States Utilities)

The major errors incurred in PTs are ratio error and phase error. PTs are designed with compensation for their series impedance by setting N_1/N_2 to provide the correct voltage ratio at a specific burden. The voltage ratio varies slightly with burden change. Phase error results from the PT magnetizing current. Phase error is seldom more than 0.5° and usually closer to 0.1° for a PT with a ratio accuracy of $\pm$ 0.3% (said to be 0.3 accuracy class).

Figure 4.29 shows a less expensive and less accurate method of providing line potential information. A capacitive voltage divider is used to provide the measurement voltage. Often the capacitance between the high voltage bushing and a metal sleeve around a portion of the bushing serves as C_1, and the capacitance between the sleeve and the case as C_2.

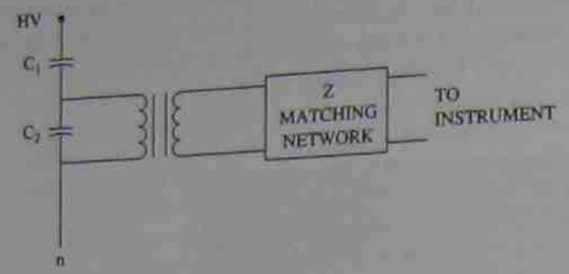


FIGURE 4.29 Capacitive potential divider

4.7 TRANSFORMER VOLTAGE REGULATION

Voltage regulation is a measure of how close the secondary voltage remains to the nominal value as the load varies in amount and power factor. The voltage drops across the internal impedance of the transformer cause the voltage variation at the secondary terminal. Let S be secondary, FL be full load, and NL be no load, then voltage regulation (VR) at full load is

$$\text{Voltage Regulation (VR)} = \frac{V_{SNL} - V_{SFL}}{V_{SFL}} \text{ pu} \tag{4.22}$$

and percent voltage regulation = pu voltage regulation × 100 Voltage regulation can be calculated for any load but full load regulation is of the most interest.

4.7.1 Voltage Regulation Calculation

Figure 3.7 showed why secondary voltage varies with load and power factor changes. We now wish to find a reasonably easy and accurate method of calculating the secondary voltage as the load changes. The voltage drop across the transformer internal impedance will be, to a very close approximation, the same whether the primary or secondary voltage is held constant. We will hold the secondary voltage constant for our calculations, in other words V_S is the reference phasor. The induced secondary voltage, $E_S = V_p/a$ is the variable voltage. The equivalent circuit referred to the secondary is shown in Figure 4.30a.

Figure 4.30b shows the phasor diagram of the secondary circuit with a lagging power factor load. The IR_{eq} voltage drop is in phase with the load current, and the IX_{eq} voltage drop is 90° ahead of the load current. The dotted lines dropping to the dotted line extending at the same angle as the load current make the phasor diagram into a right triangle. From the right triangle we can write

$$E_S = (V_S\cos\theta + IR_{eq}) + j(V_S\sin\theta + IX_{eq})$$

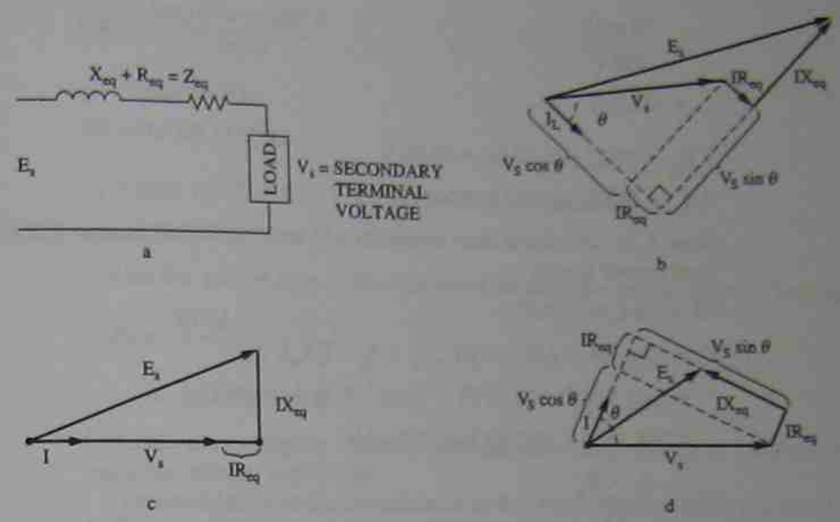


FIGURE 4.30 Diagram of transformer voltage regulation, V_S as reference (a) Equivalent circuit (b) PF lagging (c) unity power factor and (d) PF leading.

The same equation can be used for the PF = 1 load of Figure 4.30c except that cosθ = 1, and sinθ = 0. A close inspection of Figure 4.30d reveals a right triangle that yields a similar equation except the opposite side is $V_S\sin\theta - IX_{eq}$. A general equation can now be written as follows

$$E_S = (V_S\cos\theta + IR_{eq}) + j(V_S\sin\theta \pm IX_{eq}) \tag{4.23}$$

where last term is + for a lagging power factor, and − for a leading power factor.

An additional advantage to using the secondary terminal voltage as a reference vector is that aE_S is the primary voltage necessary to provide the given secondary voltage

Example 4.4:

A 2300V/240V, 75 kVA transformer has $X_{eq} = 0.07\ \Omega$ and $R_{eq} = 0.02\ \Omega$ referred to the low side. Calculate E_S with a constant $V_S = 240$ V for load power factor of 0.8 lagging, unity, and 0.7 leading, and the voltage regulation for each.

Solution:

First we find the rated current and the voltage drops across the transformer internal reactance and resistance.

$$I_S = \frac{\text{kVA}}{V}$$

$$= \frac{75\ \text{kVA}}{240\ \text{V}}$$

$$= 312.5\ \text{A}$$

$I_S X_{eq} = 312.5\ \text{A}(0.07\ \Omega) = 21.88\ \text{V}$

$I_S R_{eq} = 312.5\ \text{A}(0.02\ \Omega) = 6.25\ \text{V}$

Now E_S is calculated from equation 4.23 and VR from equation 4.22 for each load power factor.

PF = 0.8 LAGGING

$E_S = (V_S \cos\theta + I_S R_{eq}) + j(V_S X_{eq} + I_S \pm I_S X_{eq})$

$= [240\ \text{V}(0.8) + 6.25\ \text{V}] + j[240\ \text{V}(0.6) + 21.88\ \text{V}]$

$= 198.25\ \text{V} + j165.88\ \text{V} = 258.49\ \text{V}$

$$\text{VR} = \frac{E_S - V_S}{V_S}$$

$$= \frac{258.49\ \text{V} - 240\ \text{V}}{240\ \text{V}}$$

$$= \frac{18.49\ \text{V}}{240\ \text{V}}$$

$= 0.077$ pu or 7.7%

Note that since

$$a = \frac{V_P}{V_S}$$

$$= \frac{2300\ \text{V}}{240\ \text{V}}$$

$= 9.583$

for a secondary voltage of 240 V with a 75 kVA load at a PF = 0.8 the primary voltage must be

$V_P = aE_S = 9.583(258.49\ \text{V}) = 2477\ \text{V}$

PF = 1

From equation 4.23 again

$E_S = (240\ \text{V} + 6.25\ \text{V}) + j(0\ \text{V} + 21.88\ \text{V})$

$= 247.22\ \text{V}$

$$\text{VR} = \frac{247.22\ \text{V} - 240\ \text{V}}{240\ \text{V}}$$

$= 0.03$ or 3%

PF = 0.7 LEADING

$E_S = [240\ \text{V}(0.7) + 6.25\ \text{V}] + j[240\ \text{V}(0.714) - 21.88\ \text{V}]$

$= 229.6\ \text{V}$

Notice the minus sign in the last term because the power factor is leading.

$$\text{VR} = \frac{229.6\ \text{V} - 240\ \text{V}}{240\ \text{V}}$$

$= -0.043$ or -4.3%

Output voltage higher than the induced secondary voltage is indicated by negative voltage regulation.

The impedance of the transformer in this example was about 7%, which is high for a transformer of this capacity and voltage. The higher than typical impedance made the results easy to see. Normal impedance for a transformer of the voltage and capacity of the one in the example is about 3 to 4%. The curious and interested student may wish to work the example problem with a transformer whose impedance is in this range. The problem is identical for a single-phase transformer or a balanced three-phase transformer as long as per phase impedance and current are used.

4.7.2 Voltage Regulation—Per Unit Quantities

Refer to Figure 4.31. Let a be calculated from the transformer name plate voltages (as is the standard practice). Then by Kirchoff's law

$V_1/a = V_2 + I_2 Z_{eq}$

Dividing both sides by the base voltage of the secondary side, V_{2B} we obtain

$$\frac{V_1}{aV_{2B}} = \frac{V_2}{V_{2B}} - \frac{I_2 Z_{eq}}{V_{2B}}$$

but $a V_{2B} = V_{1B}$ and $V_{2B} = I_{2B} Z_{2B}$ so we obtain from the preceding equation

$V_{1pu} = V_{2pu} + I_{2pu} Z_{eqpu}$

Let V_{2pu} be the reference phasor as before, then

$I_2 = I_{2B}$

but

$I_{2pu} = 1$

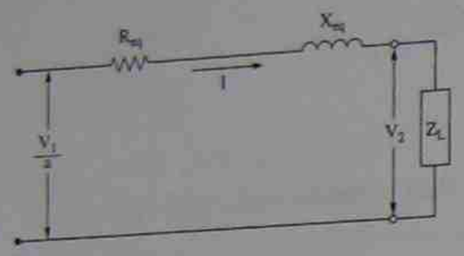


FIGURE 4.31 Voltage regulation calculation, per unit values

Now the equation becomes

$$V_{1pu} = 1\angle 0° + 1\angle \pm \theta\,(Z_{eqpu}) \tag{4.24}$$

The voltage regulation equation can now be written

$$VR = \frac{|V_1/aV_{2R}| - V_{2R}}{V_{2R}}$$

Dividing by results in

$$VR = \frac{|V_1|}{|V_{1R}|} - 1$$
$$= |V_{1pu}| - 1$$

Example 4.5:

A transformer has a per unit $R = 0.03$ and $X = 0.07$. The load power factor is 0.85 lagging. Calculate the voltage regulation.

Solution:

First calculate Z_{pu}

$Z_{pu} = 0.03 + j0.07 = 0.076\angle 66.8°$

From equation 4.24

$V_{1pu} = 1\angle 0° + 1\angle -31.78°(Z_{pu})$
$= 1\angle 0° + 0.076\angle(66.8° - 31.78°)$
$= 1 + 0.062 + j0.044$
$= 1.062 + j0.044$
$= 1.063\angle 2.35°$ pu

Finally

$$VR = |V_{1pu}| - 1$$
$$= 1.063 - 1$$
$$= 0.063 \text{ or } 6.3\%$$

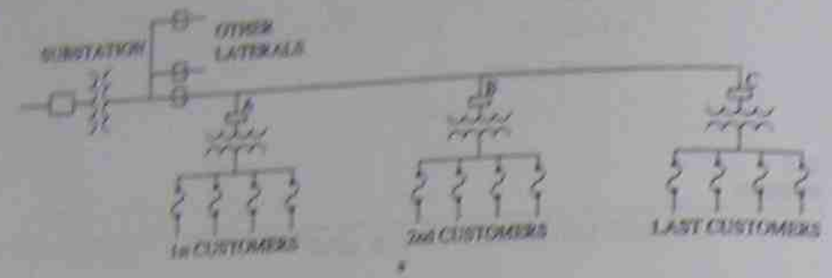
4.8 VOLTAGE DROP ALONG THE LINE

Customer taps along the line draw current through the line causing the voltage to drop as one gets further from the substation. This is illustrated in Figure 4.32, where Figure 4.32a is the lateral from a line near a substation to pad-mount transformers, each providing service to four residences. Figure 4.32b and c illustrate the voltage drop along the line with a heavy load and a light load respectively. Note that if the voltage at the substation is set at the nominal voltage the customers at the end of the line have too low a voltage under heavy load. If the voltage is set so that the customers at the end of the line receive the nominal voltage under heavy load the customers near the substation have too high a voltage, and the voltage is too high for all of the customers at light load. A compromise voltage setting must be chosen so that the voltage is at an acceptable level for all of the customers regardless of the load, and the line drop must be acceptably low under all load conditions. A favorable compromise of voltage drop and voltage setting is not always possible for all load conditions, so other means of voltage regulation have been devised for such conditions.

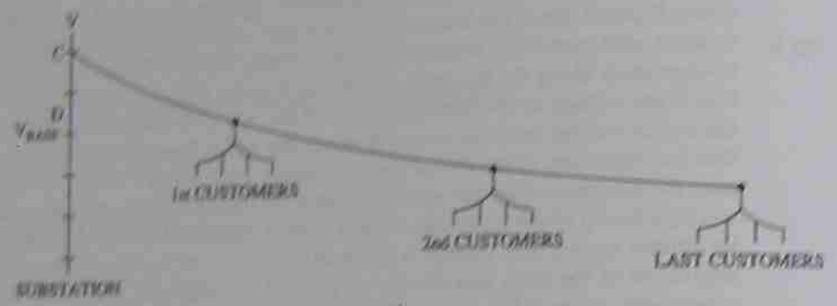
4.8.1 Capacitors for Voltage Regulation

Since most loads are lagging and the line reactance is much higher than the line resistance, switching *shunt capacitors* across the line will increase the voltage by reducing the inductive VARs drawn as in power factor correction. One can also think of the capacitors as regulating voltage as in transformer voltage regulation. However, if so much capacitance is switched across the line that the current becomes leading, the method is not cost effective because the VARs begin to rise again. Shunt capacitors are only helpful with lagging load power factors.

The capacitors are installed near load points. To raise the voltage along the lateral of Figure 4.34a the capacitors are installed at points A, B, and C. Capacitor installations are usually in three banks, one for each of the three phases. Switched capacitors can be, and sometimes are, installed on long single-phase distribution lines. A three-phase capacitor bank is shown in Figure 4.33. Fixed value banks must be selected so that the change of voltage between light and heavy loads is not excessive, and is centered around the nominal voltage. Switched capacitor banks, which contain a number of smaller capacitors that are switched in parallel to obtain the needed capacitance, are used when a compromise cannot be found because the



a



b

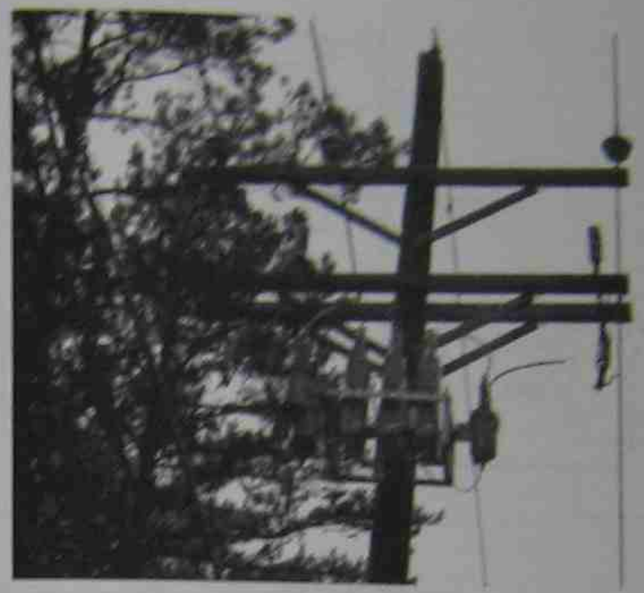


c

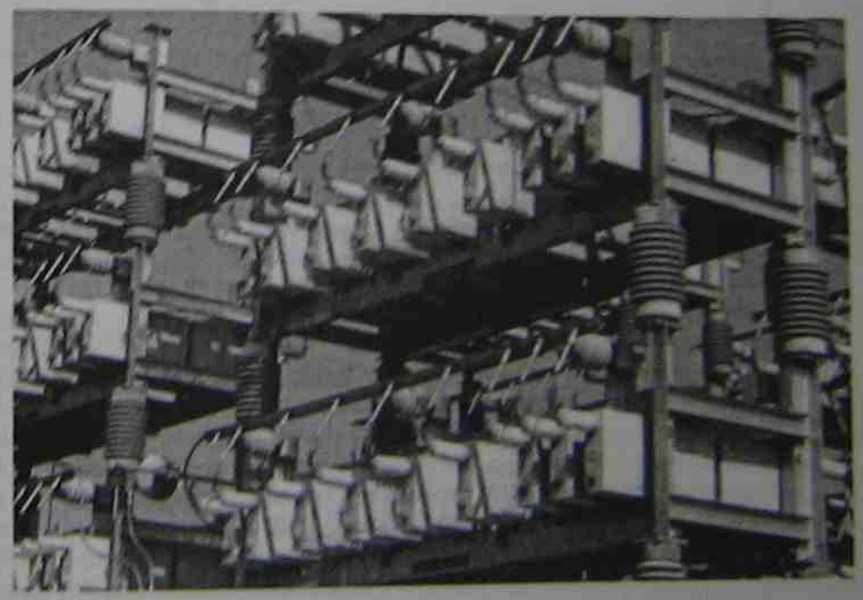
FIGURE 4.32 Voltage drop along line (a) Representation of distribution circuit (b) line voltage drop with heavy load and (c) line voltage drop with light load.

load variation is too large. Switched capacitor banks are expensive because they must have sensing equipment to monitor the line voltage and control equipment to activate the proper switching. They are installed only when essential.

All capacitor banks require protection. The entire bank will be protected with a fuse or circuit breaker, and each capacitor will be fused, as shown in Figure 4.34. The capacitors can be connected either delta or wye. The ungrounded wye is the preferred configuration because if a capacitor should short out in one leg of the wye the other two legs will limit the fault current.



a



b

FIGURE 4.33 Capacitor bank (a) poletop (b) substation (Courtesy of Houston Lighting and Power)

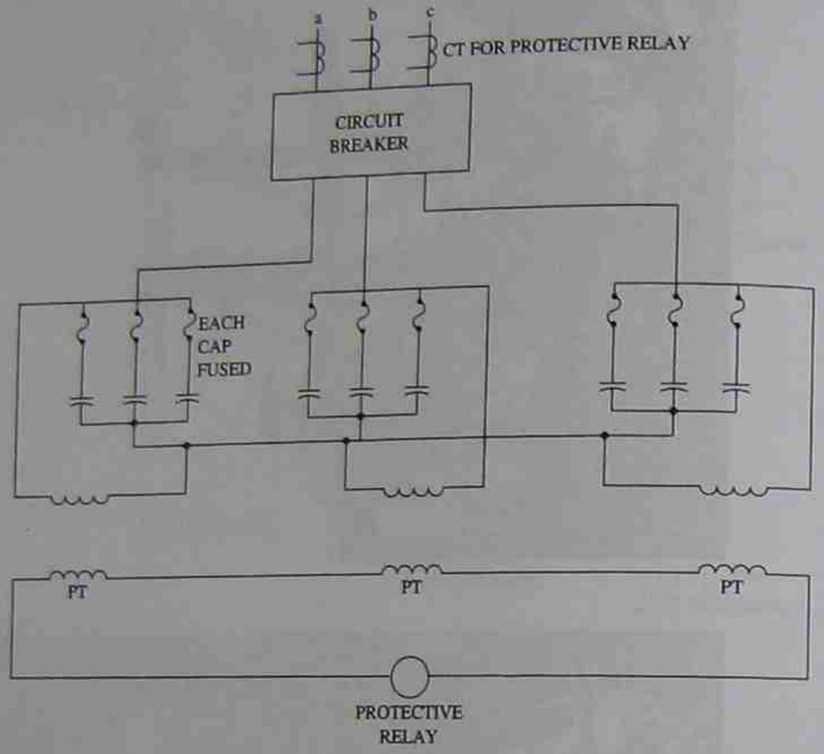


FIGURE 4.34 Ungrounded wye capacitor bank.

The charging of the capacitors can cause a large current transient when energized. Small reactors (with $X_L << X_C$) in series with the capacitors effectively reduce the inrush current by limiting the rate of rise of the current.

Shunt capacitors are usually installed in radial feeders. Their chief effect is to correct for load power factor, and their only current is from the VARs. *Series capacitors* are connected in series with the line and carry full line current. The capacitor voltage as well as current varies with the load. The capacitive reactance of the series capacitance is used to cancel the inductive reactance of the line to reduce the voltage drop along the line. The principle is shown in Figure 4.35: in a the line impedance results in the voltage drop and receiving voltage shown in b; in c the capacitive reactance cancels a portion of the line inductive reactance causing the receiving voltage to rise, as shown in part d of the figure. The series capacitance is set to undercompensate the reactance a little to prevent excessive line voltage rise during heavy loading transients such as occur with large motor starting. Series capacitors can be switched or fixed. They are protected in much the same way as are shunt capacitors.

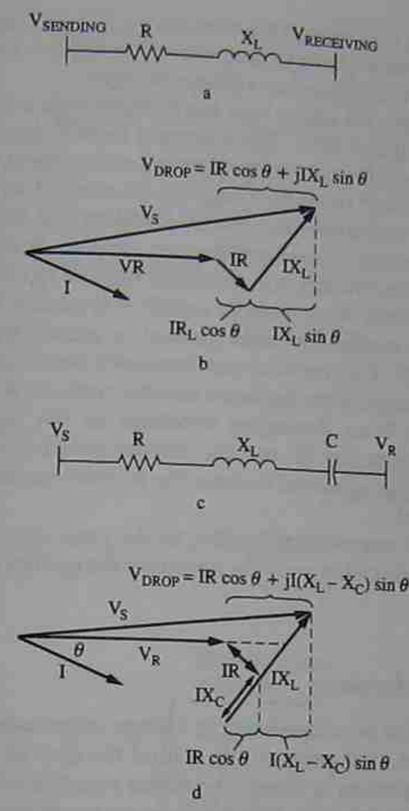


FIGURE 4.35 Series capacitor. (a) Line equivalent circuit (b) Phasor diagram with lagging power factor load (c) Equivalent circuit with capacitor and (d) Phasor diagram with capacitor (same V_S as in b).

4.8.2 Tap Changers

Another method of line voltage regulation is tap changing. Taps are connections on a transformer winding that change the turns ratio slightly. The ratio change is normally ± 10%, although ± 7.5%, and ± 5% are also available. The ratio change steps vary from 2.5% to 32 steps to cover the now normal range of ± 10% (0.625% per step). Normally the taps are located on the primary because less current has to be switched by the tap changing connections than would be necessary on the secondary. Tap changers can be manual or automatic. Some distribution transformers and distribution substation transformers have manual tap changers so that added load can be compensated for, such as a new shop in a shopping center in the first case or a new street of residences in the second. Motor driven automatic tap changers are necessary for voltage regulation with widely fluctuating loads. This

is called tap changing under load (TCUL) or load tap changing (LTC). LTC is used in distribution and subtransmission substations to keep the secondary line voltage at the proper level in response to load and primary voltage changes.

Many designs exist for tap changers. An under load tap changer with a reversing switch, type URS, is shown in Figure 4.36a. The reversing switch allows the tapped section to be connected series aiding or series opposing with respect to the un-tapped section of the winding, so that twice the range can be covered with the same number of taps. The transfer switches that switch between the taps are make-before-break type to prevent arcing at the tap changing contacts. For example, to move from tap 2 to tap 3, transfer switch A moves from tap 2 to tap 3 while transfer switch B remains on tap 2. Only after transfer switch A is on tap 3 does transfer switch B move to tap 3. A mechanical arrangement to accomplish the switching is illustrated in Figure 4.36b. The preventive autotransformer connected to line H_1 of Figure 4.36a has a high impedance between transfer contacts A and B to prevent high circulating current from damaging windings as the taps are changed, and a low impedance between line H_1 and the transfer switch contacts. The reversing switch does not switch any current because the transfer switch contacts are on tap R before it is switched.

Automatic load tap changers add approximately 50% to the price of a transformer, but the voltage regulation ability they provide improves the quality of service substantially.

4.8.3 Voltage Regulating Transformers

Regulating transformers are designed to provide a boost in voltage magnitude along a line, or a change in phase. They are used primarily to control the flow of power between two systems with different sources or along a tie feeder between two load centers that are fed by the same bulk substation. Phase regulating transformers are used to control the power flow around loops with two or more sources. They are almost always motor driven and have extensive protection and control systems.

A voltage regulating transformer is shown in Figure 4.37. The autotransformer provides a ΔV to add to the line via the series transformers.

Figure 4.38a shows a phase regulating transformer. The core arrangement causes the windings that produce ΔV to be 90° out of phase with the line to neutral voltage. Thus $V_{AN} + \Delta V_{AN}$ produces a phase shift with very little amplitude change, as shown in Figure 4.38b.

4.9 TRANSFORMER SHORT AND OPEN CIRCUIT TESTS

The information obtained from the short circuit and open circuit tests of a transformer allow the calculation of the transformer reactance and efficiency.

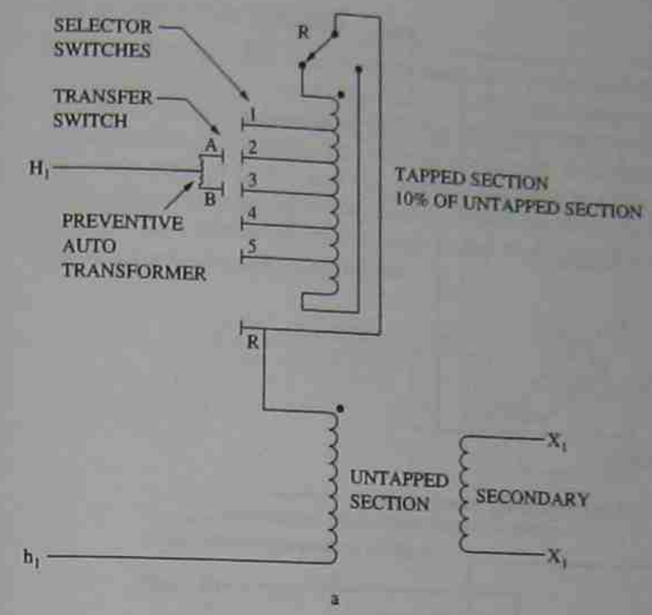


FIGURE 4.36 URS tap changer (a) Diagram and (b) mechanical switching arrangement

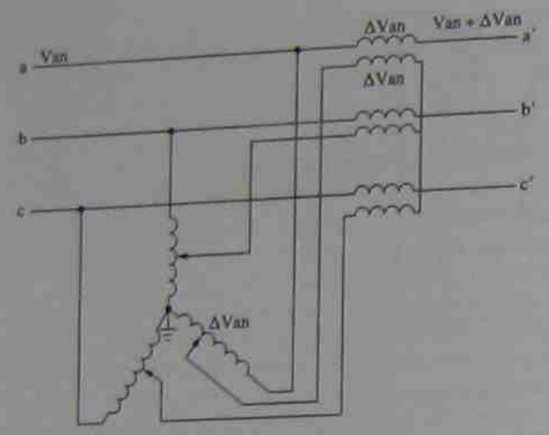


FIGURE 4.37 Voltage regulating transformer

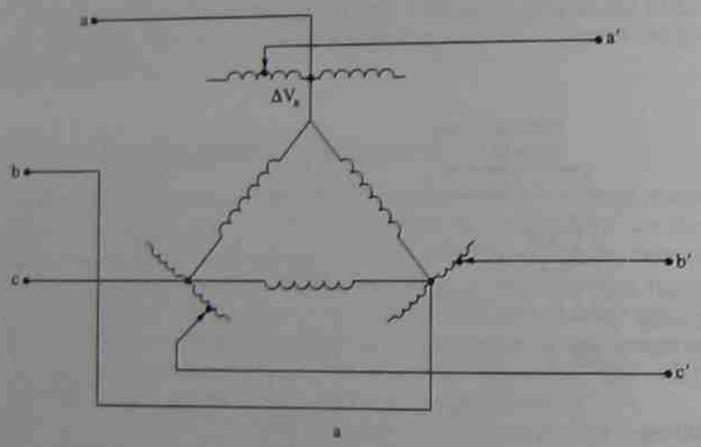
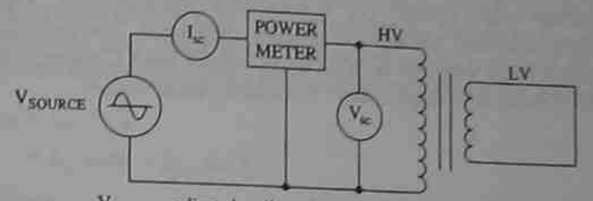


FIGURE 4.38 Phase regulating transformer (a) Diagram, parallel drawn windings are on the same core (b) Phasor diagram

4.9.1 Short Circuit Test

Refer to Figure 4.39a. The short circuit test is performed by shorting out the low voltage winding and applying voltage to the high voltage winding until rated current flows in the high voltage winding, at which time rated current should flow in the low voltage winding. The voltage and power is recorded. Because core losses are proportional to V^2, and the voltage required to cause rated current to flow with a shorted winding is low, the core losses are very low during the short circuit test. The core losses are low enough in the short circuit tests to be ignored for all but the most accurate calculations.

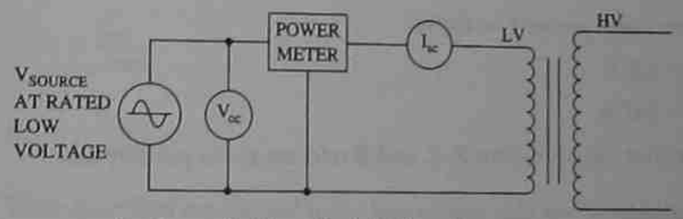


V_{SOURCE} adjusted until rated current flows in windings.
Values referred to measured windings.

$$Z_{eq} = \frac{V_{sc}}{I_{sc}} \qquad R_{eq} = \frac{P}{I_{sc}^2}$$

$$X_{eq} = \sqrt{Z_{eq}^2 - R_{eq}^2}$$

a



$$I_{oc} = I_{ex\,LV} = jI_m + I_{h+e} = jI_{ex}\sin\theta + I_{ex}\cos\theta$$

$$P_{oc} = \frac{V_{oc}^2}{R_{c_{LV}}} \qquad \cos\theta = \frac{P_{oc}}{V_{oc}\,I_{oc}}$$

b

FIGURE 4.39 Transformer test connections (a) Short circuit test (b) open circuit test

The per unit impedance of the transformer can be found from

$$\text{pu } Z = \frac{V_{SC}}{\text{rated V}} \tag{4.26}$$

Where the subscript SC stands for short circuit. For the actual impedance value

$$Z_{eq} = \frac{V_{SC}}{I_{SC}} \tag{4.27}$$

$$P_{SC} = I_{SC}^2 R_{eq} + (\text{full voltage core loss})(V_{SC}/V_{RATED})^2 \tag{4.28}$$

The last term is frequently ignored so P_{SC} is the full load copper loss, and

$$R_{eq} = P_{SC}/I^2_{SC} \tag{4.29}$$

$$X_{eq} = (Z_{eq}^2 - R_{eq}^2)^{1/2} \tag{4.30}$$

These values are referred to the side on which they are measured.

Measurements are very similar for three-phase transformers. Three-phase power, line current, and line voltage are usually measured. The calculations are done on a per phase basis whether wye or delta. Recall from Chapter 2 that delta impedance is three times wye impedance. To obtain phase values

$$P_p = P_{SC}/3$$
$$R_{eq} = P_p/I_p^2$$
$$Z_{eq} = V_p/I_p$$
$$X_{eq} = (Z_p^2 - R_p^2)^{1/2}$$

Example 4.5:

A Y-Y connected three-phase transformer, 12.47 kV/480 V, 25 kVA, has the following short circuit measurements from the primary side.

Three phase power $P = 400$ W

$V_{SC} = 620$ V

$I_{SC} = 3.47$ A

Calculate the equivalent X, Z, and R referred to the primary side.

Solution:

$$Z_{eq} = \frac{V_p}{I_{SC}} = \frac{620\text{ V}/\sqrt{3}}{3.47\text{ A}} = 103.16\ \Omega$$

$$\text{pu } Z = \frac{Z}{Z_b} = \frac{Z}{V_b/I_b} = \frac{103.16\ \Omega}{(12.47\text{ kV}/\sqrt{3})/3.47\text{ A}} = 0.05\text{ pu}$$

Notice that

$$\text{pu } Z = \frac{V_{SC}}{V_b} = \frac{620\text{ V}}{12.47\text{ kV}} = 0.05\text{ pu}$$

$$R_{eq} = \frac{P/3}{I_p^2} = \frac{133.3\text{ W}}{(3.47\text{ A})^2} = 11\ \Omega$$

$$X_{eq} = (103.16\ \Omega^2 - 11\ \Omega^2)^{1/2} = 102.57\ \Omega$$

These values of R_{eq} and X_{eq} are referred to the high voltage side.

4.9.2 Open Circuit Test

Figure 4.39b shows the connection for the open circuit test. Normally the low voltage winding is supplied with rated voltage, which should result in rated voltage on the high voltage side. The current drawn should be low enough that the copper losses are very low and the power measured is almost all from core losses. The current drawn during the open circuit test will be the excitation current.

$$I_{OC} = I_{h+e} + I_m$$
$$= I_{OC}\cos\theta + jI_{OC}\sin\theta \tag{4.31}$$

where

$$\cos\theta = \frac{P_{OC}}{I_{OC}V_{OC}}$$

now

$$R_C = \frac{V_{OC}^2}{P_{OC} - I_{OC}^2 R_{eq}} \tag{4.32}$$
$$= \frac{V_{OC}}{I_{OC}\cos\theta}$$

$$X_m = \frac{V_{OC}}{I_{OC}\sin\theta} \tag{4.33}$$

These quantities are referred to the low voltage side and need to be referred to the side of the transformer on which they will be used. Phase current, voltage, and power should be used for three-phase transformers.

Example 4.6:

For the transformer of example 4.5 the open circuit measurements are

$P_{OC} = 600$ W

$I_{OC} = 5$ A

$V_{OC} = 480$ V

Calculate the transformer X_m and R_C referred to the primary. Also calculate the transformer efficiency at full load. Load PF = 0.8.

Solution:

Calculating cosθ first

$$\cos\theta = \frac{P_{OC}/3}{V_{POC} I_{OC}}$$

$$= \frac{200\ \text{W}}{(480\ \text{V}/\sqrt{3})\ (5\ \text{A})}$$

$$= 0.144$$

$$a = \frac{V_P}{V_S}$$

$$= \frac{12470\ \text{V}}{480\ \text{V}}$$

$$= 25.98$$

$$a^2 = 674.9$$

$$I_m = I_{OC} \sin(\text{arc cos } 0.144)$$

$$= 5\ \text{A} \sin 81.7°$$

$$= 4.94\ \text{A}$$

$$X_{mS} = j\frac{V_{OC}}{I_m}$$

$$= j\frac{480\ \text{V}/\sqrt{3}}{4.94\text{A}}$$

$$= j56\ \Omega$$

$$X_m = a^2 X_{mS}$$

$$= 37.8\ \text{k}\Omega$$

Now for the hysteresis losses

$$I_{OC}^2 R_{eqS} = (5\ \text{A})^2(11\ \Omega/674.9) = 0.407\ \text{W}$$

This is only 0.079% of the open circuit power and can be neglected without serious inaccuracy in most applications.

$$R_{CS} = \frac{V_{OC}^2}{P_{OC}/3}$$

$$= \frac{(480\ \text{V}/\sqrt{3})^2}{200\ \text{W}}$$

$$= 384\ \Omega$$

$$R_C = 674.9\ (384\ \Omega)$$

$$= 259.2\ \text{k}\Omega$$

Recall that efficiency $\eta = P_{OUT}/P_{IN}$

$$\eta = \frac{P_{OUT}}{P_{OUT} + P_{CU} + P_{h+e}} \tag{4.34}$$

$$= \frac{25\ \text{kVA}(0.8)}{25\ \text{kVA}(0.8) + 400\ \text{W} + 600\ \text{W}}$$

$$= 0.952 \text{ or } 95.2\%$$

4.10 PER UNIT IMPEDANCE OF THREE WINDING TRANSFORMER

Transformers with two secondary windings often have different kVA ratings for all three windings. The percent or pu impedance of each winding is given with its own rating as a base unless otherwise stated. The impedance diagram must have a common base for all the impedances.

Let the three windings of a transformer be the primary (P), secondary (S), and tertiary (T). Additionally let

Z_{PS} = leakage impedance measured in the primary with the secondary shorted and the tertiary open.

Z_{PT} = leakage impedance in the primary with the tertiary shorted and the secondary open.

Z_{ST} = leakage impedance in the secondary with the tertiary shorted and the primary open.

Then Z referred to the voltage of one winding is

$$Z_{PS} = Z_P + Z_S$$

$$Z_{PT} = Z_P + Z_T$$

$$Z_{ST} = Z_S + Z_T$$

The simultaneous solution of these three equations is

$$Z_P = (1/2)(Z_{PS} + Z_{PT} - Z_{ST}) \tag{4.35}$$

$$Z_S = (1/2)(Z_{PS} + Z_{ST} - Z_{PT}) \tag{4.35}$$

$$Z_T = (1/2)(Z_{PT} + Z_{ST} - Z_{PS}) \tag{4.36}$$

Note the order of the terms of the equations. The equivalent circuit is shown in Figure 4.40a.

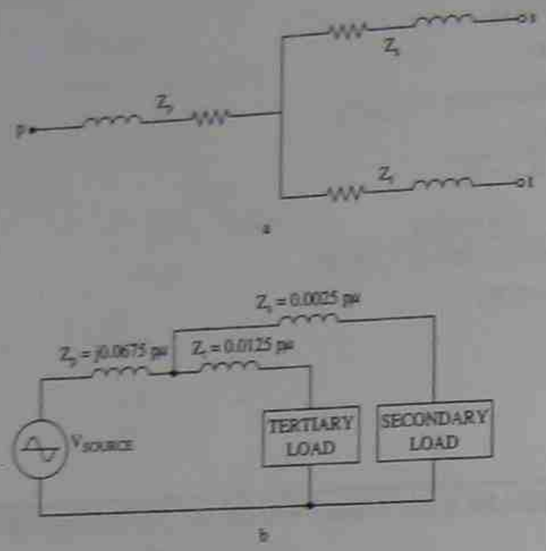


FIGURE 4.40 Three winding transformer equivalent circuit with all impedances on a common base (a) Equivalent circuit and (b) in an impedance diagram

Example 4.7:

A three winding, three-phase transformer has windings rated as follows

Primary: Y, 69 kV, 30 kVA

Secondary: Y, 34.5 kV, 20 kVA

Tertiary: Δ, 2.3 kV, 10 kVA

Z_{PS} = 7% on 69 kV, 30 kVA base

Z_{PT} = 8% on 69 kV, 30 kVA base

Z_{ST} = 4% on 34.5 kV, 20 kVA base

Assume that $Z_{eq} = X_{eq}$ and solve for the equivalent circuit components of Figure 4.40a, and connect them properly in an impedance diagram showing the loads and source.

Solution:

First all Zs must be on a common base for the equations to be used. Using the change of base equation from chapter two we obtain the tertiary impedance on the 69 kV, 30 kVA base.

$$Z_{B2} = Z_{B1} \frac{\text{base 1 kV}^2}{\text{base 2 kV}^2} \frac{\text{base 2 kVA}}{\text{base 1 kVA}}$$

$$= 0.04 \left(\frac{34.5 \text{ kV}}{69 \text{ kV}} \right)^2 \frac{30 \text{ kVA}}{20 \text{ kVA}}$$

$$= 0.04(0.25)(1.5)$$

$$= 0.015 \text{ pu}$$

Substituting into equations 4.35, 4.36, and 4.37 we obtain

$Z_P = 1/2$ (j0.07 + j0.08 − j0.015) = j0.0675 pu

$Z_S = 1/2$ (j0.07 + j0.015 − j0.08) = j0.0025 pu

$Z_T = 1/2$ (j0.08 + j0.015 − j0.07) = j0.0125 pu

The impedance diagram is shown in Figure 4.40b.

4.11 SUMMARY

Transformers are electrical machines that work by electromagnetic induction. The two major types of transformers are dry and oil immersed. The additional cooling and insulation properties of the oil result in greater power handling capabilities for the oil immersed. The power handling capability of oil transformers increases as the cooling means for the transformer oil go from natural convection of the oil through the cooling fins (OA) to adding fans to force air through the cooling fins (FA) to adding pump circulation of oil through the cooling fins (FOA). The ratio of OA/FA/FOA with respect to power handling capability is normally 1/1.33/1.67. Dry type transformers can be obtained in sealed housings filled with sulfur hexafluoride, an effective insulating gas. The insulating gas and housing, while costly, allow the transformer to be mounted in less space, which may be essential when space is at a premium.

The magnetic flux expanding and collapsing in the primary coil couples to the secondary coil(s) inducing voltage in the secondary in direct proportion to the ratio of the secondary turns to the primary turns. Energy must be preserved in the transformation so secondary current is transformed in inverse proportion to the ratio of secondary to primary turns. Transformer relationships are covered in sections 4.1.2 and 4.2.

The losses in a transformer include copper losses, power dissipated in winding resistance, hysteresis losses, power dissipated in work done reversing the magnetic field in the core once every half cycle, and eddy current losses, from power dissipated by current induced in the magnetic core laminations. These losses can be as low as 0.5% of the total transformed power, so transformers are very efficient machines.

Transfomers must be insulated to voltages well above the voltage of the system in which they are used because electrical systems are subject to transient voltages caused by switching, lightning, or faults on the lines. The insulation for transients is called the basic insulation level (BIL) and tests for BIL are performed with a waveform specified to resemble a lightning induced transient.

When power is first applied to a transformer the core must be magnetized before transformation can occur. Thus, energizing a transformer results in a high initial current, called the inrush current, to establish the initial maginetic field.

Transformer secondary voltages change both with the load power drawn and with the power factor of the load. The change in secondary voltage from no load to full load referenced to full load voltage is called voltage regulation. Voltage regulation calculation is discussed in section 4.7.

Autotransformers are constructed with a tapped single winding for each phase, similar to a taped inductor. The secondary power is partially induced and partially conducted, the fraction of each determined by the autotransformer winding ratio. The conduction of power to the secondary means that the core of an autotransformer can be smaller than that of a two winding transformer for the same power. This results in a more efficient, less expensive transformer. The loss of an autotransformer ground can result in the full primary voltge on the secondary line. Thus, autotransformers are never used when the secondary is connected to a utility customer facility.

Transformer reactance and efficiency can be calculated using the results of the short and open circuit test. These tests are explained in section 4.9.

4.12 QUESTIONS

1. State the reason that oil immersed transformers can handle higher kVA loads and higher transient voltage levels than equivalent sized dry type transformers.
2. A three-phase power transformer has the following name-plate rating; MVA 100/133/167. What does it mean?
3. State the meaning of the dots on the primary and secondary windings of a transformer schematic diagram.
4. A 69 kV/12.5 kV, 15 MVA, three-phase, Y-Y transformer is operated at full load. Calculate a, I_s, and I_p. Assume a well grounded neutral.
5. State the major sources of loss in a transformer.
6. Define BIL.
7. The transformer of problem 4 has $I_m = 0.05$ pu, and $I_{h+e} = 0.02$ pu. Calculate the actual value of the excitation, magnetization, and hysteresis (plus eddy current loss) currents.
8. Calculate the pu X_m and R_c for the transformer of problem 4.
9. If the pu $Z = 0.06$, and the pu $R = 0.01$ for the transformer of problem 4, calculate R_{eq} and X_{eq} referred to the primary and the secondary.

10. For the transformer of problem 4, use the information of problem 9 to calculate the required primary voltage for rated secondary voltage and the voltage regulation with the following loads: PF = 0.8 lagging, unity power factor, PF = 0.75 leading. All three are 15 MVA loads.
11. A 4200V/208V, 30kVA, Δ-Y connected three-phase transformer has secondary per phase $X_{eq} = 0.072\ \Omega$ and $R_{eq} = 0.0144\ \Omega$. It is loaded to 30 kVA with loads of PF = 0.76 lagging, PF = 1, and PF = 0.7 leading, respectively. For each load calculate the primary voltage necessary to maintain rated secondary voltage, and the voltage regulation.
12. Repeat the voltage regulation calculations of problem 11 with per unit quantities.
13. State the function of a delta connected tertiary winding on a Y-Y transformer.
14. State the cause of transformer inrush current and the conditions under which it is highest and lowest.
15. State the purpose of transformer protection, and the major types of equipment used for the protection.
16. An autotransformer, such as the one in Figure 4.21a, has a primary voltage of 34.5 kV and a secondary voltage of 12.5 kV. It is to supply a 60 kVA load. What equivalent two winding kVA rating must the autotransformer have? Also what portion of the load kVA is transformed and what portion is conducted?
17. Calculate the turns ratio needed by a CT and a PT to monitor a 69 kV line carrying 2000 A. Let the PT secondary be 120 V.
18. A three-phase 4200 V/480 V, Δ-Y connected, 15 kVA transformer has the following short circuit and open circuit measurements. All values are line or three phase.
    $V_{SC} = 210$ V
    $I_{SC} = 2.06$ A
    $P_{SC} = 200$ W
    all taken from the high voltage side
    $V_{OC} = 480$ V
    $I_{OC} = 0.9$ A
    $P_{OC} = 300$ W
    all taken from the low voltage side
    Calculate: Z_{eq}, X_{eq}, R_{eq}, I_m, I_{h+e}, and the efficiency of the transformer.
19. A three winding transformer, Y-Y-Δ connected, has the following ratings: primary, 138 kV at 12 MVA; secondary, 34.5 kV at 8 MVA; tertiary, 4.2 kV at 4 MVA. It has the following measured impedances
    $Z_{PS} = 8\%$ on 138 kV, 12 MVA base
    $Z_{PT} = 6\%$ on 138 kV, 12 MVA base
    $Z_{ST} = 4\%$ on 34.5 kV, 8 MVA base
    Calculate Z_P, Z_S, and Z_T

CHAPTER 5

Distribution Equipment

A large variety of equipment is necessary to economically and efficiently distribute electrical power. The equipment includes conductors, insulators, conductor support towers and poles, transformers, and protection devices. We cannot cover all of the distribution equipment in this chapter because the chapter would be too long. Some equipment, such as transformers, has already been covered, and some equipment will be covered in later chapters. This chapter concentrates on protective devices.

Practical, reliable, and safe distribution depends on protective devices to sense fault conditions and disconnect malfunctioning equipment. Protective devices must protect people and equipment from malfunctions, whether the malfunction is caused by equipment failure, weather (lightning and wind), or carelessness such as cutting an underground cable. Quickly disconnecting malfunctioning equipment minimizes the damage to the equipment and thereby shortens the time that the equipment is out of service. The development of protective devices that can operate at higher voltages, and interrupt higher fault currents (called interrupting capacity), has been crucial to the implementation of higher voltage, more efficient transmission and distribution systems.

The most important protective devices for distribution are circuit breakers, reclosers, sectionalizers, fuses, relays to sense fault conditions, and lightning arresters. Each of these, as well as switches and metering equipment, are discussed in this chapter.

5.1 CIRCUIT BREAKERS

Circuit breakers for electrical power distribution include both medium (between 600 V and 34.5 kV) and high voltage (above 34.5 kV), high current devices that must automatically disconnect faulted equipment to protect people, prevent damage to upstream equipment, and minimize damage to downstream equipment in two to five cycles. Additionally, the circuit breaker should not damage itself when it operates. To accomplish this task substation circuit breakers are far more complex than the molded case low voltage breakers used in building distribution systems.

Circuit breakers range in size from 125 V, 15 A molded case thermal or magnetic breakers used in buildings to over 800 kV at several thousand amperes. Breakers are classified by voltage, continuous current, interrupting capacity (maximum fault current the breaker can interrupt without becoming dangerous themselves), and methods of extinguishing the arc.

To illustrate the magnitude of the circuit breaker's job let us consider a mechanical analogy. A 100 MVA circuit breaker (they come as large as 20,000 MVA) must stop the flow of power in two to five 60 Hz cycles after it receives a trip signal. Assume the power factor is one and that the power is all mechanical. One hundred MW is 134,048 hp. One hp = 550 ft-lb/s, so 100 MW = 7.37265×10^7 ft-lb/s. Assume this energy consists of a weight moving at 10 miles/hour, which in ft/s is

$$(10 \text{ mi/hr})(5280 \text{ ft/mi})(1 \text{ hr}/3600 \text{ s}) = 14.67 \text{ ft/s}$$

The equivalent moving weight is

$$\frac{7.37265 \times 10^7 \text{ ft-lb/s}}{14.67 \text{ ft/s}} = 5.0268 \times 10^6 \text{ lb}$$

A 17-car freight train with an average car weight of 295,695 lb would weigh 5.0268×10^6 lb. Imagine stopping a 17-car freight train moving at 10 mi/hr in 1 second. Quite a job. A 100 MVA circuit breaker must stop the equivalent energy in 0.083 seconds if it opens in five cycles, or 0.0333 seconds if it opens in two cycles.

5.1.1 The Arc

When current carrying contacts open, the initial electric field between the just parted contacts is very high. The high electric field causes any gas between the contacts to ionize and support current flow through it, or arc. The higher the voltage that the contacts are breaking the more severe the arcing.

Inductive loads make the tendency to arc even more severe because inductive loads attempt to keep the current through the opening contacts the same as it was before they opened. Most industrial loads and faulted lines are inductive. The arc reaches very high temperatures because of the current dissipating power in the arc itself. The high temperature at the contact face causes some of the contact metal to

burn off and ionize, which worsens the arc. The arc must be extinguished to interrupt the current.

Many methods are used to extinguish an arc. They use one or both of the following two principles. The first is to lengthen the arc until it is long and thin. This causes the arc resistance to rise, thus the arc current to drop, the arc temperature to decrease, and ultimately results in insufficient energy in the arc to keep it ionized. The second is to open the arc in a medium that absorbs energy from the arc causing it to cool and quench. Air, oil, and insulating gas are normally used as the medium.

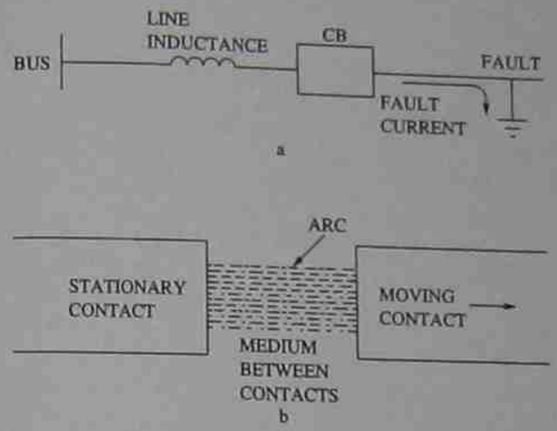
Direct current (dc) arcs are harder to break than alternating current (ac) arcs because ac goes through a current zero every half cycle, which dc does not. The same principles are used to break dc arcs, but dc rated breakers must use the principles more efficiently. After ac zero the arc will re-establish if the medium between the contacts is still ionized. Even if the arc does not re-establish immediately because the medium is de-ionized, the rise in voltage across the contacts may cause the arc to re-establish if the distance between the contacts is not sufficient to keep the electric field between the contacts below the ionization field of the medium.

Figure 5.1a shows a faulted bus with a circuit breaker. Figure 5.1b shows the arc between the separating contacts, and 5.1c shows the waveforms across the contacts. Recall the X/R ratio of a line or a transformer is high so the fault current lags the voltage. This is typical. Notice that while arc current is flowing the arc voltage is relatively low. At the zero crossing the high dV/dt of the voltage across the contacts may cause stray inductance and capacitance in the circuit to resonate at a frequency higher than 60 Hz, which can cause the voltage to shoot higher than the applied voltage. This voltage can cause re-ignition of the arc as shown at the first two current zero crossings in Figure 5.1c. This can occur several times before the contact separation is great enough that the arc is extinguished. If the medium between the contacts does not de-ionize the high voltage spike does not occur. An arc re-established in the first $^1/_4$ cycle is called a re-ignition, and an arc re-established after the first $^1/_4$ cycle is called a restrike. Notice in Figure 5.1c the oscillation riding on the applied voltage after the arc is broken. The peak voltage from oscillation can be high enough to cause equipment damage without transient protection or damping. Figure 5.1d shows an arc on a power line.

The high X/R ratio of most faulted equipment causes the arc to be more difficult to break. Recall that the offset of a fault waveform from symmetrical depends on the time during the waveform that the fault occurs. The offset from zero, as shown in Figure 5.2, is a dc component that is harder to interrupt than ac. The higher the X/R ratio the longer the dc component lasts.

The arc energy transferred to the medium between the contacts causes the medium to reach temperatures as high as 30,000°K and high pressures very quickly. The resulting expansion of the medium is almost explosive. The combination of high mechanical and arc forces can cause the ground to shake around a large breaker when it operates.

A circuit breaker must stretch and cool the arc until it breaks. Circuit breakers are classified by how they accomplish this task.



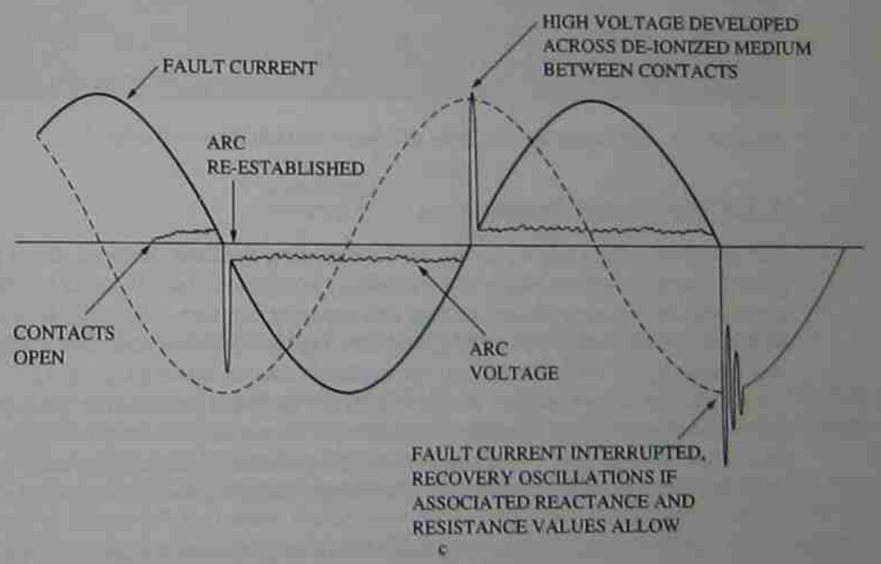


FIGURE 5.1 Contact arc (a) Equivalent circuit (b) Contacts and (c) Waveforms

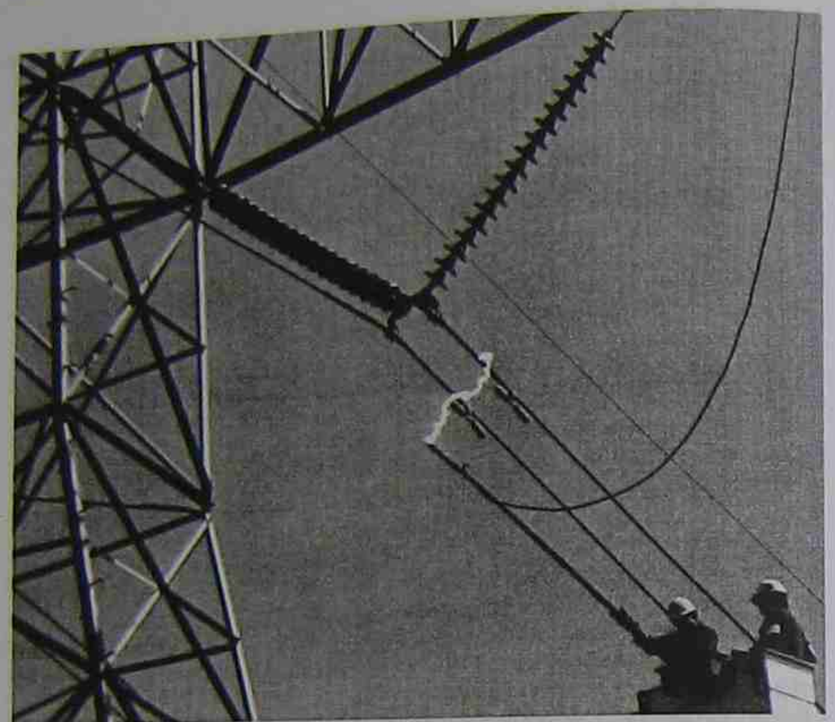


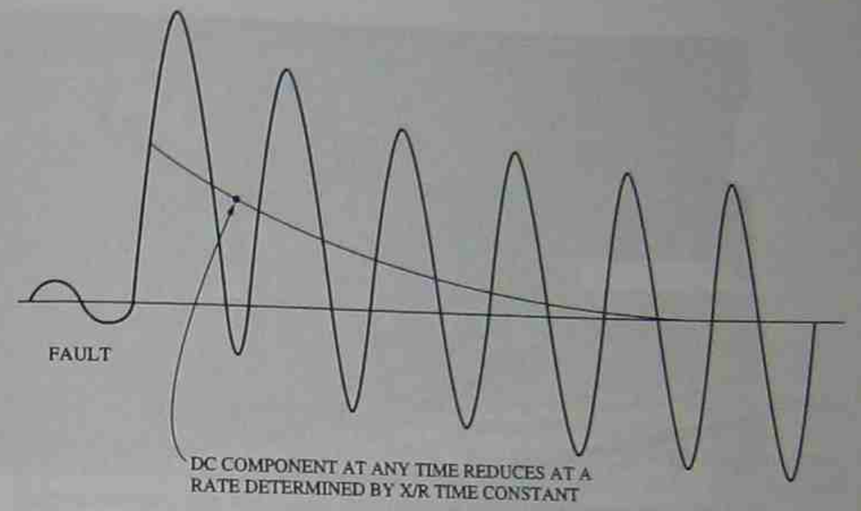
FIGURE 5.1 (d) Photograph (courtesy of Lower Colorado River Authority).

5.1.2 Air Circuit Breakers

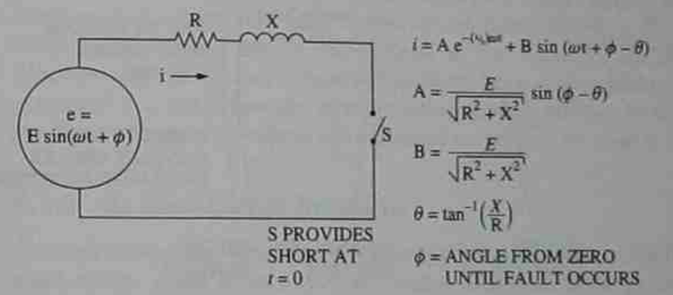
Air circuit breakers use air as the arc interrupting medium. Because air at atmospheric pressure ionizes easily some auxiliary equipment must be used to break the arc except for the very lowest voltage and capacity breakers. Almost all low voltage breakers use air as an interrupting medium. Figure 5.3 shows some low voltage circuit breakers. We will now look at the methods used to break an arc in air.

Convection causes an arc, which is hot, to rise if the contacts are properly oriented. As the rising arc stretches its resistance increases, its current drops, and its increased surface area is exposed to cooler air, causing its temperature to drop until the arc is finally extinguished. The longer an arc can be drawn out the easier it is to extinguish.

Arc tips (also called arcing contacts) break after the main contacts break. This prevents pitting of the main contacts. Because the arc tips travel further than the main contacts they stretch the arc further, thus making it extinguish earlier. Arc tips are shown in Figure 5.4a. Arc horns work on the same principle except convection drives the arc up the spreading horns causing the arc to leave the load current carrying contacts and stretch, as shown in Figure 5.4b.



a



b

FIGURE 5.2 Asymmetrical fault current waveform. (a) Current waveform (b) Circuit.

Interrupting fins placed in the path of the rising arc will stretch the arc farther, cool it more, and aid in extinguishing the arc. This is shown in Figure 5.4d. Large low voltage breakers will have interrupting fins.

Magnetic blowout refers to the use of a transverse magnetic field near the contacts to stretch and drive the arc into the interrupting fins, as shown in Figure 5.5. The magnetic field interacts with the ions of the arc to provide the driving force. The magnetic field can come from a permanent magnet in small breakers, but is provided by a properly positioned coil through which the contact current flows in larger low voltage breakers. Circuit breakers with magnetic blowout and interrupting fins can even be used for lower medium voltages. This combination can interrupt current as high as 42,000 A at 8 kV per phase. Three-phase circuit breakers



FIGURE 5.3 Low voltage circuit breakers

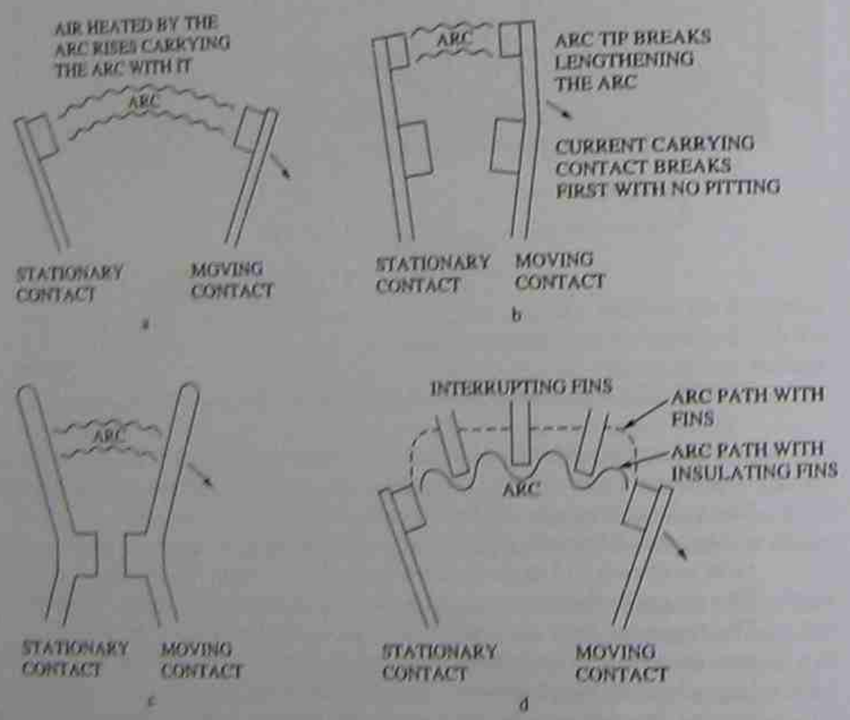


FIGURE 5.4 Arc lengthening methods include: (a) Convection (b) Arc tip (c) Arc horn and (d) Interrupting fins.

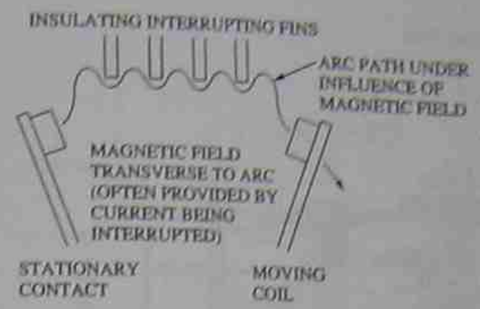


FIGURE 5.5 Magnetic blow out

use barriers between the phases made of insulating material. The barriers provide arc chutes to prevent phase-to-phase faults from originating in the breaker.

Air circuit breaker contacts are driven open by strong springs that are compressed (called charging the breaker) by rachet mechanisms or by geared down electric motors. The trip signal is usually originated by a magnetic coil or a thermal element built into the breaker, although some larger, medium voltage air circuit breakers are designed to trip on protective relay signals. Most low voltage breakers have either bolt on terminal connections, or blade springs designed to slide into a mating bus in the cabinet as the breakers are bolted into place. Medium voltage cabinet mount air breakers have spring mounted metal fingers arranged in a circle that slip over a mating tubular contact in the cabinet. Larger medium voltage air breakers are mounted on wheels for ease in installation.

5.1.3 Air Blast Circuit Breakers

Cross air blast circuit breakers are special purpose medium voltage circuit breakers used where noise is an important factor. They are used primarily at voltages between 14.4 and 34.5 kV. Figure 5.6 shows the principle of cross air blast circuit breakers. A blast of compressed air (to 800 psi) is blown across the circuit breaker contacts as the contacts open. The blast of high pressure air blows the arc into the interrupting fins, stretches the arc, and cools it.

Air blast breaker contact opening mechanisms are powered by powerful springs, as are the opening mechanisms of all high voltage and medium voltage circuit breakers. The contacts are closed by either a motor or compressed air. Most air blast circuit breakers have bushings for connection.

Axial air blast circuit breakers blow high pressure air along the axis of the contacts to stretch and cool the arc, as shown in Figure 5.7. Usually the air is blown from a port next to the stationary contact toward the moving contact. Axial air blast breakers are usually high voltage breakers. They can be built to interrupt currents as high as 63 kA at 800 kV. A single interrupting contact such as that of Figure 5.7 can operate reliably to about 70 kV, so higher voltage circuit breakers use several contacts in series. Two sets of contacts can be built into a single package called an interrupter. Figure 5.8 shows a photograph of an axial air blast breaker.

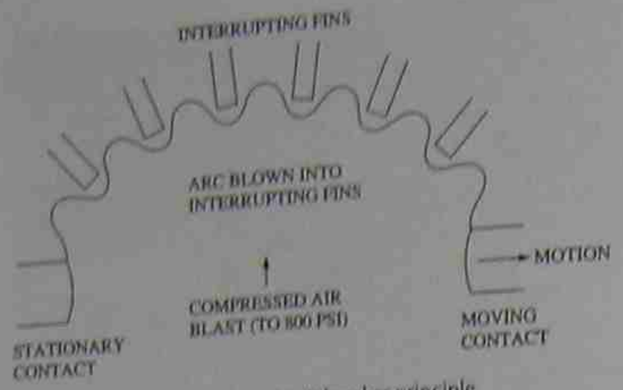


FIGURE 5.6 Cross air blast circuit breaker principle

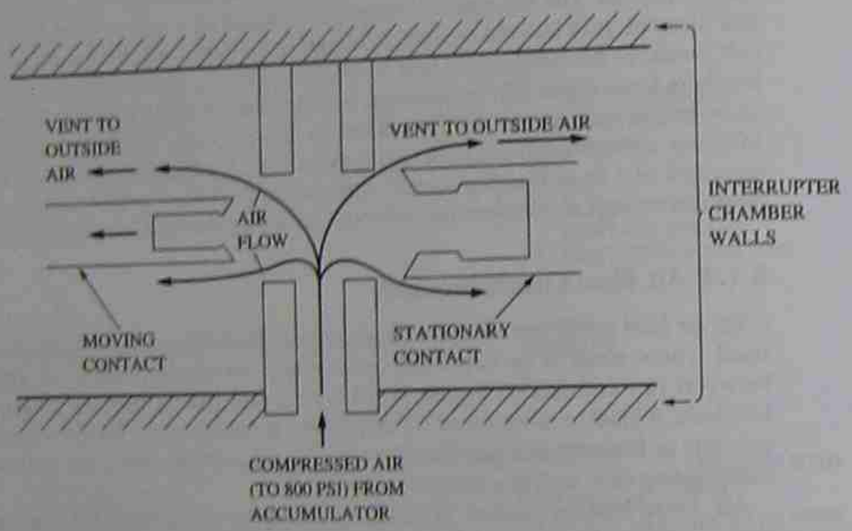


FIGURE 5.7 Axial air blast circuit breaker principle

Air blast breakers (assume axial unless otherwise noted) must have a resistor across the arc, breaking contact to dampen possible high voltage oscillations that might re-ignite the arc. Auxiliary contacts break the low current through the resistor after the arc is broken. The contacts are driven open by springs (compressed with compressed air) acting on the actuating linkages after the breaker receives a trip signal from a protective relay.

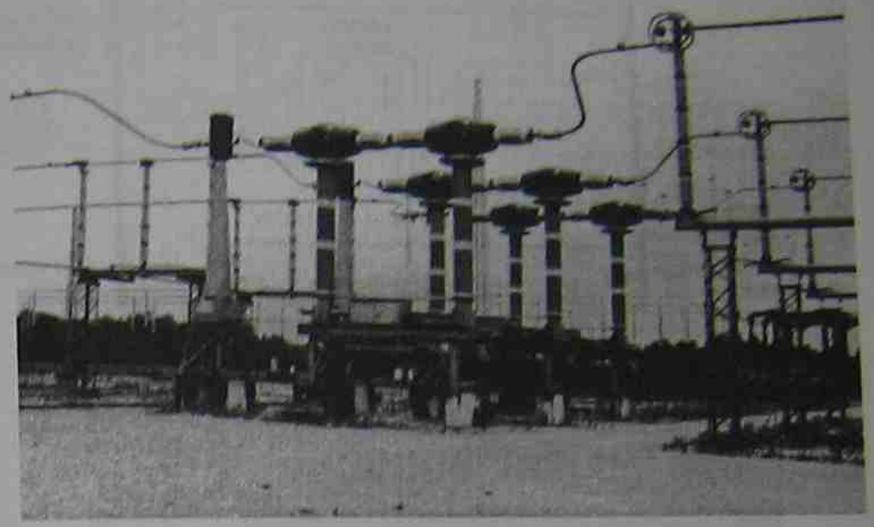


FIGURE 5.8 Axial air blast breaker (courtesy of Houston Lighting & Power).

5.1.4 Vacuum Circuit Breakers

Vacuum circuit breaker contacts, shown in Figure 5.9, are enclosed in a container with a high vacuum. No significant arcing can occur because there is no air between the contacts to ionize. A small amount of metal on the arcing sleeve around the contact may ionize on each operation, but not enough to sustain an arc. The few metal atoms that arc off on operation are ejected at nearly right angles to the contacts and collected on the metal vapor condensing shield so they do not accumulate around the contacts. A metal bellows allows the moving contact to do so. Vacuum circuit breakers are operated by spring force. Vacuum breakers are available for voltages from 480 V to over 34.5 kV. Many are suitable for cabinet mounted indoor use.

5.1.5 Oil Circuit Breakers (OCBs)

Oil circuit breakers use oil as the arc interrupting medium. A photo of a typical high voltage oil circuit breaker is shown in Figure 5.10a, and an outline drawing with some dimensions in Figure 5.10b. Oil has a dielectric strength far in excess of air. When contacts open in oil the arc causes the oil to disassociate which absorbs arc energy. One of the products of disassociation is hydrogen, which has a higher heat capacity than air and is superior to air as a cooling medium (hydrogen is not explosive if no oxygen is present). The hydrogen is ionized by the arc, which

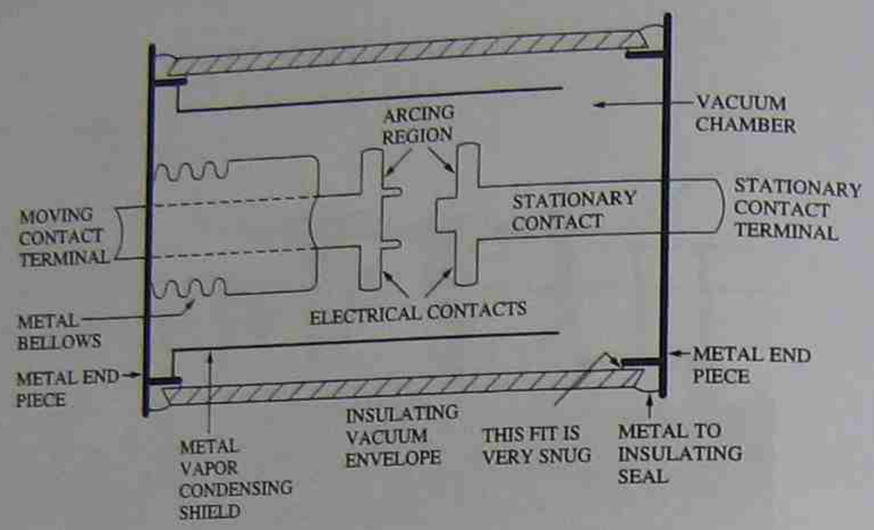


FIGURE 5.9 Vacuum circuit breaker contacts

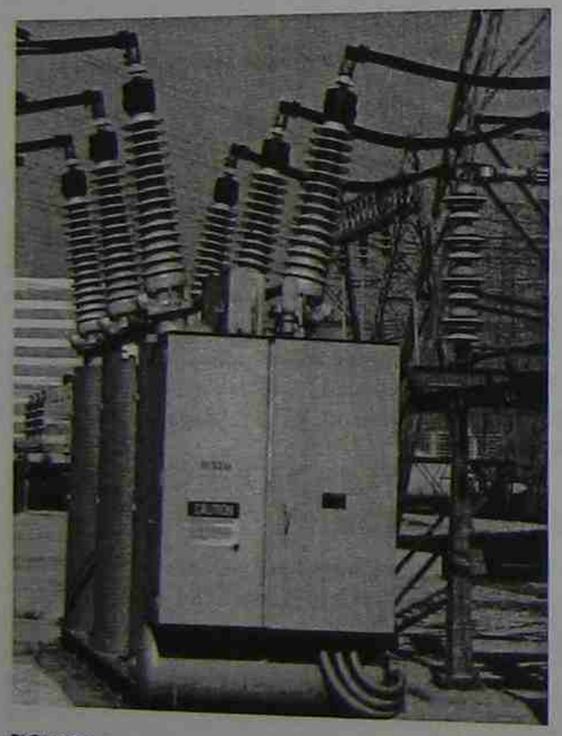


FIGURE 5.10 145 kV 2000 A Westinghouse oil circuit breaker (courtesy of Westinghouse) (a) Circuit breaker

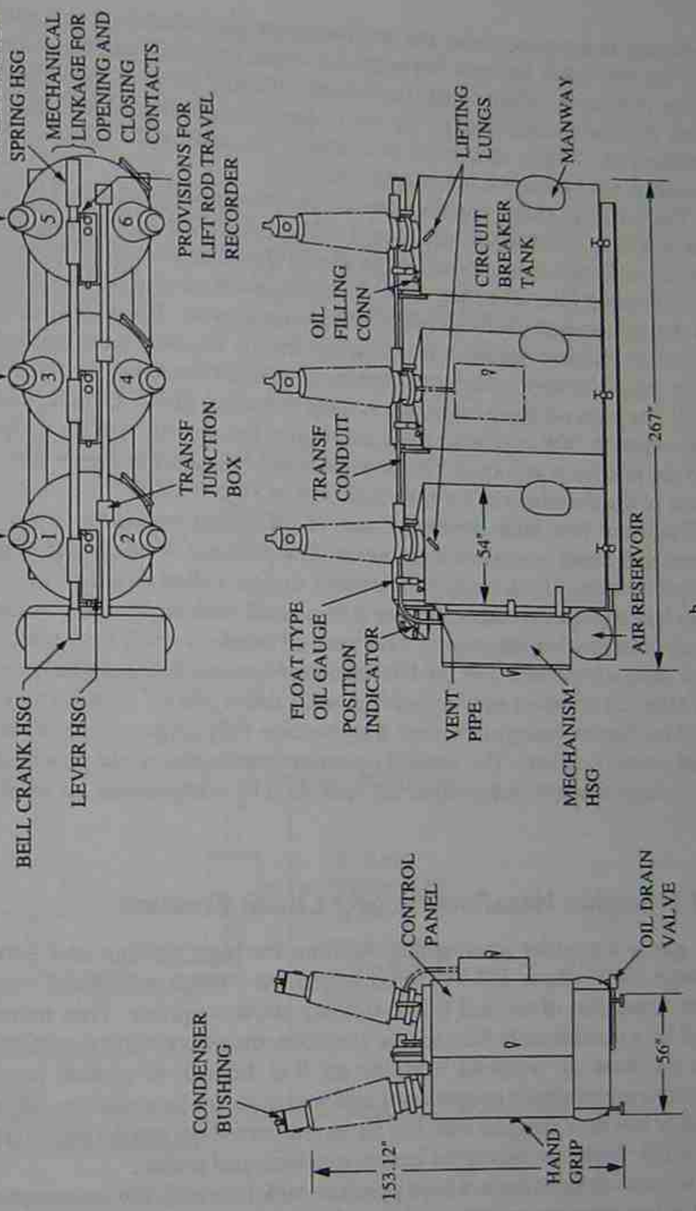


FIGURE 5.10 (b) breaker outline

removes more energy from the arc. The hydrogen bubbles move upward from the arc so new oil is brought between the contacts, which disassociates, producing more hydrogen, which ionizes and rises, allowing more oil between the contacts. This process continues until the arc is quenched. Bulk oil breakers, in which the contacts are simply immersed in a tank of oil, operate to about 230 kV. Bulk oil breakers have a limited interrupting capacity.

The use of an arcing chamber can increase the capacity of an oil breaker by a factor of 500, to 10,000 MVA and a break voltage of 500 kV. All but very modest capacity circuit breakers use them. An oil arcing chamber is shown in Figure 5.11a. It is an insulating fiber chamber, with arc interrupters on one side (called arc splitters in this application), within which the contacts open. The arcing chamber is also called an oil blast chamber. In operation the arc vaporizes the oil in the chamber very rapidly, evolving high pressure hydrogen (because it is confined in the chamber). The high pressure hydrogen is hard to ionize. The hot, high pressure hydrogen expands with explosive force and blows the arc into the arc splitters causing the arc to stretch and cool. The process could be called *hydrogen blast*. The placement of the chambers in the tank is shown in Figure 5.11b.

There are two tank configurations of oil circuit breakers. Those with large, grounded, tanks are called dead tanks. The pictures of oil circuit breakers in this chapter are dead tank designs. The other design, called live tank or minimum oil, uses less oil. The oil blast chamber is in a small tank supported on insulators like an air blast breaker interrupter. Live tank oil breakers work very well but the dead tank design is preferred in the United States because it is less likely to explode.

Oil circuit breakers are very seldom used above 345 kV even though they can be built for higher voltages because they become very large compared to SF_6 and air blast circuit breakers. The contact operating mechanisms are powered by powerful springs that are compressed for operation by compressed air at about 500 psi.

5.1.6 Sulphur Hexaflouride (SF_6) Circuit Breakers

SF_6 gas is a popular interrupting medium for high voltage and extremely high voltage (EHV, above 345 kV) applications. Its voltage withstand rating is about three times that of air and it is extremely electronegative. That means its atoms bind for a considerable time to free electrons, thus becoming negative ions. When free electrons are removed from the arc it is difficult to sustain because no free electrons are available to accelerate and ionize atoms by collision. SF_6 breakers are usually live tank designs with the tanks supported on insulators as shown in Figure 5.12a. There are two types in use, two tank and puffer.

Two tank designs have a high pressure tank in which the interrupter is located, and a low pressure reserve tank, as shown in Figure 5.12c. On a fault the high pressure tank is vented to the low pressure tank, creating turbulence to help interrupt the arc. The low pressure SF_6 is then compressed and returned to the high pressure tank. The high pressure tank must be warmed at low temperatures to keep the high pressure SF_6 from liquefying.

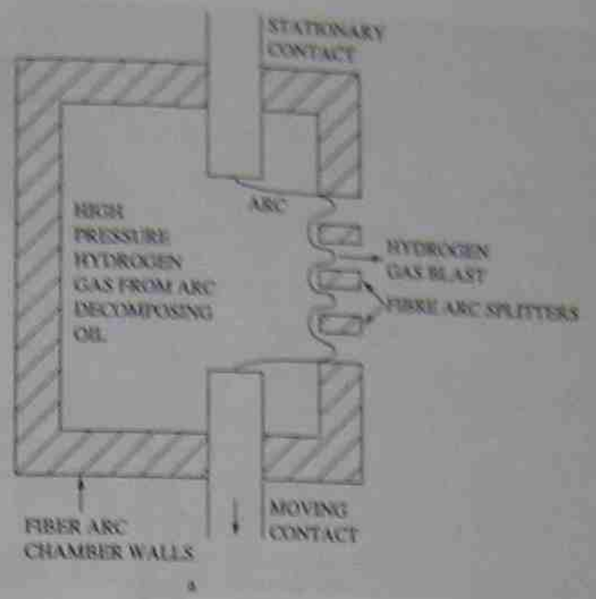
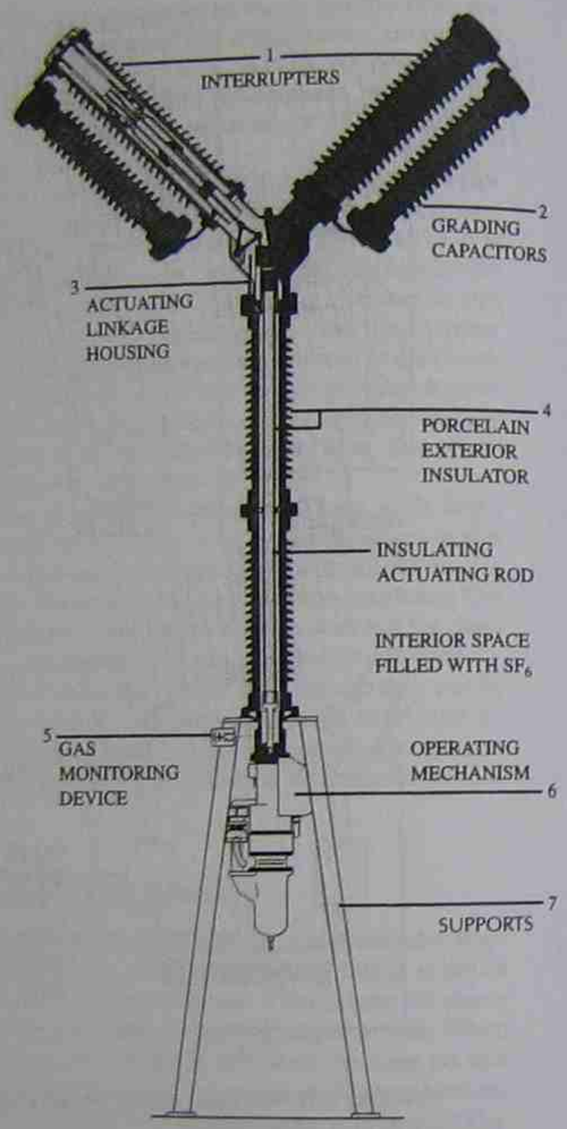


FIGURE 5.11 Oil blast chamber circuit breaker (a) Oil blast chamber and (b) circuit breaker with two series chambers

Puffer designs are simpler than two tank designs because all of the SF_6 is at one pressure, 75 psi, which does not liquify until the temperature drops to -30°C. A puffer type SF_6 circuit breaker cut away is shown in Figure 5.12b. The grading capacitors are a capacitive voltage divider to force each of the two interrupters to share the voltage equally. The mechanical actuation is driven by a strong spring.



a



b

FIGURE 5.12 SF_6 circuit breaker (a) 362 kV at 4000 A three-phase, interrupting capacity—50 kA (b) Cross section drawing

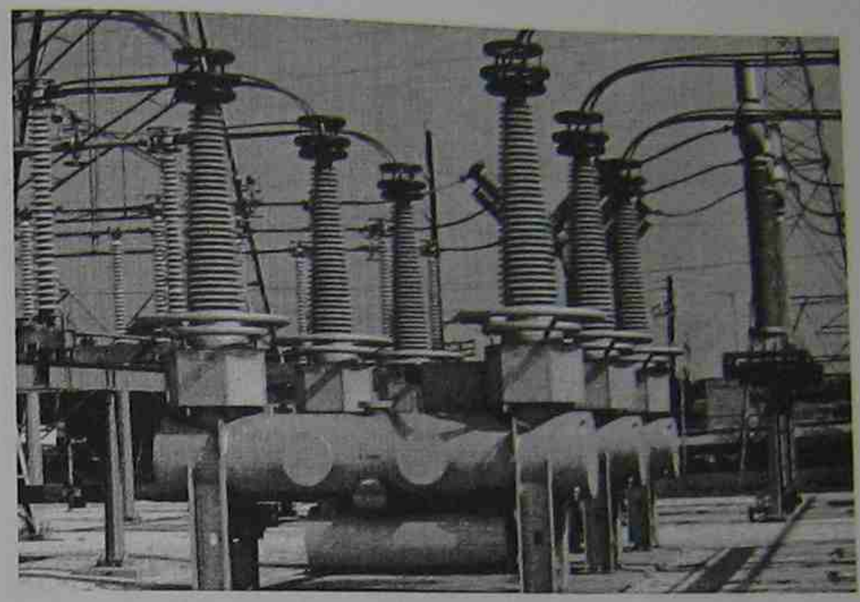


FIGURE 5.12 (c) Dead tank SF_6

On actuation a cylinder of 75 psi SF_6 is compressed to a high pressure and released across the contacts as they separate. This is illustrated in Figure 5.13.

Figure 5.14 illustrates the use of closing (also called opening) resistors for damping oscillations when the arc is broken. Even though SF_6 breakers do not need closing resistors to break the arc, the resistors provide valuable transient suppression in many applications, especially at 345 kV and above.

SF_6 breakers are available that can handle up to 8000 A continuous current and they can have interrupt capacities to 63 kA at 800 kV, and 80 kA at 230 kV. Puffer types have somewhat lower interrupt capacities (about 50 kA) than dead tank types because the operating mechanisms become massive when they are built for the same interrupt capacity.

5.1.7 Circuit Breaker Ratings

Users of circuit breakers must consider a number of ratings to select the right one. The continuous voltage rating, which may decrease at altitudes above 3300 ft, must be adequate. The rated impulse voltage (BIL) must be considered for insulation coordination, lightning, and surge protection.

The continuous current rating must be adequate for maximum loads and the interrupt capacity must be greater than the maximum fault current the breaker will have to interrupt. This means that the maximum fault current must be known. We will learn to calculate fault currents in later chapters. Additionally the MVA rating must be adequate.

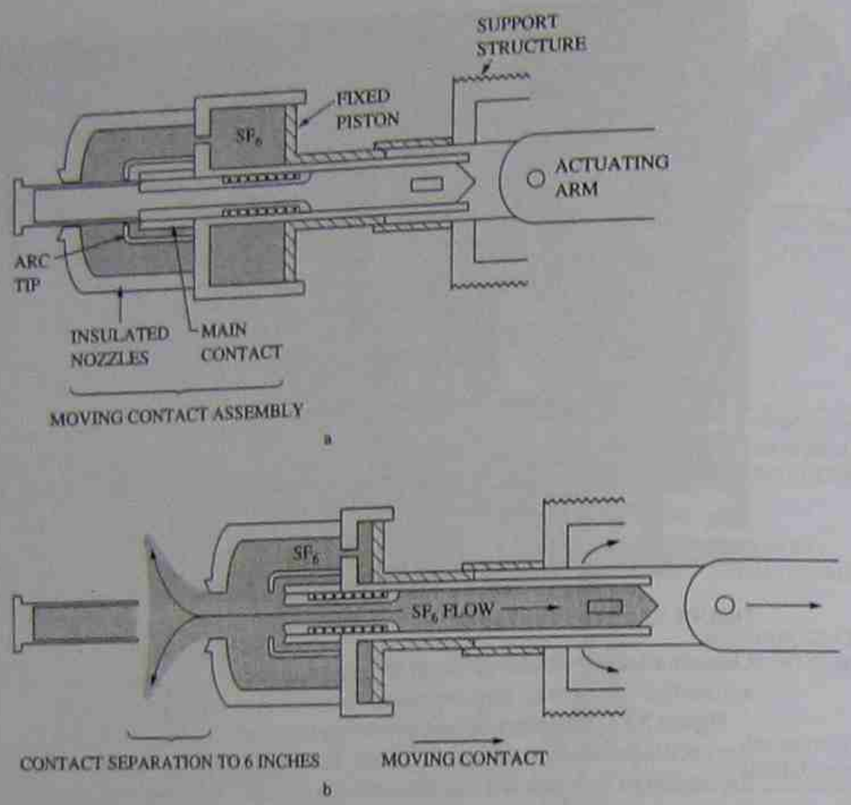


FIGURE 5.13 SF_6 puffer operation (a) Closed and (b) open

The interrupting time must be fast enough to provide proper protection for the system, and if it is to be automatically reclosed, the reclose time must be known. The current rating must be high enough to allow the system to be energized (recall that each transformer in the system will take some inrush current). Breakers above 250 MVA have no manual closing so the amount of station power needed to close the breaker must be known.

In addition to the electrical parameters there are a number of mechanical considerations such as size, foundation requirements, and space required. Table 5.1 lists a number of OCB ratings, and Figure 5.15 shows the space requirements for a series of SF_6 circuit breakers.

5.1.8 Circuit Breaker Controls

Circuit breaker controls are quite complex because of the number of functions that must be performed. The controls must include monitoring sensors for the compressed air, and equipment to start the compressor when the pressure is too

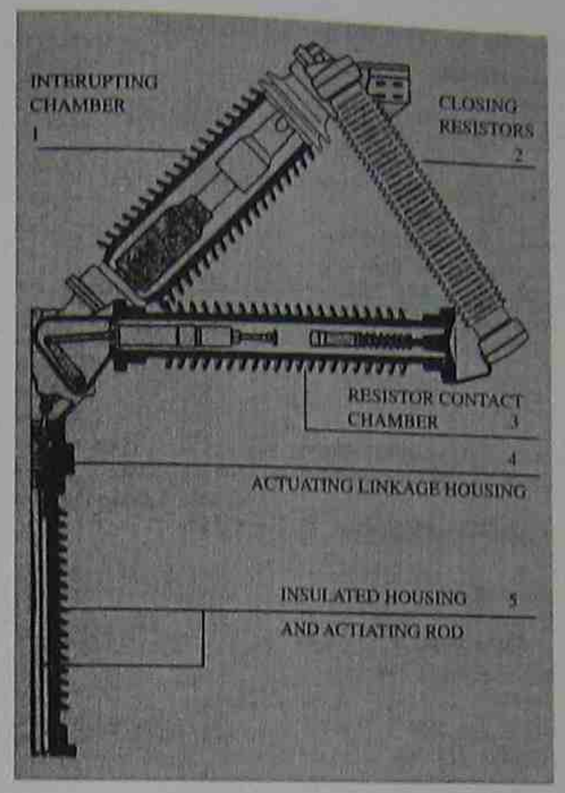


FIGURE 5.14 SF_6 interrupting unit with closing resistor (Modified from ASEA Brown Boveri. With permission.)

low, or send an alarm when the pressure is too high or zero. The interrupting medium level and/or pressure must be monitored. Any auxiliary heating equipment must be monitored and controlled.

The trip signal from the protective relays must be monitored and acted upon, and the status of the breaker (open or closed) must be relayed to the appropriate control station, so must any malfunction information. Figure 5.16 is an oil circuit breaker control panel.

5.1.9 High Voltage Circuit Breaker Comparison

Low voltage circuit breakers are usually air with arc interrupting fins, and higher capacity low voltage breakers also have magnetic blowout. Medium voltage breakers are oil, cross air blast, or vacuum typically, although many indoor medium voltage circuit breakers use magnetic blowout with interrupting fins. High voltage voltage circuit breakers use magnetic blowout with interrupting fins. High voltage and extra high voltage breakers are almost always either oil, axial air blast, or SF_6.

TABLE 5.1 Rating Structure for 145 GMB Breaker (Standard)

Symmetrical Current Basis of Rating
Table 4A, ANSI C37.06-1971

Breaker Type 145GMB63 DB No. 33-253 Standard Outline No. 2069C31
Breakdown kV 145 Voltage Range Factor K = 1
Continuous Current Rating 3000 Amps. Close & Latch Rating 101 kA
Rated RMS 3 Sec. Rating 63 kA
Rated Short Circuit Current 63 Sym. kA Max. Sym. Interrupting Rating 63 kA
Rated Overhead Line Charging Current Switching 80 Amp.
Applicable Duty Cycle CO–15 Sec.–CO Special Duty Cycle Rating Factor _____ %
one minute 60 Hertz Withstand 310 kV Impulse Withstand
Full wave 650 kV — Impulse
Full wave 488 kV — Interrupter
2 μsec. 838 kV — Chopped wave
3 μsec. 748 kV — Chopped wave

Open Time to part contacts 1.6 Cycles Closing time 16 Cycles
Reclose Time 30 Cycles Rated Interrupting Time 25–100% Rating 3 Cycles
1– 25% Rating 4 Cycles
Additional Time for Interruption Resistor Circuit 1.5 Cycles

Line Spacing	72	In.
External Creepage Over Bushing	93.5	In.
External Striking Distance Phase-to-Ground	46.31	In.
Phase-to-Phase	62.62	In.
Internal Striking Distance Phase-to-Ground	38.16	In.

Closing Circuit: Tripping Current:
E/Z Current 3 Amperes at 125 Vdc E/Z Current 28 Amperes at 125 Vdc
Cutoff Current 3 Amperes at 125 Vdc Cutoff Current 14 Amperes at 125 Vdc

Heater Requirements: Mechanism Type AA 10-80 ; Pneumatic
Volts 230 Stored Operations 5
Watts 700 Operating Pressure 270 psic
Range 225 psi (cutoff) to 270 psi

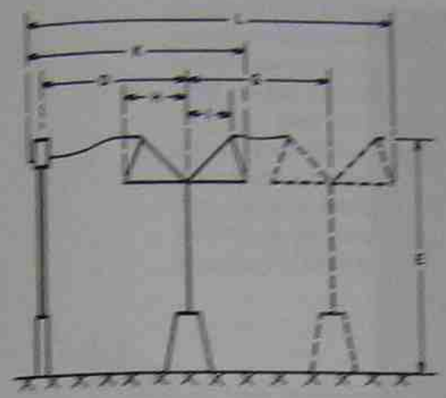
Compressor Requirements:
Motor HP 2
Voltage 230 Phase 1 Start Current 64 Amperes
Pump Up Time Lock-out to Normal 30 Minutes Run Current 12.5 Amperes

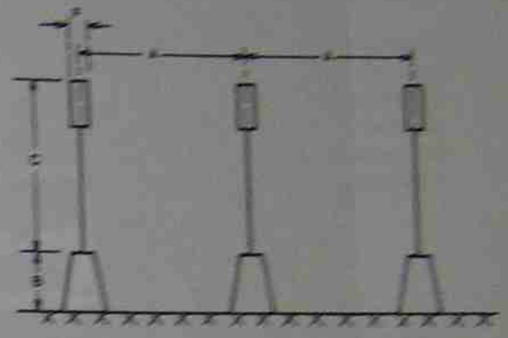
Condenser Bushing Data (not in breaker):
Type "OIC" Manufacturer Westinghouse Voltage Rating 145 kV Current 3000 Amperes

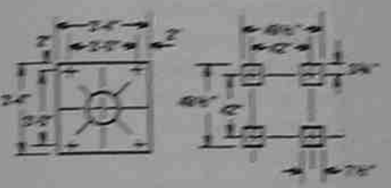
One Minute Withstand Test RMS Dry — 60 Hertz	335 kV
60 Sec. Withstand Test RMS Wet — 60 Hertz	275 kV
Impulse Withstand Test 1–1/2 x 40 Full Wave (Crest)	650 kV
Safe Cantilever Loading of Bushing Installed	150 Lb

Bushing Drawing Number 562D362 Ch4

Space Available for 18 Current Transformers No. of CT's Supplied 6
CT Type BYM CT Ratio 3000/5 Amperes CT Accuracy Class C800
Interrupter Type SB2A Contact Resistance Measured Between Bushing
Contact Travel 18 In. Top Terminals 127 Microhms
Break Distance Per Pole 33.5 In.
Head of Oil Above Contacts 45.75 In. Volume of Air Above Oil 8.8 Cu. Ft.

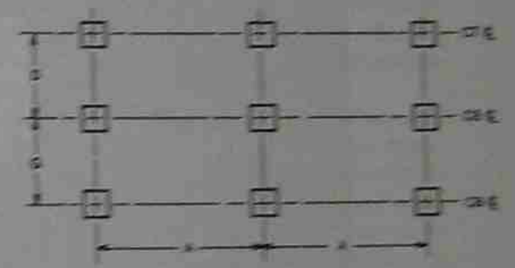






CT Base Plate (Typical)

CB Mounting Pad



Rating	A	B	C	D	E	F	G	H	I	K	L
242 kV	108	98	152	108	250	14	NA	NA	57	198	NA
362 kV	161	98	214	174	312	41	NA	93	66	266	NA
550 kV	236	98	227	180	325	41	220	87	60	—	533
800 kV	354	98	286	201	364	41	258	85	66	—	576

Dimensions in inches

FIGURE 5.15 SF_6 breaker dimensions



FIGURE 5.16 *Circuit breaker control panel*

Oil breakers have the advantages of using a very well established technology, low cost, easy installation, low maintenance, and dead tank design. Additionally, oil breakers need no closing resistors to break an arc, although closing resistors may be used to reduce switching transients. The disadvantages of oil breakers are: possible oil fire hazard, slower interrupting times than the other HV breakers, and physical size of breakers for voltages over 345 kV are excessive. Oil breakers are the oldest HV breaker type.

Axial air blast circuit breakers have the advantages of using a well established technology, high interrupt capacity, and fast interrupt times (usually one or two cycles). Their disadvantages are: they are noisy, relatively expensive, need very high pressure air (800 psi), use live tank designs, and must use closing resistors.

Two tank SF_6 circuit breakers have high interrupt capacities, a live or dead tank option, and need no closing resistors for arc quenching. Additionally, the live tank

design is well known in the United States. The disadvantages are: SF_6 tank heaters are needed in cold climates, high pressure SF_6 must be stored in the breaker and as a result the breakers have a high SF_6 leakage.

SF_6 puffer breakers are simpler than two tank types, have low leakage because only low pressure SF_6 (75 psi) is stored, and need no tank heaters until the temperature is -30°C. They need no closing resistors to break an arc. Currently the interrupting capacity of puffer designs is 20 to 30% less than two tank designs, and there is limited experience with puffer designs in the United States. All puffers are live tank designs. SF_6 puffer circuit breakers are rapidly becoming very popular for EHV applications.

5.2 RECLOSERS

Most faults (80-95%) on distribution and transmission lines are temporary, lasting from a few cycles to a few seconds. They are caused by such things as tree limbs falling or blowing across the lines and are removed when the limb burns off or is blown out of the line. Reclosers allow temporary faults to clear and then restore service quickly, but disconnect a permanent fault.

Reclosers are essentially special purpose, light duty circuit breakers. They can interrupt overloads but not severe faults. Reclosers sense an overcurrent, open, then after a preprogrammed time, reclose. They can be programmed to sense an overcurrent, open, and reclose several times (up to five times is typical) and after the preset number of operations remain open (lock out). This process is shown in Figure 5.17. They must be manually reset after lock out. The preset number of

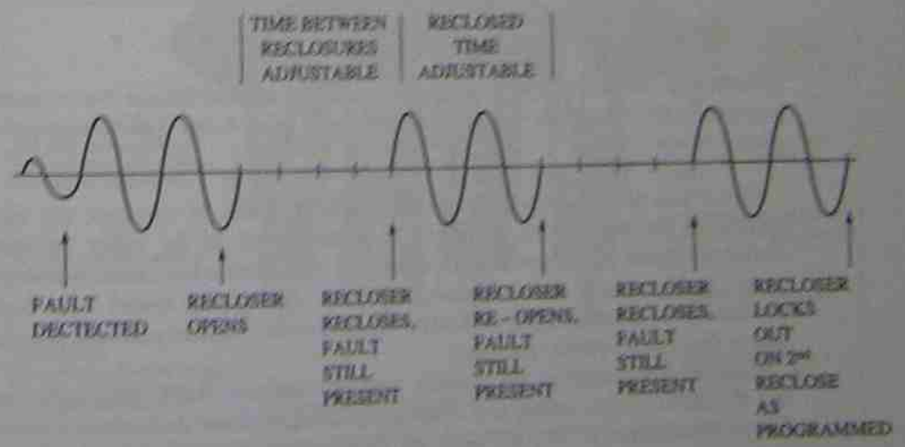
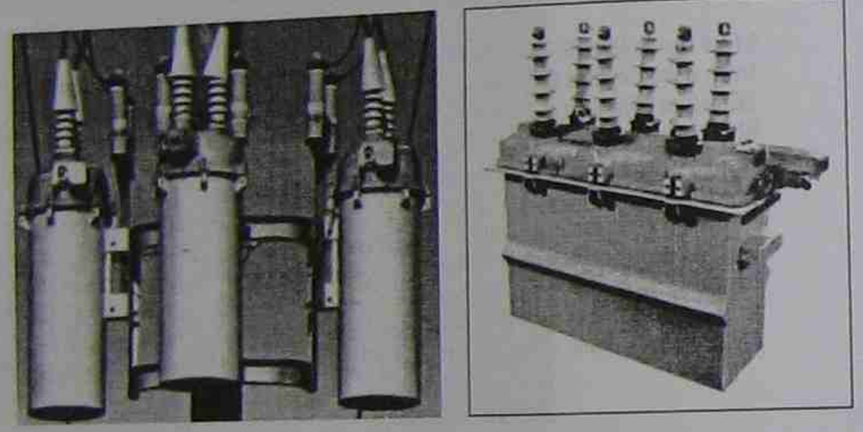


FIGURE 5.17 Recloser operation

operations is usually set at three or four. The time between reclosures and the time of the reclose can also be programmed. The time of reclose can be set from a couple of cycles (instantaneous) to around 600 cycles in fixed increments with 2 and 5 second reclosures common, and the time between recloses can be set from about 1 to 10 seconds in fixed intervals. This is necessary to coordinate the reclosers with other devices. If the recloser is not locked out and no further overcurrents are sensed for 120 seconds, the recloser resets to start counting from one again. Reclosers are much lighter, smaller, and cheaper than power circuit breakers. Pole top mounted reclosers are most used. Single-phase and three-phase reclosers are available. If single phasing of three-phase loads is possible on the protected circuit, as in a commercial area feeder, three-phase reclosers must be so that all three phases can be locked out from a single-phase trip. Single- and three-phase reclosers are shown in Figures 5.18a and 5.18b.



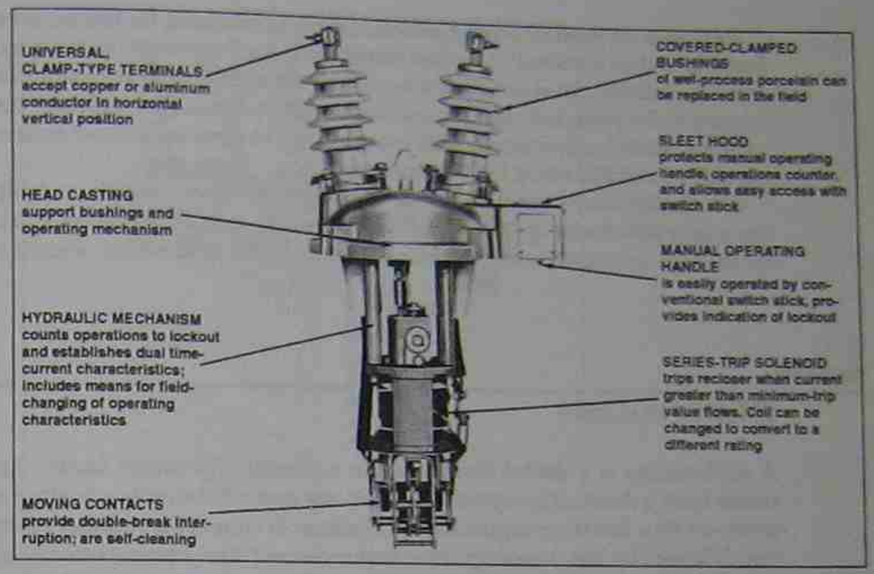
a

b

FIGURE 5.18 Reclosers (a) Single-phase recloser (Reprinted from Cooper Power Systems. With permission.) (b) Three-phase recloser (Reprinted from Cooper Power Systems. With permission.)

Two types of reclosers are currently manufactured. In one type the times are controlled by pistons in hydraulic cylinders, and in the other by electronic circuitry. Figure 5.19 show single phase and three phase hydraulic reclosers. Electronic reclosers are more flexible, accurate, and easily tested than hydraulic reclosers, but are also more expensive so electronic controls are used primarily on heavy duty three-phase reclosers.

Recloser interrupters are usually oil or vacuum. Some hydraulic reclosers use the same oil for timing and interruption. Single-phase reclosers are available to 560 A continuous at 34.5 kV with an interrupting capacity of 8 kA. Three-phase reclosers are available to 560 A continuous at 69 kV with an 8 kA interrupting capacity.



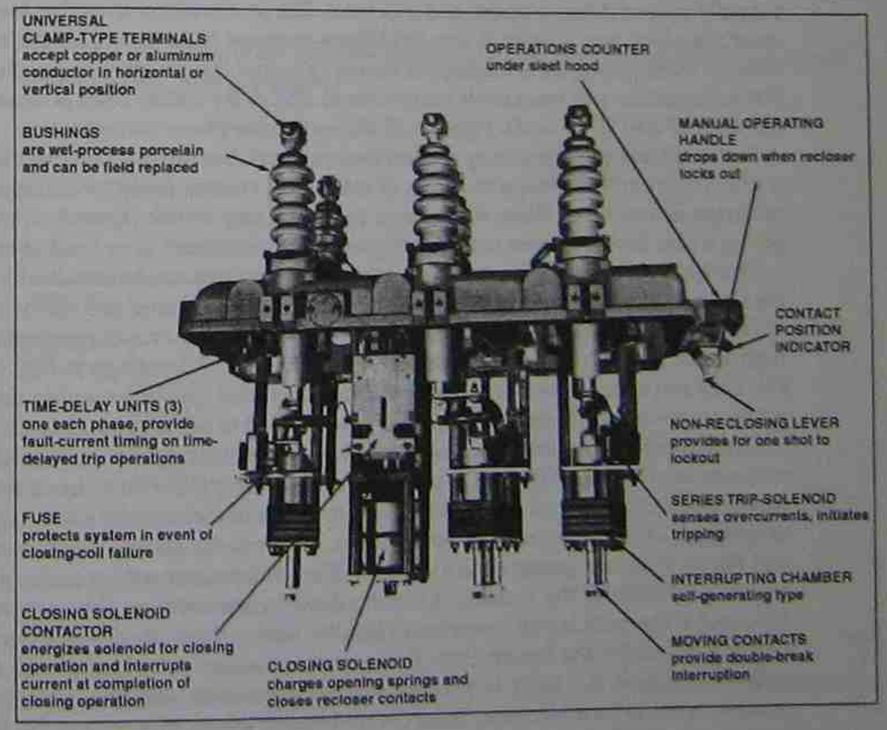


FIGURE 5.19 Recloser mechanism (a) single-phase, (b) three-phase (Reprinted from Cooper Power Systems. With permission.)

Reclosers are used to protect feeders leaving substations, for important taps on feeders, and to sectionalize faulted distribution lines to minimize the area out of service. Reclosers must be selected by voltage, continuous current, minimum fault current in the protected zone (it must be enough to operate the recloser), interrupt capacity, ability to coordinate with other protective devices, ground fault sensing capability, and BIL rating for transient protection.

Coordination means that the load side device should operate and clear a fault before the source side device operates. That way the source side device serves as a backup for the load side device and the minimum possible area is taken out of service.

5.3 SECTIONALIZERS

A sectionalizer is a device that is used to automatically isolate faulted line segments from a distribution system. It senses any current above its actuating current followed by a line de-energization by a recloser. It counts the number of overcurrent followed by line de-energization sequences and after a preset number of them (usually two or three) it opens and locks out. The sectionalizer must be manually reset after lock out. If normal line conditions continue for a preset length of time after an overcurrent, de-energization sequence below the preset lock out number, the sectionalizer will reset itself to zero count. The delay before reset is usually set between 30 and 90 seconds. Figure 5.20 shows a three-phase sectionalizer.

Sectionalizers can break very modest overcurrents, but are normally not used to do so. Their current ratings in excess of rated load current (only twice rated load on larger units) are to allow the recloser to handle any inrush current on re-energizing a line. Sectionalizers are not designed to break current in normal operation.

Two types of sectionalizers are available. Smaller ones are hydraulically operated in a manner similar to reclosers, and higher capacity ones are electronically operated. Sectionalizers are available to 34.5 kV with continuous current ratings as high as 600 A, interrupt currents as high as 1320 A, and BIL ratings as high as 150 kV. They can be equipped with voltage restraint so that only source side de-energizations are counted, and they can also be equipped to sense ground faults.

Circuit breakers, reclosers, and sectionalizers are used together to provide better protection of lines. Figure 5.21 shows a one-line diagram with a circuit breaker, transformer, recloser, and the sectionalizers for three feeder circuits and a tap from one branch. Assume a fault on feeder three. The recloser senses the overcurrent and opens. After the preset time it recloses. The sectionalizer senses each overcurrent and opening of the recloser. After the third recloser reclose the sectionalizer locks out if the fault is still present and isolates feeder three. It operates when the recloser opens for the fourth time. If the recloser senses a fault after the fourth reclose it means the fault is between the sectionalizers and the recloser. The recloser is set to lock out then. If the circuit breaker opens that means the fault is between the breaker and the reclosers or that the recloser failed to operate. If the

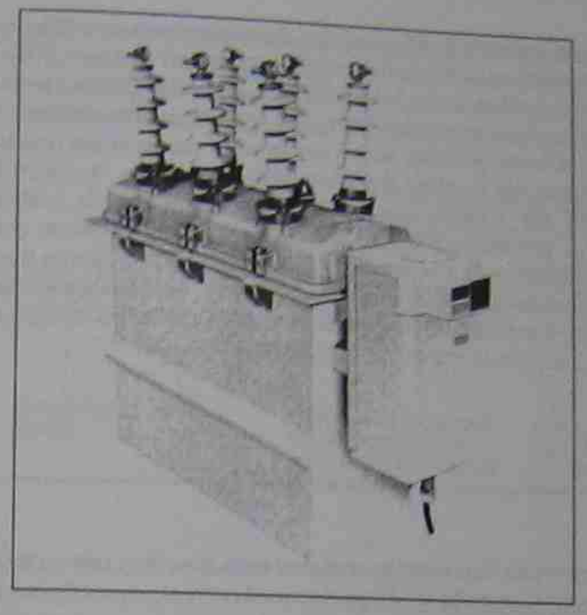


FIGURE 5.20 Three-phase electronically controlled sectionalizer (Reprinted from Cooper Power Systems. With permission.)

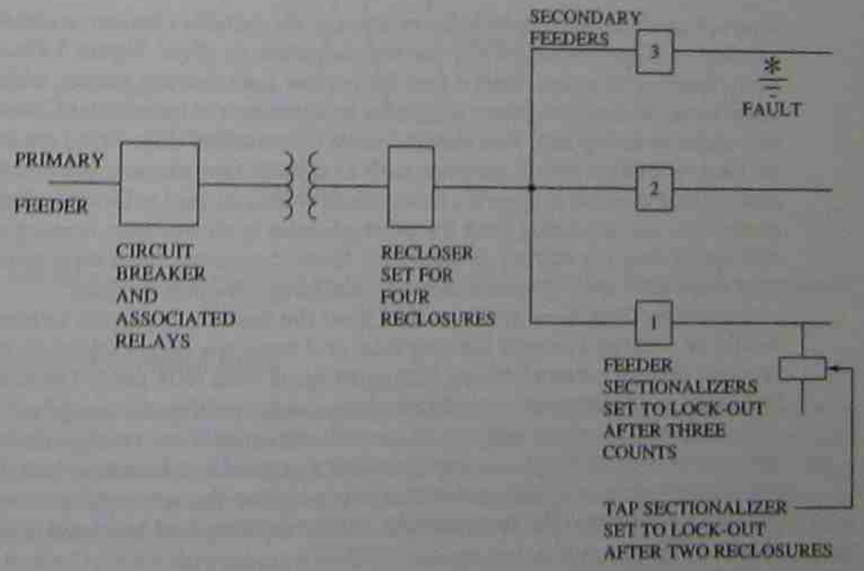


FIGURE 5.21 Circuit breaker, recloser, and sectionalizers together

fault had been on the top circuit of feeder one the top reviewer would have locked out upon the third opening of the reviewer (after an several reviews). If the fault is temporary in nature, such as a tree branch fallen across the line, the reclosure and the associated sectionalizer would reset to count equal zero after a short while.

Variations of the scheme outlined above are in wide use with the power comes and actuating currents set to meet the particular application. A circuit breaker might cost $30,000 for a particular 138 kV 2000 A application, with another $15,000 to $20,000 in protective relaying and instrument transformers. A reclosure would cost about $8000 and a sectionalizer about $20,000 for use in the protective scheme. By combining circuit breakers, reclosers, sectionalizers, and fuses (see the next section) the distribution system protection can be good while the cost is minimized.

3.4 FUSES

Fuses are one-time devices that must be replaced each time they open a fault. They use a metallic element that melts when an overload current passes through it. The melted element separates breaking the circuit.

3.4.1 Low Voltage and Current Limiting Fuses

Low voltage fuses use zinc, copper, or silver as the metallic element, while medium and high voltage fuses typically use tin, cadmium, or silver. Figure 3.22a is a cutaway drawing of a fuse. Notice that the narrow fuse element points, which melt, are in series so that the voltage is divided between two or more breaks, making the arcs easier to extinguish. Two element fuses (often called slow blow) are available for loads with high inrush currents, such as motors. One element is a normal fault interrupting element to open if a short circuit causes current to be several times the continuous current rating, and the other element is an overload sensing element that opens only if a current of about five times the continuous rating remains for over a second. Lower current overloads take longer to open the fuse.

Current limiting fuses are fuses that limit the peak fault current to less than it would be without a current limiting fuse and break the circuit (clear) in less than one-half cycle. A current limiting fuse cartridge is filled with sand. The sand melts but does not disassociate so it absorbs heat energy cooling the arc, plus the sand tilling leaves little air to support an arc. Silver elements are used in the best low voltage current limiting fuses because silver is a good conductor so very little silver is required to carry the continuous current. Thus the arc contains fewer metal ions to be quenched. The response of a current limiting fuse to a fault is shown in figure 3.22b.

Current limiting is valuable because both the heating and mechanical damage caused by a fault is proportional to the square of the current. The heating is the one

current squared, and the mechanical, caused by magnetic forces, is the peak current squared. Current limiting fuses reduce both the rms and peak fault current.

Current limiting fuses are available with voltage ratings to 69 kV, continuous current ratings to several thousand Amperes, and interrupt current capacities to 200 kA.

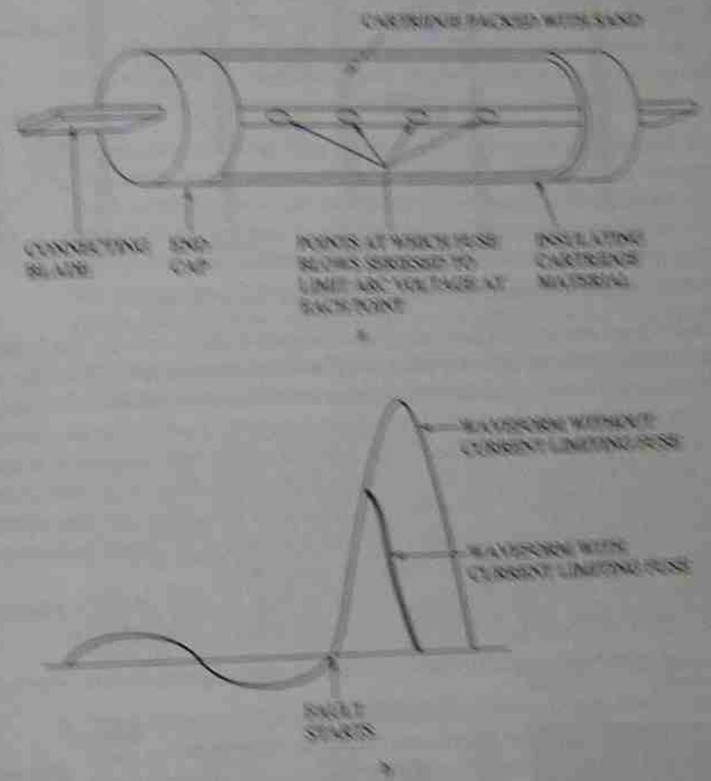


FIGURE 3.22 Current limiting fuse a) Mechanical configuration and b) fault current waveform

3.4.2 Expulsion fuses

Expulsion fuses, when blowing, use the heat generated by the melting element to decompose a material on the inner fuse wall. The decomposed material produces a high pressure turbulent gas that blows the arc out the end of the fuse tube. They sound like a shotgun when they blow. The material is usually the interior fiber of the fuse tube. boric acid powder on the interior of the fuse tube which melts, then turns to a turbulent steam, then blows the arc out, or a noninflammable gas such as carbon tetrachloride. A number of expulsion fuses are shown in figure 3.23. Expulsion fuse links are usually tin.

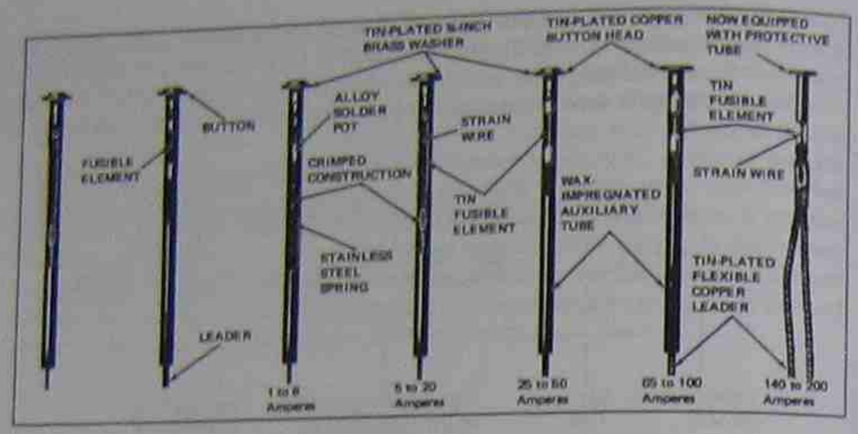


FIGURE 5.23 Expulsion fuse links (courtesy of Cooper Power Systems)

Expulsion fuses are not independent of their holders (called cutouts). The holders are designed to help break the arc by pulling the fuse element ends away from the melted point, and to provide an indication, visible from a considerable distance, that the fuse is blown. To accomplish this the cutout fuse holders are spring loaded. The fuse is attached to the spring-loaded fuse clip support. The fuse has a fine, high resistance strain wire running through it to support the force from the spring. The strain wire softens enough to break when the fuse blows. The spring-loaded part of the cutout then flies apart with great force. The fuse cutouts are designed so that they cannot be closed without a good fuse in them. Figure 5.24 shows some expulsion fuse cutouts.

Expulsion fuses are available with voltage ratings to over 34.5 kV, continuous current ratings to over 1000 A, and interrupt capacities to over 12.5 kA.

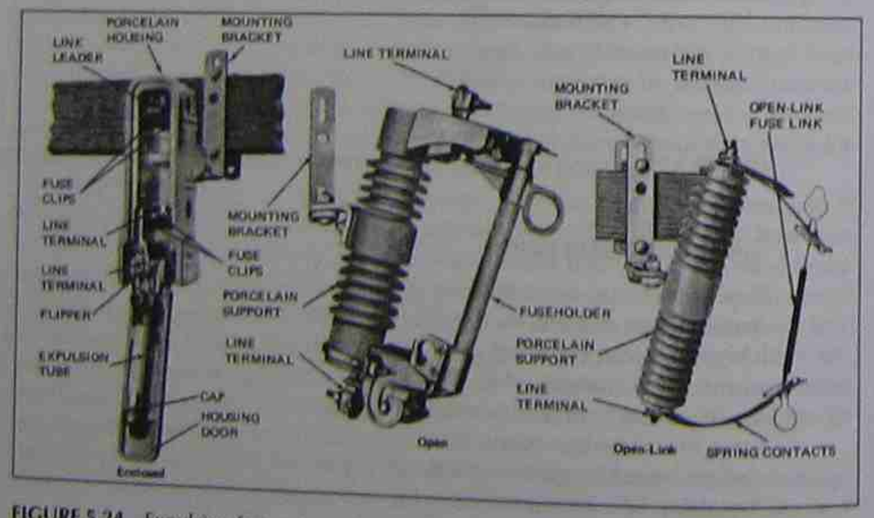


FIGURE 5.24 Expulsion fuse cutouts (courtesy of Cooper Power Systems)

5.4.3 Fuse Application Considerations

The six items to be considered for fuse applications are also items that must be considered for any overcurrent protection device.

1. Voltage: The voltage rating of the fuse must be greater than the system voltage. The fuse holder or cutout voltage rating must also be higher than the system voltage, and the BIL of the medium and high voltage fuse cutouts must be acceptable for the application. Higher voltage fuses are usually larger than lower voltage fuses to allow sufficient room to break the arc.

2. Continuous current: The continuous current rating should be 125% of the maximum load current for low voltage fuses, with the exception of bolt-on fuses in which they can be equal. Imprecision and variables such as ambient temperature can lead to fuse operation when the maximum overload current has not been exceeded if the fuse continuous current rating is exactly equal to the maximum allowed current. Medium or higher voltage fuses should have a continuous current rating equal to or higher than the maximum load current.

3. Interrupt Capacity: The fuse should be able to interrupt the highest fault current available in the zone to be protected.

4. Current Limiting: The desirability of using current limiting fuses should be considered. Often a current limiting fuse can limit the maximum current of a severe fault to a value that allows lower interrupt capacity devices to be used downstream for overload protection. An example of this is the use of current limiting fuses to protect downstream low voltage breakers in lighting panels. High interrupt capacity in a low voltage molded case breaker is very expensive, so the higher cost of the current limiting fuse is easily justified. Current limiting fuses may allow the use of equipment with lower fault current withstand ratings, such as bus structures, in some applications.

5. Time-Current: The time-current characteristic of a fuse is the time it takes the fuse to blow with different size fault currents. Fuses blow more quickly at high currents than at low currents. Figure 5.25 shows the time current curves for EEI-NEMA type T and K links, slow and fast links, respectively. The slow links allow normal motor and transformer inrush current to occur without blowing the fuse. Low voltage slow fuses use dual elements to obtain slow-blow characteristics.

6. Fuse Coordination: Coordination is accomplished by making sure the downstream fuse clears before the upstream fuse element melts. Figure 5.26 shows the melt and clear curves of a fuse. This principle is applied to the time current curves to select fuses. Coordination charts are supplied by fuse manufacturers to simplify the task of coordination. The time current curves to be coordinated need not all be fuse curves. Fuses can be coordinated with circuit breakers and reclosers. The curves for each are superimposed for evaluation. Figure 5.27b shows a group of time current melt-clear curves for coordination.

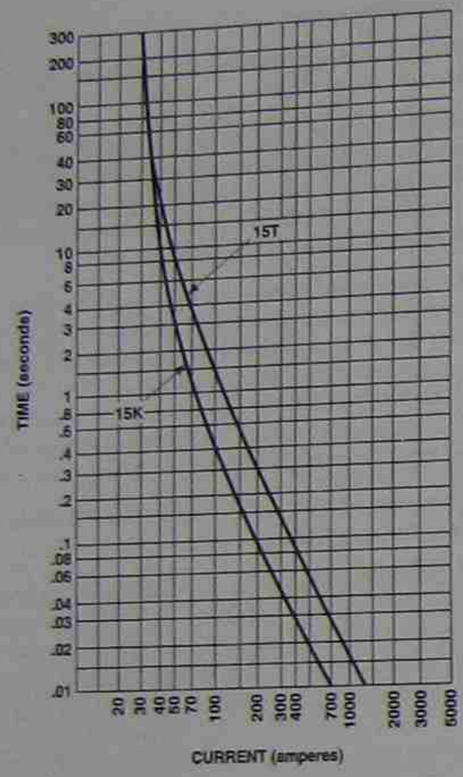


FIGURE 5.25 Fuse time-current curve (courtesy of Cooper Power Systems)

Example 5.1:

Select the proper fuses from the time current curves of Figure 5.27b, and continuous current ratings in Table 5.2, for proper overcurrent protection coordination of the circuit shown in Figure 5.27a. The maximum and minimum fault currents for each segment of the circuit is shown in the circles (we will learn to calculate fault currents a bit later).

Solution:

An interrupt current rating of 2400 A is sufficient for any of the circuit fault currents, so we will select fuses with this rating or higher. This is an easily obtained rating.

Starting at point C, we find from Table 5.2 that the 15T designated fuse carries 23 A continuous, so it is usable at point C. At the maximum fault current at point C it melts in 0.008 s and clears in 0.03 s.

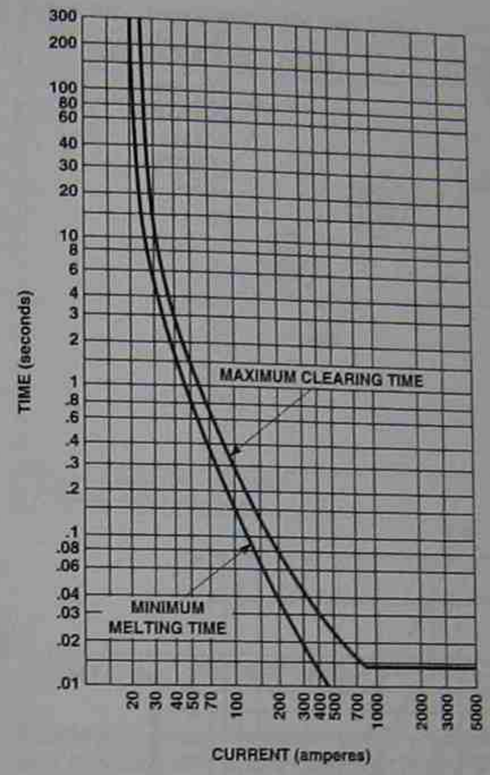
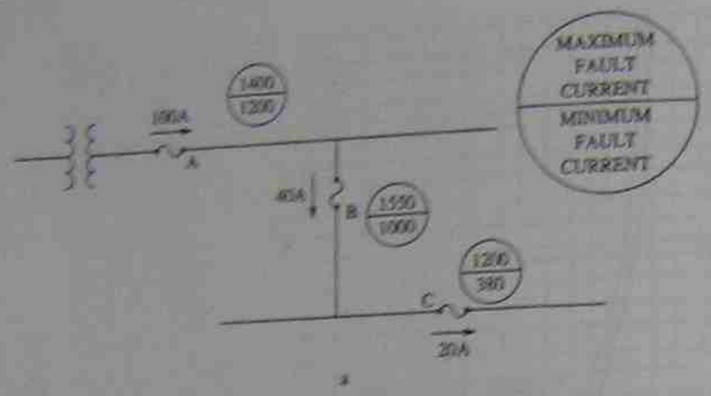


FIGURE 5.26 Melt-clear graph for 10K fuse link (courtesy of Cooper Power Systems)

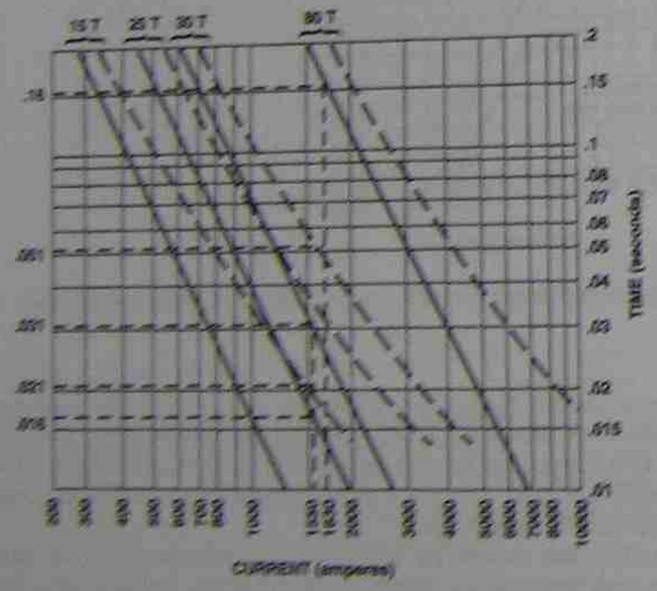
Next to point B. The next fuse on the time current chart of Figure 5.27b, the 25T, cannot be used because it cannot carry 40 A continuously. The 30T can carry 45 A continuous. Its melt time is 0.033 s, and its clear time is 0.056 s at the maximum fault current. It meets the criteria of not melting until the downstream fuse has cleared.

The 80T is able to carry 100 A continuously, and at the maximum fault current its melt time is 0.16 s, which is longer than the clear time of the 30T. Its clear time is off the chart, but we can estimate it at about 0.3s. It coordinates with the 30T, which coordinates with the 15T.

The fuses should also coordinate at the minimum fault currents. The method is the same. As long as the time-current curves do not cross, there is usually no problem at the minimum fault currents, but the coordination should be checked anyway. Once again, fuse manufacturers coordination tables simplify the job of fuse coordination.



a



b

FIGURE 5.27 Fuse coordination (a) Circuit Fuse coordination (b) Time-current curves, minimum melting curves are solid, maximum clearing curves are dashed (courtesy of Cooper Power Systems)

TABLE 5.2 Fuse Ratings, Tin Fuse Links

IEEE-NEMA K or T rating	Continuous current (amperes)
6	9
8	12
10	15
12	18
15	23
20	30
25	38
30	45
40	60*
50	75*
65	95
80	125†
100	150†
140	190
200	280

*Only when used in a 100 or 200 A cutout.
†Only when used in a 200 A cutout.

5.5

LIGHTNING PROTECTION

People have always been fascinated by lightning. The immense power and beauty of a lightning bolt is awe inspiring. Based on recorded tower strikes the current in a lightning strike can be as high as 200,000 A, but only about half of the strikes exceed 15,000 A. Lightning strikes power lines somewhere between 39 and 232 times per 100 miles each year on the average. The number varies greatly from year to year, and for different geographical locations, with Naples, Florida, having the greatest number of lightning storms per year in the United States. The National Weather Service keeps maps showing the number of strikes by location. The number of lightning strikes per year on electric power lines is sufficient to provide unreliable service in most areas if lightning protection is not used.

5.5.1 Lightning

Cloud Charge Distribution is the key to lightning formation. There are many theories on the formation of the cloud charges that lead to lightning. The most accepted ones are those of C. T. R. Wilson and G. C. Simpson with some modifications. Both relate ascending air currents and raindrop size to charge accumulation. They are summarized briefly in the following paragraphs.

The atmosphere is filled with ions that attach themselves to dust particles and small water droplets. The larger ions have low mobility (ease with which they move) and

smaller ions have higher mobility. Many larger ions are positively charged. Mackey found that water droplets in a high electric field become elongated because water is easily polarized; it has a dielectric constant of about 80. At very high electric fields, around 10,000 volts/meter, drops with an average diameter greater than 0.15 cm set up a glow discharge that evaporates water until the droplet size is reduced. Wilson posited a normal atmospheric electric field of approximately 1 V/cm at the Earth's surface that decreases to about 0.02 V/cm at 30,000 ft. Relatively large drops of water polarize in the field, positive at the bottom and negative at the top. Large drops fall fast to the cloud bottom sweeping up negative ions on their bottom as they fall, becoming negatively charged. Smaller drops fall more slowly or are held near the top of the clouds by air currents. Thus the smaller drops pick up the more slowly moving positive ions. In this fashion the top of the clouds become positively charged and the cloud bottoms become negatively charged. Ascending air currents greater than 8 m/second keep the cloud together.

Cloud movement causes an incoming high air flow at the front of the cloud that excludes larger water droplets and breaks up any that do get through. This causes the lower front part of the cloud to be positively charged near the bottom but most of the cloud bottom is negatively charged. Figure 5.28 shows a cloud whose charge distribution incorporates the modified theories of Wilson and Simpson. The theories are only partly verified but they are fairly consistent with balloon and other measurements. There is room for argument though.

The lightning stroke is not a simple phenomenon. Measurements indicate that an average of 90% of the lightning strokes lower negative charge to the ground and 10% raise negative charge to the cloud. Lower current amplitude strokes are as much as 37% positive (negative to cloud) and 63% negative. No one is sure why the difference in the percentage of positive strokes with stroke size. The fact that most of the cloud bottom is negatively charged may account for most of the strokes being negative.

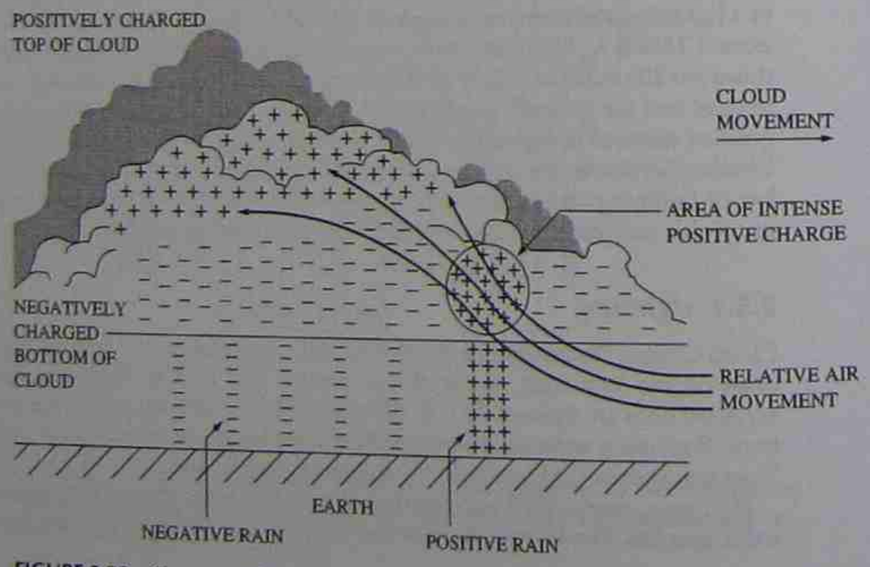


FIGURE 5.28 Charge conditions in a thundercloud from Simpson's revised theory.

Figure 5.29 shows the sequence of a lightning stroke. The initial streamers, or pilot streamers, are only a few amperes in amplitude. It has been posited that the initial streamers are following the paths of cosmic particles as they pass through the Earth's atmosphere. They move in jumps or steps of about 50 meters with each step being quite straight, but each one propagating in a new direction. The steps each propagate at about one-sixth the velocity of light, but the overall streamer propagation is only about 0.05% of the velocity of light. The leader propagates in a zigzag path.

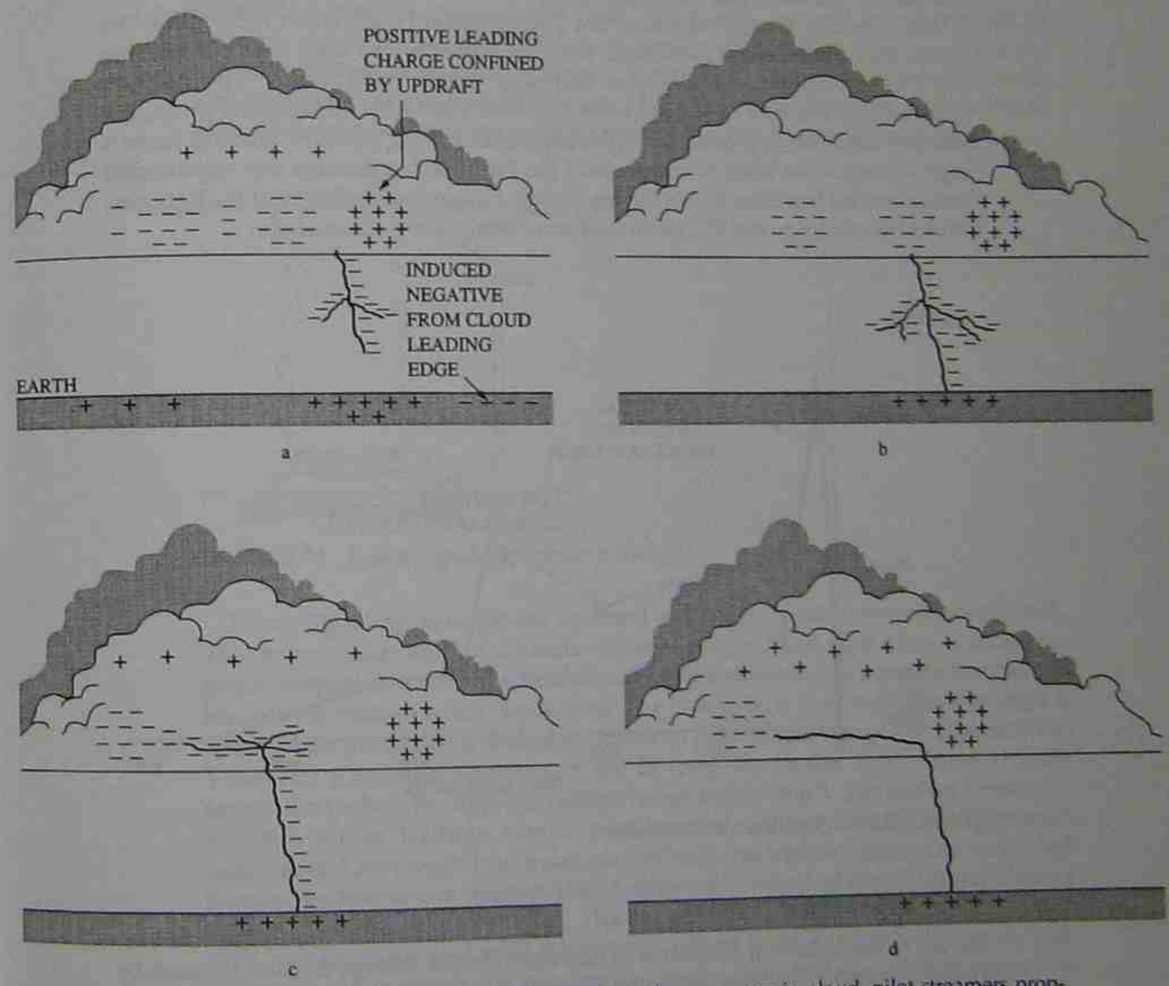


FIGURE 5.29 Lightning strike to ground (a) Charge centers in cloud, pilot streamers propagate towards Earth (b) Streamer touches ground, heavy return streamer propagates toward cloud (c) First charge center discharged to Earth, interior streamers developing between charge centers, second pilot leader along same ionized path about to touch Earth (d) Heavy return streamer to Earth, charge movement between charge centers in interior return streamer.

When the leader strikes the Earth, usually at the highest grounded point, the bright return stroke occurs following the same path as the leaders. It propagates at about 10% of the speed of light. The return stroke consists of the discharge at a high current of the charge distributed along the leader to ground. When the return stroke reaches the charge center of the cloud, more charge is lowered to the ground through the luminous ionized path of the return stroke. It takes about 10 ms for the step leader to reach the ground, but only about 50 to 100 μs for the return stroke and discharge. Most lightning flashes consist of a number of strokes that follow the same path discharging more than one cloud charge center.

The lightning current waveform (an average shape) is shown in Figure 5.30. The initial very high current associated with the return stroke lasts only a short time but the subsequent charge center discharge takes much longer. The voltages induced on a line by a stroke can reach 5 million volts without lightning protection and low impedance grounds. A lightning stroke hitting a power line will cause a high voltage wave front to travel along the line that can damage any unprotected equipment by breaking down the insulation. Notice the similarity of the lightning stroke waveform to the BIL test waveform. This is not a coincidence.

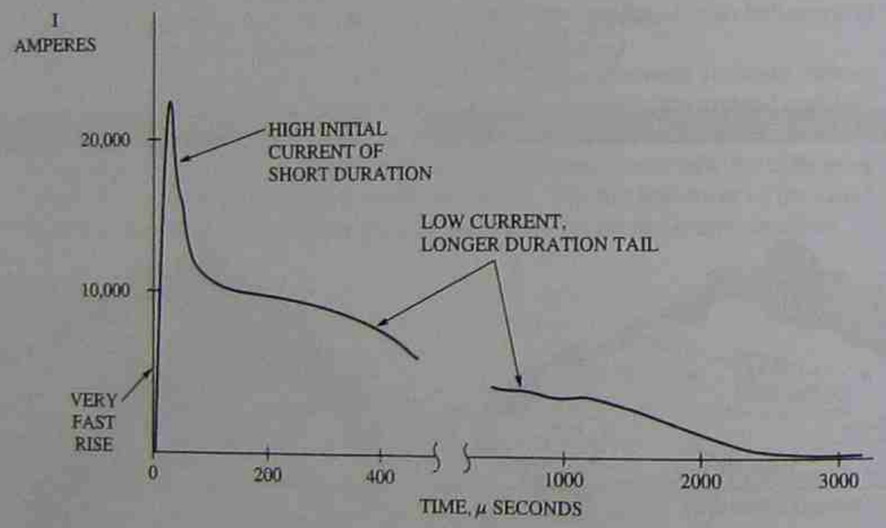


FIGURE 5.30 Lightning strike waveform

5.5.2 Lightning Arresters

The job of the lightning arrester is to clip the induced voltage transient caused by a lightning strike at a level below the BIL, but above the normal operating voltage, of the protected equipment. The lightning arrester should be an insulator at any voltage below the protected voltage, and a good conductor at any voltage above to pass the energy of the strike to ground.

The first lightning arresters were spark gaps such as the one in Figure 5.31. A spark gap breaks down at a voltage governed by the distance between the electrodes and the condition of the air between the electrodes—wet, dry, clean, or dirty. Enclosed, sealed electrodes with controlled interior atmospheres are often used to remove the variability of the spark breakover voltage caused by the uncertainty of the atmospheric condition. After a spark gap breaks down its impedance is very low, and the normal working voltage of the line must be sustained by auxiliary impedance, or the gap must become nonconducting after the strike quickly enough that the lightning arrester itself does not act as a fault. Careful selection of lightning arresters is required to accomplish this. Spark gap, as well as other types of arresters, are equipped with isolators to remove the arrester from service if the arrester becomes damaged. The isolator is essentially a fusing structure that can handle high short-time current, but cannot handle long-term current such as would occur if the arrester break over voltage dropped below the peak line voltage.

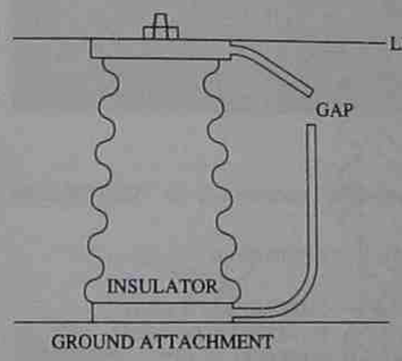


FIGURE 5.31 External spark gap lightning arrester

Newer lightning arresters use enclosed spark gaps plus a ceramic valve block. The ceramic valve block is a tubular ceramic holder filled with discs of an appropriate material that has a predictable voltage breakdown and sustains the applied breakdown voltage while conducting. For example, if the breakdown voltage is 400 V, when the device is shunting current to ground its voltage remains near 400 V (usually a bit higher because of the IR drop across the device internal resistance), then when the applied voltage drops below 400 V the device stops conducting. Silicon Carbide was a popular low voltage transient suppression material, and zinc oxide is popular for medium and high voltages. Zinc oxide has become popular at low voltages also. A drawing of a typical distribution lightning arrester is shown in Figure 5.32a. The ceramic valve block is filled with discs of solid zinc oxide stacked until the correct voltage breakdown voltage is reached. The spark gap prevents any current flow until a transient occurs. The zinc oxide material does not have an infinite nonconducting impedance so it will draw a quiescent current without the spark gap. A lightning induced voltage transient will break down the spark gap, the spark gap impedance will drop very low switching

the ceramic valve block between the line and ground, and the valve block will prevent the line voltage from rising higher by shunting the stroke current to ground.

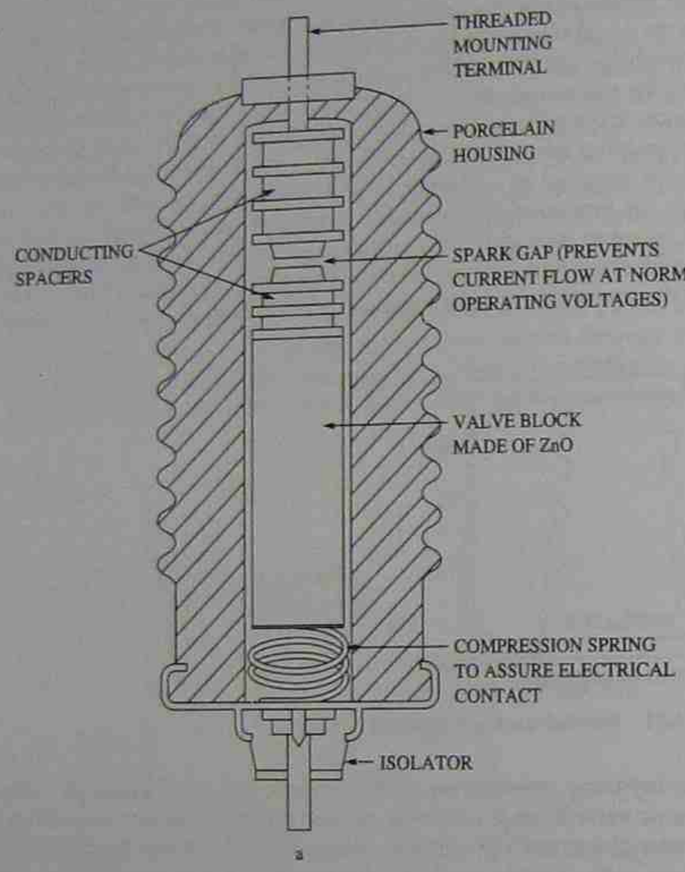
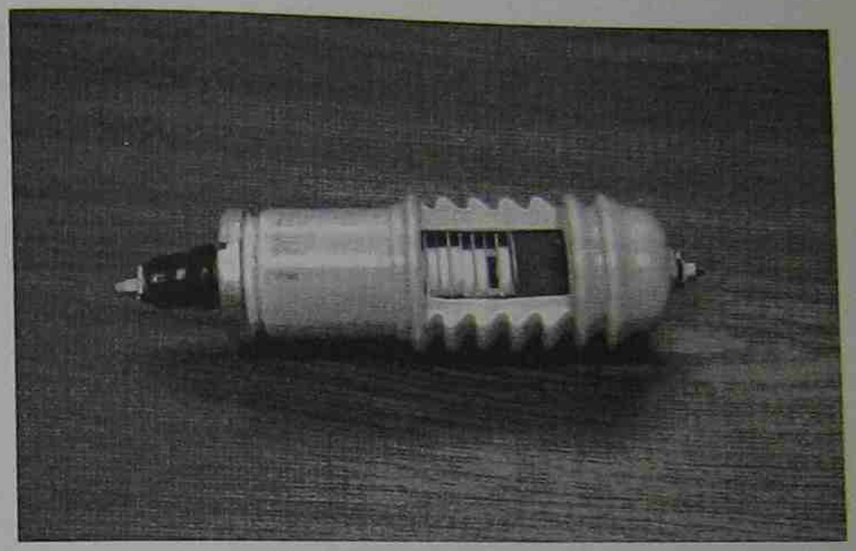


FIGURE 5.32 (a) Distribution lightning arrester

The lightning arrester should be connected as close as possible to the terminal of the equipment being protected to reduce the voltage build up from IX_L on the connecting lines before the spark gap breaks down. Figure 5.33 shows the lightning arrester connection for one phase of a distribution transformer; one set of arresters is used for each phase. Note the separate ground wires for the lightning arresters. The grounded tank is not considered a reliable enough ground for the arrester. The ground wire is solidly connected to the buried metal stake or wire mesh that serves as the station ground. Only the line side of a building distribution transformer has a lightning arrester because the line is most likely to be struck, although a tall building will very likely have a series of lightning rods for its protection.



b

FIGURE 5.32 (b) Distribution lightning arrester

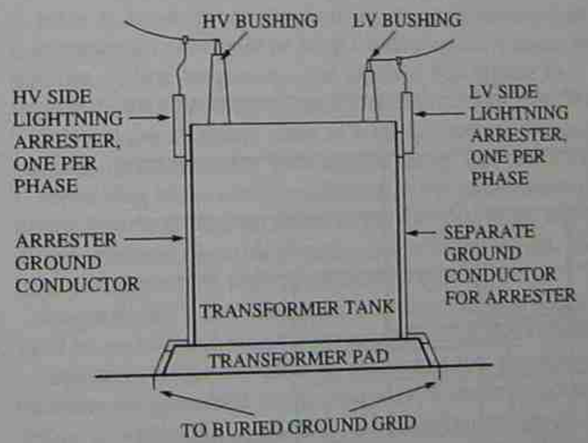


FIGURE 5.33 Lightning protection of distribution substation power transformer

Figure 5.34 shows a typical connection for a single-phase lightning arrester and for a three-phase wye with neutral interconnection. A delta would not have the neutral interconnection. The margin of protection (PM) by a lightning arrester is

$$\text{PM} = \frac{\text{BIL} - \text{arrester discharge voltage}}{\text{BIL}} \tag{5.1}$$

Where the arrester discharge voltage is the arrester break down voltage plus the arrester internal voltage drop at the expected stroke or transient current. The discharge voltage may be 5% higher than the break down voltage. The margin of protection should not be lower than 0.2.

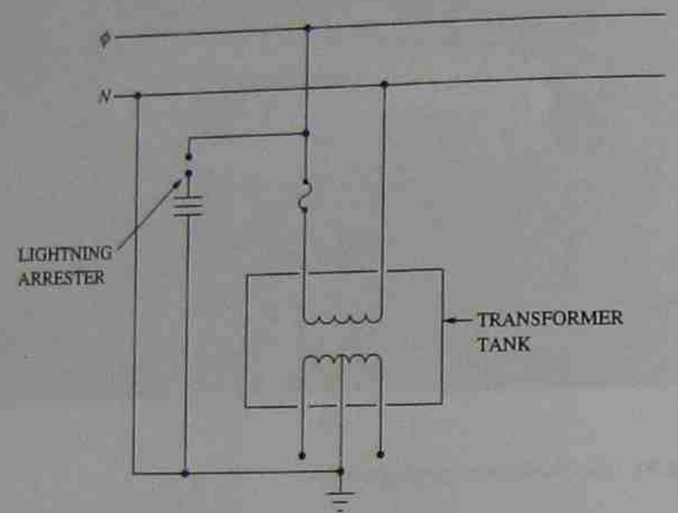


FIGURE 5.34 Distribution transformer lightning and surge protection diagrams
(a) Single-phase transformer and (b) three-phase wye, neutral interconnected transformer

5.5.3 Shield Wires for Lightning Protection of Lines

Shield, or static wires, are conductors strung above the load carrying conductors on transmission and distribution towers and poles to protect the load carrying conductors from lightning strikes. The shield wires provide a place for lightning strokes to terminate instead of the power carrying conductors, thereby protecting the power conductors. Almost all lines 34.5 kV and above use shield wires.

Figure 5.35a shows the shield wire as it is strung on a pole. Shield wires provide a 30° zone of protection on either side of a vertical line drawn from the ground to the wire, as shown in Figure 5.35a. Towers in which the power carrying conductors do not fit within the zone of protection of a single shield wire use two, as shown in Figure 5.35b. Equipment in station yards can be protected by placing it within the 30° protection zone of a tall mast with a conductor running from the tip to ground, as shown in Figure 5.35c. Shield wires must be grounded to provide a path for the lightning current. The lightning current is very high but of short duration so the conductors, sized to carry the peak current for only a few microseconds, can be relatively small.

5.6 PROTECTIVE RELAY INTRODUCTION

A relay is an electromechanical- or microprocessor-controlled electronic system that senses an abnormal or fault condition, such as an overcurrent, under or over voltage, or low frequency, and sends a trip signal to a circuit breaker. They are used to protect generators, transformers, motors, and lines.

Other types of relays exist as well as protective relays. They are systems that perform functions other than fault sensing. The major types are listed below.

Monitoring relays verify conditions in the power system or power system protection system and send an alarm when the conditions are abnormal. Monitored conditions include network phasing and voltage levels. Monitoring relays often are used in conjunction with protective relays.

Programming relays sequence events or detect sequences of events. They are used to control and monitor synchronization and reclosing sequences.

Regulatory relays are used to determine if a parameter, such as line voltage, is between programmed limits, and send a control signal to force the parameter to return to within the limits, such as a tap change signal, if the parameter leaves the limits. They send an alarm signal if the parameter will not return to within the limits.

Auxiliary relays provide miscellaneous functions within other relaying systems. Timers are an example of an auxiliary relay function.

Relays must operate reliably and quickly, be economical, and selective, operating only on the desired input. Entire books have been written about protective relays and their applications. The remarks in this section are introductory. We will consider relay types as needed throughout the text, but in this section we will discuss only overcurrent relays, under voltage relays, and differential relays.

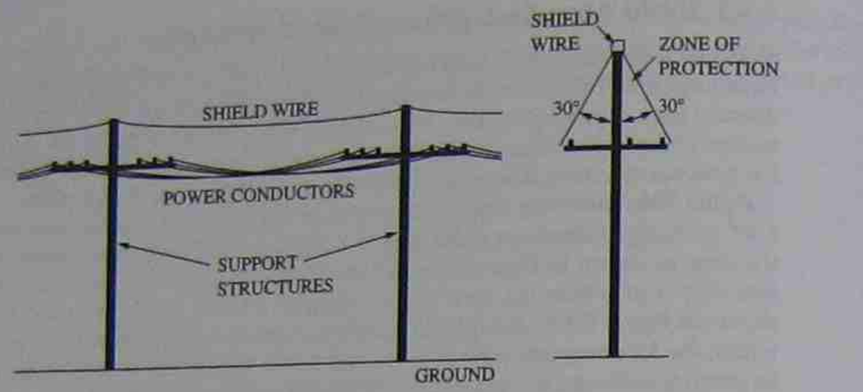


FIGURE 5.35 Shield (static) wire (a) Narrow tower or pole (b) wide tower and (c) mast for substation yard protection

5.6.1 Microcomputer Controlled Relays

The use of microprocessors in microcomputer relay systems has allowed relay systems to perform several relaying functions with a single central relaying package in a very economical manner. The multifunction capability of microprocessor-controlled relay systems has resulted in a drop in the cost per function of such relays when compared to electromechanical relays.

A one-line diagram of a microcomputer-controlled relay system is shown in Figure 5.36a. The current and potential transformers provide current and voltage

information to the relay from which the relay microcomputer calculates any additional parameters needed, such as impedance, VAR and power quantity and flow direction, trends over a fixed time, and running averages of quantities as needed. In addition the current entering and leaving the protected machine or section can be compared, called *differential relaying* (covered later in this chapter), because a difference in these currents indicates a fault within the protected section. The relay can also make use of other parameters, such as temperature and vibration sensor outputs, to monitor more conditions than electromechanical relays are able to monitor. The relay will react to out of limit parameters by sending a trip signal to a circuit breaker and an alarm signal to a central monitoring point via a telecommunication system. In addition to responding to out of tolerance parameters, a microcomputer-controlled relay may have the capability of sending monitored data, such as current, voltage, temperature, vibration, or other information, back to a central control room via a data communication system. Thus a single microcomputer-controlled relay can monitor and respond to abnormal conditions while gathering data for use in control and trend analysis.

Figure 5.36b is a block diagram of the microcomputer-controlled relay. The data acquisition system collects the transducer information and converts it to the proper form for use by the microcomputer. Information from current transformers (CTs), potential transformers (PTs), and other systems is sent through an isolation transformer or optically-coupled amplifier, amplified if needed, and sampled at a frequency well above the power line frequency (at least several kilohertz). The signal samples are digitized with an analog to digital converter and fed to registers in the microprocessor system. The microprocessor then compares the information directly with preset limits for over/under voltage, overcurrent, over/under

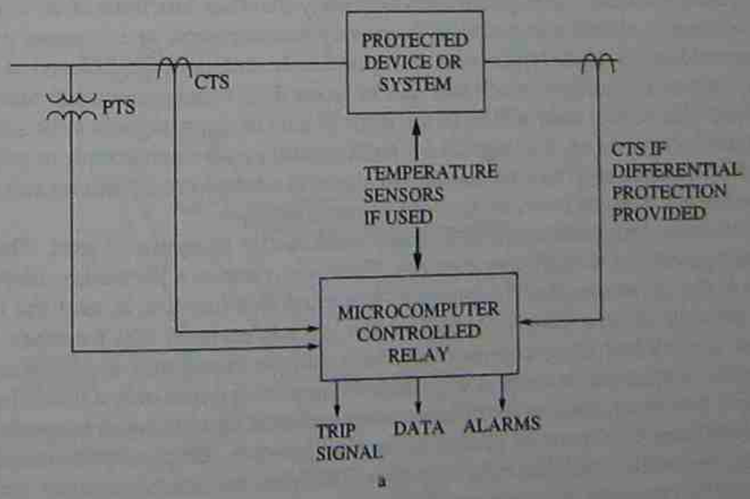


FIGURE 5.36 Microprocessor controlled relay system (a) System

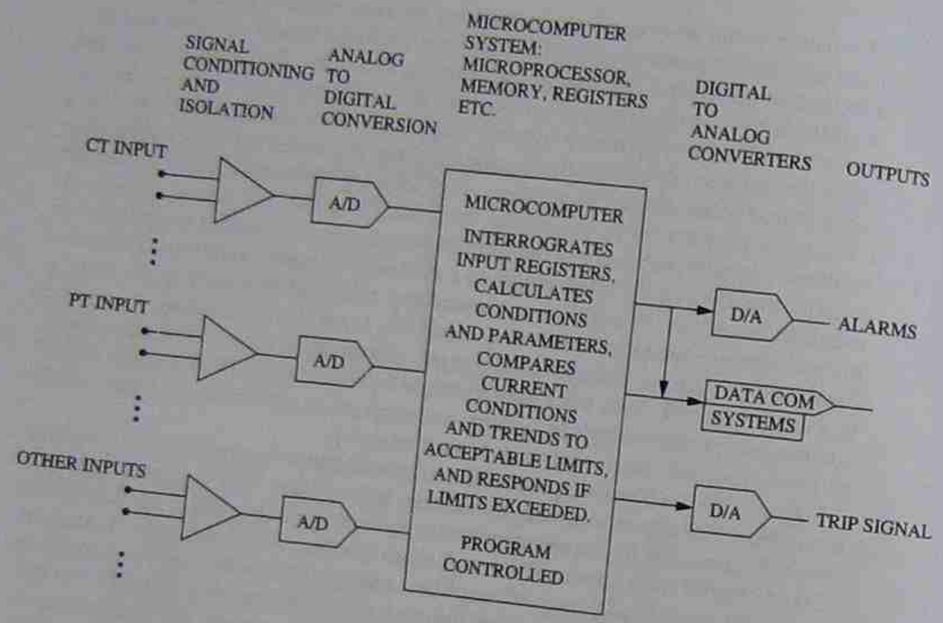


FIGURE 5.36 Microprocessor controlled relay system (b) microcomputer controlled relay

temperature or pressure, or any other directly measured parameter. The microprocessor then calculates parameters necessary for other functions such as difference current, effective impedance, frequency measurement, or compares present measured or calculated quantities with previously measured (and stored in memory) values to establish trends and checks to see if the trends are within allowable values. The output data will be in the form of data or alarm signals to be sent to a remote control room, trip signals for such conditions as overcurrent, or possibly control changes such as a voltage adjust signal to a transformer with an automatic tap changer from an over/under voltage condition.

The microprocessor-controlled relays work under program control. The programs are stored in read only memory. The more complex a particular relay function is the more complex the program to control that function is, and the longer the amount of time that is needed for the relay to perform that function. Thus, when a relay has many complex functions, such as impedance measurement, to perform it must use more time to perform them than if it had only a few relatively simple functions, such as instantaneous overcurrent measurement to perform. A trade-off must be made in system protection between complexity of monitoring and speed with which the relay responds. The faster the microcomputer and data acquisition systems, the more functions a microprocessor-controlled relay can perform in a given time. Multiple microcomputers sharing the same data acquisition

system can be used to handle functions that are too complex or too numerous for one microcomputer to handle alone. An optimized system can respond more rapidly to some conditions than others if the microprocessor system and program are sufficiently sophisticated.

Microcomputer relays are being designed for specific protection applications. For example, specialized generator and motor protection relays are commercially available that provide the specific protection that these devices need.

Microcomputer-controlled relay systems are being designed into most new electrical systems and retrofitted into older systems as relay replacement is needed because of changes in the system or protection needs. However, an enormous amount of electromechanical relaying equipment still exists, and it may be more than a decade, or maybe much more time, before it is all replaced by solid state microprocessor-controlled protective relays. Thus, electromechanical relays are also covered in the sections that follow.

5.6.2 Basic Current Relay Electromechanical Mechanisms

The *instantaneous hinged armature (clapper)* is illustrated in Figure 5.37. Current through the coil magnetizes the core, the frame, and by magnetic induction, the armature. The magnetic attraction then pulls the armature toward the coil, closing the contacts. The core plunger adjusts the magnetic circuit to adjust the pull-in current of the relay. The closing action is instantaneous (2–4 ms operating time) once the pull in current is reached. The armature movement is usually used to release a catch on a spring or gravity-driven indicating flag to show the relay has operated. Thus it is called an *indicating instantaneous trip relay* or IIT. The relay can be manufactured with many poles, normally open contacts, normally closed contact, or both.

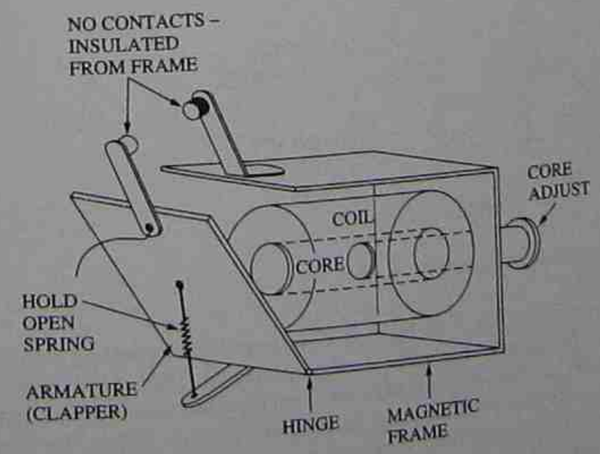


FIGURE 5.37 Hinged armature relay

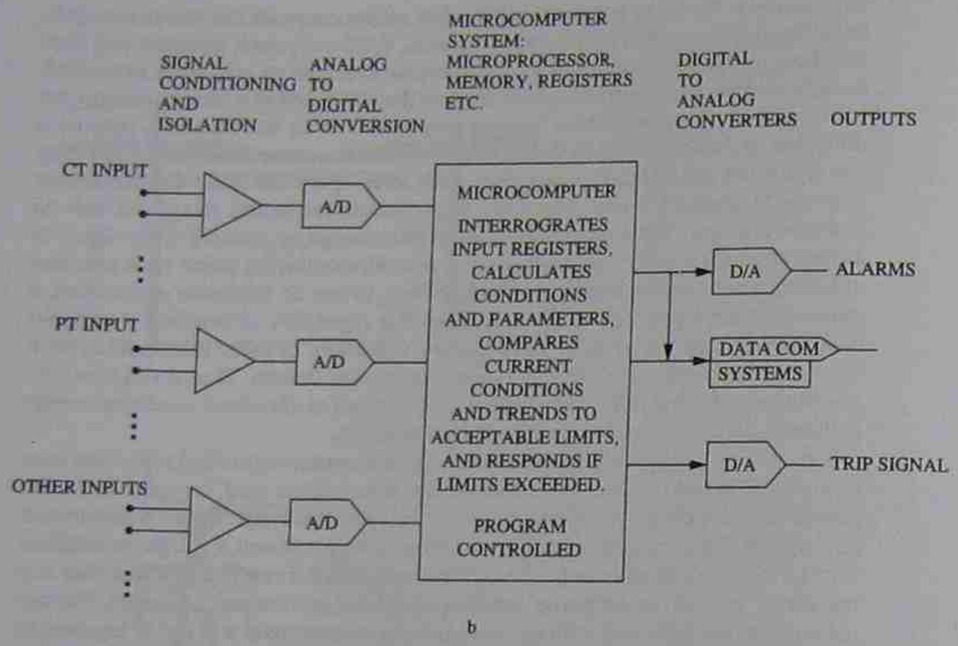


FIGURE 5.36 Microprocessor controlled relay system (b) microcomputer controlled relay

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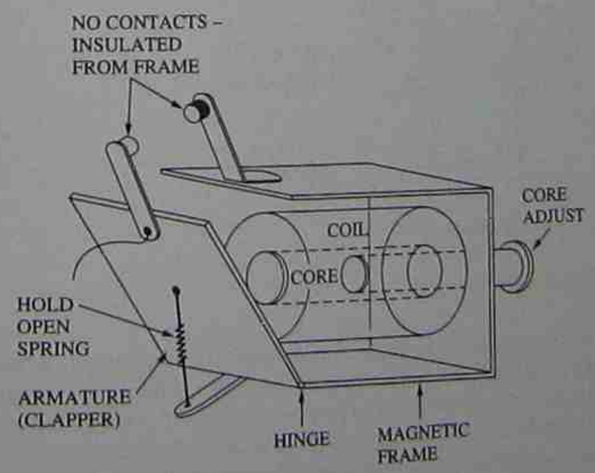


FIGURE 5.37 Hinged armature relay

The indicating contact switch (ICS) is a close cousin of the IIT. It is wound so as to reduce its operating voltage and current. It has one normally open contact set and an indicating trip unit. Its coil is in series with other relay contacts, and its contacts in parallel with other relay contacts to help carry trip current. Its primary function is to indicate a relay operation.

The *solenoid (plunger) relay*, see Figure 5.38, centers the plunger by magnetic induction when the coil current is high enough to cause it to operate. The plunger operates against a spring that holds it out when the relay is not energized. The solenoid relay is usually used as a high current instantaneous trip relay. The pull in current can be adjusted by the magnetic core air gap adjust, which varies the reluctance of the core. The contacts can be in a variety of arrangements, but the moving contact disc, which bridges the stationary contacts on operation, is popular. The operating time varies from 5 to 50 ms, depending on the overcurrent magnitude (slower with lower currents), and the relay size.

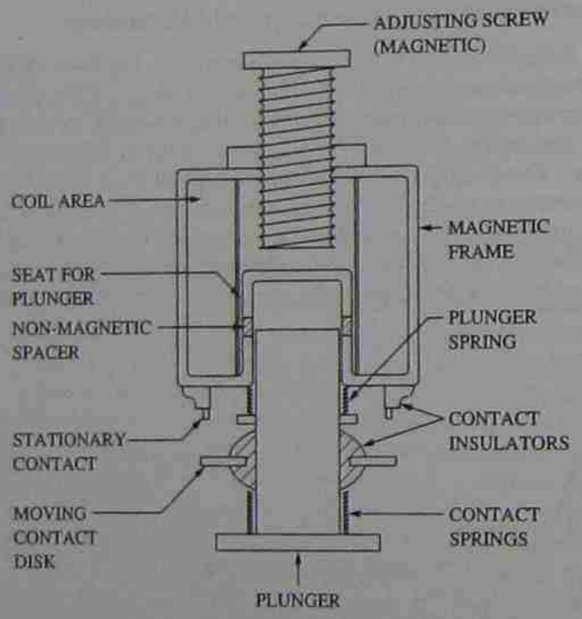
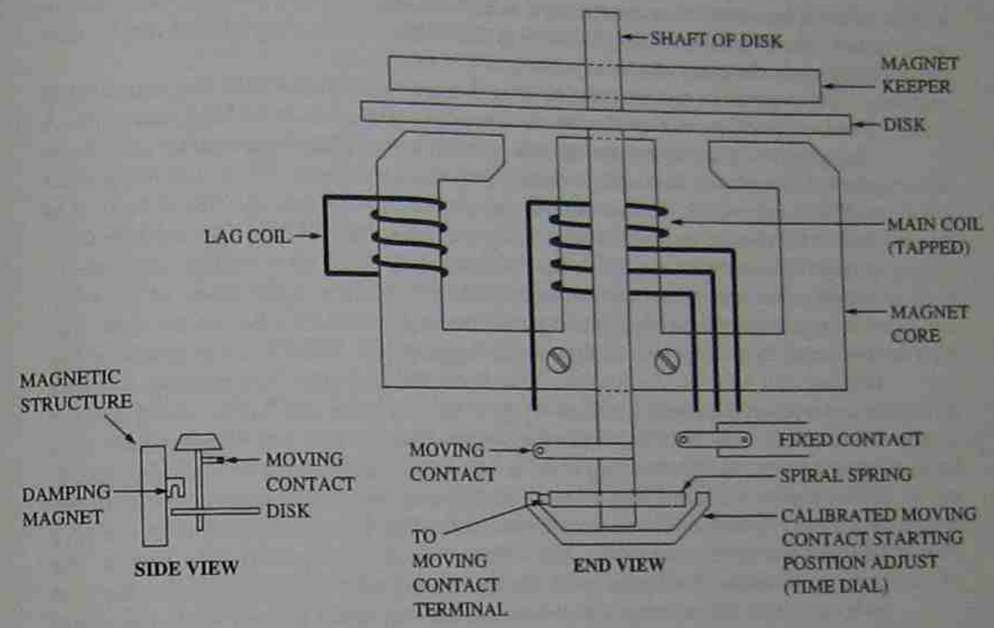


FIGURE 5.38 Solonoid or plunger relay

Induction disc relays are used as inverse time overcurrent relays, where high overcurrent causes faster operation than low overcurrent. The relay consists of an aluminum induction disc suspended between bearings with a magnetic structure held in place on one side of the disc shaft, as shown in Figure 5.39a. The disc shaft has a moving contact mounted on it that makes contact with a stationary contact, mounted on the relay frame, if the disc rotates far enough. A spiral spring is



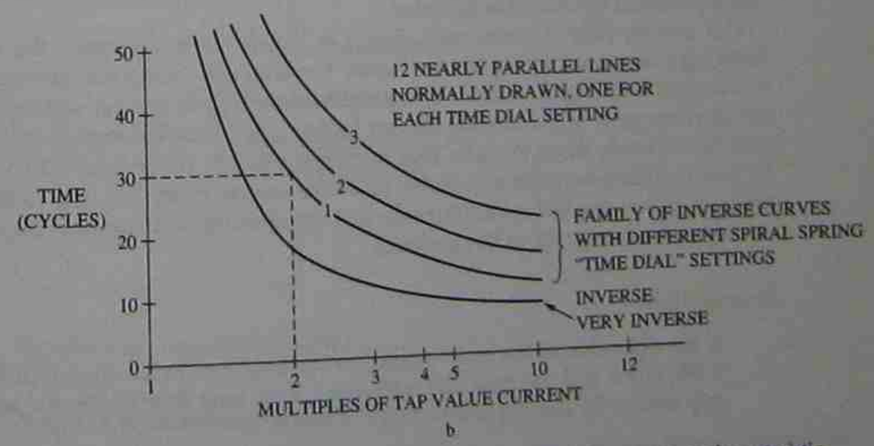


FIGURE 5.39 Induction disk relay (a) Drawing, E unit and (b) inverse time characteristic

mounted on one end of the shaft to provide both a counterforce against the disc rotation and provide a current path for the moving contact. A dial, called a time dial, is mounted over the spring to adjust the starting position of the moving contact. The higher the time dial setting, the further the moving contact must rotate before reaching the stationary contact.

The magnetic structure consists of an E core in this model with a magnetic keeper bar on the other side of the disc to lower the reluctance of the magnetic path. A damping magnet, to assure smooth operation and bounceless contact closure, is mounted near the disc with its pole facing toward the disc. The E core has a main coil through which the monitored current from the CT passes. This is tapped to adjust the trip current of the relay. A lag coil around one of the other core legs completes the magnetic circuit. The lag coil is shorted. The magnetic plugs vary the saturation characteristic of the coil to vary the inverse time characteristic of the relay.

In operation the current through the main coil induces a flux in the core. The main coil flux induces a voltage in the lagging coil, which causes current in the lagging coil to flow. As the flux from the main coil grows the lagging coil flux opposes it on the lagging coil core leg. When the main coil flux is decreasing the lagging coil flux aids the main flux in the lagging coil leg. The resultant flux sweeps from the right core leg to the left core leg, the core leg with the lagging coil, in the Figure 5.39a end view. The sweeping magnetic field induces current in the disc under the field. The magnetic field of the disc current interacts with the core field producing torque on the disc, just like a shaded pole induction motor. The torque will cause the disc to rotate toward the lag coil. The torque on the disc acts so as to rotate the moving contact toward the stationary contact while the spiral spring torque acts to keep the contacts apart. When the closing torque exceeds the opening torque long enough for the disc to rotate the moving contact to the stationary contact the relay has operated.

The inverse time characteristic, shown in Figure 5.39b, illustrates the results from high currents rotating the disc faster. The time dial moves the curve up and to the right with higher numbered settings because higher number settings move the starting point of the moving contact farther away from the stationary contact so it has to rotate more to make. Dial numbers normally range from 0.5 to 11. All 12 time dial lines are normally shown on a time-current chart. The time to make is given in cycles, and the current to make is given in multiples of the tap value. Typical tap values range up to five amperes.

Example 5.2:

If the tap value of the relay whose inverse time curves are shown in Figure 5.39b is 3 A and the time dial setting is 1, how long does it take the relay to trip from a CT current of 6 A?

Solution:

The tap value is 3 A, so 6 A is two times the tap value. Moving vertically from 2 on the multiple of tap value scale to the curve with time dial setting 1, and

from that intersection horizontally to the time axis, we find the operate time is 30 cycles, or 0.5 second.

Many alternate designs of the induction disc relay are available, as well as solid-state and microprocessor-controlled systems that perform the same function at a somewhat higher price. The microprocessor-controlled systems can perform the function of several relays using the same data acquisition system, which makes them very economical on a per function basis. Microprocessor-based relay systems are discussed later in this chapter.

The lag coil terminals can be connected to an auxiliary relay to give the induction disc directional characteristics. If the induction disc is to sense only load current, a fault on the source side could cause power flow toward the source relative to the relay location, an auxiliary relay that senses power flow can be connected to the lag terminals. If, in the event of power flow toward the source, the auxiliary relay opens the lag winding no torque can be developed on the disc, with the result that only current associated with power flow toward the load will be sensed.

The *induction cup relay* operates similarly to the induction disc relay. The lag and main coils are arranged on poles around the interior of a magnetic frame, as shown in Figure 5.40. The tubular cup fits over a circular fixed magnetic core in the center of the frame. The rotating magnetic field set up by the main and lag coils causes the cup to rotate against a spring to operate the relay. The light, low inertia cup allows induction cup relays to operate faster than induction disc relays. Like the induction disc the lag coil can be connected to give the relay directional characteristics.

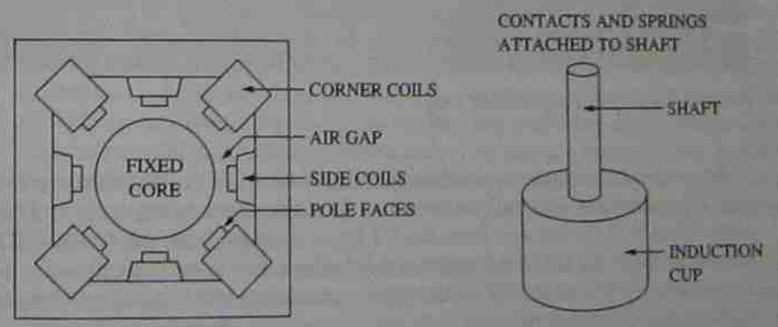


FIGURE 5.40 Induction cup relay

5.6.3 Overcurrent Relays (Type 50/51)

Type 50 relays are instantaneous overcurrent relays and type 51 are inverse-time overcurrent relays, so a 50/51 relay is a combination of both. A relay usually consists of more than one relay mechanism. The 50/51 relay, shown in Figure 5.41, on the left consists of three relay mechanisms. It has the following parts: an instantaneous

unit (IIT) for high value, close in faults; an induction disc (type CO) or cup inverse time unit for coordination with other protective devices; an indicating unit (ICS) to indicate a time trip and relieve the time unit contacts of the trip burden; a tap block to set the overcurrent that will cause the disc to turn; a time dial to set the inverse time characteristic so that a given current takes longer to activate the relay; and if the relay is directional, a directional unit.



FIGURE 5.41 50/51 overcurrent relay

An elementary diagram, or schematic, of a basic 50/51 relay is shown in Figure 5.42. The diagram is usually shown in two parts, the sensing coils and the contacts. Note that the current from the CT flows through both the CO and IIT coils, although the relay could be connected for either one to be used alone. Also note that either the CO or the IIT contacts can connect the 125 V dc circuit breaker trip voltage to the breaker trip coil.

The operating sequence is as follows. A high overcurrent causes the IIT to trip, connecting 125 V dc to the breaker trip coil tripping the breaker. The IIT indicator drops the red flag indicating an instantaneous trip. A low value overcurrent starts the CO disc turning at a rate dictated by the relay settings and the value of the overcurrent. If the overcurrent is removed before the contacts make, the disc resets. Otherwise the contacts make. The CO contacts allow current through the ICS coil causing it to pull in. The ICS contacts then carry the bulk of the trip current to the circuit breaker trip coil. The ICS also drops a flag indicating that there has been a time trip.

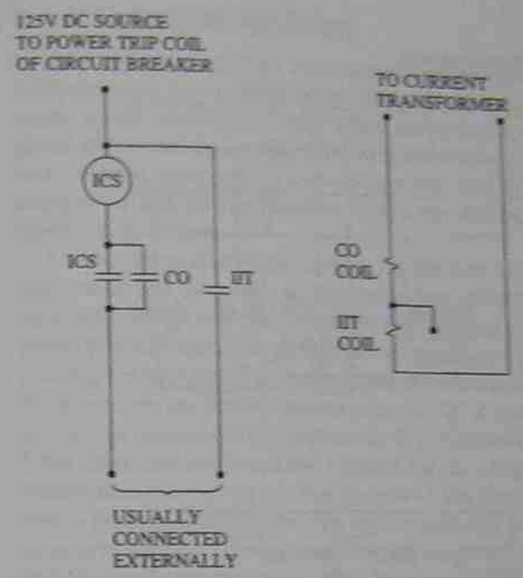


FIGURE 5.42 50/51 relay elementary diagram

Figure 5.43a shows the connection of 50/51 relay coils to provide overcurrent protection for a transformer secondary. Note the polarity of the current transformers. The polarities can be reversed but all three CTs must be the same polarity. The connection, which uses three 50/51 relays, provides a trip signal for an overload or fault on any one of the lines. The current tap and time dial settings are set to coordinate with downstream protective devices and are normally the same for all three of the 50/51 relays. Downstream overcurrent devices are set to operate faster than the upstream devices. Thus the downstream device clears before the upstream device operates.

The dc trip circuit is shown in Figure 5.43b. The 125 V dc trip bus is usually supplied by batteries that are continuously trickle charged. The batteries provide trip power even when the fault is so severe that the station voltage is very low. Notice that each relay trip circuit is in parallel with the rest so that each relay can trip the circuit breaker independently. A transformer would have more protection than we have shown here. The trip contacts for the other protective relays would be in parallel with the overcurrent relays as shown.

With a balanced load the CT neutral current will be zero, assuming matched CTs. A fourth 50/51 relay can be placed in the neutral to sense ground faults. Sensitive overcurrent relays are often used for this function. Another parallel set of contacts would be needed in the trip circuit. We will study ground fault protection more thoroughly in a later chapter.

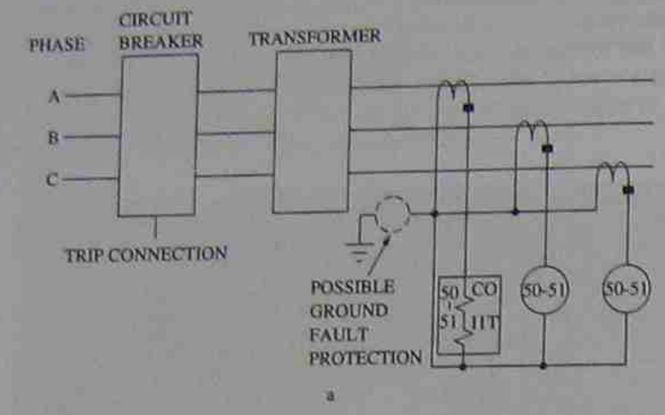


FIGURE 5.43 Transformer secondary circuit protection with 50/51 relay: (a) AC circuit and (b) DC trip circuit

Suppose the overcurrent relay is to trip in 30 cycles at a line current of 3000 A. Suppose further that the relay time current curve is that of the time dial setting equal one shown in Figure 5.39b. From the time current curve we see that a 30-second trip on the time dial one setting occurs at two times the tap setting. Recall that CT ratios are XXX A:5 A. Some common CT ratios are 300:5, 600:5, and 2000:5. If we choose the 2000:5 ratio (400:1) our CT current is 3000 A/400=7.5 A. The tap on the relays should be set to 3.75 A because the 2 times tap value provides the proper trip time, or the tap setting nearest to 3.75 A (perhaps 3.8 A). Microcomputer-controlled relay programs can provide the time-current functions available on electromechanical relays.

5.6.4 Under-Voltage Relays

Under- and over-voltage conditions can seriously damage electrical equipment. Instantaneous low voltage relays can be constructed from plunger relays with normally closed contacts, closed when the relay is de-energized. The relay is energized at normal line voltage holding the contacts open, but cannot hold in at low line voltage, thus it drops out when the line voltage is low causing the circuit breaker to trip. Instantaneous relays are not normally used because most line faults are transient.

An induction disc with voltage coils (more turns of higher resistance than current coils) can be used as under-voltage relays. In this application the relay is designed so the coil torque holds the moving contact away from the stationary contact. When the voltage is low the spiral spring torque is sufficient to rotate the moving contact into the stationary contact causing a trip. The normal coil voltage for an under- (or over-) voltage relay is 120 V, supplied by a potential transformer. A one-line diagram for application of under-voltage protection is shown in Figure 5.44a, and the time-voltage curves for an under-voltage relay in Figure 5.44b. Notice that the curves are the inverse of the overcurrent relay curves. The vertical axis is time in seconds, and the horizontal axis is in percent of tap value. There are 12 nearly parallel curves, one for each time dial setting between 0.5 and 11 (just as in CO overcurrent curves), even though only five are shown in Figure 5.44b. An example demonstrates the use of the curves.

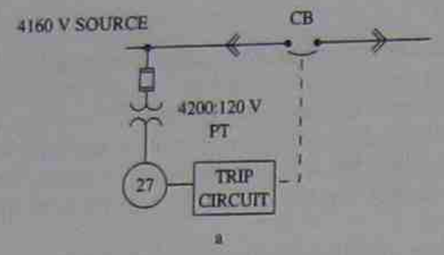
Example 5.3:

The under-voltage protection circuit of Figure 5.44 is set to trip the breaker if the voltage drops to 90% of normal, or 3744 V. The time dial setting is three. The PT ratio is 4200:120 V. What relay voltage will trip the breaker in 6 seconds?

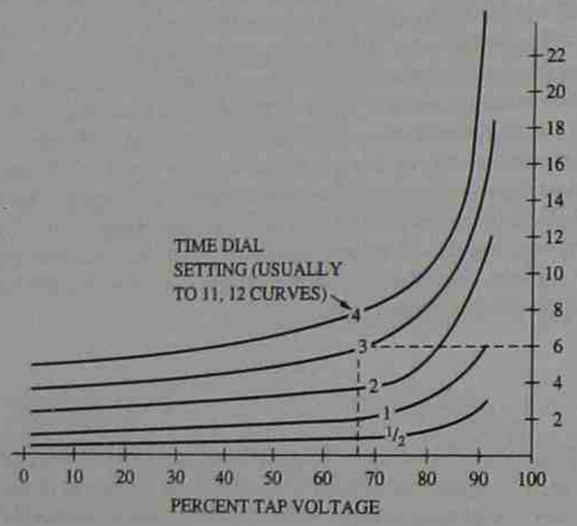
Solution:

First the normal relay voltage must be found to determine the proper tap setting. The PT ratio is 4200/120 = 35, so the normal relay voltage is 4160 V/35 = 118.5 V. The tap is set as close as possible to 3744 V/35 = 106.97. Assume a tap setting of 107 V. From the relay curves we see that the relay will send a trip signal in 6 seconds if the voltage drops to 67% of the tap value, or (0.67)(107 V) = 71.7 V. The relay will operate at 90% of the tap setting in 18 seconds. The relay will operate at 100% of tap value, but the curves are not plotted to 100% because they are not predictable with precision beyond 90% of tap value.

An induction disc relay can be used as an over-voltage relay by connecting the voltage coils so the coil torque rotates the moving contact toward the stationary contact, and the spiral spring torque rotates it away.



a



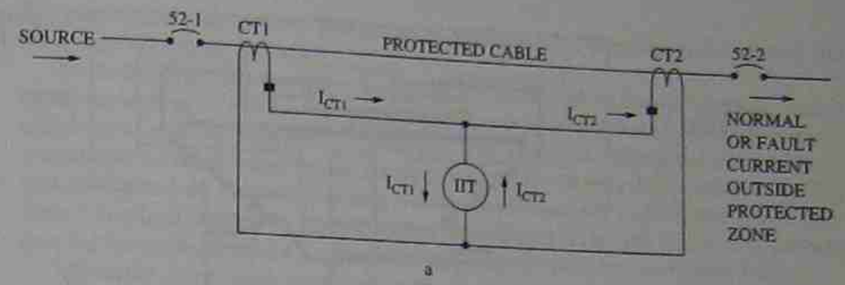
b

FIGURE 5.44 Under voltage relay use (a) One-line diagram and (b) typical curves for CV under voltage relay

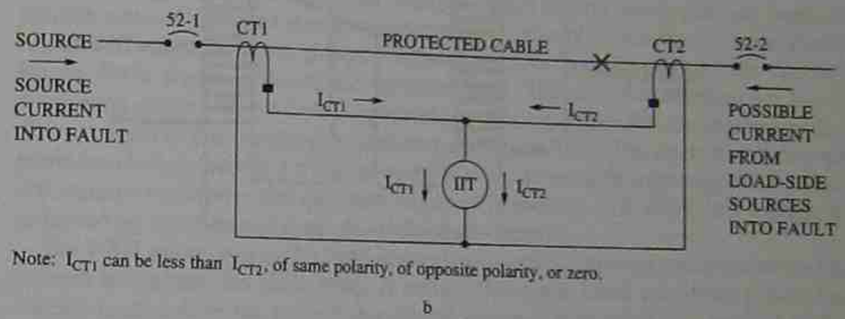
5.6.5 Differential Relays (Type 87)

A differential relay responds to the difference in two currents. If the two currents are the same, even if they are excessive, the relay does not operate. If their difference is above a preset limit the relay operates.

Any overcurrent relay can be operated in a differential mode but in most applications differential relays are more versatile and precise. The principle of differential operation is shown in Figure 5.45. When the current in both CTs is the same, as in Figure 5.45a, the current out of each CT is equal and opposite because the current is entering each CT from opposite directions with respect to the polarity markings. Thus the current from the CTs bypasses the overcurrent relay, or equal and opposite currents pass through it and cancel at any instant of time. Either



a



Note: I_{CT1} can be less than I_{CT2}, of same polarity, of opposite polarity, or zero.

b

FIGURE 5.45 Differentially connected relay (a) $I_{CT1} = I_{CT2}$, polarity opposite, currents cancel in IIT, no relay operation (b) $I_{CT1} \pm I_{CT2}$. IIT current not zero, relay operates when $I_{CT1} - I_{CT2}$ = IIT operating current, circuit breaker then receives trip signal.

concept works so pick the one you are most comfortable with. One could also say that the equal and opposite phase voltages from the CTs result in zero potential across the IIT so no current flows through it. The area between the CTs is called the *protected zone*. If a fault occurs inside the protected zone, as shown in Figure 5.45b, the CT currents are no longer the same and the current through the IIT no longer equals zero. In extreme faults the current through CT_2 changes directions and the two CT currents add at every instant of time. When the IIT current is above the actuating current the relay operates.

A differential relay provides better protection than an IIT connected differentially because it has provisions for balancing the effect of the CTs if their currents are different. Differential relays use restraining coils to prevent accidental operation in response to a fault outside of the protected zone because of CT mismatch. CTs that match well at lower currents do not match as well at current levels near or at saturation.

A *type CA induction disc differential* relay is shown in Figure 5.46a. The restraining coils are wound so that when the current through them is the same and in the same direction at any instant of time they produce opening torque, and the operating coil with no current produces no torque at the same time. If a fault occurs in the zone of protection the current through the restraining coils is no longer the

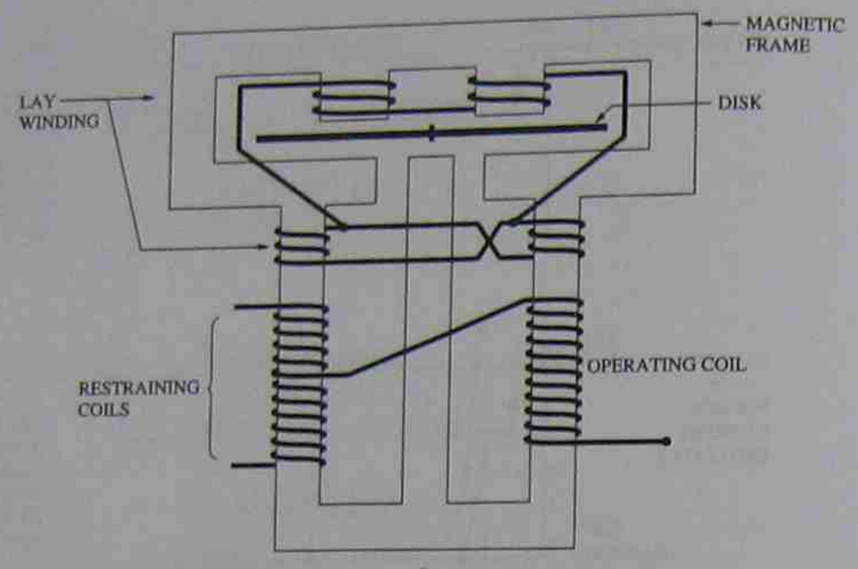


FIGURE 5.46 Type CA differential relay (a) Magnetic configuration and (b) elementary diagram, transformer protection

same and the opening torque weakens. At the same time current through the operating coil produces closing torque. When the closing torque is greater than the opening torque the relay operates. A severe fault in the protected zone causes the current through the restraining coils to be opposite in direction at any instant and

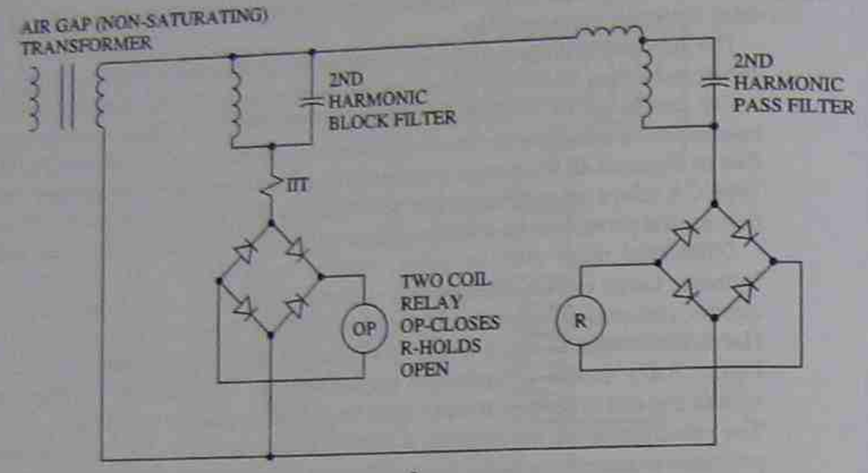
the restraining coils cancel. The currents through the operating coil add and the relay operates more quickly.

The restraining coils are tapped to allow for mismatch in the CT currents, which can be as high as 10 A. The operating coil is also tapped to set the operating current, which can be set to between 2.75 and 5 A. The type CA differential relay is fairly insensitive to transformer inrush current, which can cause a differential set up like that of Figure 5.45 to operate nearly every time if used for transformer protection. Type CA relays operate as fast as two to six cycles with severe faults. The connection for the protection of a single-phase transformer is shown in Figure 5.46b.

Differential relays with harmonic restraint units (HRU) are required for transformers. Large transformer inrush current, which has no corresponding outrush current, can cause a type CA relay to operate every time the transformer is energized. Harmonic restraint units prevent operation from transformer inrush current. Figure 5.47a shows a harmonic restraint unit. The dc relay mechanism has a restraining coil to prevent it from operating, and an operate coil to cause it to operate. The principle of the mechanism is shown in Figure 5.47c. The operate coil current provides closing force but if the restraining coil current is high enough the operate coil cannot overcome the opening force and operate. The relay coil voltage is obtained by rectifying ac from the HRU transformer.

The HRU makes use of the high second harmonic content of transformer inrush current to restrain the HRU relay. A second harmonic band pass filter passes the second harmonic to the restraining circuit where it is rectified and applied to the restraining coil of the HRU relay. A second harmonic content of about 16% is enough to prevent the relay from operating. Another filter blocks the second harmonic from the operate coil of the HRU so that the HRU relay is sure to close on any fundamental current that operates the differential unit (DU). Note in the trip circuit, shown in Figure 5.47d, that the HRU and DU contacts are in series. Even if the DU operates on inrush current the HRU contacts remain open preventing a breaker trip. On a fault in the protected zone the second harmonic content is low and both the DU and HRU contacts close to send a trip signal to the breaker.

A simplified diagram of a differential relay with an HRU is shown in Figure 5.47b. Note that the restraining current from the CTs is transformed through transformers with air gaps in their cores to make saturation difficult, rectified, and applied in parallel to the DU operating relay mechanism restraint coil. The necessary additional transformer-rectifier connection is shown for the tertiary of a three winding transformer. The operate transformer core has no air gap so that it more efficiently couples low amplitude operate current to the rectifiers that supply the operate coil. When the current through the CTs is the same and opposite in direction with respect to the polarity markings, the restraint voltages are highest and the operate coil cannot operate the DU relay. A fault in the zone of protection causes at least one restraint transformer primary current to lessen as current is diverted to the operate transformer primary and the HRU transformer primary. This current is transformed and rectified, and when high enough it operates the DU coil. The same primary current passes through the HRU primary, is rectified, and passed to the HRU operate coil so it operates at the same time as the DU. The



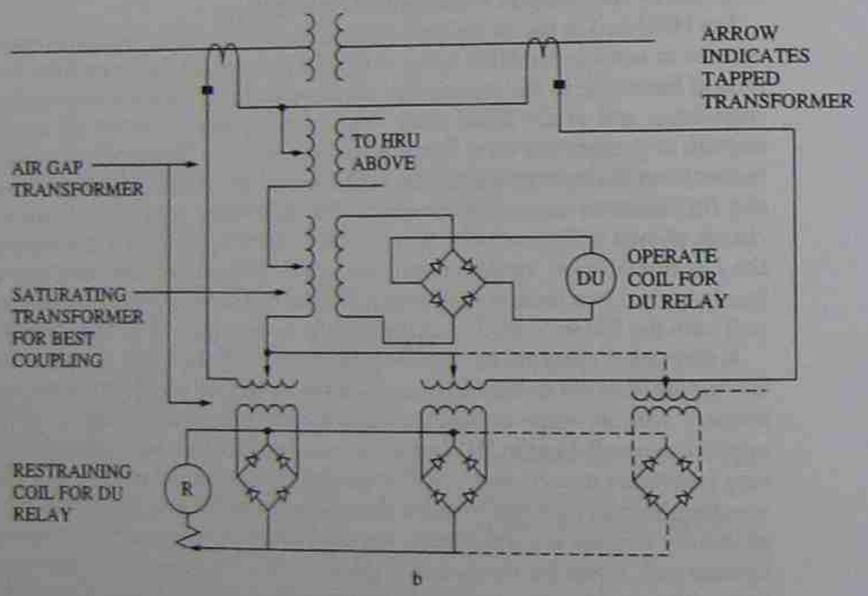
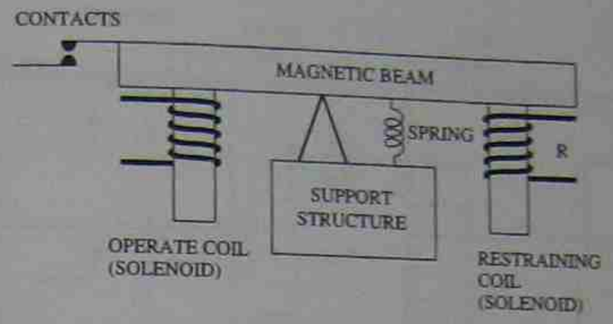
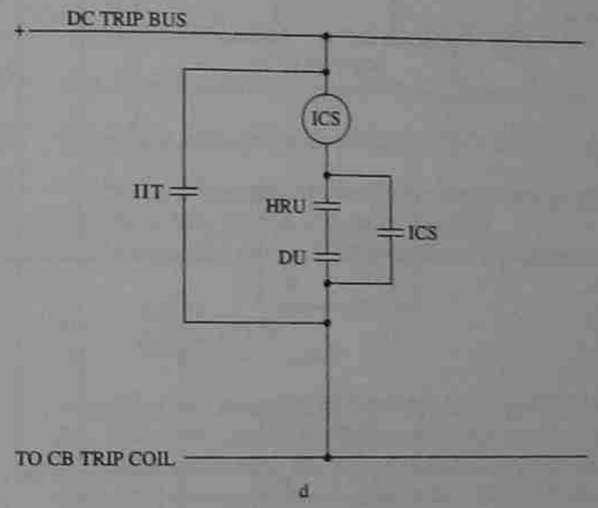


FIGURE 5.47 Differential relay with harmonic restraint unit (HRU) (a) Harmonic restraint unit (b) differential relay organization (c) two coil relay, balanced beam type and (d) trip circuit

restraining transformer continuous current rating is 10 to 22 A depending on the tap, and the operating coil pick up current is 30% of the tap value.

The trip circuit is shown in Figure 5.47d. Notice that the HRU differential relay makes use of an ICS relay to indicate a timed differential trip. It also has an IIT





unit to send a trip signal in response to massive faults that require instantaneous tripping. The trip circuit for a CA type differential relay is the same except the HRU contact is missing.

The CA type differential relay is used in smaller substations where the inrush current is smaller, and the more expensive HRU type is used in generating stations and large substations where the inrush current is high.

The Y-Δ CT connections for relaying are critical if the differential relaying is to operate properly. For Y-Y and Δ-Δ connections the CTs can be connected in a Y configuration. A Y-Δ or a Δ-Y connected transformer has a 30° phase shift between the primary and the secondary. CTs connected in the same configuration on both the primary and secondary side of the transformer have the same 30° phase shift in their currents. This acts as differential current even if the CT currents are the same. To compensate for the 30° phase shift the CTs are connected Δ on the Y side and Y on the Δ side, as shown in Figure 5.48. Additional tertiary winding CTs are connected oppositely to the tertiary connection, CTs connected Y if the tertiary is Δ and vice versa.

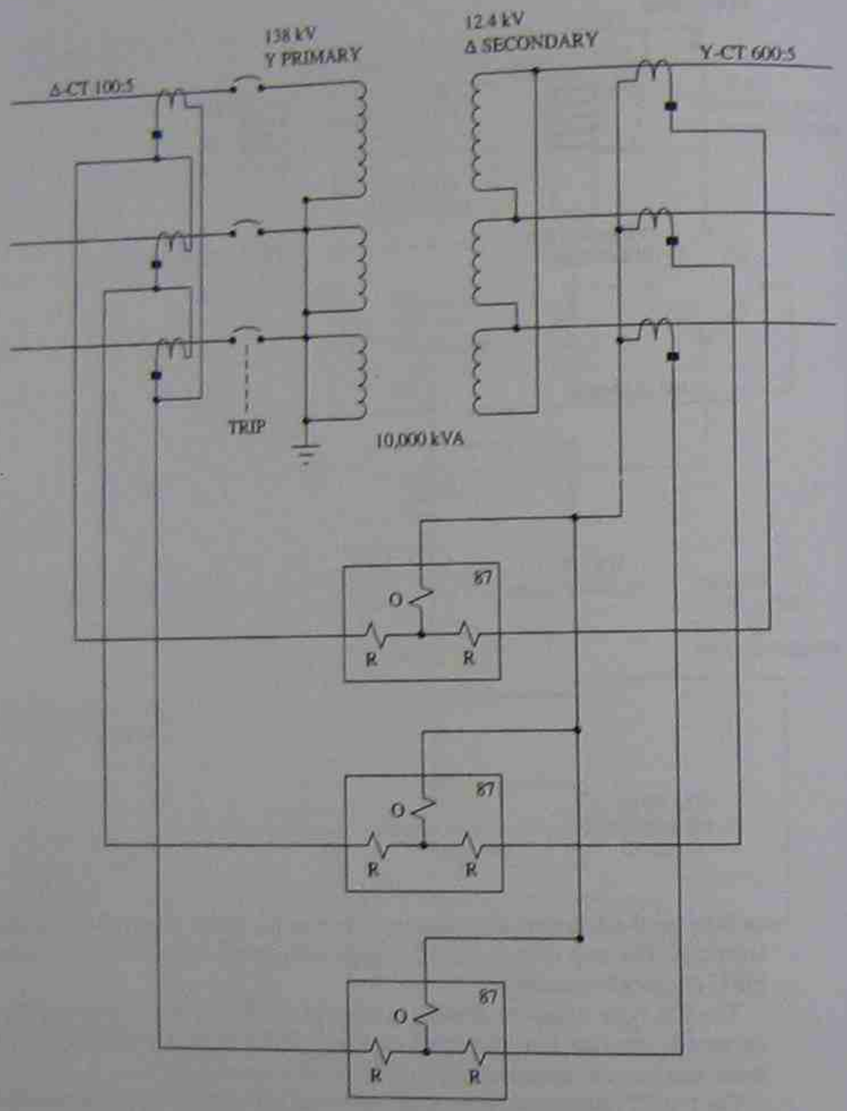


FIGURE 5.48 Current transformers in Δ-Y configuration for differential protection of a Y-Δ connected three-phase transformer

Example 5.3:

Calculate the relay currents and the tap settings for the circuit of Figure 5.48.

Solution:

First calculate the primary and secondary currents.

$$I_p = \frac{\text{kVA}}{\text{kV}(\sqrt{3})} = \frac{10{,}000\ \text{kVA}}{138\ \text{kV}\ (\sqrt{3})} = 41.84\ \text{A}$$

$$I_s = \frac{10{,}000\ \text{kVA}}{12.4\ \text{kV}(\sqrt{3})} = 465.6\ \text{A}$$

The CT ratios are 100:5 = 20:1 and 600:5 = 120:1. From these the relay currents are:

Primary relay current = (41.84 A/20)($\sqrt{3}$) = 3.62 A = I_{RH}

The $\sqrt{3}$ is because the primary CTs are Δ connected.

Secondary relay current = 465.6 A/120 = 3.88 A = I_{RL}

Where the subscripts RH stands for high voltage side relay quantity and RL stands for low voltage side relay quantity.

The tap ratios are set as close to the relay current ratios as possible.

$$\frac{I_{RL}}{I_{RH}} = \frac{3.88\ \text{A}}{3.62\ \text{A}} = 1.07$$

CA type relay taps are 5-5, 5-5.5, 5-6.6, 5-7.3, 5-8, 5-9, 5-10 for tap ratios of 1, 1.1, 1.32, 1.46, 1.6, 1.8, and 2. If our relays are CA type differential relays the 1.1 ratio is the closest. HU relay taps are 2.9, 3.2, 3.5, 3.8, 4.2, 4.6, 5, and 8.7 on both the primary and secondary side. Table 5.3 shows the ratios. The 1.094 ratio, corresponds to the 3.2 and 3.5 primary and secondary taps respectively. If the mismatch ratio between the CT current ratio and tap ratio is less than 35% for CA relays, and 30% for HU relays, normally our relaying circuit will work. The allowed mismatch varies with the relay subtypes, so check for the allowed mismatch.

Mismatch is found from the equation

$$M = \frac{\dfrac{I_{RL}}{I_{RH}} - \dfrac{T_L}{T_H}}{S}(100) \qquad (5.2)$$

Where I_{RL} and I_{RH} are from the same kVA base, T_H and T_L are high and low side relay tap settings respectively, and S is the lower of the tap and relay current ratios. For our example and an HU relay well within the most stringent requirement (10% for the CA-26 type).

TABLE 5.3 Harmonic Unit (HU) Taps and Ratios

	Ratio							
Taps	2.9	3.2	3.5	3.8	4.2	4.6	5	8.7
2.9	1.000	1.103	1.207	1.310	1.488	1.586	1.724	3.000
3.2		1.000	1.094	1.188	1.313	1.438	1.563	2.719
3.5			1.000	1.086	1.200	1.314	1.429	1.486
3.8				1.000	1.05	1.211	1.316	2.289
4.2					1.000	1.095	1.190	2.071
4.6						1.000	1.087	1.890
5							1.000	1.740
8.7								1.00

$$M = \frac{\frac{3.88\ A}{3.62\ A} - \frac{3.5}{3.2}}{\frac{3.88\ A}{3.62\ A}} \times 100 = \frac{1.071 - 1.093}{1.071}(100) = 2.04\%$$

If the CT current mismatch is too large for the tap ratio, current balancing autotransformers are used to bring the CT ratios close enough for the relay taps. For example, if a high side CT current of 6 A has to be brought down to 4.6 A to match the low side current close enough for the relay taps to take care of, the autotransformer ratio would be (6 A)/(4.6 A) or 1.33:1 turns ratio. The autotransformer is connected between the CT line to the relay and the relay, as shown in Figure 5.49. The autotransformer is Y connected regardless of the CT connection. Auxiliary CTs are available with a turns ratio of 3/2, which is often enough to obtain relay currents within the tap range.

5.7 DISCONNECT SWITCHES

Disconnect switches are designed to open and close a circuit. At high voltages the switches must have a large gap when open. An air gap of about 11 feet is required at 230 kV. Disconnect switches cannot open a fault.

5.7.1 Non-load Break Disconnect Switch

High and medium voltage disconnect switches are designed to isolate a section of a circuit after the protective device has de-energized the circuit. They allow disconnecting the faulted circuit or equipment for repair while the rest of the circuit in the zone of protection is put back into service and provide for personnel safety

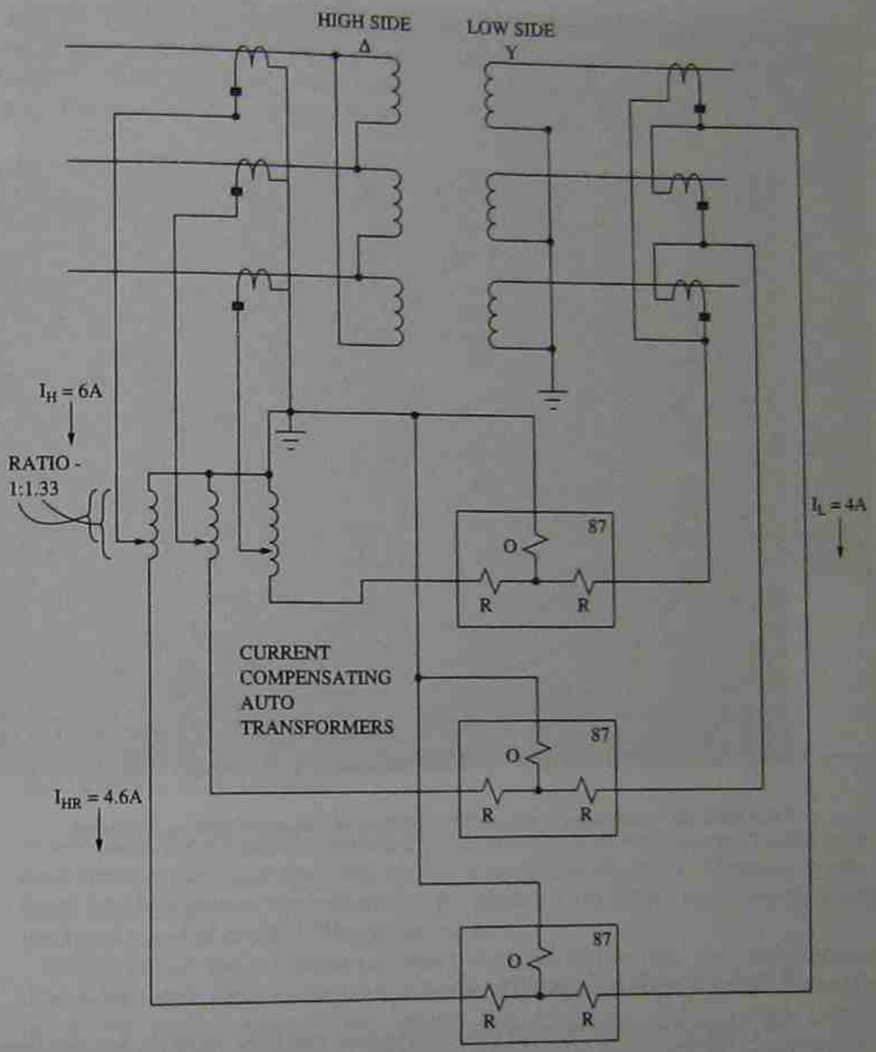


FIGURE 5.49 Current balancing autotransformer connection

while the malfunction is being repaired. Disconnect switches can open very small charging currents to unloaded equipment but that is all. The low current arc is broken by swinging the moving arm in a 90° arc, providing a long gap.

Disconnect switches can be operated by motors, as most high voltage switches are, by an insulated lever connected to a actuating arm that moves the switch blade, as many medium voltage pole top switches are, or manually by using a hook stick (a long insulated pole with a hook attached to one end). Disconnect switches

are classified as to voltage, continuous current rating, and function such as distribution pole top. They are available in single phase, single pole, and three phase, three pole. Unless a disconnect switch is specifically specified as load break it is a non-load break switch. Figure 5.50 shows a non-load break disconnect switch.

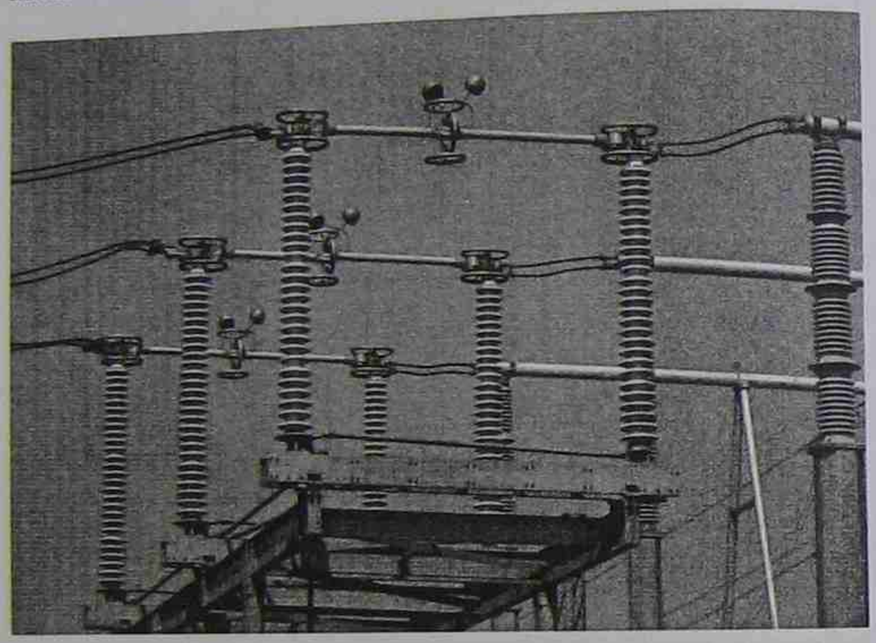


FIGURE 5.50 Non-load break switch (courtesy of Houston Lighting & Power).

5.7.2 Load Break Switches

Load break disconnect switches can interrupt normal load currents, but not large fault currents. The wall switch is the most common load break switch. Load break switches for medium and high voltages use interrupters built into the switch to break the load current before the switch disconnecting arm is swung open. The interrupters are often vacuum (medium voltage), oil, and SF_6. Some newer high voltage load break switches equipped with SF_6 interrupters can break significant fault current and accept protective relay trip signals.

Most load break switches use motors to open and close the switch blades but the interrupters are actuated by strong spring pressure. Figure 5.51 shows a SF_6 load break switch.

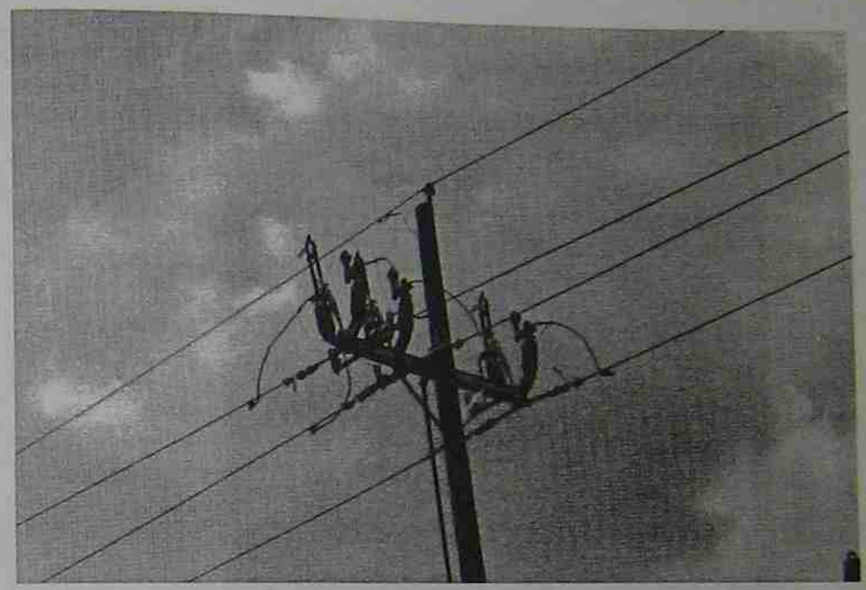


FIGURE 5.51 Load break switch (courtesy of Gulf States Utilities).

5.8 METERING EQUIPMENT

Power metering equipment records the amount of power used in a particular area, sent down a particular line, and used in a particular structure. Metering equipment provides power use information for planning for future needs from power use trends, and of course billing for revenue.

Power meters use a current coil and a potential coil to turn and an induction disc, which then turns accumulating devices. The disc rotation is proportional to the power passing through the metered line. Electronic circuitry with microprocessor control can perform the same function and also transmit the accumulated power use data to a central point or record it in a digital memory for retrieval at the meter site. Most meters for industrial use meter demand, peak power use over a given period of time (usually 15 or 30 minutes), as well as power use. High demand requires lines and equipment with capacities in excess of normal loads and the demand charges amortize a portion of the extra cost as well as encourage more consistent power use.

Low voltage meters can be hooked directly to the monitored line voltage and current, but meters for station monitoring and large commercial and industrial

customers must be fed through instrument transformers. Figure 5.52 shows some power meters. Reactive power meters are also used to monitor the VARs in a system.



FIGURE 5.52 Power meters (courtesy of Houston Lighting & Power).

5.9 SUMMARY

Distribution equipment covered in this chapter includes circuit breakers, reclosers, sectionalizers, disconnect switches, metering and protection equipment. This equipment along with transformers, lines, and bus equipment are necessary to distribute power to utility customers or within large industrial concerns or multibuilding commercial establishments.

The purpose of a circuit breaker is to open a circuit both as a switch and during a fault. Thus, a circuit breaker has to operate during a fault when abnormally high currents are present. To interrupt the current the circuit breaker must extinguish the arc, the path of ionized gas, that occurs when the circuit breaker contacts are

opened. Many means of breaking the arc have been successfully used in circuit breakers. Air circuit breakers stretch and thin out the arc until it extinguishes by using a long contact opening path and special baffles to further stretch the arc. Air circuit breakers are suitable for low and lower medium voltage applications.

Oil circuit breakers (OCBs), in which the contacts are immersed in a tank of oil, use the cooling and energy absorbing properties of oil to quench the contact arcs. Oil circuit breakers are suitable for medium and high voltages.

Circuit breakers in which the contacts are immersed in SF_6, an insulating gas that efficiently absorbs arc energy, are used for medium and high voltage circuit breakers.

Forced air circuit breakers called air blast breakers are suitable for high voltages. They interrupt an arc by forcing a high pressure air blast onto the arc to stretch and cool it.

A circuit breaker interruption method that is rapidly gaining in popularity is the use of vacuum bottles to contain the circuit breaker contacts, one bottle per phase. The bottles have bellows to allow the contacts to move for opening and closing. There are few atoms in a high vacuum to ionize, thus no arc forms. Vacuum circuit breakers have been made that are suitable for low, medium, and lower high voltage applications. To allow vacuum circuit breakers to be used at higher voltages the vacuum bottles containing the contacts are enclosed in a container of SF_6.

Most faults on a distribution line are temporary, having been caused by a falling tree branch that falls to the ground after causing a brief short circuit, or by some other brief event. Reclosers are basically smaller circuit-breaker type devices that open on a fault, but reclose after a set time. The process can be repeated for several times, but the limit is typically three recloses, after which, if the fault still exists, the recloser stays open, called *locking out*. Thus, brief faults are allowed to clear, then reclosing establishing service with minimum loss of service, but a fixed fault results in the removal of power from the circuit.

Fuses are alloy strips in a housing that melt if exposed to a current above that for which they were designed. They are an economical means of interrupting overcurrent faults. Current-limiting fuses are filled with sand that quickly absorbs the energy from the arc that forms at the point(s) that the fuse element melts. They limit the maximum amount of current that can pass during a fault. Fuses must be manually replaced after they operate so that service is restored only after someone looks for the cause of the fault. Dual element fuses have an element that operates quickly for massive faults, and one that operates slowly for overloads. Dual element fuses allow transformer energizing and motor starting current to occur without operating, but operate rapidly for large faults, and after a time for moderate overloads.

Lightning occurs nearly everywhere, just in varying frequency. Lightning induces current and voltage transients in electrical equipment. Equipment that is to be used for electrical power transmission or distribution must be protected against the effects of nearby or direct lightning strikes. Lightning arresters are devices that absorb the energy from the lightning induced transient while limiting the voltage from the transient to less than the BIL of the equipment. The most commonly used arresters in current use are made of zinc oxide. Shield (also called

static) wires are strung above distribution and transmission lines to shield the lines from direct lightning strokes. They provide a zone of protection of 30° on either side of the shield wire.

To minimize the damage to a system from a fault condition devices called protective relays are used to sense and react to abnormal conditions on the line. Sets of protective relays are used together in systems to protect the line or equipment from a variety of line disturbances such as sudden and long duration overcurrents, over- and under-voltage, and/or over and under frequency. Relay systems are designed to react to faults within an area (or zone) of protection and ignore faults outside that zone, which are detected by other relays. Instrument transformers for current and voltage transform the line currents and voltages to levels that are convenient for use by relay systems to monitor the status of the protected equipment. Microprocessor-based relays, in which data is acquired from the instrument transformers and changed to digital form for processing under program control, are rapidly replacing electromechanical relays because they are more flexible than electromechanical relays and can provide several functions in a single package. Specialized relays for motor, generator, and transformer protection are commercially available.

5.10 QUESTIONS

1. State the function of circuit breakers.
2. What is an arc and how does it originate at the breaker contacts?
3. State the two principles used in breaking an arc.
4. Why are dc arcs harder to break than ac?
5. List the four major arc extinguishing mediums.
6. List five arc breaking aids used in air circuit breakers and explain how they work.
7. What is the source of power for the opening mechanisms of almost all medium and high voltage circuit breakers?
8. How do air blast breakers extinguish an arc, and why must they always use opening resistors?
9. State the principle of the vacuum circuit breaker.
10. Describe the process by which bulk oil breakers quench an arc.
11. Describe the oil blast method of breaking an arc.
12. What property of SF_6 makes it such a good arc interrupting medium?
13. State the function of closing resistors.
14. List the factors that must be considered when selecting a circuit breaker for a given application.
15. List two advantages and two disadvantages of each of the following high voltage circuit breakers: air blast, oil, two tank SF_6, and puffer SF_6.
16. State the function of a recloser and its operating sequence.

17. Define coordination with reference to protective devices for electrical power equipment and lines.
18. Describe the function of a sectionalizer.
19. Describe the relationship of circuit breakers, reclosers, and sectionalizers in circuits that use all three.
20. State the principle of fuse operation.
21. List and briefly explain the six considerations for fuse selection.
22. Describe the arc breaking mechanism of both current limiting and expulsion fuses.
23. State the principle of fuse coordination.
24. State the purpose of lightning arresters.
25. State the difference between the terminal characteristics of spark gap and ceramic valve block types of lightning arresters.
26. State the function of a shield wire on a transmission or distribution line.
27. What is a protective relay?
28. The induction disc relay whose characteristics are shown in Figure 5.39b has a time dial setting of 3, a tap value of 4A, and a CT current of 8 A. How long will it take to operate?
29. List the major parts of a 50/51 overcurrent relay.
30. The circuit of Figure 5.44a is to be disconnected by the breaker if the source voltage falls to 80% of the nominal value of 4160 V. The under voltage relay whose characteristics are shown in Figure 4.44b is to be used. The relay time dial setting is four. Find the proper tap value and the operate time if the PT voltage is 50% of tap value.
31. State the operating principle of a differential relay.
32. State the function of an HRU in a differential relay, and the principle of HRU operation.
33. State the method of connecting CTs for Δ-Y and Y-Δ connected transformers, and the reason the method is used.
34. State the major advantages of microprocessor-controlled relays over electromechanical relays.
35. What is the reason for the trade-off of response time and complexity in microcomputer-based relay systems?
36. For the circuit of Figure 5.48 calculate the relay currents, find the HRU type restraining coil tap settings, and calculate the mismatch if the transformer is 230kV/34.5kV of the same connection and kVA rating.
37. State the difference between load break and non-load break switches in terms of operation.

CHAPTER 6

Distribution Substations

The purpose of an electrical power distribution substation is to lower the voltage from the high voltage transmission and subtransmission levels to a voltage that can be safely installed on the streets and alleys that are adjacent to the customer's premises. The smaller right of ways available near the customer's premises make the lower voltage necessary. Shapes, configurations, capacities, and voltages of distribution substations vary widely, but they all have the same purpose.

Substations for distribution consist of equipment (items that use electric power to perform a function such as motors and transformers) and devices (which help control but do not use electric power such as switches, lightning arresters, and fuses). The devices are often referred to as switch gear. Circuit breakers, though a switch, are so costly and complicated that they are often classed as equipment. Figure 6.1 illustrates a distribution substation.

6.1 SUBSTATION LAYOUT SELECTION CRITERIA

The design or layout of a substation depends on many factors, including: voltage; load requirements, density, and expected growth; available site space; location of the site; protection system sophistication and cost; and other stations in the general area.

The substations of any given power company are not alike because the items listed above vary from place to place, but substations do have as much in common as the design criteria allow. Standardization in substation design is desirable where

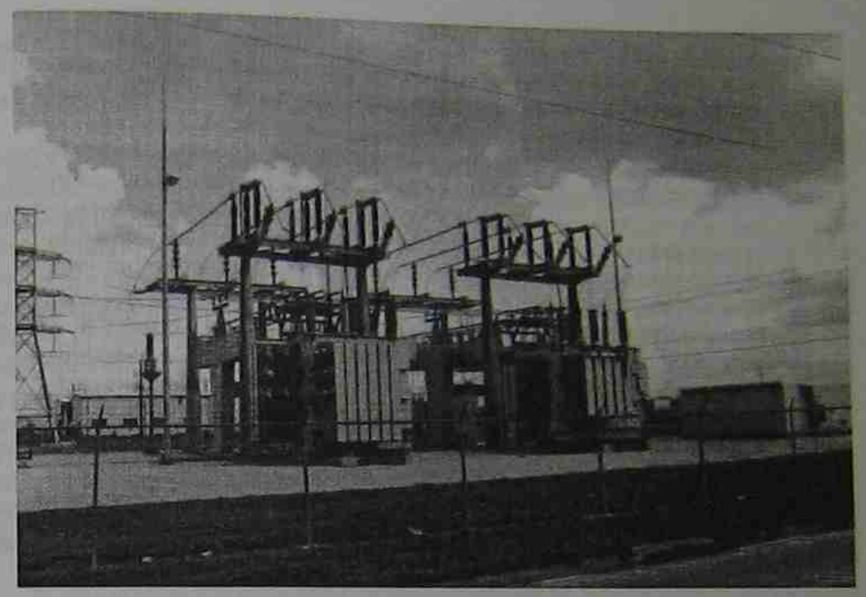


FIGURE 6.1 Distribution substation (courtesy of Houston Lighting & Power).

possible because of the savings in design time and the simplification of construction and maintenance. Standardization simplifies and usually simplification reduces cost, even in such things as stocking spare parts. Over standardization can lead to the selection of a substation design that does not economically meet the needs of the area to be serviced, so there should be a happy medium in standardization.

The design of a substation depends on both the subtransmission and/or transmission voltages available and the low voltage requirements. The trend is toward the highest distribution voltage that can be safely and economically installed in the available distribution right of ways. The higher the voltage, the lower the line resistive losses are. This is generally 34.5 kV for new distribution systems. Lower voltages must be used if a substation is to serve a lower voltage distribution line system, of course. If the substation must serve distribution lines at more than one voltage, 34.5 kV and 12.5 kV for example, it will be more complex than a single voltage substation.

6.1.1 Voltage and Spacing

The voltages determine the spacing between conductors, and the conductor clearance to ground or grounded structures. The minimum clearances are specified by the National Electric Safety Code (NESC), and usual clearances (which are larger than the minimum) are published by the Institute of Electrical and Electronic Engineers (IEEE) electrical power related divisions and the Edison Electric

Institute (EEI). The IEEE is a professional organization of individual engineers and technical people and the EEI is the professional association of electric power companies. For example the minimum clearances are 22.3 inches for 34.5 kV, and 13.2 inches for 12.5 kV for rigid buses with fixed supports.

Often the substation conductor ground clearance is dictated more by safe working and walking distance than by minimum safety code clearance. The safe walking and working distances, which are greater than the minimum safety code clearance, are reduced if only qualified personnel have access to the substation. To reduce the cost of substation by reducing the safe clearances, substations are enclosed in a fence to limit access to qualified people, who by education and experience understand the hazards involved and safety procedures to be followed when working around high voltage. Some substations, called unit substations, are completely enclosed in a metal structure. Rigid bus, copper or aluminum pipes or solid bars designed as substation conductors, can be installed in less space than required to install wire bus because wire bus sags between insulators. The sag varies with temperature and load current, which heats the conductor. Additionally, blowing wind can displace wire conductors. Rigid bus clearance can be equal to the minimum deflected wire bus clearance, which is usually considered too close for reliable wire bus installation.

6.1.2 Load

The size of the load to be served determines the capacity of the substation. Dense loads such as commercial and industrial districts are served by larger substations than loads spread over a wide area. The load must be distributed such that it can be served with reasonable feeder loss or more, smaller substations closer to the load may be used. Critical loads, such as industrial districts, are served by more complex substations, designed for maximum reliability and speed of power restoration, than residential areas where a short time power loss is usually not a disaster. Substations for critical loads usually use more than one transformer so that the load is served even if one transformer is out. Otherwise a single large three-phase transformer is used because it costs less per kVA of capacity, and requires less room, bussing, and simpler protective relaying. The expected growth of an area also influences substation design. An area that is expected to grow uses an easily expandable substation design.

Other substations in the area influence the design of a new substation. The ability of the other substations' capacities to be increased to serve growth in the area between the stations (instead of expanding the capacity of the new substation) affects the design of the new substation. Additionally, it is advantageous from a maintenance point view to use similar new and old substation designs in the same general area if possible.

6.1.3 Space and Location

More space available for substation construction allows more construction options. Densely populated areas may contain few locations suitable for substation construction, and those locations may be unsuitable for some substation designs. In some areas land costs may be so high that one substation design or layout provides considerable savings by virtue of needing less space, even if the construction cost is more for the more compact layout.

The visual sensitivity of the residents of an area can dictate substation construction. Some people do not like to see substations and insist that their neighborhood be served by a low profile substation enclosed in a fence that hides it. This costs more and the added cost for the same revenue base has an effect on the substation layout. The aesthetic considerations are the same ones that have led to increased underground distribution.

6.1.4 Distribution Substation Protection Needs

Above a minimum protection needed to avoid injury to people and damage to equipment, the level of protection of a substation is determined by how critical the loss of power is to the load. For example, the loss of electrical power to a hospital is very serious while the loss of power to a residence is inconvenient. In the event of a fault the hospital electricity must be restored in the shortest amount of time possible while the residence can be without electricity several hours without serious consequences. Industrial and commercial areas cannot be without power for any length of time without serious economic consequences. Equipping a substation with automatic switching to restore power when it is lost and to assure the least possible damage and repair time after a fault is expensive. It would be nice, but hard to justify to public utility comissions (PUCs), to provide each substation with the maximum possible protection. Thus judgment must be used in substation design and protection to assure a safe, reliable, economical substation with protection that is adequate for the load served. Figure 6.2a shows a small substation at the end of a radial subtransmission line that might be used to serve a small group of residences. It consists of two dead end poles to terminate the lines. It has two manual non-load break switches, and primary fusing. Together with the customer distribution transformers primary fusing, and fuses at taps with a 30% or more decrease in wire size, it is adequately protected to perform its function. The substation in Figure 6.2b might be used to serve a small commercial area. It has a circuit breaker as well as a primary fuse for back up, and more disconnect switches for isolation during maintenance. Additionally the circuit breaker will operate from relays that require a metal clad enclosure, instrument transformers, and a dc power supply for the trip circuit. The increased speed of fault removal supplied by the circuit breaker for this substation has substantially increased its cost over the substation shown in Figure 6.2a. Both substations are simple single-source, single-transformer, single-feeder types. The cost differences increase with the size of the substation, and the size and number of transformers used.

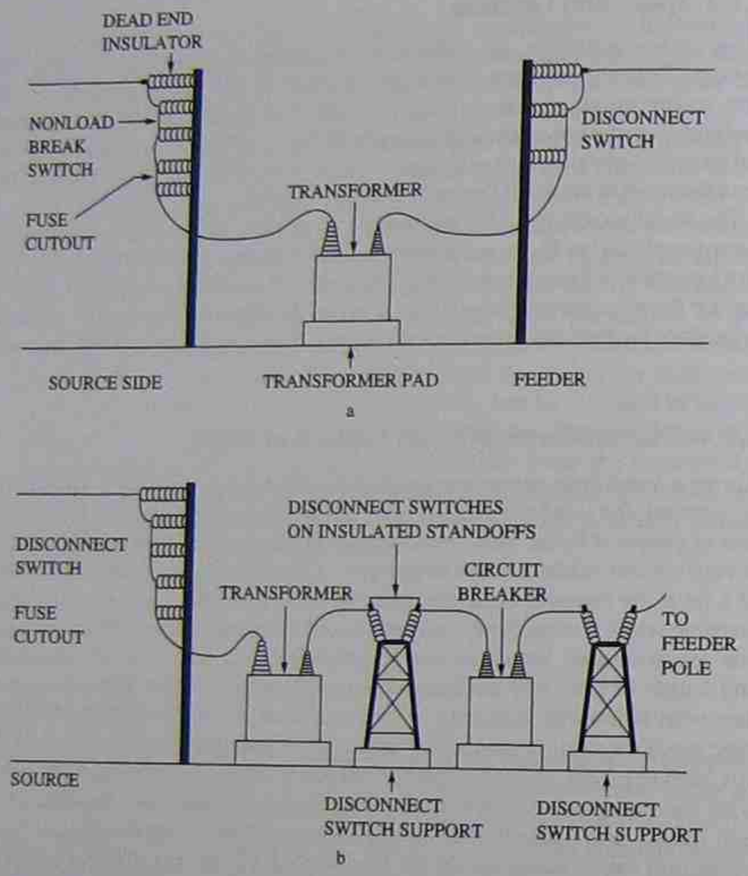
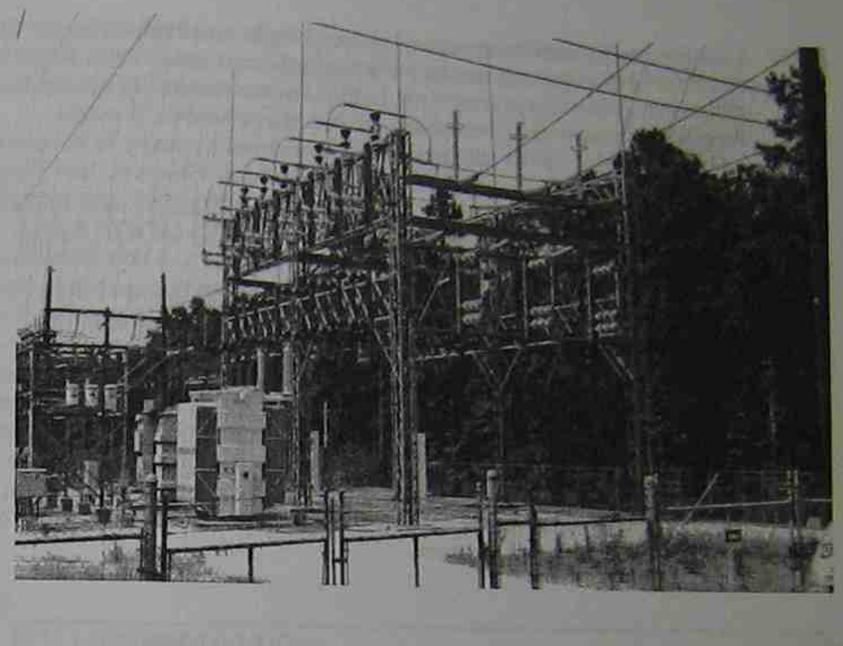


FIGURE 6.2 Simplest substations (one phase drawn) (a) Fuse protected transformer and (b) circuit breaker protected

6.2 DISTRIBUTION SUBSTATION CONSTRUCTION METHODS

Four basic methods exist for substation construction: wood, steel lattice, steel low profile, and unit. Each has advantages and disadvantages. These are shown in Figure 6.3.

Wood pole substations are inexpensive, and can easily use wire bus structures. Wood is suitable only for relatively small, simple substations because of the difficulty of building complex bus and switch gear support structures from wood. Very few wood substations are built anymore.



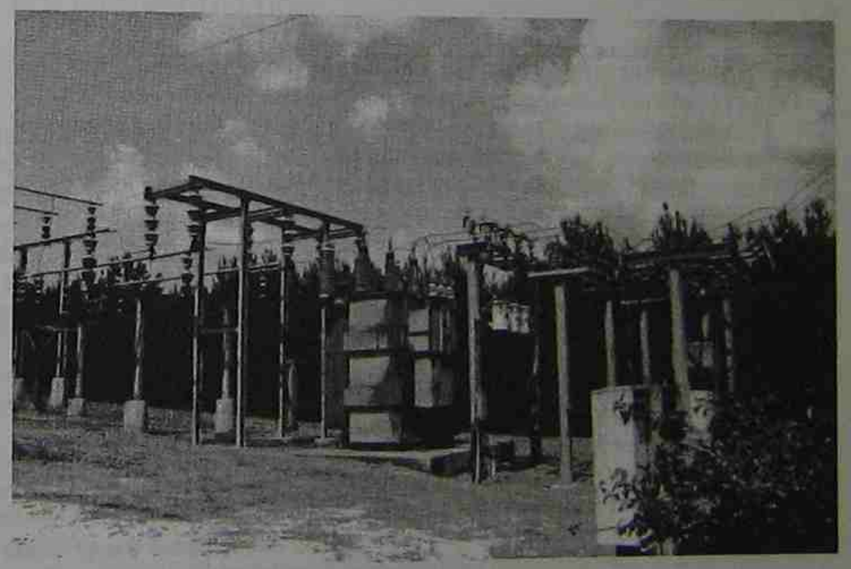


FIGURE 6.3 Substation construction methods include: (a) steel lattice (courtesy of Gulf States Utilities) and (b) low profile (courtesy of Gulf States Utilities).

Lattice steel provides structures of low weight and high strength. Complex, multilevel bus structures can be fabricated relatively easily from lattice steel, as can switch gear support structures. Lattice steel is reasonably economical and is the preferred material for substation construction whenever possible.

Solid steel low profile substations are considered by many to be aesthetically superior to lattice or wood constructed substations. However, low profile construction is more expensive than either wood or lattice steel, and requires more land because multilevel bus structures cannot be used.

The unit substation is a relatively recent development. A unit substation is one that is factory built and tested, then shipped in modules that are bolted together at the site. They are completely enclosed in metal cladding to deny access to unqualified individuals, and protect the equipment. Unit substations usually contain high and low voltage disconnect switches, one or sometimes two three-phase transformers, low voltage breakers, high voltage fusing, bus work, and relaying with overcurrent relaying the minimum. Many unit substations have provisions for underground high voltage lines to be brought in. Unit substations are usually 3000 kVA at 34.5 kV or less. Smaller unit substations can be installed in underground vaults or utility access holes. Unit substations are very expensive, but they are also very reliable and compact.

6.3 TRENDS IN DISTRIBUTION SUBSTATIONS

While large substations of 10,000 kVA or more are necessary and economical in areas of dense load, the trend is toward smaller substations where possible. There are a number of reasons for this trend. It is difficult to add small increments of capacity to large substations economically. Maximum economy is realized when low voltage feeder mileage is kept as low as possible, and all line possible is at higher subtransmission voltages. Smaller substations allow a lower loss mix of high and low voltage lines in lower density load areas. Growth is very hard to predict and has been known to be away from substations designed to serve an area making long, lossy, low voltage feeders necessary. Smaller substations also allow simpler layouts that make design, construction, relaying, and maintenance simpler and more economical.

The trend toward smaller substations is complemented by a trend toward three-phase, as opposed to three single-phase, transformers in substations. Three-phase transformers cost less per kVA of capacity, are smaller, lighter, require fewer fittings to install, and are highly reliable. Three single-phase transformers can be operated in the open delta configuration at reduced capacity should one transformer fail, but that is their only advantage. There is also a trend toward smaller transformers, in the 600 to 3000 kVA range where possible, because a spare transformer in this size range can fairly easily be kept at a central location for emergency replacement. This is the size range in which a mobile transformer can be

made available for emergency service while substation repairs are made. When mobile transformers are equipped with disconnects and protection they are often called mobile substations.

6.4 INSULATION COORDINATION

A typical method of insulation coordination is to establish a definite common level for all insulation in the station and bring all equipment and device insulation to that level. Lightning protection is set at least 20% below this level, but above normal peak operating voltages. The basic impulse level (BIL) standards have been established as a result of insulation flashover tests. For example the BIL standard for 34.5 kV is 200 kV, and for 8.7 kV is 75 kV for distribution class equipment and 95 kV for power class equipment when tested with the standard 1.5 us × 40 us impulse crest waveform. Solidly grounded systems are easier to protect against overvoltage.

6.5 VOLTAGE REGULATION

When the feeder load is such that a fixed tap cannot keep its voltage between the allowed limits some form of voltage regulation is required. Automatic tap changing under load is the most popular voltage regulation scheme, but the voltage level of all feeders from the transformer are changed simultaneously. If this is not acceptable, it usually is, then capacitors or regulating transformers must be used on the individual feeders involved, as shown in Chapter 4.

6.6 DISTRIBUTION SUBSTATION LAYOUT

This section discusses some common distribution substation layouts or designs. These are a representative sample of the layouts in use. The variations on the main themes are many. The designs vary from utility to utility and within the same utility. The nomenclature used for substation designs also varies from utility to utility, so the names we used here are as generic as possible.

6.6.1 The One Feeder Substation

Figure 6.4 shows the one-line diagram of a single-source, single-feeder substation. Note the minimum equipment used. A bypass switch is often provided so service

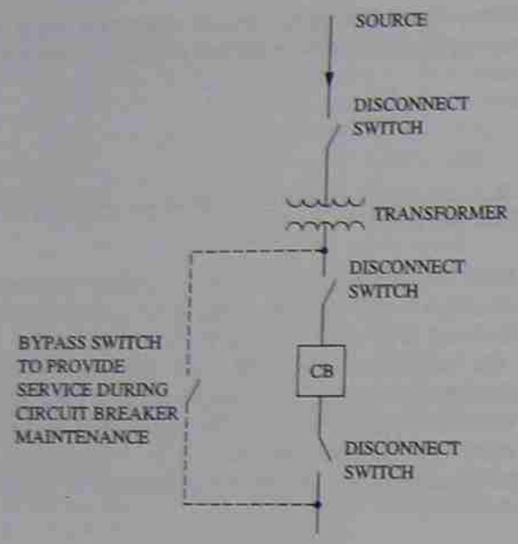


FIGURE 6.4 One-line diagram of single source, single feeder substation

can continue during circuit breaker maintenance. The probability of a fault during circuit breaker maintenance is small, but still there. The transformer usually has a primary fuse to back up the breaker, and provide some protection for internal transformer faults. The minimum relaying is overcurrent on the secondary of the transformer. Frequently differential relaying is provided for the transformer. The switches, as in all substations in this section, can be manually or motor operated. They are normally manual in a substation this simple.

6.6.2 Single Bus Substation

Figure 6.5a shows the one line of a single bus substation fed by a single radial subtransmission line. Each feeder must have its own overcurrent protection. The primary side switch should be interlocked with the feeder breakers so it cannot be opened under load. The primary switch must be able to break the transformer excitation current. The high voltage side breaker is often omitted because the probability of a fault between the transformer high voltage bushings and the feeder breakers is small in a small substation. The transformer rating is often so small compared to the subtransmission circuit that a transformer fault will not operate the subtransmission circuit breaker, so the transformer primary is protected by at least a fuse whose clear time is longer than the feeder breaker operate times. The transformer may have differential relaying that trips all of the feeder breakers in the event of a fault. Each distribution voltage the substation supplies must have its own bus.

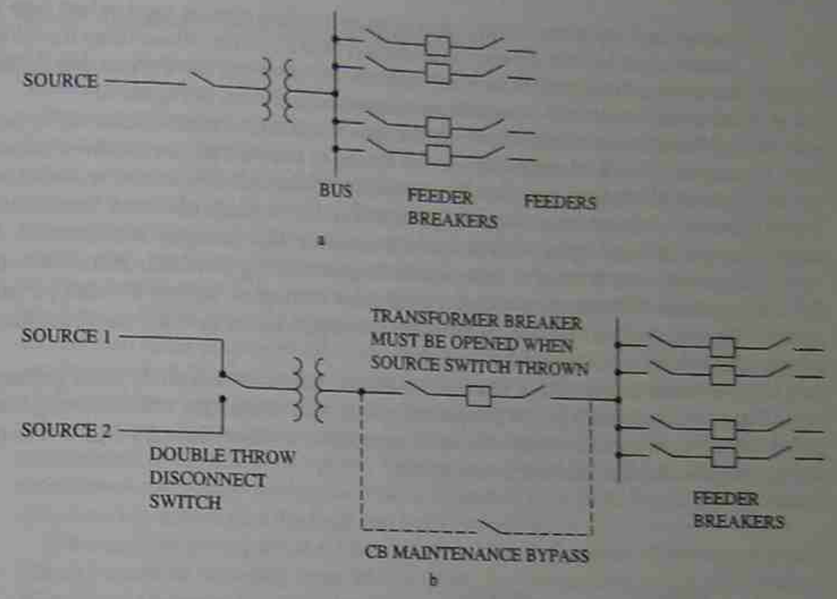


FIGURE 6.5 Single bus substation (a) Single source and (b) two source

The possibility of a subtransmission circuit fault is much higher than a transformer fault. Two sources allow service to be restored more quickly upon a subtransmission circuit fault. The double throw switch on the primary side, shown in Figure 6.5b, allows the transfer to be made quickly from one subtransmission circuit to another. The switch should have an open position to remove the high voltage completely. The switch is interlocked with the transformer breaker so it cannot be opened under load. The switch can be replaced by two manual high voltage breakers that can break the load, and expected fault, current. If high voltage breakers are used the transformer secondary breaker is usually omitted. The transformer secondary breaker makes possible very effective differential bus protection to detect faults internal to the bus. The bus relays then trip all of the circuit breakers connected to the bus upon a bus fault.

Please note that all of the circuit breakers probably have a bypass switch to allow service during circuit breaker maintenance. Figure 6.5b shows only the bypass switch for the transformer breaker to avoid cluttering the one-line drawing. The reader can assume a bypass switch around all feeder breakers henceforth.

6.6.3 Two Transformer Distribution Substations

More critical loads may be out of service an unacceptable length of time in the event of a transformer failure. Two transformers used at a substation can eliminate this eventuality. Normally the transformers are rated at 75% capacity when self

cooled and equipped with automatic air cooling that is used when one transformer must handle the entire substation capacity. Sometimes three transformers are used to reduce the spare capacity the others must have when one of them is out of service. A two transformer substation is shown in Figure 6.6.

Notice the tie switch between the two transformer connections to the bus. This is open when both transformers are in use to prevent the transformer secondaries from operating in parallel. Even small differences in the two transformer secondary voltages can cause large currents to circulate between them and cause excessive heating, as well as make automatic tap changers malfunction. Special reactors must be used to force equal current sharing if transformers are to operate in parallel. Momentary parallel operation during switching is often permissible. The primary side switching is arranged so that either or both transformers can be fed by either subtransmission line.

In a substation of this complexity the transformers normally have primary fuse protection as well as differential relaying, and secondary overcurrent protection. The bus often has differential relay protection to disconnect the bus if it faults and each feeder has overcurrent relaying.

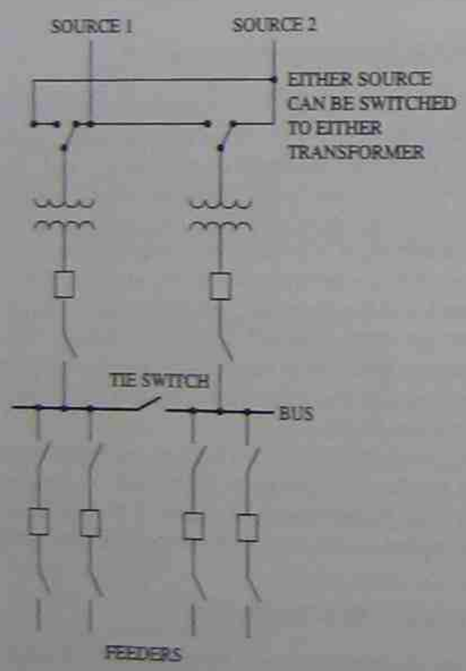


FIGURE 6.6 Two transformer substation

6.6.4 Automatic Switching (Throw-over)

All of the substation layouts we have looked at so far require manual switching to restore power after a fault. Service outage time can be reduced considerably by using circuit breakers to automatically, or on command from a central control station, disconnect the faulted source or bus and connect the substation so that power can reach all of the feeders. Figure 6.7a shows a substation connected for automatic switching, also called throw-over or roll-over. Assume sources 1 and 2 are connected as radial lines. If source 1 should be lost, breaker 1 would open under relay control disconnecting source 1, and breaker three would close connecting transformer 1 to source 2, and vice versa. If transformer 1 should fail breakers 1, 3, and 4 would open to disconnect it. The low voltage bus tie breaker, would then close to connect all of the feeders to transformer 2. The low voltage tie breaker is interlocked with transformer secondary breakers 4 and 5 to prevent parallel transformer operation. If even momentary parallel operation cannot be tolerated, relaying can assure that the tie breaker opens as the transformer being reconnected to the bus is energized. This station is said to have both high and low side throw-over. Once the breakers have operated on a fault they must be manually closed to assure that the fault has been corrected.

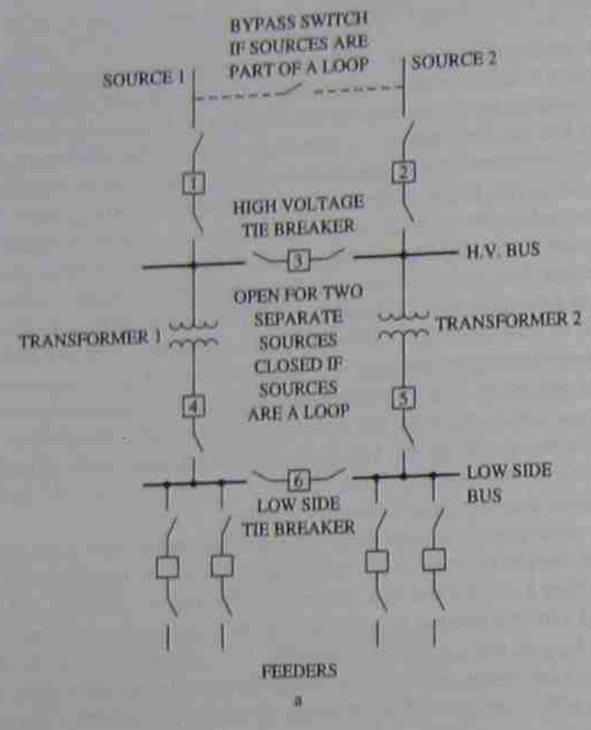
If the sources were part of a loop the high side tie breaker would be normally closed instead of normally open as it is when the sources are radial lines ends or taps. Circuit breaker 1 would remove source 1 in the event of a fault, and circuit breaker 2 would remove source 2. A bypass switch, shown in the dashed line, would close the loop in the event circuit breaker 1, 2, or 3 were down for maintenance. A preferred automatic switching scheme for loop connected supply lines is shown in Figure 6.7b. Circuit breakers A and B remove a faulted line from service, while circuit breakers C and C′ and D and D′ remove the transformers in the event they fault. Upon a transformer failure the low voltage tie breaker connects all of the feeders to whichever transformer is working.

Notice that each circuit breaker has disconnects on either end to isolate it from the circuit during maintenance. Each feeder breaker probably has a bypass switch so the feeder can operate during breaker maintenance.

A substation of this complexity is well protected with overcurrent protection on the transformer secondaries, and the feeders. The transformers and the bus have differential relay protection with overcurrent backup.

6.6.5 Double Bus Substation

In densely populated areas, whether with people or business, and high load areas, like downtown, 10,000 kVA and larger substations are economical. A bus fault will bring the entire substation down interrupting service to all of the customers served by the substation. The solution is to have a spare bus to use in the event one faults. This solution should be familiar by now. The spare bus is often called an inspection bus because it is in service during maintenance in a single-source substation. Each bus is protected with differential relaying that connects the feeders



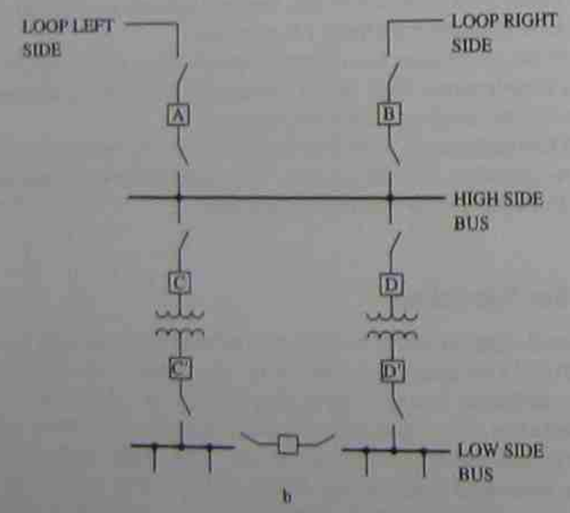


FIGURE 6.7 Automatic switching two source, two transformer substation (a) Two source, radial or loop and (b) better high side loop arrangement

served by one bus to the other bus upon a fault. The automatic switching also removes power from the faulted bus.

A double bus substation is shown in Figure 6.8 that has double bus on both the high and low voltage sides. The reader may enjoy determining the breakers to be switched in the event of a fault in various parts of the substation. Recall that the transformers are not operated with their secondaries in parallel. The relaying for this substation is quite complex and thorough. Notice the feeders are connected to the busses by disconnect switches that must be manually thrown, even if a motor does the work. It is much quicker to connect automatically the feeders to the desired bus.

6.6.6 Bus Arrangements

The bus arrangements in this section can be used for high or low voltage side busses.

The *ring bus*, shown in Figure 6.9 requires only one circuit breaker per line so it is economical. Power can reach any feeder from two directions so no feeder need be disconnected when one breaker is down for service. Two breakers are operated when a feeder fault occurs, one on either side of the feeder.

If a second breaker trips when one feeder is down the entire bus may be disconnected from a source. The ring bus is therefore seldom used if the feeders exceed the source lines by more than a factor of two. Additionally the ring bus is hard to expand. The current capacity of the circuit breakers must be large enough to handle the load of all feeders that may be connected through it. The ring bus is normally used in smaller substations.

The *breaker and a half*, shown in Figure 6.10, is a reasonably economical, versatile, reliable, and easy to expand bus arrangement. It is very popular. A bus or feeder fault can easily be isolated while the station remains in service. The name is from the fact that three circuit breakers are required for every two feeders, or 1.5 breakers per feeder. The breaker and a half is usually used in substations with more than four feeders.

The current carrying capacity of the circuit breakers must be equal to the maximum load of the two feeders they serve because the feeders may be fed from either bus.

The *double bus-double breaker* arrangement, shown in Figure 6.11, is the ultimate in versatility, protection, and the highest in cost. Each circuit has full protection with any breaker out of service for maintenance and no breaker carries the load for more than one circuit. If the bus switches of Figure 6.8 were replaced with circuit breakers, which would replace the individual feeder breakers on the low side and the transformer primary breakers on the high voltage side, it would be a double bus-double breaker substation. This arrangement is only used at important locations because of the expense.

6.7 FAULTS

A fault, recall, is a malfunction in the system. Most faults are, or result in, short circuits. Most faults are the result of lightning and wind of storms, with lightning causing the greatest number. The wind may cause lines and poles to break, or tree

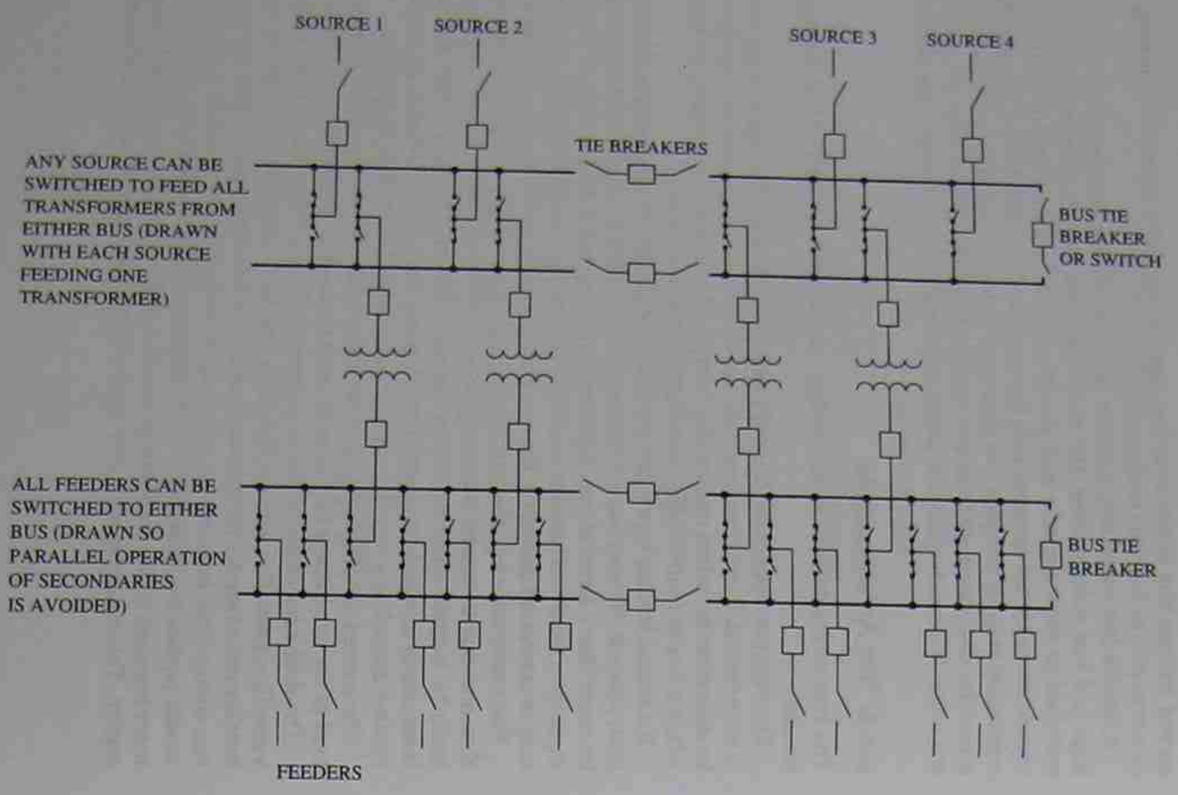


FIGURE 6.8 Double bus distribution substation (high and low voltage double bus)

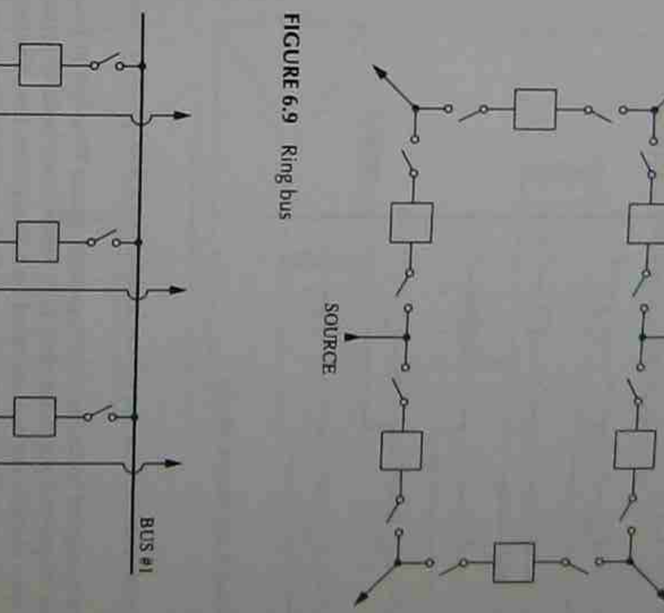


FIGURE 6.9 Ring bus

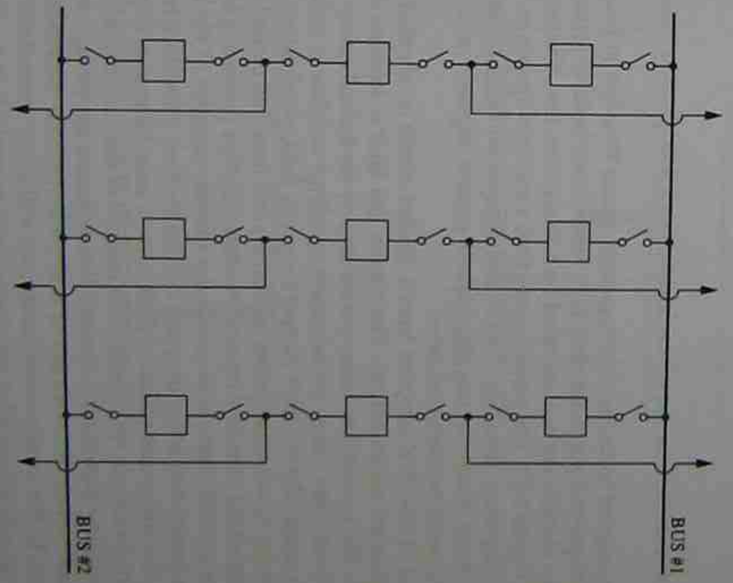


FIGURE 6.10 Breaker and a half

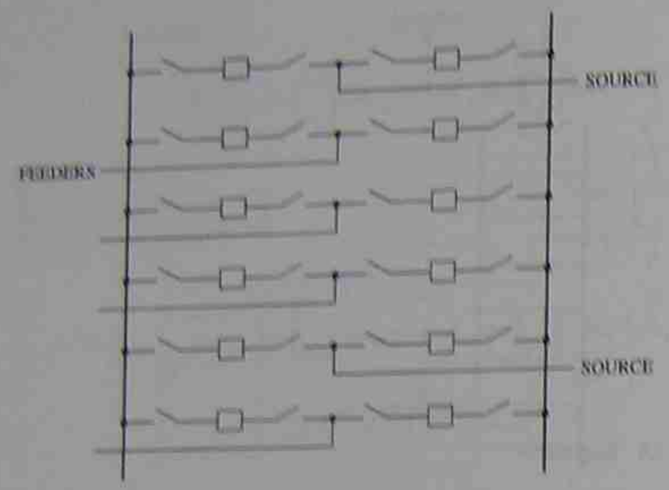


FIGURE 6.11 Double bus-double breaker

limbs to blow across lines, or in the winter ice and snow loading may cause lines to break.

The major categories of faults are: line to ground, about 70%; line to line, about 15%; double line to ground, approximately 10%; three-phase faults to ground, less than 1%; and open circuits not accompanied by a short, very few. The first three are illustrated in Figure 6.12. The percentages given vary from system to system but the order of frequency does not. People and equipment must be protected from system faults by disconnecting the faulted system segment with circuit breakers, reclosers, sectionalizers, and fuses.

Prompt removal of electrical supplies from a faulted circuit is essential to prevent several unpleasant consequences. The sooner the fault is isolated the less damage is done to the equipment, lines, and devices in the faulted circuit. A sustained fault may melt lines, cause transformers windings and bus to twist from mechanical forces caused by the fault current magnetic field, overheat and ignite the oil in transformers causing dangerous explosions and fires, and extend the service outage because of the extensive repairs required. Another problem a fault can cause, we will discuss why later, is to reduce the stability margins of the system. This can result in generators being dropped off line by their protective relaying.

The maximum and minimum values of fault current must be known to provide proper protection for a circuit. An approximate method of fault current calculation is available for building distribution systems that assumes the voltage does not drop during a fault (which it does), but it is not adequate for distribution and transmission faults. In the transmission section we will study *symmetrical components*, which is an accurate method of calculating fault currents. In fact, symmetrical components are most of Chapter 10.

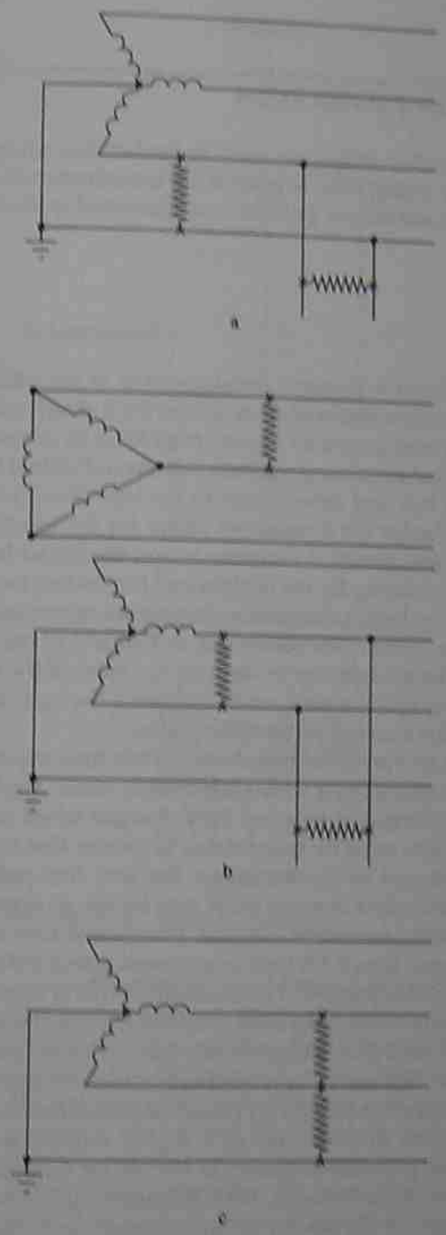


FIGURE 6.12 Major fault types include: (a) Line to ground (b) Line to line and (c) Double line to ground.

6.8 DISTRIBUTION SUBSTATION PROTECTION

Circuit breakers tripped by protective relays are used to protect the equipment within a substation, with primary fusing used to protect the transformers in some smaller substations. Transmission substation protection is discussed in the transmission section of the book.

6.8.1 Zones of Protection

Each relay set and circuit breaker is set to protect a certain portion of the substation and restrict the amount of the substation removed from service for a given fault. The portion of the substation removed from service by a given relay set is its zone of protection. In Figure 6.13 the feeder breakers zone of protection is the individual feeder. The bus zone of protection is the bus and connections to the bus. Should a catastrophic close in fault occur on a feeder the overcurrent relays for the transformer secondary breaker should eventually operate if for some reason the feeder breaker does not trip. This breaker is then a backup for the feeders and for the bus too. Each protective element normally has a backup in this manner to provide protection if the first line protection fails to operate. More of the substation, in Figure 6.13 the whole substation, is taken out of service by the back-up protection, but most of the station can be put back into service quickly, which would not be the case if the back-up protection was not used. Notice that the zones of protection overlap.

The relays operate from current and potential transformers, but their trip circuits operate from 125 V dc normally supplied by a substation battery bank. The batteries, usually lead-acid, are trickle charged so they are fully charged when needed.

The overcurrent protective devices must be coordinated to assure that only the faulted substation section is taken out of service unless the first line protective device fails. Thus the upstream protective element must take longer to operate on any fault current than the downstream protective element. The inverse-time characteristic of fuses, reclosers, and inverse time (CO) type overcurrent relays aid in their coordination. The procedure for coordinating CO overcurrent relays is identical to that for fuses, except for the necessity of selecting a tap. Fuse coordination was illustrated in Chapter 5. Relay, recloser, and fuse manufacturers have detailed literature on coordination for their protective devices, usually with application examples.

Instantaneous trip overcurrent devices (IT and IIT) must be coordinated strictly by operating current. The upstream IT must trip at a higher current than the downstream IT. Usually this is no problem because ITs are set for fault currents instead of overload, and upstream fault currents, both minimum and maximum are higher in a distribution system. If ITs cannot be coordinated on current trip points, then the upstream device will have a fixed time delay to prevent operation until the downstream IT has time to operate. If the downstream IT fails to operate then the upstream IT will operate after the fixed delay.

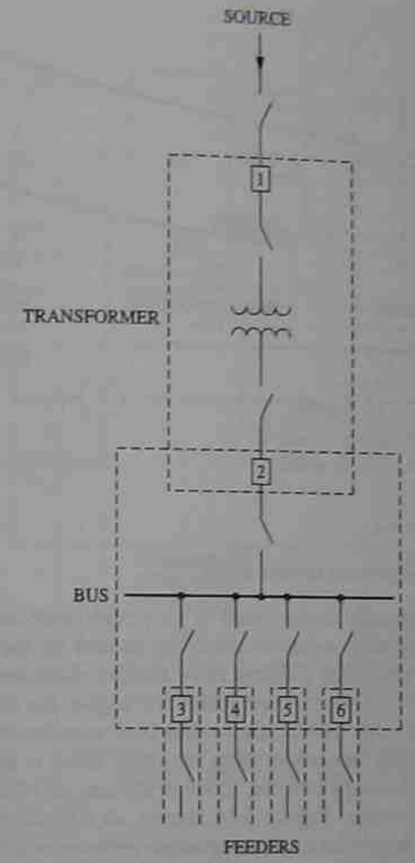


FIGURE 6.13 Zones of protection

Coordination by inverse-time devices (fuses, CO relays, and reclosers) along a distribution feeder is illustrated in Figure 6.14. The solid curves are the CO relay inverse time characteristic. Recall that the further from a source that a fault occurs, the more line impedance is in the circuit, and the lower the fault current is. Usually the maximum fault current is available from a fault just downstream from the protective device, and the minimum fault current is available from a fault at the downstream end of the protective device zone of protection. The inverse-time characteristic means that the protective device operates faster for high fault currents than for low. Thus, as shown in Figure 6.14, the time current curve of an inverse-time protective device correlates with distance along the line. The higher the fault current, the closer the fault, the faster the protective device operates, and vice versa. The instantaneous IT devices used to back up the inverse-time

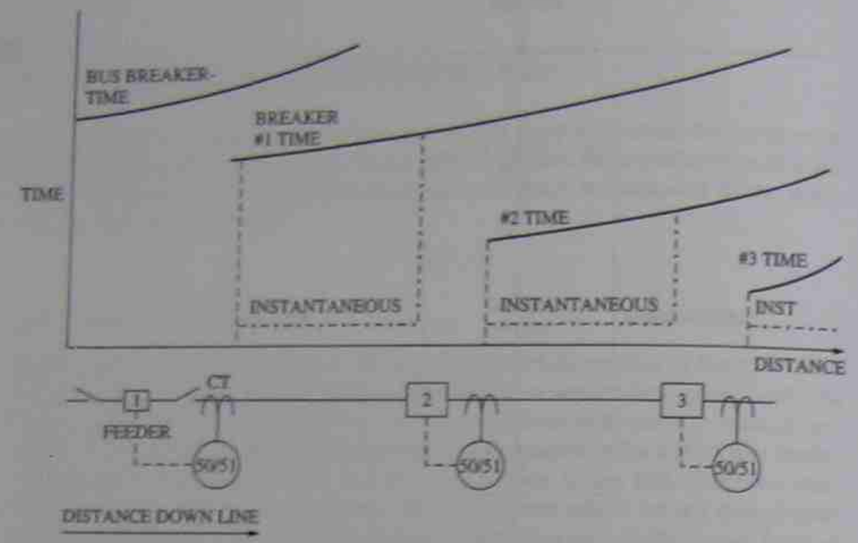


FIGURE 6.14 Coordination of inverse-time over current relays

overcurrent devices are set to trip quickly in the event of very high fault currents, usually from close in faults, and thereby minimize damage caused by the fault.

Coordination is easiest if all inverse-time devices have similar characteristics. For example use all CO-9 relays. In CO overcurrent relays the higher the number the more inverse the characteristic, with CO-2 called short (not very inverse but not an IT characteristic), CO-5 is long (meaning more inverse), CO-6 is definite (for definitely inverse), CO-7 is moderately inverse, CO-8 is inverse, CO-9 is very inverse, and CO-11 is extremely inverse. Figure 6.14 shows all CO relays and breakers but the protective devices might be a circuit breaker, recloser, and fuse in that order.

6.8.2 Transformer Protection

Transformers are, as we noted before, very expensive, and so are well protected. A substation transformer has a minimum of: secondary overcurrent relaying, primary fusing, and a sudden pressure relay. Except for very small substations transformers also have differential relaying with back-up overcurrent relaying. The basic transformer relaying scheme is shown in Figure 6.15a. The delta winding is shown on the source side because the distribution side is normally wye to make the phase to neutral taps needed by the customers. Not all subtransmission transformer connections are delta, but if they are then no tertiary is needed for harmonic control. Note that a circuit breaker is a type 52 device.

The sudden pressure relay (SPR) is a relay, attached to a valve on the transformer tank, that will detect the sudden rise in pressure caused by internal arcing

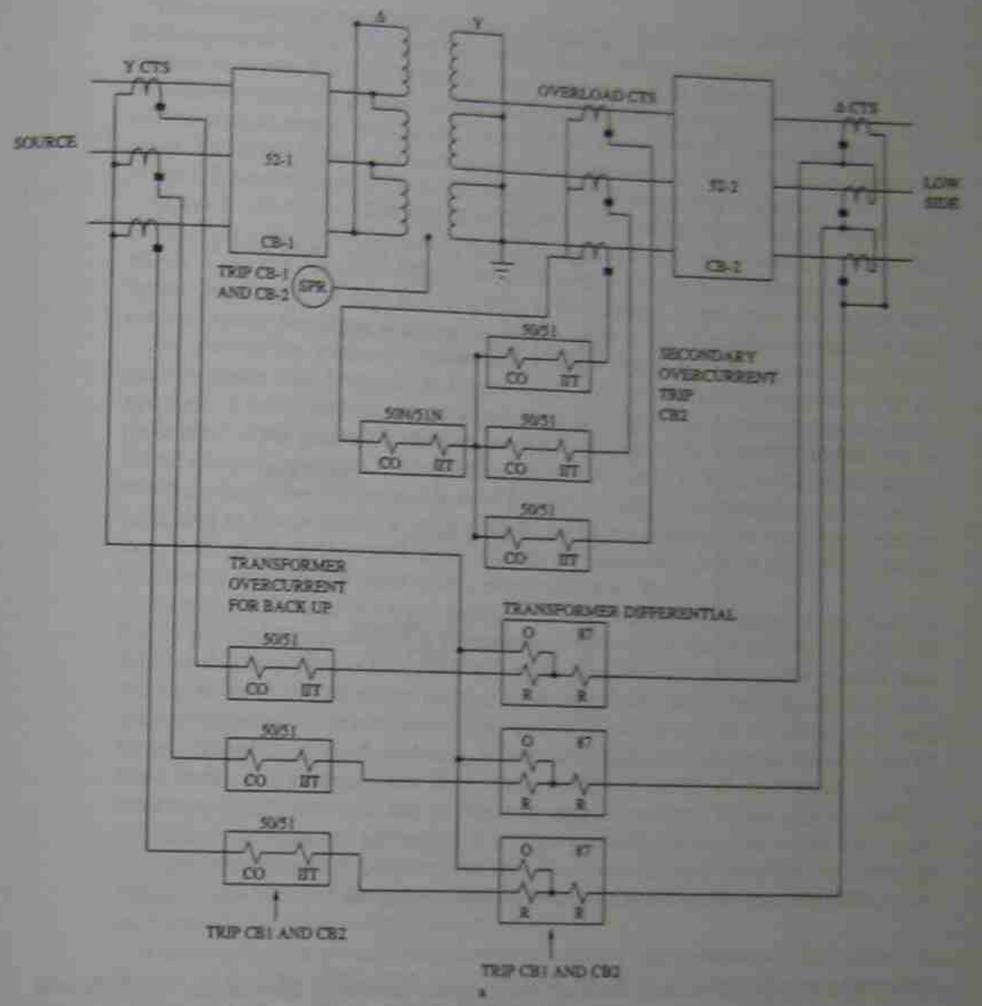


FIGURE 6.15 Transformer protection (a) Simplified circuit

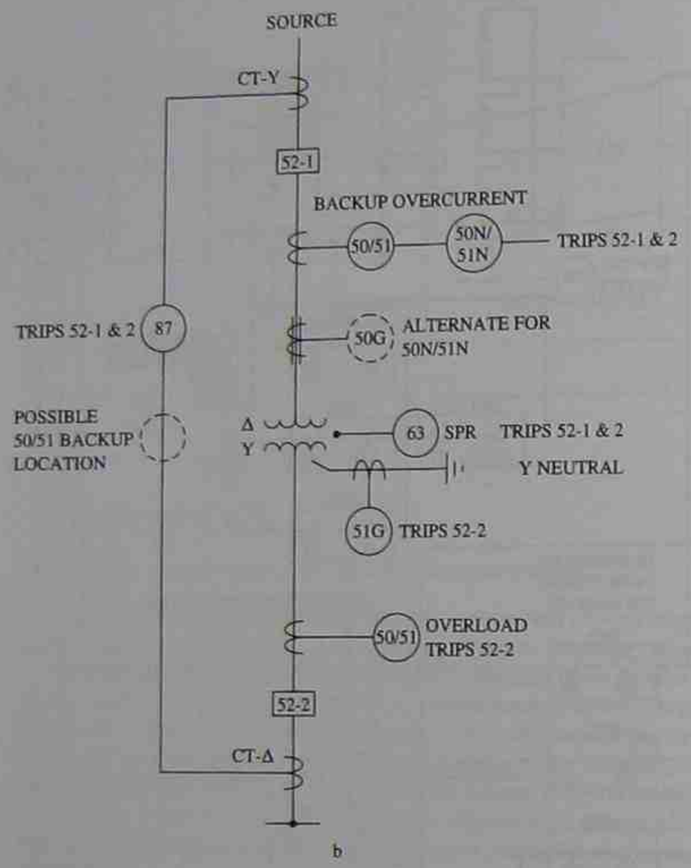


FIGURE 6.15 Transformer protection (b) one-line diagram

and trip the secondary breaker, and primary breaker if there is one. The SPR will not respond to the gradual rise in pressure caused by an increase in loading. The SPR is classified as a type 63 devise, and operates in 2 to 37 cycles, depending on the rate of pressure rise.

Notice in Figure 6.15a that the differential relays also have back-up 50/51 overcurrent relays. The CO relays used in this application must usually be set well above the maximum allowed overload current (200 to 300%) to coordinate with downstream devices. The IIT will be set at 125% of the maximum through fault. Primary overcurrent relays alone can protect against internal transformer faults, and are used on many small installations, but to minimize internal transformer damage from internal faults differential relays are needed.

The secondary overcurrent relaying of Figure 6.15a includes a 50N/51N relay to detect ground faults. The 50N/51N relay is a sensitive overcurrent relay designed for this purpose. If a fault to ground occurs on one of the phases, even a fairly high impedance fault, the phase currents will no longer sum to zero, so the CT currents will no longer sum to zero, and CT neutral current will flow through the 50N/51N relay. If enough flows, the relay trips CB-2. We could have connected a 50N/51N in the CT neutral line of the differential/back-up overcurrent relays.

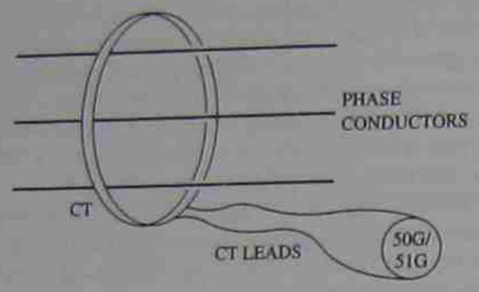
Figure 6.15b shows a one-line drawing of a well-protected transformer. Notice that the back-up primary overcurrent protection can use separate CTs than the differential relays. A number of different ground fault protection possibilities are shown in the figure. Starting at the top, the 50N/51N in the primary overcurrent relaying is connected exactly the same as shown in Figure 6.15a in the secondary overload relays.

An alternative method of detecting ground faults in delta systems is shown next. A closer look is shown in Figure 6.16a. This is a current transformer with an aperture of sufficient size to allow all three (four including neutral if used with a grounded wye) phase conductors to pass through. The current transformer is called a zero sequence CT for reasons we will discover in the symmetrical components section. The CT output should be zero as long as the phase currents sum to zero, but in the event of a ground fault the phase current will no longer sum to zero and relay current will flow causing an alarm or a trip. A 50G/51G ground fault relay is normally used with a zero sequence CT.

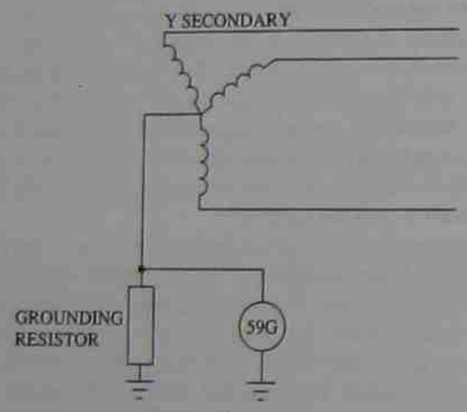
A good place to detect a ground fault in a grounded wye system is on the neutral to ground conductor. This is shown in Figure 6.15. No current should flow in this conductor unless a ground fault exists. Resistors are used in the ground conductor to limit the transient voltage from line capacitance charging on long subtransmission and transmission lines, and to limit current in the event of a fault from a phase to ground. Reactors, which limit sudden changes in current, can be used instead of resistors but the common practice in the United States is to use resistors, which cost less and perform as well as reactors. When possible, solidly grounded neutrals are preferred. If a neutral resistance is used a type 59G overvoltage relay provides positive and sensitive ground fault detection, as shown in Figure 6.16b. Ground fault neutral current causes a voltage across the resistor proportional to the fault current through it.

A more sensitive ground fault detection method using standard CTs is shown in Figure 6.16c. The 50N/51N relay obtains all of the current from a mismatch because the phase CTs have no relay burden.

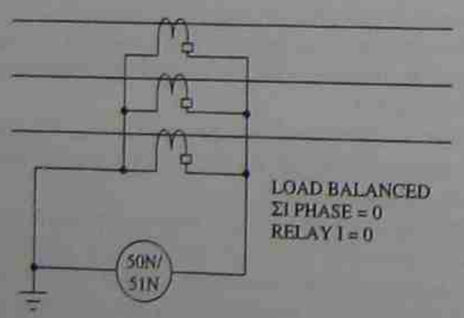
Ground fault relaying, especially on delta systems, may only provide an alarm, allowing the system to continue operating while the fault is found, instead of tripping a circuit breaker. The phase overcurrent relays then trip on a sufficient fault to cause a serious problem. A combination can be used with a CO providing an alarm and an IIT providing a trip if the fault is serious enough to warrant it. The ground fault relaying must not be so sensitive that normal phase load mismatch causes operation, though excess sensitivity is seldom a problem. There are many ground fault protection schemes, but these four are the most common. Their use is not limited to transformer ground fault detection.



a



b



c

FIGURE 6.16 Ground current detection (a) Ungrounded system ground fault detection using zero sequence CT (b) 59G over voltage relay for ground fault detection (c) Three CT method for ground fault protection

6.8.3 Bus Protection

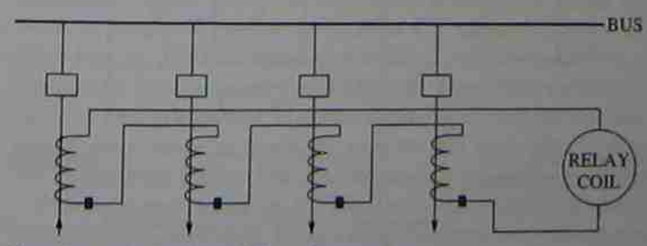
Differential protection is effective for bus faults because the current leaving the bus on feeders and the current entering the bus from sources should be zero at any instant. Additionally, differential protection can distinguish between internal bus faults and external feeder faults. A feeder fault can result in the CTs on the feeder saturating, and the dc offset of a fault worsens the situation. Thus special care must be taken in bus differential relaying to prevent external faults from causing a trip on the circuit breakers supplying the bus. Three major systems are used:

1. Linear coupler (LC) system, which works by eliminating the iron core of the CTs.
2. Multi-restraint, variable percentage relays (CA-16).
3. High impedance voltage operated differential relays (KAB).

Linear coupler systems use air core transformers that do not saturate. Those used for LC relaying look similar to normal iron core CTs, and can be specified for bushing mount at the time of purchase of the substation circuit breakers. The LC system is fast, less than 16 mS for LC-1 and 32 mS for LC-2 relays, easy to apply, and easy to adapt to bus changes. The LCs are actually designed to provide 5 V secondary voltage for every 1000 A primary current. The relay detects voltage.

The LC connection for a very small bus is shown in Figure 6.17. Notice that the LCs are connected in series. At least one of the lines is a source. In normal operation or during an external fault the sum of the LCs voltages is zero because the LC voltages are proportional to the line current and the source and feeder currents sum to zero. During a bus fault at least one of the feeder currents approaches zero and its LC voltage drops. The voltage sum of the LCs is no longer zero and the relay operates.

The LC-1 relay uses a solenoid connected through an impedance matching autotransformer. The impedance matching autotransformer is to allow the relay impedance to match the total impedance of the LCs. The LC-1 and LC-2 relays both have taps of 30, 40, 60, and 80 Ohms. The LC-2 relay uses a polar dc relay mechanism energized by the rectified output of an impedance matching transformer. The transformer source is, of course, the LCs. The LC-1 is designed for use where high fault currents are available, and the LC-2 for lower available fault current applications, though it can be used with high fault currents.



Normal operation or external fault – voltage sum zero
internal fault, feeder current drops – voltage sum not zero

FIGURE 6.17 Linear coupler bus protection (one-phase of connections shown)

The *multi-restraining CA-16* uses conventional CTs that saturate on heavy fault currents. The relay is more complex to compensate for CT saturation. The CA-16 consists of two sets of three restraining coils and one operating coil each on an induction disc. The two discs are mounted on a common shaft, which carries the moving contact. The restraining coils provide opening torque to the disc, and the operating coils provide closing torque. Each restraint coil is paired with another giving a total of six restraining coils. More than one relay is used if more restraining coils are needed.

The relay is said to be variable percentage because on light faults, where CT performance is good, its sensitivity is high and a very small current difference causes the relay to operate. On heavy faults, where CT performance is poor, a higher difference current is needed to operate the relay. This characteristic is provided by a saturating autotransformer across the operating coil, as shown in Figure 6.18. Heavy fault currents saturate the autotransformer causing current to be shunted away from the operating coil. The autotransformer also shunts the dc component from asymmetrical fault currents away from the operate coil. The dc in the restraining coils has a braking effect on the induction disc.

The connection for one phase of a four circuit CA-16 bus protection relay system is shown in Figure 6.18a. A circuit consists of from one CT, especially on a source, to several paralleled CTs from different feeders. Preferably each circuit provides

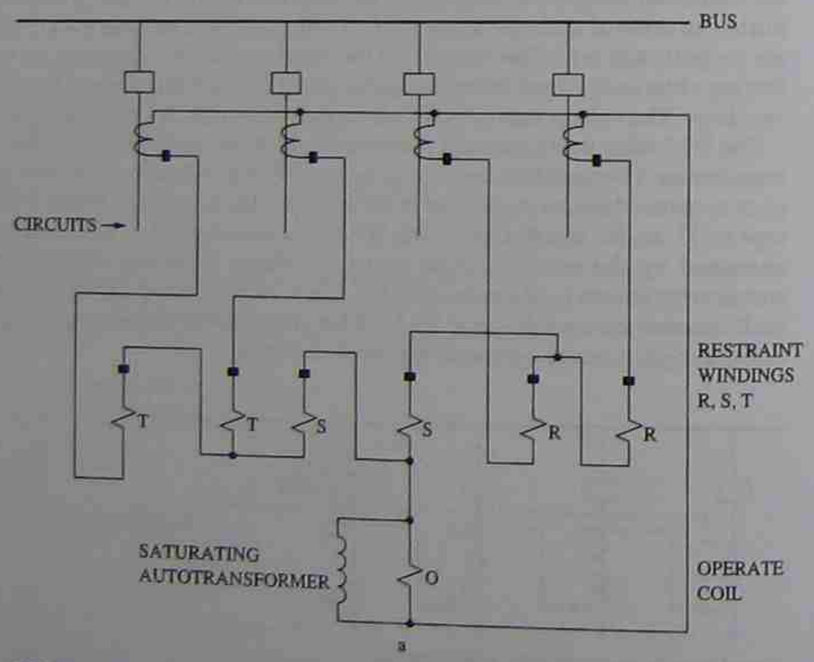


FIGURE 6.18 Multi-restraint bus protection (one-phase connections shown). Each circuit may be two or more paralleled feeder CTs or two or more parallel source CTs. (a) Four circuit connection, one CA-16 used per phase

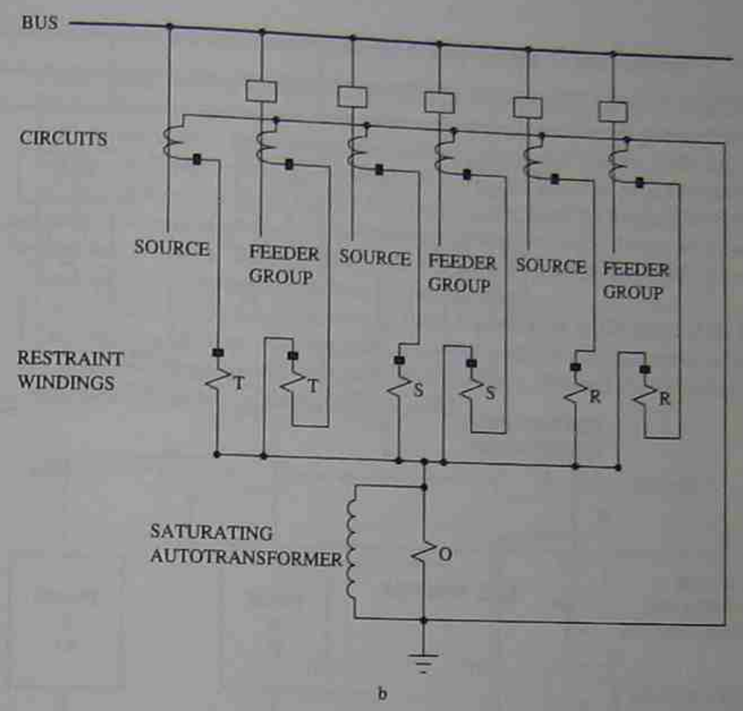


FIGURE 6.18 (b) Six circuit protection, one CA-16 relay per phase.

about the same total CT current. The total parallel CT current should not exceed 14 A through any restraining coil. The restraining coils are not tapped. Figure 6.18b shows the relay connections for one phase of a six-circuit bus. Notice the source and feeder group polarity connections. For a three-circuit connection use the R, S, T windings of the same polarity and do not connect the other three restraining coils.

The *KAB* is a *high impedance differential relay*. The KAB relay uses conventional current transformers, but loads them with a high impedance overvoltage relay, as shown in Figure 6.19. The high relay impedance forces false difference currents from external faults that saturate a CT through the lower impedance CTs. The KAB has an instantaneous overvoltage cylinder unit (*V*), a tuned circuit to pass the power line frequency and block dc from fault current asymmetry, an IT overcurrent unit connected in series with a low voltage varister (blocks current until threshold voltage is reached), and an ICS unit. The IT provides faster action on severe internal faults. The KAB operating speed is about 25 mS.

The voltage can rise on a CT loaded with a high impedance so use of taps on the CTs should be avoided. If taps must be used the voltage across the CT from autotransformer action must be safe at the highest available fault current. The CTs paralleled connections should be connected in the station yard as close to the CTs as possible and the lead lengths should be as even as possible.

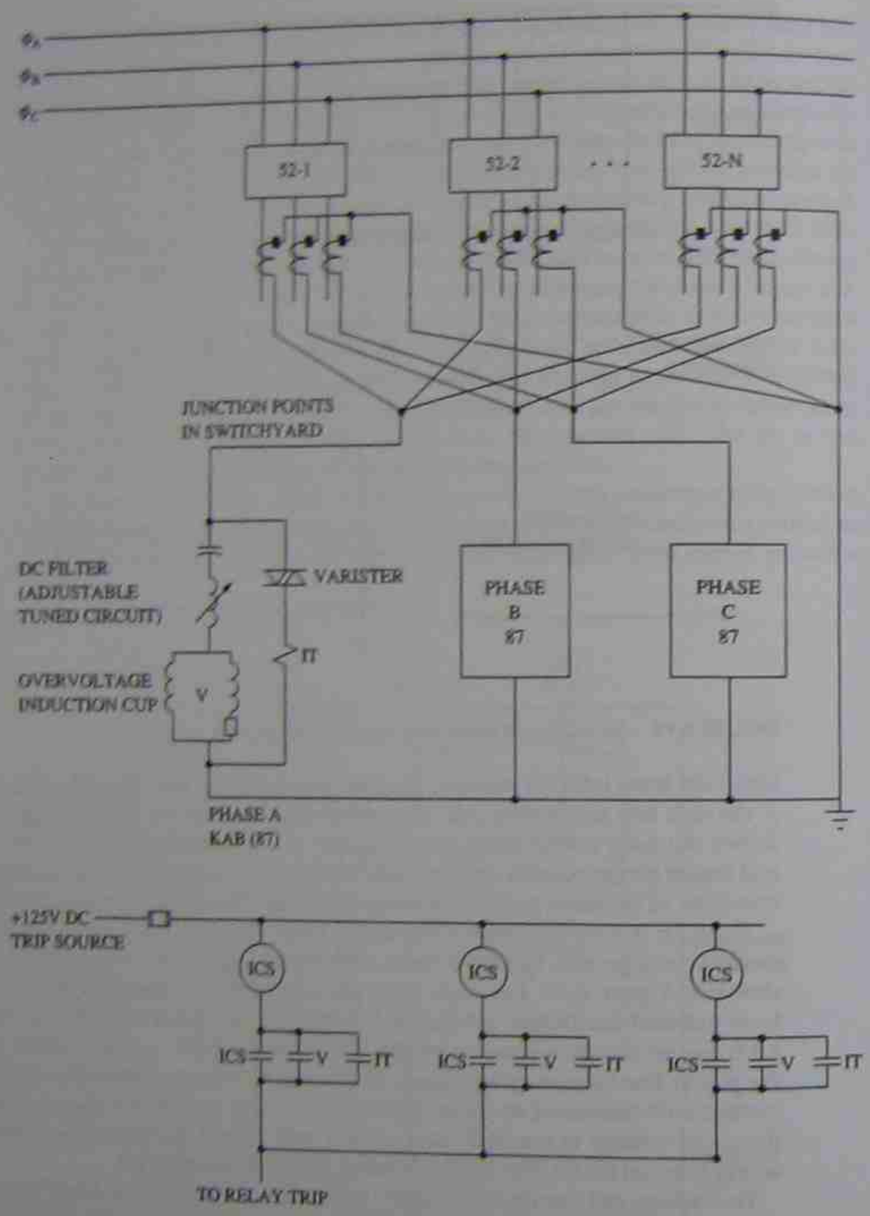


FIGURE 6.19 KAB relay bus protection

6.8.4 Combined Protection of a Bus and a Transformer

Combining bus and transformer protection is generally done on small substations. Ideally the bus and transformer have separate protection. Separate bus and transformer protection provides better fault isolation and easier fault location. If the substation location and/or economy require that the bus and the transformer be protected together the CA-26 or HU type relays must be used. The CA-26 is more inverse than the CA-16, and has a higher pick up current. It has an operating time of about 3 cycles. The HU relays are preferred because the HRU provides more immunity to false operation from inrush current.

The HU-1, with three restraining coils, connection is illustrated in Figure 6.20. The HU-4, with four restraint coils, must be used for a transformer with a tertiary or a two winding transformer with three feeders. Beyond that level of complexity separate protection is almost always used.

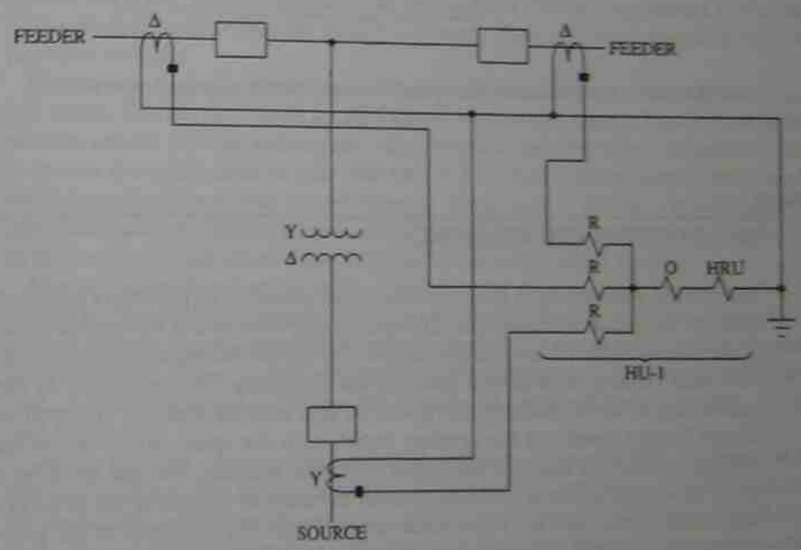


FIGURE 6.20 HU-1 relay protection for bus and transformer together

6.8.5 Feeder Overcurrent Protection

Basic feeder overcurrent protection is shown in Figure 6.21. The basic and now familiar 50/51 with 50N/51N ground fault sensing is the standard relaying scheme for feeders. If the relays must be coordinated with downstream fuses CO-8 or 9, very inverse, or CO-11, extremely inverse relays are usually needed. Recall that a tap off of a feeder in which the conductor size decreases by 30% or more must be fused.

The feeder, bus, and transformer protection must all be coordinated using the principles already discussed.

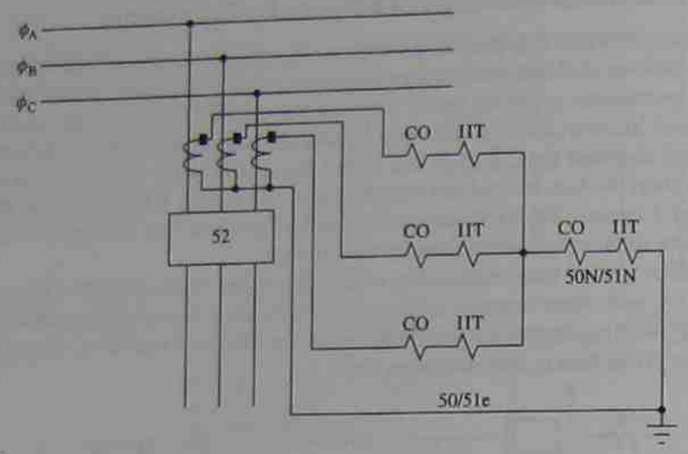


FIGURE 6.21 Distribution feeder overcurrent protection, one per feeder needed

6.9 SUBSTATION GROUNDING

Substation grounding is first for safety, and secondly to provide a stable reference voltage for protection systems. The grounding system of a substation consists of a ground mat made of substantial size (4/0 to 600 MCM) bare conductors, connected in a grid pattern, and buried beneath the substation. The perimeter of the grid is connected to metal rods driven about 30 feet into the ground. The grid wires are about 20 feet apart but the spacing varies with the conductivity of the soil. More highly conductive soil can use larger grid wire spacing. The soil must be tested at each location and the soil characteristics are used in designing the ground mat. All substation structures are to be constructed within the perimeter of the grid.

The fence around a substation has two buried ground wires connected to the fence every few feet. One runs about 3 feet outside the fence, and one runs about 3 feet inside the fence. Both wires are connected to grounding rods every 50 feet. This is to protect the public from shocks due to voltage induced in the fence by the substation electric and magnetic fields.

6.10 SUMMARY

Among the factors that effect the design of a substation are: voltage, load requirements, available site space, site location, expected load growth, aesthetic considerations,

and protection requirements. The substations of a large industrial concern or utility vary because of changes in these factors, but as much substation standardization as is practical is used because standardization reduces cost and eases maintenance.

The National Electric Safety Code contains the minimum clearance between conductors and conductors to ground, with the spacing increasing as voltage increase. Usually clearances are larger than those specified in the code to allow additional safety margins. The usual clearances are published by the IEEE.

Distribution substations support structures are constructed of wood, steel lattice, steel low profile, or unit. Wood is inexpensive but suitable only for small substations. Steel lattice construction is flexible, strong, low weight, and reasonably expensive. Solid steel low profile stations are considered by many to be aesthetically superior to other construction materials, but are expensive and normally require more space because multilevel buses are not used. Unit substations are factory built and tested, and shipped as modules that are connected in the field. Unit substations are normally totally enclosed. They are very expensive, but compact and reliable.

Single-source single-feeder substations provide maximum economy for noncritical loads. The single-source single-bus substation provides a bus so that several feeders can tie into the substation. More critical loads have two sources available to power the substation in case one feed is lost. Two transformer substations are used for critical loads that cannot tolerate down time in case of a transformer failure. Automatic switching (throw over) is used to change sources or transformers in the event of a failure of either in substations with critical loads.

Densely populated areas with critical loads that require many feeders are served by double bus substations so that service can continue in the event of a single bus failure. Double bus substations are expensive but provide a high degree of fault tolerance. The standard substation bus arrangements are ring, breaker and a half, and double bus-double breaker in order of simple to more complex, flexible, and expensive.

On the average, phase to ground faults account for about 70% of electrical system faults, line to line faults cause about 15%, double line to ground faults account for about 10%, and three-phase to ground faults are responsible for somewhat less than 1%. Substation protection includes both time and instantaneous overcurrent, transformer and bus differential, and ground fault. Substations must be well grounded for reliable protection operation and personnel safety.

6.11 QUESTIONS

1. State the purpose of an electrical power distribution substation.
2. List five criteria that must be considered in substation design.
3. What are the advantages of standardization in substation design?

4. What two electrical factors directly influence substation site size? What non-electrical factor?
5. Why are some substations more heavily protected than others of the same capacity?
6. List the four major substation construction methods along with a major advantage and disadvantage of each.
7. List and explain two major trends in substation design.
8. What is meant by insulation coordination?
9. Why is substation voltage regulation often needed?
10. The two single-source single-feeder substations in Figure 6.2 are quite different. Why?
11. Why are two sources desirable for a substation?
12. List two reasons for using two transformers in a substation.
13. Automated throwover is very expensive. Under what conditions is its use justified?
14. State the purpose of double bus substation layouts.
15. List the advantages and disadvantages of each of the following bus arrangements: ring, breaker and a half, and double bus-double breaker.
16. What changes are needed to convert the substation in Figure 6.8 to a double bus-double breaker?
17. Define zone of protection.
18. What is meant by back-up protection?
19. List and state the function of each relay normally used with a well-protected distribution substation power transformer.
20. List and briefly explain the principle of the three major methods of bus protection.
21. Why is it best to protect the bus and transformer separately?
22. State two purposes of substation grounding.
23. Draw three methods of ground fault protection.
24. How are IT units coordinated?
25. Explain how time-current curves can correspond to distance along a line.

CHAPTER 7

Distribution Line Construction

Electrical power distribution lines connect the distribution substation to the ultimate customer. They are an important part of the electrical power system. They must be reliable, low in maintenance, economical, and long lasting. Successful distribution line construction principles and techniques have become standard practice in the industry. This chapter briefly describes the major construction practices.

7.1 DISTRIBUTION CONSTRUCTION SPECIFICATIONS AND STANDARDS

Distribution lines are normally connected grounded wye. The most common distribution voltages are 12,470 V line to line, 7200 V phase to ground, 34.5 kV line to line, and 20 kV line to neutral. The grounded wye configuration aids in loading all three phases proportionately and any accidental phase grounding shows up as a phase to ground fault, which is easily detected by the overcurrent relays.

Distribution lines are normally constructed along easements on streets, alleys, or along property lines between or behind buildings. The easements are granted by the governing body of a locality to providing utility service to its citizens. Often the easements are called *right of ways*. The close proximity of distribution lines to buildings and dwellings gives the public a very real and legitimate interest in the

voltages and construction methods used for distribution systems. Thus these have been codified by the National Bureau of Standards (Standards Handbook C-2) and designated as the National Electric Safety Code (NESC).

Work on the NESC was begun by committees of the Association of Public Utilities, the Inspection Societies of Municipalities, and the IEEE (Institute of Electrical and Electronic Engineers) in 1913. The work was completed in 1938 and has been periodically revised and updated since then. In 1973 the IEEE was designated as the administrative secretariat for the National Bureau of Standards Handbook C-2 (NESC). Since then revisions have been published approximately every 3 years. The revisions are studied and recommended to the IEEE by committees composed of representatives from the IEEE, EEI (Edison Electric Institute), Association of Inspectors, and National Fire Underwriters. One committee was formed for each of the four sections of the NESC.

The four parts of the code are:

Part I: Rules for the Installation and Maintenance of Electrical Supply Stations and Equipment.
Part II: Safety Rules for the Installation and Maintenance of Overhead Electrical Supply and Communication Lines.
Part III: Safety Rules for the Installation and Maintenance of Underground Electric Supply and Communication Lines.
Part IV: Rules for Operation of Electric Supply and Communications Lines and Equipment.

Anyone may address a proposed change in the NESC to the IEEE, which will refer it to the appropriate committee for consideration. The work of the committees is periodically reviewed and the proposed changes accepted and endorsed or rejected. Endorsed changes are printed in the next published edition of the code.

Legal acceptance of the NESC comes by its adoption in the building codes of municipalities and cities for projects within their jurisdiction, and state and federal government for contracts supported with their funds. In areas in the United States in which there are no building codes (primarily county land outside cities and towns), the courts in judicial proceedings involving liability for accidents in which electricity is a factor use the NESC as the standard of proper electrical practices for the installation and maintenance of electrical systems. This practice makes the NESC the de facto standard throughout the United States.

Most electric utilities have developed company standards that incorporate the provisions of the NESC as well as local practice and good judgment concerning local conditions. For example, a locality with frequent high winds may need line spacing considerably in excess of the NESC requirements. Less stringent requirements than the code are not an option. One of the most widely used standards is the one developed by the REA (Rural Electrification Administration) as a set of construction specifications for use by all borrowers of REA funds. Appendix B contains sample REA specifications.

One of the more critical specifications contained in the NESC is the safe minimum line spacing. Table 7.1 gives a partial listing from tables 1, 4, and 8 of the

NESC. NESC table 1 deals with line clearance over specified items, table 4 is for clearance of supply lines from buildings, and table 8 concerns line to line clearances, which vary with the line sag between conductor supports. The NESC tables and standards cover nearly every conceivable construction situation.

TABLE 7.1 Sample Spacings from the NESC Tables

From Table 1 Open Supply Lines

	Voltage		
	0 to 750	750 to 15,000	15,000 to 50,000
	Required clearance over specified items		
Railroad tracks	27'	28'	30'
Public streets, alleys, or roads	18'	20'	22'
Driveways to residential garages	10'	20'	22'
Areas accessible to pedestrians only	10'	15'	17'
Parallel to streets	18'	20'	22'
Parallel to rural roads	15'	18'	20'

From Table 4 Clearance of supply lines from buildings

Voltage of supply conductors	Horizontal clearance	Vertical clearance
300 to 8,700	3'	8'
8,700 to 15,000	8'	8'
15,000 to 50,000	10'	10'

From Table 8 Separation in inches required for line conductors #2 AWG or larger versus span sag

Voltage between conductors	Span sag in inches				
	36	48	72	96	120
2,400	14.5	16.5	20.5	23.5	26.0
7,200	16.0	18.0	22.0	25.0	27.5
13,200	18.0	20.0	23.5	26.5	29.5
34,500	24.0	26.5	30.0	33.0	35.5
69,000	36.6	36.5	40.5	43.5	46.0

7.2 DISTRIBUTION CONDUCTOR SUPPORTS

Distribution systems are usually designated as either overhead or underground. Overhead distribution consists of conductors, structures to support conductors, and insulators. Underground systems consist of ducts, vaults, and cables. Underground systems are discussed a bit later in this chapter.

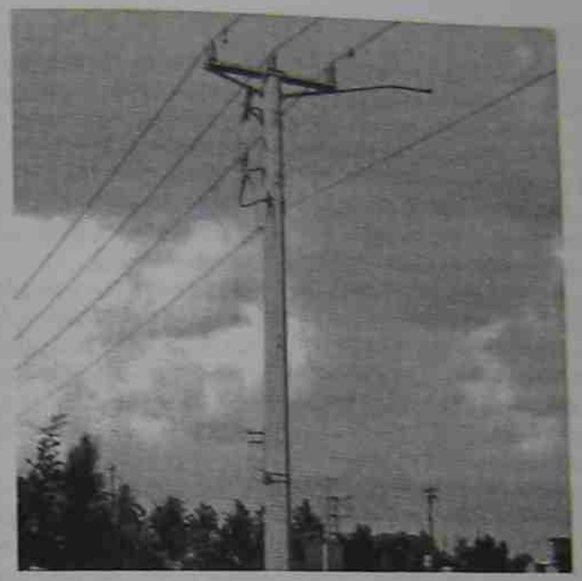
The overhead structures consist of wood or steel poles, cross arms, brackets, insulator supports, and miscellaneous hardware for device and conductor attachment. By custom the cross arms, brackets, and related hardware are referred to as *framing*. Distribution circuits very rarely use steel lattice towers, so we will discuss wood and steel poles here. Figure 7.1(a–d) shows a variety of distribution poles.



FIGURE 7.1 Distribution pole types include: (a) Wood (courtesy of Gulf States Utilities)



(b) Wood dead end (courtesy of Gulf States Utilities)



(c) Steel (courtesy of Houston Lighting & Power)



(d) Steel dead end (courtesy of Houston Lighting & Power).

7.2.1 Wood Poles

The simplest and cheapest support structures are wood poles. These were the first extensively used electrical conductor support structures. Wood poles have been made from larch, spruce, cedar, pine, and fir trees, selected for height and straightness. The most commonly used trees for poles are the Southern Yellow Pine (SYP), about 70%, and Douglas Fir, about 25%. All of the others comprise only about 5 percent of the wood poles used. Poles from 25 to 65 feet are generally SYP while poles over 65 feet are generally Douglas Fir. Wood poles are available in heights from 25 to 130 feet (or more on special order) in 5-foot increments.

Wood pole heights and strengths have been codified from tests, and tables prepared to make distribution design easier. A reliable average for maximum longitudinal fiber stress in both pine and fir is 8000 psi. That is the psi at which the wood fibers will start to split or slide past each other. So all design strengths have been calculated from this value. The loading profile from a force at the top of a pole is shown in Figure 7.2. As force is gradually increased, a pole will fail first by splitting along the pole and then by breaking.

Poles are designated by strength and degree of straightness as class 1 (best) through 5 (worst). Larger poles have their own classification as extra heavy duty classes 0, 00, 000, and 0000, with more zeros being heavier duty. The zeros are usually written as H1, H2, H3, H4. Figure 7.3 shows where to find the pole classification on a pole.

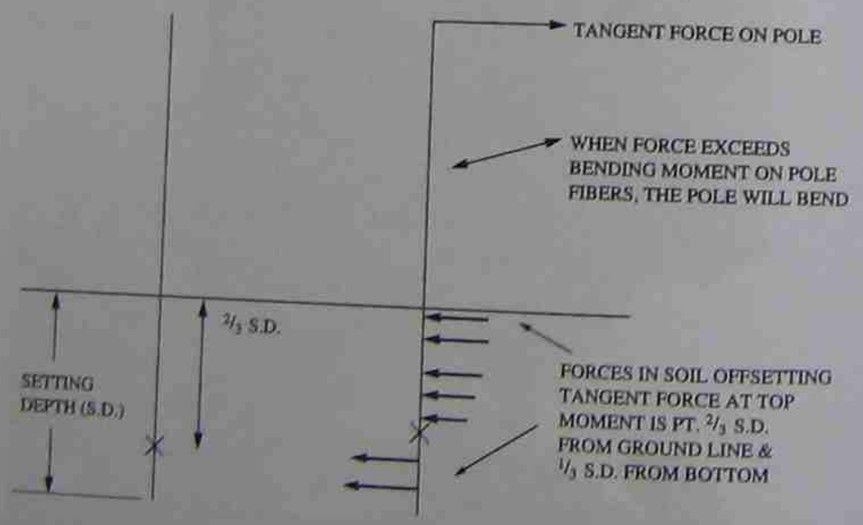


FIGURE 7.2 Pole loading profile

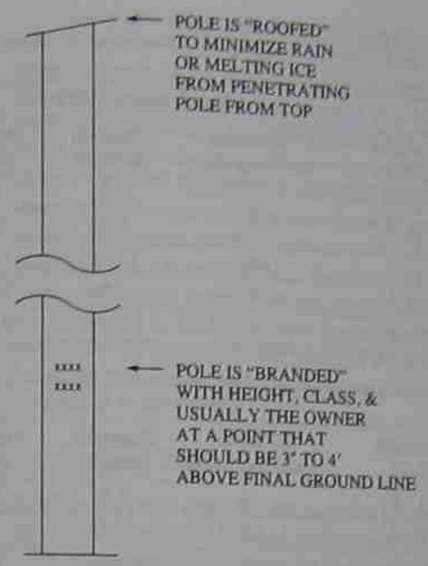


FIGURE 7.3 Wood pole details

Table 7.2 gives some sample pole strengths. The table gives the pole classification and its weight first. The first column gives the distance from the top of the pole that the force is applied, the second column gives the diameter of the pole at that point, and the third column gives the moment (essentially torque) in units of feet-klb, usually abbreviated ft-k. In other words the maximum allowable force perpendicular to a class 1 pole at the top of the pole, 50 feet above the pole attachment point, is $(51.5 \times 10^3$ ft-lb$)/50$ ft $= 1034$ lb. At 10 feet below the top, 40 feet up, it is $(77.3 \times 10^3$ ft-lb$)/40$ feet $= 1932$ lb. The tables are based on an 8000 psi ultimate pole bending stress. The force on the pole is called tangent, see again Figure 7.2, because it is tangent to the line attached to the pole. A perpendicular pole force is taken to mean a force perpendicular to the direction that the line is strung.

Wood poles have the flexibility to bend and give under sudden severe loads, and resume their shape when the load is removed. This property makes wood a very desirable conductor support material when it can be used. Under severe force, such as storm winds perpendicular to the line, the force on the pole may be dissipated in the ground. Usually the pole can be straightened or, after extreme loads, reset. Wood poles seldom break in two.

After they are cut and cured, wood poles are pressure treated with a coal tar derivative, usually creosote, until the wood has been completely saturated. This treatment gives the pole an expected lifetime of 40 to 50 years unless attacked by ground rot or woodpeckers, the major enemies of wood poles.

TABLE 7.2 Wood Pole Strength Tables

50 Ft. Pole, Douglas Fir or SYP					
Class H1, Wt. = 2,200 lb.			Class 1, Wt. = 1,970 lb.		
Distance from top (feet)	Diameter (inches)	Moment (ft.-k)	Distance from top (feet)	Diameter (inches)	Moment (ft.-k)
0	9.23	51.5	0	8.59	41.5
10	10.57	77.3	10	9.90	63.4
30	13.28	152.1	30	12.50	127.9
40	14.58	203.0	40	13.80	149.6
50	15.92	264.2	50	15.11	179.2
50 Ft. Pole, Douglas Fir or SYP					
Class 2 Wt. = 1,700 lb.			Class 3 Wt. = 1,220 lb.		
Distance from top (feet)	Diameter (inches)	Moment (ft.-k)	Distance from top (feet)	Diameter (inches)	Moment (ft.-k)
0	7.96	33.0	0	7.32	25.7
10	9.19	50.8	10	8.48	39.9
30	11.65	103.4	30	10.79	82.3
40	12.88	139.4	40	11.95	111.7
50	14.11	183.7	50	13.11	147.4
70 Ft. Pole, Douglas Fir or SYP					
Class H1, Wt. = 3,640 lb.			Class 1, Wt. = 3,225 lb.		
Distance from top (feet)	Diameter (inches)	Moment (ft.-k)	Distance from top (feet)	Diameter (inches)	Moment (ft.-k)
0	9.23	51.5	0	8.54	41.5
30	12.96	142.5	30	12.18	118.1
50	15.45	241.3	50	14.56	202.1
70	17.93	377.6	70	16.95	318.7
70 Ft. Pole, Douglas Fir or SYP					
Class 2, Wt. = 2,840 lb.			Class 3, Wt. = 2,470 lb.		
Distance from top (feet)	Diameter (inches)	Moment (ft.-k)	Distance from top (feet)	Diameter (inches)	Moment (ft.-k)
0	9.23	33.0	0	7.32	25.7
30	11.00	96.7	30	10.60	78.0
50	13.68	167.5	50	12.79	137.0
70	15.97	266.3	70	14.98	220.0

Poles can be protected against woodpeckers by wrapping the pole with a ¾ inch galvanized wire mesh. This is not completely effective, but it is the best available protection that does not harm the birds.

Ground rot occurs in areas where the pole base is alternately wet and dry—almost everywhere. It occurs from just above the ground line to a foot or so beneath the ground, and severely weakens the pole if not treated. Tamping the fill dirt well and mounding it around the base of the pole, so the water runs away from the pole, helps prevent ground rot. Treatments to prevent ground rot, or kill it if it has started, are applied to the wood from 6 inches above ground to 18 inches below ground. Several treatments are available including some in which the chemical is forced into the wood under pressure through small holes drilled in the wood. If ground rot has caused pole weakening often the pole can be repaired after the rot has been killed. Repairs can be as simple as bolting split pipe to the base of the pole across the damaged section. Several commercial repair methods are available in which a loose metal sleeve is put around the damaged area (usually from 18 inches under ground to a foot or so above ground) and the space between the sleeve and the pole are filled with high density epoxy or foam.

7.2.2 Steel Poles

Steel poles have been in use now for a long time, and are well proven. They do not have the elasticity of wood poles, nor do they have the lifetime. The life of a steel pole is governed primarily by the quality and thickness of the galvanizing. There are special paints to make a steel pole look better longer, but it is impractical to paint the inside of the pole, so the galvanizing sets the pole life. Steel poles typically last from 25 to 30 years.

Steel poles are much more expensive than wood poles, but become more economically favorable in lengths from 90 to 130 feet. The principal reason for using steel poles is their looks. Many people think steel poles are more attractive than wood poles. They are extensively used in highway and street lighting, sports arena lighting, and in commercial and residential areas where the developers believe that steel poles are preferable. Ninety foot steel poles for tangent use (line extends both ways from the pole) cost about $2600 as opposed to about $1600 for a 90 foot wood pole. The reason that steel poles become competitive in the longer lengths is shipping costs. Long wood poles are grown in the Northwest United States, and require two train cars to ship because of their length. Steel poles can be manufactured in convenient shipping lengths that can be slip fitted together like fishing rods at the construction site, as shown in Figure 7.4. Also, steel poles are manufactured at several places throughout the United States. The shipping savings can offset much of the higher price of long steel poles, particularly in the Eastern half of the United States.

There are no standard steel poles. They are manufactured to order for each job so the steel thickness varies with the expected load. This is part of the reason the price of steel poles is so high. The typical weight for a 50 foot tangent steel pole is 2500 lb, and 4500 lb for a 70 foot pole. Dead end poles (wires attached to only one side) are built heavy enough to take the strain without bending so typical weights for steel dead end poles are 5000 lb for a 50 foot, and 9000 lb for a 70 foot pole.

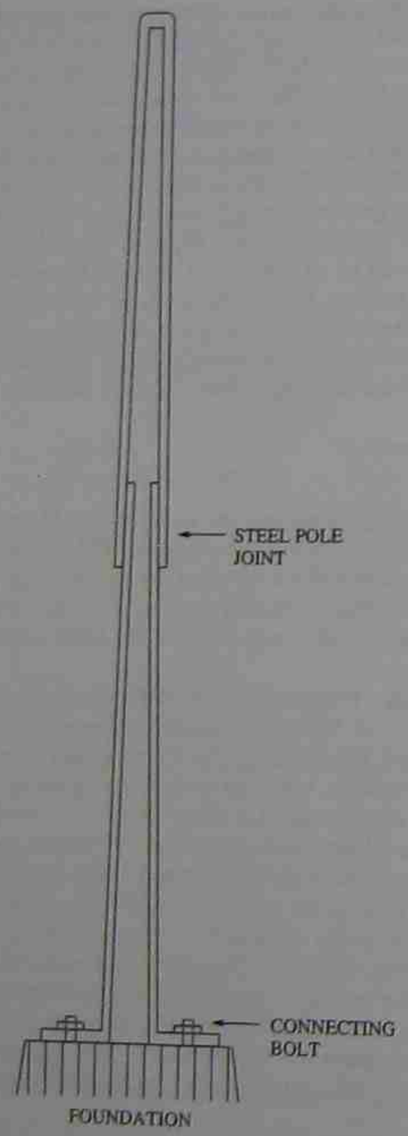


FIGURE 7.4 Steel pole construction (cut away view)

7.2.3 Pole Foundations

Wood poles are set by direct imbedment as shown in Figure 7. 5. Steel poles may be set by direct imbedding also, or may be set on a foundation and attached with anchor bolts. Direct imbedment for either steel or wood poles is the same and

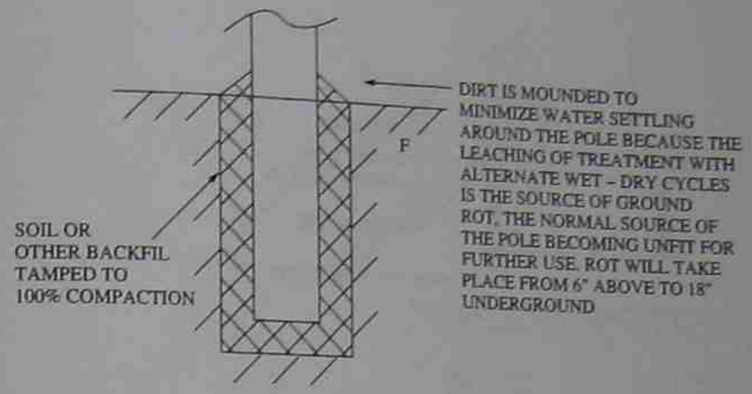


FIGURE 7.5 Wood pole imbedment

requires an imbedment depth of 10% of the height plus 2 feet for standard soil. Thus a 50 foot pole has an imbedment of 7 feet while a 70 foot pole has an imbedment of 9 feet. The soil must be tamped to 100% compaction, meaning to the density it was before the hole was dug. Specifications usually require two tampers for each shoveler when the soil is filled in around the pole. A pole set in soil can be loaded immediately.

Imbedment can be reduced if concrete stabilized sand, rock, or concrete are used for fill. Concrete stabilized sand is a mixture of ¾ sand and ¼ concrete used for fill where the soil has too much give to support a pole well. The concrete stabilized sand essentially increases the size of the pole end so that the loading per unit area on the soil is lower. The concrete must set up before the pole can be loaded.

Reinforced concrete foundations for steel poles can be very expensive, costing more than the pole for some dead end poles. They are necessary in soils that are particularly corrosive to steel. Figure 7.6 is a sketch of a reinforced concrete steel pole foundation. Anchoring is much cheaper and is used on wood and directly imbedded steel poles.

Poles and imbedments are designed to support forces that are balanced on either side of the pole. Down guy wires and anchors are used to balance the forces on the pole in situations in which balanced pole loading is not possible. Anchoring for a dead end pole is shown in Figure 7.7. Extra loading in the tangent direction is absorbed by the conductor, guy wire, and anchor as long as the ultimate strength of these components is not exceeded. Perpendicular forces, such as storm winds, are absorbed by the pole and transferred to the ground. As mentioned earlier, if the pole is not damaged from excess perpendicular loading it can be straightened or reset. Usually the conductors, anchor, and guy wire are not severely damaged and can be reused. Pole anchors are needed any place that the normal pole loading changes from tangent, so both bends and dead ends need to be anchored. Bend anchoring is illustrated in Figure 7.8.

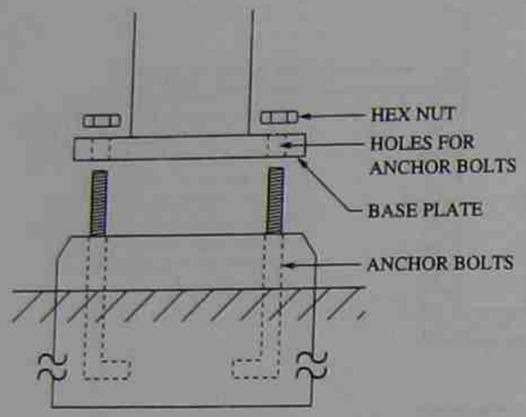


FIGURE 7.6 Reinforced concrete steel pole foundation

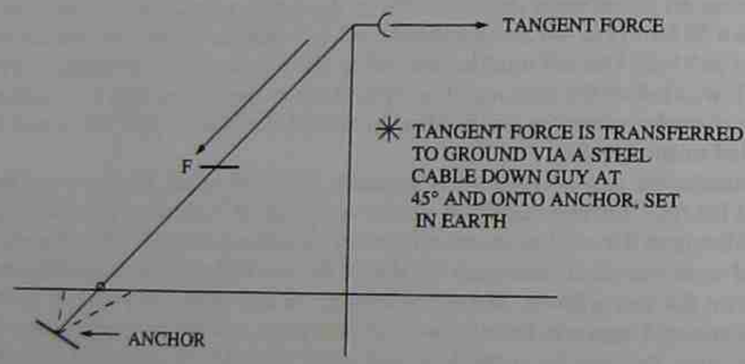


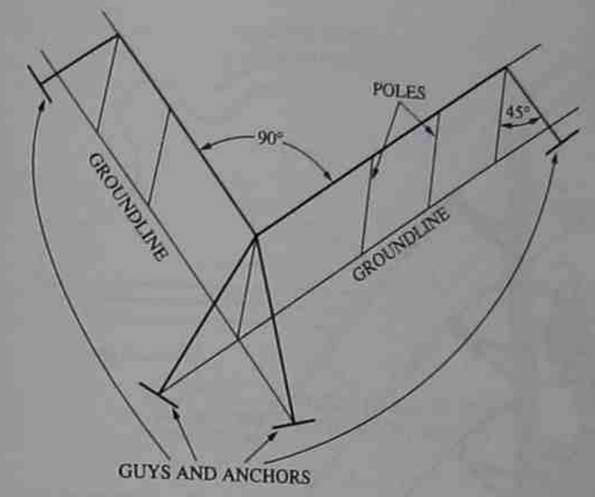
FIGURE 7.7 Pole down guy and anchor

7.2.4 Framing

The structural member attached to the pole to support the insulators and conductors, including all of the bolts, washers, and other associated hardware, is called *framing*. The framing holds the conductors in the proper position with the proper spacing. Both wood and fiberglass are used for the cross arms. Steel or fiberglass is used for the brackets. Figure 7.9 shows some typical framing.

7.2.5 Insulators used for Distribution

Insulators separate the current carrying conductors from grounded structures. They are usually made of glazed porcelain or glass, but fiberglass is becoming increasingly popular. Insulators must be clean to perform properly so they are



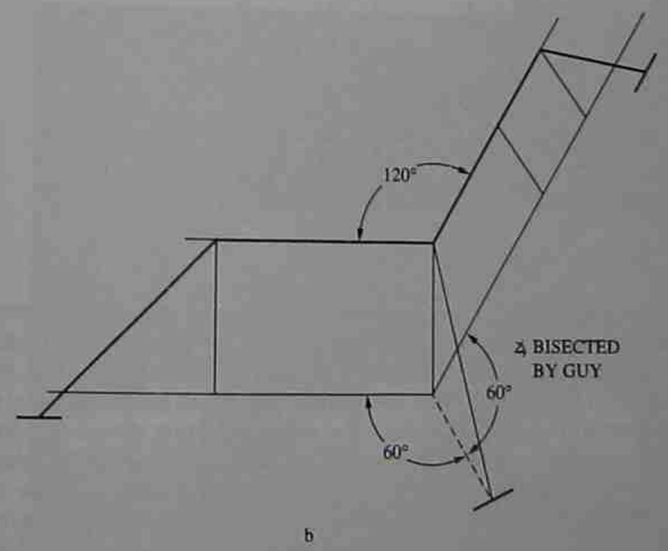


FIGURE 7.8 Pole anchors on line direction changes (a) 90° and (b) 120°

designed to use rain to wash away dirt and sediment from areas on which they can settle.

The crucial electrical factor for insulation is the length of the path from the conductor to the insulator support. Insulator skirts are fluted to increase the path length, as shown in Figure 7.10. The conductors are heavy so glass and porcelain

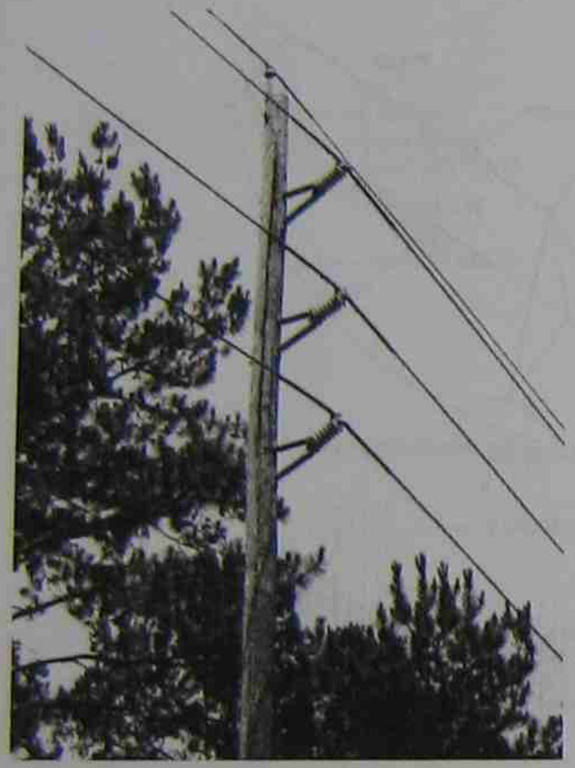


FIGURE 7.9 Framing

may seem to lack the strength to support them. However, both materials have great compression strength, and insulators are designed so that the glass or porcelain is loaded only in compression. The compression loading is easy to see with the pin insulator shown in Figure 7.10, but is less obvious in the ball and socket and clevis insulators shown in Figure 7.11. In these the steel supporting structures overlap, with glass or porcelain (usually porcelain in these types) between the overlapping parts. Thus the porcelain is loaded in compression only. These parts are totally enclosed within the insulator so the skirts can provide the proper path length.

The clevis and ball and socket insulators are used only as dead end insulators in distribution, although they are the normal tangent insulators in transmission. The clevis insulators use a clevis on one insulator across a mating structure on the next one with a pin holding the two insulators together. The ball and socket insulators are held together by a ball on one insulator fitting into a socket on the other. The ball goes into the socket from the side of the insulator and slips forward a bit so that a perpendicular force cannot cause the ball to come out of the socket when the insulators are under load. The ball and socket is the most expensive but it can be

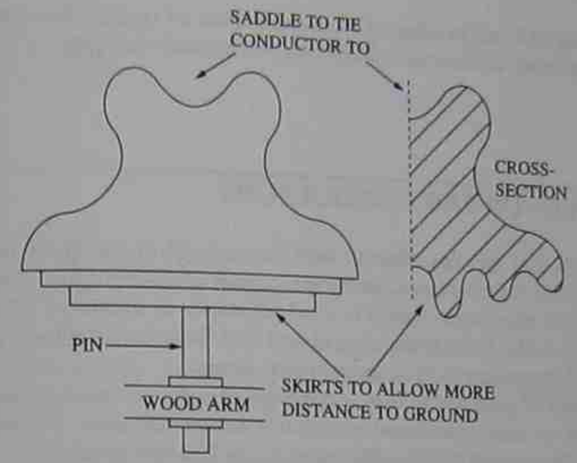


FIGURE 7.10 Pin insulator

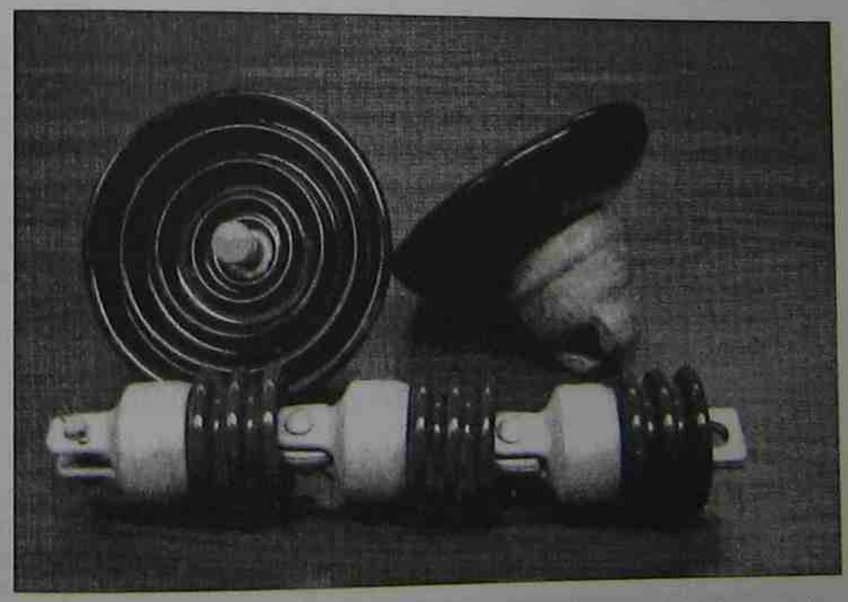


FIGURE 7.11 Distribution dead end insulators Clevis (lower) and ball and socket (upper)

changed out hot by experienced crews with hot sticks and proper maintenance tools. For this reason ball and socket insulators are used by nearly all electric utility companies. The mechanical loading must be supported by an auxiliary

structure before the ball can be slipped from the socket, of course. Insulators are rated for both maximum withstand voltage and mechanical strength.

7.3 DISTRIBUTION OVERHEAD CONDUCTORS

The only two metals that are cost effective and low enough in resistivity for electrical transmission and distribution systems are copper and aluminum. Copper is so much heavier than aluminum that it is used primarily in insulated wires and cables. Aluminum is suitable for transmission and distribution and allows the use of much lighter and more economical support structures.

The tensile strength of pure aluminum is not high enough for most applications so aluminum alloys or steel reinforced aluminum alloys are used. The primary cables used in distribution are ACSR, AAC, and AAAC, in that order.

7.3.1 ACSR (aluminum conductor, steel reinforced)

This is the most common transmission and subtransmission conductor, and it is the most commonly used distribution conductor for long spans and large, high capacity lines. The length of the span and the allowable sag determine the conductor characteristics required. ACSR maximizes span and minimizes sag.

ACSR consists of one or more layers of hard drawn alloy #1350 aluminum wire wrapped concentrically around a high strength galvanized steel core, which may consist of a single steel wire or several strands of steel wire as shown in Figure 7.12a. A single steel strand, seven steel strands, and for very large conductors 19 steel strands, are most common. The conductors are listed as aluminum conductors/steel conductors with 6/1 (six aluminum, one steel strand), 26/7, and 54/7 being common sizes. Many other sizes are available.

7.3.2 AAC (all aluminum conductor)

All aluminum conductor is available in 7, 19, 37, 61, and 91 strands of #1350 aluminum wire. It is shown in Figure 7.12b. AAC has slightly better conductivity at low voltages than ACSR, but it has less strength and more sag per span length. It is used for lines with short spans. AAC costs about the same as ACSR.

Distribution spans are generally short because the lines are built on public roads, streets, and easements. It is not permissible to serve a building with service drops across streets or across the property of another land owner. This means two lot widths is the general span for residential, and light commercial and business districts. This is typically between 120 and 200 feet.

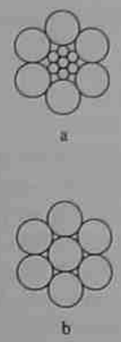


FIGURE 7.12 Conductor cross sections (a) ASCR and (b) AAC

7.3.3 AAAC (all aluminum alloy conductor)

AAAC is constructed like AAC, shown in Figure 7.12b, but uses aluminum alloy #6201-T81. It has the strength of ACSR but is lighter in weight. It is also much more expensive. AAAC is used for very long spans where the strength of ACSR is needed but light weight is essential. This means its distribution use is limited to such applications as river crossings. For transmission and subtransmission there are applications in which the support structures must be very light so they can be transported by helicopter. Extremely rough mountains and swamps comprise most of these situations. AAAC is often used in these applications and in river crossings.

Most utilities select a few standard size conductors that meet their requirements and stock only those conductor sizes and accessories (such as splice sleeves and dead end shoes). They then use these sizes for all of their construction.

7.4 UNDERGROUND DISTRIBUTION

Underground distribution systems consist of buried ducts (conduit systems for cables), vaults, and cables. An underground distribution system is very expensive compared to an equivalent overhead system, and has a shorter life span. Underground systems suffer fewer outages during their life spans because they are protected from storms, lightning, and vehicle accidents. When an outage does occur, such as when a buried cable is cut during construction excavation or a pad mount lightning strike that burns up a cable, it is longer and more expensive to repair than an overhead outage.

The NESC also governs underground distribution setting such standards as cable depth below grade, separation from other buried utility service such as gas and water pipes, insulation class, and access limitations. The two extremes of

underground distribution are residential direct buried cable and downtown vault, utility access hole, and cable duct systems for networks.

7.4.1 Underground Cables

Underground cables normally use stranded copper instead of aluminum for conductors. The lower resistivity of copper helps keep losses lower since reactive losses are higher for underground cables. Some underground cable is shown in Figure 7.13.

Practical residential underground distribution began when direct buried underground cable was developed that used a relatively inexpensive plastic insulation, typically cross-linked polyethylene, and, as mentioned in Chapter 3, practical elbow connectors. The cable consists of an insulated cable of stranded conductors with a bare concentric neutral.

A variety of types and sizes of plastic insulated underground cable is available for industrial and commercial use, including three-phase and single-phase cable, shielded, bare neutral, and insulated neutral cable. Cable with operating voltages to over 25 kV is available for direct burial service. Guaranteed lifetimes are about 15 years, and seem accurate.

For many years the favored underground cable was stranded copper with an oil impregnated paper insulation wrapped in a lead sheath. It is still used in cable ducts, although plastic insulated cable is being used more and more. This cable is expensive to buy, install, and splice, but once in service it has a long life. Some are 50 years old and still in service in duct vaults. Oil impregnated paper insulated cable is available in single-and three-phase cable and in voltages up to 46 kV.



FIGURE 7.13 Plastic insulated underground cable

Oil-filled cables, in which liquid oil fills a void around the paper insulation, can withstand voltages between 23 and 69 kV for three-phase cables, and 69 to 230 kV for single-phase cables. The oil space is provided by a helical spring running the length of the cable. Periodic oil reservoirs are required for oil-filled cables. All cable can handle any voltage below the maximum operating voltage. Another type of cable that uses dry nitrogen at 10 to 15 psi (instead of oil) is available up to 46 kV.

Underground transmission, like underground distribution, is avoided when overhead can be used. Wide river crossings and service to downtown areas make both unavoidable. Underground transmission cables are more complex than underground distribution cables, and more expensive, because of the higher voltages involved. Underground transmission cables have three insulated single-phase cables that are usually contained inside pipes filled with high pressure (about 200 psi) oil or nitrogen. Cables of this type can handle up to 550 kV. Recently the use of SF_6 for underground transmission line pipe fill has become common. The SF_6 transmission line has the conductor supported in the center of a larger outside pipe by insulating disks, which have holes to let the insulating gas pass through. The SF_6 storage, pumping, pressure monitoring, and distribution equipment for SF_6 transmission systems is expensive and complex.

7.4.2 Residential Direct Burial

Underground residential distribution (URD) uses direct buried cable exclusively, allowing installation costs to be reasonable. The heavy three-phase feeders are overhead along the periphery of a development, and the laterals to the pad-mount transformers are buried about 40 inches deep. The lateral cable conductors come up from underground into the high voltage compartment of the transformer. The secondary service lines then run to the individual dwellings at a depth of about 24 inches, and come up into the dwelling meter through a conduit. The service conductors run along easements and do not cross adjacent property lines.

7.4.3 Commercial Direct Burial

To avoid the substantial cost of excavation and backfill rural telephone cable, highway lighting, and perimeter wiring in some industrial plants is installed with a cable plow. A cable plow is a small shoe-like plow connected to the draw bar by a long knife-shaped blade structure. The structure has a tube through which cable can be fed from the top down to the plow. The cable is then fed out behind the plow, usually at a depth of 48 inches. A D-8 Caterpiller tractor is usually needed to pull the cable plow, with a second needed to carry the cable reel. The tractor with the cable reel goes in front of the plow-pulling tractor and feeds cable back over it to the plow. Cable plows require a lot of room to bury cable. Many specifications prohibit the use of cable plows because the condition of the cable as it goes into the ground cannot be seen.

Most direct buried cable for commercial and industrial applications is placed in machine dug trenches. The trenches allow special backfill and cable handling

requirements to be met. Some specifications require 3 inches of sand in the bottom of the trench under the cable, and another 3 inches over the cable to prevent rocks from damaging the cable insulation. Many specifications also require a 2- by 8-inch oak plank to be placed 8 inches below grade during backfill to deter accidental breaking of the cable during subsequent excavations. Bright yellow plastic is sometimes used instead of the oak plank to warn of high voltage.

7.4.4 Underground Duct Banks

Underground duct bank, with access at vaults and utility maintenance holes, is the most sophisticated, reliable, and costly method of underground distribution. The high reliability is why it is used for large industry such as chemical plants and refineries, and for downtown networks.

A duct bank is a set of parallel conduits made of steel, PVC covered steel, heavy walled PVC, or thin walled PVC in reinforced concrete. Large, long duct bank conduits are of thin walled PVC, evenly spaced and set in reinforced concrete as shown in Figure 7.14a. The concrete is often dyed red to warn of high voltage in the event an excavation should uncover the duct bank. The duct banks terminate in utility access holes or vaults, as shown in Figure 7.14b. Duct bank runs from a utility access hole at one intersection to another. At points between utility access holes smaller duct banks or rigid galvanized steel conduits leave the main bank to take power to a building. This is illustrated in Figure 7.15. Smaller duct banks leading from the main duct bank to buildings must be of thicker material than thin wall PVC if they are not enclosed in concrete. Transformers and network protectors are usually housed in vaults near the utility access hole, often under a building.

Duct banks are seldom filled to over 40% capacity (40% of the holes filled) upon installation to allow room for expansion of service capacity and fault repair. A serious cable fault in a duct frequently damages the duct. It is less expensive and quicker to run a new cable in another duct conduit, cut the old cable free, and splice to the new cable, than to remove the old cable first. The old cable can be removed later for fault analysis and scrap value.

The handling, splicing, and fireproofing of cables in vaults is costly. Additionally, the cost of equipment suitable for installation in vaults is high. The vault, cable duct bank, and utility access hole underground distribution system is the most reliable and safe system available, but it is very expensive.

7.5 RESIDENTIAL DISTRIBUTION LAYOUT

The following exercise illustrates the design of an overhead distribution system for a small subdivision. The system will allow for future expansion and voltage conversion. The present feed is from a 12.47 kV, three-phase, 600 MCM feeder on Main Street. The area is to be converted to 34.5 kV in the future, as the load builds

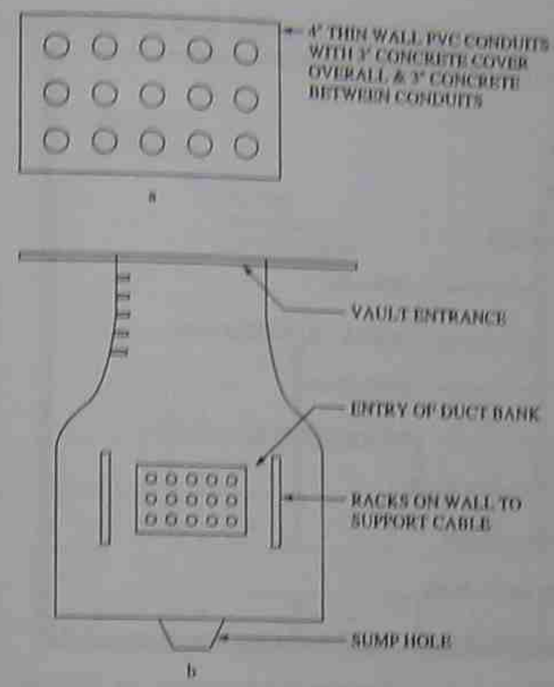


FIGURE 7.14 Duct bank (a) Cross-section and (b) location in maintenance access vault

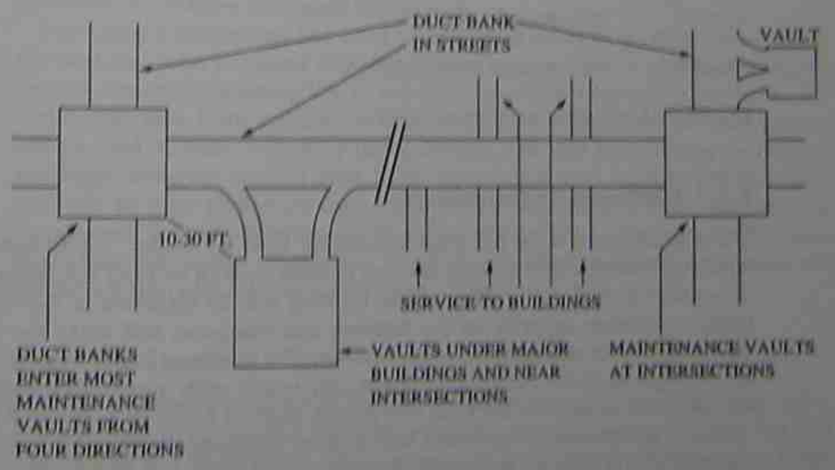


FIGURE 7.15 Underground distribution facilities in downtown area

up, to avoid excessive distribution loss. The symbols used for distribution design are shown in Figure 7.16, and the neighborhood is shown in Figure 7.17.

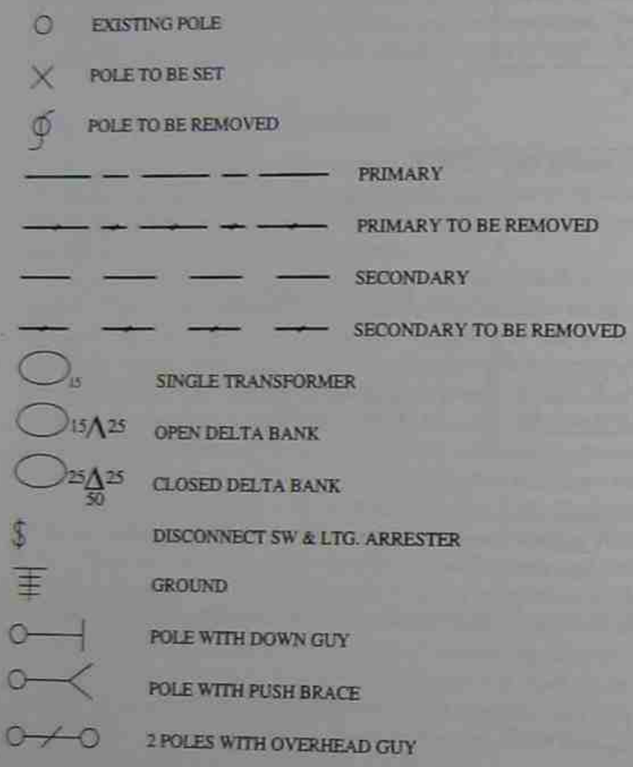


FIGURE 7.16 Distribution drawing legend

7.5.1 Easement Requirements

The subdivision is to be fed from an existing 12.47 kV feeder. The transformers, lightning arresters, and usually the fuse cutouts, will all be 12.47 KV. Since future conversion to 34.5 kV is planned the framing will be insulated to 34.5 kV. The higher insulation capacity on the framing and insulators will make the voltage conversion faster and simpler when it occurs. The easement obtained must also be for voltages to 35 kV. To do the voltage conversion with minimum outage time, the subdivision must be fed from two points, marked E and W in Figure 7.17.

The 35 kV perimeter easement and interior easements required are shown in Figure 7.17. The interior easements must reach each lot not reached by a perimeter easement. The perimeter easement is necessary on three sides of the development.

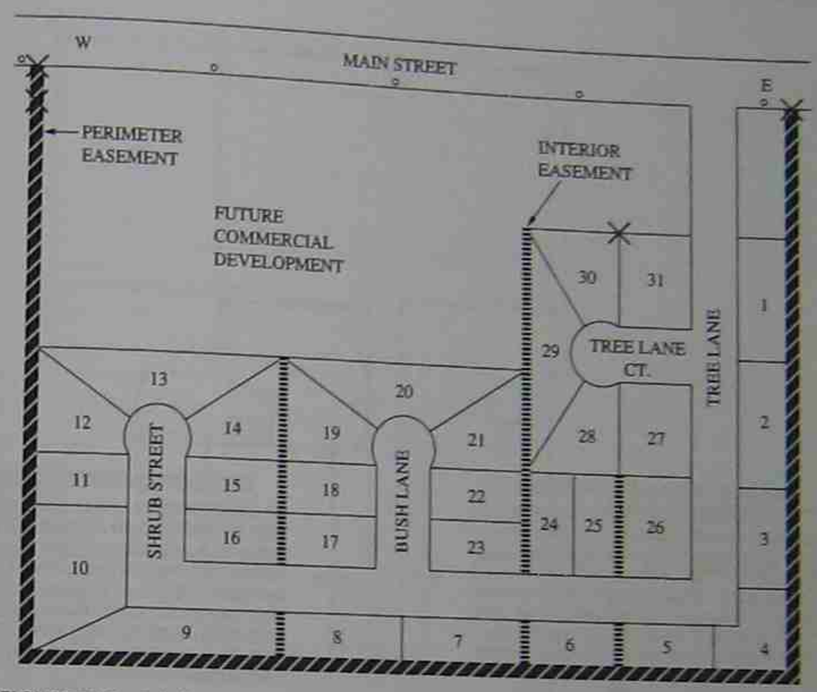


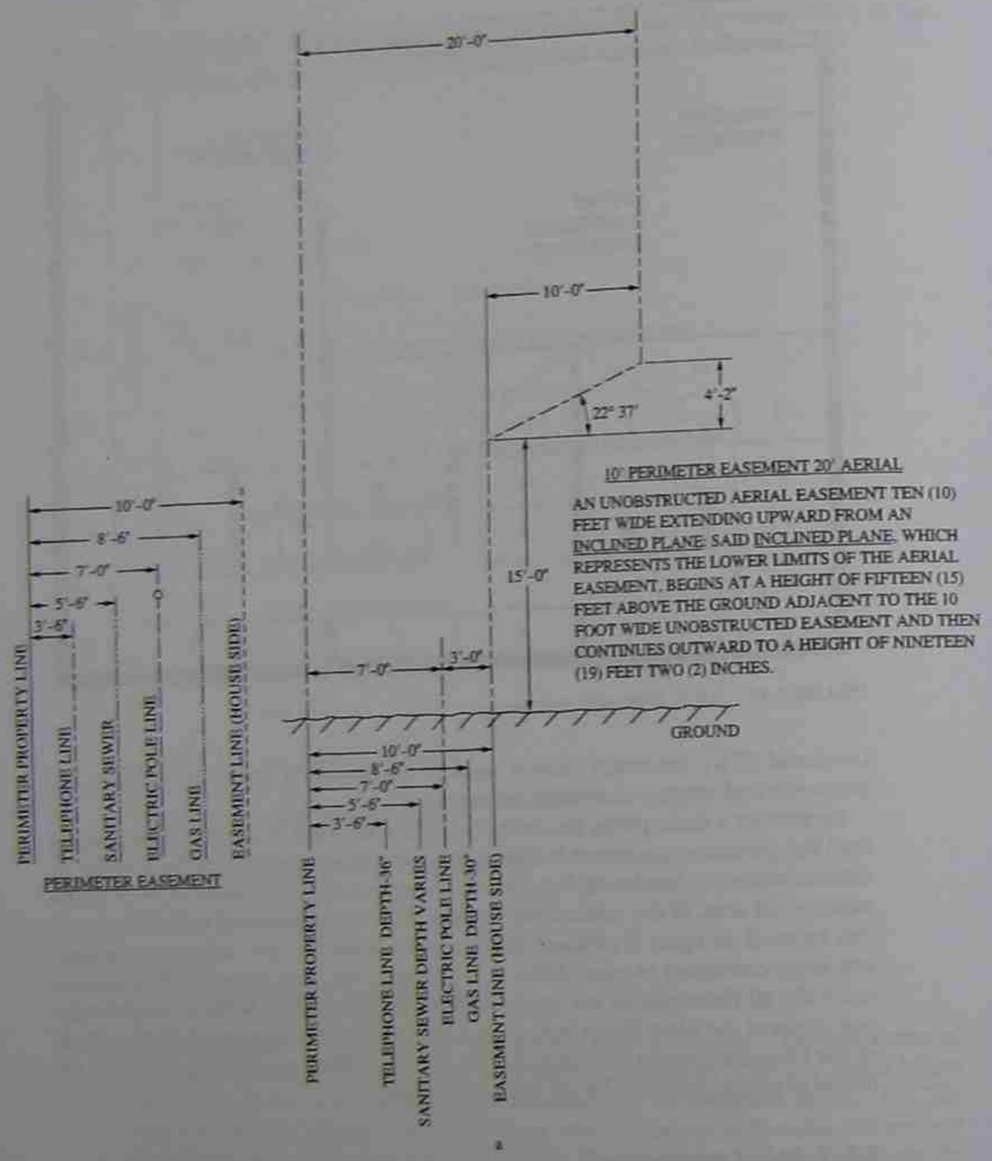
FIGURE 7.17 Subdivision with easements

Overhead 35 kV easement vertical sections are shown in Figure 7.18a and b for perimeter and interior easements respectively.

Eventually a three-phase line must be built from point W on Main Street along the West perimeter easement to the Northwest corner of lot 12, and then along an interior easement bordering lots 13 and 20, to provide three-phase service to the commercial area. If the commercial load is 150 kVA or less then any two phases can be used in open Y primary configuration with the low voltage secondary windings connected in open delta. If the commercial load exceeds 150 kVA then normally all three phases are used. Until the commercial area is developed only one phase of the Main Street feeder need be tapped. Two taps are needed because of the planned voltage changeover. The East and West perimeter easements are the most logical places to tap for the lateral lines.

7.5.2 Pole Location

The pole locations are shown in Figure 7.19. They are set in the following order. First the poles in the existing Main Street line are set at the intersection of the line and the East and West laterals. These poles must be at least the length of the existing poles to insure proper ground clearance, but preferably they are about 5 feet

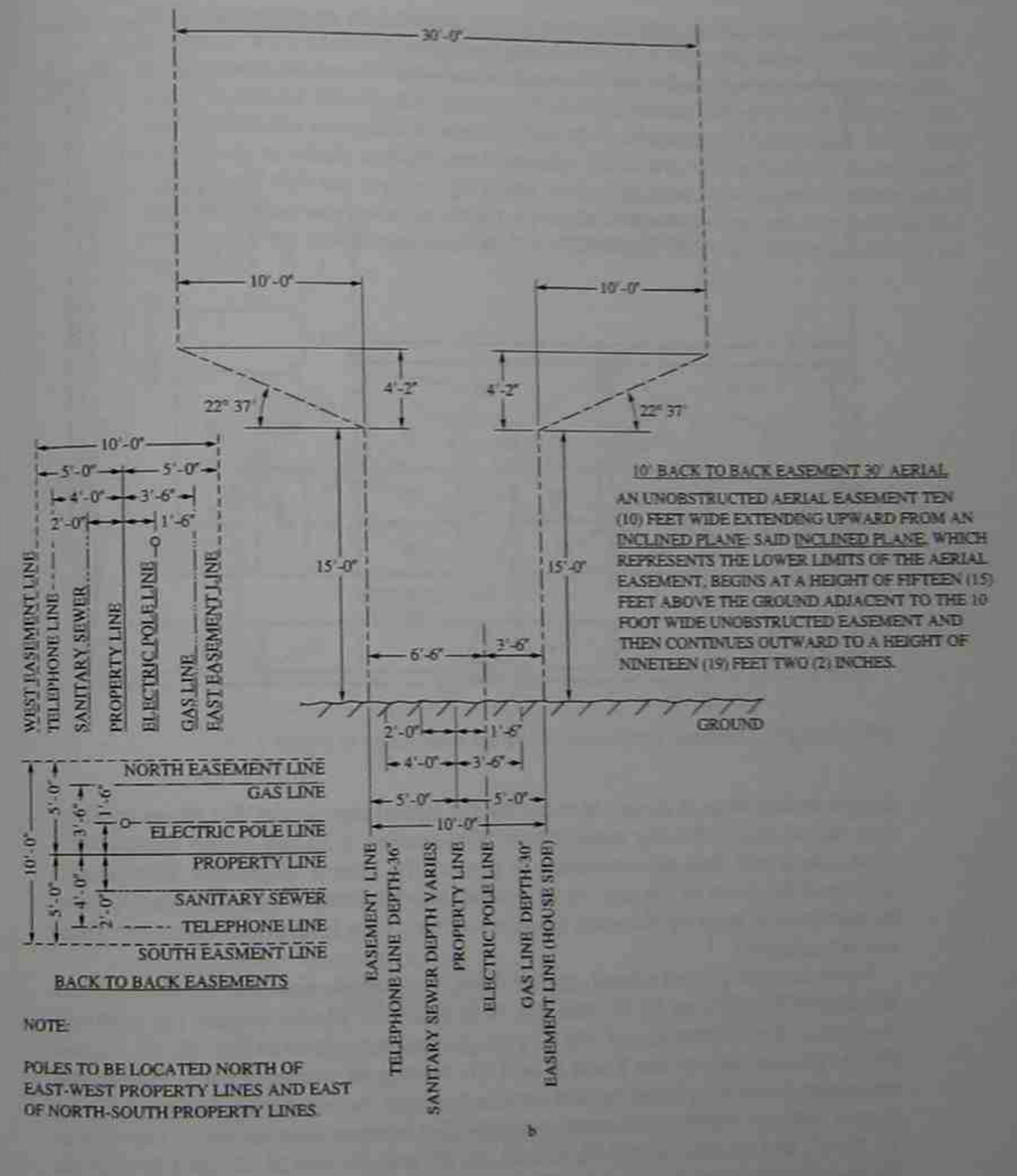


10' PERIMETER EASEMENT 20' AERIAL

AN UNOBSTRUCTED AERIAL EASEMENT TEN (10) FEET WIDE EXTENDING UPWARD FROM AN INCLINED PLANE: SAID INCLINED PLANE, WHICH REPRESENTS THE LOWER LIMITS OF THE AERIAL EASEMENT, BEGINS AT A HEIGHT OF FIFTEEN (15) FEET ABOVE THE GROUND ADJACENT TO THE 10 FOOT WIDE UNOBSTRUCTED EASEMENT AND THEN CONTINUES OUTWARD TO A HEIGHT OF NINETEEN (19) FEET TWO (2) INCHES.

a

FIGURE 7.18 35 kV easement, vertical views (a) Perimeter easement



10' BACK TO BACK EASEMENT 30' AERIAL

AN UNOBSTRUCTED AERIAL EASEMENT TEN (10) FEET WIDE EXTENDING UPWARD FROM AN INCLINED PLANE: SAID INCLINED PLANE, WHICH REPRESENTS THE LOWER LIMITS OF THE AERIAL EASEMENT, BEGINS AT A HEIGHT OF FIFTEEN (15) FEET ABOVE THE GROUND ADJACENT TO THE 10 FOOT WIDE UNOBSTRUCTED EASEMENT AND THEN CONTINUES OUTWARD TO A HEIGHT OF NINETEEN (19) FEET TWO (2) INCHES.

BACK TO BACK EASEMENTS

NOTE:

POLES TO BE LOCATED NORTH OF EAST-WEST PROPERTY LINES AND EAST OF NORTH-SOUTH PROPERTY LINES.

b

(b) interior easement

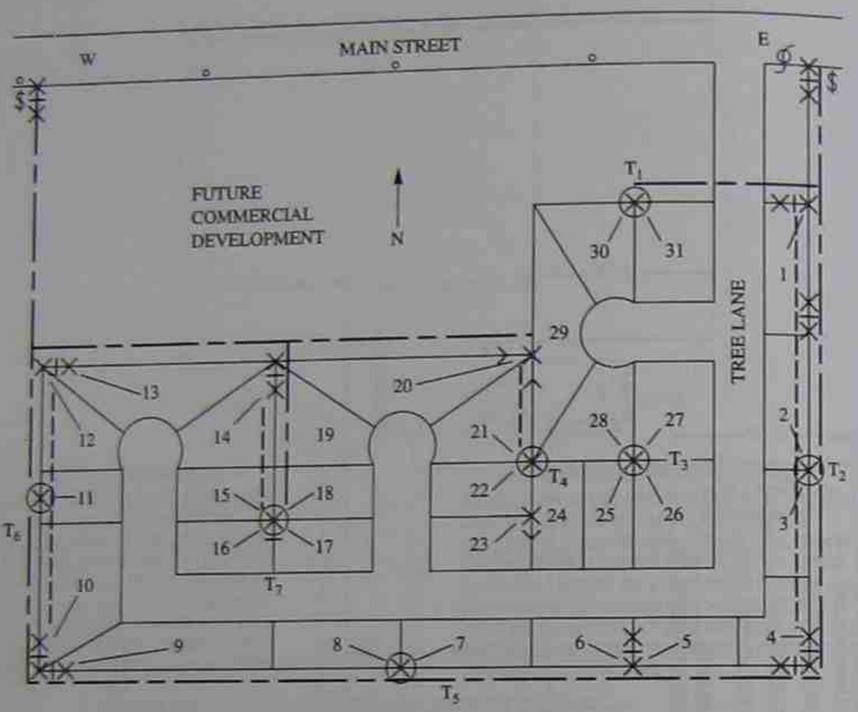


FIGURE 7.19 Overhead distribution layout for subdivision of Figure 7.17

longer so that there is plenty of room for the lateral taps under the phase conductors. Recall that if the tap conductor is 30% smaller than the feeder conductor a fuse cutout and fuse are necessary to protect the lateral conductor. This project will need the fuses at the tap. Some poles along the Main Street line may have to be relocated to even up the span lengths so that a very long and a very short span are not adjacent.

Poles are now placed at each corner (lot 4, the intersection of lots 9 and 10, and the intersection of lots 20, 21, and 29). Next poles are placed at each tap point on the lateral: the intersection of lots 12 and 13; the intersection of lots 13, 14, 19, and 20; the intersection of lots 5 and 6; and the Northeast corner of lot 1. Finally the remaining poles are placed so that service drops to the remaining lots can be connected without crossing adjacent property (the intersections of: lots 7 and 8; lots 15, 16, 17, and 18; lots 30 and 31; lots 25, 26, 27, and 28; lots 21, 22, and 24; lots 22, 23, and 24; lots 2 and 3; and at lot 11).

Many corners must be used in our subdivision layout. The wire at a 90° connection or at a corner will tend to pull over an unreinforced pole. Recall that a guy wire and anchor are used to balance the wire tension on poles used for corners or dead ends. The owner of the subdivision does not own the property outside the

perimeter easement and cannot give a guy easement at the outside subdivision corners or at the Main Street taps. The owners of the property adjacent to the subdivision have no incentive to donate their land for the corner guys for our subdivision overhead distribution system. A reinforcement scheme that requires no land outside the easement is needed. Two such schemes are commonly used: the slack span, in which a short mechanically unloaded, or slack, span is run to a nearby pole that has a down guy and anchor on the side opposite the tension span; and the push brace, in which a pole is lodged against another pole in the direction of the unbalanced tension. The slack span and push brace are shown in Figure 7.20.

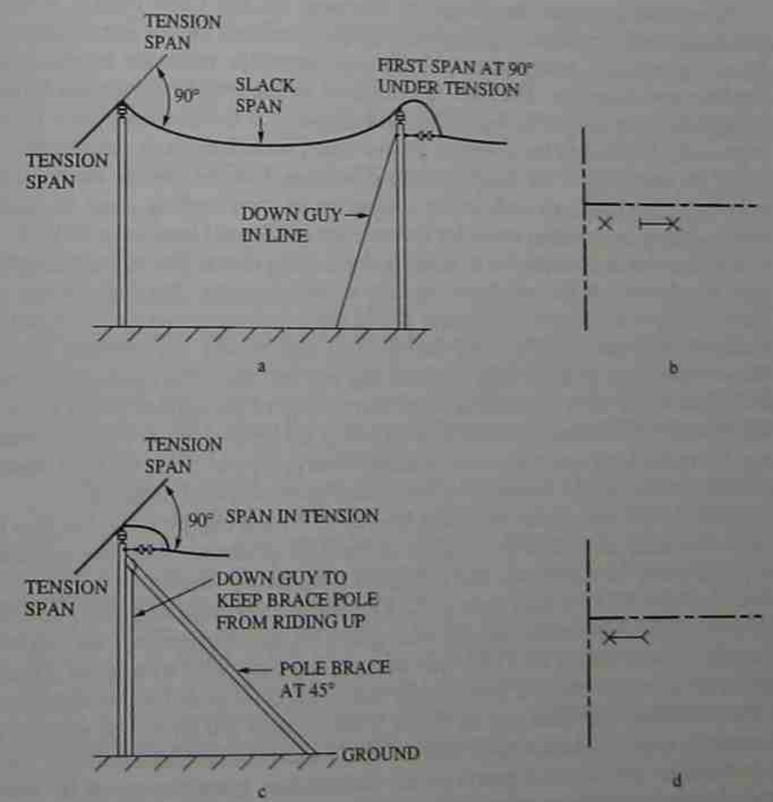


FIGURE 7.20 Methods of in line pole reinforcement (single conductor shown) include: (a) Slack span (b) slack span symbol (c) push brace and (d) push brace symbol.

7.5.3 Transformer Selection

Estimating residential transformer capacity is not simply a matter of adding the individual residence loads. Lot sizes differ, with larger lots usually having larger houses that have more heating and cooling needs, which may or may not be electric. Larger houses do not necessarily have more electric appliance loads than smaller houses. Additionally it would be very rare for a house to have all of its electric appliances in use at once and even rarer for several houses to have most of their electric appliances on at once. The diversity of residential loads is great, so the estimates used for residential loads are the results of many historical studies that compile actual usage for residences of various types over a long period. These studies are updated from time to time. Most electric utilities use their own data to establish their own residential load estimates.

For apartment type dwellings the National Electric Code (NEC), which provides nationally recognized minimum safety standards for the installation of electrical wiring and equipment in buildings, provides rules for establishing the loading and wire size. The NEC is published by the Fire Underwriters Protection Association for the protection of life and property. It has the same force for buildings as the NESC has for electrical power utility installations. A similar set of rules could be established for single family dwellings, but the electric utilities are not subject to the NEC, so each utility makes up its own loading chart as described above. Many companies consider the average residential load to be 25 kVA.

A factor that is considered in making the loading charts (for all installations, not only residential) is the overload capacity of transformers. The transformer nameplate rating is the amount of power (kVA) the transformer can carry continuously without overheating. Oil filled distribution and power transformers can withstand considerable short-time overloading without materially reducing their reliability or lifetime. A transformer can carry 300% of its normal rating for a short while without damage, and 150% of its rating for several hours without overheating. Thus the load from the rare occasions that everyone turns on all of their electric appliances can be handled by the transformer overload capability.

If one house has a total electrical load of 25 kVA it can be served with a transformer smaller than 25 kVA because of the load diversity. A 15 kVA transformer will normally be adequate, but a 20 kVA transformer would be better. For two houses with a 25 kVA load each a 37.5 kVA transformer will be good. Four 25 kVA houses can be adequately served with a 50 kVA transformer, and six can be adequately served with a 67.5 kVA transformer, but since 67.5 kVA is not a standard size a 75 kVA transformer is normally used. Standard pole top residential distribution transformer sizes are 15, 25, 37.5, 50, 75, and 100 kVA. The normal transformer to connected load ratio is between 50 and 60% for most utilities. Table 7.3 summarizes the loading practices for distribution transformers at 50 and 60% transformer capacity to connected load ratios. The distance between houses normally prevents connecting more than six to eight houses to the same transformer.

In the rare instances when a customer reports low voltage, or the transformer is getting too hot, the utility company changes out the transformer to a larger capacity to handle the load. The 25 kVA assumed load with no more than about 50% of

TABLE 7.3 Residential transformer capacities for normal 25 kVA connected load per residence

Number of houses served by transformer	Capacity required for given connected load		Transformer normally used
	Percent Transformer capacity of load		
	50%	60%	
1	12.5 kVA	15 kVA	15 kVA is the smallest distribution transformer built. Many utility companies use nothing smaller than 25 kVA.
2	25 kVA	30 kVA	a 37.5 kVA X-former is an acceptable choice.
4	50 kVA	60 kVA	a 50 kVA X-former is an acceptable choice because of the diversity of 4 houses.
6	75 kVA	90 kVA	75 kVA is acceptable because of load diversity
8	100 kVA	120 kVA	100 kVA is acceptable because of load diversity. 87.5 kVA would be acceptable for the same reason if that size is available.

connected load turned on at a time is normally a good assumption for most residential areas. Situations in which the assumption breaks down are so rare as to be considered abnormal loading. Thus the utility can afford to upgrade the transformer capability when the abnormal loading occurs, and still provide economical service to the rest of the neighborhood.

Referring to Figure 7.19, we will now choose the transformer capacities for our subdivision. T_1 serves two houses so it is chosen to be 37.5 kVA, a conservative rating. T_2, T_3, and T_6 each serve four houses so they are chosen to be 50 kVA transformers. T_5 serves five houses and is chosen to be the next larger capacity available than that used for four houses, or 75 kVA. T_4 and T_7 both serve six houses and are chosen to be 75 kVA from Table 7.3. The total estimated connected load is (31 houses × 25 kVA) = 775 kVA. The individual transformer capacities add up to 412.5 kVA, or 53.23% of the estimated connected load. This ratio normally allows good service without dangerous transformer overheating because of the load diversity, because not everything is on at once.

7.5.4 Secondary Connections

The transformer secondary service drops must be made such that no service drop crosses adjacent property lines outside the easement. This means some pole to pole spans of secondary conductor are needed for our subdivision electrical

distribution system. From Figure 7.19 we see that: T_2 needs two spans of secondary to serve four houses, as do T_4, T_5, and T_6; T_7 needs only one span; and T_1 and T_3 have only direct service drops, no secondary spans.

To choose the proper secondary conductor we must calculate the worst case voltage drop along a secondary span. The worst case span is the two lot span running East from T_5 with two houses connected at the end of the span. This is a span of about 240 feet with 50 kVA connected at the end. Number 2 all aluminum conductor (AAC) is a common secondary conductor with a resistance of 0.159 Ω /M ft. Thus the resistance for 240 feet is (120 ft./1000 ft.)(0.159 Ω /M ft.) = 0.3816 Ω. The current through this resistance is (50 kVA/240 V) = 208 A. Therefore the voltage drop across the 240 ft. span is (208 A)(0.03816 Ω) = 7.95 V, or 3.31%. This drop is at maximum loading that will rarely, if ever, occur, so #2 AAC conductor is a good choice for the secondary conductor. A larger conductor would be a waste of money because a lower voltage drop is not necessary, but a smaller conductor would be marginal in performance on the longest secondary span.

Most utilities stock only two or three standard secondary conductor sizes to reduce their inventory of wire sizes. This saves them money because of reduced warehousing costs, even if occasionally a conductor is oversized for the application.

7.5.5 Primary Conductor Selection

The primary conductor must be chosen. It too will be one of a few standard sizes stocked by the utility. The total transformer capacity connected is 412.5 kVA at 7.2 kV (12.47 kV/$\sqrt{3}$), so the primary current is 57.29 A at full transformer loading, no overloading included. ACSR conductor in the #2 size is a common primary wire size for small developments, and is the minimum size stocked by most utilities. It has a resistance of 0.319 Ω/M ft. The maximum distance for the primary from a Main Street tap (only one tap will be used at a time) is roughly 2500 feet. The total primary resistance is 2.5 M ft. × 0.319 Ω/M ft. = 0.798 Ω, making the voltage drop 45.68 V, which is only 0.63% of 7.2 kV. Number 2 ACSR will serve nicely as a primary conductor.

7.5.6 Primary Fusing

Primary fusing is usually set to 150% of full load and then raised to the next higher available continuous current rating. Though raising the fuse continuous current rating to the next higher available rating is allowed by the NESC, it is not always recommended. The fuse size for the West and East taps is calculated as follows:

(412.5 kVA)(1.5)/(7.2 kV) = 85.9 A

The next available size is 100 A, which is also the maximum current allowed for #2 ACSR. The transformer primary fuses are found in the same manner so for the transformers used in our subdivision the primary fuse sizes are: 37.5 kVA, 7.8 A, with a 7.5 A fuse recommended; 50 kVA, 10.4 A, with 10 A recommended; 75 kVA, 15.6 A, with 15 A recommended; and 100 kVA, 20.8 A, with 20 A recommended.

7.5.7 Voltage Changeover

Subdivision Conversion

The subdivision will be converted to 34.5 kV in the following manner:

1. One lateral will be left on the 12.47 kV line and the other will be connected to the higher voltage. Figure 7.21 shows the West lateral left on the 12.47 kV line, and the East lateral connected to the 34.5 kV line on Main Street, but not energized yet. The cutout at the East lateral tap will be fused for 34.5 kV. The cutout will be changed if it is rated for 12.47 kV.

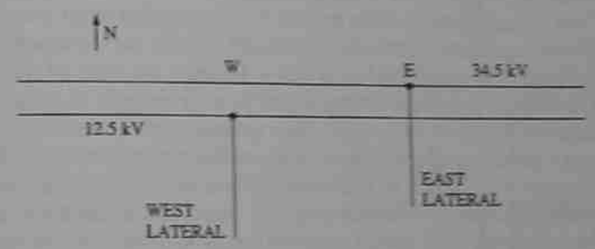


FIGURE 7.21 12.47 kV to 34.5 kV change over

2. The primary line will be opened at a jumper at the corner behind lot 4. If the primary insulators were not already 34.5 kV they would be changed as the process progresses. Transformers T_1 and T_2 will be replaced with 34.5 kV transformers, as will their disconnects and lightning arresters. The change out will normally require about 1½ to 2 hours during which the houses on lots 1 through 4 and 30 and 31 will be without power. After the change out, the section of line to the corner of lot 4 will be energized so that those customers can resume their normal life.
3. Next the primary circuit will be broken at the intersection of lots 9 and 10. The transformers (T_3 and T_4), lightning arresters, and disconnects will be replaced with like items rated at 34.5 kV. This will require about 1½ hours, after which this section of line will be energized at 34.5 kV.
4. Next the line disconnect at the West lateral tap will be opened and all the transformers, lightning arresters, and disconnects connected to the primary line between the intersection of lots 9 and 10, and the West lateral tap will be replaced with 34.5 kV rated ones. The disconnect and fuse cutout at the West lateral tap will also be replaced with 34.5 kV rated devices. The remaining line will then be energized at 34.5 kV from the intersection of lots 9 and 10.

Both taps will not be in use at once unless there is a break in the primary line. In this case both the East and West lateral taps may be energized while an isolated section of primary line is being repaired. Notice that the job is broken down into smaller tasks that can be accomplished in a relatively short time to reduce the time

that any customer is without electricity. In our example no one would have been without power for more than 2 hours.

Main Street Feeder Conversion

The voltage change over for the Main Street feeder is done as follows:

1. Temporary framing for 12.47 kV is installed below the present line as shown in Figure 7.22. Generally a 12 to 14 foot cross arm is used for 12.47 kV lines. This can be done without killing power.

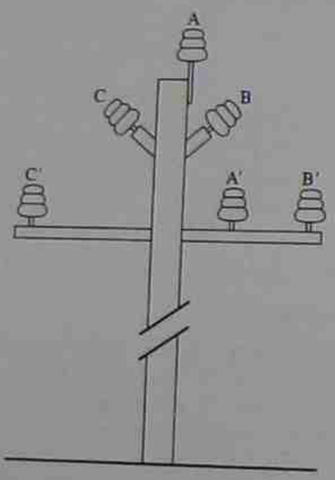


FIGURE 7.22 Pole configuration for feeder voltage change over

2. The 12.47 kV conductors are moved to the temporary framing with hot line tools. First A is moved to A′, then B to B′, and finally C to C′. All 12.47 kV loads are connected to these conductors.
3. The old framing and insulators are changed, if needed, and new conductor is installed for the higher voltage. The new conductor is then energized at 34.5 kV.

All laterals tapping off this feeder are changed out in the manner described for our subdivision. In this manner a major voltage change can be accomplished with no extended outage experienced by any customer on the Main Street line.

7.5.8 Underground Layout for Residential Neighborhood

If the subdivision of Figure 7.19 were to be laid out as an underground system instead of an overhead some changes would need to be made. First, the same easements are needed plus one across the North end of lots 1 and 31 (and across the street), but they are 10 feet wide at, above, and below ground level.

The portion that will be overhead, if any, has to be chosen. It is likely that the commercial section will be served with overhead because of the potential load size. If so, an overhead line will be built from the West lateral tap, along the West easement to the intersection of lots 12 and 13, and then over to intersection of lots 20 and 29. These may be underground but unless both are owned by the same developer, the residential developer will not pay to put the eventual commercial service underground. We will assume the lines along the commercial area are overhead.

The terminal poles (the location at which the service goes underground), with their cable terminators, fused disconnect switches, and lightning arresters, will be located at the West easement intersection of lots 12 and 13, at the intersection of lots 13 and 20, at the intersection of lots 20 and 29, and at the East easement at the Northeast corner of lot 1. Splice cabinets, to provide a protected environment for primary cable splices, will be needed at the intersection of lots 5 and 6, and at the Northeast corner of lot 1. Figure 7.17 illustrates this requirement. The primary line would be 34.5 kV cable if a voltage changeover is contemplated, to avoid the necessity of digging up and burying new cable in a completed neighborhood. The 34.5 kV cable is considerably more expensive than 12.5 kV cable.

The transformers will be pad mount types, mounted on concrete pads. The transformer capacities and locations can be the same as those chosen for the previous overhead illustration. The primary and secondary cables can be routed the same as the overhead lines shown in Figure 7.19. The poles, of course, will not be needed, except for the terminal poles. The lines will be energized from either the West or the East lateral tap for normal operation. The underground system will be safe, out of sight, and expensive.

7.6 INDUSTRIAL DISTRIBUTION LOAD

Industrial loads tend to be much more predictable than residential and commercial loads. These loads must be known to select wire sizes and protective devices. Where large machines are used the choice of machine (such as synchronous instead of induction motor) can make a considerable difference in current. As we noted before, a high power factor is helpful in keeping total electricity costs down in an industrial plant. The outdoor distribution may be overhead or underground, and may be served by its own substation. The construction methods will be the same as those already discussed for outdoor distribution. The indoor, within a building, distribution system is planned using the methods studied in an electrical system design course. A practice problem to calculate currents using what is sometimes called the "P&Q" method will be helpful.

Example 7.1:

Calculate the steady state currents I_1, I_2, and I_3 for the circuit of Figure 7.23.

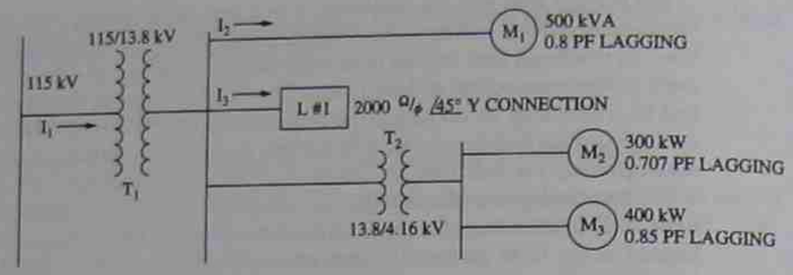


FIGURE 7.23 Circuit for Example 7.1

Solution:

Starting with M_1, which is 500 kVA at 0.8 PF lagging.

$\cos\theta = 0.8$ lagging so $\theta = -36.87°$

$S = 500\ \text{kVA}\angle -36.87° = 400\ \text{kW} - j300\ \text{kVAR}$

three-phase power $P = (\sqrt{3})IV\cos\theta$ so

$$I_2 = \frac{P}{(\sqrt{3})V\cos\theta} = \frac{400\ \text{kW}}{(\sqrt{3})13.8\ \text{kV}\ (0.8)} = 20.92\ \text{A}\angle -36.87$$

Now for load L#1 = 2000 Ω/phase ∠45°, Y connected.

L#1 = (1.414 + j 1.414) kΩ in rectangular coordinates.

The phase voltage is

$13.8\ \text{kV}/\sqrt{3} = 7.97\ \text{kV}$

thus

$$I_3 = \frac{V_p}{Z} = \frac{7.97\ \text{kV}}{2000\ \Omega\angle 45°} = 3.985\ \text{A}\angle -45°$$

We will need P and Q later so

$P_p = I^2R = (3.985)^2(1.414\text{k}\ \Omega) = 22.4\ \text{kW}$

$P_{3P} = 3xP_p = 67.2\ \text{kW}$

By inspection we see that since the absolute values of R and X are equal

$Q_{3P} = 67.2\ \text{kVAR}$

To find the final current we must know the P and Q for M_2 and M_3. P is given for each so we need only find Q. Recall $Q_{M2} = S\sin\theta = (P/\cos\theta)\sin\theta = (300\ \text{kW}/0.707)\sin(-45°) = -300\text{kVAR}$ similarly $Q_{M3} = 247.9\ \text{kVAR}$

Except for the power losses within the transformers (which we will assume negligible here) the power and reactive volt amperes remain constant as they flow through the transformers. The changing voltage levels result in the power being produced by different current levels on the high and low voltage sides of a transformer. To find I_1 we must only add the total power and VARs supplied at that point in the circuit, and calculate the current.

$P_T = P_{M1} + P_{L\#1} + P_{M2} + P_{M3}$

$= (400 + 67.2 + 300 + 400)\text{kW} = 1167.2\ \text{kW}$

$Q_T = Q_{M1} + Q_{L\#1} + Q_{M2} + Q_{M3}$

$= (-300 - 67.2 - 300 - 247.9)\ \text{kVAR} = -915.1\ \text{kVAR}$

now $S = P + Q$ so

$S_T = 1167.2 - j915.1 = 1483.16\ \text{kVA}\angle -38.1°$

$\text{PF} = \cos\theta = P/S = 0.7870$

and from the three-phase power equation $P = (\sqrt{3})VI\cos\theta$

$$I_1 = \frac{P}{(\sqrt{3})V\cos\theta} = \frac{1167.2\ \text{kW}}{(\sqrt{3})\ 115\ \text{kV}\ (0.787)} = 7.45\ \text{A}\angle 21.5°$$

With the currents quickly calculated in this manner, the resistivity of the conductors, and the distance they must run, the proper size conductors can be chosen for an acceptable voltage drop. Usually a worst case voltage drop of 5% is acceptable. Once the proper conductors for steady state operation are chosen the calculation must be repeated using the motor locked rotor values to assure that the voltage dip from the motor starting current is not excessive. The motors may never all be started simultaneously so several variations of the problem may have to be worked. This problem could be worked more precisely with pu quantities, but this quicker method is accurate enough for this purpose.

7.7 SUMMARY

The most common distribution voltages are 12.47 kV line to line (7.2 kV line to ground), and 34.5 kV line to line (20 kV line to ground). Public easements are provided for utility services to commercial, industrial, and residential loads. The safety standards for distribution line construction are published the National Electric Safety Code (NESC).

The common supports for overhead distribution lines are wood poles and steel poles. Wood poles are normally Southern Yellow Pine (about 70%) or Douglas Fir (about 25%). Wood poles are simple, inexpensive, and reliable. Steel poles are more expensive than wood poles, but become competitive in lengths greater than

90 feet. Steel poles are considered more attractive than wood poles by many people. Wood poles are normally set by direct imbedment in firm soils. Concrete stabilized imbedment and guy wire anchoring are used in less stable soils and for dead end poles. Steel poles can be set by imbedment, but reinforced concrete foundations are often used for steel pole foundations.

Distribution insulators are normally made of glass or porcelain but fiberglass insulators with silicone rubber skirts are becoming more popular. The most common overhead conductors used for distribution are, most common to least: ASCR (aluminum conductor, steel reinforced), which is strong because of the steel reinforcement; all aluminum conductor (AAC), which has slightly better conductivity than ACSR but has less strength; and AAAC (all aluminum alloy conductor), which is stronger than AAC but more expensive.

Underground distribution is less subject to weather outages and is less visible than overhead distribution. Direct buried underground cable has markedly improved in recent years with the reliability increasing and voltages to over 34.5 kV now available. Oil impregnated cable is still used in many networks.

Factors critical in distribution system layout are the easement requirements, which are set by the voltage, the geometry of the service area, the types and density of the loads, and the expected load growth. An example distribution layout is shown in section 7.5.

7.8 QUESTIONS

1. State the function of the electrical power distribution system.
2. List two advantages of a grounded wye distribution system.
3. What is the NESC, and what organization is responsible for its publication?
4. How often are revisions to the NESC published?
5. What is the procedure for making changes in the NESC?
6. List the four parts of the NESC.
7. List the clearances required by the NESC for a 12,470 V line: a. over a railroad track; b. from a building; c. from any area accessible by a pedestrian.
8. Why does the required line to line clearance increase as sag increases?
9. What trees are most commonly used for wood poles?
10. How is wood pole failure under load defined?
11. Calculate the tangent load a 70 foot wood pole can carry at its top, assuming the bottom is securely anchored, if it is of the following class: H1, 1, 2, 3.
12. Why are ft-k values listed in the tables for the bottom of the wood poles? Look carefully at Figure 7.2 before you answer.
13. Name the two worst enemies of wood poles and the defense(s) against them.
14. State the major advantage of steel poles.
15. Under what circumstances do steel poles become competitive with wood poles?

16. What is meant by direct imbedment?
17. What is concrete stabilized sand?
18. How much of the length of a 90 foot pole must be imbedded?
19. How are directly imbedded poles reinforced at turns and dead ends?
20. Define framing.
21. State the two characteristics of insulators that must be specified.
22. What is the advantage of ball and socket insulators?
23. State the major advantage of each of the following conductor types: ACSR, AAC, AAAC.
24. List three types of commonly used underground distribution cable.
25. What is meant by direct buried cable?
26. Describe a duct bank.
27. Why are only 40% of the duct bank conduits filled at the time of the system installation?
28. What is an easement?
29. For the neighborhood of Figure 7.24 lay out an overhead distribution system including easements needed, pole and transformer placement, transformer

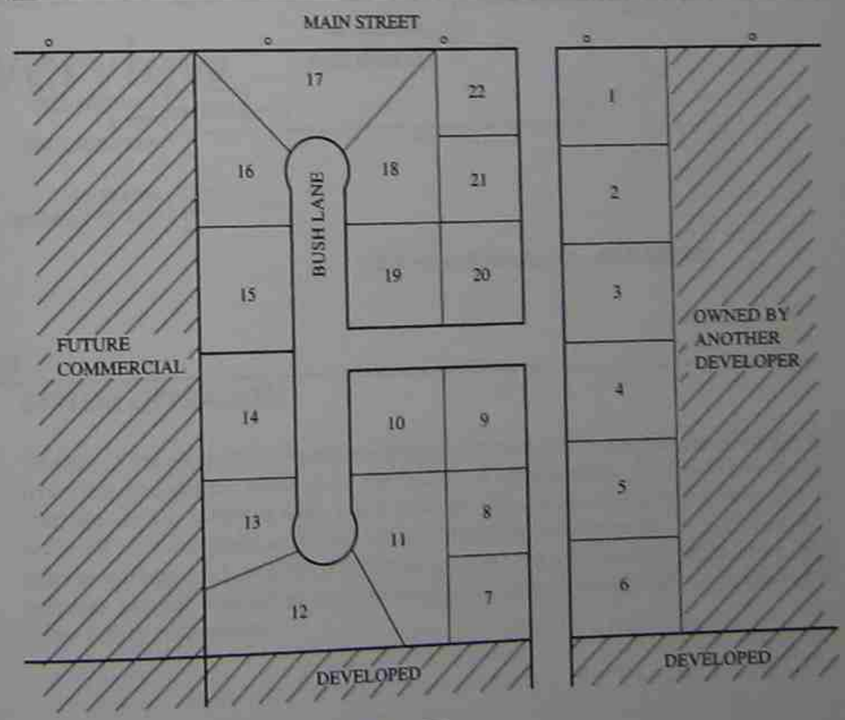


FIGURE 7.24 Neighborhood for Problem 7.29

sizing assuming that the maximum connected load for each house is 25 kVA and the (capacity/connected load) ratio used by our company is 60%, and primary fuse requirements. The distribution primary voltage is 34.5 kV and no change is contemplated, and the secondary voltage is 240 V. Show the primary and secondary conductor paths, and calculate the worst case voltage drop for each if the primary conductor is #2 ACSR and the secondary is 2/0 AAC.

30. What changes will be needed if the system of problem 30 is to be underground instead of overhead?
31. Describe the process by which one distribution voltage level is changed to a higher voltage.
32. For the circuit of Figure 7.25 calculate the total S, P, Q, and currents I_1 through I_4.

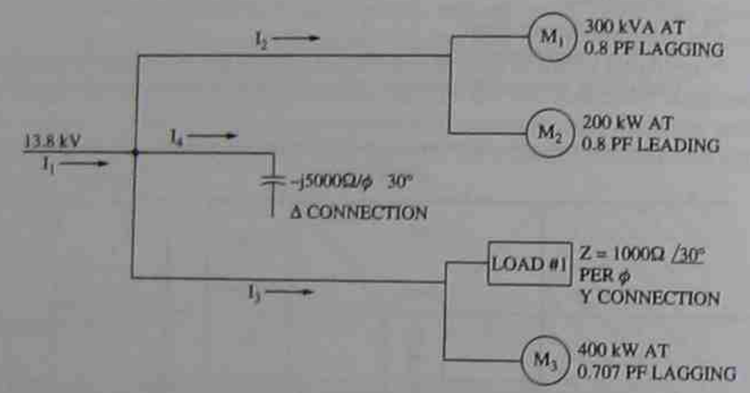


FIGURE 7.25 Circuit for Problem 7.32

SECTION III

Electrical Power Transmission

CHAPTER 8

Transmission System Overview

8.1 SYSTEM OPERATION

The job of the electrical power transmission system is to transport electrical power from the generating stations to the points of distribution, the distribution substations, or the interties with other utilities. The electrical power system should serve all its customers and interconnect partners economically and reliably. The system voltage and frequency must be maintained within acceptable limits, and accurate records should be kept of all power transferred to both customers and other utility companies.

8.1.1 Operation Components

The major components of operation are planning, control, and accounting. Digital computers are now heavily used in all three components of operation.

Planning is the process of choosing among alternate courses of action in the utility operation. Planning has both long-term and short-term aspects. Load forecasting is an example of long-term planning. Load forecasting is necessary to assure that needed state permits, financing, right of ways, and finally generating equipment, transmission lines, distribution lines, and substations are constructed by the time the customer needs the power. Short-term planning includes such things as load diversity forecasting for efficient machine utilization, generating unit commitment, spinning reserve commitment, and interconnect power transfers. Planning also includes choosing emergency procedures for various malfunctions such as emergency load shedding procedures for when a critical generator or line is lost. Maintenance scheduling, fuel selection and acquisition, personnel requirements, and financial needs are also planned ahead of time if the company is to perform its function efficiently.

Control in this context refers to operation control, the minute by minute management of the utility system. This includes the myriad calculations and decisions required in such things as automatic generation control (AGC), all of the checks and control needed to assure proper generating station operation, automatic VAR and power dispatch, allocation of generation to various generating units for maximum efficiency and minimum fuel use, and keeping net interchange of power with neighboring utilities at desired values. The large number of decisions to be made constantly throughout a system would be impossible without digital computers to provide timely preplanned responses within the system to varying load conditions.

Accounting is more than billing and financial record keeping, although these are very important jobs. Accounting also refers to the collection of operating and production statistics, maintenance information, and records of abnormal conditions. The records allow evaluation of performance from a factual base.

8.1.2 Control Function

If a generator is operating with a given load and the load increases, the increased electrical load causes more mechanical counterforce in the rotor, and the rotor counterforce causes the prime mover to attempt to slow down. A drop in prime mover speed causes the generator frequency to drop, as shown in Figure 8.1a. Most governors allow a generator to drop about 5-6% from full load to no load. Such a drop in frequency is not acceptable for a power system that contains frequency sensitive loads such as electric motors. The generator control system responds to the load increase by increasing prime mover power so that the increased load can be met with only a very small drop in the generator frequency, as shown in Figure 8.1b. The frequency still drops, but less. A drooping characteristic of a generator, where frequency drops as load increases, is important if more than one generator is to be used because it enables proportionate sharing of load by generators.

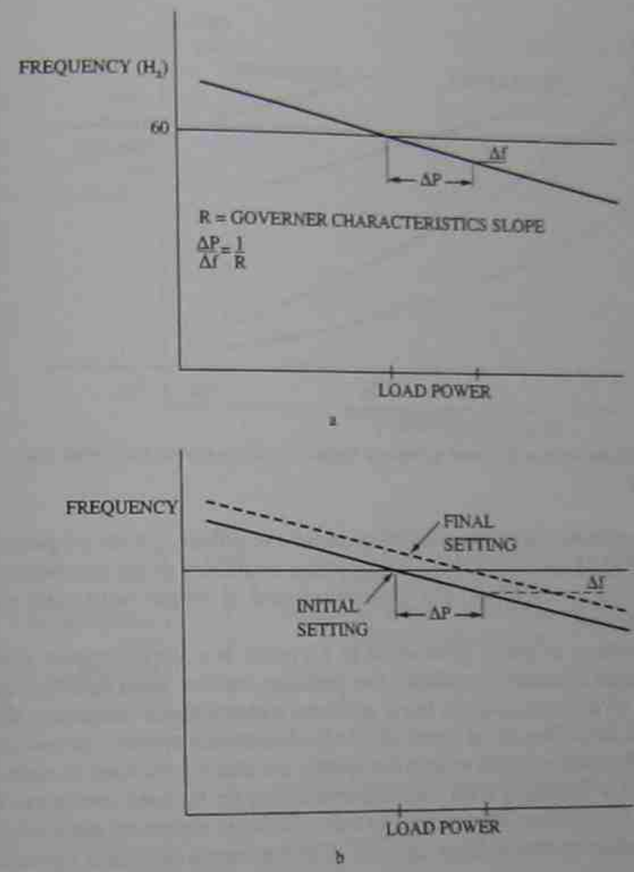


FIGURE 8.1 Generator regulation (a) Frequency drop with load (b) Corrective action of governor and turbine control

Figure 8.2 shows the regulation curve of two generators, each handling a portion of the total load. If the load is increased each generator picks up an equal amount of the load increase, and the system frequency drops. If one of the generators has a rising characteristic, frequency increasing with increasing load, it would pick up all of the load, possibly overload and fail. The generators whose regulation curve is shown in Figure 8.2 would pick up proportional amounts of the load increase if the slopes of the drooping regulation slopes were set to be inversely proportional to generator capacity instead of identical. In an actual system the control system of the generators acts to drive the frequency back to almost what it was before the load increase. A large frequency drop, nearing a Hz, indicates an emergency condition in the system in which load exceeds generating capacity.

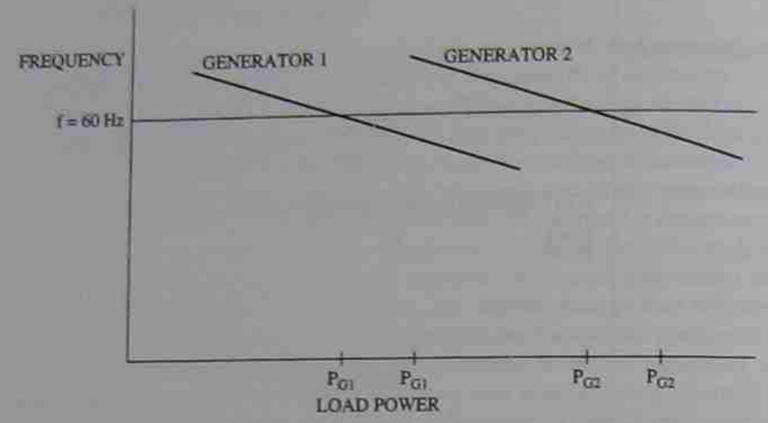


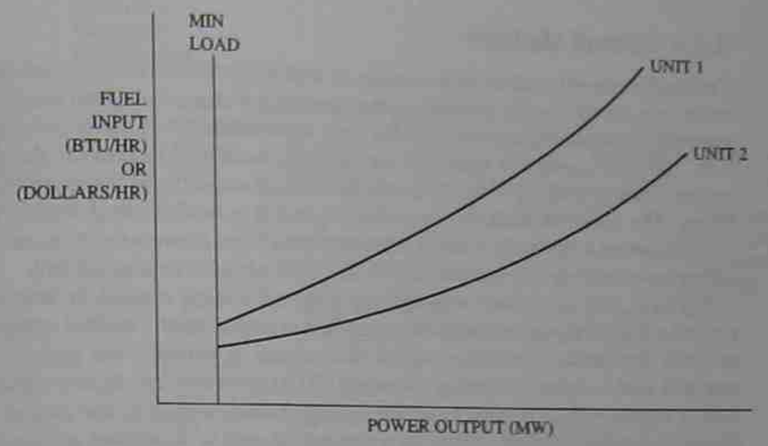
FIGURE 8.2 Generators with same governor regulation slope divide increased load proportionately.

Frequency sensitive relays are used to monitor the power system frequency and automatically shed noncritical load if the system frequency drops too much. Many books on electrical machines and generation deal at length with load sharing between generators.

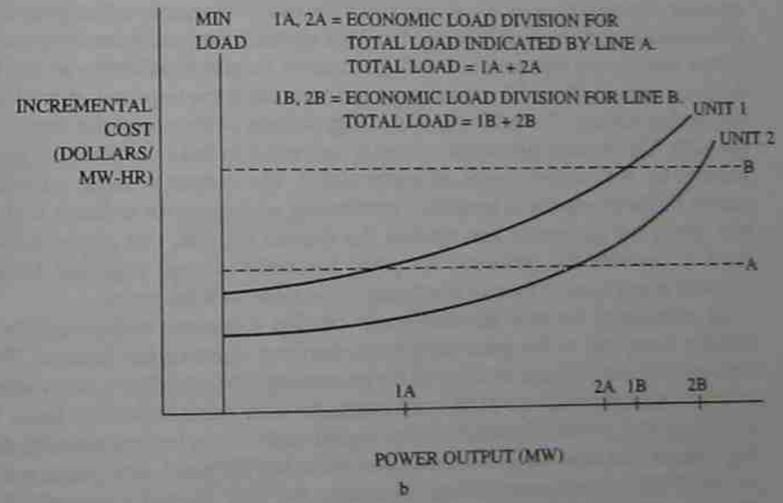
The coordination of many generators in a system is a very complex problem. Interties between systems complicate the problem further. Each intertied system must operate so as to maintain a fairly uniform instantaneous frequency, the correct integrated frequency (over time), divide loads between systems as needed, and assure the generating stations within the system are sharing the load in such a way that the system is operating with maximum economy for the load condition. This is no small task. Computers are essential to solve the large equations associated with economical operation and to keep up with all of the details of system operation.

8.1.3 Economic Generation Allocation

Economic allocation of generation means taking into account individual generating unit efficiency and location in the network to decide how much each unit should contribute to most economically serve a given total system load. Figure 8.3a shows a plot of fuel input versus power output for two generators. Figure 8.3b shows the plots of the incremental fuel cost (change in fuel input/change in power output) for the same two generators. It has been shown mathematically that the optimum operating economy occurs when the incremental cost of operating the units is equal. This is true as long as line losses, which depend on the location of the unit within the system, are neglected. The problem of economic allocation (also referred to as economic dispatch) is more complicated when line losses are included. It is still approximately true that maximum generation economy occurs when the total load is divided among the generating units so that their



a



b

FIGURE 8.3 Economic allocation on basis of fuel efficiency (a) Input-output curves and (b) Incremental cost curves

incremental costs are the same. The availability of fuels may mean that the equal incremental cost criteria may have to be violated at times. Also a new unit may be so much more efficient than older units that it is operated at maximum capacity all of the time, with the load the new unit cannot handle being allocated among the older generating units on an equal incremental cost basis.

8.1.4 Control Methods

Originally control systems were analog, in which all of the control signals and circuitry are continuously variable. A mechanical governor for speed control is an example of an analog control, as is the field current control of many older generators. The field current is manually set (perhaps remotely) to provide the desired output voltage and the circuitry holds the voltage constant as the generator load varies. The problem with analog control is that it is hard to send analog signals long distances accurately, making remote control from a central station, or coordinating several remotely controlled stations, difficult with analog control.

The next step in control was digitally directed analog control. In this type of control a digital signal is sent to the controlled machine from a central computer to indicate the desired machine output (this signal is called a set point). At the machine site a digital to analog converter (D/A) converts the digital signal to an analog signal, which is used to set the analog control output to the proper value. Digitally directed analog control for a generating unit is illustrated in Figure 8.4a. The computer set output is held by the analog control except when the value is modified by the area control error (ACE). The ACE is a signal that indicates the amount of power needed by an area when the power demand is changing because of increased or decreased loading. The ACE signal is derived from frequency and power measuring equipment (recall that system frequency changes as the power demand varies). The ACE signal is converted to the form required, digital or analog, at the control. The ACE signal is in digital form at the computer input in Figure 8.4b. The desired generator output is converted to field current and governor settings by the control signal generator (CSG). The output voltage, current, and power of the generator is sensed by monitoring equipment to indicate to the control when the generator has reached the desired output. The digital computer used to provide the generator set point is usually a large one that takes into account many system factors in arriving at the generator set points.

As computers became less costly and capable it became economical to use a smaller computer at the generating site to perform direct digital control. The system information needed to arrive at the generating unit set point is often sent from a larger central computer to the unit computer over communication lines. Originally, and still in some locations, direct digital control was backed up with an analog control that held the generator output at the last set point, or a preset set point, in the event of computer failure. Normally the unit control computer is large enough to handle several computing and status monitoring jobs at the generating site on a time-share basis. The transducers for many measurements, such as voltage, and control actuators, such as field current supplies, are analog. The analog transducer information must be converted to digital for the computer and the digital control signals must be changed to analog for actuator control. Direct digital control with analog back-up is illustrated in Figure 8.4b.

The next step in control is to use a small computer for back-up control instead of an analog controller. The reduced cost and increased capability of microprocessor-based microcomputers, which outperform large minicomputers of only a few years ago, have made possible this form of control, illustrated in Figure 8.4c.

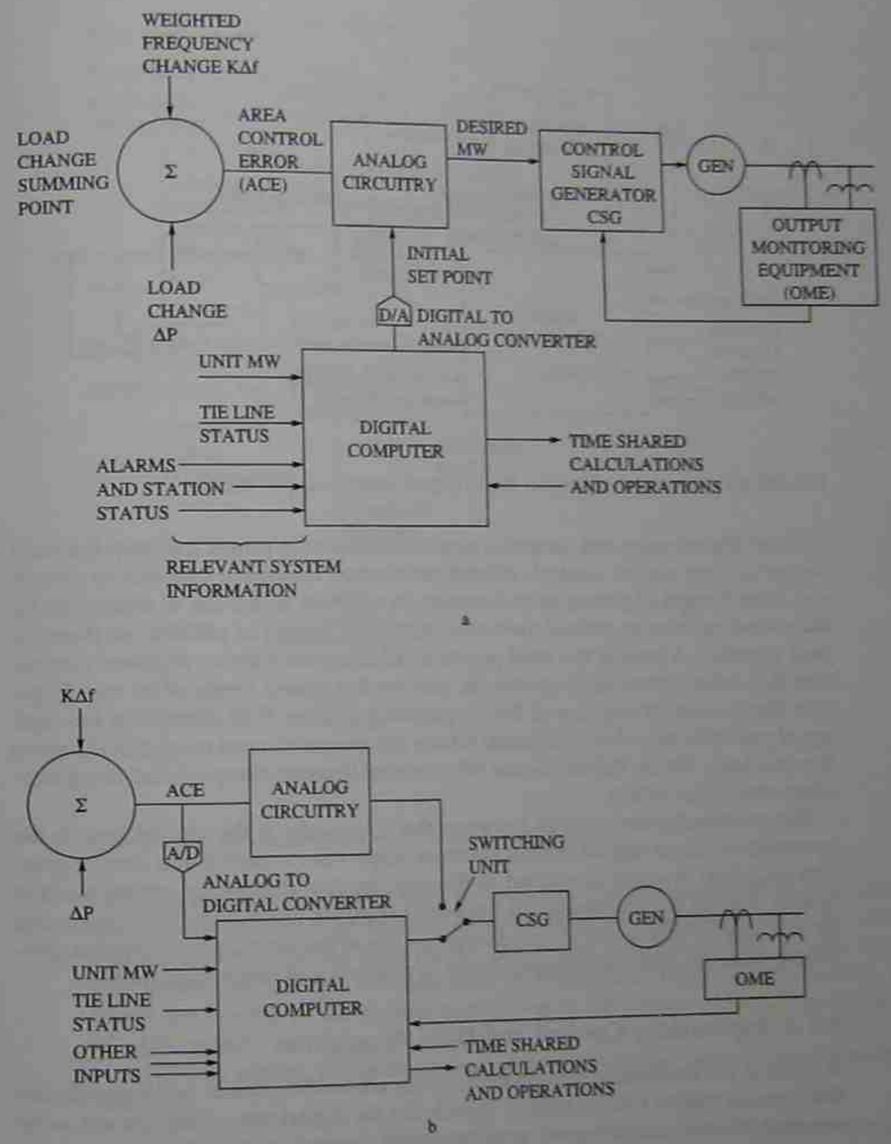


FIGURE 8.4 Generator control (a) Digitally-directed analog control (b) Direct digital control—analog backup

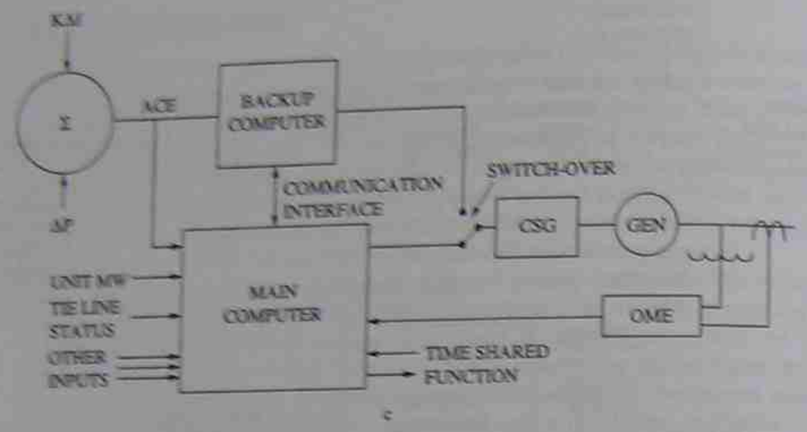


FIGURE 8.4 Generator control (c) Direct digital control—digital backup

Direct digital computer control is now the norm in the power industry. It is used for generating station control, substation control, economic dispatch of power, and interchanges of power over interties. In addition to the use of computers by individual utilities to control their own activities, groups of utilities use them for pool dispatch. A pool is the total power available from a group of power companies that have agreed to cooperate in serving the power needs of an area larger than that served by any one of the cooperating utilities. Pool dispatch is the routing of power from and to individual power companies to most economically serve the area load. Figure 8.5 shows the relationship between the pool and one generating unit of one utility.

The communication system between the computers is the critical link in the operation of direct digital control systems. Supervisory control and data acquisition (SCADA) systems, described in the next section, supply the communication system. Not all communication is between machines. Voice communication must be available for communication between people at the central control station, generating stations, and maintenance crews at manned and unmanned stations.

8.1.5 Supervisory Control and Data Acquisition

SCADA is the equipment and procedures for controlling one or more remote stations from a master control station. It includes the digital control equipment, sensing and telemetry equipment, and two-way communications to and from the master station and the remotely controlled stations.

The SCADA digital control equipment includes the control computers and terminals for data display and entry. The sensing and telemetry equipment includes the sensors, digital to analog and analog to digital converters, actuators, and relays used at the remote station to sense operating and alarm conditions and to

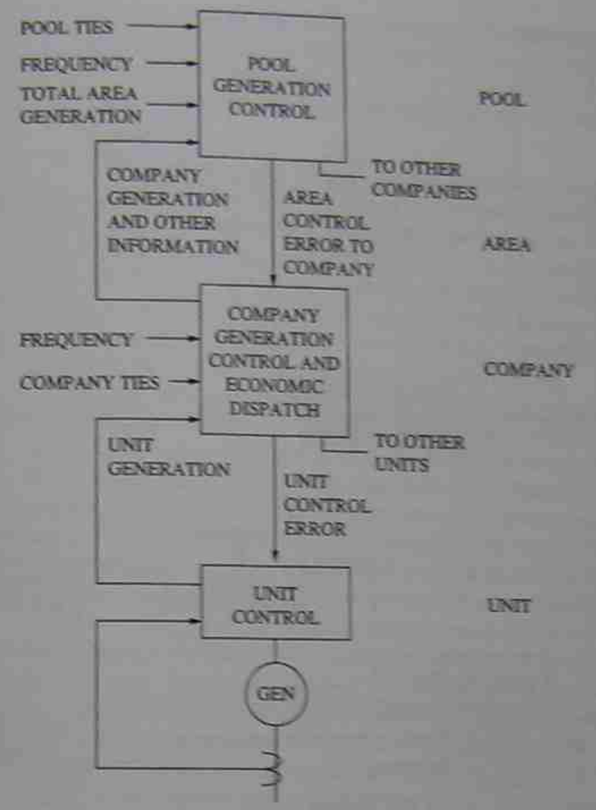


FIGURE 8.5 Relationship between company and pool

remotely activate equipment such as breakers. The communications equipment includes the MODEMs (modulator-demodulator) for transmitting the digital data, and the communications links (radio, phone line, microwave link, or wire line). The procedures are the man-machine interfaces and the programs needed to match the control to the system needs. Figure 8.6 shows a block diagram of a SCADA system.

A SCADA system performs at least one, but usually more, of the following functions:

1. Alarm sensing for such things as fire or the performance of a non-commanded function.
2. Control and indication of the position of a two or three position device such as a circuit breaker or motor driven switch respectively.
3. State indication without control such as transformer fans on or off.
4. Control without indication such as capacitors switched in or out.

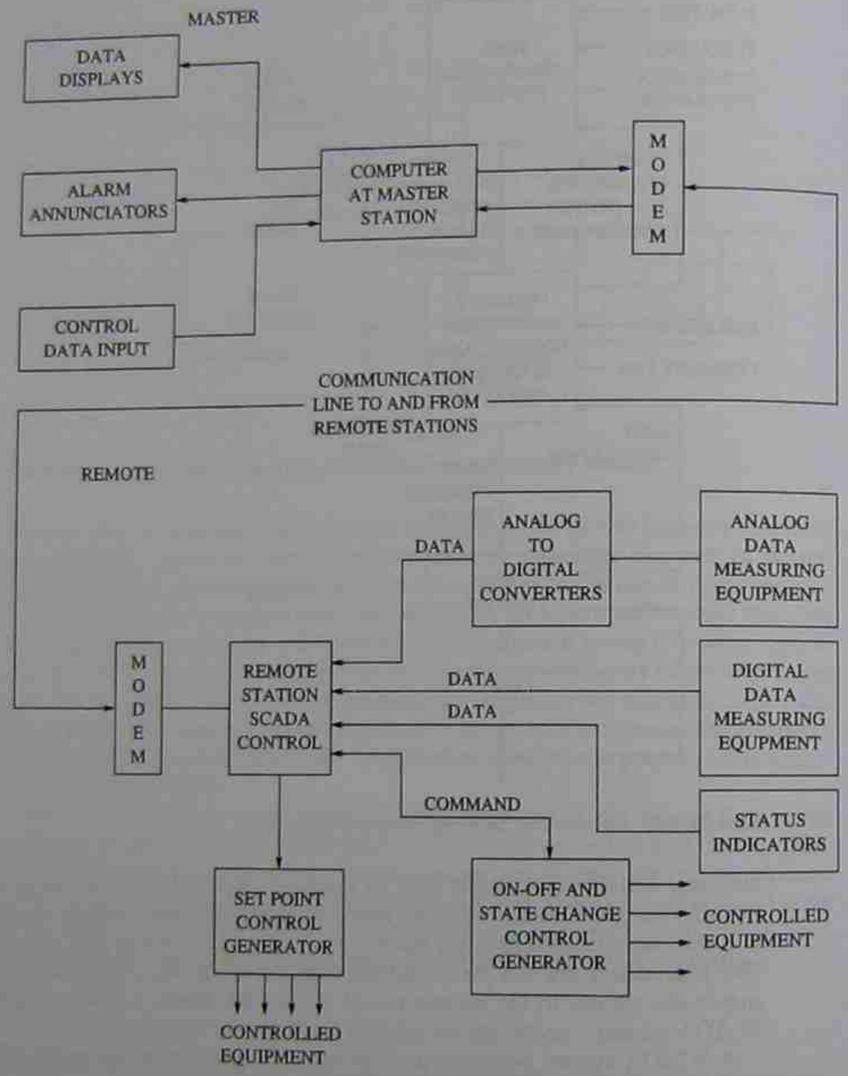


FIGURE 8.6 Supervisory Control and Data Acquisition (SCADA)

5. Set point control of remote control station such as nominal voltage for an automatic tap changer.
6. Data acquisition from metering equipment, usually via an A/D converter and digital communication link. Examples of this are the power transmitted over a particular tie line or the power used by a particular customer.

7. Initiation and recognition of sequences of events such as sectionalizing a bus with a fault on it or routing power around a bad transformer by opening and closing circuit breakers.
8. Allow operators to initiate operations at remote stations from a central control station.

SCADA systems have enough capabilities that it has been many years since there has been a manned substation in the United States. Almost all routine substation functions are remotely controlled. A complete SCADA system, with the appropriate relays and auxiliary equipment, can perform the following substation control functions: synchronism check, automatic reclosing after a fault, protection of equipment in a station, automatic bus sectionalizing, voltage and VAR control, fault reporting, transformer load balancing, equipment condition monitoring, data acquisition, status monitoring, and data logging.

SCADA systems provide two-way data and voice communication between the master and the remote stations. Digital codes are used for information exchange with various error detection schemes to assure that all data are received correctly. MODEMs at the sending and receiving ends modulate (put information on the carrier frequency) and demodulate (remove information from the carrier) respectively. The remote terminal unit (RTU) contains circuitry to properly code remote station information into the proper digital form for the MODEM to transmit, and to convert the signals received from the master into the proper form for each piece of remote equipment.

During operation a SCADA system scans all routine alarm and monitoring functions periodically by sending the proper digital code to interrogate, or poll, each device. Upon being polled the device sends its status or data to the master station. The total scan time for a substation might be 30 seconds to several minutes depending on the speed of the SCADA system and the substation size. An alarm condition interrupts a normal scan. Upon an alarm the computer polls the equipment at the station that initiated the alarm. An alarm may trigger a computer-initiated sequence of events such as breaker action to sectionalize a faulted bus. Each activated device has a code to activate it, in other words to make it listen, and another to cause the controlled action to occur. Some alarm conditions may sound an alarm at the control station that indicates action is required by an operator. The operator then initiates the action via a keyboard or a CRT.

The computers used in SCADA systems must have considerable memory to store all the data, codes for the controlled devices, and the programs for automatic response to abnormal events. SCADA is computer control, and it is the communication link for direct digital control.

8.1.6 System Security

A secure system is one that is operating normally. Automatic equipment, such as direct digital control and SCADA, help system security by automatic monitoring and detecting abnormal conditions early, so that damage can be minimized, and by automatically implementing corrective strategies. Automation cannot replace good system design and construction with quality components.

The system states are:

Normal: No emergencies exist on the system. All customer loads are being met and no lines or equipment is overloaded.

Alert: An insecure state in which one or more contingencies could cause an emergency condition. Examples are: an approaching hurricane or winter storm, concurrent events such as an intertie problem at the same time a generating unit is down.

Emergency: A condition in which critical operating constraints are being violated but the system is still carrying the load. Examples are: an overloaded transmission line based on capacity or system stability limits, voltage limits exceeded, or a transient that causes an oscillatory response that could cause a portion of the system to loose synchronization. An emergency state requires immediate action.

Extremis: This state is one in which system integrity has been lost by load shedding or separation of the system into islands. Extremis states usually result in some portion of the system being blacked out.

Restorative: This state is the one in which repairs are being made after an extremis state.

8.2 SYSTEM STABILITY

A stable system is one in which all opposing forces are in equilibrium, or will be returned to equilibrium by a restoring force in the event of a system disturbance. Electrical power system stability is defined in the same way. Often power system stability refers to the synchronism of all synchronous machines, basically generators, in the system. A synchronous machine is said to be operating stably when the forces tending to accelerate and decelerate the rotor are balanced. A generator is stable when the mechanical power in from the turbine is equal to the electrical power out plus the generator mechanical and electrical losses.

If a generator, operating in equilibrium, is disturbed by a load increase, the mechanical counter-torque on the rotor caused by the load current is increased. The counter-torque causes the rotor to begin to decelerate. The generator control system and governor increase the turbine accelerating torque to prevent a decrease in the generator frequency. The decelerating torque from the load increases and the accelerating torque from the generator control system in response to the load increase must be temporary or the rotor will begin oscillations of increasing amplitude that continue until the rotor loses synchronism with the rotating stator magnetic field. Damping within the generator, which absorbs energy from the rotor when it rotates at a rate different than the stator magnetic field, provides a restoring force to prevent loss of synchronism by the machine.

The maximum power that can be transferred between machines or groups of machines with no loss in synchronism following a disturbance is the stability limit of the system. There are two categories of instabilities: steady state and transient. Steady state instability occurs when the system is slowly put into a condition for

which no equilibrium exists. For example, steady state instability occurs when the power limits of the system are gradually exceeded. Transient instability occurs when a sudden system disturbance causes a loss of equilibrium. A large fault can induce transient instability.

8.2.1 Power Transfer

Figure 8.7 shows a three-phase synchronous generator supplying power to a three-phase motor through connecting line impedance Z. The line impedance is predominantly reactive so a change in $V_1 - V_2$ results in mostly reactive current. If $X/R = 10$ then the per phase current is

$$I = \frac{V_1 - V_2}{Z} = \frac{V_1 - V_2}{R + j10R} = \frac{V_1 - V_2}{10.05\,|R|\,\angle 84.29^\circ} = I\angle -84.29^\circ$$

which is mostly reactive. The representation of a line by a reactor is thus justified for approximate calculations. The reactive current exchange between the synchronous machines provides synchronizing force on the machine rotors.

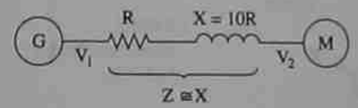


FIGURE 8.7 Line mostly reactive

Recall that a load change on a synchronous machine causes the angle of the rotor to change with respect to the rotating magnetic field of the stator. The angle tends to advance more in a generator, and lag more in a motor. This is illustrated in Figure 8.8. The angles are designated δ_1 and δ_2 for the generator and motor respectively. The total angle is the sum of the two

$$\delta = \delta_1 + \delta_2$$

and the power exchanged depends on the total angle.

We will now obtain an expression for power transfer from a source to a load. Refer to Figure 8.9. The generator is operating into a receiving bus large in capacity compared to the sending bus. We will use the receiving bus as our reference and the angle, δ, will all be from the sending bus, which may be a single generator or an entire system. The connecting line impedance includes the generator and receiving bus impedance, for simplicity we are lumping all of these into one. By Kirchoff's law we write

$$V_S - IZ - V_R = 0$$

Solving for $I\angle\Phi$ we find

$$I\angle\Phi = \frac{V_S\angle\delta}{Z\angle\theta} - \frac{V_R}{Z\angle\theta}$$

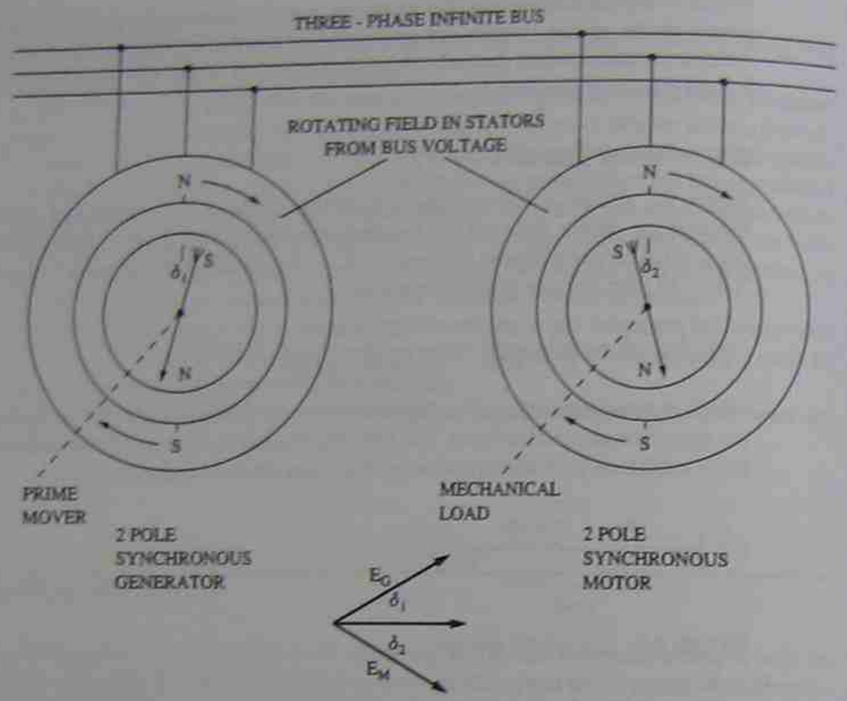


FIGURE 8.8 Synchronous machine rotor with respect to rotating magnetic field

$$= \frac{V_S\angle(\delta-\theta)}{Z} - \frac{V_R\angle-\theta}{Z} \tag{8.1}$$

Recall that apparent received power, $S_R = V_R I^*$, and that the apparent power sent is, $S_S = V_S I^*$. The complex conjugate of the current, where $I^* = I\angle{-\theta}$ instead of $I\angle\theta$, is used to make the power flow sign convention consistent with the sign convention chosen for reactance. Thus we can write

$$I^* = \frac{V_S}{Z}\angle(\theta-\delta) - \frac{V_R}{Z}\angle\theta \tag{8.2}$$

now

$$S_R = V_R I^* = \frac{V_R V_S}{Z}\angle(\theta-\delta) - \frac{V_R^2}{Z}\angle\theta \tag{8.3}$$

from which

$$P_R = \frac{V_S V_R}{Z}\cos(\theta-\delta) - \frac{V_R^2}{Z}\cos\theta \tag{8.4}$$

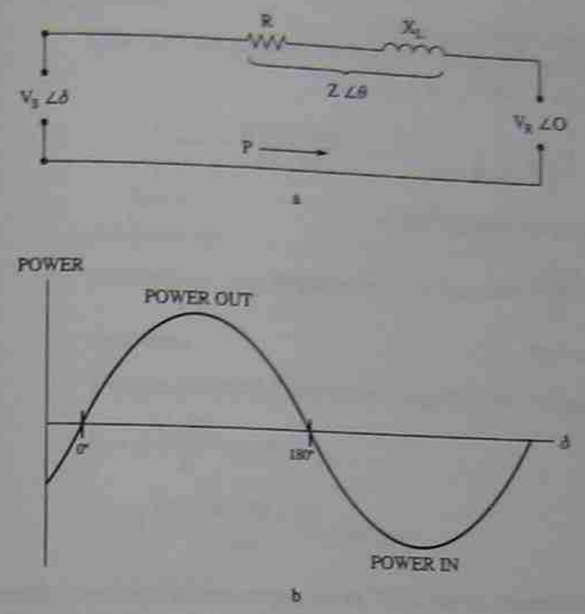


FIGURE 8.9 Power transfer (a) Sending and receiving voltage linked by line impedance (b) Power angle vs sending power flow (sending machine on infinite bus)

and of course

$$Q_R = S_R\sin\angle(V,I^*) \tag{8.5}$$

If we recall from trigonometry that

$\cos(a \pm b) = \cos a\cos b + \sin a\sin b$

equation 8.4 reduces to

$$P_R = \frac{V_R V_S}{Z}\cos\theta\cos\delta + \frac{V_R V_S}{Z}\sin\theta\sin\delta - \frac{V_R^2}{Z}\cos\theta \tag{8.6}$$

If we now consider that $R << X$, a very good approximation, so that $\theta = 90°$ equation 8.6 reduces to

$$P_R = \frac{V_R V_S}{X}\sin\delta \tag{8.7}$$

The angle δ is the total angle between the receiving and sending voltages. In our development the receiving voltage angle is zero because the receiving voltage is our reference, but this is not the general case. A similar analysis would reveal that

$$Q_R = \frac{V_R V_S}{X}\cos\delta \tag{8.8}$$

The power sent, by a similar analysis is

$$S_S = V_S I^* = \frac{V_S^2}{Z}\angle\theta - \frac{V_S V_R}{Z}\angle(\theta + \delta)$$

$$P_S = \frac{V_S^2}{Z}\cos\theta - \frac{V_S V_R}{Z}\cos(\theta + \delta)$$

Using the trigonometric identity again

$$P_S = \frac{V_S^2}{Z}\cos\theta - \frac{V_S V_R}{Z}\cos\theta\cos\delta + \frac{V_S V_R}{Z}\sin\theta\sin\delta \tag{8.9}$$

and if $R = 0$ so $\theta = 90°$

$$P_S = \frac{V_R V_S}{X}\sin\delta \tag{8.10}$$

and

$$Q_S = \frac{V_S V_R}{X}\cos\delta \tag{8.11}$$

Note that the maximum occurs at 90° in the approximate equations above. This is approximately true for nonsalient pole generator, but for salient pole machines (poles stick out instead of being smooth) the maximum occurs before 90° because the higher reluctance magnetic path between the poles causes the magnetic flux to be more concentrated at the poles than in a nonsalient pole machine.

A generator operates with a power angle of 20° to 25°, and any angle beyond 90° is unstable because the restoring force on the rotor is lost. Any power angle beyond 180° results in a reversal of power flow, as shown in Figure 8.9b. A reversal of power flow in a generating station results in extreme mechanical force being applied to the generator rotor and the turbine. This severely damages many station components as well as the generator and turbine. Frequency relays are used to protect the generator by detecting the frequency drop caused by an overload and removing the generator from the line before damage occurs. A reverse power relay is used to back up the frequency relay. The power angle across a long transmission line seldom reaches 10°, and seldom exceeds 40° across a whole system.

The loss components of equation 8.6 reduces the peak power transferred by $(V_R^2/Z)\cos\theta$, and shifts the curve of Figure 8.9b to the left by $90° - \theta$.

From the preceding equations we can see that VAR flow on a line is controlled by adjusting the voltage $V_S - V_R$. The power flow between two points in a system must be varied by changing the power angle, δ, between the two points. Phase shifting transformers, both fixed and variable, are available to control power flow by adjusting δ. Note that the angle varies at different points in the system and that the power flow is from the point with the most leading angle to the point with the most lagging angle. VAR flow is from the higher voltage on a line to the lower voltage. Power and VAR flow need not be in the same direction.

Example 8.1:

Calculate the power flow between the buses in Figure 8.10.

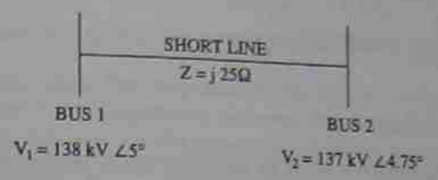


FIGURE 8.10 Figure for Example 8.1

Solution:

Using equation 8.7 and converting to phase voltages we find

$$P = 3\frac{V_{P1}V_{P2}}{Z}\sin(\delta_1 - \delta_2)$$

$$= 3\frac{79.67\text{ kV}\ 79.1\text{ kV}}{25\ \Omega}\sin(0.25°)$$

$$= 3.3\text{ MW}$$

Calculating the power transferred using per unit (pu) and a base of 10 MVA and 138 kV we find

$$V_1 = 1.0\text{ pu}$$

$$V_2 = 0.99275\text{ pu}$$

$$\text{base } Z = \frac{(\text{base kV})^2}{\text{base MVA}}$$

$$= \frac{(138\text{ kV})^2}{10\text{ MVA}}$$

$$= 1.904\text{ k}\Omega$$

$$\text{pu } Z = \frac{Z}{\text{base } Z} = \frac{25\ \Omega}{1.904\text{ k}\Omega} = 0.01313\text{ pu}$$

$$\text{pu P} = \frac{1.0\ (0.99275)}{0.01313}\sin 0.25° = 0.32997\text{ pu}$$

$$P = \text{base MVA}\ (0.32997) = 3.2997\text{ MW}$$

The difference in the two values of transferred power is from round off error.

Note that if the line voltage doubles the pu impedance is a quarter of its lower voltage value.

$$\text{base } Z = \frac{(2 \times 138\ \text{kV})^2}{10\ \text{MVA}} = 7.618\ \text{k}\Omega$$

$$\text{per unit } Z = \frac{25\ \Omega}{7.618\ \text{k}\Omega} = 0.00328\ \text{pu}$$

8.2.2 Power Flow Division

If two parallel transmission lines are used to transfer power the lowest impedance line transfers the most power, all other factors being equal. Recall from ac circuits that for two impedances in parallel

$$\text{path 1 current} = \frac{(\text{path 2 impedance})}{(\text{total impedance})} \text{ total current}$$

Multiplying both sides by base voltage we obtain

$$\text{path 1 power flow} = \frac{(\text{path 2 impedance})}{(\text{total impedance})} \text{ total power flow} \qquad (8.12)$$

Similarly more apparent power flows in the lower impedance line. If the lines are not at the same voltage the line with the lower pu impedance transmits more power. The following example demonstrates this.

Example 8.2:

Calculate the power flow for each path of Figure 8.11. All pu impedances are to the same base.

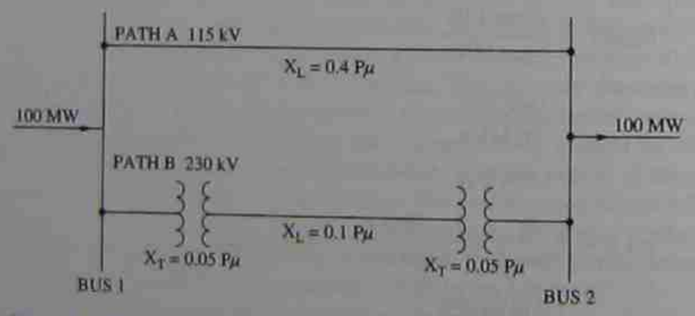


FIGURE 8.11 Power flow division

Solution:

The power flowing in line a is found by equation 8.12 after the path impedances are found.

Z path A = j0.4 pu

Z path B = j(0.05 + 0.1 + 0.05) pu = 0.2 pu

$$\text{path A power flow} = \frac{(0.2\ \text{pu})}{(0.2\ \text{pu} + 0.4\ \text{pu})}\ 100\ \text{MW} = 33\ \text{MW}$$

and by subtraction path B power flow is 67 MW.

Given equal line impedances the higher voltage line carries the most power because its pu impedance is lower. In general the losses are lower on the higher voltage line because the current is lower for a given power transfer.

The division of the power in Example 8.2 can be altered by inserting a phase shift transformer in one line, changing δ for that line. Making the phase shift larger from one end of a line to the other increases the power flow on that line. If possible the voltage transformation and phase shifting functions are combined in one transformer.

If one line opens then the remaining line must carry all of the load, which usually results in an overload of the remaining line until corrective action is taken. More than two paths for power flow helps but does not guarantee that no remaining lines will be overloaded. Referring to Figure 8.12 we see three lines are transferring power from bus A to bus C. The power flow on the lines has divided in inverse proportion to the pu impedance of the lines. The 230 kV lines carry more power than the 115 kV line. The two 230 kV lines have a pu Z of 0.1 each and the 115 kV line has a pu Z of 0.4 including transformer T_3. To keep the calculations direct and illustrative assume that the impedance of T_4 is negligible, and that the power angle is the same across all three lines. Then, with the 230 kV line parallel impedance equal to 0.05 pu

230 kV line power = (0.40/0.45)(600 MW) = 533.3 MW

and each 230 kV line carries half the power. The remaining 67.7 MW is carried by the 115 kV line. If one 230 kV line is removed from service the power split will be 120 MW on the 115 kV line and 480 MW on the remaining 230 kV line. This is an increase of about 80% on each line and T_3. If the MVA rating (thermal limit because of I^2R heating) of either line or the transformer is exceeded action must be taken by the control station dispatcher. The most likely action is to increase the power delivered to bus B or bus C with reserve generating capacity, or possibly intertied power, and reduce the power to bus A until the lines are operating at an acceptable level of power transfer. The power transfer level of the two remaining lines may be higher than normal until the other 230 kV line is restored to operation. The last resort is to shed load on bus B or C to avoid overloading the lines. A line is not removed from service unless it is tripped out on a fault, or removed for maintenance. If the line is removed from service for maintenance, it is at a time when the load is at its lowest.

Steady state stability refers to a system's ability to withstand small disturbances from equilibrium without losing synchronism between two or more synchronous machines on the system. Two subdivisions of steady state are defined: classical and dynamic.

Classical steady state stability is that in which the generator field excitation is not changed for small deviations from equilibrium. Early steady state stability studies

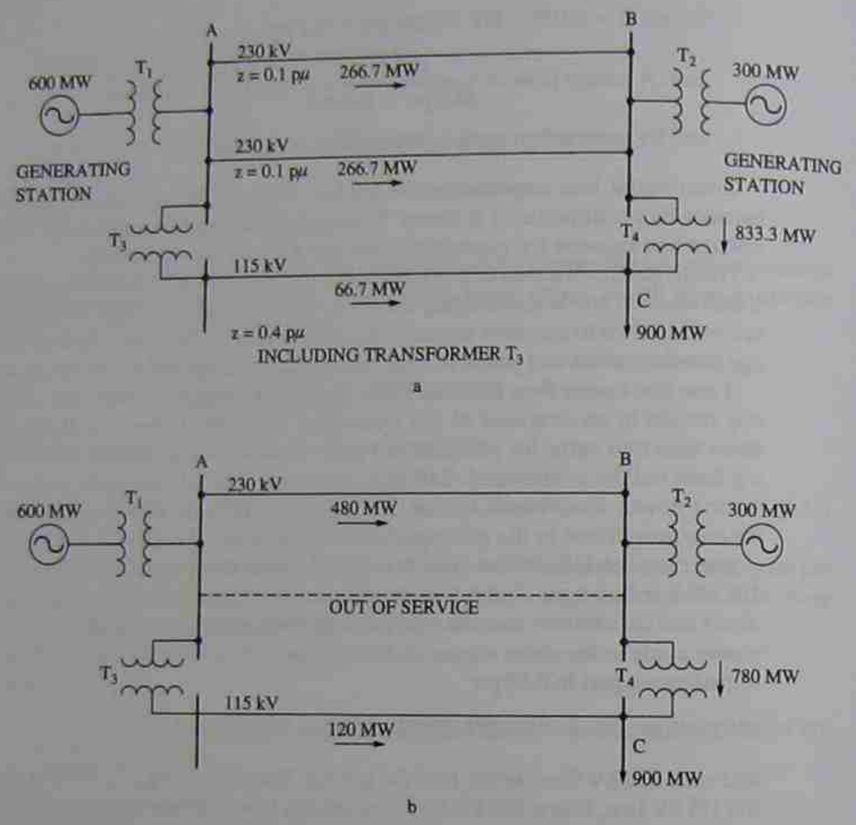


FIGURE 8.12 Effect of opening a line (a) Three lines in operation and (b) one line removed

were made with this assumption. The early stations had voltage regulators with *dead bands*, a span of output changes allowed with no control action, to prevent control action for small variations from the set point. The early voltage regulators were too slow and insensitive to effectively adjust for very small rapid changes in the output voltage. If such response was allowed it often resulted in a regulator induced oscillation that was worse than the original change. Thus the regulators were set to respond only to changes that represented a significant deviation from the set point. Small changes in the regulator setting were made manually.

Dynamic steady state stability is that in which the system generators are equipped with automatic field controls that are sensitive enough and fast enough to respond to small deviations in the output voltage from the set point, even if they occur rapidly. Such controllers resulted from the use of electronic circuitry instead of electromechanical systems for field control. The automatic voltage regulators allow higher power transfers with stability than did the older regulators. Thus the only steady state stability studies done today are dynamic.

Steady state stability limits are exceeded under the following conditions: (1) When the slow increase in load in some section is such that a generator is pulled out of step. The ability to transfer load from one place to another within the system reduces the possibility of this type of stability loss. (2) When a small load change causes an oscillation in the system to start, and the oscillation continues to grow until a machine is pulled out of synchronization. Good system damping reduces the possibility of this occurring.

Steady state stability can be enhanced by a number of actions that increase the ability of the system to transfer power.

Multiple transmission circuits: Two circuits carry twice the power of one. Additionally, one circuit can provide partial service while one is down for repair. Double circuit transmission lines are very common.

Higher line voltage: As we calculated earlier, increasing line voltage decreases pu impedance and increases line capacity, if all other factors remain constant. Additionally, resistive losses are lower.

Reducing series line reactance: This can be done with series capacitance, as discussed in Chapter 4, and by bundling conductors (which also reduces corona).

Shunt reactors: As we will calculate in Chapter 9, long transmission lines have a lot of shunt capacitance, both from line to line, and from line to ground. The capacitance can cause the line charging current to be excessive when the line is energized, and cause the line voltage to rise above acceptable limits, as discussed in Chapter 4. Shunt inductive reactance at the beginning and end of the line (and possibly at points in between) cancel some of the capacitive reactance. The inductors at the generator end provide lagging VARs that cause the field current to be higher for a given output voltage. This is because lagging load VARs cancel some of the rotor flux, thus a higher field current is needed to maintain the generator output voltage.

This causes the rotor to be harder to pull out of synchronization, which improves stability. The inductors at the receiving end help hold the line voltage at acceptable levels by cancelling the capacitive reactance.

Damping: Damping in a generator is provided by the production of a counter torque on the rotor when it tries to change speed. The generator rotor damper windings provide direct counter torque to the rotor proportional to any instantaneous speed variation. The generator rotor inertia and the prime mover inertia tend to prevent deviations in speed. Anything that removes power from the generator also provides damping, as resistance does in a resonant circuit. The friction and wind losses of the generator also provide damping. High capacity lines that can move a lot of power away from a generator in the event of a disturbance also provide damping, as long as the power demand by the lines does not exceed the generator capacity.

Voltage regulators: Voltage regulators that adjust the terminal voltage very quickly to the set point value in the event of a load change increase the ability of the generator to supply power because the effect of the generator impedance is not seen by the line, as shown in Figure 8.13. The increased capacity provides a stabilizing effect on the system.

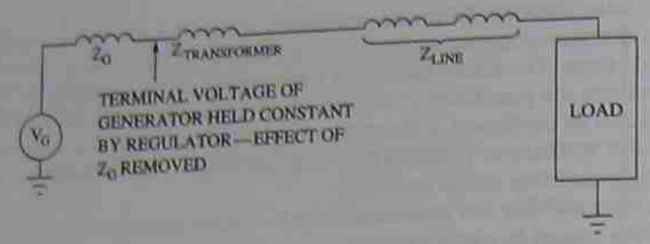


FIGURE 8.13 Generator regulation to improve stability

Computer power dispatching: The network of a modern electric power utility can consist of several generators, several transmission lines, a vast distribution network, and many tie points. The complexity of the system means that a computer must be used to provide the coordination of all the parts of the system in a timely manner. The computer can solve the complicated power flow equations quickly, providing prompt action in the event a generator, or a part of the system, is approaching a potentially unstable condition. The computer's capability to quickly route power where it is needed improves the stability of the system.

8.2.4 Transient Stability Definition

Transient stability refers to the ability of a system to withstand sudden and severe changes in system conditions without loosing synchronization. These sudden and severe changes are usually the result of switching or fault conditions, but sudden large load changes can also introduce transient disturbances.

8.2.5 Transfer Impedance

A fault on a circuit that connects two system sections reduces the ability of the circuit to transfer power between the two sections. A three-phase fault with zero fault impedance reduces the power transfer capability to zero. A single phase fault reduces power transfer to a lesser degree. The higher the fault impedance, the less power transfer capability is reduced. All of the faults must be removed from service by opening a circuit breaker, which reduces the power transfer capability to zero. Figure 8.14a illustrates a line with a fault.

The transfer impedance is the impedance of the faulted section prior to opening a breaker. Figure 8.14b is the reactance diagram for the faulted line of Figure 8.14a. The transfer impedance is defined as

$$Z_{TR} = \frac{E_A}{I_B} \tag{8.13}$$

If we let $R = 0$ then

$$X_{TR} = \left.\frac{E_A}{I_B}\right|_{V_B = 0} \tag{8.14}$$

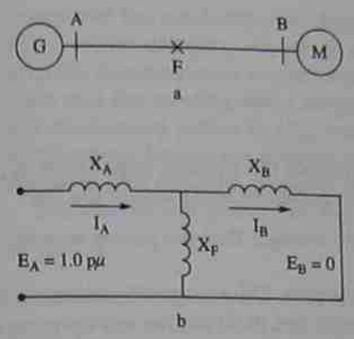


FIGURE 8.14 Transfer impedance (a) One-line representation (b) reactance diagram

If we let $E_A = 1.0$ pu, the equation reduces to

$$X_{TR} = 1/I_B \tag{8.15}$$

with $V_B = 0$. Now let the components in Figure 8.14b be defined as:

X_A = reactance to the fault

X_F = fault reactance

X_B = reactance from fault to receiving end of line

Then

$$I_A = \frac{1}{X_A + \dfrac{X_B X_F}{(X_B + X_F)}}$$

and

$$I_B = \frac{X_F}{X_B + X_F}(I_A)$$

$$= \frac{X_F}{X_B + X_F} \times \frac{1}{X_A + \dfrac{X_B X_F}{X_B + X_F}}$$

$$= \frac{X_F}{X_A(X_B + X_F) + X_B X_F}$$

rearranging

$$I_B = \frac{X_F}{(X_A + X_B)X_F + X_A X_B}$$

$$X_{TR} = \frac{1}{I_R} = X_A + X_B + \frac{X_A X_B}{X_T} \tag{8.16}$$

From equation 8.16 we see that:

1. If $X_T = \infty$ there is no fault and X_{TR} equals the through impedance, $X_A + X_B$
2. If $X_T = 0$, $X_{TR} = \infty$, and no power is transferred to the end of the line.

In most faults the fault impedance is low enough that the power transfer of the line is seriously impaired.

Most faults involve arcing, which is resistive. The system impedance is largely reactive so the arc resistance is usually neglected in all studies not done on a computer. The fault impedance, and therefore the transfer impedance vary with the type of fault. It is least in a three-phase fault, but this is the rarest type of fault. Fault impedances are calculated in Chapter 9.

In practice faulted lines are disconnected from the system as quickly as the relays can detect them and the circuit breakers can open. A common practice, as noted earlier, is to use a double circuit line to connect two parts of a system. Before a fault the total power transfer capability is described in Equation 8.10, where the impedance (or reactance, if resistance is assumed zero) is the parallel impedance of the two lines. If a fault occurs on one line the transfer impedance is larger than the line through impedance, and the power transfer capability of the line is reduced. After the protective relay detects the fault condition and isolates the faulted line by opening the circuit breakers connecting the line to the system, the transfer impedance is now the through impedance of one circuit of the double circuit line. This impedance is higher than that of the two circuits in parallel so the power transfer capability of the line is reduced, usually to about half of the double circuit capability. The more tie lines that two system sections have between each other, the less that the loss of one line reduces the power transfer capability.

8.2.6 Inertia

The rotors of large generators and turbines have considerable inertia because they are massive. (Recall from physics that inertia, *In*, of a body is the sum of each mass element, *m*, over its radius, *R*, squared; $In = \Sigma\, mR^2$.) The inertia tends to keep a body in motion once the motion has been established. In other words inertia opposes changes in motion of a mechanical body in much the same way inductance opposes changes in current in an electrical circuit. Before a disturbance a motion of a generator rotor is a constant speed rotation that is the result of a balance of all the torques applied to the rotor. These include the prime mover torque, the counter torque from the electrical output, and the damping torques such as friction and windage.

In the event of a transient disturbance in which the mechanical torque, which is proportional to power, the electrical counter torque, which is proportional to electrical power out, and the damping torques, which are proportional to the loss factors such as windage and friction, are not in balance the power angle changes

because of the acceleration or deceleration from the imbalance. Note the damping effect of the damping windings occurs only during a disturbance because they provide damping only in response to a change in the relative motion between the rotor and the rotating stator magnetic fields. If the transient disturbance results in the mechanical power in (P_M) exceeding the electrical power out (P_E) there is an accelerating torque (or power) on the rotor that causes the power angle (δ) to advance. The opposite occurs if $P_E > P_M$.

The mechanical power into the rotor can be expressed as

$$P_M = \omega T_{IN}$$

where $\omega = 2\pi f$, and T = torque. If ω is written as 1 pu, then

$$P_M = T_{IN}$$

The electrical power out is equal to

$$P_E = P_{E\,MAX} \sin\delta$$

for round rotor machines. Salient pole machines have a more complex equation because of the concentration of magnetic flux at the poles. $P_{E\,MAX}$ during the transient is expressed as

$$P_{E\,MAX} = \frac{e_1 e_2}{X'} \tag{8.17}$$

where:

e_1 and e_2 are the constant voltages supplying the transient reactances during the transient. Most faults are lagging, which causes the generator flux to weaken. The fast acting generator voltage regulators as well as the action of the damping windings force the gap flux to remain almost constant during the first 0.5 seconds or so of a transient disturbance. Thus the generator voltage does not change appreciably during this period of time. The inertia of any receiving machines holds their voltage almost constant during this time. Referring to equation 8.10, $E_1 = e_1$, and $E_2 = e_2$.

X' is the sum of the transient reactance of the generator (X_d'), the connecting system reactance (X_{TR}), and the transient reactance of the receiving system machines (X_d'). The transient reactance in a machine results from damping windings, and in a generator the voltage regulator, trying to hold the gap flux constant.

$$X' = X_{dG} + X_{TR} + X_{dM}$$

δ is the angle between e_1 and e_2

The accelerating torque on the generator rotor is then the difference in the mechanical input torque and the electrical output torque, all of which are proportional to their associated power. Expressed as power in per unit terms

$$P_A = P_M - P_E = \frac{H}{180 f}\frac{d^2\delta}{dt^2} \tag{8.18}$$

where

f = frequency

δ = power angle in electrical degrees

H = per unit inertia constant in kW-seconds/kVA

The inertia constant can be found from the following equation

$$H = \frac{(0.231)(WR^2)\,(\text{rpm})^2 \times 10^{-6}}{\text{base kVA}}$$

The resulting rotor acceleration (a) from an accelerating power input P_A is

$$a = \frac{180 f P_A}{(H)\,(\text{kVA})} \tag{8.19}$$

where

$H \times$ kVA is the rotor stored energy.

In summary, a transient condition results in an imbalance between the mechanical and electrical torque acting on the rotor because the power into and out of the rotor are different. The torque imbalance causes the rotor to accelerate or decelerate. The inertia resists the change in rotational speed from the imbalanced torque, but a change in the power angle still occurs.

8.2.7 Equal Area Criterion

Figure 8.15a illustrates two electrical power system segments tied together by a double circuit tie line. S is the sending circuit segment and R is the receiving circuit segment (S could be a single generator and R a single synchronous motor). S is at power angle δ_S and R is at δ_R. One line has faulted at F. Transferred power during the fault is given by Equation 8.18

$$P = \frac{e_s e_R}{X'} \sin(\delta_S + \delta_R)$$

The power transferred before and after the fault is given by equation 8.10.

The power transfer equation is plotted for three conditions in Figure 8.15b. Curve a is the pre-fault condition. The impedance is the through impedance of the lines in parallel plus the normal terminal impedance of the two system segments. The peak power is not the maximum power that can be transferred between the two systems, but the maximum synchronizing power (proportional to torque) capability of the two system areas. The lines will often lack the capacity to transfer this peak power. The prime mover power is represented as 1 pu on the diagram. The power angle of the system is at the intersection of the power curve and the prime mover power line. Before the fault this is at the prime mover power line and

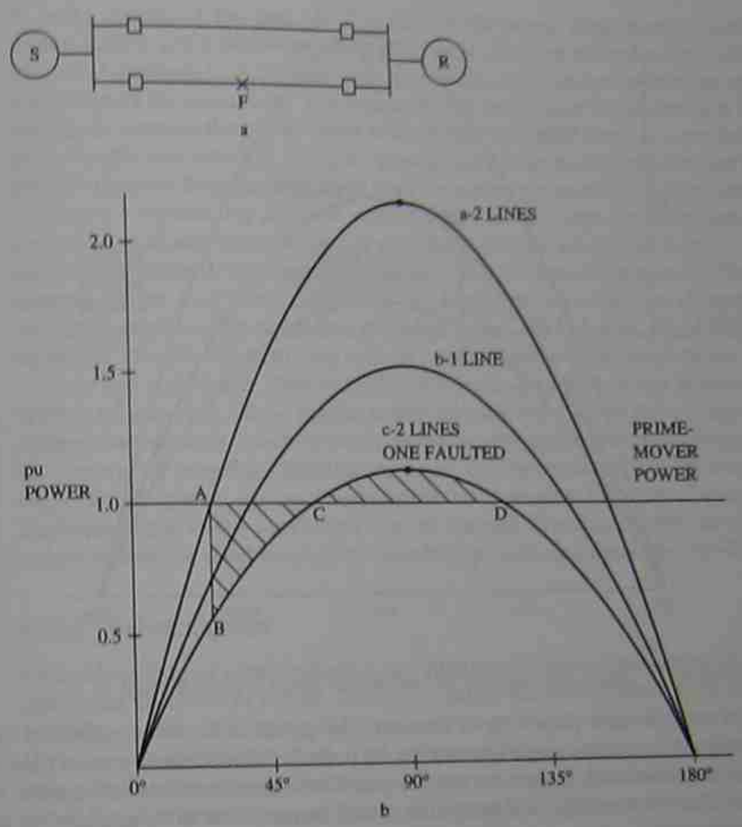
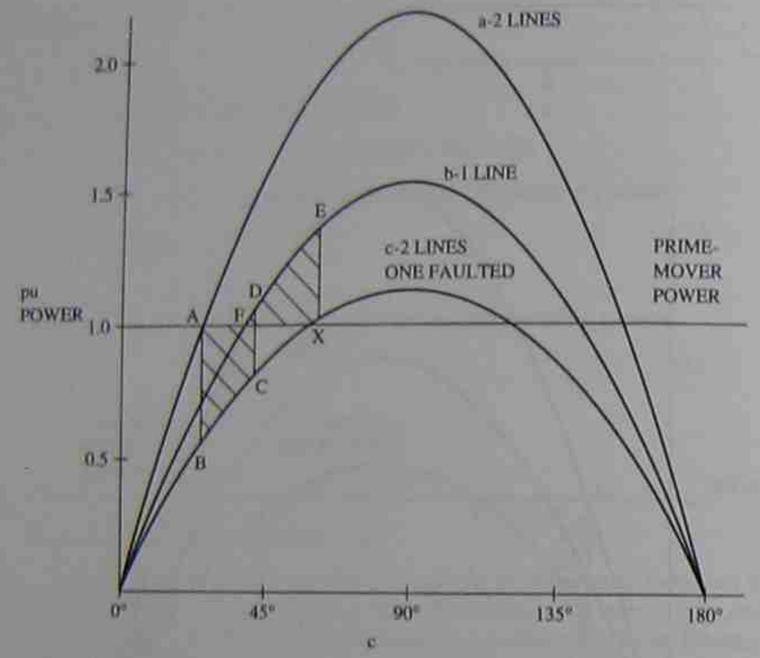


FIGURE 8.15 Equal area criterion (a) Double circuit connection between system areas (b) Transient power (or torque) angle curves for double circuit line

curve a. Curve b is the power curve with two lines, one of which is faulted. The fault causes the transfer impedance between the system segments to rise (recall this is not the fault impedance to ground), reducing the power that can be transferred between them. Curve c is the P-δ curve after the faulted line has been isolated by opening circuit breakers at either end. The power transfer capability has been improved in comparison to the faulted condition, but it is not as high as the original double circuit line.

We will now trace the conditions that occur during the fault relative to the power curves. At the instant of the fault the operating point of the system moves from point A in Figure 8.15b, the intersection of the unfaulted power curve and the prime mover power line, to point B, the same power angle on the faulted power curve. The prime mover power exceeds the transferred power so the rotor is accelerated along curve c, the operating curve, toward point C, at which the power



c

FIGURE 8.15 Equal area criterion (c) Faulted line circuit breaker tripped

angle and the new power curve intersect. The inertia of the rotor causes the rotor to overshoot the power angle represented by point C. After the rotor passes point C the rotor is decelerated. If the rotor reaches point D the synchronism of the system is lost. If the shaded area ABC of Figure 8.15b, which is equivalent to the accelerating energy acting on the generator rotor, is less than area CD, the decelerating energy, the system tends to stay in synchronism because the decelerating force causes the operating point to move back toward point C. This is called the equal area criterion. If the area ABC is greater than CD the accelerating torque drives the system out of synchronism as the operating point moves past D. If area ABC < CD the operating point (the power angle) oscillates around point C along the power curve with decreasing amplitude excursions until the damping absorbs the oscillatory energy. The relays should open the circuit breakers on the faulted line long before the oscillations are damped.

Removing a faulted line from the system quickly improves the transient stability of the line. To see why, refer to Figure 8.15c. As in the previous explanation, the system is operating at the power angle shown at point A, the intersection of the unfaulted power curve, a, and the prime mover line when a fault occurs. The fault moves the operating point to B and the operating point moves along curve c as the power angle advances. The power angle is advancing because $P_M > P_E$. At point C the faulted line is isolated from the system. The operating point moves to point D on the single line power curve, b. Inertia causes the power angle to advance, forcing the operating point along curve b toward point E. The force on the rotor is now decelerating because

$P_E > P_M$. At point E the area ABCD = DEX so the power angle stops advancing and moves back to point F. The operating point now oscillates around point F with excursions that decrease in amplitude with time as the rotor (or system) damping absorbs the energy of the oscillations. The reason the fast isolation of the faulted line improves stability is because the power curve of the single unfaulted line has a greater range of power angle over which $P_E > P_M$, the power curve is above the prime mover line, thus providing more decelerating torque than the power curve with a faulted line.

During a typical day a power system experiences many transient disturbances, caused by sudden load changes or switching (faults cause only a few of the transient disturbances), that cause oscillations on a portion of the system. These oscillations, which may have periods of up to several seconds, are damped by the system generator damping, line capacity, losses, and inertia. Their amplitude is normally low enough that they are not noticed by the utility customers.

Transient and steady state stability calculation for a system is a massive job for a system of any size. Thus, digital computers are used to do the calculations. The system impedances, machine characteristics, and network configuration must all be known. A possible disturbance must be chosen and the resulting system response calculated for small increments of time after the disturbance, from the minimum time to the maximum time of interest. The step by step method of calculation must be used because the machine power equations are non-linear.

8.2.8 Swing Curves

One calculation of great interest is the advance of rotor angle versus time for each generator involved in a fault. The curve, called the swing curve, then indicates the stability, or lack of it, of a generator for a given length of disturbance. Figure 8.16 shows a set of swing curves. The power angle-time curves vary depending on when the fault is removed, so the swing curves must be plotted for each fault clearing time of interest. The generators of Figure 8.16 appear to be stable for a fault cleared in 0.23 seconds because the curves have begun to swing back toward the original power angles. The first swing may not indicate stability because the dynamic stability of a machine may be poor, allowing the oscillations to build up after the disturbance until synchronism is lost. A plot of several seconds may be necessary to spot the tendency toward post-fault isolation synchronism loss. Figure 8.17 shows the swing curves for one generator for several fault clearing times. Note that the quicker the fault is cleared the better the post-fault stability.

8.3 TRANSMISSION VOLTAGE LEVELS

The transmission system is made up of the high voltage lines and bulk power substations that connect the generating stations with the distribution substations. The transmission system can be further broken down into the transmission and

subtransmission systems. The high voltage transmission lines must often be terminated in a bulk power substation some distance from the loads because the loads are dispersed and the very high voltage stations are not allowed in populated areas. Lines with voltage levels and capacities between those used for transmission and those used for distribution, called subtransmission lines, are then used to carry power from the bulk power substations to the distribution substations and large individual customers. The right of way width is smaller for subtransmission lines than for transmission lines.

Distribution voltages are normally between 4 kV and 34.5 kV. Subtransmission voltages are normally between 69 kV and 138 kV, with 69 kV, 115 kV, and 138 kV being common. Transmission voltages are usually in the EHV range, greater than 230 kV, and UHV range, over 800 kV. Common ac transmission voltages are 230 kV, 345 kV, 500 kV, 550 kV, and 765 kV. 1100 kV and 1500 kV lines are planned. Voltages for dc transmission range from about 100 kV to 1200 kV with ± 100 kV (200 kV), ± 250 kV, ± 400 kV, ± 500 kV, and ± 550 kV being common. Higher dc transmission voltages are being planned.

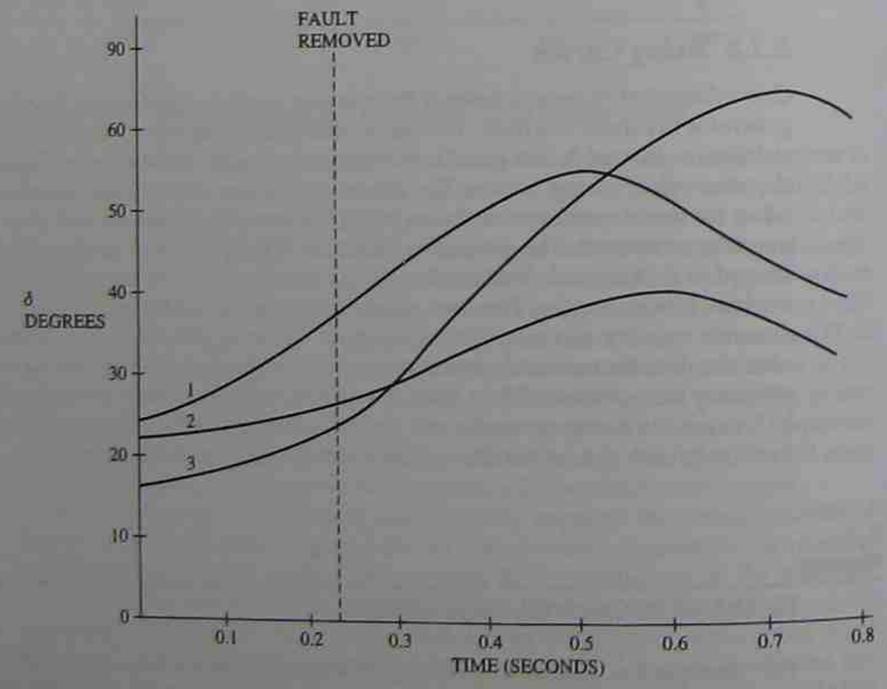


FIGURE 8.16 Swing curves

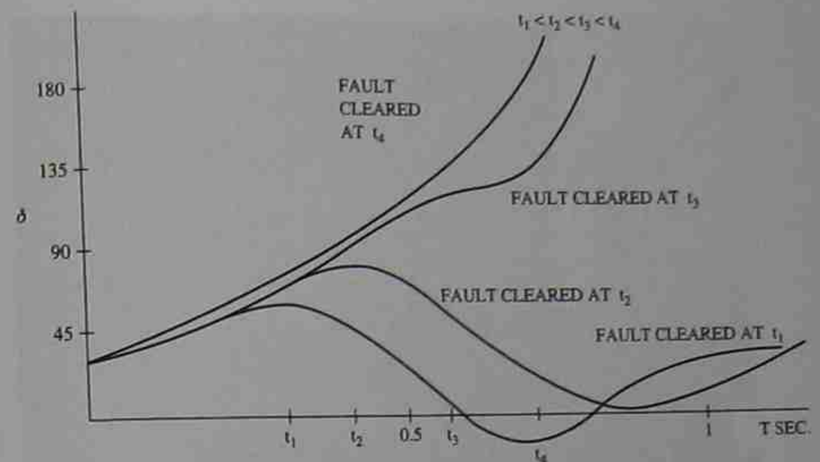


FIGURE 8.17 Swing curve vs time to clear fault

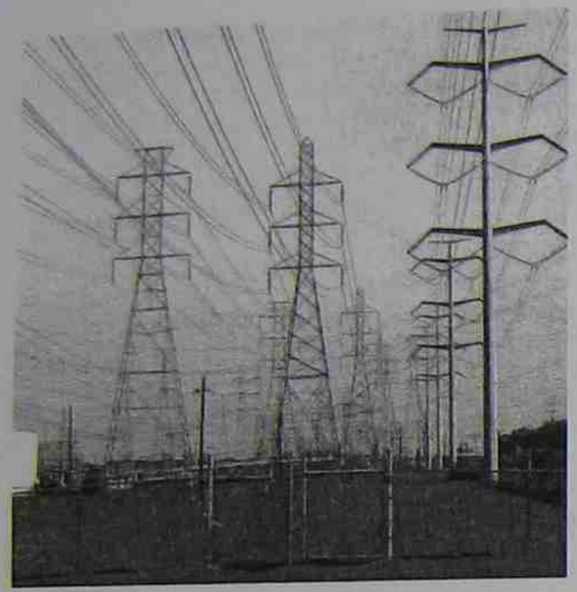
8.4 TRANSMISSION LINE CONSIDERATIONS

Electrical power transmission lines can be ac, dc, underground, or overhead. Overhead ac is the most used method of electrical power transmission. Transmission lines represent from 10 to 20% of the investment of a typical electric utility company. This significant amount must be carefully spent so as to assure reliable, efficient, and economical electric power transmission.

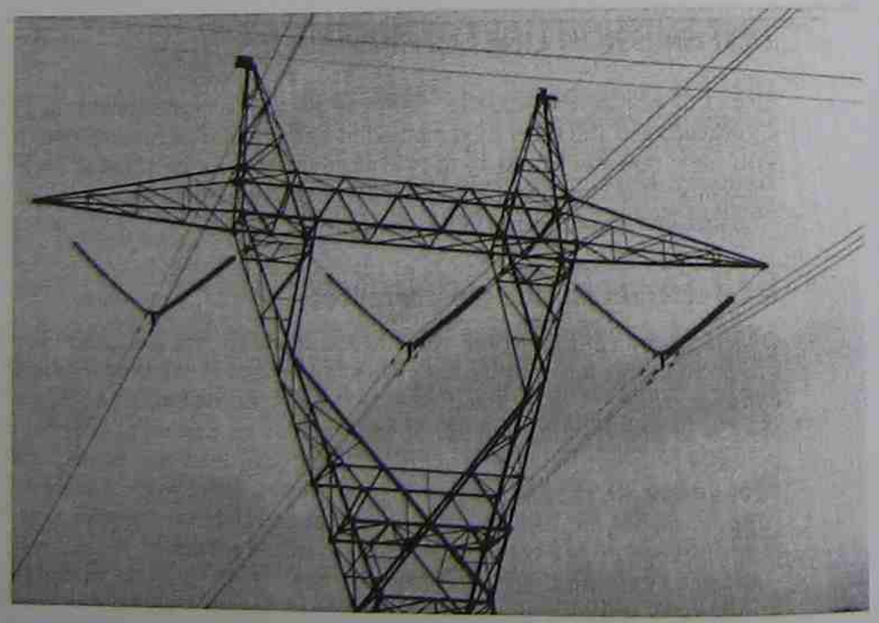
8.4.1 Overhead Line Considerations

Overhead transmission line construction is much less expensive than underground because it is simpler. Bare wires can be used in overhead transmission line construction with insulation used only at the points that the wire is suspended, as shown in Figure 8.18. The use of bare conductors alone cuts both the cost and losses of an overhead line compared to an underground line. Wood or galvanized steel towers are used to support the conductors. The insulators at the conductor support points are usually ball and socket porcelain or fiberglass rods covered with skirts made of a compound similar to silicon rubber.

Overhead transmission lines must be very reliable because an outage on one leaves many homes and businesses without electricity. Thus transmission lines are well protected against lightning with lightning arresters placed periodically along the line, and shield wires along the entire line. The conductors and conductor

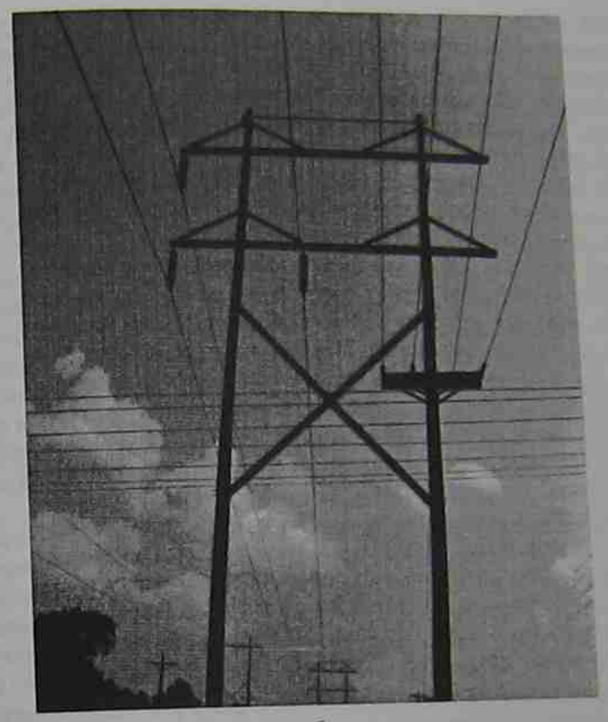


a



b

FIGURE 8.18 Overhead transmission line (a) 345 kV (Courtesy of Houston Lighting and Power) (b) 500 kV (Courtesy of Gulf States Utilities)



c

FIGURE 8.18 Overhead transmission line (c) double circuit 138 kV H structure with one circuit installed on the left, with a distribution underbuild on the right (Courtesy of Gulf States Utilities)

supports must be strong enough to withstand severe weather, which can subject the lines to considerable wind, snow, and ice loading. Bundled conductors, which are used almost universally at 230 kV and above, to reduce series reactance and corona, experience more weather related loading than single conductors. Thus bundled conductors must be supported better, at a higher cost, than single conductor lines.

There is a trade off between the losses on a transmission line and the cost of constructing the line. Lowering I^2R losses usually means using larger conductors or more conductors to increase the conductor area. Larger conductor area means increased conductor weight, which means the strength of the supporting towers and insulators must be greater. The increased strength required means that the manufacturing cost, transportation cost, and construction cost of every line component is higher. Transmission line costs are also effected by the terrain that the line must pass through. The rougher the terrain the higher the cost. Terrain, such as swamp land, that is not suitable for normal foundations or temporary access roads also increases the cost of construction because helicopter pole placement and special support guys become necessary.

The magnitude of the power that a transmission line carries makes the reduction of loss a major consideration. For example, a 2% loss on a 1000 kVA line, at 6 cents/kW-hr, costs only $1.20/hr. A 50% reduction in loss amounts to a savings of only 60 cents an hour. The same loss on a 1000 MVA line at 6 cents/kW-hr costs $1,200/hr. A 50% reduction in this loss is a savings of $600/hr, or $600/hr × 24hr/day × 365 days/yr = 5.26 million dollars a year. Over the expected 40-year lifetime of a transmission line this is a savings of 210.4 million dollars. Thus the reduction in line loss must be carefully weighed against increased construction costs to plan a transmission line that is optimally economical.

Obtaining right of way is not a large problem for distribution system construction. The areas that do not grant right of ways do not get electric service. Very few distribution right of way requests are denied. Transmission lines do not effect people so immediately, are considered unsightly by some people, require larger right of ways than distribution lines, and are considered a health hazard by a few people, so people are not as willing to grant transmission right of ways. The courts tend to agree and support the reluctance of people to grant right of ways for transmission lines. As a result the right of way cost is a very large portion of the cost of constructing a transmission line, especially when litigation is necessary.

In rural areas the utility pays a landowner a fee for each transmission structure on that owner's property, for which the owner allows the structure, or its replacement, to be on the property as long as it is needed. The landowner must also allow access to each structure on the right of way via an easement. The utility maintains the right of way by clearing bush, weeding, and mowing grass. The landowner can graze or farm the right of way, but cannot build on it. The fee is paid one time, as in a purchase, or annually. In and around cities the usual practice is to purchase right of ways. The purchased right of ways are called fee strips.

8.4.2 Underground Line Considerations

Less than 1% of the total transmission line miles in the United States are underground. The most extensive underground system in the United States is in the New York City area. Underground transmission lines are most commonly used to feed urban substations in high load density areas, such as downtown. Industrial plants use underground transmission and/or distribution lines in areas where overhead lines are not practical because of the clearance required. The highest underground transmission line voltage is 525 kV. This installation used nine oil type cables (three circuits), running about 6500 feet to connect the generation plant to the switch yard at the Grand Coulee Dam. Since the cost of an underground transmission line is 9 to 15 times the cost of an overhead line, they are installed only where they offer a clear advantage, or there is no alternative.

Underground lines are more expensive than overhead for a variety of reasons. Underground cables must be insulated, and EHV insulation is expensive. It must be installed in pipe, which is expensive, and cooled with a oil circulation system, which is expensive both to install and maintain. Should a failure occur in an underground system, it is expensive to repair because of the difficulty in access.

The pipes used for underground transmission cable conduit are usually steel or bronze, 6 to 8 inches in diameter. Bronze, while more expensive, is not magnetic so it has less effect on cable reactance. The pipes are insulated on the outside to prevent cathodic currents (essentially from battery action in the soil involving the pipe as one electrode), and buried from 4 to 8 feet deep, enveloped within reinforced concrete. The pipe comes in 30 and 40 foot lengths. It must be welded securely enough to hold a vacuum and the joint must be insulated on the outside. After the run of pipe is in place a cup driven by compressed air, called a rabbit, is used to pull a light line through it. Then a mandril, called a pig, is pulled through the pipe to remove any welding burrs. The pipe is then put under a vacuum to test for leaks. The cables are then installed. The pipe is then put under a vacuum (to exclude moisture and air) with the cables installed and filled with oil. Figure 8.19 shows a cross section of a pipe with cables installed.

The cables are constructed much like the oil impregnated paper insulated underground distribution cables, except that the transmission cables have more oil impregnated paper insulation in more layers. The cable has a spiral (or double spiral) metal wire wound around the outside of the insulation to prevent damage to the cable when it is pulled through the pipe, or from movement caused by expansion or contraction caused by heating or cooling as load current changes. The entire cable is covered with a thin lead sheath that keeps the oil impregnation in the insulation and prevents handling damage during shipping and installation. During cable pulling the lead sheath is removed just as the cable enters the pipe. The cable must enter the pipe, and cable splices must be made, in a clean, humidity controlled environment so an air conditioned building is constructed where the cable is fed into the pipe.

After the cable is installed the pipe is filled with oil. The oil is pumped through the pipe to cool as well as insulate the cable. Pumping cool oil through the pipe can greatly increase the capacity of the cable. The oil circulation system includes pumps, filters, and oil tanks. Sulphur hexaflouride (SF_6) is sometimes used to insulate underground transmission cables, but is not as popular as oil because it does not provide an increase in capacity as does cooled oil. The popularity of SF_6 is increasing because of its relative simplicity.

We see that all of the complexity associated with underground transmission lines cause them to be extremely expensive in comparison to overhead transmission lines. However, properly installed underground transmission lines are very reliable.

8.4.3 DC or AC Considerations

DC transmission systems are costly because of the converters at the line taps. DC lines have lower losses than ac lines because the skin effect is negligible, allowing the entire conductor cross-section to carry current, and the line reactance is zero for steady state loads (line reactance almost disappears after the line is charged). The fast acting controllers used in the dc to ac, and ac to dc, converters react very quickly to load change, so a dc line can improve the stability of a power system. DC lines also require less right of way than an ac line of the same voltage. At

present dc lines are used for long transmission lines to lower line loss, and for short tie lines between systems that are not in synchronism.



FIGURE 8.19 Fayette Power Project, Units I and II (courtesy of Lower Colorado River Authority).

8.5 HVDC TRANSMISSION

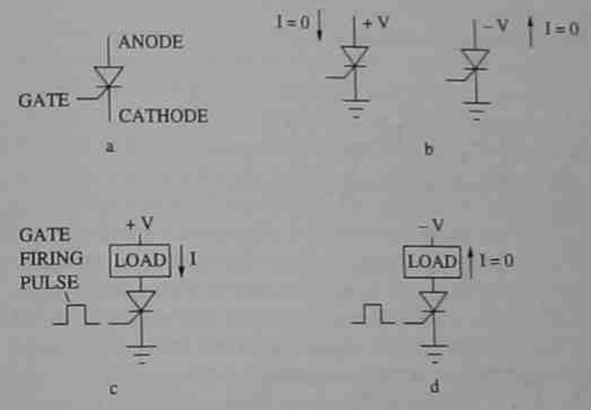
High voltage dc (HVDC) transmission, as noted in Chapter 1, originated in Germany in WWII. The first commercial line was installed in Sweden in 1954. The use of HVDC transmission lines has grown steadily ever since. The growth was accelerated when high voltage, high current (to 5 kV and 2000 A) silicon controlled rectifiers (SCR) were developed to replace the bulkier, less efficient mercury rectifiers that had been used until that time. The invention of effective dc air blast and SF_6 circuit breakers and lightning arresters also did much to encourage the use of HVDC transmission lines. Today there are over 40 HVDC lines throughout the world serving as high capacity long haul lines or assynchronous ties between systems.

Walter Coffer, one of the authors of this book, was in charge of constructing the Inga-Shaba extra high voltage direct current (EHVDC) converter stations and intertie line between Inga and Kolwezi in Zaire, Africa. The 1700 kM ± 500 kV line serves to transport up to 1120 MW from the hydroelectric generators in the Inga area to the mining district of Shaba. The project was completed in 1976.

8.5.1 Thyristor Valves and Bridges

An SCR is a four-layer device of the thyristor family. It blocks voltage both ways until it receives a gate signal of sufficient magnitude to turn it on while it is

forward biased (anode positive with respect to the cathode). A reverse biased SCR cannot be turned on. Once an SCR is on it then remains on until its anode current is held at a very low value for sufficient time for the device to turn off. In phase control, used by dc transmission converters, the negative line voltage (with respect to the cathode) is used to turn the SCR off. The time from the beginning of the positive, or forward biasing, cycle until the SCR is fired, expressed in degrees, is the retard angle, α. These items are illustrated in Figure 8.20.



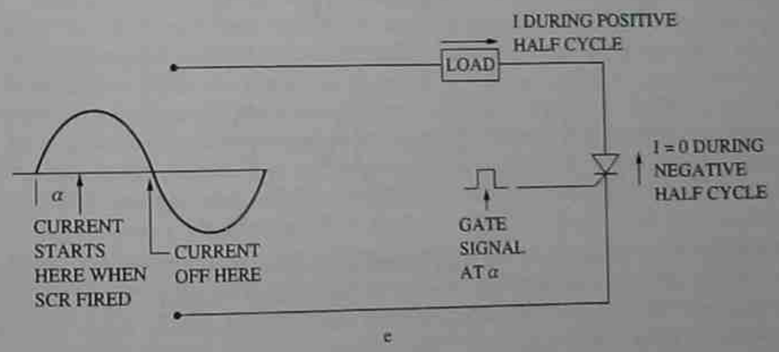


FIGURE 8.20 Silicon controlled rectifier (SCR) (a) Symbol (b) SCRs block current both ways when off (c) Current flows when forward biased SCR fired (d) Reverse biased SCR cannot fire (e) Negative line voltage turns SCR off

HVDC converters use three-phase full controlled bridges to convert ac to dc and vice versa. Conceptually they work like the single-phase full controlled bridge shown in Figure 8.21a. Essentially the bridge is a full wave rectifier that does not rectify until the SCRs are fired. They are fired in pairs, SCRs 1 and 3 control the line half cycle that is positive with respect to the reference line, and SCRs 2 and 4

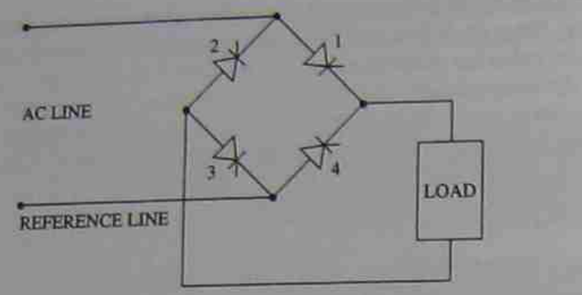


FIGURE 8.21 Phase control (a) Full control single-phase bridge (b) Load current (and voltage) waveform, resistive load, $\alpha = 90°$ (c) Load voltage waveform, highly inductive load, $\alpha = 45°$, dc current flow constant. Net load voltage is positive, power flow into load. (d) Load voltage waveform, highly inductive load, $\alpha = 135°$, dc current flow constant. Net load voltage negative, power flow to ac line from load.

control the ac half cycle that is negative with respect to the reference line. The output waveform for $\alpha = 90°$ and a resistive load is shown in Figure 8.21b. Notice that the voltage waveform is discontinuous because the load current stops flowing twice a cycle as the SCRs turn off. Two current pulses are delivered to the load each ac input cycle, so the circuit is called a two-pulse converter.

When a full controlled converter (all SCRs, no diodes) has a highly inductive load, the negative half cycle of the input ac does not turn the SCRs off because the

inductive load discharge from collapsing magnetic flux keeps the cathode more negative than the anode. This keeps the SCRs forward biased. Only firing the positively biased SCRs turns the SCRs with negative anodes off, by diverting their current to the supply. During all of this time the dc load current never changes direction. In other words, if SCRs 1 and 3 are on during the positive ac input half cycle they do not turn off as the input ac becomes negative with a highly inductive load. To turn SCRs 1 and 3 off we must turn SCRs 2 and 4 on so that the inductor current is diverted to the positive source, away from SCRs 1 and 3. Then SCRs 1 and 3 can turn off. The load voltage for this situation is shown in Figure 8.21c for an $\alpha = 45°$. Note that the net load voltage is positive. This is called the rectifying mode of operation. If the retard angle is advanced to 135° (the SCRs are fired later in the cycle) the net load voltage is negative because the inductive load spends more time discharging from contracting flux than charging (flux expanding) from being connected to the positive line. This is shown in Figure 8.21d. The negative voltage with no change in current direction results in negative power, which signifies power transfer from the dc to the ac side of the bridge. This is called the inverting mode of operation. Of course an inductive load soon discharges its energy, but if a dc supply is connected to the bridge in place of the load, with the negative dc connected at the cathode junction of SCRs 1 and 4, energy can be transferred to the ac line as long as the SCR retard angle is between 90° and 180°. Where can we find such a dc source? How about the dc side of a similar bridge operated so that the retard angle is more than 0° and less than 90°. Note that the same bridge can be used to turn ac to dc and dc to ac by simply varying the retard angle of the SCRs and the polarity of the dc.

A single SCR can block only a small portion of the voltage used for dc transmission. To block such high voltages a large number of SCRs are connected in series forming modules called valves. An SCR of the style used in dc converters and two heat sinked SCRs are shown in Figure 8.22. The series SCRs must have resistor-capacitor voltage dividers across them, as shown in Figure 8-23a, to assure that they each block an equal share of the applied voltage. The resistors assure that the voltage across each SCR is within acceptable limits, and the capacitors assure that transient voltages and voltage changes are shared evenly. If the converter current is higher than a single series SCR stack can handle (about 2000 A) then the SCRs must be paralleled. A current sharing reactor forces the current to divide equally between the SCRs, as shown in Figure 8.23b. If the current in the right hand SCR tries to increase, the voltage drop across the right hand winding of the reactor gets larger with the dot becoming more negative with respect to the common point. Transformer coupling causes the voltage on the anode of the left hand SCR to become more positive, causing the current in that SCR to increase. This process keeps the current shared evenly by the SCRs.

The bridges used in dc transmission system converters are six pulse, as shown in Figure 8.24a. These have three-phase input ac and deliver six pulses of dc current to the load every input cycle. The three-phase rectification delivers smoother dc than single phase. The firing sequence of the bridge SCRs is shown in Figure 8.24b. Each SCR is fired only during the portion of the ac cycle in which it is

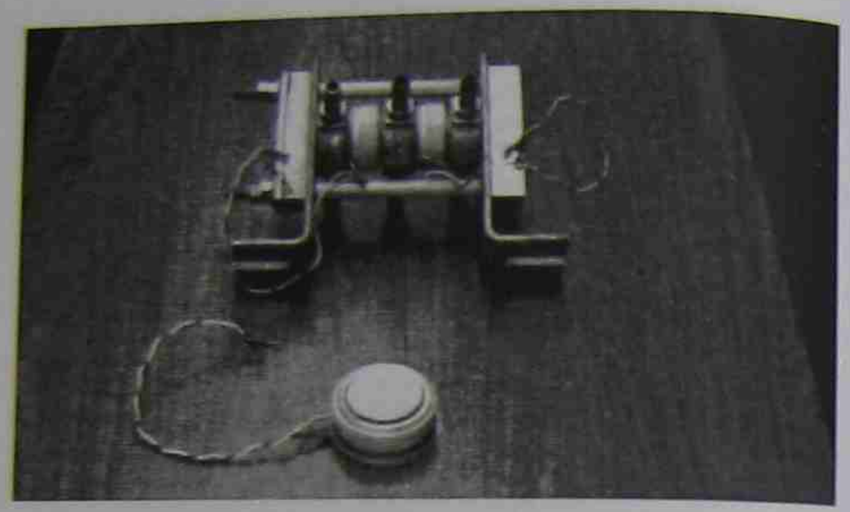


FIGURE 8.22 Converter valve: SCR (bottom) and two SCRs in a water cooled heat sink (top).

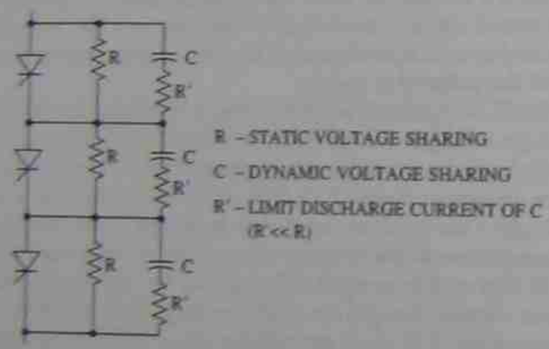
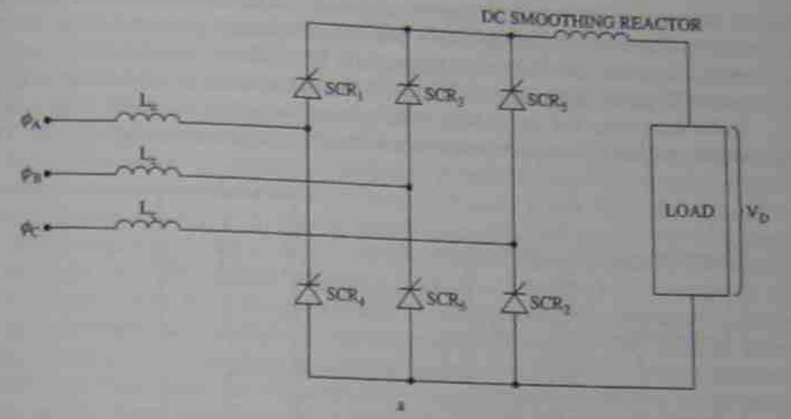
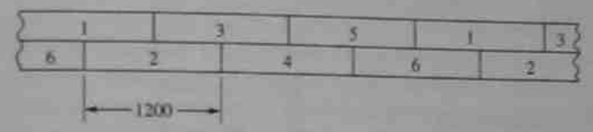


FIGURE 8.23 SCR series and parallel operation (a) Series, forced voltage sharing (b) Parallel, forced current sharing





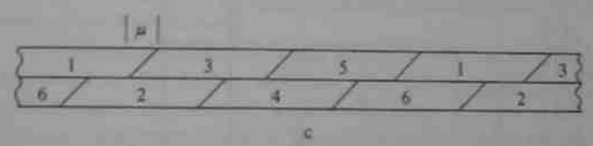
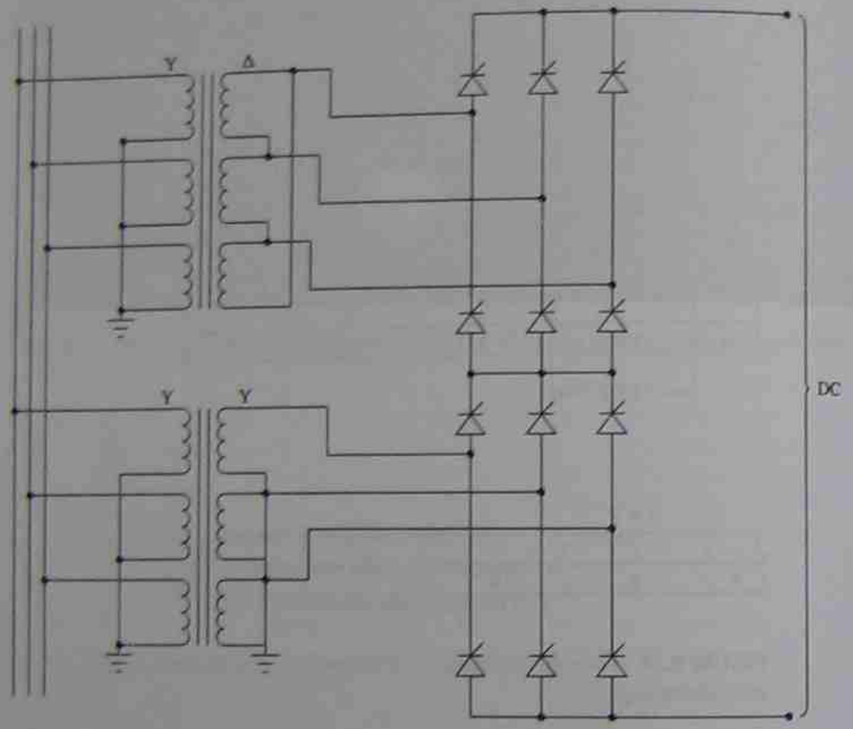


FIGURE 8.24 Six-pulse full control SCR bridge (a) Circuit (b) Firing order and (c) Overlap angle, μ

forward biased. The overlap of the three phase voltages means that any one SCR is forward biased between 30° and 150° of a half cycle. If the bridge retard angle is between 30° and 90° the bridge is rectifying and power is delivered from the ac to the dc side of the bridge. If the retard angle is between 90° and 150° and the voltage is reversed, the bridge is inverting, and power is delivered from the dc to the ac side of the bridge.

When SCRs are turned on, the current does not switch from the one SCR set to another instantaneously. That means that for a short time both the SCRs turning on and the SCRs turning off are conducting current while switching. This time is called the overlap angle, μ, and it is illustrated in Figure 8.24c. Inductors are used to prevent excessive current change during the overlap angle. These inductors are called commutating (when used with SCRs this term means turn off) inductors. They are inductors L_c in Figure 8.24a.

Better, smoother dc with fewer harmonics can be obtained from a 12-pulse converter. The switching of the SCRs in a six-pulse bridge generates a lot of fifth, seventh, eleventh, and thirteenth harmonics. The fifth and seventh harmonics cancel in the 12-pulse converter. A 12-pulse converter is constructed by connecting a six-pulse converter fed by a delta transformer secondary in series with a six-pulse converter fed by a wye transformer secondary, as shown in Figure 8.25. The wye



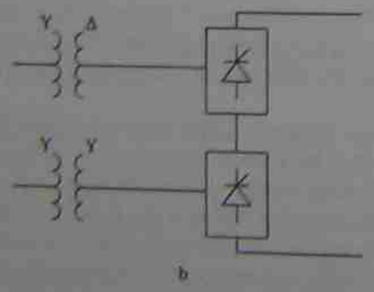


FIGURE 8.25 Twelve-pulse converter (a) Circuit and (b) One-line symbol

and delta secondaries are 30° out of phase causing 12 pulses of current to be delivered to the load each cycle. The transformers are usually wound so that each six pulse bridge has the same input line voltage. The converter output voltage is varied by adjusting the retard angle on the SCR firing control for small changes, and by transformer tap changers for large changes.

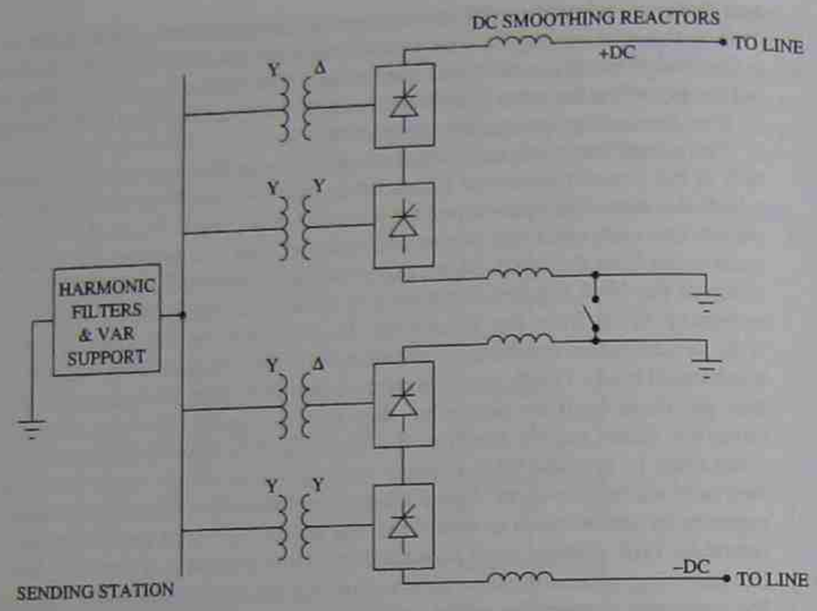
The dc converters require a lot of reactive power. Reactive power of about 40 to 60% of the power transferred is needed to provide energy for the harmonics from which the nonsinusoidal converter waveforms are made. Since the ac to dc converters can only send real power (dc contains only real power) the VAR support must come from the input. Shunt capacitor banks and the harmonic filters provide much of the VAR support, because it is usually not desirable to obtain all of the necessary VARs from the generators. In some stations the VARs are generated with synchronous condensers (synchronous motors run over excited with no mechanical load). The dc to ac converters cannot receive VARs from the dc line, so they get them from the ac system they supply. Again, capacitors along with the harmonic filters supply much of the VAR support. Synchronous condensers are often used to provide VAR support in systems for which the dc line is the sole source of electrical power. A receiving system that does not have the short circuit capacity to absorb three to five times the power delivered by the dc converter is unstable. VAR support must be added until this condition is met. In other words, the receiving system must be able to provide an ac pilot signal for the bridges in the converter to start. An initial oscillatory response or a synchronous condenser can provide this. Figure 8.26 shows a block diagram of a sending and receiving station showing the placement of the VAR support and the dc polarity relationship of the two stations.

Thyristors dissipate about 30 to 40 W/cm^2 of thyristor area. The heat must be removed or the valves will fail. The valves have finned metal heat sinks over which clean, dry, cool air is blown by fans. The warm air is then forced through a heat exchanger to cool it. SCRs can be water cooled but air is simpler for high voltage applications because of the insulation requirements.

All of the series and paralleled SCRs in a valve must be fired in unison to avoid over voltage and/or overcurrent conditions in some of the SCRs during turn on. Because of the high voltage involved the pulse shaping circuit for the SCR gate drive is powered from the voltage the SCR is blocking. The firing command signal is carried by light pipes to a light activated semiconductor on each firing circuit board. Older systems use Xenon flash tubes for the light firing signals, but more recent systems use cesium-mercury flash lamps, which send UV light to small light activated SCRs that then fire the larger SCRs.

Light guides in the form of fiber optic cables are used to carry valve status information back to the central monitoring and control circuitry. The fiber optic cables provide the isolation from high voltage for the control system.

The earth return shown in Figure 8.26 allows the system to be operated at reduced capacity when one line is down or a converter is malfunctioning.



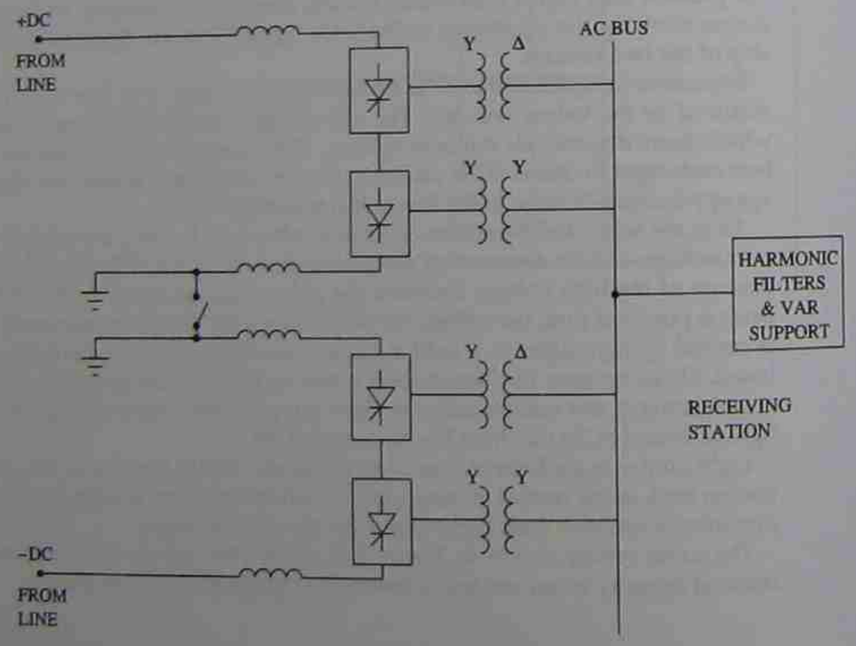


FIGURE 8.26 Converter stations

8.5.2 Converter Operation

Figure 8.26 shows the ac to dc converter, the dc line, and the dc to ac converter. The two converters look alike, only the operating modes and polarity of dc connection differ. If the receiving station has excess ac power from generators and the sending station needs power, the stations can reverse their function, under proper coordination and control, and the power flow on the dc line is reversed. This is a very useful capability for lines used as system ties. Long haul dc lines normally transmit power only one way.

Recall, the time expressed in degrees from the beginning of a half cycle that an SCR is on until it is fired is called the retard or firing angle (α). In a three-phase system the half cycle may be considered to begin 30° after the voltage zero crossing because the SCR is not forward biased until then. The time expressed in degrees from the SCR firing until the end of the cycle is called the conduction angle. If the converter is operating as an inverter, the conduction angle is called the extinction angle (γ). In normal operation the inverter retard angle is about 130°, and the rectifier retard angle is about 10° to 20°. The power transferred is

$$P_{DC} = \frac{(V_{D1} - V_{D2})}{R} V_{D2} \tag{8.20}$$

where, referring to Figure 8.24a

$$V_{D1} = \frac{3\sqrt{2}}{\pi} V_1 \cos\alpha - \frac{3\omega}{\pi} (L_{C1} I_D - I_D R_1 - 2V_T) N \tag{8.21}$$

$$V_{D2} = \frac{3\sqrt{2}}{\pi} V_2 \cos\gamma - \frac{3\omega}{\pi} (L_{C1} I_D - I_D R_2 - 2V_T) N \tag{8.22}$$

where

V_1 = converter 1 rms ac line voltage

V_2 = converter 2 rms ac line voltage

α = retard angle

γ = extinction angle

I_D = dc line current

V_D = dc converter voltage

R = dc resistance of converter circuit

L_C = commutation inductor reactance

N = number of six pulse bridges

The sending voltage can be changed using the retard angle or tap changing, as can the receiving station output voltage. The retard angle is used for small, fast adjustments, and the taps are used for larger voltage changes.

The normal operating modes are illustrated in Figure 8.27. The constant current mode shown in Figure 8.27a holds the current to that demanded by the receiving station by adjusting the sending converter (rectifier) voltage. Frequency relays capable of sensing minute fractions of a Hz change are often used to indicate the need for more receiving station power. As the receiving station ac frequency

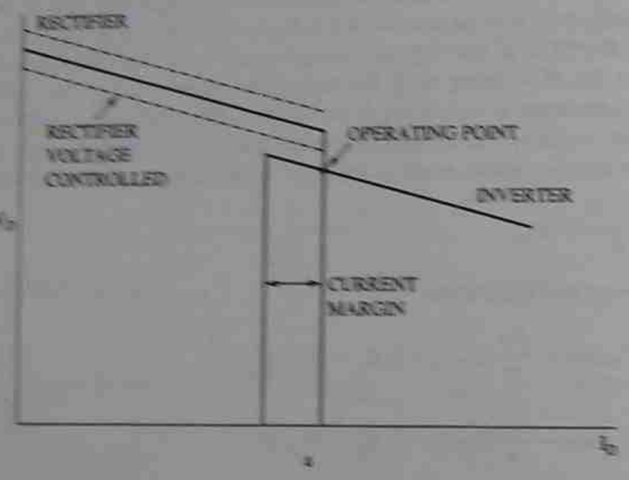


FIGURE 8.27 DC control (a) Constant current and (b) Constant power (current margin)

drops, more power is required. A communication system signals the sending station to send more power, and the sending converter raises the rectifier voltage in response. Notice the inverter and rectifier curves have some overlap to allow for rapid adjustment of power flow in response to changing loads.

Figure 8.27b illustrates the constant power mode, also called current margin control. In this mode the rectifier is held constant except for very large load condition changes, and the inverter changes in voltage and accepted current from the available margin to provide the power its ac load needs. Frequency relays are usually used to indicate power needs. An advantage of this mode of control is that it can continue with no communication to the sending station. For this reason it is used as a back-up mode for constant current control in the event communication between the sending and receiving stations is lost.

8.5.3 DC Converter Stations

The area requirements for a dc converter station are approximately 15 to 20 m^2/MW. A major portion of the station area requirements is for the harmonic filters and reactive power support. The valve hall usually requires only 1 to 2 m^2/MW. Where space is a major factor the use of SF_6 for insulation wherever possible has made it possible to build a station in as little as about 8 m^2/MW, at a higher cost.

Since the thyristor bridges generate harmonics the grounded metal clad buildings in which they are housed double as electromagnetic shielding. Proper spacing sets limits on the size of each part of a station. Insulating the dc side is more difficult than the ac side, and requires more space. Figure 8.28 shows a HVDC electrical layout, and Figure 8.29 shows a corresponding physical layout without synchronous condensers.

8.6 SUPERCONDUCTORS

Superconductivity was discovered in 1911 by Dutch scientist Heike Onnes. He discovered that mercury lost its resistance when cooled to 4°K (−269°C). Superconducting materials lose all resistance and exclude external magnetic fields when they become superconducting. The temperature at which they become superconducting is the transition (or critical) temperature T_c. At temperatures above T_c the resistance of the material is not zero. In like manner the magnetic field strength at which a superconducting material loses its superconductivity is the critical field. A useful superconductor has a high critical temperature and field. In the early 1960s it was discovered that niobium-titanium and some other compounds were superconducting at temperatures as high as 18°K, and a niobium-germanium alloy as high as 23.2°K. In 1973 alloys of yttrium, barium, and copper oxide exhibited superconductivity at temperatures as high as 28°K. All these must be cooled

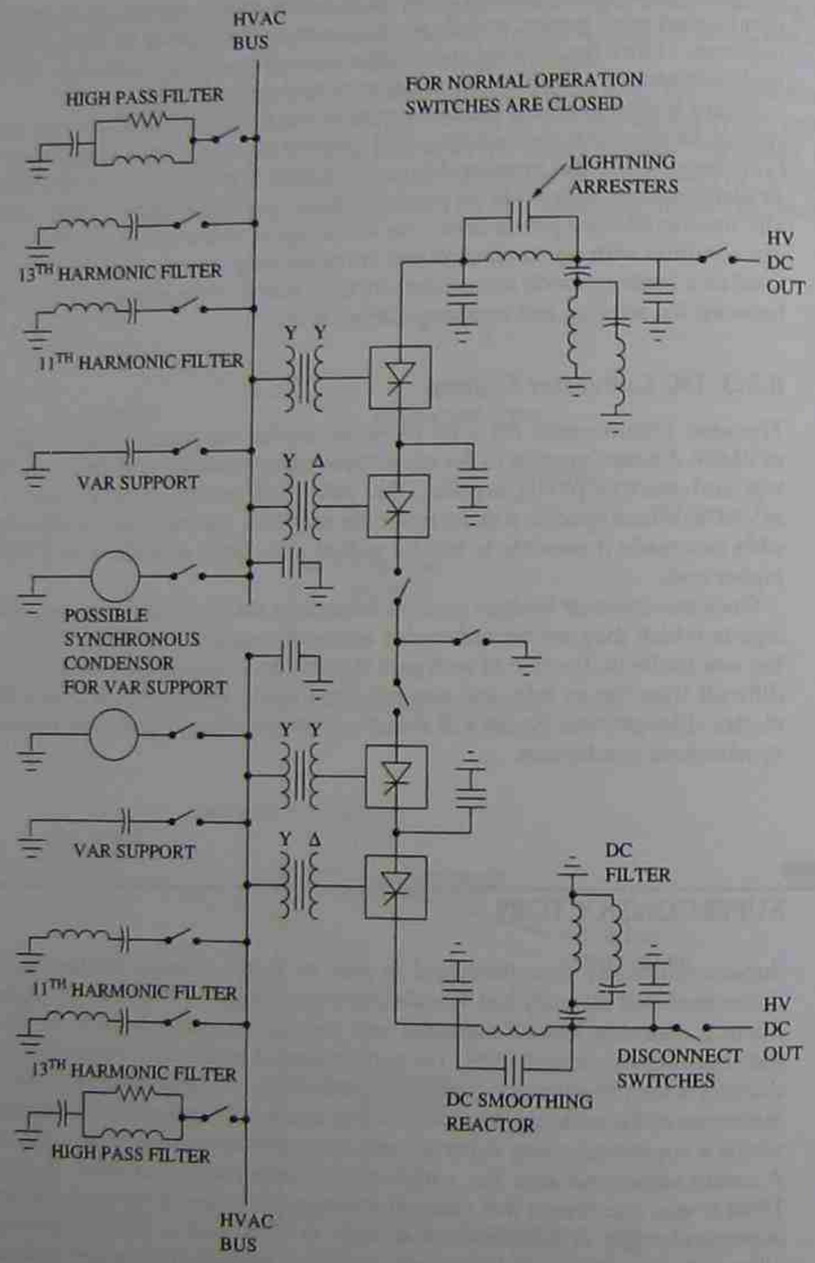


FIGURE 8.28 HVDC station electrical layout

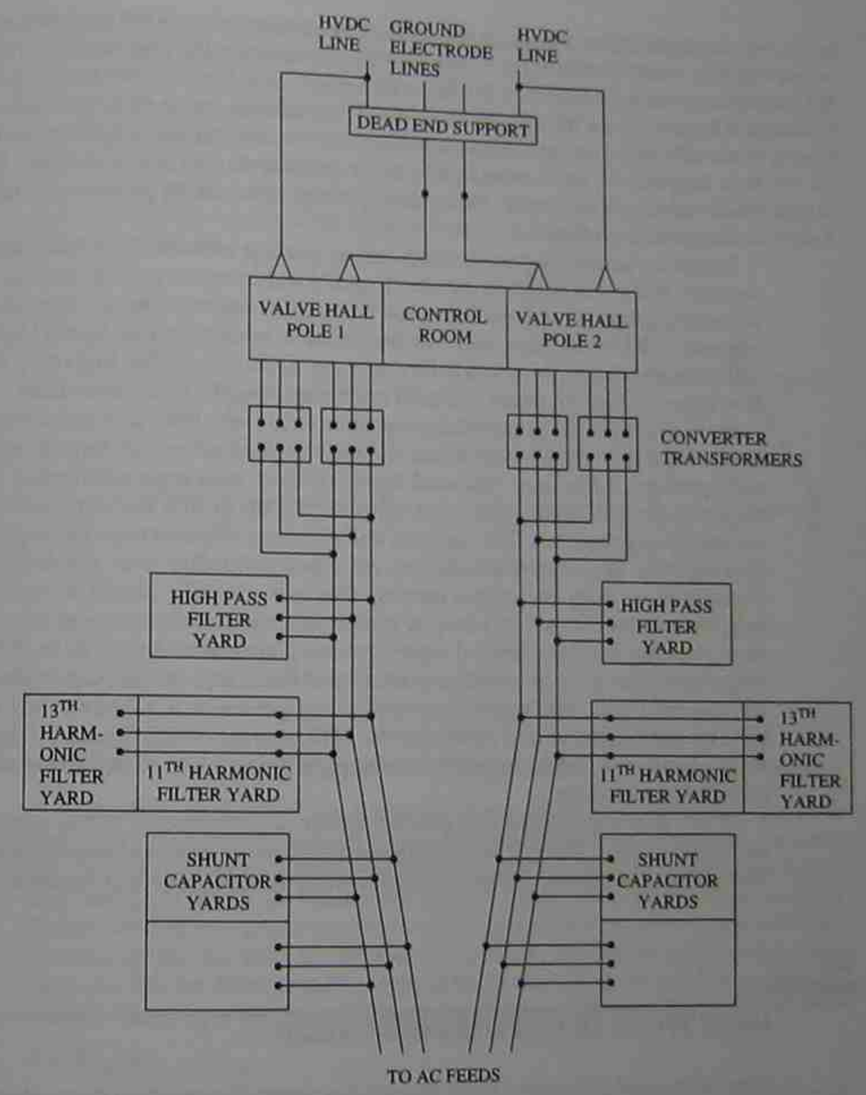


FIGURE 8.29 HVDC station physical layout

by liquid helium, which boils at 4.2°K. In 1986 workers at IBM Zurich discovered that certain ceramic compounds of lanthium, barium, and copper oxide would superconduct at 30°K under pressure. A race began to find compounds whose fit into the crystal lattice would replace (act like) pressure. In January of 1987 the

superconductivity transition temperature of a compound of yttrium, barium, and copper oxide was found to be about 90°K. This is above the temperature of liquid nitrogen, which boils at 77°K. Higher transition temperatures have been reported, but have not been reliably reproduced yet. The new superconducting compounds are brittle, but have been drawn into fine wire. The mechanical properties and current densities of the new materials show promise for electronic devices. Much work remains before they can be used for superconducting generators, motors, and transmission lines.

Superconducting magnets for high energy particle research have been around since the 1960s. The magnets are used to guide and focus the particle beams. Thin superconducting films have been used to measure minute voltage, current, and magnetic field levels. They have also been used to make very fast digital logic circuit elements that show promise for computer applications. The higher T_C of the new superconducting material should encourage research in all these areas.

Short experimental superconducting lines have been built and operated, but have not yet been shown economical. Superconducting generators have been built and operated. It has been estimated that generators with superconducting fields can be made 40% smaller, 1% more efficient, and up to 30% less expensive than conventional generators. The cost, size, and efficiency all come from the superconducting rotor. The magnetic field from the superconducting rotor windings is so strong that no magnetic core is needed, although a metallic shield is needed to help contain the coolant and keep ac electric and magnetic fields from the stator from reaching the rotor. Several superconducting generators in the 20 to 50 MVA range have been built by concerns in the United States and abroad. Generally they have worked well. The largest superconducting generator, a 300 MVA unit, to be built by Westinghouse and funded by the EPRI, was cancelled. Economic reasons were cited. Large generating units have recently become less attractive because of economic uncertainty.

At this time superconducting electrical power components are in the very early development stage. The rate at which the development of practical power components made from superconducting materials will develop is unpredictable at this time.

8.7 HIGH PHASE ORDER LINES (SIX-PHASE)*

High phase order lines are those designed to transmit more than three phases of electrical power, normally six, but nine- and twelve-phase transmission are possible. As shown in Figure 8.30 three-phase ac consists of three phasors offset by 120° and six-phase ac consists of six phasors offset by 60°. Similarly, nine-phase ac

*The high order phase information contained in this section was made available by New York State Electric & Gas Corporation. Credit and thanks is extended to all involved in the project, the Empire State Electric Energy Research Corp. (ESEERCO), the New York State Energy Research Development Authority (NYSERDA), the NY State Energy Office (NYSEO), the US Department of Energy (DOE), and the Electric Power Research Institute (EPRI).

consists of nine phasors offset by 40° and 12-phase ac consists of 12 phasors offset by 30°. Three-phase transmission was accepted as the standard for ac transmission for two reasons. The first is that three phases are the least number required for power flow that is constant with time, and the second is that electrical machine power does not increase as phases are increased beyond three. Electrical power transmission with more than three phases has some advantages, so a 93 kV demonstration line was built by New York State Electric & Gas Corporation between Goudey and Oakdale in New York to demonstrate the commercial feasibility of the concept.

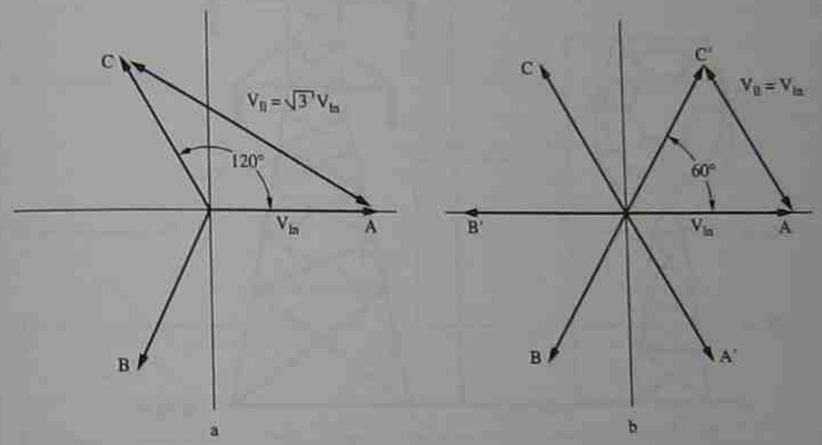


FIGURE 8.30 Polyphase voltage phasors (a) Three-phase phasor and (b) Six-phase phasor

Notice from Figure 8.30 that the ratio between line and phase voltage for three phases is $\sqrt{3}$ but for six phases it is one. The phase and line voltages are the same for six-phase systems. Thus for a phase to ground voltage of 79.6 kV the line to line voltage is 138 kV for three-phase systems and 79.6 kV for six-phase systems. In like manner, for a phase to ground voltage of 132.8 kV the line voltage is 230 kV for three-phase and 132.8 kV for six-phase systems, and for 199.2 kV the line voltages are 345 for three-phase ac and 199.2 kV for six-phase ac. The maximum power, assuming unity power factor, that a six phase line can handle is

$$P = 6\, I_{\text{line}} V_{\text{phase to neutral}}$$

and the maximum power that a double circuit three-phase line of the same line to neutral voltage is

$$P = 2(3\, I_{\text{line}} V_{\text{phase-to-neutral}})$$
$$= 6\, I_{\text{line}} V_{\text{phase to neutral}}$$

which is the same as a six-phase line. The lower line to line voltage of the six-phase line allows the support structures to be smaller than for a double circuit

three-phase line of the same phase to neutral voltage, as illustrated in Figure 8.31. Thus smaller six-phase right of ways can be used to transmit the same power as a double circuit three-phase line with the same phase to neutral voltage, assuming the same conductor current capacity.

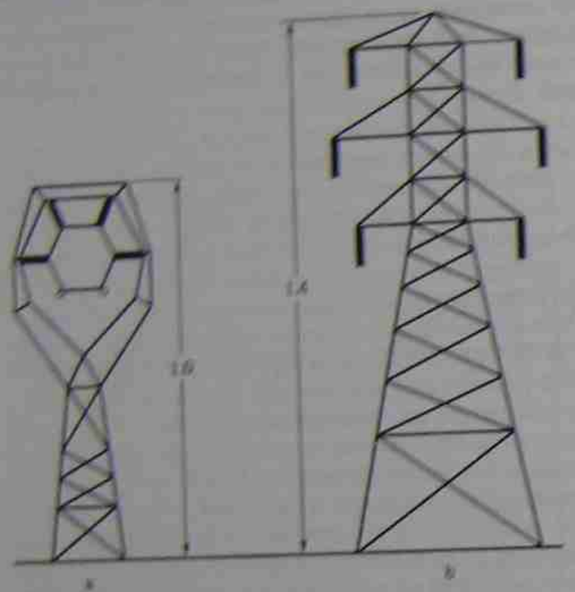


FIGURE 8.31 Relative tower heights (a) Six phase and (b) Double circuit three phase

The power capacity of a six-phase line with the same line voltage as a double circuit three-phase line is

$$P = 6 I_{line} \frac{\sqrt{3}}{2} V_{phase\ to\ neutral}$$

Thus, the capacity of a six-phase line is 173% that of a double circuit three-phase system with the same line to line voltage, and similar space requirements.

An additional advantage of six-phase transmission is that the magnetic fields are three to four times lower than a double circuit three-phase line at similar distances from the center line of the right of way. The corona loss should be lower on six-phase lines because the electric field gradients on the conductors are lower.

Six-phase transformer connections are more complex than three-phase, which drives the installation cost up. If six-phase transmission becomes common transformers will be designed and built for six-phase substation applications. Two conventional three-phase transformers can be connected to obtain six-phases. One transformer is connected delta-wye and the other delta-inverted wye or one wye-wye and the other wye-inverted wye. The secondary connections are then interspaced to obtain six-phase ac as shown in Figure 8.32.

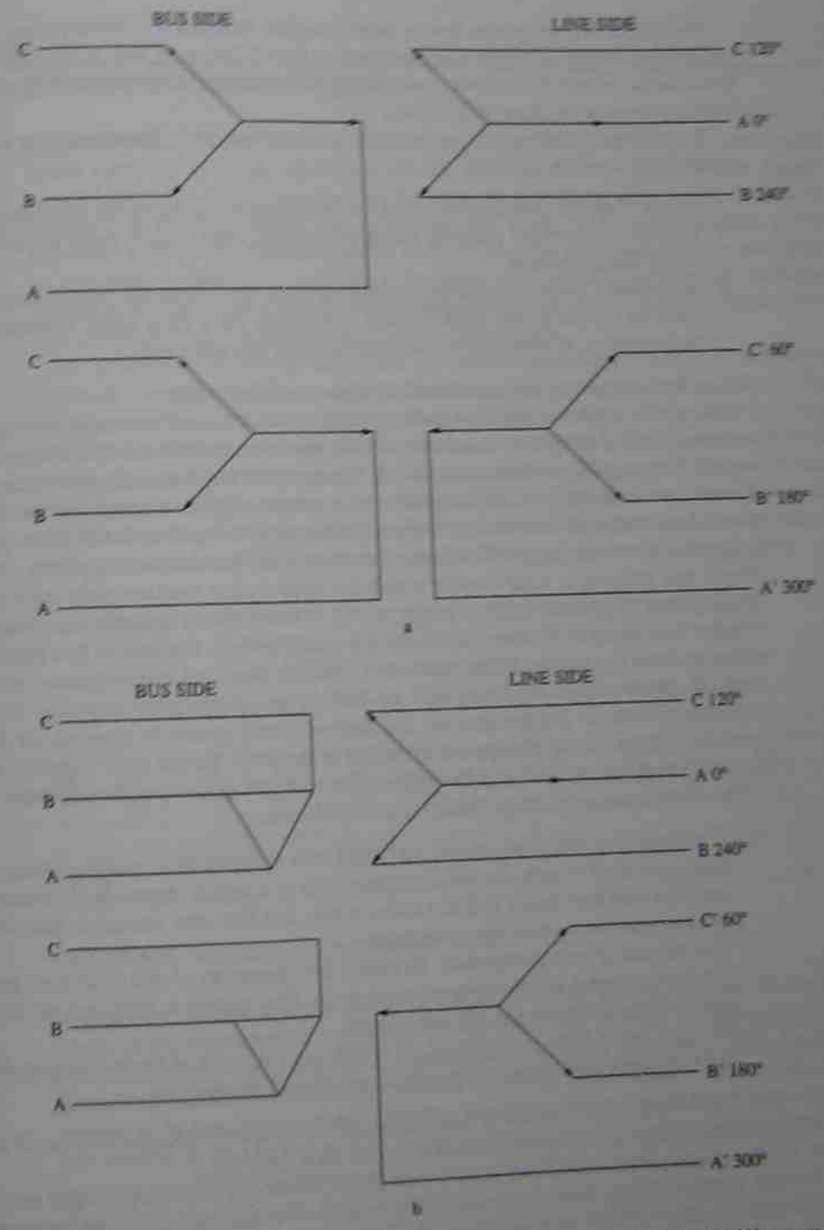


FIGURE 8.32 Six-phase connection from two three-phase transformers (a) Wye-wye wye-inverted wye (b) Delta-wye delta-inverted wye

Protection of a six-phase line is more complex than for a double circuit three-phase line. There are more combinations of line to line and line to neutral faults that can occur and the tools for calculating fault current are not as well developed for six-phase as for three-phase lines.

Three types of protection are used for the New York State Electric & Gas Corporation Goudey-Oakdale line:

1. Phase distance (impedance) relays with directional ground current relays.
2. Current differential relaying using pilot signal over a fiber optic based communication channel.
3. Segregated phase comparison relays for back up. These are relays that compare the phase at the ends of each conductor, via a fiber optic communications system, to determine if an internal fault has occurred.

The relays are microprocessor based for speed and flexibility.

Three trip schemes are reasonably possible. All can, and normally would, be reclosed after a delay for temporary faults, and then locked out if a second trip occurs. *Tripping all six phases* on a fault is the easiest to implement but provides the lowest line availability. *Alternate phase trip*, in which only the breaker for the three-phase segment that is faulted is tripped, either phases 1-3-5 or 2-4-6. Both phase group breakers are tripped if a fault occurs on a conductor of each phase group. *Single pole tripping* is a scheme in which the appropriate breaker pole trips for a single phase to ground fault. A single reclose is done after a suitable time and the breaker is tripped and locked out if the line is still faulted. For line to line faults on adjacent lines the faulted poles open, and a reclose then lock out sequence is initiated. If faults occur on lines 120° or 180° apart single pole tripping is not attempted. Instead the breaker on the faulted phase group is opened, or both breakers if both phase groups are involved in the fault. Single pole tripping provides the best line availability, but is the most complex and expensive scheme.

The relay arrangements possible for reliability are:

1. The *one out of two arrangement*, in which two independent relay systems are used, either of which can initiate a trip. This is a highly dependable arrangement in that few faults will not cause a trip, but not very secure in that transient events may cause spurious trips.
2. The *two out of two arrangement*, in which the operation of relays in two independent systems is necessary to cause a trip. This system is very secure, but is not as dependable as the one out of two.
3. The *two out of three arrangement*, in which any two out of three independent relay systems can cause a trip is both secure and dependable.

The New York State Electric & Gas Corporation Goudey-Oakdale line used one out of two with an independent third system for a back up.

Six-phase transmission may gain in popularity if difficulty in obtaining right of way and concern about electromagnetic fields from electric transmission lines increases. The Goudey-Oakdale line demonstrated that an existing double circuit three-phase line could be upgraded to a six-phase line that integrates into a three-phase system.

8.8 STATIC VAR COMPENSATION

Transmission lines are very costly so it is important to load them to as near maximum capacity as stable operation allows. Loading can be closer to the design capability of the line if the line can be damped quickly in response to transient events and the line losses can be minimized. Static VAR compensation using thyristor switching helps to provide VARs in a matter of milliseconds in response to transient events, thus providing damping, and helps hold terminal voltages constant by minimizing line losses (by improving load power factors) and reactive line drops for a given load/power factor combination.

In *switched VAR compensation* one or more reactors (capacitive or inductive depending on the need) are switched onto the line, as shown in Figure 8.33. The reactors can be switched in series or shunt with the line depending on the line type and needs, although shunt switching is shown in Figure 8.33. Stepping down the voltage to the reactors results in less expensive lower voltage switching and reactive elements. The harmonics of switched VAR compensation are low because the thyristors, connected in inverse parallel, can be switched when the line and reactor voltage is equal and the thyristors turn off as line current passes through zero.

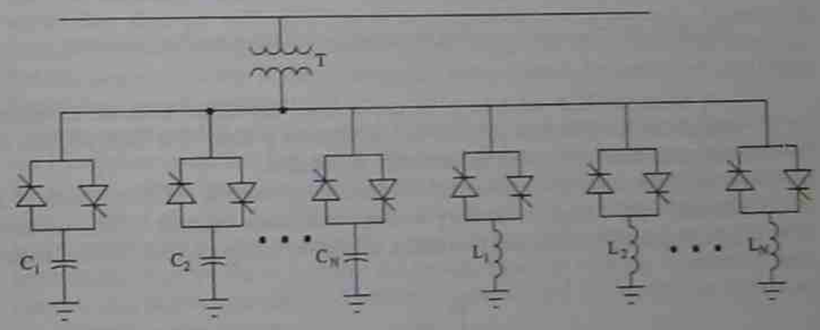


FIGURE 8.33 Multistep switched reactor

Thyristor controlled shunt reactance (TCR) is shown in Figure 8.34. The retard angle of the thyristors is controlled between 90° and 180° for maximum to minimum reactance resulting in a continuously varying reactance. The thyristor switching causes discontinuous current resulting in harmonics, but most of the energy is in the fundamental. Filtering is required to make TCR practical. A system similar to that in Figure 8.33, controlled by an automatic voltage regulator, can be used for TCR. The reactors are often connected in delta configuration on the secondary to eliminate third harmonics. Each delta branch has a reactor and inverse parallel connected thyristors. Gapped core inductors are commonly used to increase the range of linear control.

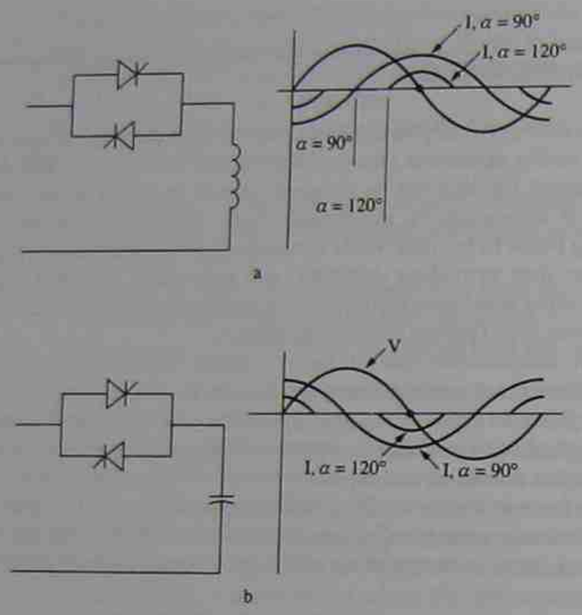


FIGURE 8.34 Thyristor controlled reactance (a) Inductive and (b) Capacitive

A common TCR scheme is to use a fixed capacitor with an inductive TCR branch in shunt with it (one set per secondary phase). The TCR adjusts the total reactance from capacitive to inductive as needed.

Thyristor-controlled high-impedance transformer control (TCT) consists of a transformer with a high secondary leakage reactance (almost 100%) controlled by inverse parallel connected thyristors, as shown in Figure 8.35. The controlled delta

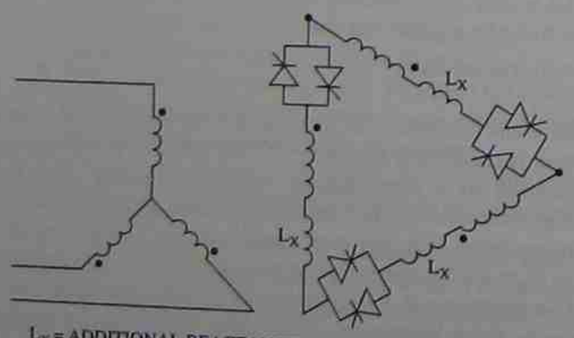


FIGURE 8.35 Thyristor controlled high impedance transformer

secondary eliminates third harmonic. Ungrounded wye secondary connected transformers also eliminate third harmonics but have the highest fifth harmonic amplitude. Transformers with controlled grounded wye secondaries and delta tertiary windings have the highest third but the lowest fifth and seventh harmonic amplitude. Additional reactance can be added to the secondaries if required. TCR and TCT can be used together for a wider range of control.

8.9 SUMMARY

The job of the electrical power transmission system is to transport large amounts of electrical power safely, economically, and reliably. The major components of power system operation are planning, control, and accounting. Digital computers are now used to control most real time power flow and routing. They are used in accounting and planning also.

Planning consists of load forecasting and all the steps necessary to secure needed financing, right of way, permits, and all equipment and construction required to meet the forecast load. Operation is the real time control of power flow and the ancillary functions such as maintenance, equipment utilization, and scheduling that go with the day-to-day operation of a system. Accounting includes not only billing customers for power usage and financial record keeping, but also keeping records of the performance factors that help in efficient and effective planning and operation.

Supervisory control and data acquisition (SCADA) systems are needed to oversee the system operation and gather the operating and performance data needed for power system operation. SCADA systems are complex communication systems coupled to data acquisition and remote control facilities throughout the power system. SCADA systems often use a variety of communication and control technologies and media to perform the critical function of tying together system function and status information. They can be envisioned as the nervous system of the electrical power system.

System stability refers to the ability of the system to provide power without oscillations in the system or unplanned shut downs. The ability to quickly dispatch power and VARs as load needs change is important to stability. High capacity lines that can handle the dispatched power also contribute to stability.

Normal ac transmission voltage levels are: subtransmission—69 kV and 138 kV; transmission—230 kV, 345 kV, 500 kV, and 765 kV. Common dc transmission voltages are ± 200 kV, ± 400 kV, and ± 500 to ± 550 kV.

Overhead transmission lines are the most common and the least costly to construct and maintain. Obtaining right of way for transmission lines is becoming more difficult. Underground transmission lines are much more expensive than overhead lines and are used only for relatively short line segments or in places that overhead lines cannot be built. Underground lines are constructed with

insulated lines inside a steel or bronze conduit. Circulating oil and increasingly SF_6 are used to insulate underground lines.

HVDC have become increasingly attractive for long lines because dc lines have lower loss than ac and no synchronization is needed between the power source and user. Additionally, the conversion equipment for HVDC has become more efficient and reliable.

Six-phase transmission is being investigated because less space is required to transmit the same power as a double circuit three-phase line. If the line to line voltages are the same the six-phase line can transmit more power than a double circuit three-phase line. Also, the magnetic field of a six-phase line is lower than an equivalent double circuit three-phase line.

Superconducting transmission lines, while feasible, are not economically attractive at the present time. The use of buried superconducting rings to store large amounts of power that can be switched onto a line in milliseconds promise to add the ability to stabilize lines to the extent that they can be loaded almost to capacity because the loading margin for stable operation is reduced.

8.10 QUESTIONS

1. State the function of the electrical power transmission system.
2. Explain briefly the three major components of utility operation.
3. Define ac generator regulation.
4. What is the function of a turbine governor?
5. Discounting line loss, under what power sharing condition do generating units operate together most economically?
6. Define ACE.
7. What is a power pool?
8. What is the most common configuration of generator control system in use today?
9. What is a SCADA and what does it do?
10. List and briefly explain the system security states.
11. Define steady state and transient stability.
12. Referring to Figure 8.10, let $V_1 = 345\ \text{kV} \angle\delta_1$ and $V_2 = 343\ \text{kV} \angle\delta_2$. If $Z = j90\ \Omega$ calculate $\delta_1 - \delta_2$ for power transfers of 100 MW and 500 MW.
13. Repeat problem 12 for $V_1 = 765\ \text{kV} \angle\delta_1$ and $V_2 = 760\ \text{kV} \angle\delta_2$.
14. In Figure 8.11 path A is a 345 kV line with pu $Z = j0.1$ and path B is a 765 kV line with pu $Z = j0.02$. The transformers each have pu $Z = j0.05$. 400 MW is being transferred from bus 1 to bus 2. Calculate the power transferred on each path if δ path A is the same as path B.
15. Explain a reasonable emergency operating strategy to avoid line overload if one line of Figure 8.12a are down.
16. List five steps that can be taken to improve steady state stability.

17. Define transfer impedance.
18. State the effect of generator rotational inertia in the event of a transient disturbance.
19. Why is it important to isolate faulted lines from a system as quickly as possible?
20. State the equal area criterion.
21. What is a swing curve?
22. What are subtransmission lines?
23. Discuss the economic trade off between minimum transmission line loss and construction costs.
24. What factors make underground transmission lines so much more expensive than overhead lines?
25. Why are underground transmission lines used in light of their great expense?
26. State the two major advantages of HVDC transmission over HVAC.
27. State the difference between the rectifying and inverting modes of a six pulse full controlled SCR bridge.
28. State the two major advantages of a twelve pulse converter over a six pulse.
29. List the two modes of control used for dc lines.
30. List four possible uses for superconductors in the electrical power industry.

CHAPTER 9

Transmission Line Parameters

Transmission lines consist of resistance, inductance, and capacitance. Thus a transmission line is an RLC circuit with the values of R, L, and C constrained by the function and geometry of the line. The job of the transmission line is to transport large amounts of electrical power from one location to another with the lowest loss that can be economically attained. The materials available, cost restraints set by available capital, terrain the line must pass through, right of way availability and cost, and other factors prevent transmission lines from being optimized for electrical characteristics alone. The designers of transmission lines must obtain the lowest loss line that can be built to carry the needed load over the desired path at a reasonable cost.

This chapter covers transmission line resistance, inductance, capacitance, and equivalent circuits.

9.1 TRANSMISSION LINE RESISTANCE

Recall that the resistance of a conductor can be expressed in equation form (see equation 2.3) as

$$R = \frac{\rho l}{A}$$

where

ρ = resistivity

l = conductor length

A = conductor area

Also recall that the direct current (dc) resistance is not equal to the alternating current (ac) resistance because of the skin effect.

The ac and dc resistance of most commonly used transmission line conductors have been calculated and are available in tables such as Table 9.1. Table 9.1 is for ACSR conductors, which are the most commonly used transmission line conductors. Similar tables are available from conductor manufacturers for other types of conductors and for cables. In Table 9.1 the dc and ac resistance is given at 20°C, which is considered the light load temperature of a transmission line. Because power losses along the line cause self heating within the line 50°C is considered the standard loaded temperature. The standard temperature for short circuit calculations is 80°C. By standard temperature we mean the temperature used when the actual operating temperature is not known. Computer programs are now available that estimate closely the actual operating temperature of the line if the weather conditions along the line and the load are known.

Notice that in Table 9.1 the conductors are referred to by code names that are the names of birds. The area of the conductors is given in circular mils (CM). A circular mil is the area of a circle with a diameter of one thousandth of an inch (1×10^{-3}). One circular mil is equal to 0.7854 square mil. The circular mil and thousand circular mils (MCM) are popular units of conductor area in power work. For this reason tables often give resistivity in Ω—CM/ft for convenient use. The aluminum area is given, excluding the steel, because virtually all of the current flows in the aluminum. The resistivity of steel is higher than that of aluminum, and the aluminum strands are effectively in parallel with the steel strands, so most of the current flows through the lowest resistance.

Table 9.1 also gives the stranding of the conductor in aluminum strands/steel strands. Recall the steel strands provide strength for the conductor and the aluminum strands conduct almost all of the current. The number of layers of aluminum strands is also given. Figure 9.1 illustrates the stranding of ACSR conductor. The conductor strands are twisted, which causes the length of all but the center strand to be greater than that of the composite conductor. Thus the stranded aluminum has a resistance that is 1 to 2% higher than that of a solid aluminum conductor of the same total area. The table also gives the outside diameter of the cable in inches.

The standard of conductivity ($1/\rho$) is annealed copper (silver is more conductive but is not a practical metal for transmission line conductor fabrication). Hard drawn copper, used for most copper conductors, has 97.3% of the conductivity of annealed copper because the drawing process causes imperfections in the grain structure of the metal. ACSR conductors have a conductivity 61% that of annealed copper conductors. The resistivities of Al and annealed Cu at 20°C are 17 Ω—CM/ft and 10.66 Ω—CM/ft respectively.

TABLE 9.1 Electrical characteristics of bare aluminum conductors steel-reinforced (ACSR)†

Code Word	Aluminum area, cmil	Stranding Al/St	Layers of aluminum	Outside diameter, in	Resistance			GMR	Reactance per conductor 1-ft spacing, 60 Hz	
					D_C, 20°C, Ω/1,000 ft	Ac, 60 Hz		D_s, ft	Inductive X_a, Ω/mi	Capacitive X'_a, MΩ·mi
						20°C, Ω/mi	50°C, Ω/mi			
Waxwing	266,800	18/1	2	0.609	0.0646	0.3488	0.3831	0.0198	0.476	0.1090
Partridge	266,800	26/7	2	0.642	0.0640	0.3452	0.3792	0.0217	0.465	0.1074
Ostrich	300,000	26/7	2	0.680	0.0569	0.3070	0.3372	0.0229	0.458	0.1057
Merlin	336,400	18/1	2	0.684	0.0512	0.2767	0.3037	0.0222	0.462	0.1055
Linnet	336,400	26/7	2	0.721	0.0507	0.2737	0.3006	0.0243	0.451	0.1040
Oriole	336,400	30/7	2	0.741	0.0504	0.2719	0.2987	0.0255	0.445	0.1032
Chickadee	397,500	18/1	2	0.743	0.0433	0.2342	0.2572	0.0241	0.452	0.1031
Ibis	387,500	26/7	2	0.783	0.0430	0.2323	0.2551	0.0264	0.441	0.1015
Pelican	477,000	18/1	2	0.814	0.0361	0.1957	0.2148	0.0264	0.441	0.1004
Flicker	477,000	24/7	2	0.846	0.0359	0.1943	0.2134	0.0284	0.432	0.0992
Hawk	477,000	26/7	2	0.858	0.0357	0.1931	0.2120	0.0289	0.430	0.0988
Hen	477,000	30/7	2	0.883	0.0355	0.1919	0.2107	0.0304	0.424	0.0980
Osprey	556,500	18/1	2	0.879	0.0309	0.1679	0.1843	0.0284	0.432	0.0981
Parakeet	556,500	24/7	2	0.914	0.0308	0.1669	0.1832	0.0306	0.423	0.0969
Dove	556,500	26/7	2	0.927	0.0307	0.1663	0.1826	0.0314	0.420	0.0965
Rook	636,000	24/7	2	0.977	0.0269	0.1461	0.1603	0.0327	0.415	0.0950
Grosbeak	636,000	26/7	2	0.990	0.0268	0.1454	0.1596	0.0335	0.412	0.0946
Drake	795,000	26/7	2	1.108	0.0215	0.1172	0.1284	0.0373	0.399	0.0912
Tern	795,000	45/7	3	1.063	0.0217	0.1188	0.1302	0.0352	0.406	0.0925
Rail	954,000	45/7	3	1.165	0.0181	0.0997	0.1092	0.0386	0.395	0.0897
Cardinal	954,000	54/7	3	1.196	0.0180	0.0988	0.1082	0.0402	0.390	0.0890
Ortolan	1,033,500	45/7	3	1.213	0.0167	0.0924	0.1011	0.0402	0.390	0.0885
Bluejay	1,113,000	45/7	3	1.259	0.0155	0.0861	0.0941	0.0415	0.386	0.0874
Finch	1,113,000	54/19	3	1.293	0.0155	0.0856	0.0937	0.0436	0.380	0.0866
Bittern	1,272,000	45/7	3	1.345	0.0136	0.0762	0.0832	0.0444	0.378	0.0855
Pheasant	1,272,000	54/19	3	1.382	0.0135	0.0751	0.0821	0.0466	0.372	0.0847
Bobolink	1,431,000	45/7	3	1.427	0.0121	0.0684	0.0746	0.0470	0.371	0.0837
Plover	1,431,000	54/19	3	1.465	0.0120	0.0673	0.0735	0.0494	0.365	0.0829
Lapwing	1,590,000	45/7	3	1.502	0.0109	0.0623	0.0678	0.0498	0.364	0.0822
Falcon	1,590,000	54/19	3	1.545	0.0108	0.0612	0.0667	0.0523	0.358	0.0814
Bluebird	2,156,000	84/19	4	1.762	0.0080	0.0476	0.0515	0.0586	0.344	0.0776

†Most used multilayer sizes.
‡Data, by permission, from Aluminum Association, Inc. "Aluminum Electrical Conductor Handbook," New York, September 1971.

The variation of resistance with temperature is nearly linear over the normal temperature range that transmission lines experience. At very low temperatures, near absolute zero, the change of resistance with temperature is no longer linear. By assuming that the change of resistance with temperature is linear and plotting

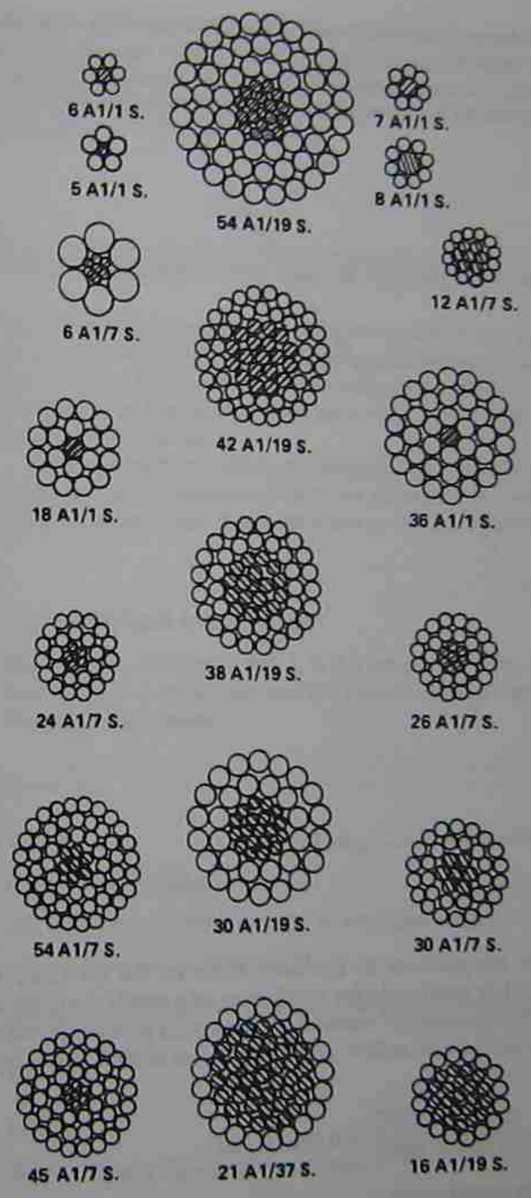


FIGURE 9.1 ACSR structure, 26/7 stranding, 2 Al layers (courtesy of the Aluminum Association's Aluminum Electrical Conductor Handbook [AECH]).

the mythical $R = 0$ temperature, as shown in Figure 9.2 provides a useful constant ($C_{R=0}$) that can be used to calculate resistance at a second temperature if the resistance at one temperature and the constant are known. Equation 9.1 gives the relationship. $C_{R=0} = 234.5$ for hard drawn Cu, and 236 for hard drawn Al.

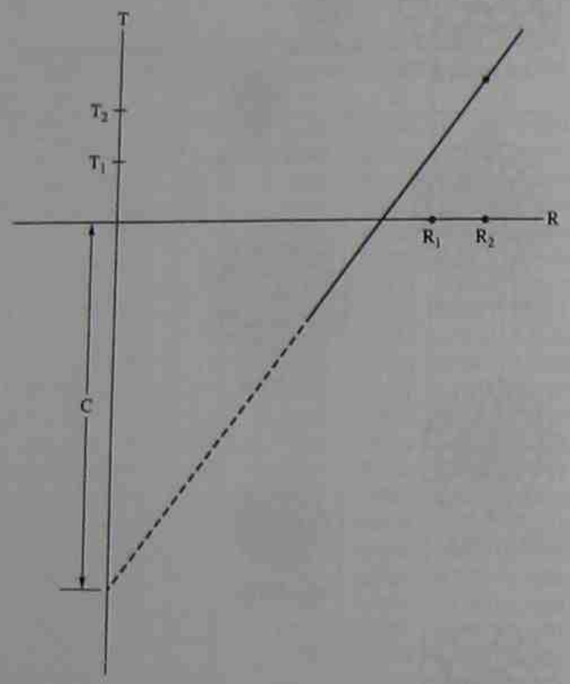


FIGURE 9.2 Source of the constant, $C_{R=0}$, for Equation 9.1

$$\frac{R_2}{R_1} = \frac{C_{R=0} + T_2}{C_{R=0} + T_1} \tag{9.1}$$

Where T_1 and T_2 are temperature in the same units as the constant, usually degrees C. Equation 9.1 is good only for conductors of a single material such as AAC, but not ACSR. For example, 37 strand hard drawn Cu wire of 700 MCM area has a tested value of 0.0871 Ω/mi at 25°C and 0.0947 Ω/mi at 50°C. From Equation 9.1 we find

$$R_{ac(50°C)} = 0.0871\ \Omega/\text{mi}\ \frac{(234.5 + 50)°\text{C}}{(234.5 + 25)°\text{C}} = 0.0955\ \Omega/\text{mi}$$

This is very close to the tested value.

Drake is a very commonly used transmission conductor. From Table 9.1 we find for Drake: Al area = 795 MCM; stranding is 26/7 (Al/st) with 2 layers of Al strands; outside diameter (OD) = 1.108 in; R_{DC} = 0.0215 Ω/1000 ft (or 0.1135 Ω/mi); R_{ac} = 0.1172 Ω/mi at 20°C; and R_{ac} = 0.1284 Ω/mi at 50°C. It is interesting to note that at 20°C R_{ac}/R_{DC} = 1.0325, which means that the increase in resistance from the skin effect is 3.25%. The increase in resistance from skin effect gets larger as conductor diameter increases.

9.2 TRANSMISSION LINE INDUCTIVE REACTANCE

To obtain the impedance of a line we need both the resistance and inductive reactance. The magnetic flux produced by the current in a conductor cuts the conductor itself as well as the adjacent conductors. Thus to calculate the series X_L of a transmission line both the self and mutual (with other conductors) flux coupling must be considered.

When possible we obtain the inductive reactance of a transmission line conductor from the tables. However, there are situations in which the tables do not provide accurate results and it is instructive to see the equations used to obtain the tables.

9.2.1 Mutual Inductance

Recall from Chapter 2 that L is the proportionality constant between the voltage induced on a conductor and the current change that caused the flux change that induced the voltage.

$$e = L\frac{dI}{dt} \tag{2.4}$$

where

e = induced voltage

dI/dt = time varying current in amperes/second

L = inductance in Henries (H)

Recall also that the voltage induced on a conductor in a magnetic field is

$$e = \frac{d\Phi}{dt} \tag{4.2}$$

where

Φ = magnetic flux in Webers (Wb)

t = time in seconds

If the flux is given in Weber turns (Wbt) = $N\Phi$ then

$$e = N\frac{d\Phi}{dt} \tag{9.2}$$

Equating equations 9.2 and 2.4 results in

$$L\frac{dI}{dt} = N\frac{d\Phi}{dt}$$

so that

$$L = \left(\frac{d\Phi}{dt}\right)\left(\frac{dt}{dI}\right)N$$

where L is in Henries, and if the permeability is held constant for all flux levels, as in air then

$$L = \frac{N\Phi}{I} \tag{9.3}$$

This results in an expression for flux linkages of

$$N\Phi = Li \qquad \text{Wbt} \tag{9.4}$$

where i and Φ are instantaneous values.
If I is rms current and $N\Phi = \psi$, phasor flux linkages in Wbt,

$$\psi = LI \qquad \text{wbt} \tag{9.5}$$

and

$$L = \psi/I\,\text{H} \tag{9.6}$$

The mutual inductance (M) between two conductors is the flux linkage in conductor 1 caused by the current in conductor 2 (ψ_{12})

$$M_{12} = \psi_{12}/I \qquad \text{H} \tag{9.7}$$

The mutual reactance is $X_{M12} = j2\pi f\ M_{12}$, so the voltage drop on conductor 1 from the flux produced by conductor 2 is

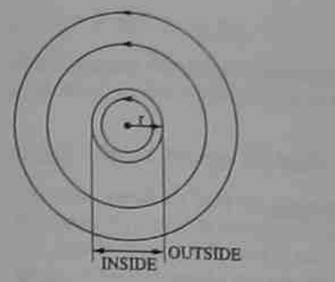
$$V_j = j\,\omega\,M_{12}\,I_2 \tag{9.8}$$

$$= j\omega_{12}\,\psi_{12} \tag{9.10}$$

The mutual inductance between power line conductors is a large part of the total line inductance.

9.2.2 Conductor Self Inductance

The self inductance of the conductor is caused by the flux generated by current within the conductor interacting with charges within the conductor. Figure 9.3a shows the flux distribution inside and outside of a conductor caused by current



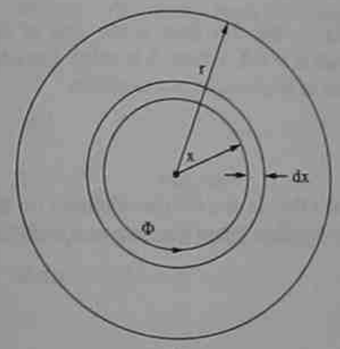


FIGURE 9.3 Magnetic flux lines in a conductor (a) Distribution, I out of page (e^- into page) (b) Figure for developing Equation 9.11

within the conductor. We will now develop an equation for the self inductance per unit (pu) length of a conductor.

From basic magnetics we know that the magnetomotive force around any closed path is equal to the current enclosed by the path. Thus at a distance x from the center of the conductor in Figure 9.3b the current enclosed (I_x) is

$$I_x = \left(\frac{\pi x^2}{\pi r^2}\right)I \tag{9.11}$$

where

I = total conductor current

r = radius of conductor

Additionally we know that the magnetomotive force (H) is equal to the magnetic field intensity times the distance over which it is applied. For the circle at x, if $H_x = H$ at distance x

$$H_x(2\pi x) = I_x \tag{9.12}$$

Equating equations 9.11 and 9.12 we find

$$2\pi x H_x = \left(\frac{\pi x^2}{\pi r^2}\right) I$$

$$H_x = \left(\frac{x}{2\pi r^2}\right) I \qquad \text{in Ampereturns per meter}$$

The flux density $B = \mu H$ so

$$B_x = \mu H_x = \frac{\mu x I}{2\pi r^2}$$

In the tube dx the flux $d\phi$ perpendicular to the flux lines is the area of the tube cross section times the flux density (recall $\phi = BA$, where A is area). For an infinitesimal dx the area is dx times the length of interest, in our case 1 m.

$$d\phi = \frac{\mu x I}{2\pi r^2} dx \qquad \text{Wb/m}$$

$d\psi$ is the linkages pu length caused by the flux in the tubular element on the area outside the tubular element. It is equal to the flux times the current (i_x) enclosed by the ring dx.

$$d\psi = d\phi i_x = \frac{\mu I x^3}{2\pi r^4} dx$$

Solving for ψ_i, the internal flux linkages, by integrating (summing) from $x = 0$ to $x = r$ yields

$$\psi_i = \int_0^r \frac{\mu I x^3}{2\pi r^4} dx$$

$$= \frac{\mu I x^4}{2\pi r^4}\Big|_0^r$$

$$= \frac{\mu I}{8\pi} \tag{9.13}$$

which is the internal flux from the internal current.

The permeability (μ) within Cu or Al (but not within the steel reinforcing strands of ACSR) is almost equal to the permeability of a vacuum, $4\pi \times 10^{-7}$ Wb/m. For AAC or Cu

$$\psi_i = \frac{I}{2} \times 10^{-7} \qquad \text{Wbt/m} \tag{9.14}$$

and

$$L = 0.5 \times 10^{-7} \qquad \text{H/m} \tag{9.15}$$

if the current density is uniform. This is approximately true for ACSR also because almost all of the current flows in the Al.

9.2.3 Flux Linkage Outside a Conductor

We now need to find an expression for the inductance caused by flux linkages between two points external to a current carrying conductor, as shown in Figure 9.4. The two points P_1 and P_2 are at distances D_1 and D_2 from the conductor respectively. The flux paths are represented as concentric circles around the conductor. All of the flux between P_1 and P_2 lie within circles through P_1 and P_2 in Figure 9.4. In a manner almost identical to that of the last section we find that H_x in a tubular section a distance x from the conductor is $2\pi x H_x = I$, thus

$$H_x = \frac{I}{2\pi x}$$

and

$$B_x = \frac{\mu I}{2\pi x} \qquad \text{Wb/m}^2$$

The flux, $d\phi$, in a small element dx at distance X is

$$B\,dA = B\,dx\,\pi X$$

so

$$d\phi = \frac{\mu I}{2\pi x} dx \qquad \text{Wb/m}$$

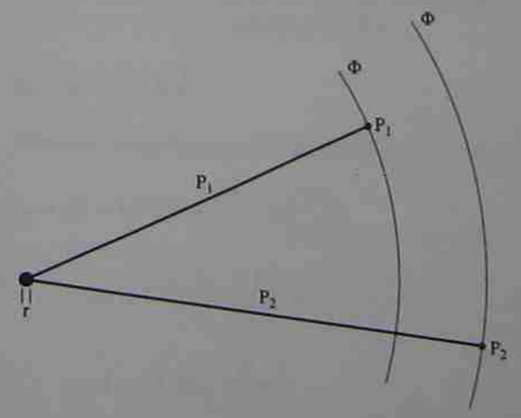


FIGURE 9.4 Flux outside a conductor

Note that $d\phi = d\psi$ per meter since flux external to the conductor links all of the current in the conductor (that is what caused the flux to begin with). As in section 9.2.2 we calculate the flux between P_1 and P_2 by integrating $d\phi$ from D_1 to D_2.

$$\psi_{12} = \int_{D_1}^{D_2} \frac{\mu I}{2\pi x}\, dx$$

$$= \frac{\mu I}{2\pi} \ln x \Big|_{D_1}^{D_2}$$

$$= \frac{\mu I}{2\pi} (\ln D_2 - \ln D_1)$$

$$= \frac{\mu I}{2\pi} \ln\left(\frac{D_2}{D_1}\right) \tag{9.16}$$

which for $\mu_R = 1$, (recall $\mu = 4\pi \times 10^{-7}$ H/m)

$$\psi_{12} = (2 \times 10^{-7})\, I \ln\left(\frac{D_2}{D_1}\right) \quad \text{Wb}\frac{\text{t}}{\text{m}} \tag{9.17}$$

Thus L from flux between P_1 and P_2 is

$$L_{12} = (2 \times 10^{-7}) \ln\left(\frac{D_2}{D_1}\right) \quad \text{H/m} \tag{9.18}$$

9.2.4 Inductance Between Two Single-phase Conductors

Note in Figure 9.5 that a line of flux produced by current in conductor 1 that is at a distance greater than $D + r_2$ from conductor 2 cannot link conductor 2. Flux at a distance less than $D + r_2$ from conductor 1 will link with conductor 2. The fraction

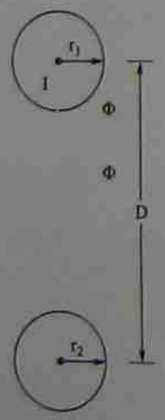


FIGURE 9.5 Two conductors, magnetic field from current from one conductor

of flux from conductor 1 that links with conductor 2 current varies from 1 to 0 between $D - r_2$ and $D + r_2$. If $D >> r$ the fractional flux linkage can be considered 1 from $D - r_2$ and 0 from D to $D + r_2$ with very little error. If we let $D_2 = D$ and $D_1 = r$ for conductor 1 of Figure 9.5 and use Equation 9.18 we obtain

$L_{1\,EXT} = (2 \times 10^{-7}) \ln(D/r_1)$ H/m

and from Equation 9.15

$L_{1\,INT} = (0.5 \times 10^{-7})$ H/m

Thus L_1 total = $L_{1\,INT} + L_{1\,EXT}$ giving

$$L_1 = (0.5 + 2\ln(D/r_1) \times 10^{-7} \quad \text{H/m} \tag{9.19}$$

A favored form of Equation 9.19 is found as follows

$$L_1 = (2 \times 10^{-7})[1/4 + \ln\left(\frac{d}{r_1}\right)]$$

$$L_1 = (2 \times 10^{-7})[\ln e^{1/4} + \ln\left(\frac{d}{r_1}\right)]$$

but $1/4 = \ln(e^{1/4})$, so

$$= (2 \times 10^{-7}) \ln\left(\frac{D}{r_1 e^{-1/4}}\right)$$

$$= (2 \times 10^{-7}) \ln\left(\frac{D}{r_1'}\right) \tag{9.20}$$

where $r_1' = r_1 e^{-1/4} = 0.7788 r_1$. Equation 9.20 has no self inductance term, but $r' = 0.7788r$ compensates for the self inductance.

Now we will use Equation 9.20 for L_2

$$L_2 = (2 \times 10^{-7}) \ln\left(\frac{D}{r_2'}\right)$$

The total inductance is found from $L_T = L_1 + L_2$ yielding

$$L_T = (2 \times 10^{-7})\, [\ln\left(\frac{D}{r_1'}\right) + \ln\left(\frac{D}{r_2'}\right)]$$

$$= (4 \times 10^{-7}) \frac{1}{2} \ln\left(\frac{D^2}{r_1' r_2'}\right)$$

$$= (4 \times 10^{-7}) \ln\left(\frac{D}{\sqrt{r_1' r_2'}}\right) \tag{9.21}$$

which for $r_1 = r_2$ reduces to

$$L_T = (4 \times 10^{-7})\ln\left(\frac{D}{r_1'}\right) \tag{9.22}$$

9.2.5 Geometric Mean Distance (GMD)

Two single phase multi–filament lines with equal current shares ($I = I_T/n$ and $I = I_T/m$ in conductors A and B respectively) are shown in Figure 9.6. The GMD, written as D_m in equations, is the distance between the geometric centers of the two lines. The following equation defines the GMD.

$$D_m = \sqrt[mn]{(D_{aa'} D_{ab'} C_{ac'} \ldots D_{am})(D_{ba'} D_{bb'} C_{bc'} \ldots D_{bm}) \ldots (D_{na'} D_{nb'} C_{nc'} \ldots D_{nm})} \tag{9.23}$$

where

$D_{aa'}$ = distance between filament a in conductor A and filament a′ in conductor B.

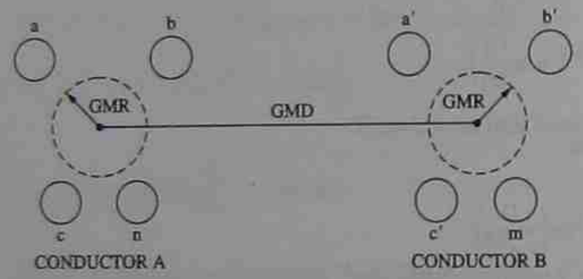


FIGURE 9.6 Two multifilament conductors used for single-phase line

Note that the multiplication is continued until the distances between all filaments are used in the product. Thus the GMD is a root-mean-power distance.

The geometric mean radius (GMR), written as D_S in equations (the s is for self), is the effective or root-mean-power radius of a multi filament conductor. The equation for the GMR is

$$D_s = \sqrt[n^2]{(D_{aa} D_{ab} C_{ac} \ldots D_{an})(D_{ba} D_{bb} C_{bc} \ldots D_{bn}) \ldots (D_{na} D_{nb} C_{nc} \ldots D_{nn})} \tag{9.24}$$

where

$D_{aa} = r_a'$, $D_{bb} = r_b'$, $D_{cc} = r_c'$, and $D_{nn} = r_n'$

D_{ab} = distance from filament a center to filament b center

Note that Equation 9.20 can be modified to calculate the inductance of one filament of one conductor. For example the inductance of filament a is

$$L_a = \frac{\psi}{I/n} = (2n \times 10^{-7})\ln\left(\frac{D_m}{D_s}\right) \quad \text{H/m} \tag{9.25}$$

The inductance of each filament can be written in the same way. The total inductance of conductor A is the sum of the inductances of the filaments in conductor A.

The inductances may not all be the same, even with the same current in each filament, because the spacing of each filament with respect to the rest of the filaments may not be the same. The average inductance can be used to compensate for this.

The inductance of each filament is effectively in parallel with that of the other filaments in the conductor because each has the same source and destination. If all filaments in a conductor have the same inductance, or if the average inductance is used

$$L_{ave} = (L_a + L_b + \ldots + L_n)/n$$

Now L_A can be written as

$$L_A = \frac{L_{ave}}{n} \tag{9.26}$$

so, in the form of Equation 9.21 and $L_T = L_A + L_B$ for two conductors A and B

$$L_T = (4 \times 10^{-7})\ln\left(\frac{D_m}{\sqrt{D_{sA} D_{sB}}}\right) \quad \text{H/m} \tag{9.27}$$

An example with very large filament spacing, to make the example both easy to see and easy to work, follows.

Example 9.1:

For the two conductors in Figure 9.7a calculate GMD, GMR, L_A, L_B, and L_T. Conductor A consists of three 0.4 cm diameter filaments and B of two 0.8 cm diameter filaments. The filaments share the conductor current evenly.

Solution:

First we calculate the m × n root of m × n distances to obtain the GMD.

$$D_m = \sqrt[6]{D_{aa'} D_{ab'} D_{ba'} D_{bb'} D_{ca'} D_{cb'}}$$

where

$D_{aa'} = D_{bb'} = 12$ m

$D_{ab'} = C_{ba'} = D_{cb'} = \sqrt{12^2\ \text{m} + 6^2\ \text{m}} = 13.416$ m

$D_{ca'} = \sqrt{12^2 + 12^2} = 16.97$ m

yielding

$$D_m = \sqrt[6]{(12\ \text{m})(13.416\ \text{m})(13.416\ \text{m})(12\ \text{m})(16.97\ \text{m})(13.416\ \text{m})} = 13.443\ \text{m}$$

Now we calculate the GMR of conductor A, the 9th root of 9 distances, from Equation 9.24.

$$D_{sA} = \sqrt[9]{D_{aa} D_{ab} D_{ac} D_{ba} D_{bb} D_{bc} D_{ca} D_{cb} D_{cc}}$$

where

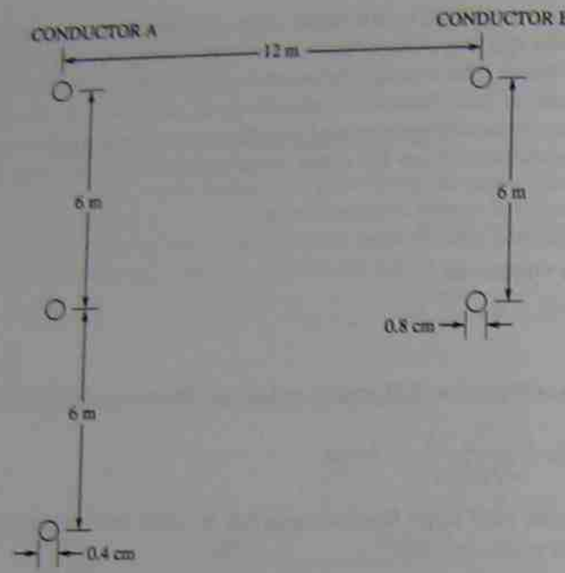


FIGURE 9.7 Two single-phase conductors (a) Physical layout and (b) Equivalent geometry

$$D_{aa} = D_{bb} = D_{cc} = 0.2\text{ cm}\, e^{-0.25} = 0.2\,(0.7788)$$
$$= 0.15576\text{ cm} = 1.5576 \times 10^{-3}\text{ m}$$
$$D_{ab} = D_{bc} = D_{bc} = D_{cb} = 6\text{ m}$$
$$D_{ac} = D_{ca} = 12\text{ m}$$

resulting in

$$D_{sA} = \sqrt[9]{(1.5576 \times 10^{-3})^3 (6\text{m})^4 (12\text{m})^2} = 0.446\text{m}$$

Similarly for conductor B

$$D_{sB} = \sqrt[4]{D_{a'b'} D_{a'a'} D_{b'a'} D_{b'b'}}$$
$$= \sqrt[4]{(0.4 \times 0.7788 \times 10^{-2})^2 (6\text{m})^2}$$
$$= \sqrt[4]{349.36 \times 10^{-6}}$$
$$= 0.136\text{m}$$

Figure 9.7b shows the equivalent geometry of the conductors in Figure 9.7a. We now use Equation 9.26 to find the inductance of each conductor.

$$L_A = (2 \times 10^{-7}) \ln \frac{D_m}{D_{sA}}$$
$$= (2 \times 10^{-7}) \ln \left(\frac{13.443\text{m}}{0.446\text{m}} \right)$$
$$= 0.681 \times 10^{-6} \quad \text{H/m}$$
$$L_B = (2 \times 10^{-7}) \ln \frac{D_m}{D_{sB}}$$
$$= (2 \times 10^{-7}) \ln \left(\frac{13.443\text{m}}{0.136\text{m}} \right)$$
$$= 0.918 \times 10^{-6}\ \text{H/m}$$

and from Equation 9.27

$$L_T = (4 \times 10^{-7}) \ln \left(\frac{D_m}{\sqrt{D_{sA} D_{sB}}} \right)$$
$$= (4 \times 10^{-7}) \ln \left(\frac{13.443\text{m}}{0.246\text{m}} \right)$$
$$= 1.599 \times 10^{-6} \quad \text{H/m}$$

9.2.6 Inductive Reactance From the Conductor Table

The GMR of each conductor is given in Table 9.1. X_L at 60 hz is given in Ω/mi, and is listed as X_a. X_L is found by multiplying the inductance obtained from Equation 9.25, 9.26, or 9.27 by jω. Xa in the table is the inductive reactance of a line with a 1 foot spacing. The inductive reactance of the line can be expressed as the reactance for a 1 foot spacing plus a spacing factor reactance. To find the spacing factor first we multiply Equation 9.25 by $2\pi f$. The inductive reactance for one conductor is then

$$X_L = 2\pi f (2 \times 10^{-7}) \ln \frac{D_m}{D_s}$$
$$= (4\pi \times 10^{-7}) f \ln \frac{D_m}{D_s} \tag{9.28a}$$

Changing meters to miles (1609 m/mi), and separating

$$X_L = (2.022 \times 10^{-3}) f \ln \frac{1}{D_s} + (2.022 \times 10^{-3}) f \ln D_m$$
$$= X_a + X_d \tag{9.28b}$$

where X_d is the spacing factor reactance. Now we see that

$$X_a = (2.022 \times 10^{-3}) f \ln \frac{1}{D_s} \tag{9.29}$$

Which is in Table 9.1

$$X_d = (2.022 \times 10^{-3}) f \ln D_m \tag{9.30}$$

Which is in Table 9.2.

X_d calculated for distances other than 1 foot is found in Table 9.2. Note that X_d for conductor separation less than a foot is negative.

Example 9.2:

Drake is a widely used ACSR conductor in transmission. Calculate the X_L per mile of a single-phase circuit using Drake conductors spaced 20 feet apart.

Solution:

From Table 9.1 we find that Drake has $Ds = 0.0373$ ft and $X_a = 0.399\ \Omega$/mi. From Equation 9.30 we find

$$X_d = (2.022 \times 10^{-3})(60\text{ Hz})\ln(20\text{ ft}) = 0.363\ \Omega/\text{mi}$$

so that

$$X_L = X_a + X_d = 0.399\Omega/\text{mi} + 0.363\Omega/\text{mi}$$
$$= 0.762\Omega/\text{mi}$$

Alternately, using Equation 9.28a

$$X_L = (2.022 \times 10^{-3})(60\text{ Hz}) \ln \frac{20\text{ ft}}{0.0373\text{ ft}} = 0.7625\Omega/\text{mi}$$

From Table 9.2 we see that X_d for 20 feet is 0.3635. Normally we would just use the table instead of calculating X_d.

9.2.7 Balanced Three-Phase Line Inductance

The flux coupling between the lines of three-phase lines must be considered in calculating the inductive reactance. For balanced loads, and most loads are reasonably well balanced, the net current of a three-phase line is zero. So for a symmetrically spaced, balanced three-phase line such as the one shown in Figure 9.8 the equation for L per phase remains in the same form as for a single-phase line.

$$L_a = (2 \times 10^{-7}) \ln \frac{D}{D_s} \tag{9.31}$$

Since $r_a' = r_b' = r_c'$, $L_T = 3L_a$.

TABLE 9.2 Inductive reactance spacing factor X_d at 60 Hz† (ohms per mile per conductor)

	Separation											
	Inches											
Feet	0	1	2	3	4	5	6	7	8	9	10	11
0	.....	−0.3015	−0.2174	−0.1682	−0.1333	−0.1062	−0.0841	−0.0654	−0.0492	−0.0349	−0.0221	−0.0106
1	0	0.0097	0.0187	0.0271	0.0349	0.0423	0.0492	0.0558	0.0620	0.0679	0.0735	0.0789
2	0.0841	0.0891	0.0938	0.0984	0.1028	0.1071	0.1112	0.1152	0.1190	0.1227	0.1264	0.1299
3	0.1333	0.1366	0.1399	0.1430	0.1461	0.1491	0.1520	0.1549	0.1577	0.1604	0.1631	0.1657
4	0.1682	0.1707	0.1732	0.1756	0.1779	0.1802	0.1825	0.1847	0.1869	0.1891	0.1912	0.1933
5	0.1953	0.1973	0.1993	0.2012	0.2031	0.2050	0.2069	0.2087	0.2105	0.2123	0.2140	0.2157
6	0.2174	0.2191	0.2207	0.2224	0.2240	0.2256	0.2271	0.2287	0.2302	0.2317	0.2332	0.2347
7	0.2361	0.2376	0.2390	0.2404	0.2418	0.2431	0.2445	0.2458	0.2472	0.2485	0.2498	0.2511
8	0.2523											
9	0.2666											
10	0.2794											
11	0.2910											
12	0.3015											
13	0.3112											
14	0.3202											
15	0.3286											
16	0.3364											
17	0.3438											
18	0.3507											
19	0.3573											
20	0.3635											
21	0.3694											
22	0.3751											
23	0.3805											
24	0.3856											
25	0.3906											
26	0.3953											
27	0.3999											
28	0.4043											
29	0.4086											
30	0.4127											
31	0.4167											
32	0.4205											
33	0.4243											
34	0.4279											
35	0.4314											
36	0.4348											
37	0.4382											
38	0.4414											
39	0.4445											
40	0.4476											
41	0.4506											
42	0.4535											
43	0.4564											
44	0.4592											
45	0.4619											
46	0.4646											
47	0.4672											
48	0.4697											
49	0.4722											

At 60 Hz, in Ω/mi per conductor
$X_d = 0.2794 \log d$
d = separation, ft
For three-phase lines
$d = D_{eq}$

†From "Electrical Transmission and Distribution Reference Book," by permission of the Aluminum Association, Inc.

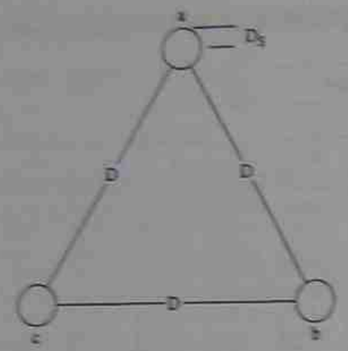


FIGURE 9.8 Equilateral spacing of three-phase line

Bundling of transmission lines, recall, reduces the line series impedance, which reduces line loss and improves line capacity and system stability over the use of a single conductor of the size used in the bundle. Recall also that the bundling of conductors at voltages of 230 kV and above is to reduce the loss from corona. The spacing between bundle conductors is usually 18 inches (45.72 cm) in the United States, and 45 centimeters in Canada and Europe.

To adjust for conductor bundling the Ds of equation 9.31 is replaced with the GMR of the bundle (Dsb). For a bundle of 2, used for voltages between 230 kV and 345 kV, separated by a distance d

$$D_{sb2} = \sqrt[4]{(D_s d)^2} = \sqrt{(D_s d)} \tag{9.32}$$

for a bundle of three, used at 500 kV

$$D_{sb3} = \sqrt[9]{(D_s dd)^3} = \sqrt[3]{(D_s d^2)} \tag{9.33}$$

and for a bundle of four, used from 700 kV up

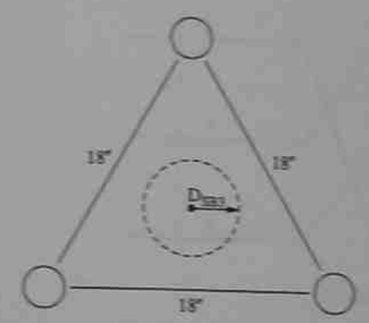
$$D_{sb4} = \sqrt[16]{(D_s d d 1.414 d)^4} = 1.09\sqrt[4]{(D_s d^3)} \tag{9.34}$$

Figure 9.9 shows the common bundling configurations.

If the line does not have equilateral spacing, such as the one shown in Figure 9.10, the coupling between the lines is not balanced because of the asymmetrical spacing, thus the inductance of the lines is not equal. The balance of the inductive reactance of the line can be restored by transposing the lines as shown in Figure 9.11 so that each line occupies each position for one third of the line length. Very long transmission (and distribution) lines are often transposed more than three times to assure balance along the length of the line, but many are not transposed at all. The unbalance in inductive reactance caused by asymmetrical spacing is small at the common transmission line spacings. It is common practice to calculate the inductive reactance of an asymmetrically spaced line using the equivalent *symmetrical* spacing of the line, which is calculated using the GMD equation (9.23).

$$D_{eq} = \sqrt[6]{D_{12}D_{21}D_{23}D_{32}D_{13}D_{31}}$$





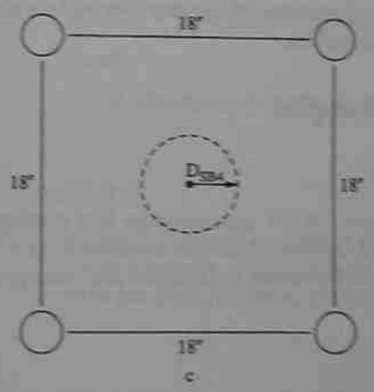


FIGURE 9.9 Common bundles (a) Bundle of two (230 kV to 345 kV) (b) Bundle of three (500 kV) and (c) Bundle of four (700 kV and up)

However $D_{12} = D_{21}$, $D_{23} = D_{32}$, and $D_{31} = D_{13}$ so

$$D_{eq} = \sqrt[6]{D^2_{12}D^2_{23}D^2_{31}}$$

$$D_{eq} = \sqrt[6]{(D_{12}D_{23}D_{31})^2}$$

$$D_{eq} = \sqrt[3]{D_{12}D_{23}D_{31}} \tag{9.35}$$

D_{eq} is used as D in Equation 9.31.

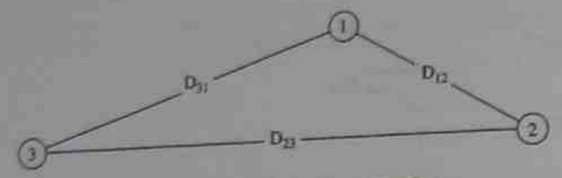


FIGURE 9.10 Asymmetrical three-phase spacing

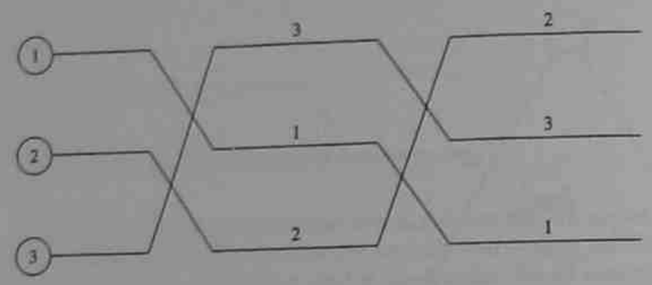


FIGURE 9.11 Transposing phases for balance

Parallel lines are handled by calculating the combined GMD from the individual circuit GMDs, and the combined GMR of each parallel line set from the GMR of each line. The result is a single equivalent three-phase line. We will do an example in the transmission line capacitance section.

9.2.8 Three-Phase Inductance Examples

Example 9.3:

Figure 9.12 shows a very common 138 kV transmission line configuration and spacing. The H fixtures hold 336 MCM Linnet conductor at a 15 foot spacing. Using the tables calculate the series impedance per mile per phase of this line.

Solution:

From the tables we see that Linnet has: Al area = 336,400 CM, 26/7 stranding, R_{ac} at 50°C = 0.3006 Ω/mi, D_s = 0.0243 ft, and X_a = 0.451 Ω/mi. First we solve for D_m

$$D_m = \sqrt[3]{(15\text{ ft})(15\text{ ft})(30\text{ ft})} = 18.9\text{ ft}$$

Interpolating from Table 9.2

$$X_d \text{ at } 18.9\text{ ft} = [0.3507 + 0.9(0.3573 - 0.3507)]\ \Omega/\text{mi}$$
$$= (0.3507 + 0.00594)\ \Omega/\text{mi} = 0.3566\ \Omega/\text{mi}$$

and from Table 9.1

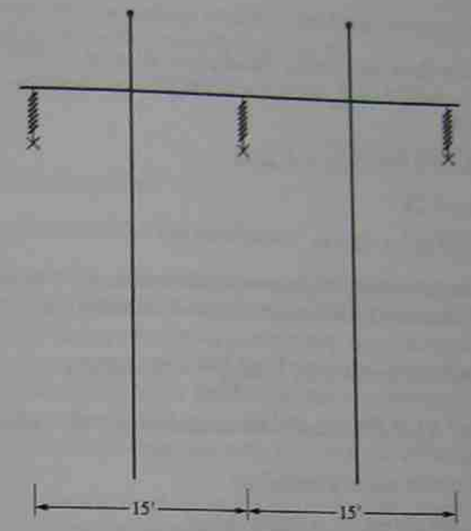


FIGURE 9.12 Spacing for Example 9.3 (138 kV)

$$X_L = X_a + X_d = 0.451 + 0.3566 = 0.8076\ \Omega/\text{mi}$$

Finally

$$Z = 0.3006\ \Omega/\text{mi} + j0.8076\ \Omega/\text{mi} = (0.8617\ \Omega/\text{mi})\angle 69.58°$$

Example 9.4:

Figure 9.13 shows a common spacing for a 345 kV line using Drake conductor in a bundle of two (18 inch bundle spacing). Calculate the series impedance per mile per phase of the line. The conductor tables may be used.

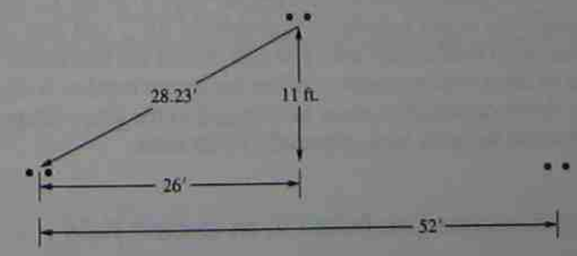


FIGURE 9.13 Spacing for Example 9.4 (345 kV)

Solution:

From Table 9.1 we find for Drake conductor: Al area = 795 MCM; 26/7 stranding; GMR = 0.0373 ft; R_{ac} (50°C) = 0.1284 Ω/mi; and X_a = 0.399 Ω/mi. From Equation 9.32

$$D_{sL} = \sqrt{D_s d} = \sqrt{(0.0373 \text{ ft})(1.5 \text{ ft})} = 0.23 \text{ ft}$$

and from Equation 9.23

$$D_m = \sqrt[4]{(28.23 \text{ ft})^4 (52 \text{ ft})^2} = 34.6 \text{ ft}$$

Because the tables give only single conductor values we must calculate X_L using Equation 9.28a with a 1609 m/mi factor to obtain Ω/mi.

$$X_L = 2\pi(60 \text{ Hz})(1609 \text{ m/mi})(2 \times 10^{-7}) \ln \frac{D_m}{D_{sL}} = 0.604 \Omega/\text{mi}$$

Note from the tables that X_L of a single Drake conductor is 0.829 Ω/mi, 27% more than the bundled value.

The conductors of a bundle are in parallel so

$$R_{ac} = 0.5(R_{ac50C}) = (0.1284 \Omega/\text{mi})/2 = 0.064 \Omega/\text{mi}$$

Thus the impedance per mile per phase is

$$Z = (0.0642 + j0.60486) \Omega/\text{mi} = 0.60825 \Omega/\text{mi} \angle 83.94°$$

9.3 TRANSMISSION LINE CAPACITANCE

Overhead transmission line conductors are separated from each other and from ground by air, which is a dielectric. Thus transmission lines have capacitance. The effective plate area is small and the plate separation large so the leakage from line to line and line to ground because of the shunt capacitive susceptance is negligible in comparison to total power flow in lines shorter than 50 miles. However, current does flow through the shunt capacitive susceptance (jB_C), and this current flows even when there is no load on the line. The real part of the line shunt admittance, G, is negligible in lines with no corona. When the circuit breaker is closed to energize a line the shunt capacitance must be charged to the line voltage. The initial charging current can be quite high, especially on dc lines.

9.3.1 Voltage Between Two Points in an Electric Field

The electric field flux density (𝔇) is defined as the electric flux pu area, normally in Coulombs per square meter. A long uniformly charged conductor has lines of electric flux extending radially out from the conductor surface. For a cylindrical conductor the flux density is given as

$$\mathfrak{D} = q/(2\pi x) \qquad \text{C/m}^2$$

where

q = electric charge

x = distance from the conductor

If the medium around the conductor is a dielectric other than air the electric field lines are concentrated by the dielectric constant, ϵ, also called the relative permitivity. Recall that relative permitivity is a measure of the ease with which a dielectric can support electric field lines in comparison to a vacuum. The relative permitivity (ϵ_r) of air is 1.00054 and is considered to be one in most calculations. The permitivity of a vacuum is $\epsilon_0 = 8.85 \times 10^{-12}$ F/m. The dielectric surrounding most overhead lines, the only type we calculate for in this chapter, is air so we use the $\epsilon_r = 1$.

The electric field intensity (E) is a vector quantity that is equal to the flux density divided by the permitivity with units of volts/meter.

$$E = \frac{q}{2\pi x \epsilon}$$

$$= \mathfrak{D}/\epsilon \qquad \text{V/m} \tag{9.36}$$

The voltage between two points in an electric field is equal to the work in joules per coulomb required to move charge from one point to the other. No work is required to move a charge perpendicular to an electric field because the potential is the same (equipotential) along a path perpendicular to electric field lines.

Referring to Figure 9.14, the voltage between points 1 and 2 can be found by calculating the work needed to move a charge from point 1 to point 2. The path chosen is from point 1 to point A, along which work is performed moving the charge, and from point A to point 2, along which no work is performed because this path is along an equipotential line. The polarity of the calculation depends on the polarity of the charge moved and the direction in which it is moved. The work can be calculated by summing the electric field along path x from P_1 to P_2 by integrating.

$$V_{12} = \int_{D_1}^{D_2} E dx = \int_{D_1}^{D_2} \frac{q}{2\pi\epsilon x} dx$$

$$= \frac{q}{2\pi\epsilon} \ln \frac{D_2}{D_1} \tag{9.37}$$

Note the form of this equation is reminiscent of Equation 9.16.

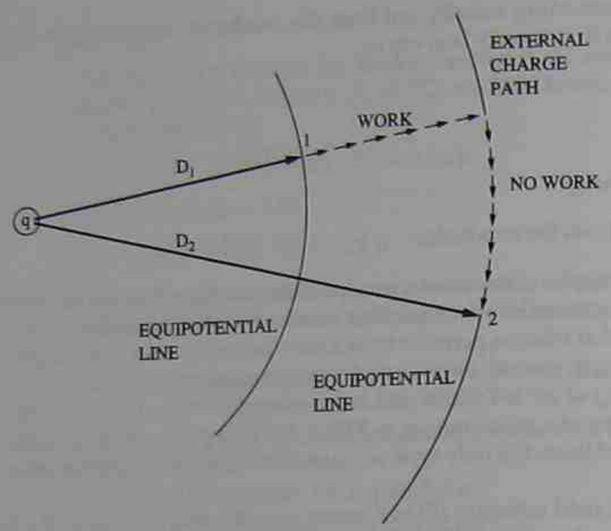


FIGURE 9.14 Potential between two points a distance away from a charge

9.3.2 Capacitance of a Two Wire Line

Capacitance is defined as charge accumulated per volt ($C = Q/V$). Along a conductor we will calculate charge/volt per meter. To calculate the capacitance of the line in Figure 9.15 we first apply Equation 9.37 to calculate the voltage between the lines.

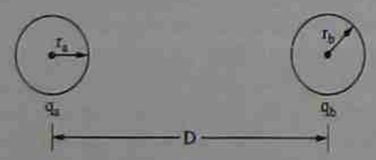


FIGURE 9.15 Voltage between two charged conductors

V_a = V from q_a + V from q_b.

$$V_{ab} = \frac{q_a}{2\pi\epsilon}\ln\frac{D}{r_a} + \frac{q_b}{2\pi\epsilon}\ln\frac{r_b}{D}$$

Note that with respect to conductor a there is a reversal in D_1 and D_2 in the second term. In a two wire line $q_a = {}^{-}q_b$ so

$$V_{ab} = \frac{q_a}{2\pi\epsilon}\left(\ln\frac{D}{r_a} - \ln\frac{r_b}{D}\right)$$

$$= \frac{q_a}{2\pi\epsilon}\ln\frac{D^2}{r_a r_b} \tag{9.38}$$

but

$$C = \frac{q_a}{V_{ab}} = \frac{2\pi\epsilon}{\ln\frac{D^2}{r_a r_b}} \quad \text{F/m} \tag{9.39a}$$

and if $r_a = r_b$

$$C = \frac{\pi\epsilon}{\ln\frac{D}{r}} \quad \text{F/m} \tag{9.39b}$$

The actual conductor radius is used in capacitance calculations.

9.3.3 Line to Neutral Capacitance

The line to neutral capacitance per phase is the value usually calculated. Notice that the line to neutral point capacitance is not the line to ground capacitance. Instead it is to the neutral or zero point between conductors with equal and opposite voltages from equal and opposite charges. Basically it is the capacitance to the electric field neutral point between the conductors. The line to line capacitance is illustrated in Figure 9.16a, and the line to neutral capacitance in Figure 9.16b. Intuitively we see that the line to neutral capacitance must have half the effective plate separation with no change in plate area thus it is twice the line to line capacitance. Another way to look at it is that the two series line to neutral capacitors must have the same capacitance as the line to line capacitance, therefore the line to neutral capacitance of each line must be twice as large as the line to line capacitance. Using that approach

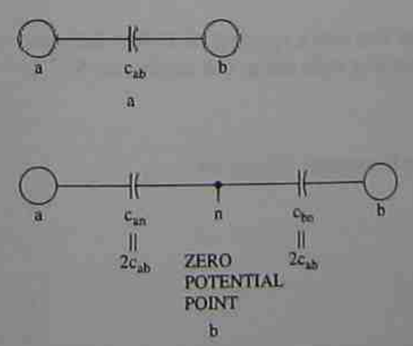


FIGURE 9.16 Line capacitance (a) Line to line and (b) Line to neutral

$$C_{ab} = \frac{1}{\frac{1}{C_{an}} + \frac{1}{C_{bn}}} = \frac{C_{an}C_{bn}}{C_{an} + C_{bn}}$$

but $C_{an} = C_{bn}$ so $C_{ab} = C_{an}/2$ and $C_{an} = 2\,C_{ab}$. Therefore

$$C_{an} = \frac{2\pi\epsilon}{\ln\frac{D}{r}} \quad \text{F/m} \tag{9.40}$$

recall that $X_C = 1/(2\pi fC)$ so for $\epsilon_r = 1$

$$X_C = \frac{1}{4\pi^2 f\epsilon^e} \ln\frac{D}{r} = \frac{2.862 \times 10^9}{f} \ln\frac{D}{r} \ \Omega\text{m to neutral}$$

Now we convert to Ω mi by dividing by 1609 m/mi to obtain

$$X_C = \frac{1.779 \times 10^6}{f} \ln\frac{D}{r} \quad \Omega\text{mi} \tag{9.41}$$

To more easily use the tables in which are split into a 1 foot term (X_a') in Table 9.1, and a distance correction term (X_d') in Table 9.3, we split Equation 9.41 into two parts.

$$X_C = X_a' + X_d'$$

$$X_C = \frac{1.779 \times 10^6}{f} \ln\frac{1}{r} + \frac{1.779 \times 10^6}{f} \ln D \quad \Omega\text{mi} \tag{9.42}$$

The reason that X_C is set up to come out Ohm miles is that in the transmission line power flow and loss calculation $B_C = 1/X_C$. The reciprocal comes out S/mi as desired for most calculations.

Example 9.4:

A single-phase, 60 Hz, Linnet line has a spacing of 26 feet between conductors. Calculate the susceptance per mile using the conductor tables.

Solution:

First, from the tables, the line to neutral values are

$X_a' = 0.1040$ M Ω mi

$X_d' = 0.0967$ M Ω mi

$X_C = (0.1040 + 0.0967)$M Ω mi

$= 0.2007$ M Ω mi

$B_C = 1/X_C = 4.98$ μS/mi

TABLE 9.3 Shunt capacitive-reactance spacing factor X_d' at 60 Hz* (megohm-miles per conductor)

	Separation											
	Inches											
Feet	0	1	2	3	4	5	6	7	8	9	10	11
0	.....	−0.0737	−0.0532	−0.0411	−0.0326	−0.0260	−0.0206	−0.0160	−0.0120	−0.0085	−0.0054	−0.0026
1	0	0.0024	0.0046	0.0066	0.0085	0.0103	0.0120	0.0136	0.0152	0.0166	0.0180	0.0193
2	0.0206	0.0218	0.0229	0.0241	0.0251	0.0262	0.0272	0.0282	0.0291	0.0300	0.0309	0.0318
3	0.0326	0.0334	0.0342	0.0350	0.0357	0.0365	0.0372	0.0379	0.0385	0.0392	0.0399	0.0405
4	0.0411	0.0417	0.0423	0.0429	0.0435	0.0441	0.0446	0.0452	0.0457	0.0462	0.0467	0.0473
5	0.0478	0.0482	0.0487	0.0492	0.0497	0.0501	0.0506	0.0510	0.0515	0.0519	0.0523	0.0527
6	0.0532	0.0536	0.0540	0.0544	0.0548	0.0552	0.0555	0.0559	0.0563	0.0567	0.0570	0.0574
7	0.0577	0.0581	0.0584	0.0588	0.0591	0.0594	0.0598	0.0601	0.0604	0.0608	0.0611	0.0614
8	0.0617											
9	0.0652											
10	0.0683											
11	0.0711											
12	0.0737											
13	0.0761											
14	0.0783											
15	0.0803											
16	0.0823											
17	0.0841											
18	0.0858											
19	0.0874											
20	0.0889											
21	0.0903											
22	0.0917											
23	0.0930											
24	0.0943											
25	0.0955											
26	0.0967											
27	0.0978											
28	0.0989											
29	0.0999											
30	0.1009											
31	0.1019											
32	0.1028											
33	0.1037											
34	0.1046											
35	0.1055											
36	0.1063											
37	0.1071											
38	0.1079											
39	0.1087											
40	0.1094											
41	0.1102											
42	0.1109											
43	0.1116											
44	0.1123											
45	0.1129											
46	0.1136											
47	0.1142											
48	0.1149											
49	0.1155											

At 60 Hz, in Ω/mi per conductor
$X_d' = 0.06831 \log d$
d = separation, ft
For three-phase lines
$d = D_{eq}$

*From "Electrical Transmission and Distribution Reference Book," by permission of the Aluminum Association, Inc.

The line to line value of B_C is one half this value because the capacitance is one half the line to neutral value. From Equation 9.41 we find, using the physical conductor radius

$$X_C = \frac{1.779 \times 10^6}{60\ Hz} \ln \frac{26\ ft}{0.0243\ ft} = 0.2068$$

9.3.4 Three-Phase Line Capacitance

Refer to Figure 9.17a. Applying Equation 9.37 to all three lines we obtain

$$V_{ab} = \frac{1}{2\pi\epsilon}\left(q_a \ln \frac{D}{r} + q_b \ln \frac{r}{D} + q_c \ln \frac{D}{D}\right)$$

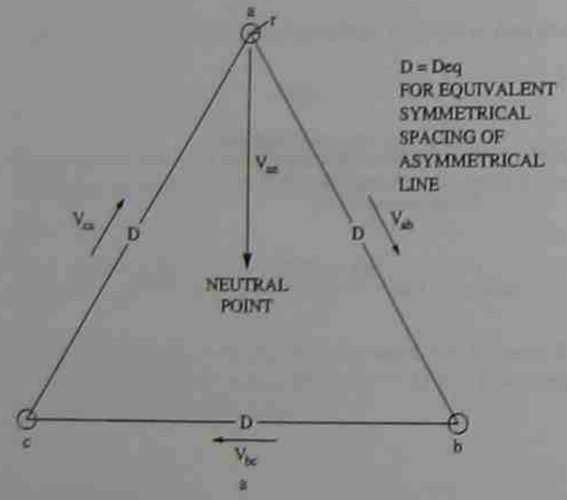


FIGURE 9.17 Three-phase line spacing (a) Equilateral and (b) Asymmetrical spacing for developing Equation 9.45

Similarly

$$V_{ac} = \frac{1}{2\pi\epsilon}\left(q_a \ln \frac{D}{r} + q_b \ln \frac{D}{D} + q_c \ln \frac{r}{D}\right)$$

Adding these two equations yields, with ln(D/D) = 0,

$$V_{ab} + V_{ac} = \frac{1}{2\pi\epsilon}\left[2q_a \ln \frac{D}{r} + (q_b + q_c) \ln \frac{r}{D}\right]$$

In a balanced three phase circuit $q_a + q_b + q_c = 0$ so $q_b + q_c = -q_a$ thus

$$V_{ab} + V_{ac} = \frac{1}{2\pi\epsilon}\left(2q_a \ln \frac{D}{r} - q_a \ln \frac{r}{D}\right)$$

$$= \frac{1}{2\pi\epsilon}\left(2q_a \ln \frac{D}{r} + q_a \ln \frac{D}{r}\right)$$

$$= \frac{3q_a}{2\pi\epsilon} \ln \frac{D}{r}$$

But for a balanced three-phase line, V_{an} is offset 30° from V_{ab}

$V_{ab} = \sqrt{3}\, V_{an}(0.866 + j0.5)$

$V_{ac} = -V_{ca} = \sqrt{3}\, V_{an}(0.866 - j0.5)$

$V_{ab} + V_{ac} = \sqrt{3}\, V_{an}(0.866 + j0.5 + 0.866 - j0.5) = \sqrt{3}\, V_{an}(1.73) = 3\, V_{an}$

thus

$$3\, V_{an} = \frac{3q_a}{2\pi\epsilon} \ln \frac{D}{r}$$

and

$$V_{an} = \frac{q_a}{2\pi\epsilon} \ln \frac{D}{r} \tag{9.42}$$

Now

$$C_{an} = \frac{q_a}{V_{an}} = \frac{2\pi\epsilon}{\ln \frac{D}{r}} \quad F/m \tag{9.43}$$

Note that $C_{an} = C_{bn} = C_{cn}$ for a balanced symmetrical line.

The charging current (I_{CH}) per phase of the line is V/X_C and can be written

$$I_{CH} = V_{an} j\omega C_{an} = V_{an} B_C \quad A/mi \tag{9.44}$$

Usually the nominal phase voltage is used to calculate nominal charging current.

If the spacing of a three-phase line is asymmetrical, as illustrated in Figure 9.17b, the GMD is used as D_{eq} in the calculation of line capacitance.

$$D_{eq} = \sqrt[3]{D_{12}D_{23}D_{31}}$$

resulting in

$$C_{an} = \frac{q_a}{V_{an}} = \frac{2\pi\epsilon}{\ln\frac{D_{eq}}{r}} \quad \text{F/m} \tag{9.45}$$

As always $X_C = 1/(j\,\omega\,C)$ thus

$$X_{an} = \frac{1}{1609f(4\pi^2\epsilon)} \ln\frac{D_{eq}}{r}$$

$$= \frac{1.779 \times 10^6}{f} \ln\frac{D_{eq}}{r} \quad \Omega\text{mi} \tag{9.46}$$

Equation 9.46 can be broken into

$$X_{an} = X_a' + X_d'$$

for convenient use of the conductor tables. D_{eq} is used in Table 9.3.

Bundled conductors are handled identically except that D_{sB} values are used in the equations for the conductor radius. Equations 9.32, 9.33, and 9.34 are used to calculate D_{sB2}, D_{sB3}, and D_{sB4} respectively. The actual radius of the conductor is used instead of $0.7788r$. The distance between phase conductor bundles is measured from the geometric center of the conductor bundles. For asymmetrical bundled conductors Equation 9.45 becomes,

$$C_n = \frac{2\pi\epsilon}{\ln\frac{D_{eq}}{D_{sB}}} \quad \text{F/m} \tag{9.47}$$

and Equation 9.46 becomes

$$X_{an} = \frac{1.779 \times 10^6}{f} \ln\frac{D_{eq}}{D_{sB}} \quad \Omega\text{mi} \tag{9.48}$$

Parallel three-phase circuit geometry is handled the same way as in inductance calculations, except the actual conductor radius is used for D_s. An example follows shortly.

The presence of the Earth causes the capacitance of the lines to be larger than it would be from the conductors alone. At normal line spacings the distance to the Earth is larger than the distance between conductors so the additional capacitance to the Earth is very small and is normally ignored in calculations of transmission line performance for balanced loads. To calculate the line to Earth capacitance the Earth is considered to be a perfect neutral between the transmission line conductors and image conductors identically spaced below the Earth as shown in Figure 9.18. This assumption allows the previous equations to be used with a distance correction term to adjust for the presence of the Earth. The distance correction term is

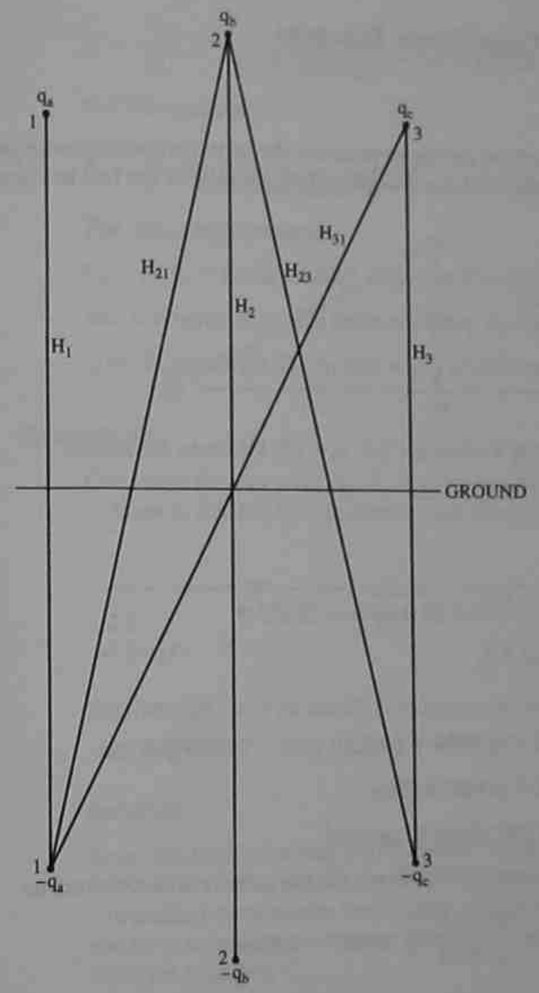


FIGURE 9.18 Capacitance from line to ground

$$\ln\frac{\sqrt[3]{H_{12}H_{23}H_{31}}}{\sqrt[3]{H_1H_2H_3}}$$

and causes Equation 9.48 to become

$$C_n = \frac{2\pi\epsilon}{\ln\frac{D_{eq}}{D_{sB}} - \ln\frac{\sqrt[3]{H_{12}H_{23}H_{31}}}{\sqrt[3]{H_1H_2H_3}}} \quad \text{F/m} \tag{9.49}$$

9.3.5 Three-Phase Capacitance Examples

Example 9.5:

Calculate the capacitive reactance per mile, the capacitive susceptance per mile, the charging current, and the charging MVA per mile of the line in Figure 9.19.

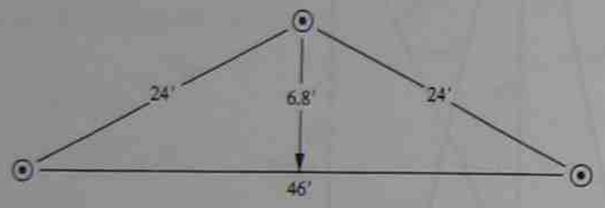


FIGURE 9.19 Spacing for Example 9.5. V_l = 220 kV, Drake conductors.

Solution:

First calculate D_{eq}

$$D_{eq} = \sqrt[3]{D_{12}D_{23}D_{31}} = \sqrt[3]{24\text{ ft}\,24\text{ ft}\,46\text{ ft}} = 29.812\text{ ft}$$

From Tables 9.1 and 9.3

$$X_C = X_a' + X_d'$$

$$= 0.0912\ \text{M}\Omega\text{mi} + [0.0999 + 0.812(0.1009 - 0.0999)]\text{M}\Omega\text{mi}$$

$$= 0.0912\ \text{M}\Omega\text{mi} + 0.1007\ \text{M}\Omega\text{mi}$$

$$= 0.1919\ \text{M}\Omega\text{mi per phase to neutral}$$

Checking with Equation 9.46, where r is the actual conductor radius

$$X_C = \frac{1.779 \times 10^6}{60\text{ Hz}} \ln\frac{29.812\text{ ft}}{0.045\text{ ft}} = 0.193 \quad \text{M}\Omega\text{mi}$$

Which is quite close.

Just for fun we will use Equation 9.45 to find C, converting to miles as we do.

$$C = \frac{2\pi\epsilon(1609\text{ m/mi})}{\ln\frac{D_{eq}}{D_s}} \quad \text{F/m}$$

$$= \frac{2\pi(8.85 \times 10^{-12}\text{ F/m})(1609\text{ m/mi})}{\ln\frac{29.812\text{ ft}}{0.045\text{ ft}}} = 13.773\ \text{n F/mi phase to neutral}$$

and the capacitive reactance is

$$X_c = \frac{1}{\omega C} = \frac{1}{\omega(13.773\text{nF/mi})} = 0.193\ \text{M}\Omega\text{mi}$$

and the susceptance

$$B_c = \frac{1}{X_c} = \frac{1}{13.773\text{F/mi}} = 5.189 \quad \mu\text{S/mi}$$

The charging current is

$$I_{ch} = V_{an}B_c = (220\text{kV}/\sqrt{3})(5.189\mu\text{S/mi}) = 0.659 \quad \text{A/mi per phase}$$

and the reactive power from charging the capacitance is

$$Q = \sqrt{3}(220\text{ kV})(0.659\text{ A/mi}) = 251\text{ kVAR/mi}$$

Example 9.6:

Calculate the per mile X_C, B_C, I_{CH} for the line shown in Figure 9.20. The line voltage is 750 kV, the conductors are Pheasant in a bundle of four per phase.



FIGURE 9.20 750 kV bundle of four line spacing for Example 9.6

Solution:

From the tables we find for Pheasant: Al area = 1272 MCM, 54/19 stranding, 1.382 in diameter, and X_a' = 0.0897 MΩmi per conductor.

Bundled conductors necessitate calculating C and X_C because the tables are for a single conductor per phase.

First we calculate D_{eq}

$$D_{eq} = \sqrt[3]{56\text{ ft}\,56\text{ ft}\,112\text{ ft}} = 70.556\text{ ft}$$

and from Equation 9.34, where D_s is the actual conductor radius

$$D_{sB4} = \sqrt[4]{0.0576\text{ ft}\,1.5\text{ ft}\,1.5\text{ ft}\,(1.414 \times 1.5\text{ ft})} = 0.724\text{ ft}$$

Now from Equation 9.47

$$C = \frac{2\pi(8.85 \times 10^{-12}\text{ F/m})(1609\text{ m/mi})}{\ln\frac{70.556\text{ ft}}{0.724\text{ ft}}} = 19.53\text{ nF/mi}$$

and from Equation 9.48

$$X_{cn} = \frac{1.779 \times 10^6}{f} \ln \frac{70.556 \text{ ft}}{0.724 \text{ ft}} = 0.135 \text{ M}\Omega\text{mi}$$

and the susceptance

$$B_c = \frac{1}{0.135 \times 10^6 \ \Omega\text{mi}} = 7.365 \quad \mu\text{S/mi}$$

so that the charging current is

$$I_{ch} = \frac{750\text{kV}}{\sqrt{3}} (7.365\mu\text{S/mi}) = 3.189 \text{ A/mi}$$

At this voltage the corona loss is between 5 and 30 kW per mile for conductor diameters between 3 and 1.45 inches. The equivalent diameter of our bundle of four is 17.376 inches, which reduces corona loss to a negligible amount except in very unusual weather conditions. The insulator leakage is typically about 3 kW per mile at this voltage level. Insulator losses are lower at lower voltages.

Example 9.7:

Figure 9.21a shows two parallel 138 kV lines using Grosbeak conductors. Calculate C, X_C, and I_{CH} per mile.

Solution:

From the tables for Grosbeak: Al area = 636 MCM, diameter = 0.990 in = 0.0825 ft, stranding is 26/7.

First we calculate the distance between conductors.

$$D_{ab} = D_{bc} = \sqrt{(10 \text{ ft})^2 + (2 \text{ ft})^2} = 10.198 \text{ ft}$$

$$D_{ac} = 20 \text{ ft}$$

$$D_{ab'} = D_{b'c} = D_{a'b} = D_{c'b} = \sqrt{(10 \text{ ft})^2 + (20 \text{ ft})^2} = 22.36 \text{ ft}$$

$$D_{ac'} = D_{ca'} = \sqrt{(20 \text{ ft})^2 + (18 \text{ ft})^2} = 26.91 \text{ ft}$$

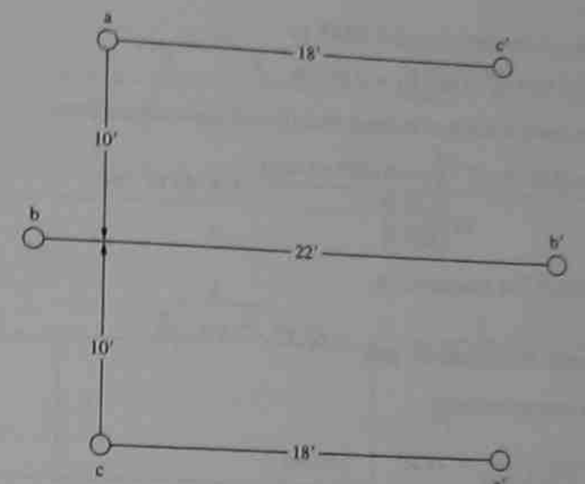
Now we calculate the GMD between phases on each side, where subscript p means parallel.

$$D_{pab} = D_{pbc} = \sqrt[4]{D^2_{ab} D^2_{bc}} = \sqrt{10.198 \text{ ft } 22.36 \text{ ft}} = 15.10 \text{ ft}$$

$$D_{pca} = \sqrt[4]{(20 \text{ ft})^2 (18 \text{ ft})^2} = 18.97 \text{ ft}$$

Thus, the equivalent parallel spacing is that shown in Figure 9.21b. Now we need the effective D_{eq}.

$$D_{eq} = \sqrt[3]{(15.1 \text{ ft})^2 (18.97 \text{ ft})} = 16.29 \text{ ft}$$



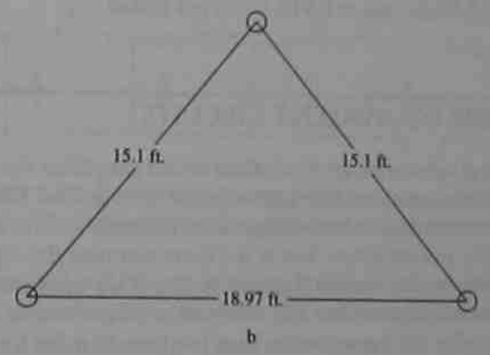


FIGURE 9.21 Spacing of parallel circuit for Example 9.7. Grosbeak conductor. (a) Actual spacing and (b) Equivalent spacing for parallel circuit.

We must now calculate the GMR of each equivalent conductor in Figure 9.21b. D_s is the actual conductor radius.

Equivalent conductor a − a′:

$$GMR = \sqrt{(26.91 \text{ ft})(0.0412 \text{ ft})} = 1.053 \text{ ft}$$

Equivalent conductor b − b′:

$$GMR = \sqrt{(22 \text{ ft})(0.0412 \text{ ft})} = 0.952 \text{ ft}$$

Equivalent conductor c − c′, the same as a − a′:

$$GMR = \sqrt{(26.91 \text{ ft})(0.0412 \text{ ft})} = 1.053 \text{ ft}$$

Now the equivalent parallel GMR is

$$D_{ps} = \sqrt[3]{(0.819\text{ ft})^2(0.952\text{ ft})} = 0.861\text{ ft}$$

We now have sufficient information to calculate capacitance.

$$C_n = \frac{2\pi(8.85\times10^{-12}\text{ F/m})(1609\text{ m/mi})}{\ln\frac{16.29\,ft}{0.861\,ft}} = 30.43\text{ nF/mi}$$

From which the reactance is

$$X_c = \frac{1}{2\pi(60\text{ Hz})(30.43\text{nF/mi})} = 87.17 \quad \text{k}\Omega\text{/mi}$$

and the susceptance is

$$B = \frac{1}{87.17\text{k}\Omega\text{/mi}} = 11.47 \quad \mu\text{S/mi}$$

Finally the charging current is

$$I_{ch} = (138\text{kV}/\sqrt{3})(11.47\mu\text{S/mi}) = 0.914\text{ A/mi per phase}$$

9.4 TRANSMISSION LINE EQUIVALENT CIRCUITS

As with other circuits and networks, an equivalent circuit simplifies the calculations that are made to obtain transmission line performance estimations. The equivalent circuit that is used for transmission line calculations depends on the transmission line length; the longer the transmission line is the more complex the equivalent circuit must be for accurate results. Recall that in Chapter 2 we used the series reactance of the line for most calculation. For many short distribution lines this is entirely adequate. Generally for transmission lines less than 50 miles long the equivalent circuit of Figure 9.22a is accurate enough. Distribution lines are less than 50 miles long so this is a good equivalent circuit for overhead distribution lines. Transmission lines that are between 50 and 100 miles long can be modeled with the π equivalent circuit of Figure 9.22b with sufficient accuracy for most purposes. The equivalent circuits of Figure 9.22a and b are called lumped parameter because the parameter represented in the equivalent circuit is lumped into one equivalent device. For example, the resistance is distributed along the line, but the equivalent circuit considers it to be a resistor in one place. Long transmission lines must take into account the distributed nature of the transmission line parameters, as illustrated in Figure 9.22c. The lumped parameter π circuit can be used with errors less than 5% for most lines up to about 200 miles when this accuracy is sufficient.

Throughout this section the bold italic underlined letter parameters will be the pu length value. For example $\underline{Z}$ = impedance per mile. The normaly signified values will be the lumped parameter value. For example $Z = \underline{Z}\times l$ = equivalent impedance.

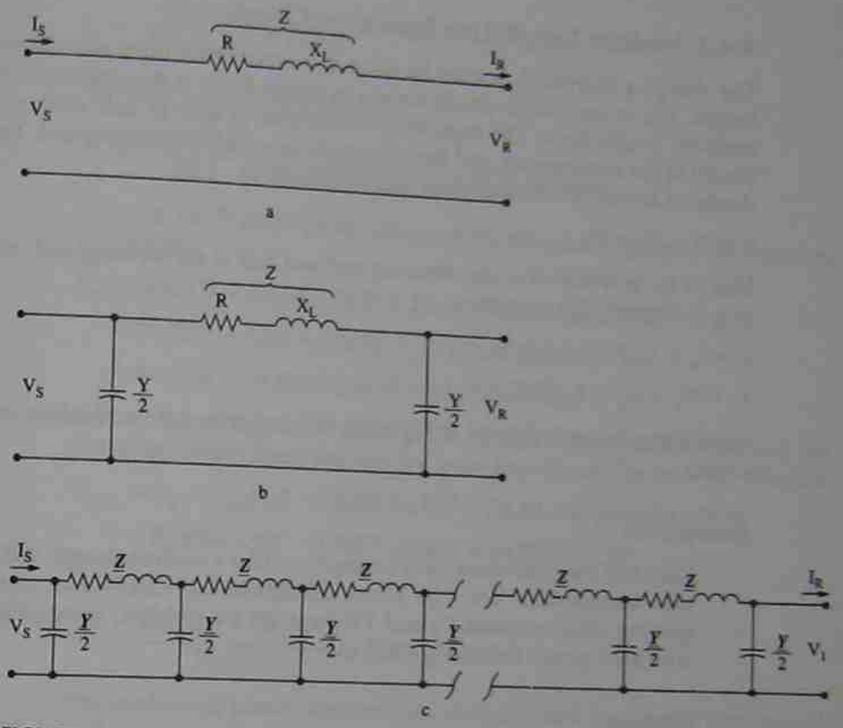


FIGURE 9.22 Transmission line equivalent circuits including: (a) Short line (less than 50 miles) (b) Medium length line (50 miles to 120 miles) and (c) Long lines (over 120 miles)

Subscript R will refer to receiving end quantities, such as V and I, and subscript S will refer to sending end quantities. We will assume balanced three-phase loads.

9.4.1 The Short Line Equivalent Circuit

The short line equivalent circuit consists of lumped series impedance parameters. This equivalent circuit, shown in Figure 9.22a, is accurate to about 50 miles. There is no shunt path so

$$V_S = V_R + I_R Z \tag{9.50}$$

The voltage regulation (VR) is calculated in the same manner as for transformers (shown in Chapter 4.7). Thus, from Equation 4.22 we obtain

$$\text{VR} = \frac{|V_{RNL}| - |V_{RFL}|}{|V_{RFL}|} \tag{9.51}$$

where the subscripts *FL* and *NL* are full load and no load respectively. The percent regulation is found by multiplying Equation 9.51 by 100.

9.4.2 Medium Length Line Equivalent Circuit

The charging current (I_{CH}) must be taken into account for lines over 50 miles in length. The π equivalent circuit shown in Figure 9.22b is the preferred one for medium length lines. The capacitive susceptance is split in half with one half placed at the sending end, and the other half placed at the receiving end. The conductance is very low in most lines without corona so

$$Y = G + jB_c \approx jB_c$$

Half of I_{CH} is removed at the receiving end and half at the sending end, so referring to Figure 9.22b we write

$$I_S = I_R + I_{CH} \tag{9.52}$$

$$V_S = V_R + (I_R + I_{CH}/2)Z \tag{9.53}$$

Voltage regulation is defined in Equation 9.51, but is harder to calculate with this circuit.

Example 9.8:

Calculate the equivalent circuit components for a medium length 138 kV, 100 mile transmission line. Use Hawk conductors with an 18 foot equilateral spacing. Also calculate V_S and *VR* for a 138 kV 60 MVA, three-phase load with a 0.9 power factor. V_R = 138 kV.

Solution:

Using Table 9.1 we find for Hawk: Al area = 477 MCM, OD = O.857 in, D_s = 0.0289 ft. X_a = 0.43 Ω/mi, X_a' = 0.0988 MΩmi, and R_{ac} at 50° = 0.2120 Ω/mi. From Tables 9.2 and 9.3 we find that for our spacing X_d = 0.3507 Ω/mi, and X_d' = 0.0858 MΩmi. Now we can solve for the equivalent circuit components.

$\underline{X}_L = X_a + X_d = (0.430 + 0.3507)\text{MΩmi} = 0.780\ \Omega/\text{mi}$

$X_L = 100\underline{X}_L = 78\ \Omega$

$Z = R + j\underline{X}_L = 21.2\Omega + J78\Omega = 80.83\Omega\angle 74.8°$

$\underline{X}_c = X_a' + X_d' = (0.0988 + 0.0858)\text{MΩmi} = 0.1846\ \text{MΩ/mi}$

$$\underline{Y} \approx \underline{B}_c = \frac{1}{\underline{X}_c} = 5.417\ \mu\text{S/mi}$$

$B = 100(5.417\mu\text{S/mi}) = 541\ \mu\text{S}$

$B/2 = 270.85\ \mu\text{S}$

Calculating I_{CH} and the line current we obtain

$I_{CH} = (138\text{kV}/\sqrt{3})(541\mu\text{S}) = 43.1\ \text{A}$

$$I_R = \frac{60\text{MVA}}{\sqrt{3}\,(138\text{kV})} = 251\ \text{A}$$

The load impedance is equal to

$$Z_L = \frac{138\text{kV}/\sqrt{3}}{251\text{A}} \angle \arccos(0.9) = 317\Omega\angle 25.8° \text{ per phase}$$

V_R is 138 kV, 79.67 kV phase voltage, at the reference angle, so from Equation 9.53 we see

$V_S = 79.67\text{kV} + (251\text{A}\angle -25.8° + 21.6\text{A}\angle 90°)(80.83\Omega\angle 74.8°)$

$= 79.67\text{kV} + (226 - j109.24 + j21.6)\text{A}(80.83\Omega\angle 74.8°)$

$= 79.67\text{kV} + 19.592\text{kV}\angle 53.6° = 92.65\text{kV}\angle 9.8°$

The source voltage is not equal to the no load voltage because one half the charging current flows through the series impedance. The no load voltage is

$V_{RNL} = V_S - (I_{CH}/2)Z = 92.65\text{kV}\angle 9.8° - (21.6\text{A}\angle 90°)(80.84\Omega\angle 74.80°$

$= 92.65\text{kV}\angle 9.8° - 1.76\text{kV}\angle 164.8° = 94.23\text{kV}\angle 9.35°$

Finally, from Equation 9.51

$$\text{VR} = \frac{94.23\text{kV} - 79.67\text{kV}}{79.67\text{kV}} = 0.183 \text{ or } 18.3\%$$

The reader will please note that this problem could have easily been solved with pu values if an appropriate base is chosen. If the calculations are for a larger system of which the line is only a part, especially with one or more transformers, pu expressions would be almost a necessity for reasonably easy calculations.

9.4.3 Generalized Circuit Constants

Referring again to Figure 9.22b we can write

$$V_S = (I_R + I_{CH}/2)Z + V_R = \left(I_R + \frac{V_R Y}{2}\right)Z + V_R$$

Rearranging terms we obtain

$$V_S = \left(\frac{YZ}{2} + 1\right)V_R + ZI_R \tag{9.54a}$$

and we write the sending current as

$$I_S = V_S\left(\frac{Y}{2}\right) + V_R\left(\frac{Y}{2}\right) + I_R \tag{9.55}$$

Substituting Equation 9.54a into Equation 9.55

$$I_S = V_R\left(\frac{YZ}{2} + 1\right)\left(\frac{Y}{2}\right) + V_R\left(\frac{Y}{2}\right) + I_R + ZI_R\left(\frac{Y}{2}\right)$$

$$= V_R\left(\frac{Y}{2}\right)\left(\frac{YZ}{2} + 2\right) + I_R\left(1 + \frac{ZY}{2}\right)$$

Thus

$$I_S = V_R Y\left(1 + \frac{YZ}{4}\right) + I_R\left(1 + \frac{ZY}{2}\right) \quad (9.54b)$$

Equations 9.54a and b are in the form of generalized four terminal network equations. The general form is

$$V_S = AV_R + BI_R \quad (9.56)$$

$$I_S = CV_R + DI_R \quad (9.57)$$

where

$$A = D = YZ/2 + 1 \quad (9.58a)$$

$$B = Z \quad (9.58b)$$

$$C = Y(YZ/4 + 1) \quad (9.58c)$$

The **ABCD** constants are called generalized circuit constants. They are usually complex numbers. They can be evaluated as follows.

Let $I_R = 0$, in other words no load, then

$$A = V_S/V_R \quad (9.59a)$$

$$C = I_S/V_R \quad (9.59b)$$

Now let $V_R = 0$, the output terminal short circuited, and

$$B = V_S/I_R \quad (9.59c)$$

$$D = I_S/I_R \quad (9.59d)$$

A bit of algebra allows us to calculate the receiving current and voltage in terms of the sending current and voltage

$$V_R = DV_S - BI_S \quad (9.60)$$

$$I_R = -CV_S + AI_S \quad (9.61)$$

where $(AD - BC) = 1$

The general four terminal network is shown in Figure 9.23a. The **ABCD** constants vary with the contents of the four terminal network.

The use of the **ABCD** constants has subsided with the advent of computers because a computer program can use the most precise equivalent circuit available for long, medium, and short lines with equal ease. The **ABCD** constants are very useful for calculator and general purpose mathematics solver programs computations, though.

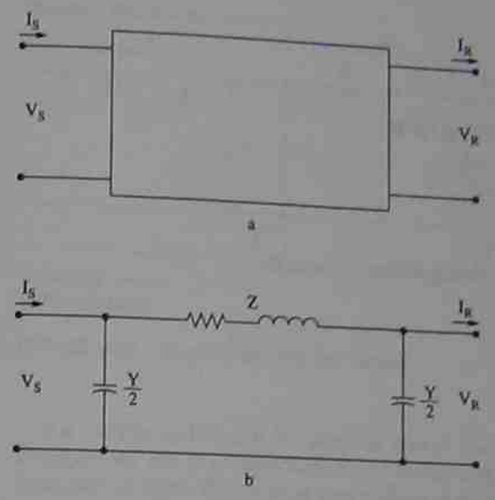


FIGURE 9.23 Generalized circuit constants (a) Four terminal network and (b) π network

Example 9.9:

Derive the **ABCD** constants of Figure 9.23b, and calculate their value for the line in Example 9.8.

Solution:

Using Equations 9.59a–d and letting

$$Z' = 1/(Y/2) = 2/Y$$

we solve for each constant. Let $I_R = 0$.

First **A**

$$V_R = V_S\left(\frac{Z'}{Z + Z'}\right)$$

$$A = \frac{V_S}{V_R} = \frac{Z + Z'}{Z'} = \frac{Z + 2/Y}{2/Y} = \frac{YZ}{2} + 1$$

Now for **C**

$$I_S = I_R + \frac{V_R}{Z'} + \frac{V_S}{Z'} = 0 + \frac{V_R}{Z'} + V_R\left(\frac{Z + Z'}{Z'}\right)\left(\frac{1}{Z'}\right)$$

$$= V_R\left(\frac{1}{Z'}\right)\left(1 + \frac{Z + Z'}{Z'}\right) = V_R\left(\frac{Y}{2}\right)\left(\frac{YZ}{2} + 2\right)$$

$$C = \frac{I_S}{V_R} = Y\left(\frac{YZ}{4} + 1\right)$$

Now let $V_R = 0$. Solving for **B**

$$B = \frac{V_S}{I_R} = \frac{V_S}{\left(\frac{V_S}{Z}\right)} = Z$$

Now for **D**. The receiving voltage is zero so

$$I_R = \frac{V_S}{Z}$$

$$I_S = \frac{V_S}{Z} + \frac{V_S}{Z'}$$

$$D = \frac{I_S}{I_R} = \frac{\frac{V_S}{Z} + \frac{V_S}{Z'}}{\frac{V_S}{Z}} = 1 + \frac{Z}{Z'}$$

$$D = \frac{YZ}{2} + 1 = A$$

The values of the **ABCD** constants are evaluated by multiplying the value pu distance by the distance and using Equations 9.58a, b, and c. In Example 9.8 we found the lumped parameter values. Evaluating for **ABCD** we obtain

$B = Z = 80.83\ \Omega\ \angle 74.8°$

$Y/2 = 271\ \mu S\ \angle 90°$

$A = D = (YZ)/2 + 1 = 21.905 \times 10^{-3}\ \angle 164.8° + 1 = 0.978\ \angle 0.336°$

$C = Y[(YZ)/4 + 1]$

$= 542\ \mu S\ \angle 90°[(135.5\ \mu S\ \angle 90°)(80.83\ \Omega\ \angle 74.8°) + 1]$

$= -1.556 \times 10^{-6} + j(536.27 \times 10^{-6}) = 536.28 \times 10^{-6}\ \angle 90.16°$

Appendix C gives some generalized constants for some useful four terminal networks.

9.4.4 Long Transmission Line Equivalent Circuit, Traveling Waves

To accurately calculate the current and voltage along a long line we must take into account that the series impedance $(R + jX_L)$ and the shunt admittance $(G + jB_C)$ are distributed along the line. In Figure 9.24 the long line distributed parameters are illustrated as lumped parameters per unit distance, as is commonly done. Each section, Δd, represents a section of line, usually a mile or a kilometer.

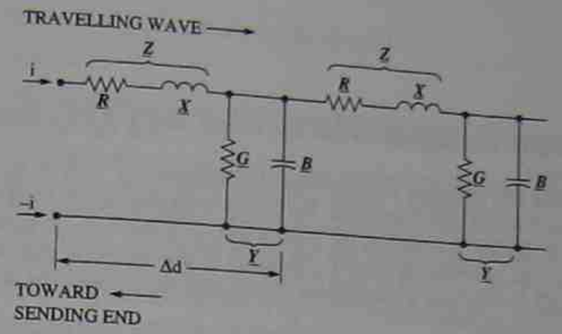


FIGURE 9.24 Generalized long line section

If a switch is closed at the sending end of the line in Figure 9.22c the line must energize by the line capacitance and inductance charging one section at a time, from left to right. The voltage and current then propagate by one small element of the line at a time. The charging current of the segment of the line the wave front is at is the voltage at that section divided by the impedance of that section of line. The impedance of a section of the line is called the line characteristic impedance (Z_C). Referring to Figure 9.24 we see

$$\frac{\Delta v}{\Delta d} = -L\frac{\Delta i}{\Delta t} - Ri \tag{9.62}$$

$$\frac{\Delta i}{\Delta d} = -C\frac{\Delta v}{\Delta t} - Gv \tag{9.63}$$

Letting R and G equal zero, a lossless line, and dividing Equation 9.62 by Equation 9.63 we find

$$\frac{-\frac{\Delta v}{\Delta d}}{-\frac{\Delta i}{\Delta d}} = \frac{L\frac{\Delta i}{\Delta t}}{C\frac{\Delta v}{\Delta t}}$$

$$\left(\frac{\Delta v}{\Delta i}\right)^2 = Z_C^2 = \frac{L}{C}$$

$$Z_C = \sqrt{\frac{L}{C}} \tag{9.64}$$

Typical transmission line characteristic impedance values are from around 400Ω to around 800Ω. If the loss components are not zero a somewhat more complicated process of mathematics gives the following equation for Z_C

$$Z_c = \sqrt{\frac{\underline{Z}}{\underline{Y}}} \tag{9.65}$$

Where $\underline{Z}$ is the complex line impedance per unit length, and $\underline{Y}$ is the complex line admittance pu length.
Equation 9.65 yields the complex characteristic impedance, $Z_C = R + jX$, which reduces to Equation 9.64 if R and G are zero. Try it. G is normally nearly zero and can be neglected, but R cannot. Because of the power loss in R the voltage wave front decreases in amplitude as it travels from the sending to the receiving end of a line.

As $\Delta d \rightarrow 0$ Equations 9.62 and 9.63 become differential equations. The solutions to them are in section 9.4.5.

If we multiply Equations 9.62 and 9.63 together, once again with R and G equal to zero, and solve for t we have the time it takes the voltage (or current) waveform to travel Δd in Figure 9.24.

$$\frac{\Delta v}{\Delta d}\frac{\Delta i}{\Delta d} = LC\frac{\Delta i \Delta v}{(\Delta t)^2}$$

$$\frac{(\Delta t)^2}{(\Delta d)^2} = \frac{1}{v^2} = LC$$

If the $\Delta d = 1$, a unit distance then

$\Delta t = \sqrt{\underline{LC}}$ per unit length (9.66)

$\Delta t \times l$ = time to propagate the length of the line. (9.67)

and the velocity of propagation, v, is,

$$v = \frac{1}{\sqrt{\underline{LC}}} \quad \text{unit distance per second} \tag{9.68}$$

The square root of the complex impedance times the complex admittance is not the complex time, instead it is the propagation constant, γ.

$\gamma = \sqrt{\underline{ZY}} = \sqrt{(\underline{R} + j\underline{X}_L)(\underline{G} + j\underline{B}_C)}$ (9.69)

Which, after some complex math can be expressed as

$\gamma = \alpha + j\beta$ (9.70)

where

α = attenuation constant per unit length (1 neper = 8.68 dB)

$\approx \underline{R}/(2\underline{Z})$

and

β = phase constant in radians pu length

$= (2\pi)/\lambda$ (9.71)

where λ = wavelength in the same units as β

The velocity of the wave on the line is

$v = f\lambda$ (9.72)

The total attenuation (reduction in amplitude) along the line is αl, and the total phase shift is βl.

Summing up, after the sending end switch is closed energizing the line the voltage and current move down the line as a wave front. The impedance of the line to the travelling wave is $\sqrt{L/C}$, and the velocity of the wave front is $1/\sqrt{LC}$. The voltage amplitude is reduced along the line by αl, and the total phase shift of the wave front along the line is βl. At the end of the line all of the power that reaches the receiving end is absorbed if $Z_R = Z_C$. In transmission lines the object is to transport power with a minimal voltage loss so normally $Z_R > Z_C$

9.4.5 Long Transmission Line: Reflections

The portion of the incident traveling wave front that is not absorbed by the receiving impedance is reflected and travels back toward the sending end where, if it is not all absorbed, a portion is re-reflected toward the receiving end. This process continues until all an equilibrium condition is established. If $Z_R > Z_C$ the reflected voltage (V_{rfl}) has the same instantaneous polarity as the incident voltage (V_{inc}). If $Z_R < Z_C$ the polarity of the incident voltage is reversed at reflection.

Let us first consider a line energized with a dc voltage, as shown in Figure 9.25a. Let the line resistance and conductance be negligible and the source and load impedances be pure resistance. The voltage wave begins to travel at $t = 0$, when the switch is closed. We will monitor a point just on the source side of the switch. Normally we would monitor just on the line side of the switch. As the wave front moves across the switch it encounters $Z_c = \sqrt{\underline{L}/\underline{C}}$. The incident voltage divides between the source impedance and the characteristic impedance at this point, with the amplitude of the wave traveling on down the line being the voltage dropped across Z_C. This is shown in Figure 9.25b. The voltage at the observation point does not change until the reflected wave returns from the load. This is twice the time it takes the wave to travel from the source to the load, $t = 2l\sqrt{\underline{LC}}$.

At the end of the line the incident wave encounters the load impedance. If $Z_C \neq Z_R$ then a portion is reflected. To calculate the reflected voltage refer to Figure 9.26a. The maximum available voltage at the end of the line occurs if all of the incident wave is reflected. This can occur if none is absorbed, or $Z_R = \infty$. In this case all of the incident voltage is reflected in the same polarity as the incident voltage and the voltage on the line is twice the incident voltage, $V_{inc} + V_{rfl} = 2V_{inc}$. If we close the switch just at the point the voltage at the end of the line reaches maximum, this voltage divides between Z_C and Z_R. Now, we close the switch in Figure 9.26a at $t = l\sqrt{LC}$. After closure

$$V_{rfl} = 2V_{inc}\frac{Z_R}{Z_C + Z_R} - V_{inc} = \frac{2V_{inc}Z_R}{Z_R + Z_C} - \frac{V_{inc}(Z_R + Z_C)}{Z_R + Z_C}$$

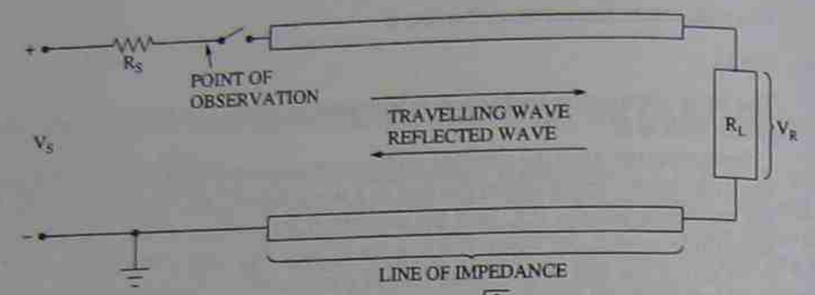


FIGURE 9.25 Reflections on a dc line (a) Line and source and (b) Voltage at observation point

$$= V_{inc}\frac{2Z_R - Z_R - Z_c}{Z_R + Z_c} = V_{inc}\frac{Z_R - Z_c}{Z_R + Z_c}$$

The ratio of the reflected voltage to the incident voltage is the reflection coefficient (Γ). From the equation above we see

$$\Gamma = \frac{V_{rfl}}{V_{inc}} = \frac{Z_R - Z_c}{Z_R + Z_c} \tag{9.73}$$

If $Z_R > Z_C$ then Γ is + and V_{rfl} adds to V_{inc}

If $Z_R < Z_C$ then Γ is − and V_{rfl} subtracts from V_{inc}

To keep the volt amperes constant at a reflection the reflected current polarity is opposite to the voltage so

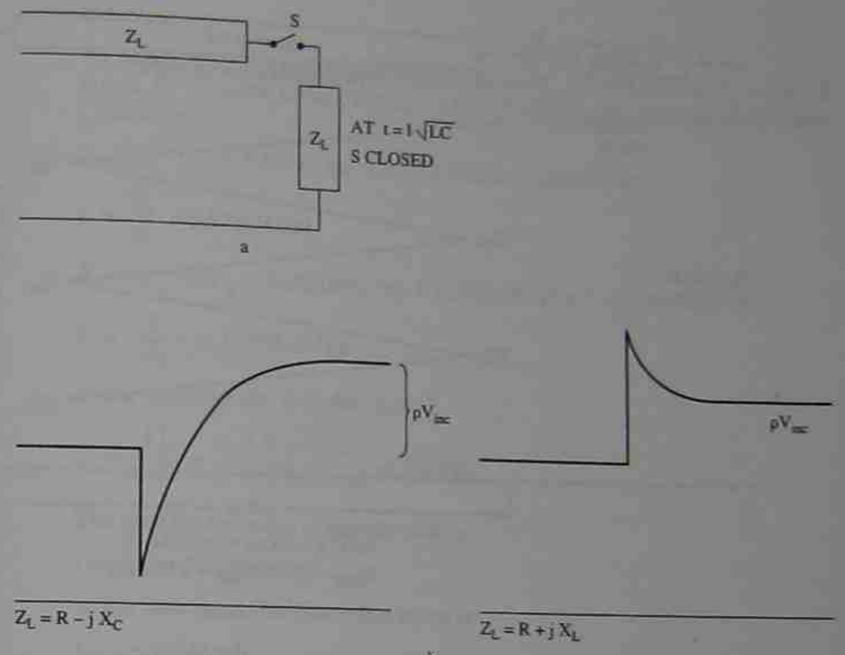


FIGURE 9.26 Reflections (a) Circuit for reflection coefficient equation development and (b) DC reflections from complex loads

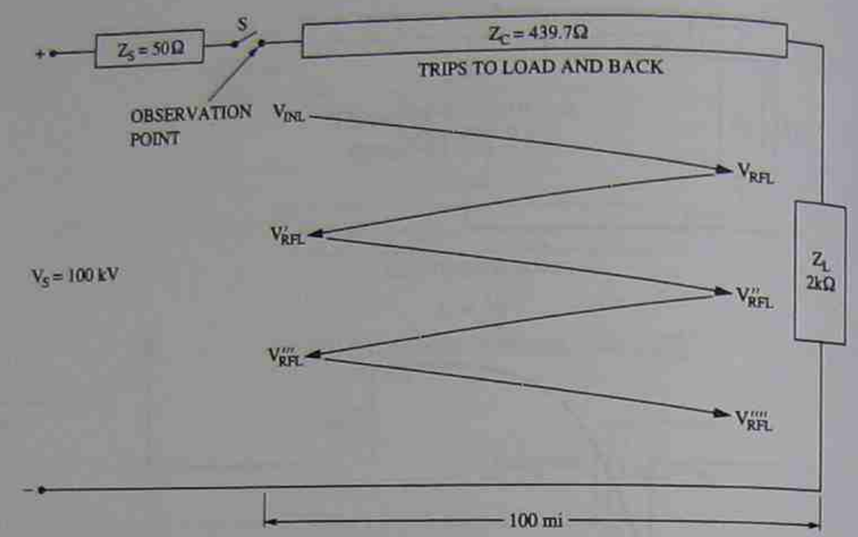
$$\Gamma_I = \frac{I_{inc}}{I_{rfl}} = \frac{Z_R - Z_c}{Z_R + Z_c} \tag{9.74}$$

Notice that the reflection coefficient magnitude is the same.

The reflections of dc voltage from a complex impedance are shown in Figure 9.26b. The capacitive load pulls the voltage down while it charges and the inductive load causes voltage to peak until the incident current begins to rise. The final value of the reflected wave is the reflection coefficient from the resistances and characteristic impedance, $\sqrt{L/C}$, of the line times the incident voltage for a dc wavefront. AC waves reflect according to the complex receiving and line impedances.

Example 9.10:

Draw the voltage reflection waveform for the dc line shown in Figure 9.27a for the first three reflections. Also calculate the time for the voltage wave to travel from one end of the line to the other. The dc line uses Hawk conductors spaced 49 feet apart. Ignore R_{line} in Z_C calculation.



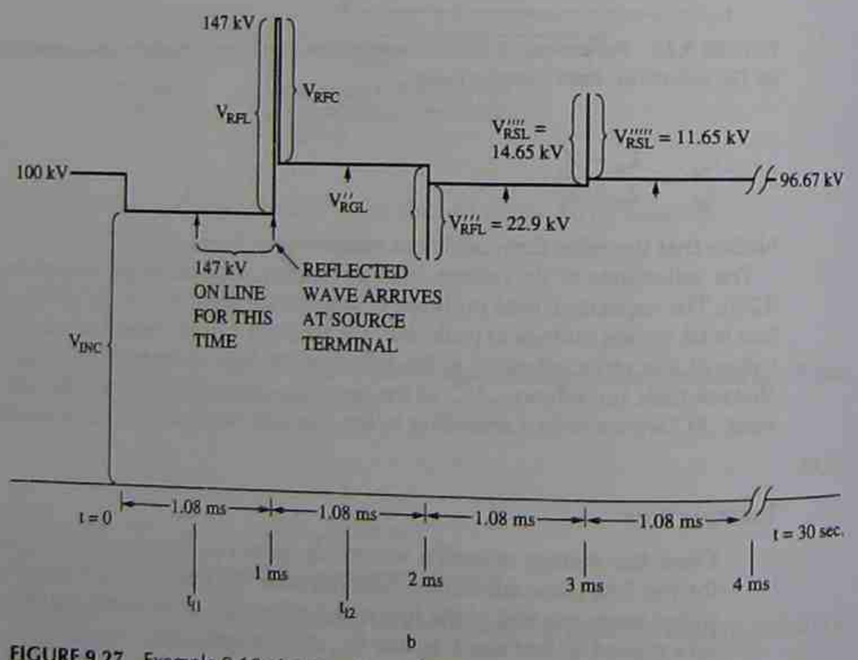


FIGURE 9.27 Example 9.10 circuit and waveform (a) Circuit and (b) Voltage waveform at observation point. t_r = time of reflection from load

Solution:

We find in the conductor tables that for Hawk: $X_a = 0.430\ \Omega/\text{mi}$, $X_d = 0.4722\ \Omega/\text{mi}$, $X_a' = 0.0988\ \text{M}\Omega\text{mi}$, and $X_d' = 0.1155\ \text{M}\Omega\text{mi}$. We now calculate L and C per mile.

$$X_L = X_a + X_d = 0.430\ \Omega/\text{mi} + 0.4722\ \Omega/\text{mi} = 0.902\ \Omega/\text{mi}$$

$$L = \frac{X_L}{\omega} = 2.39\ \text{mH/mi}$$

$$X_C = X'_a + X'_d = 0.0988\ \text{M}\Omega/\text{mi} + 0.1155\ \text{M}\Omega/\text{mi} = 0.2143\ \text{M}\Omega/\text{mi}$$

$$C = \frac{1}{X_C} = 12.378\ \text{nF/mi}$$

so the characteristic impedance is

$$Z_c \approx \sqrt{\frac{L}{C}} = \sqrt{\frac{2.39\ \text{mH/mi}}{12.378\ \text{nF/mi}}} = 439.7\Omega$$

The time for the wave to travel a mile is

$$t = \sqrt{LC} = 5.4425\mu\text{S/mi}$$

so the time needed to travel 100 miles is

$$t_{100\,mi} = 0.544\ \text{mS}$$

The incident voltage is

$$V_{inc} = V_S \frac{Z_c}{Z_S + Z_c} = 100\text{kV}\frac{439.7\Omega}{439.7\Omega + 50\Omega} = 89.7\ \text{kV}$$

After travelling 100 miles the incident wave reaches the load and reflects.

$$V_{rfl} = V_{inc}\Gamma = V_{inc}\frac{Z_R - Z_c}{Z_R - Z_c}$$

$$= 89.7\text{kV}\frac{2\text{k}\Omega - 439.7\Omega}{2.4397\text{k}\Omega} = 89.7\text{kV}(0.6397) = 57.36\text{kV}$$

The reflected voltage adds to the incident voltage because it is the same polarity, since $Z_R > Z_C$. Notice the total voltage on the line behind the reflected wave is 89.7 kV + 57.36 kV = 147 kV. This voltage must be anticipated when selecting the equipment BIL levels.

The reflected voltage now travels back to the source, and is reflected. $Z_S < Z_C$ so the voltage reflected back from the source is opposite in polarity to the voltage incident on the source. The source side reflection coefficient is

$$\Gamma_S = \frac{Z_S - Z_c}{Z_S + Z_c} = \frac{50\Omega - 439.7\Omega}{50\Omega + 439.7\Omega} = -0.7958$$

and the reflected voltage is

$$V^{-}_{r0} = (-0.7958)(57.36\text{ kV}) = -45.6\text{ kV}$$

The reflected voltage from the source causes an immediate change in our observed total line voltage because our observation point is at the source, as shown in Figure 9.27b. The total line voltage is now 147 kV − 45.6 kV = 101 kV. The −45.6 kV reflected voltage wave travels back toward the load subtracting from the 147 kV as it goes.

When it reaches the load an amount governed by the reflection coefficient reflects again.

$$V^{-}_{r0} = (-45\text{kV})(0.6397) = -28.78\text{ kV}$$

This reflected voltage is of the same polarity as the incident voltage that just arrived, not the total line voltage. Now the total line voltage at the load is 102 kV − 28.78 kV = 73.22 kV. As the reflected wave V_{r0}^{-} travels back toward the source the total line voltage adjusts to 73.22 kV as it travels. After 0.544 ms the voltage reflected from the load arrives back at the source and is reflected again.

$$V^{-}_{r0} = (-0.7958)(-28.78\text{kV}) = 22.9\text{ kV}$$

This reflection brings the line voltage to 73.22 kV + 22.9 kV = 96.12 kV as V^{-}_{r0} travels back toward the load. The reflections continue until the dc steady state conditions

$$V_R = V_S \frac{Z_L}{Z_S + Z_L + R_{DC}} = \frac{100\text{kV} \times 2\text{k}\Omega}{50\Omega + 2\text{k}\Omega + 18.85\Omega} = 96.67\text{kV}$$

are met.

Z_C, Z_S, and Z_L are usually complex in transmission line circuits, but other than the waveform adjustments at the line ends, as shown in Figure 9.26b, and some loss along the line causing V_{inc} and V_{r0} drop along the line, the reflection process is the same for any dc line.

The same reflection process occurs at the line ends with an ac voltage applied but the reactance causes the phase of the continuously changing ac wave to either retard, inductive Z_R, or advance, capacitive Z_R, as it reflects. Because an ac V_{inc} is continuously changing, the voltage reflected from it is continuously varying. The incident and reflected ac voltages add and subtract from each other along the line, just as in the dc case, thus the total line voltage at any point is an ac voltage whose instantaneous voltage is the algebraic sum of the waves travelling along the line in opposite directions. This process, illustrated in Figure 9.28, causes the ac voltage to be higher at some locations on a line than at others. The ratio of the maximum to the minimum voltage on the line is the voltage standing wave ratio (VSWR).

$$\text{VSWR} = \frac{V_{max}}{V_{min}} \tag{9.75}$$

It is useful to express the VSWR in terms of the reflection coefficient. Note that

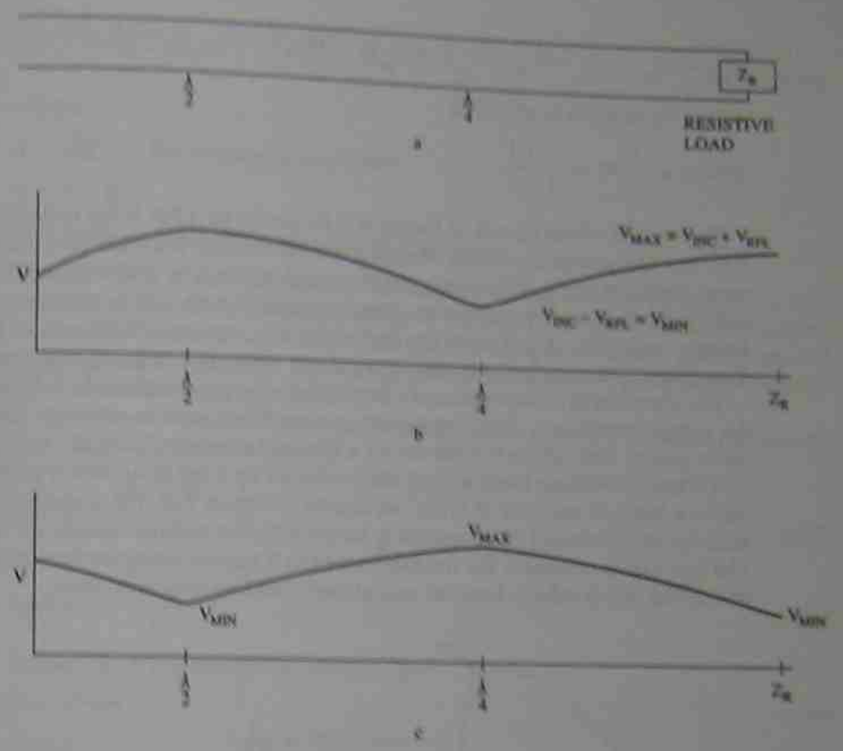


FIGURE 9.28 Standing waves (a) Line (b) rms voltage along line if Z_R is resistive and larger than Z_C (c) rms voltage along line if Z_R is resistive and smaller than Z_C and (d) Waveform of voltage at V_{min} and V_{max}

$$V_{max} = V_{inc} + V_{r0} = V_{inc} + V_{inc}\Gamma = V_{inc}(1 + \Gamma)$$

and

$$V_{min} = V_{inc} - V_{ref} = V_{inc} - V_{inc}\Gamma = V_{inc}(1 - \Gamma)$$

Using the definition of VSWR

$$\text{VSWR} = \frac{V_{max}}{V_{min}} = \frac{1 + \Gamma}{1 - \Gamma}$$

The VSWR of the circuit of Example 9.10 would be 4.549 if the voltage source was ac. The waves are called standing waves because the maximum and minimum voltages occur at the stationary locations on the line, as illustrated in Figure 9.28. If the load is complex the maximum and minimum voltage points are not at integer multiples of $\lambda/4$ from the end of the line, but are still spaced $\lambda/4$ apart. The current wave reflects, as does the voltage wave, but in the opposite polarity.

The characteristic impedance of a line with the series R neglected ($\sqrt{L/C}$) is called the surge impedance. This impedance is sometimes used to estimate the maximum power that can be transferred by a line into a matched load ($Z_R = Z_C$).

A transient voltage (such as that often induced by a lightning strike) propagates down a line at a velocity of $1/\sqrt{LC}$, as shown in Figure 9.29. The transient voltage adds to, or subtracts from depending on polarity, the voltage already on the line. The line losses attenuate the transient wave as it travels along the line, and at the end of the line it reflects from an unmatched load like any other wave.

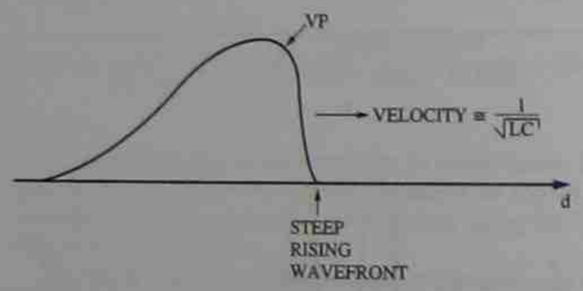


FIGURE 9.29 Transient from lightning on long line

9.4.6 Long Transmission Line Equivalent Circuit: Equation Solution

The solution of Equations 9.62 and 9.63 involve replacing the deltas with derivatives (for example $\Delta V/\Delta t$ with dV/dt) and solving the differential equations. The solution steps are somewhat lengthy and are presented in several of the references in Appendix E. We will present the solutions here. The current and voltage at any point along the line, referenced to the receiving current and voltage, are given in the following two equations.

$$V = \frac{V_R + I_R Z_c}{2} e^{\gamma l_R} + \frac{V_R - I_R Z_c}{2} e^{-\gamma l_R} \tag{9.76}$$

$$I = \frac{(V_R/Z_c) + I_R}{2} e^{\gamma l_R} - \frac{(V_R/Z_c) - I_R}{2} e^{-\gamma l_R} \tag{9.77}$$

where

$\gamma = \sqrt{ZY}$ the propagation constant

$\gamma = \alpha + j\beta$

l_R = distance from the receiving end of the line

The first term of each equation is the incident voltage (9.76) or current (9.77), and the second term is the reflected voltage or current, Equations 9.76 and 9.77 respectively. The first terms increase in magnitude toward the source and the second terms decrease, generally. The voltage, current, impedance, and propagation constant are all complex quantities.

Equations 9.76 and 9.77 are sometimes easier to solve if γ is broken into its real and imaginary parts as follows.

$$\sinh\theta = \frac{e^{\theta} - e^{-\theta}}{2} \tag{9.80}$$

$$\cosh\theta = \frac{e^{\theta} + e^{-\theta}}{2} \tag{9.81}$$

Recall that if a quantity θ is complex that

$$e^{\theta} = e^{\theta_R} e^{j\theta_I} \tag{9.82}$$

where

θ_R = real part

θ_I = imaginary part

Some algebraic manipulation of Equations 9.76 and 9.77 result in the following forms

$$V = V_R \frac{e^{\gamma l_R} + e^{-\gamma l_R}}{2} + I_R Z_c \frac{e^{\gamma l_R} - e^{-\gamma l_R}}{2}$$

$$I = I_R \frac{e^{\gamma l_R} + e^{-\gamma l_R}}{2} + \frac{V_R}{Z_c} \frac{e^{\gamma l_R} - e^{-\gamma l_R}}{2}$$

which can be written as

$$V = V_R \cosh\gamma l_R + I_R Z_c \sinh\gamma l_R$$

$$I = I_R \cosh\gamma l_R + \frac{V_R}{Z_c} \sinh\gamma l_R$$

If we let $l_R = l$, the entire line distance, in the preceding two equations we obtain the source voltage and current.

$$V_S = V_R\cosh\gamma l + I_R Z_c \sinh\gamma l \tag{9.83}$$

$$I_S = I_R\cosh\gamma l + \frac{V_R}{Z_c}\sinh\gamma l \tag{9.84}$$

Referring back to Equations 9.56 and 9.57 we notice that they are the same as Equations 9.83 and 9.84 if the general constants are as follows

$$A = D = \cosh\gamma l \tag{9.85}$$

$$B = Z_C \sinh\gamma l \tag{9.86}$$

$$C = (1/Z_c)\sinh\gamma l \tag{9.87}$$

The long line equivalent circuit can be represented with lumped parameters, as shown in Figure 9.30. The long line lumped parameters are primed. To be equivalent to the medium length line the coefficients of Equations 9.83 and 9.84 and Equations 9.56 and 9.57 must be equal. Thus from B

$$Z' = Z_c \sinh\gamma l \tag{9.88}$$

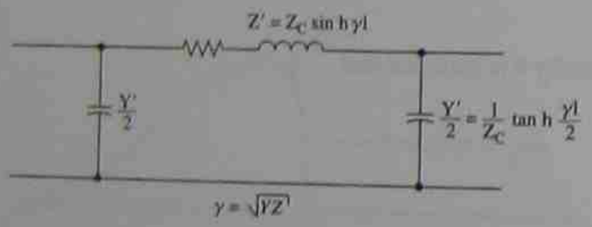


FIGURE 9.30 Lumped parameter long line π equivalent circuit

For A and D

$$\frac{Z'Y'}{2} + 1 = \cosh\gamma l$$

$$\frac{Y'Z_c\sinh\gamma l}{2} + 1 = \cosh\gamma l$$

$$\frac{Y'}{2} = \frac{\cosh\gamma l - 1}{Z_c\sinh\gamma l}$$

$$\frac{Y'}{2} = \frac{1}{Z_c}\frac{\cosh\gamma l - 1}{\sinh\gamma l}$$

From the hyperbolic function identities (check these with the exponential forms if you wish)

$$\tanh\frac{\gamma l}{2} = \frac{\cosh\gamma l - 1}{\sinh\gamma l}$$

Thus

$$\frac{Y'}{2} = \frac{1}{z_c}\tanh\frac{\gamma l}{2} \tag{9.89}$$

Equations 9.62 and 9.63 can be solved for receiving values in terms of sending values yielding

$$V_R = V_S\cosh\gamma l - I_S Z_c \sinh\gamma l \tag{9.90}$$

$$I_R = I_S\cosh\gamma l - \frac{V_S}{Z_c}\sinh\gamma l \tag{9.91}$$

Many calculators and mathematics-solving computer programs have hyperbolic function tables or evaluation programs built in, but few can evaluate the hyperbolic functions of complex arguments. The following two identities make the evaluation of complex arguments in terms of real numbers possible.

$$\begin{aligned}\cosh\gamma l &= \cosh(\alpha l + j\beta l)\\ &= \cosh\alpha l\cos\beta l + j\sinh\alpha l\sin\beta l\end{aligned} \tag{9.92}$$

$$\begin{aligned}\sinh\gamma l &= \sinh(\alpha l + j\beta l)\\ &= \sinh\alpha l\cos\beta l + j\cosh\alpha l\sin\beta l\end{aligned} \tag{9.93}$$

where α and β are found by computing

$$\gamma l = \sqrt{ZY}\,l = (\alpha + j\beta)l = \alpha l + j\beta l \tag{9.94}$$

Examples follow to illustrate the use of the equivalent circuits.

9.5 TRANSMISSION LINE LOSS EXAMPLE

The purpose of this example is to show the effect of voltage, length, and bundling on line loss for 69 kV, 138 kV, 345 kV, and 500 kV lines in lengths of 50, 100, and 200 miles. To make the example reasonable to do with a scientific calculator (programmable type preferable), or a mathematics-solving program for PCs, some simplifying assumptions were made.

1. The medium length lumped parameter equivalent circuit was used and considered sufficient in accuracy for the 200 mile line. The error is normally less than 5% for overhead lines with this equivalent circuit.
2. The source has no impedance and infinite capacity.

3. The load and load power factor for each line is fixed. The standard assumed power factor of 80% lagging is used.
4. The conductor used is Linnet, which is normally used only for 115 kV and 138 kV lines in the United States. To have a comparison basis Linnet is used for the 69 kV, 138 kV, 345 kV line (in a bundle of two), and the 500 kV line (in a bundle of three) of the example.
5. To have a basis for comparison the current per conductor of each line is 100 A. This causes the loads to be a bit light, but still reasonable. 100 A is a reasonable current for Linnet.
6. Common line spacings, shown in Figure 9.31, are used.
7. The resistance at 50°C is used.
8. The line lengths are to be the same for all the example lines for comparison. Actually a 69 kV line seldom exceeds 30 miles, a 138 kV line seldom exceeds 100 miles, and 345 kV and 500 kV lines are seldom built for distances less than 100 miles.

Example 9.11:

Calculate the line loss for a 50 mile, a 100 mile, and a 200 mile line for each voltage of 69 kV, 138 kV, 345 kV, and 500 kV. Use the spacings of Figure 9.31, and Linnet conductor. The current per conductor is 100 amperes. The 345 kV line is to use a bundle of two, and the 500 kV line a bundle of three conductors per phase. The medium length lumped parameter equivalent circuit is to be used throughout the example.

Solution:

From Table 9.1 we find for Linnet: Al area = 336,400 CM, 26/7 stranding, 0.721 in OD, GMR = 0.0243 ft, $X_a = 0.451\ \Omega/\text{mi}$, $X_a' = 0.1040\ \text{M}\ \Omega\text{mi}$, and R_{ac} at 50°C = 0.3006 Ω/ mi.

The resistances per mile are

69 kV and 138 kV—0.3006 Ω/mi

345 kV bundle of two—0.3006/2 = 0.1503 Ω/mi

500 kv bundle of three—0.3006/3 = 0.1002 Ω/mi

The inductive reactances are dependent on the spacing as well as the diameter of the conductor. For each conductor X_L is

69 kV X_L: 10 ft – 10 ft – 20 ft spacing

$$D_{eq} = \sqrt[3]{10\text{ ft}\ 10\text{ ft}\ 20\text{ ft}} = 12.6\text{ ft}$$

$$X_L = (2.022 \times 10^{-3}) f \ln \frac{D_{eq}}{D_s}$$

$$X_L = (2.022 \times 10^{-3})(60\text{ Hz}) \ln \frac{12.6\text{ ft}}{0.0243\text{ ft}} = 0.75825\ \Omega/\text{mi}$$

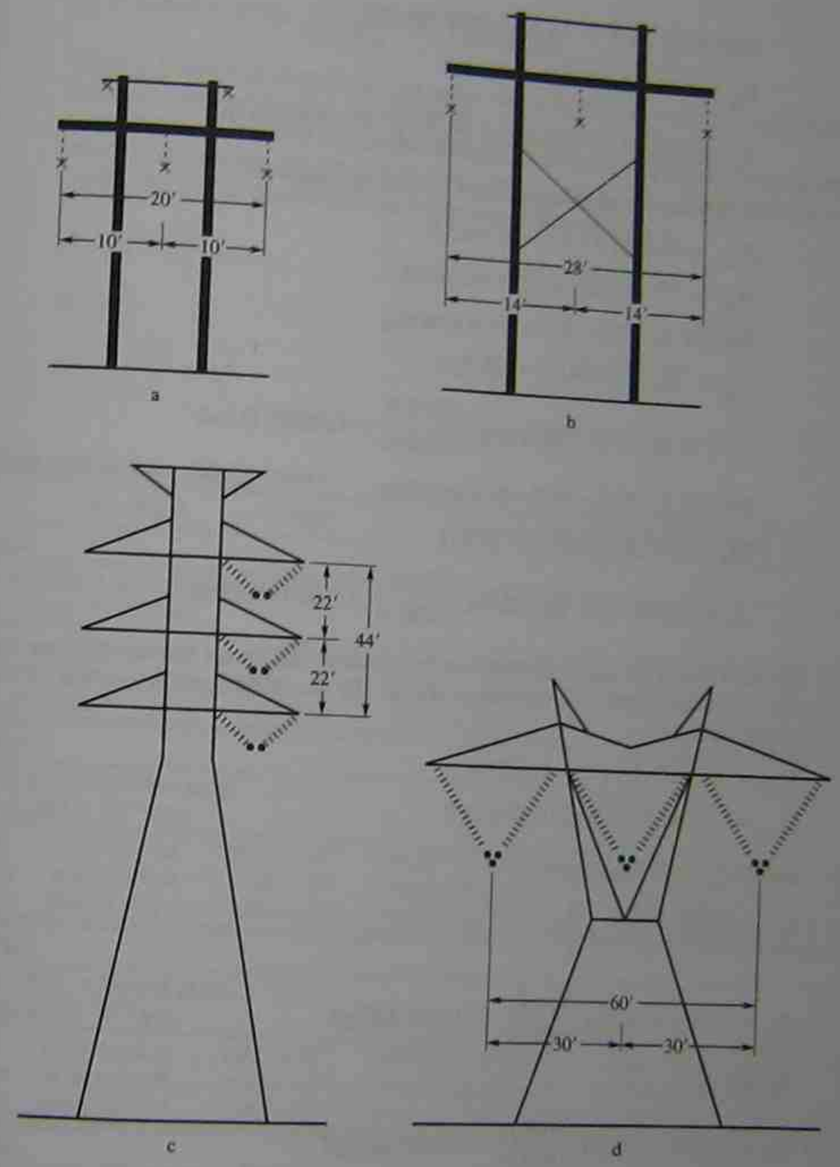


FIGURE 9.31 Towers and spacings for Example 9.11 (approximately to scale) (a) 69 kV H fixture (b) 138 kV H fixture (c) 345 kV restricted R.O.W. type tower and (d) 500 kV cross country type tower

138*KV* X_L: 14 ft – 14 ft – 28 ft spacing

$D_{eq} = \sqrt[3]{14\text{ ft} \cdot 14\text{ ft} \cdot 28\text{ ft}} = 17.64\text{ ft}$

$$X_L = (2.022 \times 10^{-3})(60\text{ Hz}) \ln \frac{17.64\text{ ft}}{0.0243\text{ ft}} = 0.79919\ \Omega/\text{mi}$$

D_s for the bundled conductors Bundle spacing—18"

$D_{sB2} = \sqrt{0.0243\text{ ft} \cdot 1.5\text{ ft}} = 0.1909\text{ ft}$

$D_{sB3} = \sqrt[3]{0.0243\text{ ft}(1.5\text{ ft})^2} = 0.3795\text{ ft}$

345 KV X_L: 22 ft – 22 ft – 44 ft spacing

$D_{eq} = \sqrt[3]{22\text{ ft} \cdot 22\text{ ft} \cdot 44\text{ ft}} = 27.72\text{ ft}$

$$X_L = (2.022 \times 10^{-3})(60\text{ Hz}) \ln \frac{27.72\text{ ft}}{0.1909\text{ ft}} = 0.60385\ \Omega/\text{mi}$$

500 kV X_L: 30 ft – 30 ft – 60 ft spacing

$D_{eq} = \sqrt[3]{30\text{ ft} \cdot 30\text{ ft} \cdot 60\text{ ft}} = 37.8\text{ ft}$

$$X_L = (2.022 \times 10^{-3})(60\text{ Hz}) \ln \frac{37.8\text{ ft}}{0.3795\text{ ft}} = 0.55813\ \Omega/\text{mi}$$

We now have enough information to calculate the series impedance pu length. Now for the capacitive reactance. D_s of the bundled conductors for X_C using actual radius

$D_{sB2} = \sqrt{0.0300\text{ ft} \cdot 1.5\text{ ft}} = 0.2121\text{ ft}$

$D_{sB3} = \sqrt[3]{0.0300\text{ ft}(1.5\text{ ft})^2} = 0.4072\text{ ft}$

69 kV X_C from Equation 9.46

$$X_C = \frac{1.779 \times 10^6}{f} \ln \frac{D_{eq}}{r}$$

$$X_C = (2.965 \times 10^4) \ln \frac{12.6\text{ ft}}{0.030\text{ ft}} = 0.1791\ \text{M}\Omega\text{mi}$$

138 kV X_C

$$X_C = (2.965 \times 10^4) \ln \frac{17.64\text{ ft}}{0.030\text{ ft}} = 0.1891\ \text{M}\Omega\text{mi}$$

345 kV X_C bundle of two

$$X_C = (2.965 \times 10^4) \ln \frac{27.72\text{ ft}}{0.2121\text{ ft}} = 0.1445\ \text{M}\Omega\text{mi}$$

500 kV X_C bundle of three

$$X_C = (2.965 \times 10^4) \ln \frac{37.8\text{ ft}}{0.4072\text{ ft}} = 0.1344\ \text{M}\Omega\text{mi}$$

Table 9.4 lists the impedance per mile, the admittance per mile, and the ABCD constants needed for the calculation of V_S and I_S.

We proceed for each line length as follows. First the equivalent circuit parameters are calculated, except in Table 9.4 Y rather than $Y/2$ is listed. Second we calculate the ABCD constants from Equations 9.58a, b, and c.

$$A = D = \frac{YZ}{2} + 1$$

$$B = Z$$

$$C = Y\left(\frac{YZ}{4} + 1\right)$$

TABLE 9.4 ABCD Values

	Z = B(Ω)	Y(S)	A = D	C(S)
69 kv				
$Z = 0.3006 + j0.7582\ \Omega/\text{mi}$ $Y = j5.583 \times 10^{-6}$ s/mi				
50 mi	$15.03 + j\,37.91$	297.2×10^{-6}	$0.9947 + j2.098 \times 10^{-3}$	$-292.9 \times 10^{-9} + j278.4 \times 10^{-6}$
100 mi	$30.06 + j75.828$	558.3×10^{-6}	$0.9788 + j8.391 \times 10^{-3}$	$-2.342 \times 10^{-6} + j0.5524 \times 10^{-3}$
200 mi	$60.12 + j151.65$	1.118×10^{-3}	$0.9153 + j33.57 \times 10^{-3}$	$-18.74 \times 10^{-6} + j1.069 \times 10^{-3}$
138 kv				
$Z = 0.3006 + j0.7992\ \Omega/\text{mi}$ $Y = j5.288 \times 10^{-6}$ s/mi				
50 mi	$15.03 + j39.96$	264.4×10^{-6}	$0.9947 + j1.987 \times 10^{-3}$	$-262.7 \times 10^{-9} + j263.7 \times 10^{-6}$
100 mi	$30.06 + j79.92$	528.8×10^{-6}	$0.9789 + j7.948 \times 10^{-3}$	$-2.101 \times 10^{-6} + j0.5232 \times 10^{-3}$
200 mi	$60.12 + j159.8$	1.058×10^{-3}	$0.9155 + j31.79 \times 10^{-3}$	$-16.81 \times 10^{-6} + j1.013 \times 10^{-3}$
345 kv				
$Z = 0.1503 + j0.6038\ \Omega/\text{mi}$ $Y = j6.923 \times 10^{-6}$ s/mi				
50 mi	$7.515 + j30.19$	346.2×10^{-6}	$0.9948 + j1.301 \times 10^{-3}$	$-225.1 \times 10^{-9} + j345.2 \times 10^{-6}$
100 mi	$15.30 + j60.38$	692.3×10^{-6}	$0.9791 + j5.203 \times 10^{-3}$	$-1.801 \times 10^{-6} + j0.6851 \times 10^{-3}$
200 mi	$30.06 + j120.8$	1.385×10^{-3}	$0.9164 + j20.81 \times 10^{-3}$	$-14.41 \times 10^{-6} + j1.327 \times 10^{-3}$
500 kv				
$Z = 0.1002 + j0.5581\ \Omega/\text{mi}$ $Y = j7.445 \times 10^{-6}$ s/mi				
50 mi	$5.010 + j27.91$	372.3×10^{-6}	$0.9948 + j.9325 \times 10^{-3}$	$-173.6 \times 10^{-9} + j371.2 \times 10^{-6}$
100 mi	$10.02 + j55.81$	744.5×10^{-6}	$0.9792 + j3.730 \times 10^{-3}$	$-1.388 \times 10^{-6} + j0.7368 \times 10^{-3}$
200 mi	$20.04 + j111.62$	1.489×10^{-3}	$0.9169 + j14.92 \times 10^{-3}$	$-11.11 \times 10^{-6} + j1.427 \times 10^{-3}$

Third we calculate V_S and I_S from Equations 9.56 and 9.57. V_S is the phase voltage.

$V_S = AV_R + BI_R$

$I_S = CV_R + DI_R$

Fourth we find the power received

$P_R = \sqrt{3}\, V_R I_R \cos(^-36.8°)$

and the power sent

$P_S = \sqrt{3}\, V_S I_S^* \cos\angle V_S I_S^*$

where V_S has been converted back to the line value. S_S may at times be smaller than S_R ($S_R = \sqrt{3}\, V_R I_R \angle^-36.8°$) in magnitude, but the S values are vector values and $P_S > P_R$. Finally the line loss, $\Delta P = P_S - P_R$. Appendix D gives the received voltage, sending end voltage, and line loss (ΔP) per phase for both the medium and long line equivalent circuit at 100A and 300A.

Example calculation of loss 69 kV 50 mile line

The values pu length are

$Z = (0.3006 + j0.75825)\ \Omega/\text{mi}$

$Y = B_C = j5.583\ S/\text{mi}$

so the lumped parameters are 50 miles times the value per mile

$Z = (15.03 + j37.91)\ \Omega$

$Y = j279.15\ \mu S$

The ABCD constants are

$$A = D = \frac{ZY}{2} + 1 = 0.9947 \times 10^{-3} + j2.098 \times 10^{-3}$$

$$B = Z$$

$$C = Y\left(\frac{YZ}{2} + 1\right) = {}^-292.9 \times 10^{-9} + j278.4 \times 10^{-6}$$

and the sending voltage and current are, from Equations 9.56 and 9.57

$V_S = 3.855 \times 10^4 + j4.018 \times 10^3 = 38.76\ kV\underline{/5.94°}\ \ V$

The sending line voltage is

$\sqrt{3}\, 38.76\ kV = 67.14\ kV\underline{/5.94°}\ \ V$

$I_S = 79.44 + j70.94 = 106.51\underline{/41.76°}\ \ A$

The received power is

$P_R = \sqrt{3}\ 69\ \text{kV}\ 100\text{A} \cos 36.87° = 9.561\text{MW}$

and the sent power is the real part of $S_S = \sqrt{3}\, V_S \bar{I}_S$

$S_S = \sqrt{3}\ (67.14\ \text{kV}\angle 5.94°)(1065\text{A}\angle^-41.76°) = 10.043\ \text{MW} - j7.247\ \text{MVAR}$

Thus $P_S = 10.043\ \text{MW}$

so the line loss is

$\Delta P = P_S - P_R = 482\ \text{kW}$

Which is 4.41% of the received power. The results of the calculations for all of the lines are in Appendix D.

9.6 SUMMARY

Transmission lines have resistance, inductance, and capacitance. These parameters, R, L, and C, are distributed along the line, a fact that makes the calculation of the parameters more complicated. Additionally, the line electric and magnetic fields couple to each other, which complicates the calculation task even more. Field interactions with the shield lines and ground are additional complicating factors. The line parameters are usually represented on a pu length basis, usually R, L, or C per mile or kilometer. Tables are available that allow easy calculation of the line parameters. The equations for the line electrical parameters are presented in sections 9.1 through 9.4.

Transmission line distributed calculations are very complicated, so equivalent circuits for transmission lines are used to simplify both discussion and calculations. As transmission line length is increased the equivalent circuit needed to accurately model the line becomes more complex. The equivalent circuits of transmission lines are covered in section 9.4.

The load impedance is always more than the line impedance on unfaulted electrical power transmission lines. If the load impedance differs from the line impedance when an electrical wave travels down a line reflections occurs. If the load impedance is larger than the line impedance the voltage is reflected in phase and the total line voltage rises until the line stabilizes. This phenomena can result in switching transients of almost twice the line voltage. These transients must be taken into account when transmission line protection systems are designed.

9.7 QUESTIONS

1. Calculate the percent resistance increase from skin effect at 60 Hz and 200C for Waxwing, Ortulan, and Bluebird ACSR conductors. Use Table 9.1.

2. Calculate the total inductance of a single-phase, 60 Hz, circuit with Waxwing conductor spaced 9 feet apart.
3. Three conductor filaments are 1 cm in diameter and separated from two 2 cm diameter conductor filaments, as shown in Figure 9.32. Calculate the GMR of each conductor and the GMD between the conductors.

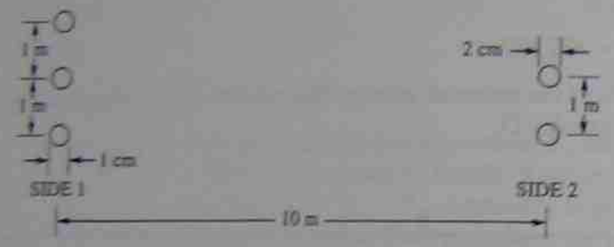


FIGURE 9.32 Conductor arrangement for Problem 9.3

4. Calculate the total inductance of the equivalent geometry of the conductors in problem 3. Assume single-phase line voltage.
5. Calculate, with the aid of Tables 9.1 and 9.2, the inductance per mile of Osprey conductors spaced 22 feet apart.
6. The circuit shown in Figure 9.12 uses Osprey conductors. Calculate the series impedance per mile.
7. The 345 kV line of Figure 9.13 uses Ortulan conductors. Calculate the series impedance per mile.
8. Calculate the line to neutral capacitance per meter of the conductors of Figure 9.15 if $r_a = 2$ cm, $r_b = 5$ cm, and D = 2 m.
9. Calculate the capacitance per meter of the equivalent geometry of the conductors in Figure 9.32.
10. Calculate the shunt admittance per mile of the circuit of problem 6.
11. Calculate the shunt admittance per mile of the circuit of problem 7.
12. Calculate the series impedance, shunt admittance, and charging current per mile of the line shown in Figure 9.19 if the conductor is Hawk.
13. The conductor of Figure 9.20 is changed to Drake. Calculate the series impedance, shunt admittance, and charging current per mile.
14. Calculate the π lumped parameter medium length line equivalent circuit for the line of problem 12 if the line is 60 miles long.
15. Calculate the π lumped parameter medium length line equivalent circuit for the line of problem 13 if the line is 120 miles long.
16. Calculate the ABCD generalized circuit parameters for a single capacitor, as shown in Figure 9.33.
17. Calculate the power loss on the line of problem 14 if the receiving voltage, current, apparent power, and power factor are 220 kV, 140 A, 53.347 MVA, and 0.9 respectively.
18. Repeat problem 17 with a 120 mile line length.



FIGURE 9.33 Circuit for Problem 9.16

19. Calculate the power loss on the line of problem 15 if $V_R = 750$ kV, $I_R = 800$ A, SR = 1,039 MVA, and the receiving power factor is 0.8.
20. If electric power costs $0.08 per kW hr, what is the difference in the cost of line power loss between the lines of problem 18 and problem 19?

Optional

21. Repeat problem 19 using the long line equivalent circuit.

CHAPTER 10

Transmission Line Fault Current Calculation, Protection, and Bulk Power Substations

This chapter deals with three major topics. The first is a method of accurately calculating fault currents on transmission lines. The method is called *symmetrical components*. The second topic is *transmission line protection*. Protective relays are used to protect transmission lines. The relays are housed in the substations at which the transmission lines terminate. The third topic is *bulk power substations*. We have already studied the equipment used in bulk power substations since it varies only in capacity and size from that used in distribution substations. So we will contrast bulk power and distribution substations, and take a closer look at grounding.

10.1

TRANSMISSION LINE FAULT CALCULATIONS

This section classifies faults, introduces symmetrical components, and shows an example fault current calculation.

10.1.1 Fault Classifications

A transmission system fault is defined as any abnormal condition. In this section we are concerned only with faults caused by a transmission line short circuit. The short circuit faults are classified as:

1. Line to ground. Line to ground faults are caused by a transmission line touching the ground. Wind, ice loading, or an accident such as a tree limb falling on a line can cause a line to ground fault. This category accounts for about 70% of all transmission line short circuit faults.
2. Line to line. These faults are normally caused by high winds blowing one line into another, or by a line breaking and falling on a line below it. These account for about 15% of transmission line faults.
3. Double line to ground. This category is caused by the same things that cause single line to ground faults, except two lines are involved instead of one. These account for about 10% of transmission line faults.
4. Three-phase faults. If a line condition occurs in which all three phases are shorted together, either by something falling on the phase conductors, an equipment failure, or all three lines falling to the ground, it is called a three-phase fault. These are relatively rare, accounting for only about 5% of all transmission line faults.

These faults are summarized in Figure 10.1. Open circuits also occur but they are normally caused by relays responding erroneously to a switching transient or load change. This accounts for about 3% of all relay operations.

The point at which a conductor touches ground or another conductor during a fault is usually accompanied by an arc. The arc is resistive, but arc resistance varies widely. The usual utility practice is to consider the fault resistance zero to calculate the maximum fault current that can occur at a point of interest on a line, and the fault resistance 20 Ω (40 Ω for REA) to calculate minimum fault current. The fault resistance consists of the arc resistance, plus the ground resistance in the event a fault is to ground.

The fault current that flows depends on the source, line, and fault impedances, as illustrated in Figure 10.2.

$$I_{FAULT} = \frac{V_{SOURCE}}{Z_s + Z_L + Z_f} \qquad (10.1)$$

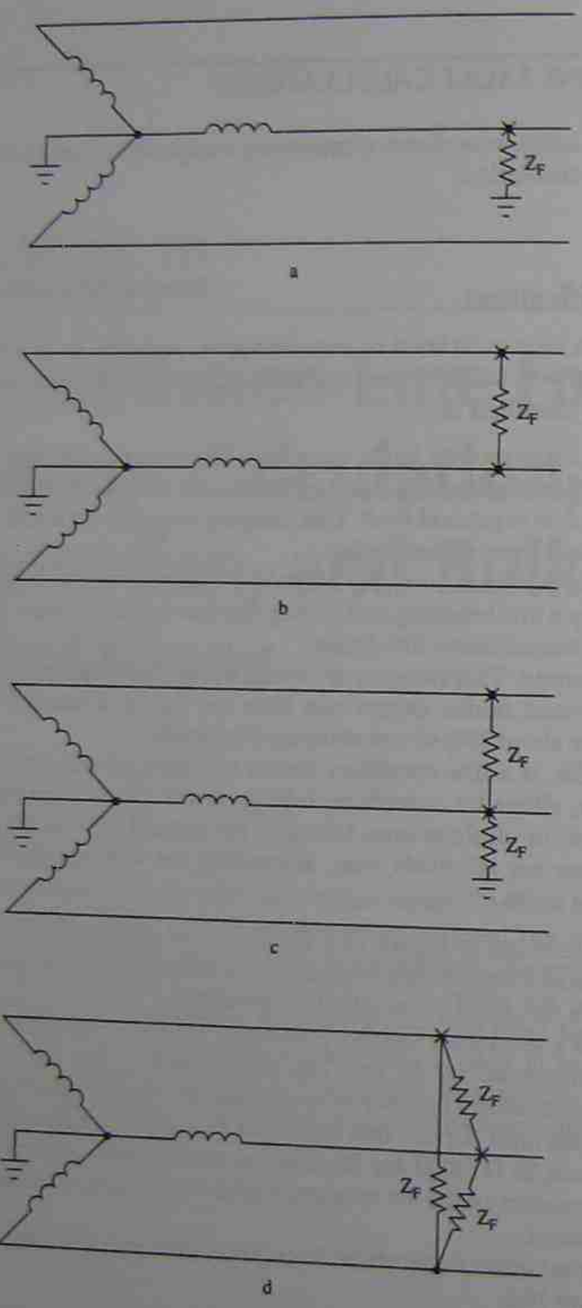


FIGURE 10.1 Fault classifications (a) Line to ground (b) Line to line (c) Double line to ground and (d) Three-phase fault

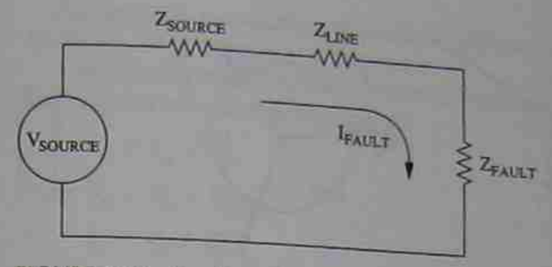


FIGURE 10.2 Simple equivalent circuit for fault current calculation

Recall from Chapter 5.1.1 that the fault current is normally asymmetrical, as shown in Figure 5.2.

A shorthand, per phase, method of calculating line current and voltages called per unit (pu) was introduced in Chapter 2. We can solve nearly all power problems using per phase values, although when no base change is necessary, such as in the single line loss problems of Chapter 9, actual values may be as convenient as pu. Our methods of calculation to this point have depended on the load fed by the system being reasonably well balanced. The line voltages and currents during a fault are very seldom balanced.

A method of calculating voltage and current for unbalanced loads was published by C. L. Fortescue in 1918. It is called the method of symmetrical components. The method is a powerful technique for analyzing ac power systems with unbalanced loads.

10.1.2 Definition of Symmetrical Components

An unbalanced system of N phasors can be resolved into N systems of balanced phasors, each of which has phasors of equal amplitude with equal angles between each phasor. The systems of balanced phasors are called symmetrical components. The vector sum of the symmetrical components is equal to the original system of unbalanced phasors. Thus an unbalanced three-phase system is the sum of three sets of balanced phasors, or symmetrical components.

The symmetrical components of a three-phase system, illustrated in Figure 10.3a, are:

1. *Positive sequence components.* These are three phasors of equal magnitude, offset from each other by 120°, and rotating in the same direction as the original phasors, usually signified counterclockwise in a phasor diagram. Positive sequence quantities are signified by the subscript 1, for example V_{A1} or I_{B1}.
2. *Negative sequence components.* Three phasors of equal magnitude, offset from each other 120° in phase, and rotating in the opposite direction to the original phasor, make up the negative sequence components. Normally the rotation of the phasors is considered to be in the same direction as the original phasors, but two of the phase vectors, b and c, are reversed, as shown in Figure 10.3a. Thus the negative sequence components phase rotation is acb instead of abc. Negative sequence quantities are given subscript 2 identification as in Z_2 or V_2.

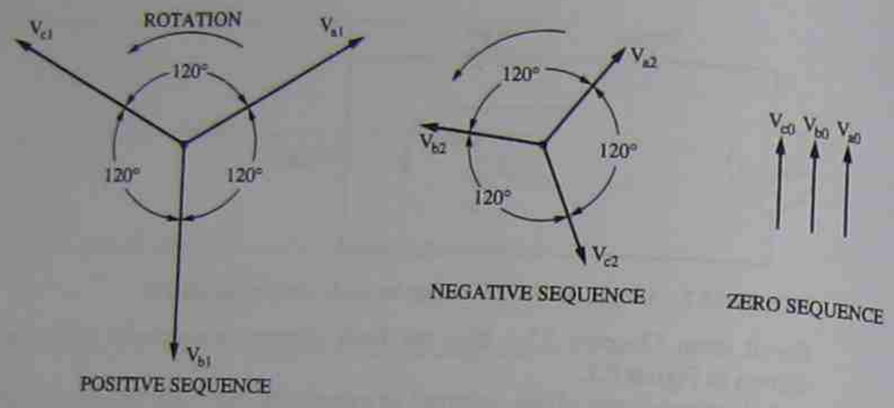


FIGURE 10.3 Symmetrical components of unbalanced phasors (a) Symmetrical components (b) Unbalanced phasor, sum of symmetrical components

3. *Zero sequence components.* These are three phasors of equal magnitude with no phase offset between them. They are in phase. The zero sequence components are often considered to be nonrotating, like a dc voltage. However, zero sequence impedance is complex, so the zero sequence voltage is treated as a single-phase source for calculating zero sequence impedance in relaying problems. Zero sequence quantities are identified with a subscript zero as in I_0 or Z_0.

Figure 10.3b shows the asymmetrical phasors of which the phasors of Figure 10.3a are the symmetrical components.

The defining equations for the symmetrical components, where V_a, V_b, and V_c are the original unbalanced phasors, are

$$V_a = V_{a1} + V_{a2} + V_{a0}$$

$$V_b = V_{b1} + V_{b2} + V_{b0} \tag{10.2}$$

$$V_c = V_{c1} + V_{c2} + V_{c0} \tag{10.3}$$

(10.4)

The quantities in the symmetrical components are generally complex. These equations are illustrated in Figure 10.3b. The current equations are identical in form.

$$I_a = I_{a1} + I_{a2} + I_{a0}$$

$$I_b = I_{b1} + I_{b2} + I_{b0} \tag{10.5}$$

$$I_c = I_{c1} + I_{c2} + I_{c0} \tag{10.6}$$

(10.7)

10.1.3 Operators

The j operator, which we have used since ac circuits, signifies a 90° phase shift. The a operator is used to indicate a 120° phase shift.

$$a = 1\angle 120° = -0.5 + j0.866$$

$$a^2 = 1\angle 240° = -0.5 - j0.866$$

$$a^3 = 1\angle 360° = 1\angle 0°$$

The relative angular position of the three phasors for a three-phase voltage can be expressed as the product of the amplitude of the phasor and the operator, a. Referring to Figure 10.3a we see, since $V_{a1} = V_{b1} = V_{c1}$

$$V_{b1} = a^2 V_{a1}$$

$$V_{c1} = aV_{a1}$$

and

$$V_{b2} = aV_{a2}$$

$$V_{c2} = a^2 V_{a2}$$

and

$$V_{c0} = V_{b0} = V_{a0}$$

Now Equations 10.2 through 10.4 can be written

$$V_a = V_{a1} + V_{a2} + V_{a0} \tag{10.8}$$

$$V_b = a^2 V_{a1} + aV_{a2} + V_{a0} \tag{10.9}$$

$$V_c = aV_{a1} + a^2 V_{a2} + V_{a0} \tag{10.10}$$

10.1.4 Symmetrical Components of Asymmetrical Phasors

The magnitudes of the phasors of each sequence of symmetrical components are equal. Thus we need only find the magnitude of V_{a1}, V_{a2}, and V_{a0} to calculate V_a, V_b, and V_c, as shown in Equations 10.8, 10.9, and 10.10. If we add the terms in Equations 10.8, 10.9, and 10.10 we find

$$V_{a1} + a^2V_{a1} + aV_{a1} = |V_{a1}| + (-0.5 - j0.866)\,|V_{a1}| + (-0.5 + j0.866)\,|V_{a1}| = 0$$

and similarly

$$V_{a2} + aV_{a2} + a^2V_{a2} = 0$$

thus

$$V_{a0} = \frac{1}{3}(V_a + V_b + V_c) \tag{10.11}$$

We can eliminate the Va1 column coefficients by multiplying Equation 10.9 by a and Equation 10.10 by a^2 yielding

$$V_{a1} = \frac{1}{3}(V_a + aV_b + a^2V_c) \tag{10.12}$$

Multiplying Equation 10.10 by a and Equation 10.9 by a^2 and adding results in

$$V_{a2} = \frac{1}{3}(V_a + a^2V_b + aV_c) \tag{10.13}$$

As before, the form of the current equations is the same as the voltage equations.

$$I_{a0} = \frac{1}{3}(I_a + I_b + I_c) \tag{10.14}$$

$$I_{a1} = \frac{1}{3}(I_a + aI_b + a^2I_c) \tag{10.15}$$

$$I_{a2} = \frac{1}{3}(I_a + a^2I_b + aI_c) \tag{10.16}$$

Recall that for an unbalanced three-phase system with a neutral

$I_n = I_a + I_b + I_c$

From Equation 10.14 we see that

$I_n = 3I_{a0}$

Example 10.1:

Calculate the symmetrical components of the currents shown in Figure 10.4.

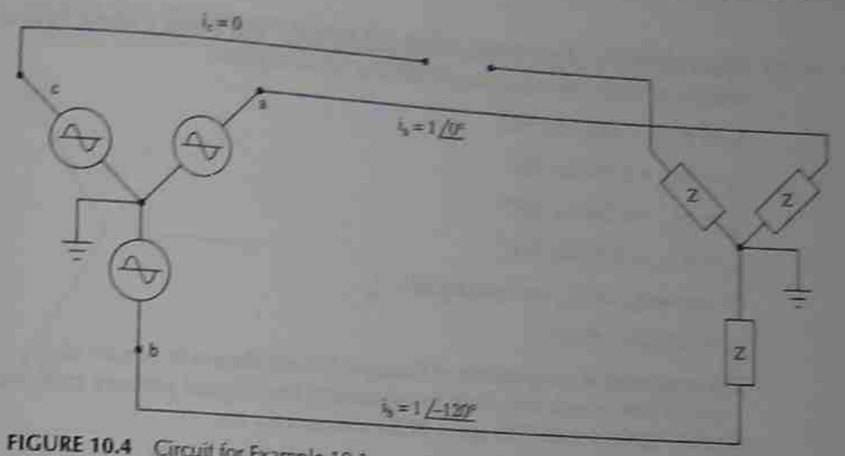


FIGURE 10.4 Circuit for Example 10.1

Solution:

First we express the currents in component form for future use

$I_a = 1\angle 0° = 1 + j0$

$I_b = 1\angle -120° = -0.5 - j0.866$

$I_c = 0$

From Equation 10.14 we calculate the zero sequence current

$$I_{a0} = \frac{1}{3}(I_a + I_b + I_c) = \frac{1}{3}(1 - 0.5 - j0.866) = \frac{1}{3}(0.5 - j0.866)$$

$$= 0.\frac{999}{3}\text{A}\angle -60° = 0.333\text{A}\angle -60°$$

Using Equation 10.15 we calculate the positive sequence current.

$$I_{a1} = \frac{1}{3}(I_a + aI_b + a^2I_c) = \frac{1}{3}[1 + (1\angle 120°)(1\angle -120°)]$$

$$= \frac{1}{3}(1 + 1) = 0.667\text{A}\angle 0°$$

Using Equation 10.16 to calculate the negative sequence current

$$I_{a2} = \frac{1}{3}(I_a + a^2I_b + aI_c) = [1 + (1\angle 240°)(1\angle -120°)]$$

$$= \frac{1}{3}[1 + (-0.5 + j0.866)] = 0.333\text{A}\angle 60°$$

These are the a phase symmetrical components. The b and c phase symmetrical components are the same magnitude but offset in phase.

$I_{b1} = \alpha^2 I_{a1} = 0.667\text{A}\angle 240°$

$I_{c1} = \alpha I_{a1} = 0.667\text{A}\angle 120°$

$I_{b2} = \alpha I_{a2} = 0.333\text{A}\angle 180°$

$I_{c2} = \alpha^2 I_{a2} = 0.333\text{A}\angle 300°$

Of course I_{b0} and I_{c0} are both equal to I_{a0}.

$I_{a0} = 0.333\text{A}\angle -59.9°$.

The symmetrical components of Example 10.1 are shown in Figure 10.5.

Let us now check our work by calculating the original phasors from the symmetrical components. The sums of the components are:

$$I_a = I_{a0} + I_{a1} + I_{a2} = 0.333\text{A}\angle -60° + 0.667\text{A}\angle 0° + 0.333\text{A}\angle 60°$$
$$= (0.1667 - j0.2887)\text{A} + 0.667\text{A} + (0.1667 + j0.2887) = 1\text{A}\angle 0°$$

$$I_b = I_{b0} + I_{b1} + I_{b2} = 0.333\text{A}\angle -60° + 0.667\text{A}\angle 240° + 0.333\text{A}\angle 180°$$
$$= (0.1667 - j0.2887)\text{A} + (-0.333 - j0.557)\text{A} - 0.333\text{A} = 1\text{A}\angle 120°$$

$$I_c = I_{c0} + I_{c1} + I_{c2} = 0.333\text{A}\angle -60° + 0.667\text{A}\angle 120° + 0.333\text{A}\angle 300°$$
$$= (0.1667 - j0.2887)\text{A} + (-0.333 + j0.557)\text{A} + (0.1667 - j0.2887)\text{A} = 0$$

Figure 10.6 shows the sums of the symmetrical components of Example 10.1.

10.1.5 Sequence Impedances

The sequence impedance is defined as that obtained by providing unit current of that sequence in the three phases of the apparatus in question and writing the equation for the voltage drop. The sequence impedance, which can also be found by measurement, is normally expressed in pu for calculations. The impedance of one sequence need not be that of another. For example, linear networks such as transmission lines normally have equal positive and negative sequence impedances, but the zero sequence impedance, which must take into account the neutral return line impedance and coupling, is different. Transformers also have identical positive and negative sequence impedances, but different zero sequence impedance. Rotating machines may have different positive and negative sequence impedances as well. The sequence impedances for rotating machines is the transient (X'_d) or subtransient impedances (X''_d) depending on the time of interest. X''_d is normally used for calculating fault currents to set relays because it is the effective machine impedance during the relay sensing time. X'_d may be used to calculate currents used to set time delay relays and other slower devices. Frequently only the sequence reactance is used to calculate fault currents when the resistance of a component is much less than its reactance. Computer programs normally include the resistance to obtain the added accuracy. Computers do not tire of tedious calculations as easily as do people.

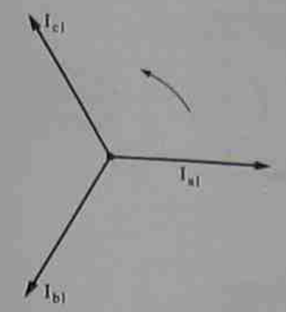


FIGURE 10.5 Symmetrical components of Example 10.1 (a) Positive sequence (b) Negative sequence and (c) Zero sequence

10.1.6 Sequence Networks

Sequence networks are one phase to neutral diagrams showing the elements of interest for each sequence of the network under consideration. The sequence networks are called the positive sequence network, the negative sequence network,

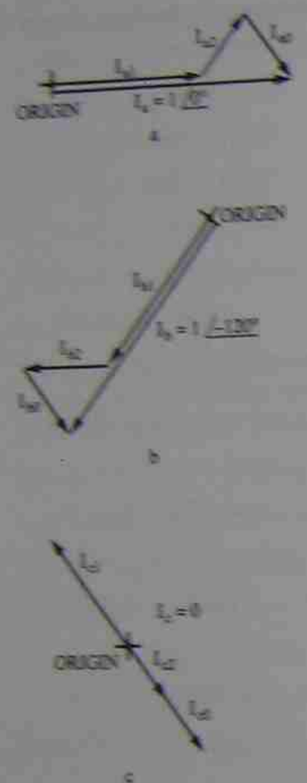


FIGURE 10.6 Phase sums of symmetrical components in Figure 10.5
(a) Phase a (b) Phase b and (c) Phase c

and the zero sequence network. In a balanced three-phase network the sequence components are independent of each other until a fault occurs. The sequence impedance networks can therefore be computed independently and combined appropriately for calculating a fault current.

The positive sequence network contains all of the generator voltages and the positive sequence impedance of all generators, transformers, lines, and motors in the network under consideration. The negative sequence network consists of the negative sequence impedances of all the elements of the network. The zero sequence impedance contains the zero sequence impedances of all the elements of the network. All three of the networks are not needed for every fault. For example, a system with no neutral return has an infinite zero sequence impedance, so the zero sequence network is not used in calculating the current for the faults that can occur in the system. The configuration of the sequence networks varies with the type of fault on the system. Figure 10.7 shows the sequence networks of a grounded wye connected generator with a line to ground fault at one terminal. The fault impedance may be drawn outside of the sequence networks.

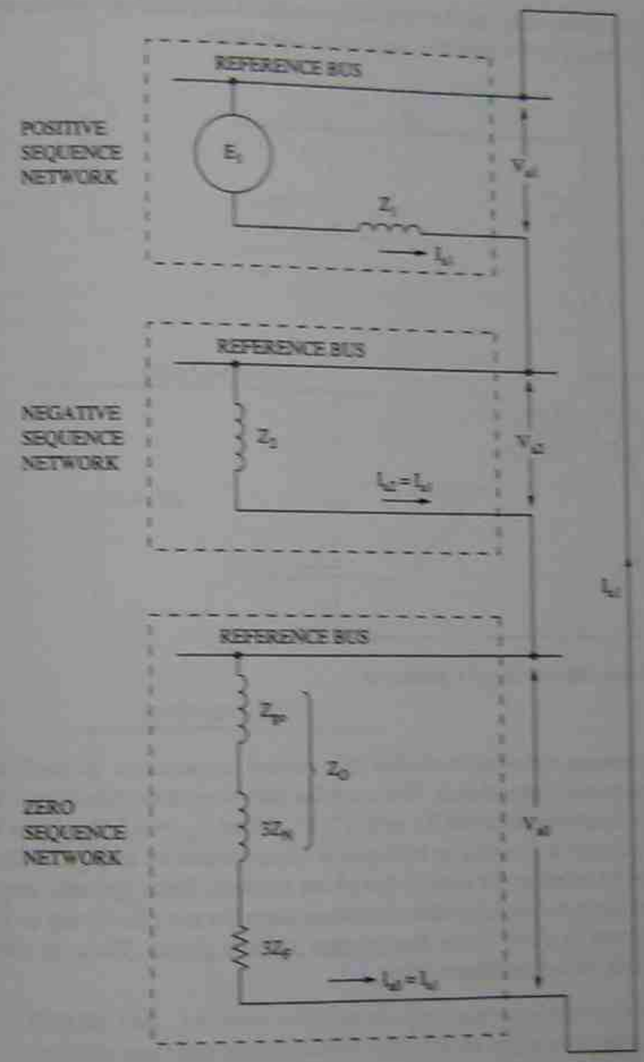


FIGURE 10.7 Sequence networks, connected for line to ground fault

10.1.7 Generator Sequence Networks

Figure 10.8 shows the equivalent circuit of a generator for transient conditions. Let $E_a = E_b = E_c$ and $Z_1 = Z_2 = X''_d$. The positive sequence network will contain E_a and Z_1 as shown in Figure 10.9a. The sequence impedances must be obtained from the machine manufacturer or from testing. The negative sequence network, shown in

Figure 10.9b, consists only of the negative sequence impedance, which is often approximately equal to the positive sequence impedance.

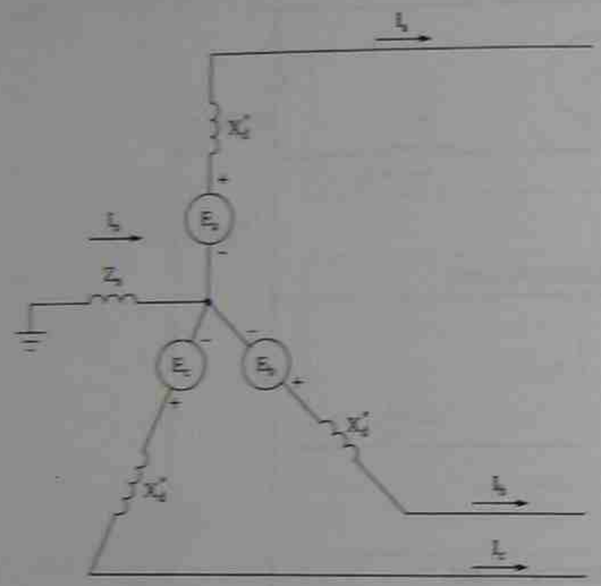


FIGURE 10.8 Equivalent circuit of a generator

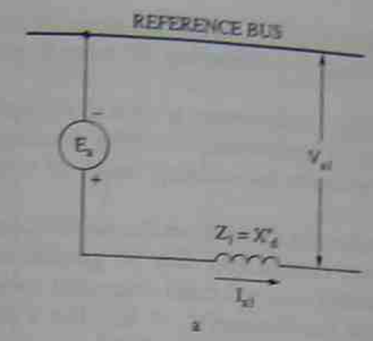
The zero sequence network includes the neutral impedance as well as the machine zero sequence impedance. The machine zero sequence impedance varies with the type of machine between 0.1 and 0.7 X''_d. Often $Z_{g0} = 0.5X''_d$. Note that if zero sequence current is flowing in each phase of the generator in Figure 10.8 that the neutral current must be the sum of the phase currents. Since the zero sequence current phasors have no angular offset between them (or are effectively in phase) the neutral current is three times the current in each phase. Thus in the zero sequence network shown in Figure 10.9c,

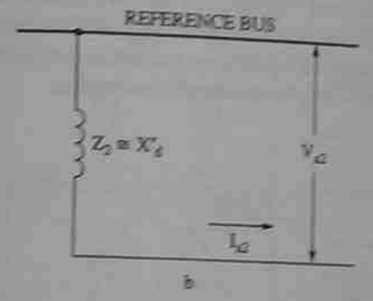
$$V_{a0} = 3I_{a0}Z_n + I_{a0}Z_{g0}$$

$$Z_0 = \frac{V_{a0}}{I_{a0}} = 3Z_n + Z_{g0} \tag{10.17}$$

Thus the effect is like tripling Z_n at the zero sequence phase current.

The sequence networks for a large synchronous motor during a fault is the same as that for a generator. In the event of a fault on a line supplying a motor, the motor becomes a source until the protective relays open or the motor rotor stops.





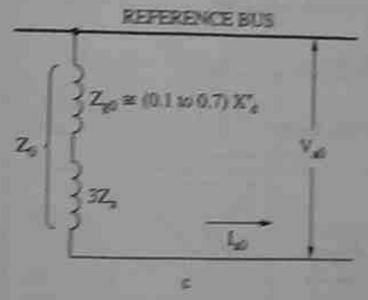


FIGURE 10.9 Sequence networks of a generator (sequence impedances are obtained from machine specifications) (a) Positive sequence (b) Negative sequence and (c) Zero sequence

10.1.8 Transformer Sequence Impedance

Transformers are static machines so their positive and negative sequence impedances are the same. Recall that the pu impedance of a transformer is the same from the high or the low side of a transformer.

The 30° phase shift in a delta-wye transformer must be considered in sequence networks. Recall that the convention in the United States is to connect the high side, whether it is the delta or the wye connected side, to lead the low side by 30°

as shown in Figure 10.10a. The phase shift is taken care of in sequence networks by adding 30° to the transformer impedance, or subtracting 30° from it, as shown in Figures 10.10b and c.

The T equivalent circuit of three winding transformers is used in sequence networks. The equations for the equivalent T impedances of a three winding transformer are given in Chapter 4.10. Transformer impedances must, of course, be referred to the system base values.

The zero sequence impedance of a transformer differs from the positive and negative sequence impedances. No significant current can flow to ground from an ungrounded system. Thus for an ungrounded wye or a delta connected transformer $Z_0 = \infty$. For shell constructed three-phase transformers $Z_0 = 3Z_1$. For a core constructed three-phase transformer Z_0 ranges from about $0.8Z_1$ to $0.85Z_1$ because there is no path for zero sequence flux return in the core. Figure 10.11 shows the zero sequence impedance for some two winding three-phase transformer configurations. Some electrical power handbooks contain several pages of equivalent sequence impedances for just about any conceivable two or three winding transformer connection.

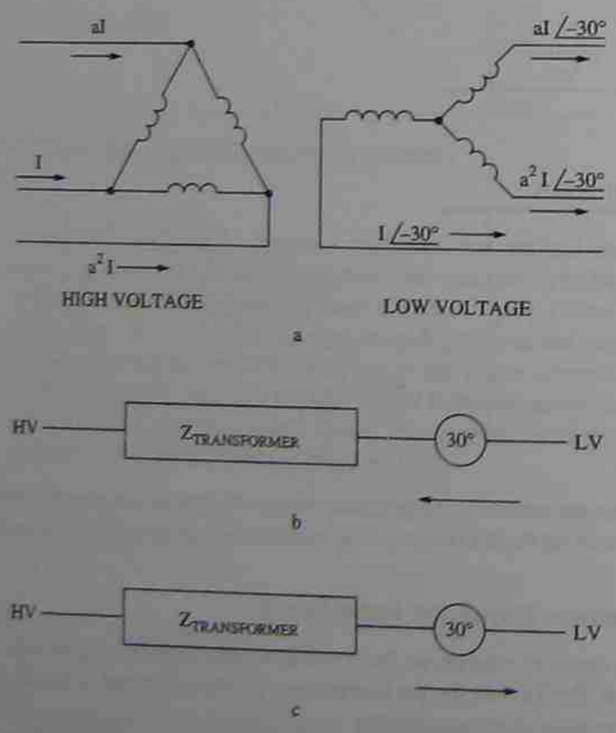


FIGURE 10.10 Sequence phasor phase shift through delta-wye or wye-delta transformer connection (a) Transformer connection, current phase shift (b) From low voltage to high voltage add 30° to impedance angle (c) From high voltage to low voltage subtract 30° from impedance angle

CONNECTION SOURCE	CONNECTION LOAD	ZERO SEQUENCE EQUIVALENT	Z FROM LOAD SIDE
		ZERO SEQUENCE REFERENCE BUS S • Z_0 • L	$Z_{0L} = \infty$
		S • Z_0 • L	$Z_{0L} = \infty$
		S • Z_0 • L	$Z_{0L} = Z_1$
		S • Z_0 • L	$Z_{0L} = \infty$
		S • $3Z_n$ Z_0 • L	$Z_{0L} = Z_1 + 3Z_n$
		S • Z_0 • L	$Z_{0L} = \infty$
		S • Z_0 • L	$Z_{0L} = \infty$
		S • Z_0 • L	$Z_{0L} = \infty$

FIGURE 10.11 Zero sequence equivalent circuits for three-phase transformer banks

10.1.9 Transmission Line Sequence Impedance

The positive and negative sequence impedances of a transmission line are equal, and they are the line impedances as calculated or found in the tables in Chapter 9. The zero sequence impedance of the transmission line must take into account the resistance and inductance of the neutral return conductors, including the flux coupling of each ground wire with each phase conductor. This is a complicated and tedious calculation that is carried out like those of Chapter 9. Each conductor is treated like a single phase conductor for the calculations. A useful, but often violated, rule of thumb is $Z_0 = 3Z_1$.

The sequence impedances of cables is very difficult to calculate because of the capacitive effect of the insulating dielectric, and the magnetic coupling from induced currents in near-by conduit, water pipes, and soil. Steel conduit, which is magnetic, complicates calculations even further. Sequence impedances for cables is available from cable manufacturers. Usually the positive and negative sequence impedances are equal and equal to the cable impedance. The zero sequence impedance can range from two to 50 times the positive sequence impedance.

Accurate tables of sequence impedances for commonly used overhead distribution conductors and spacings, as well as some underground cable, is available in the McGraw Edison (now Cooper Power Systems) book listed in the reference list.

10.1.10 Motor Sequence Impedance

Motors are a factor in fault current for systems in which there are large motors. When a fault occurs the motors connected on the system continue spinning for a short time because of the load inertia. The motor rotors cause the motors to operate as generators driven by their loads until the rotors stop or they are disconnected from the system by relays. Thus both system motors and generators deliver fault current initially, as shown in Figure 10.12. Only very large motors need to be included in fault current calculations. In many systems all motors under 50 hp are neglected.

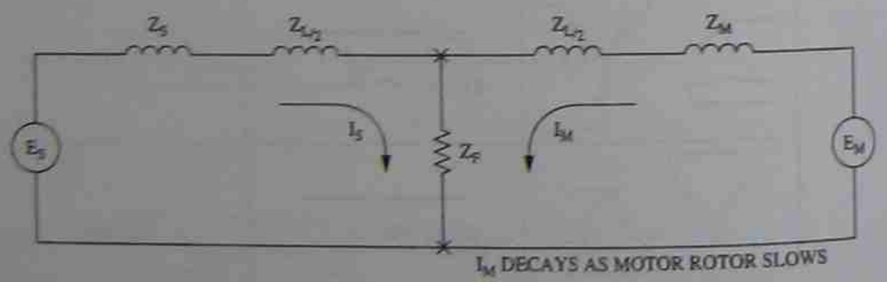


FIGURE 10.12 Motor delivering current to a fault

The equivalent circuit for a synchronous motor is the same as that of a synchronous generator for fault current calculations. The positive and negative sequence networks for an induction motor are shown in Figure 10.13. The actual values of

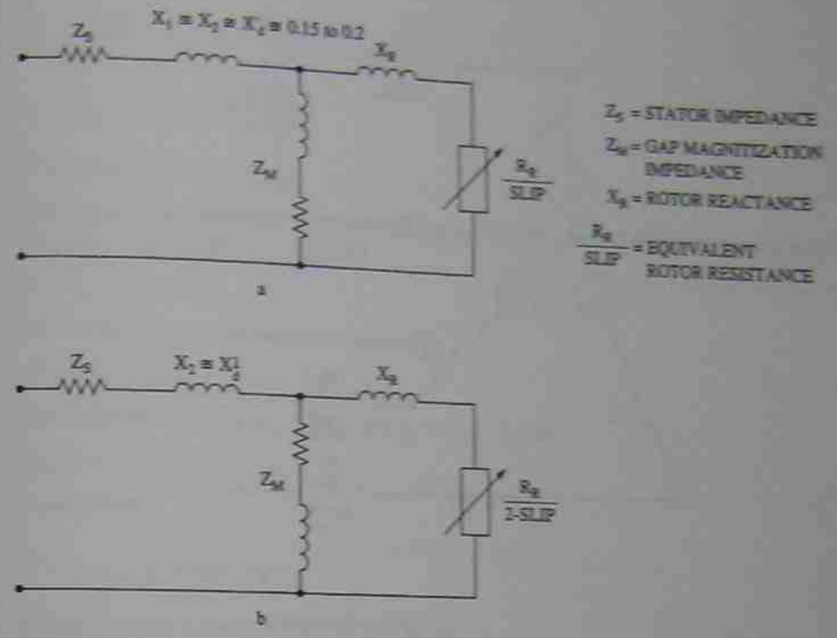


FIGURE 10.13 Induction motor equivalent circuit (Z_1 and Z_2 furnished by motor manufacturer) (a) Positive sequence and (b) Negative sequence

the elements must be obtained from the manufacturer or measured. The zero sequence impedance of an induction motor is infinite because induction motors are not normally grounded neutral for voltages less than 4160 V. At 4160 V and above corona in the windings may be a problem if the motor is not grounded. The zero sequence impedance of a grounded neutral induction motor is not infinite.

10.1.11 Phase to Ground Fault

The most commonly occurring system fault is phase to ground, as illustrated in Figure 10.14a. If we ignore R and use the total sequence impedance we get

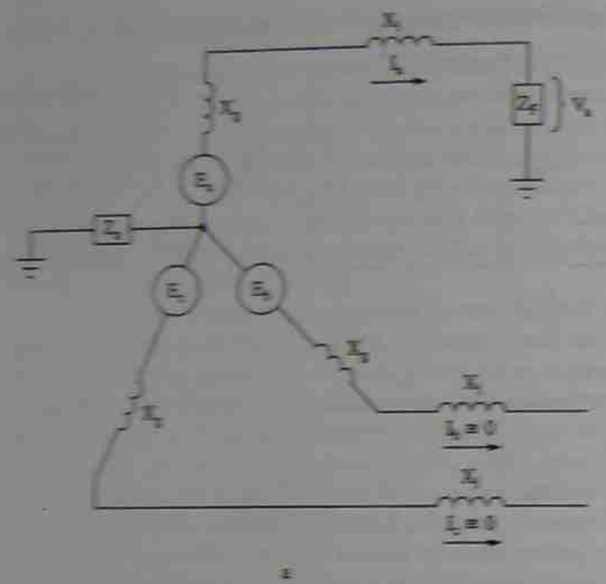
$$Z_1 = Z_2 = X''_d + X_1$$

$$Z_0 = 0.5X''_d + 3X_1 + 3Z_n$$

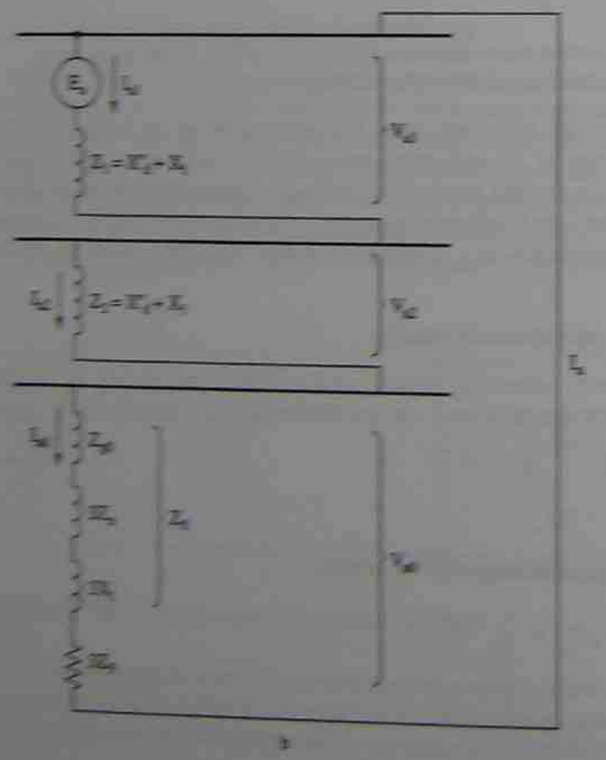
Solving for the sequence currents we obtain

$$I_{a1} = \frac{1}{3}(I_a + aI_b + a^2I_c) = \frac{I_a}{3}$$

$$I_{a2} = \frac{1}{3}(I_a + a^2I_b + aI_c) = \frac{I_a}{3}$$



a



b

FIGURE 10.14 Phase to ground fault on line (a) Equivalent circuit and (b) Sequence network

$$I_{a0} = \frac{1}{3}(I_a + I_b + I_c) = \frac{I_f}{3}$$

$$I_{a1} = I_{a2} = I_{a0} = \frac{I_f}{3}$$

Therefore $I_{a1} = I_{a2} = I_{a0}$

Referring to the sequence networks of Figure 10.14b we see that the voltage across the fault impedance, $V_a = I_f Z_f$ and

$$V_a = V_{a0} + V_{a1} + V_{a0}$$

substituting from the sequence network

$$I_a Z_f = E_a - I_{a1} Z_1 - I_{a2} Z_2 - I_{a0} Z_0$$

But from above we see $I_a = 3I_{a0}$ and $I_{a1} = I_{a2} = I_{a0}$, so

$$3I_{a0} Z_f = E_a - I_{a2} Z_1 - I_{a1} Z_2 - I_{a1} Z_0$$

from which

$$I_{a0} = \frac{E_a}{Z_1 + Z_2 + Z_0 + Z_f \cdot 3}$$

Recall that the fault current $I_a = I_f = 3I_{a0}$ so

$$I_f = \frac{3E_a}{Z_1 + Z_2 + Z_0 + Z_f \cdot 3} \tag{10.18}$$

The sequence network connection is shown in Figure 10.15a.

Many faults greatly reduce the line current in the remaining two lines because the generator terminal voltage is reduced.

The maximum fault current occurs when $Z_f = 0$ and the fault is close to the source. The minimum fault current occurs when the Z_1 is maximum and the fault is at the far end of the line. The intervening line impedance lowers the fault current. The fault impedance varies with the resistivity of the soil in a ground fault and the arc resistance. The commonly used fault impedance by most electric utilities is $Z_f = 20\ \Omega$ resistive, but the REA specifies $Z_f = 40\ \Omega$. Once a faulted conductor is in good contact with the ground the fault impedance is very low, almost zero.

The major problem associated with the use of symmetrical components to calculate fault currents is the simplification of the networks into sequence networks. The methods used are the same as those used to simplify any network into a pu equivalent circuit. The system network must be simplified into three sequence networks instead of only one as for steady state calculations.

10.1.12 Summary of Sequence Network Configurations

The fault current equations for the other common fault conditions are found by using the appropriate sequence networks and solving for the current as is done in

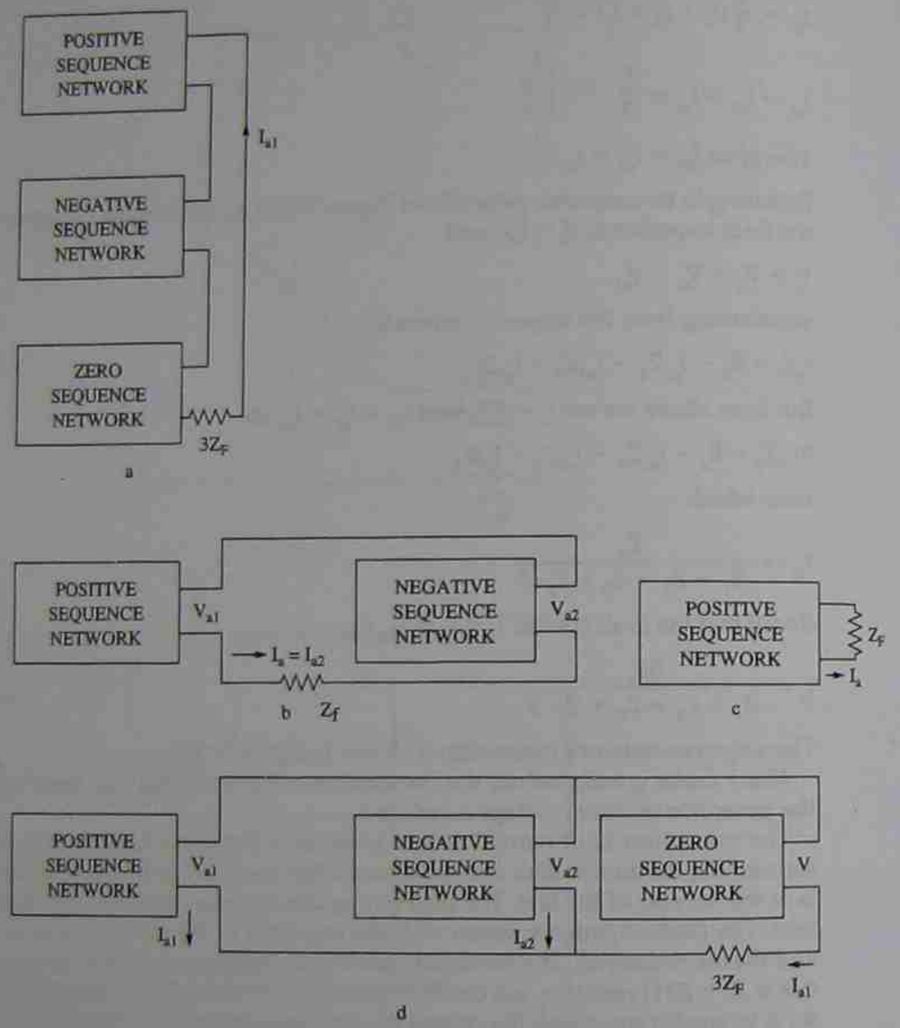


FIGURE 10.15 Sequence network configurations (a) Line to ground fault (b) Line to line fault (c) Three-phase fault and (d) Double line to ground fault

the preceding section. We will present the final equations in this section. In the following equations Z_1, Z_2, and Z_0 are the sequence impedances viewed from the fault. Z_f is the fault impedance and V_f is the positive sequence voltage, usually the equivalent system supply voltage. Figure 10.15 shows the sequence network connections for each major fault current.

Three-phase fault: A balanced three-phase fault has no zero sequence impedance because the neutral current is zero, and because the system is still in balance there

is no negative sequence impedance. The fault current is calculated using only the positive sequence network, as shown in Figure 10.15c. The equation is

$$I_f = \frac{V_f}{Z_1 + Z_f} \tag{10.19}$$

Line to line fault: A line to line fault causes no fault current in the system neutral, so the zero sequence impedance is not used to calculate fault current. The system is unbalanced by a line to line fault so the negative sequence impedance must be used in the fault current calculations. The sequence network is shown in Figure 10-15b, and the equation is

$$I_f = \pm j\frac{\sqrt{3}\,V_f}{Z_1 + Z_2 + Z_f} \tag{10.20}$$

Double line to ground fault: A double line to ground fault causes both system neutral current and system unbalance so all three sequence networks must be used. The positive and negative sequence networks appear as in a line to line fault except both are supplying current to the fault. Thus the networks appear as shown in Figure 10.15d looking back from the fault. The equation for the phase one and two fault currents are:

Phase one

$$I_f = -j\sqrt{3}V_f\frac{Z_0 + 3Z_f - aZ_2}{Z_1Z_2 + (Z_1 + Z_2)(Z_0 + 3Z_f)} \tag{10.21a}$$

Phase two

$$I_f = +j\sqrt{3}V_f\frac{Z_0 + 3Z_f - a^2Z_2}{Z_1Z_2 + (Z_1 + Z_2)(Z_0 + 3Z_f)} \tag{10.21b}$$

All of the quantities in the sequence networks can be complex.

10.1.13 Symmetrical Component Example

The following example is to illustrate the use of symmetrical components to calculate a fault current. The network in the example is simple. The calculations for a complex network use the same equation, but the sequence networks have more elements.

Example 10.2:

Calculate the minimum and maximum fault current for a phase to ground fault at point A for the circuit shown in the one line diagram of Figure 10.16. Use $Z_f = 20\ \Omega$ for minimum fault current and $Z_f = 0\ \Omega$ for maximum fault current. The line is a 138 kV with spacing as shown in Figure 9.31. It is constructed with Linnet conductors. Include the transmission line resistance.

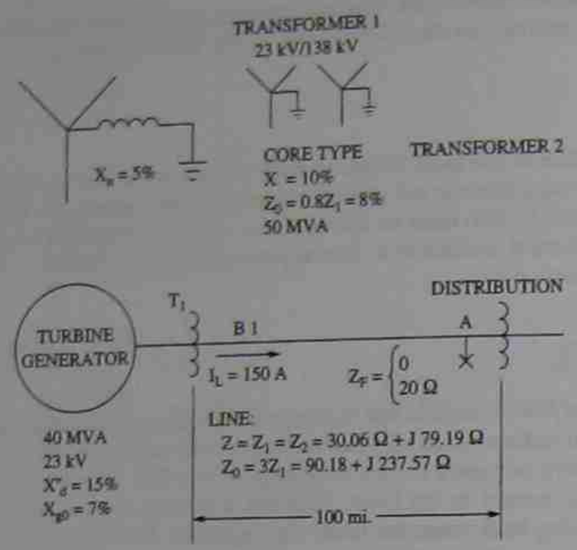


FIGURE 10.16 Circuit for Example 10.2

Solution:

The system impedances are given in Figure 10.16. First we must select a system base and express all system quantities in that base. Let the base $S = 50$ MVA, The base $V = 138$ kV. Using the change of base equation

$$Z_{pu2} = Z_{pu1}\frac{kV^2_{B1}}{kV^2_{B2}}\frac{MVA_{B2}}{MVA_{B1}}$$

we calculate

$$X''_d = 0.15(0.02778)(1.25) = 0.00521\text{pu}$$

$$X_{g0} = 0.07(0.02778)(1.25) = 0.00243\text{pu}$$

$$X_n = 0.05(0.02778)(1.25) = 0.00174\text{pu}$$

The transformer is already expressed in base pu. Next we calculate the pu impedance of 100 miles of the transmission line.

$$Z_{BASE} = \frac{(\text{BASE } kV)^2}{\text{BASE } MVA} = 380.88\Omega$$

thus

$$Z_{pu\,TL} = \frac{(30.06 + j79.19)\Omega}{380.88\Omega} = 0.0789 + j0.207\text{pu}$$

and the fault impedance is

$$Z_f = \frac{20\Omega}{380.88\Omega} = 0.052\text{pu}$$

The sequence networks are shown in Figure 10.17.

Using Equation 10.18 to calculate the minimum fault current

$$I_f = \frac{3(1\text{pu}V)}{[(0.0789 + j0.312) + (0.0789 + j0.312) + (0.393 + j0.869)}$$

$$= \frac{3\text{pu}}{(0.551 + j1.493)\text{pu}} = \frac{3\text{pu}}{1.59\text{pu}\angle 70^\circ} = 1.86\text{pu}\angle -51^\circ$$

$$I_f = I_{pu}I_B = 1.886\angle -70^\circ(362.3\text{A}) = 683.2\text{A}\angle 70^\circ$$

We use the same equation without Z_f to calculate the maximum fault current at the end of the line.

$$I_f = \frac{3\text{pu}V}{[(0.0789 + j0.312) + (0.0789 + j0.312) + (0.234 + j0.869)]\text{pu}Z}$$

$$= \frac{3\text{pu}V}{(0.394 + j1.493)\text{pu}Z} = \frac{3\text{pu}V}{1.554\text{pu}Z\angle 75.2^\circ} = 1.943\text{pu}\angle -75.2^\circ$$

$$= (1.943\text{pu}\angle -75.2^\circ)362.8\text{A} = 703\text{A}\angle -75.2^\circ$$

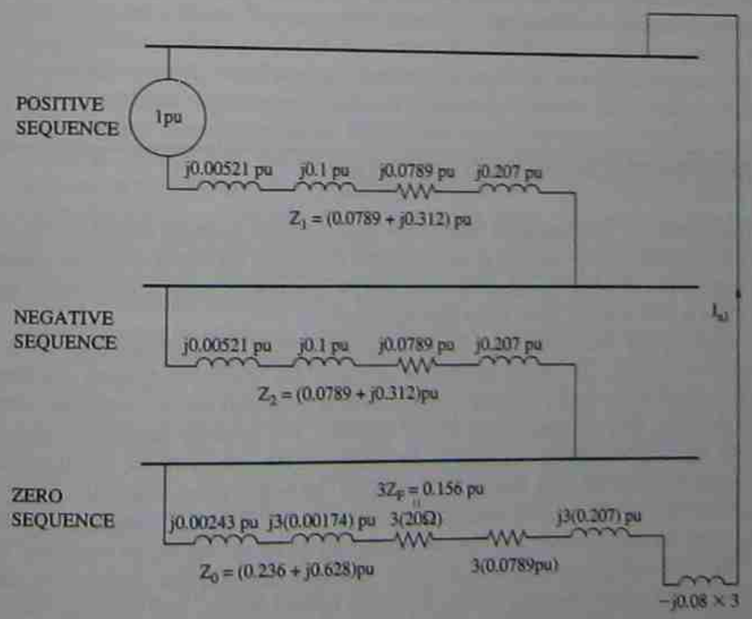


FIGURE 10.17 Sequence networks for Example 10.2

The maximum fault current the protective system has to interrupt occurs when a fault is close to the supplying substation, point B in Figure 10.16. At this point the transmission line impedance is zero. The interrupt capacity needed by the station circuit breaker is greater than the maximum close in fault current. First we calculate the sequence impedances without the line impedance.

$Z_1 = Z_2 = j.00521 + j0.1 = j0.10521\text{pu}$

For I_{max}, we let $Z_f = 0$

$Z_0 = j0.00243 + j3(0.00174) + 3(j0.08) = j0.248\text{puZ}$

and

$$I_f = \frac{3\text{pu}V}{(j0.10521 + j0.10521 + j0.248)\text{puZ}}$$

$$= \frac{3\text{pu}V}{0.459\text{puZ}} = 6.543\text{pu}I$$

Thus the maximum close in fault current is

$I_f = 6.543\text{pu}(362.3\text{A}) = 2{,}367\text{ A}$

The protective relays must detect a fault current of 674 A and open the circuit breakers. The relays must also detect 4,984 A and open the breakers very fast to prevent equipment damage.

10.2 TRANSMISSION LINE PROTECTION

The subject of transmission line protection contains enough detail to fill a book. Our purpose in this section is to introduce the major concepts of transmission line protection and some commonly used relays. The reader may wish to refer again to Chapter 5 to review basic relay mechanisms.

High speed fault clearing provides the following three advantages for a transmission system: (1) Limits conductor damage; (2) Improves system stability; and (3) Permits high speed reclosing that prevents extended service outages from transient faults, and also improves system stability. The primary function of the protection for a transmission system is to preserve the integrity of the transmission system by clearing only the faulted section. The relays must detect the fault, determine which line is faulted, and clear only the faulted line. The idea is to trip the line but not the load. Ideally the load will continue to be served by an auxiliary line.

In this section we will discuss pilot line and pilot carrier protection, distance relays, directional ground relays, auxiliary carrier relays, and back-up protection.

Microcomputer controlled relays continue to be developed that perform the functions of electromechanical relays more precicely at a cost per function that is

below that of electromechanical relays. As with the relays discussed in Chapter 5 they consist of data acquisition systems to acquire the line voltage and current, and sometimes conductor and ambient temperature along with other desirable data. From the relative values and phase of the line parameters the microcomputer program decides what action must be taken to assure faults are interrupted reliably.

10.2.1 Pilot Wire Carrier

A pilot wire is a metallic conductor that carries an ac signal from one end of a transmission line segment to another to prevent a relay from tripping (provide a blocking signal). The conductor is usually a shielded twisted pair. The blocking signal is sent to keep relays from tripping from a fault detected outside of the transmission line signal. Pilot wire carrier is used for fairly short transmission line segments because the pilot line resistance is limited to about 2 kΩ, about 10 to 20 miles. The pilot line signal is about 20 V at 60 Hz. The pilot line is protected from over voltage by a gas tube and two drainage reactors, which prevent the gas tube from shorting out the pilot line when the gas tube fires. The pilot wire is normally connected to ground through lightning arresters at either end to prevent excessive voltage on the pilot relays during a transient on the line. The lightning arrester break over voltage is usually about 3 kV. The pilot line protection is shown in Figure 10.18.

The most frequently used pilot relays are the HCB and HCB-1. Figure 10.18a shows a simplified schematic of these relays, which differ only in the design of their sequence filters. The sequence filter combines the three phase currents into a single phase voltage of about 20 V rms. The HCB relay cannot detect negative sequence current, and therefore cannot detect phase to phase faults. The HCB-1 can detect both negative and positive sequence currents, so it detects both phase to phase and three-phase faults. Both relays can detect ground faults.

The ac voltage from the sequence filter is transferred to the relays by a tapped saturating transformer. The saturating transformer, along with the zener diodes, limits the voltage on the relays in the event of a large, close in fault. The saturating transformer tap adjusts overall relay sensitivity. The relay taps should be set as per the instructions in the operating manual. The ac signal from the saturating transformer is rectified and applied to the restraint coil, which is tapped so the restraint sensitivity can be adjusted. The restraint coil is effectively in series with the operate coil, which also operates on rectified ac current. The operate and restraint coils are both wound on the center leg of a dc polar unit. A polar unit is a relay core with a magnetic shunt that causes the armature to move preferentially in only one direction when the coil is energized. A permanent magnet attached to the core structure causes the relay to respond to current of one polarity only. Two additional taps in the sequence filter allow the relay sensitivity to phase and ground faults to be adjusted.

The normal connection of the relays in the system is shown in Figure 10.18b. Under normal operating conditions the phase of the pilot line ac is such that the restraint coils receive most of the relay power while the operate coils receive very little. The relay coils operate on the same principle as a differential relay. If a fault

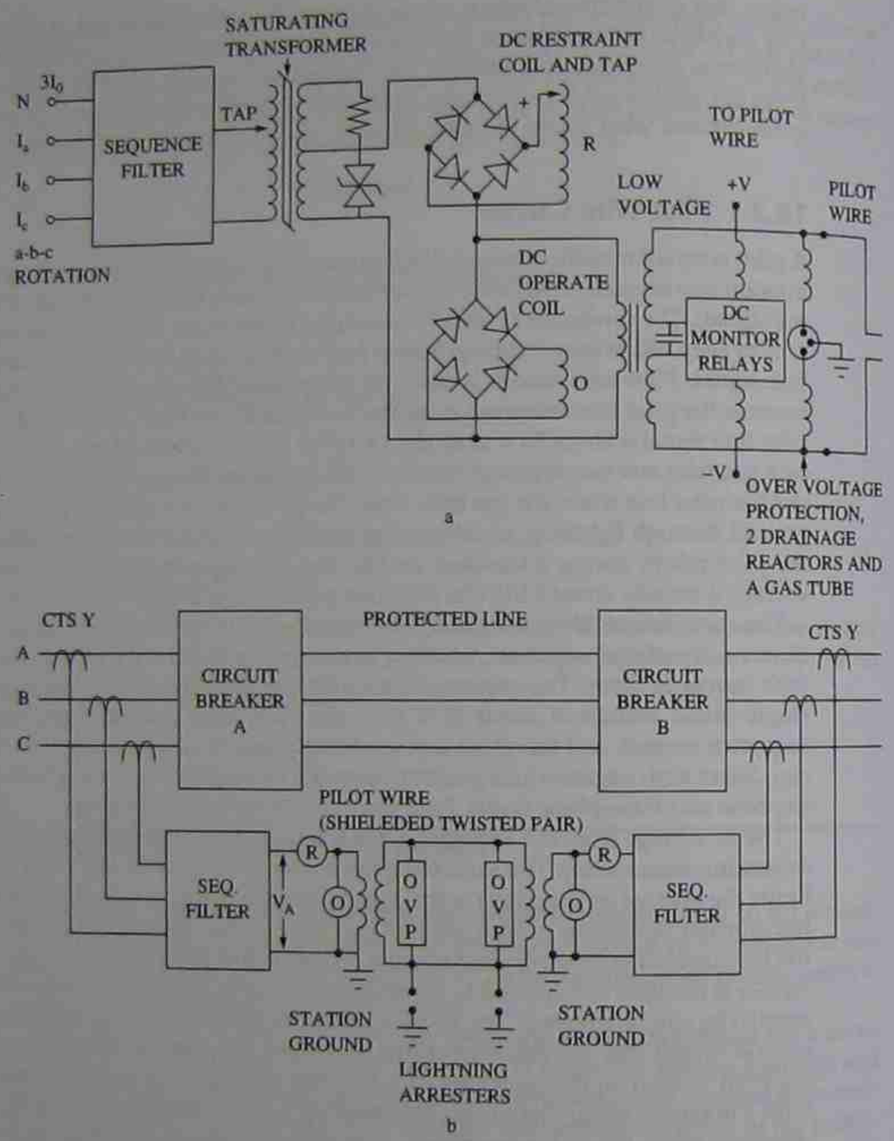


FIGURE 10.18 Pilot wire carrier (a) HCB and HCB-1 simplified circuit diagram and connections (b) System configuration

occurs outside the protected line section the current through the restraint coils becomes stronger. If a fault occurs inside the protected area, the voltage from the two sequence filters shift in phase relative to each other causing the torque from the operate coil to strengthen as the restraint coil torque weakens, once again like a differential relay. The signal from one relay is strong enough to operate the relay

coils at both ends of the line in the event the sequence filter on one end fails. The sequence phase shift in one filter is enough to cause the restraining coil torque to weaken and the operate coil strengthen.

A circuit is connected to inject about 20 V dc across the capacitor into the pilot line, as shown in Figure 10.18a. The circuit has sensitive dc monitor relays that are held closed by the current from the injected dc current. The dc monitor relays open from a current shortage if the pilot line becomes shorted across, shorted to ground, open, or is connected in reverse phase. The dc monitor relays send an alarm signal to the appropriate center if the pilot line fails.

Recently fiber optic cables have been used to provide pilot line protection. Fiber optic cables are light, and they are immune to electromagnetic interference, which is a problem on shielded twisted pairs. The pilot signal is a code sent by pulses of light on the fiber optic cable. Electronic circuitry generates and interprets the pilot signal on the fiber optic cable.

10.2.2 Pilot Carrier Relaying

Pilot carriers, like pilot wires, are normally used to block, or prevent, a relay from operating in response to a fault outside of the protected zone. Two major versions of carrier are used: power line carrier and microwave carrier.

Power line carrier, in which a radio frequency signal, usually between 30 kHz and 300 kHz, is injected on one phase of the power circuit. Power line carrier is economical and reliable. If the phase that has the rf carrier is faulted to ground a blocking signal is not desired so no relaying reliability is lost. Additionally the power line carrier can carry voice information if more than one frequency is used. With more frequencies supervisory control and data acquisition (SCADA) data channels can be transferred on the carrier. Sometimes the carrier is injected on the static wire. In this case the static wire must be insulated from the support structure yet still conduct transients to ground. Pilot voltages are usually less than 120 V so insulators or lightning arresters with breakdown voltages of about 300 V are used to support the static wire. This voltage is negligible in comparison to a switching or lightning induced transient. Phase conductors are preferred for the carrier. Power line carrier is useful to over 100 miles.

Microwave carrier is used when the distance between substations is too great for power line carrier because of signal radiation from the power line. The carrier signal is at a much higher frequency (in FCC allocated channels around 2, 6, and 12 GHz) and can carry many channels of communication of various types. Microwaves can be used for carrier signaling over many hundreds of miles, but the antennas must be in line of sight from each other. Relaying receiver/transmitter (R/T) stations must be used for irregular terrain. The microwave signal processing equipment is expensive and bad weather can cause carrier signal fading, but the additional SCADA channels are often a deciding factor in microwaves over power line carrier.

We will discuss only with power line carrier here. Even though the carrier transmission medium and frequency are different, the relaying action of the carrier is the same.

Figure 10.19 shows a basic power line carrier system. When a fault outside the protected line is detected by a relay the carrier is keyed (turned on) and the relays protecting the line between CB2 and CB3 are prevented from generating a trip signal. If the fault external to the protected line segment continues for long enough that it is probable the protective system of the faulted line segment has failed to operate, the relaying for the line segment between CB2 and CB3 ignores the carrier blocking signal and allows the breaker closest to the external fault to trip as back-up protection. Relay time delays are set for this function.

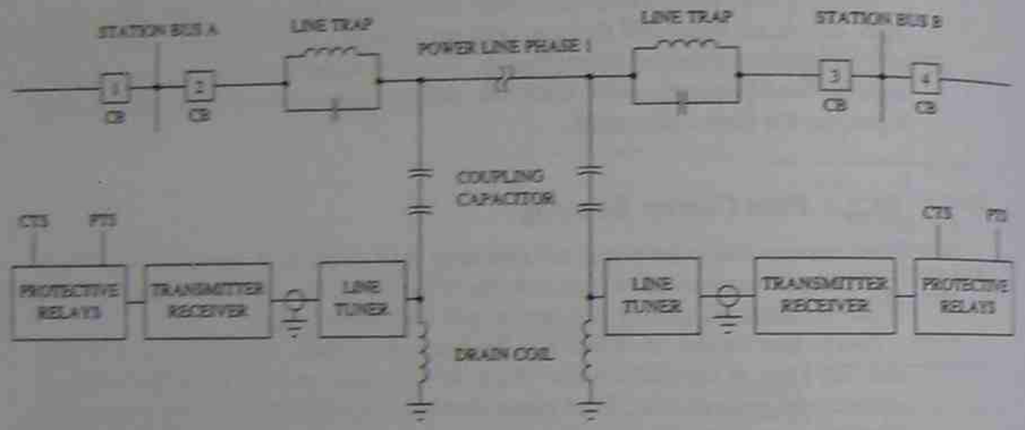


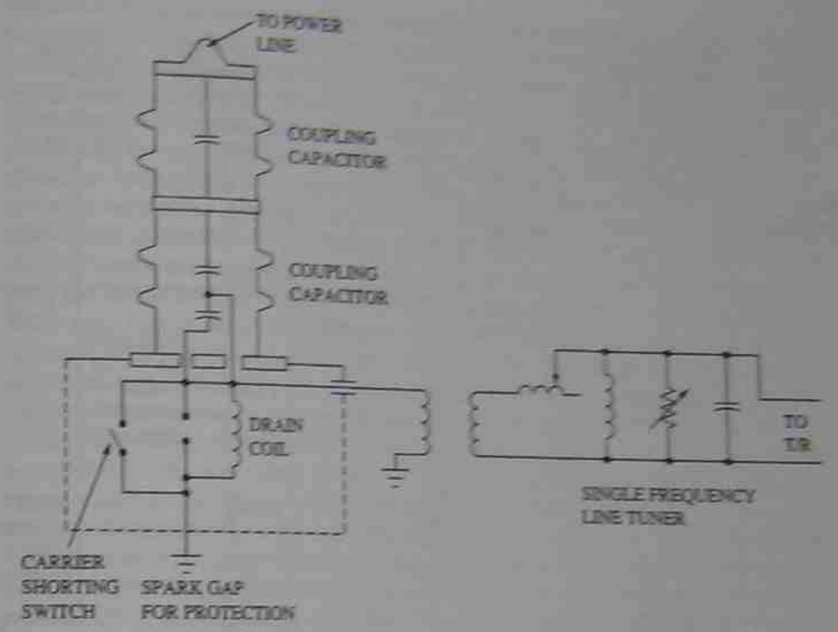
FIGURE 10.19 Power line carrier

If several channels of information are carried on the carrier, only one frequency is used for relay blocking. The line tuner separates the blocking signal from the other signals to activate the relays. The communication and SCADA channel frequencies may be present all of the time but the carrier frequency rf is only present when it is needed.

The rf carrier must be coupled to the line tuner and R/T units where the carrier signal is turned into a dc signal for the relays to use. A capacitive voltage divider called a coupling capacitor (which it is) is used to transfer the rf to the signal conditioning units. The line tuner is a band pass filter that only passes the desired frequency. A coupling capacitor and single frequency line tuner are illustrated in Figure 10.20a.

The rf carrier is kept out of the substation by a parallel tank circuit known as a line, or wave, filter, shown in Figure 10.20b. The filter coil must be constructed of conductor heavy enough to carry the entire line current without excessive loss. The line filter capacitors are usually placed inside of the coil.

Carriers are not used alone. They must be used with auxiliary carrier relays that can block other relay trip signals when a carrier is received. A popular carrier auxiliary relay is the *KA-4* (type 85). The trip circuit of the KA-4 is shown in Figure 10.21, and the current sensing coil is shown in Figure 10.21. The relay has a receiver unit that consists of the RRH and RRT coils wound on a core with an



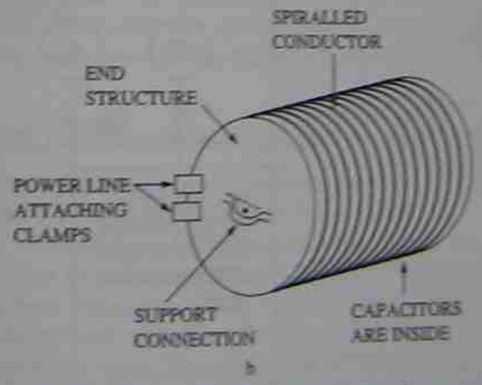


FIGURE 10.20 Power line carrier high voltage components include (a) Coupling capacitor and (b) Line (or wave) trap. Uses large conductors for the coil to carry line current.

armature that has two normally open contacts, RRP and RRG. The RRP is a polar restraining coil that does not allow the RRT operating coil (T for trip) to close the contacts when the carrier signal is present. The RRT is supplied with a continuous dc so it holds the RRP and RRG contacts closed as long as the circuit breaker is closed, except when a carrier signal is received. The carrier signal indicates a fault

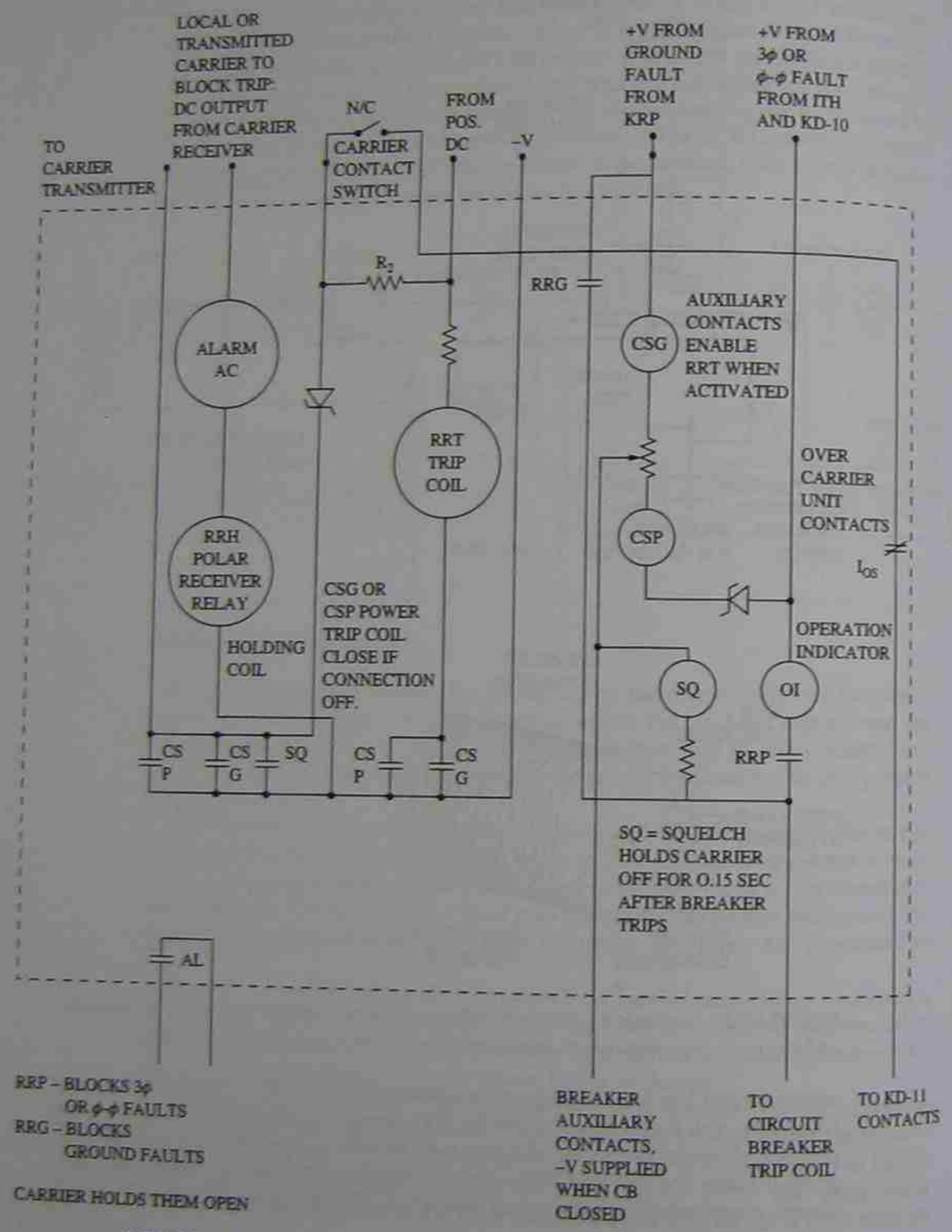


FIGURE 10.21 KA-4 carrier auxiliary relay (current sensing element shown in Figure 10.28)

outside of the protected zone. The CSG and CSP are coils that are energized from the negative dc station voltage when the CB is closed and when a phase to phase fault is indicated by -V from a KD-10 relay or a phase to ground fault is indicated by -V from a KRP relay. (We will discus the KD-10 and KRP relay in a later section.) The RRG contacts pass along a phase to ground trip signal when the CB is closed and the carrier is not blocking, and the RRP contacts pass along a phase to phase or three-phase trip signal under the same conditions. Summarizing the essential operation: if the circuit breaker is closed and a phase to phase or three-phase fault is detected by an ITH or a KD-10 relay the CSP coil operates, closing the CSP contacts allowing the RRT coil to operate and close the RRP contacts, tripping the circuit breaker unless the carrier restrains the RRT coil by energizing the RRH coil; and if the circuit breaker is closed and a phase to ground fault is detected by the KRP relay the CSG coil energizes, operating the CSG contacts, which energizes the RRT coil, which then closes the RRG contacts tripping the circuit breaker, unless a carrier signal is applied to the RRH coil blocking the trip.

An alarm (AL) coil in the KA-4 relay will not close if the carrier strength is below acceptable limits and cause an alarm. The alarm unit is less sensitive than the receiver unit so the carrier will still be strong enough to operate the holding coil. A receiver alarm indicates a loss of carrier. The squelch unit (SQ) holds the carrier off for 150 ms after the circuit breaker status contacts (and therefore the circuit breaker) open to allow all of the faulted line circuit breakers to trip before a carrier is transmitted. OI is an operation indicator. The overcurrent contacts allow -V to be applied to the carrier transmitter when they open. The induction cylinder overcurrent unit opens these contacts when it detects an overcurrent. This starts the carrier on a phase to ground fault. The KA-4 overcurrent unit starts the carrier because it is not directional, so a ground fault it detects could be outside the protected zone. If the fault is within the protected zone another relay trips the circuit breaker.

10.2.5 Directional Ground Overcurrent Relay (Type 67)

Two commonly used electromechanical directional overcurrent ground relays are the KRP and IRP, shown in Figure 10.22.

The KR type relays are directional and can be blocked by a carrier. The relays come in voltage polarized (KRP), current polarized (IRP), and dual current and phase polarized (KRD) models. They differ in the reference source used for the directional unit. We will discuss the KRP. The KRP directional unit is an induction cylinder type. The polarizing (reference) flux is from two different coils placed opposite one another with respect to the induction cylinder. The operate coils are set to provide maximum torque when the voltage leads the current by 60°, an angle that only occurs under fault conditions. The directional unit responds to a fault in one direction only.

The overcurrent unit of a KRP is a typical induction cylinder unit. While it does have an inverse time characteristic it is very fast and is considered instantaneous. The overcurrent unit is fed by a saturating transformer, with setting taps, which reduces the burden at high fault currents, and protected from excessive voltage by

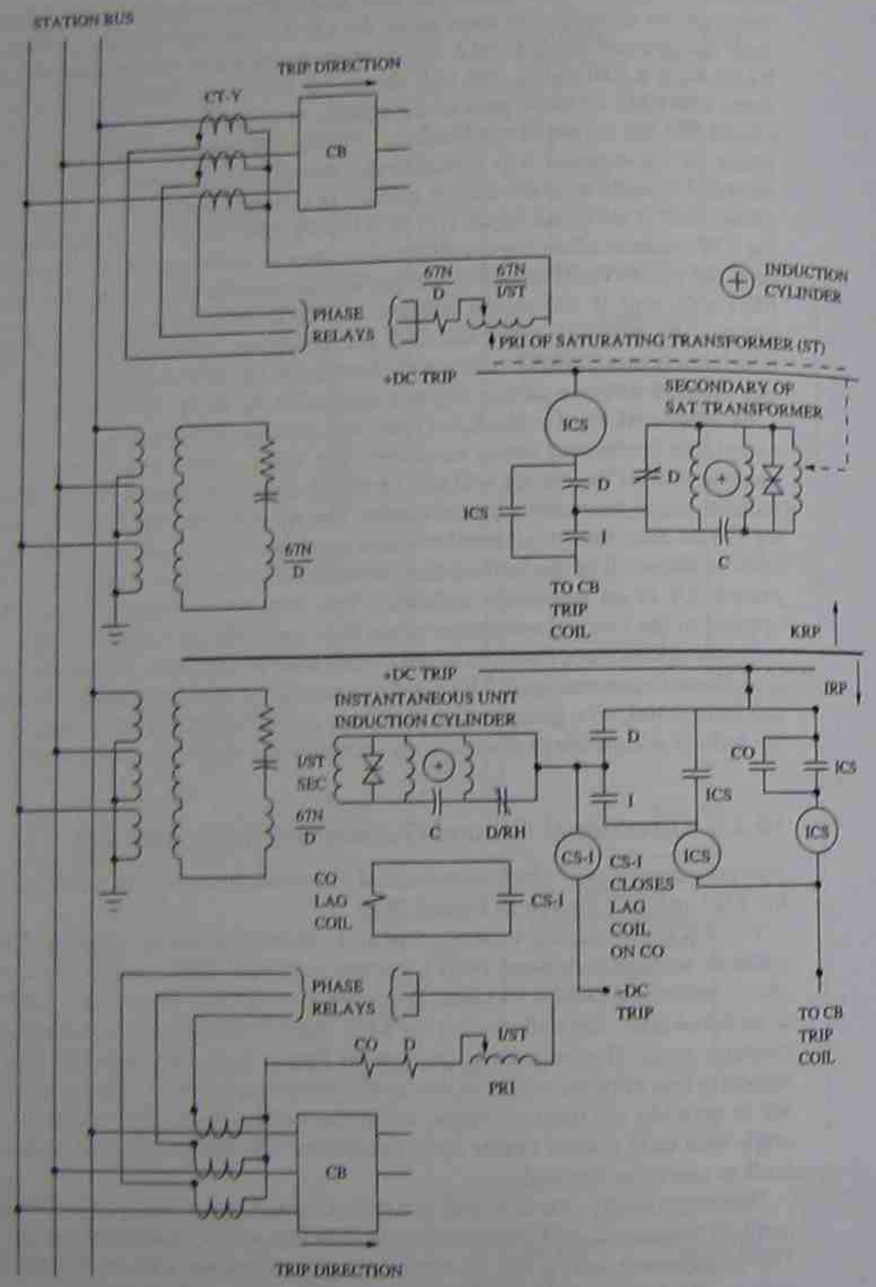


FIGURE 10.22 KRP and IRP directional ground fault relays and connections

a varister type device. The relay also has an ICS unit to indicate trip and carry circuit breaker trip current.

The IR series is similar to the KR series except that they are not designed for carrier blocking, and they have with inverse time CO type overcurrent units. They are available with voltage (IRP), current (IRC), and dual phase and current (IRD) directional polarization. The directional unit is almost identical to that used in the KR series, and must indicate a fault in the trip direction before the overcurrent unit lag coil is enabled (by CS1). The IRP overcurrent unit is similar to the CO induction disk overcurrent relays (type 51) and has very similar tap settings. The relays are purchased with the inverse time characteristic desired. As in the type 51 relays the amount of inverse time characteristic is specified by a number, so one purchases an IRP-X, where X is the inverse characteristic number from 2, slightly inverse, to 11, extremely inverse. The overcurrent unit is fed by a saturating transformer. The IRP relay also has an instantaneous overcurrent unit to detect very high current, close in faults, and two ICS units that indicate if the relay was tripped by the inverse time or the instantaneous unit.

Both the KR and IR relays are in the K-DAR family of directional, carrier blocking relays. The K-DAR family of relays also includes directional phase tripping relays (KD-4), phase start relays (KD-41), and distance relays, to be covered next.

10.2.6 Distance (Impedance) Relays (Type 21)

A distance relay compares the current and voltage of a power system at the relay installation site to determine if a fault is within the length of line the relay is set to protect, or beyond. If the distance to the fault is within the protected distance the relay trips. If the distance to the fault is farther than the distance the relay is set to protect the relay does not trip. The voltage, current, and phase sensed by the relay are proportional to the line impedance to the fault, thus the relays are often called impedance relays. The total impedance of a line to a fault varies with the distance to a fault, so the relays are most often called distance relays.

The impedance, therefore the distance, is set by taps inside the relay. The tap setting is the total impedance of the line to the maximum protection distance (called the balance point).

$$Z_{TAP} = Zd \tag{10.22}$$

where

Z = impedance of the line per unit length

d = number of unit lengths (usually miles) protected

To obtain an intuitive idea of how electromechanical distance relays work refer to Figure 10.23a. A balanced beam holds a moving contact. A voltage coil acts as a restraining coil, and a current coil acts as an operating coil. Under fault conditions the current rises, and the voltage drops, causing the effective impedance of the system to drop. When the impedance is as low as the faulted line impedance the beam tips toward the current coil, closing the contact. The beam is balanced when

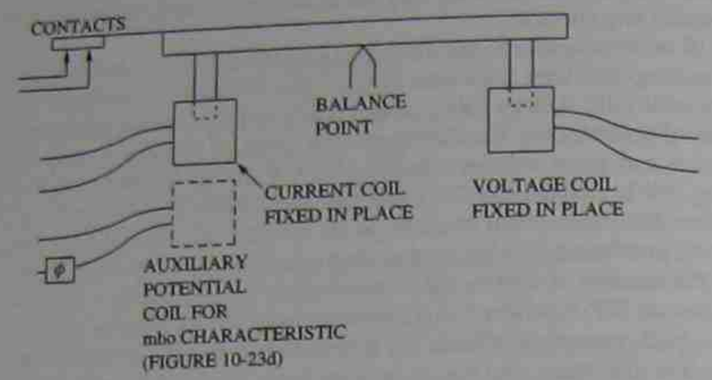


FIGURE 10.23 Impedance (distance) relay (a) Balanced beam anology (b) Characteristic of impedance relay (c) Reach of distance relay and (d) Mho characteristic

the torques from the two coils are equal. This is called the balance point and the impedance the voltage and current represent at that point is the maximum range of the relay.

In a commercial electromechanical relay the coils provide torque on an induction disk or cylinder, which holds the moving contact. The contacts close when

$$K_1 I^2 < K_2 V^2$$

$$\frac{V^2}{I^2} < \frac{K_1}{K_2}$$

so the reach to the balance point is

$$\frac{V}{I} = Z_{TAP} = \sqrt{\frac{K_1}{K_2}}$$

The reach to the balance point is called the relay's *zone of protection*.

The characteristic of the balance beam, or induction disk equivalent, is shown in Figure 10.23b. The characteristic is nondirectional. A directional unit can be added to obtain the half circle characteristic indicated by lining in Figure 10.23b. The zone of protection is shown in Figure 10.23c.

It is usually desirable for a distance relay to be sensitive only in the quadrant in which the fault impedance is likely to lie. This is of course the first quadrant for down line faults. The mho type relays accomplish this by modifying either the restraint or operating quantities. Adding a potential coil to the operate side as shown in the dotted part of Figure 10.23a to close, if K_3 is a torque constant proportional to operate coil watts, when

$$K_3 VI\cos(\theta - \phi) > K_2 V^2$$

$$\frac{V}{I} = Z_{TAP} = \frac{K_3}{K_2}\cos(\theta - \phi)$$

where

θ = the angle of the line impedance

ϕ = the phase shift between the V and I coils of the coils on the operate side caused by a phase shift network

Figure 10.23d shows the mho characteristic, which is inherently directional. The characteristics of a distance relay can be tailored to just about any desired amount of directionality.

Two common electromechanical distance relays are the K-DAR family KD-10 and KD-11, both with mho characteristics. The KD-10 is a three-phase relay that provides a single zone of protection for three-phase, two phase to ground, and phase to phase faults. It provides instantaneous trip for those faults. The KD-11 is similar to the KD-10 except that the origin is just within its characteristic (meaning it can detect faults where it is) instead of on the circumference as in the KD-10. The KD-11 can be used with a KA-4 relay to initiate carrier blocking, and with a time delay.

Both relays, see Figures 10.28 (the sensing elements) and 10.29 (the trip circuits), have separate three-phase and phase to phase distance units. Both relays also have ICS units to indicate a trip. The distance units have taps to vary the distance of the balance point. The phase to phase units have three tap ranges, with seven tap settings in each range, from 0.2 Ω to 4.5 Ω, 0.75 Ω to 21.2 Ω, and 1.27 Ω to 36.7 Ω, as well as multipliers to extend the basic range. The three-phase unit has taps from 0.87 Ω to 5.8 Ω with multiplier taps to extend the range. The taps should be set with the relay operating manual in hand until one is very experienced.

Solid state microcomputer controlled distance relays are becoming popular. They use voltage, current, and phase measuring circuits to obtain trip information instead of electromechanical components. They are more flexible than the electromechanical distance relays.

10.2.7 Zones of Protection and Carrier Blocking

The zone of protection is that distance of line that is protected. A forward zone of protection is one in the direction of the protected line, and a reverse zone is in the opposite direction of the protected line. More than one zone of distance relaying is normally used, with a different distance relay needed for each zone. The three zones of distance relay protection are referred to by number.

Zone 1 is a forward zone with the balance point set to 80% to 90% of the length of the protected line, as shown in Figure 10.24a. Note that the zone 1s from each end of the line overlap. This is normally a KD-10 relay.

Zone 2 is a forward zone set to look about 50% to 80% of the distance between station B and the next station beyond it (125% to 180% if the station distances are equal). This zone is to detect faults beyond the next station and key carrier blocking in zone 1, and with time delay as a back-up for the zone 1 relaying and the forward relaying of station B. Zone 2 relays set near 125% are frequently used with time delay alone for backup, while Zone 2 relays that reach further are used to key carrier blocking also. Figure 10.24b illustrates zone 2, which is normally provided by a KD-11 or a KD-10 with an auxiliary time delay relay.

Zone 3 is either forward or reverse looking depending on the philosophy of the line protection designer. Zone 3 relays are also timed relays with time delays greater than zone 2 relays and are also carrier blocked. Forward looking zone 3 relays look beyond the receiving substation to at least the one beyond it and perhaps even further (200 to 300% for equidistant substations). Zone 3 is often set to look in reverse and key carrier blocking because a fault detected with a zone 3 relay is outside of line section that relay system is protecting. The zone 3 relay operates after a time delay of sufficient duration (normally about 90 seconds) to know the proper relay set for the line segment in reverse from station A has failed to operate, acting as a delayed back-up for that section. The zone 3 reach is normally set for 200% to 300% of the distance between stations A and B. Zone 3 may not reach or may reach beyond the next station. Reverse looking zone 3 is illustrated in Figure 10.24c. Again, zone three may also look forward beyond the next station

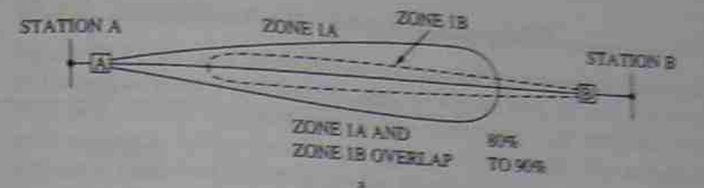


FIGURE 10.24 Distance relay zones (a) Zone 1, typically 80% to 90% of the protected line length (distance from substation A to substation B) (b) Zone 2, typically 125% to 200% of protected line length (c) Zone 3, typically 200% to 300% of protected line length, may or may not reach next station, or may reach beyond

beyond station B. It functions then as back-up for zone 2 relaying. Zone 3 relays are usually KD-11 relays.

Figure 10.25 illustrates how the time delays of the zone relays provide back-up protection for each other. Figure 10.26 summarizes the relationship between the zones of protection and the carrier blocking. The carrier can be either power line, fiber optic, or microwave; the operation is the same. In every case the carrier is keyed to prevent the protected line section circuit breakers from tripping in response to a fault outside the protected section. This allows instantaneous tripping to be used on internal faults for quicker fault clearing.

Note that the KD-10 and KD-11 relays have phase to phase and three-phase direction units. They can detect double line to ground faults but not ground faults. The relay system must have ground fault relays to provide ground fault protection.

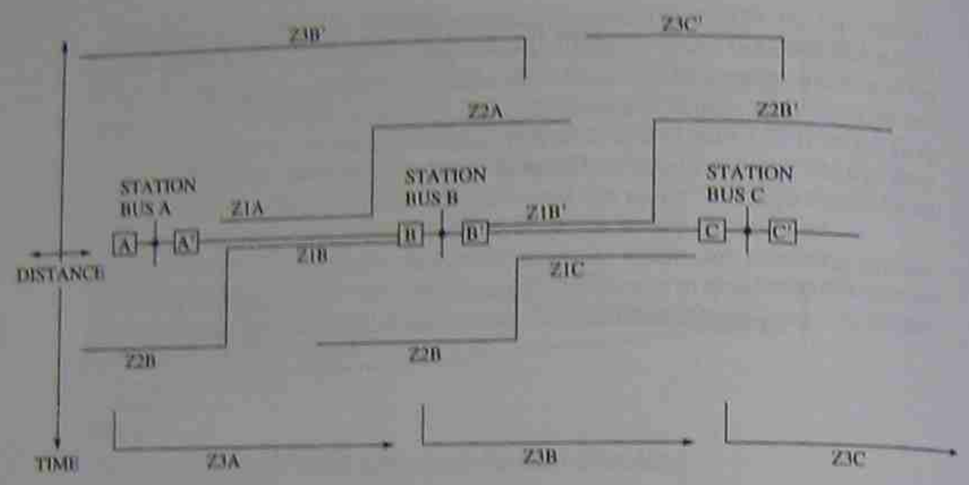
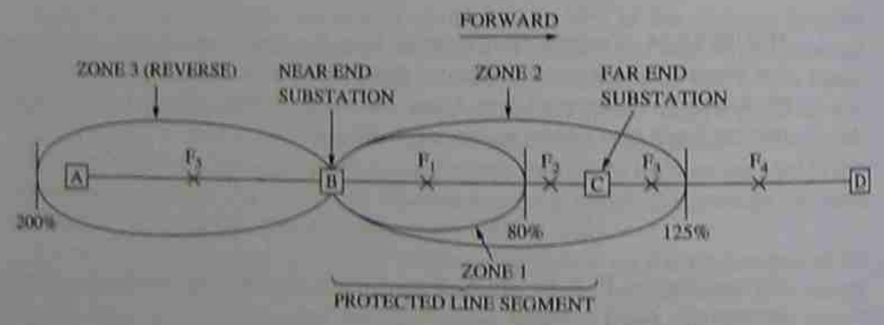


FIGURE 10.25 Time delays for zone coordination



F1 - ZONE 1 TRIPS BREAKER B INSTANTANEOUSLY

F2 - ZONE 2 TRIPS BREAKER B INSTANTANEOUSLY (WILL NOT BE BLOCKED BY CARRIER)

F3 - ZONE 2 BACKS UP RELAYS AT C CARRIER BLOCKING AND TIME DELAY PREVENTS B FROM TRIPPING UNLESS C RELAYS FAIL TO

F4 - NO ACTION

F5 - ZONE 3 (REVERSED) PUTS BLOCKING CARRIER ON LINE FROM B TO C TO PREVENT TRIP AT B AND C. KA-4 OR KD-11 MAY KEY CARRIER DEPENDING ON FAULT TYPE ZONE 3 MAY TRIP AFTER A TIME DELAY IF FAULT IS NOT CLEARED NORMALLY

FIGURE 10.26 Distance relay zones of protection and carrier coordination

10.2.8 Transmission Line Relaying Example

Figure 10.27 shows a fairly typical differential scheme for transmission line protection. This is for a line fed by a ring or similar bus, or that can be fed by more than one source. The protection is split into main and back-up systems, where each system is fed by its own instrument transformers. The actual relay sensing system is shown in Figure 10.28. The trip circuit for the main system is shown in Figure 10.29, and the trip circuit for the back-up relays is shown in Figure 10.30

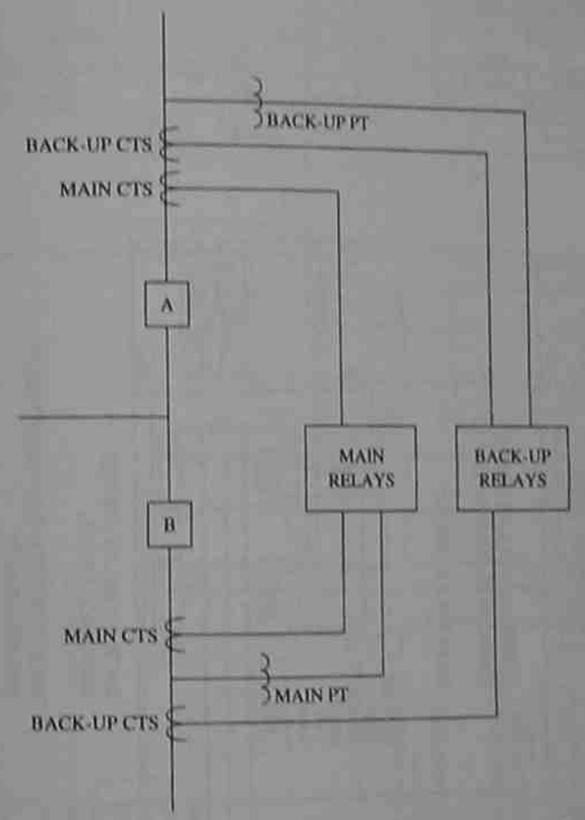


FIGURE 10.27 Back-up protection, differential connection for line with two breakers. Each relay set is fed by separate instrument transformers.

The main relay circuit of Figure 10.28 starts with an ITH instantaneous overcurrent relay set to detect very high current close in faults. Next is a KD-10 relay set forward for zone 2, and a KD-11 relay set reverse for zone 3. Some schemes use a KD- 10 zone 1 relay in the main relay system. What is important is that all of the protection zones are not on the same instrument transformers. The KRP directional ground fault relay is next to detect ground faults in the forward direction.

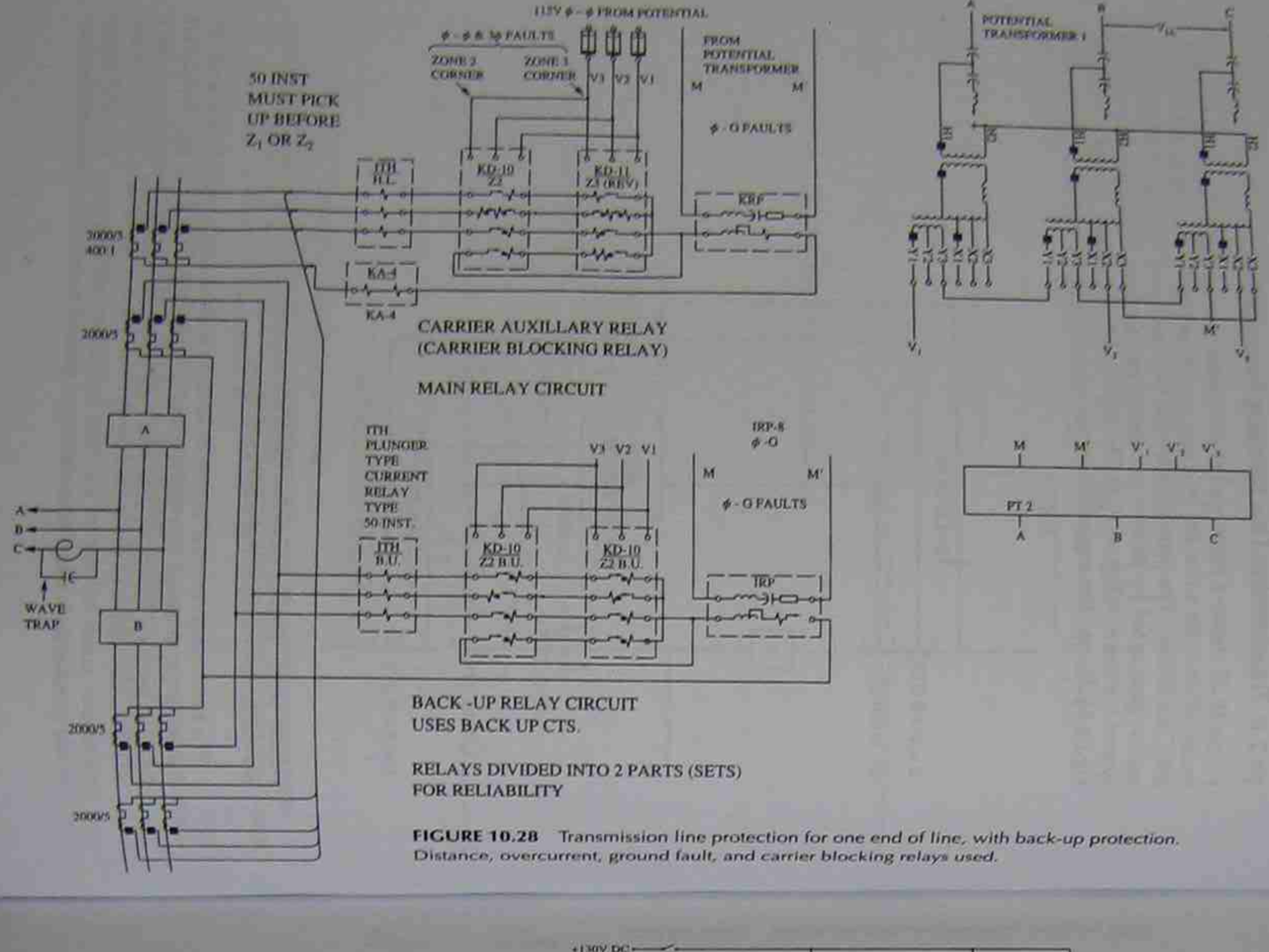


FIGURE 10.28 Transmission line protection for one end of line, with back-up protection. Distance, overcurrent, ground fault, and carrier blocking relays used.

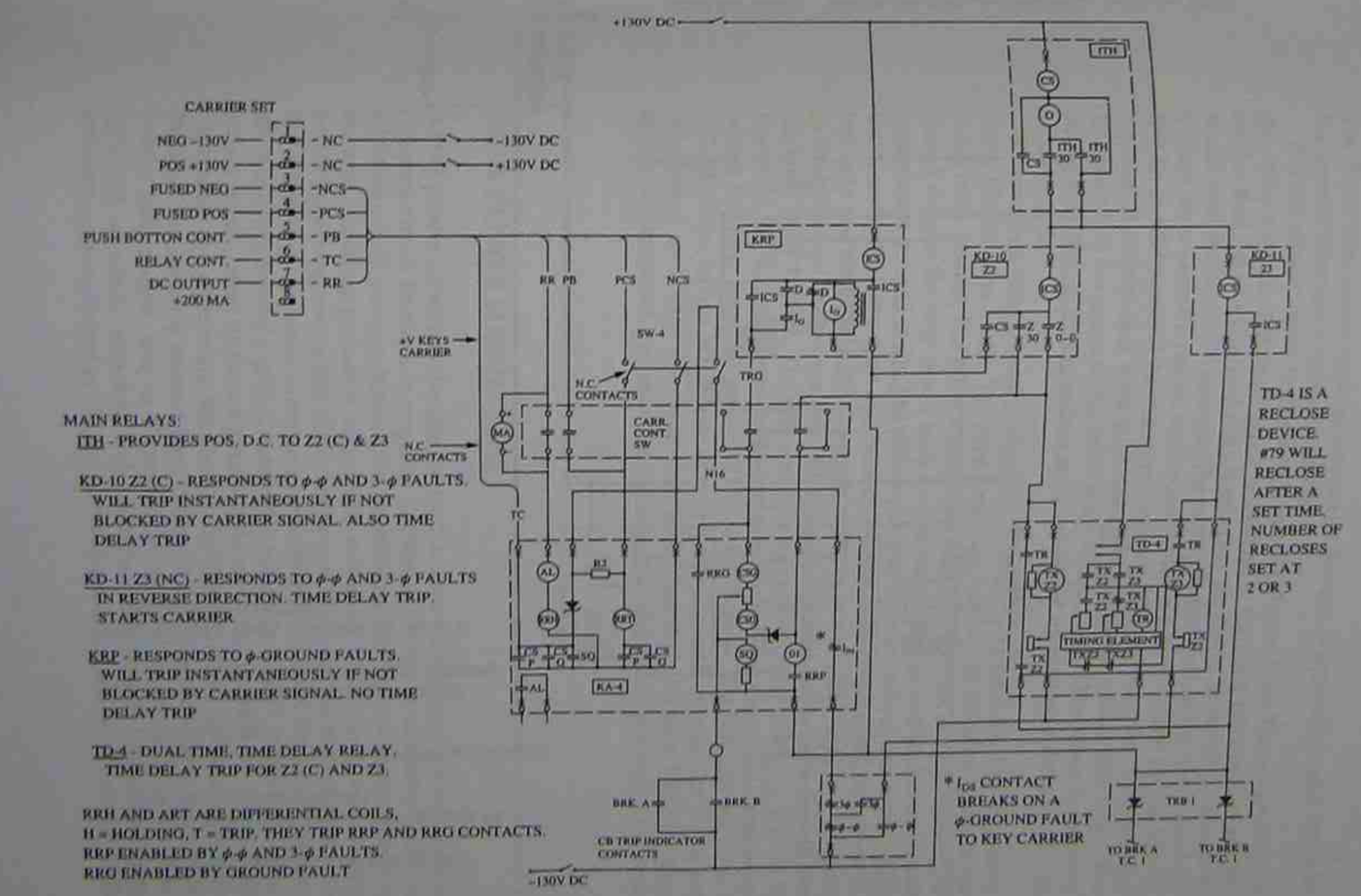


FIGURE 10.29 Trip circuit of main relaying in Figure 10.28

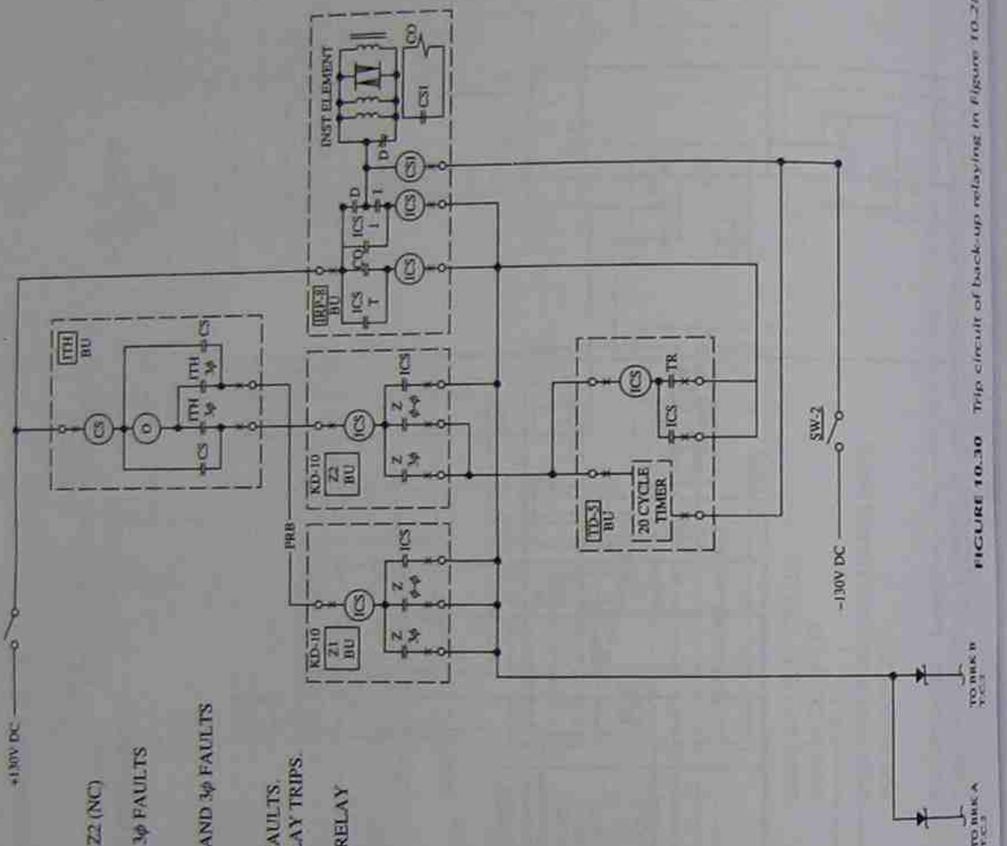


FIGURE 10.30 Trip circuit of back-up relaying in Figure 10.29

The KA-4 relay comes next. Its overcurrent function is to detect ground faults in the reverse direction and key the carrier.

The trip circuit for the main relays is shown in Figure 10.29. The relationship of the relay contacts and operation was detailed in the KA-4 relay section earlier. Notice that the KD-11 zone 3 relay is set to key the carrier by opening contacts in series with the KA-4 IOS contacts. The recloser is set to reclose the circuit breakers a short time (usually one or two seconds) after a fault is sensed by the KD-10, KD-11, or ITH relays. If the trip signal has been removed when the circuit breaker recloses, it stays closed. If the fault was not transient the breaker trips again. The TX coils close the contacts that activate the recloser timer. The recloser is normally set so that after it tries to reclose and trips two or three times it locks the circuit breaker open.

The back-up relay system of Figure 10.28 has an ITH relay, a KD-10 zone 1 relay, and a KD-10 zone 2 relay. The zone 2 relay is a back-up for the zone 2 relay of the main relay system, but it has a time delay only and does not key the carrier. The zone 1 relay is the only zone 1 relay and the main zone 1 protection for every fault type except ground faults. The philosophy is to have two zone relays in each relay set. Usually both the main and back-up relay systems both contain zone 2 relays, but only one zone 1 and zone 3 relay is used, one in the main system and the other in the back-up. The inverse time IRP directional ground fault relay is used in this back-up relay system. The trip circuit of the back-up relay system is shown in Figure 10.30. Notice that an auxiliary timer, a TD-5, is used to provide a time delay before tripping from the zone 2 KD-10 or IRP-8 relays. The ITH and the zone 1 KD-10 are set to trip at the same current in this particular system. The ITH is not directional so it trips on a fault from either direction. The zone 1 KD-10 relay, which is directional, passes on the trip signal only if the fault is in zone 1 forward.

10.3 BULK POWER SUBSTATIONS

A bulk power substation changes voltage to or from transmission level voltages and operates circuit breakers in response to transmission line or substation faults. In addition a bulk power substation has the following functions: controlling power to an area, housing protective relays and instrument transformers, and housing switching arrangements that allow maintenance of any substation equipment without disrupting the power to any area served by the substation. Basically it performs all of the functions of a critical distribution substation at much higher voltage and power levels. Most of the equipment is the same, and operates the same, as the equipment at a distribution substation except that it is scaled up in size and capacity. Thus the reader is referred back to Chapter 4 for power and instrument transformer information, and to Chapter 5 for information about circuit breakers, lightning arresters, switches, and substation protection. Substation switching arrangements are shown in Chapter 6, and are useful for high or low voltage. Major

differences between bulk power and distribution substations are that spacings are greater, autotransformers are often used, reactors are sometimes housed, and grounding is more critical in bulk power substations. In this chapter we will discuss the bulk power substation attributes that are different from distribution substations.

10.3.1 Compensating Reactors

Reactors are used to compensate transmission line capacitance to avoid excessive line voltage. The reactors may be switched, similar to capacitors, to compensate for loading changes. Reactors switched by SCRs are being used to respond rapidly to load changes. At heavy loads some inductive reactance is switched out to improve line voltage regulation, and at light loads more reactance is switched in to avoid excessive line voltage from the line capacitance. Normally half of the reactance is located at the substation from which the transmission line originates, and half at the substation at which it terminates.

10.3.2 Autotransformers in Bulk Power Substations

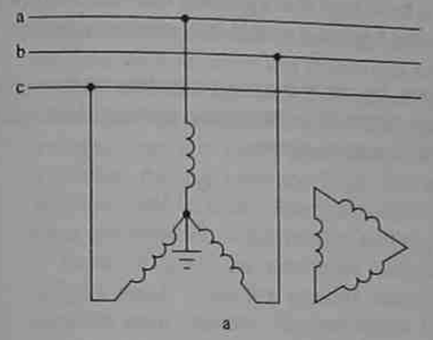
We noted in Chapter 4 that an autotransformer is never used as a distribution transformer because the lack of isolation can cause dangerously high voltages in a customer's premises if the neutral opens. In a bulk power substation, where voltages are transformed from one high voltage to another high voltage or from a transmission voltage to a subtransmission voltage, and which are accessible only by well equipped and trained workmen, autotransformers are often used. The first transformer after the generator is almost always a two winding transformer for dc isolation, and the last transformer in the substation feeding a customer is always a two winding transformer for safety.

Recall from Chapter 4.6.2 that the advantage of an autotransformer is that it can conduct some of the volt-amperes it transforms instead of transforming it all by induction. Thus the core loss is smaller in an autotransformer, and less magnetic core material is needed for magnetic induction. This allows autotransformers to be lower in cost, size, and cooling requirements than two winding transformers of the same MVA rating. The major disadvantage of autotransformers in applications for which they are suited is that their impedance is low so fault currents are high in comparison to two winding transformers.

10.3.3 Types of Grounding

Most transmission and subtransmission systems are solidly grounded to provide a solid reference voltage for relaying equipment, provide ample fault current for relays to detect in the event of a ground fault, and reduce voltage stress on the equipment. Transmission systems are usually grounded wye, but subtransmission systems are often delta connected to raise the zero sequence impedance in the event of a ground fault. To avoid voltage stress phase 1 of a delta system is often grounded. Delta systems may also be grounded through grounding transformers.

Grounding transformers, shown in Figure 10.31, are normally wye–delta or interconnected wye, called zig-zag. These transformers are designed to provide neutral potential equivalent to that of a wye system with the same line voltage while using very little power themselves. The windings are connected to limit the current from a ground fault to the rated neutral current by preventing core saturation. The transformers are used only for grounding and carry little current except during a ground fault, so they are fairly small. They are usually rated with the stipulation that they carry current for no more than 5 minutes. The relays should operate long before that. They are connected to the station ground.



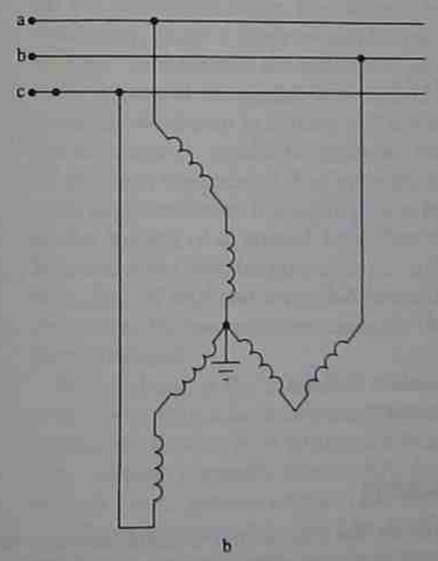


FIGURE 10.31 Grounding transformers (a) Wye-delta and (b) Zig-zag. Windings drawn parallel are wound on the same core.

Wye system grounding may be solid, through a conductor, reactance (impedance), through a reactor, resistance, through a resistor, or resonant, through both a reactor and a capacitor. These are shown in Figure 10.32. Reactance and resistance grounding are used to reduce zero sequence ground fault current while still providing an adequate ground for protective relaying. Reactance grounding reduces zero sequence current, but normally resistance grounding reduces it more. In some instances resistance grounding provides enough power loss to reduce generator power angle advance during a fault thereby improving stability. Resonant grounding uses a capacitor to cancel the grounding reactance during a fault, thereby providing a high impedance to the ground fault. The intent is for the parallel resonant circuit impedance to be so high that a ground fault arc cannot maintain itself. Resonant grounding is the highest cost and may cause problems when systems are interconnected.

A solidly grounded system allows the use of the most effective and economical lightning protection. It is the most common transmission system, but reactance and resistance grounding are used in many systems.

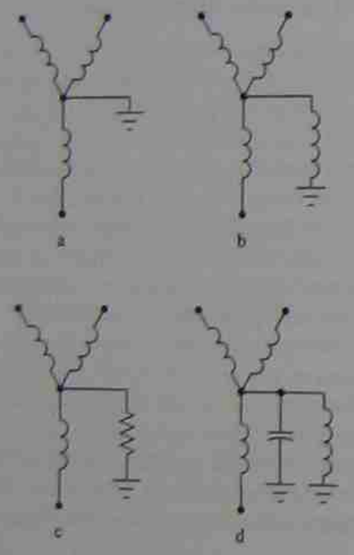


FIGURE 10.32 Grounding methods include: (a) Solid (b) Reactance (c) Resistance and (d) Resonant.

10.3.4 Bulk Substation Grounding

Equipment protection is only part of the reason that substations are so well grounded. Personnel protection is a major consideration. A continuous current through the trunk part of the body of about 0.15 A is almost always fatal. Electric shock death usually occurs from ventricular fibrillation, where the electrical signals

that drive the heart contractions go wild causing very rapid but ineffectual heart contractions to occur. The trunk of the body can withstand higher currents, but only for short times, and any current in the trunk over 0.1 A is dangerous. The Institute of Electrical and Electronic Engineers (IEEE) has set a standard for nonfatal body current at 201 mA for 0.33 s for a 50 kG (110 lb) person for the general public.

$$I_{MAX\ PUBLIC} = 0.116/t$$

For workmen inside a substation the limit is 272 mA for 0.33 s for a 70 kG (110 lb) person.

$$I_{MAX\ WORKMEN} = 0.157/t$$

These currents would be reached in a person only under unusually poor circumstances, such as when wet from a rain and standing on wet ground with wet shoes.

The body current is limited around a substation, or any other electrical power structure such as a transmission tower, by reducing the ground impedance to such a degree that any easily touchable point will not develop enough voltage to cause a fatality during a ground fault. The assumed body resistance for such calculations is 1000 Ω, much less than normal body resistance. Two safety related voltages are defined, touch voltage and step voltage.

Touch voltage is the maximum voltage allowed on any structure from any point within reach from the ground, standing 3 feet from the structure, because of ground fault current. The maximum touch voltage is 653 V inside a substation, where only competent workers in proper clothing should be allowed, and 207 V on the substation fence. The magnitude of fault current that would produce the maximum touch voltage would be very large. Figure 10.33a illustrates the touch voltage. To minimize the touch voltage, which would be dropped along the structure, a ground conductor is buried 18 inches below the surface 3 feet from the structure as shown in Figures 10.33a and b. The buried copper cable is attached to the structure by conductor, and also connected to 58 inch copper clad rods driven 10 feet into the ground. The principle is to give the ground fault current a better path to ground than through a person hapless enough to be touching the structure at the instant of a ground fault. The buried cable also prevents a voltage from becoming too high because of fault current flowing through the soil near the structure. The 10 foot rod is needed to assure good connection of the grounding conductors to the low resistance subsoil. The resistance of topsoil is much higher than that of subsoil.

Step voltage is the maximum voltage that can flow from foot to foot as one is walking during a fault condition, as shown in Figure 10.34a. The maximum step voltage allowed is 2010 V in a substation, and 225 V at the substation fence. A high step voltage normally occurs only during a phase to ground fault. If a phase should fall to ground between two towers on a right of way, as shown in Figure 10.34b, the phase voltage will be distributed evenly along the Earth between the conductor ground point and the ground return points. If the line potential is 100 kV and the line is faulted 1000 feet from the tower on the left the ground potential per foot is

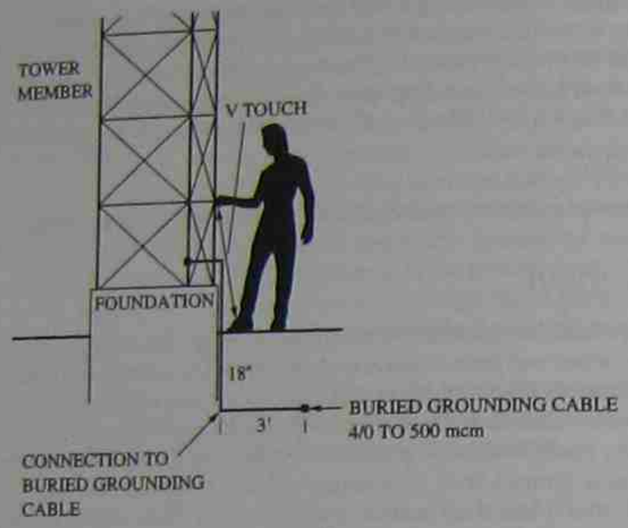


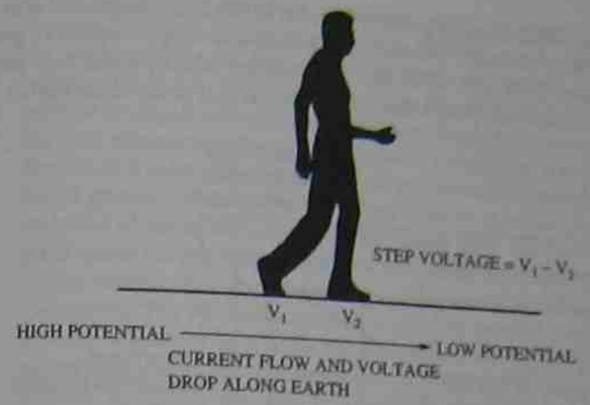
FIGURE 10.33 Touch voltage (a) Definition and (b) Minimized by grounding

$$V_{ft} = \frac{V}{d} = \frac{100\,kV}{1000\,\text{ft}} = 100 \text{ volts per foot}$$

If the foot to foot body resistance of a person under the line walking with 3 feet strides is 1000 Ω, the step voltage is 300 V and the foot to foot current is

$$I_{\text{foot to foot}} = \frac{300V}{1000\Omega} = 0.3\,\text{A}$$

which is fatal. Of course foot to foot resistance is normally much higher because people normally wear shoes. Additionally the protective relays open the circuit breaker within five cycles, and the voltage at the ground point of the faulted phase



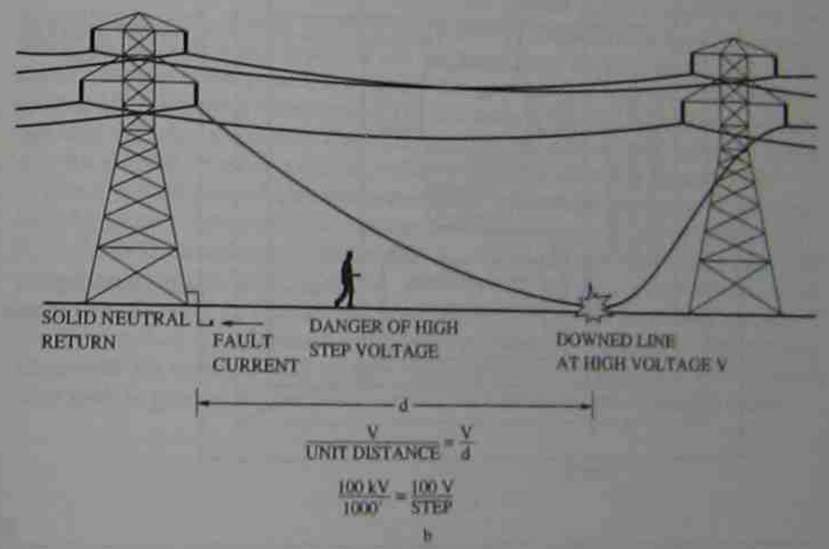


FIGURE 10.34 Step voltage (a) Definition and (b) How a high step voltage can occur

is reduced by the voltage drop along the other impedances in the circuit. Within a bulk power substation the ground resistance is so low that the step voltage is less than the maximum except during the most severe ground faults.

All substations have a ground mat. Every piece of equipment and every support structure in the substation is connected to the ground mat, as is the substation fence. In generation substation s the generator is also grounded. The purpose of the ground mat is to ensure personnel safety by keeping both the touch and step voltages

low during ground faults, and to prevent induced voltages on equipment and structures during normal operation. The same equipment and support structure grounding system is used even with delta and ungrounded wye systems that have no neutral return. A small bulk power substation ground mat is shown in Figure 10.35.

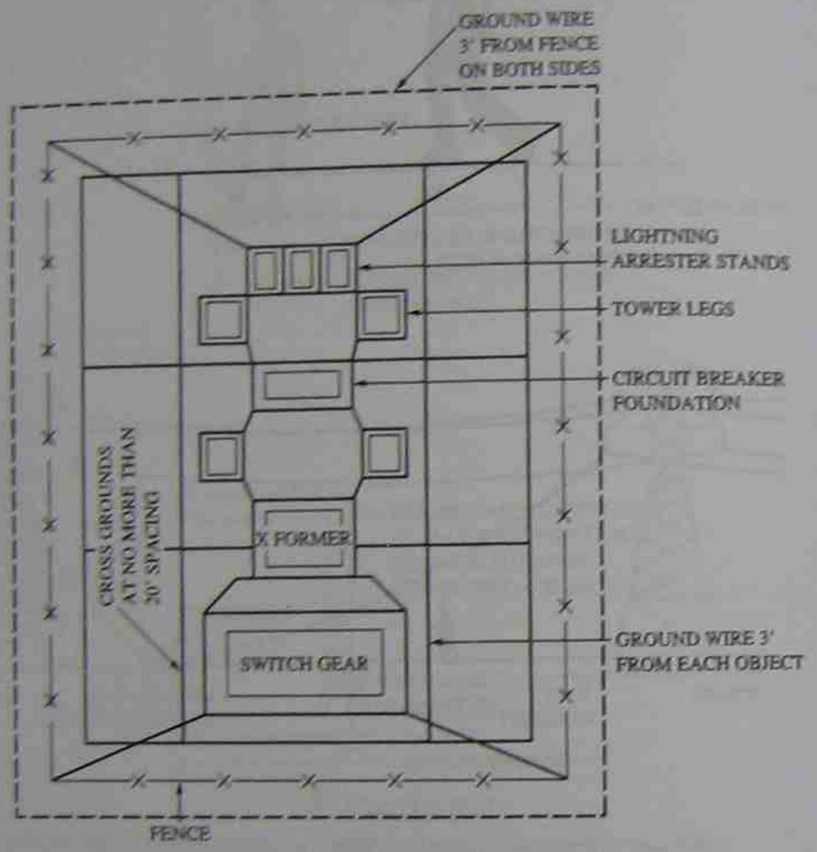


FIGURE 10.35 Small substation ground mat (a) Overview and (b) Transformer ground cross section

The bulk of the resistance associated with a grounding system is in the contact between the Earth and the ground conductors. If a good contact is established between the conductor and the deep subsoil the Earth resistance is very small. In fact the Earth resistance is so low that it can be used as the return line for a dc system in which the positive or negative line is out of service so the system can operate at about half capacity. Such returns may be over a thousand miles long. The ground contact consists of deep buried cable (8 feet or more) with special soil treatment, such as enclosing the 500 MCM ground cable inside compacted coke or charcoal. The buried ground cable at each end of the system may be over 3 miles long. The low resistance of the soil once good contact is established is why a well-established fault has a negligible resistance.

The resistance of the grounding conductors are in the low milliohm range in a substation. The #6 conductor that is used to ground a wood pole has less than an ohm of resistance on a 50 foot pole. Because the bulk of the resistance of grounding systems is in the conductor to soil interface, to measure the effective ground system resistance the soil to ground resistance must be included. A popular method of measuring ground system resistance is the fall of potential method, shown in Figure 10.36a. A current in the low ampere range is injected into the grounding system, usually through one of the two transformer grounding connections. The current return is placed 162 feet away from the instrument, and a voltmeter measures the potential between the ground mat and the voltage probe located 100 feet from the instrument. The resistance is the ratio of the measured voltage and the injected current. The remote probes are copper rods driven 18 inches into the subsoil. Another common probe connection is shown in Figure 10.36b.

The specified ground resistance, including the ground conductor to soil interface, for some common electrical power installations are: bulk power substations—$R_g < 0.005\ \Omega$, distribution substations—$R_g < 5\ \Omega$, transformers (other than bulk power substation) and lightning arresters—$R_g < 5\ \Omega$, transmission tower grounds—$R_g < 10\ \Omega$, and distribution poles—$R_g < 25\ \Omega$. The ground systems of electrical power installations are complex, efficient, and expensive. They are very important for safety as well as a protective relaying reference and a low impedance path to ground for transient current, such as that from a lightning stroke.

10.4 SUMMARY

Transmission line fault current calculations for balanced three-phase systems can be done on a per phase basis using either actual values or the pu method. Asymmetrical system fault current can be calculated using the method of symmetrical components. In this method a three-phase system is resolved into three sets of balanced phasors. They are:

1. *Positive sequence components* are three phasors of equal magnitude and offset from each other by 120° that rotate in the same direction as the original phasors.

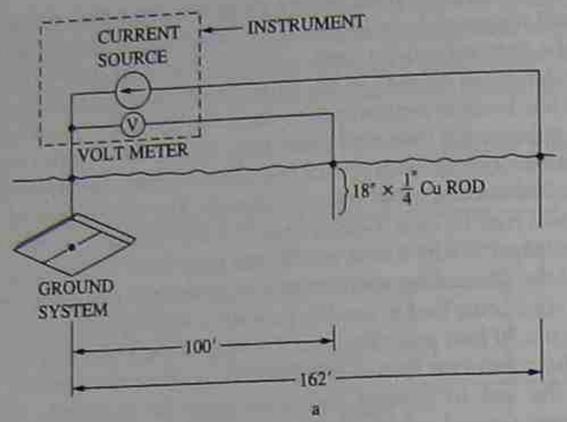


FIGURE 10.36 Fall-of-potential method of ground resistance measurement
(a) Most common connection and (b) Alternate connection

2. *Negative sequence components* are three phasors of equal magnitude and offset from each other by 120° that rotate in the opposite direction as the original phasors. Normally they are considered to rotate in the same direction as the original with phases b and c reversed.
3. *Zero sequence components* are three phasors of equal magnitude with no offset in phase between them.

Sequence impedance is obtained by providing unit current to the three phases of the apparatus under question and writing equations for the voltage drop. The sequence impedance of the system is found by properly including the sequence impedance of each apparatus in the system. Fault current is then found by dividing the system voltage by the system sequence impedance.

Transmission lines and substation represent a substantial investment and must be protected well. Transmission lines are protected by time and instantaneous overcurrent relays and ground current relays, often directional. Differential

schemes in which the current entering and leaving a section of line are compared, with the sending and receiving information transmitted by a variety of media and encoding schemes depending on the length of the line.

Specialized impedance relays called distance relays are often used for transmission line protection. The distance to a fault is proportional to the line impedance to the fault, so distance relays allow good definition of zones of protection. Normally three zones are used with distance relays to provide both main and back-up protection. They are:

1. *Zone 1* is a forward looking zone with the impedance of the distance relays set to about 80% to 90% of the impedance of the line segment impedance between substations. Zone 1 is normally set with no time delay.
2. *Zone 2* is a forward looking zone in which the relay is set to look between the receiving substation and the one beyond it. If all substations were the same distance apart zone 2 would be set to about 125% to 180% of the distance between substations for which the zone 1 relay is protecting the transmission line. Zone 2 is time delayed to operate only if the zone 1 of the receiving substation does not operate for faults in the overlap. Zone 2 relays are blocked from operating by a carrier signal if zone 1 relays operate anywhere in the distance they protect.
3. *Zone 3* is either forward or reverse looking depending on the philosophy of the line protection designer. Zone 3 relays are also timed relays with time delays greater than zone 2 relays and are also carrier blocked. Forward looking zone 3 relays look beyond the receiving substation to at least the one beyond it and perhaps even further (200% to 300% for equidistant substations). Reverse looking zone 3 relays look backward past the nearest substation and often to the one beyond it, again 200% to 300% for equidistant substations. Zone 3 relays function as back-up to the back up relays.

Transmission substations never feed customers directly and thus autotransformers are often used in them. The high value of fault current available in a transmission substation makes proper grounding of a substation essential.

10.5 QUESTIONS

1. List the most common short circuit faults and their approximate percentage of occurrence.
2. Define the term fault.
3. State the basic principle of symmetrical components.
4. List the symmetrical components of a three-phase system.
5. The currents in Figure 10.4 are changed to $I_a = 12\,A\angle 60°$, $I_b = 12\,A\angle -60°$, and $I_c = 0$. Calculate the positive, negative, and zero sequence phasors, then check your work by calculating the vector sum of the symmetrical components.
6. Why are electrical machine transient and subtransient impedances used for most symmetrical component problems in electrical power networks?

7. Define a sequence network and list the major components of the three-phase sequence networks.
8. A Δ-Y transformer with high side (primary) phase currents of 300 A∠0°, 300 A∠-120°, and 300 A∠120°, and a turns ratio of 0.1 is connected by the United States standard connection method. Calculate the low side (secondary) currents.
9. Why is the zero sequence impedance infinite in an ungrounded system?
10. The system of Figure 10.16 has the following specifications:
    Generator: two pole, conductor cooled, turbine driven, 100 MVA at 23 kV, $X''_d = 20\%$, $X_2 = X''_d$, $X_0 = 12\%$.
    Transformer 1: core type, Y-Y, grounded neutral, 23 kV/138 kV, 150 MVA, $X = 10\%$, $X_0 = 7\%$.
    Line: three-phase, Drake conductor, spacing of 14 feet, 14 feet, 28 feet, $Z_1 = Z_2$, $Z_0 = 3Z_1$.
    Fault impedance: max = 20 Ω, min = 0 Ω.
    a. Calculate the maximum and minimum fault current for a line to ground 100 miles from transformer 1.
    b. Calculate the maximum and minimum fault current for a three-phase fault 50 miles from transformer 1.
    c. Calculate the maximum line to line fault current at a distance of 25 miles from transformer 1.
    d. Calculate the maximum double line to ground fault current at the secondary of transformer 1.
11. State the basic philosophy of transmission line protection.
12. List three advantages of clearing a fault quickly.
13. Briefly state the function of a pilot wire carrier.
14. State the function of the sequence filter in the HCB and HCB-1 relays.
15. Why is a low current dc injected on a pilot wire?
16. What is power line carrier relaying?
17. State the function of the carrier in relaying.
18. State the function of the wave trap and coupling capacitor in power line carrier relaying.
19. Briefly state the function of the following relays: A. KA-4, B. KRP, C. IRP.
20. Why must directional relays be used in transmission line protection?
21. What is meant by zones of protection of distance relays?
22. What is the most common coverage of the three most commonly used distance relay zones.
23. How are the distance relays coordinated?
24. What property does the KD-11 distance relay have that makes it useful for zone 2 and 3 use?
25. State the principle of back-up protection for transmission line relays.
26. In what ways do bulk power substations differ from distribution substations?
27. Define touch and step voltages.
28. List the four common types of grounding and one advantage of each.
29. What is the source of most of the resistance of electrical transmission and distribution equipment grounding systems?

CHAPTER 11

Transmission Line Construction

This chapter discusses the steps involved in constructing a transmission line.

11.1 INTRODUCTION

Transmission line design has become a classic example of the adaptation of available standard designs to best fit the needs of a particular job after consideration of power loss, voltage drop, reactance, and thermal overload conditions. To make proper design adaptations, one must understand all factors influencing that design decision.

Complete transmission design is complex, but once a good design is developed, it can be used repeatedly. Good design is changed only when experience with that design indicates it will not handle a particular transmission condition efficiently.

An example of this is the Texas Inter-connected Network, the network that connects Houston Lighting and Power (HL&P) and Texas Utilities of Dallas. Although Texas Power and Light had originally designed double circuit 345 kV towers, the design was inadequate. As a result, before the Dallas/Houston intertie was built, a new tower design was developed and approved by both companies for their new 345 kV line. Since then, the majority of all 345 kV double circuit lines in Texas have been built using that new tower design system. The towers

were designed, (dead ends, swing angle, and tangent towers) so that on any 345 kV line, the layout could be made using those towers. Now, the designer has only to adapt the towers to the job at hand, select the conductors, the tower spanning, the foundations, and the auxiliary equipment. The details of the towers, the hardware, and the fittings are already accomplished and decided as policy. In fact, about 75% of the total design has been previously established. By selecting tower materials already designed and in use, the cost is significantly lowered. For their own use, HL&P has developed a tall, double circuit 345 kV line with vertical phases for use in narrow right-of-ways (ROW) (those that are seen within Houston city limits), but this more expensive tower is never used in rural areas where wider ROW are available.

With computers and standard line designs, a new line can be designed quickly. Companies only change a standard structure after much consideration, and after allowing for testing and production of the required materials.

Each power company has developed its own standards, and insist on their use, but because of the common designs, only a few systems have been developed. Originally, three engineering companies were responsible for all of the design work for approximately 80% of the power companies in the United States. Engineers went from one company to the other and the best of all available designs were adopted by each engineer and recommended to their utility clients. Conductors, fittings, and hardware were standardized by the Institute of Electrical and Electronics Engineers (IEEE) and the National Electrical Manufacturing Association (NEMA), and towers were standardized by major steel tower manufacturers. Now, common understanding makes all lines similar.

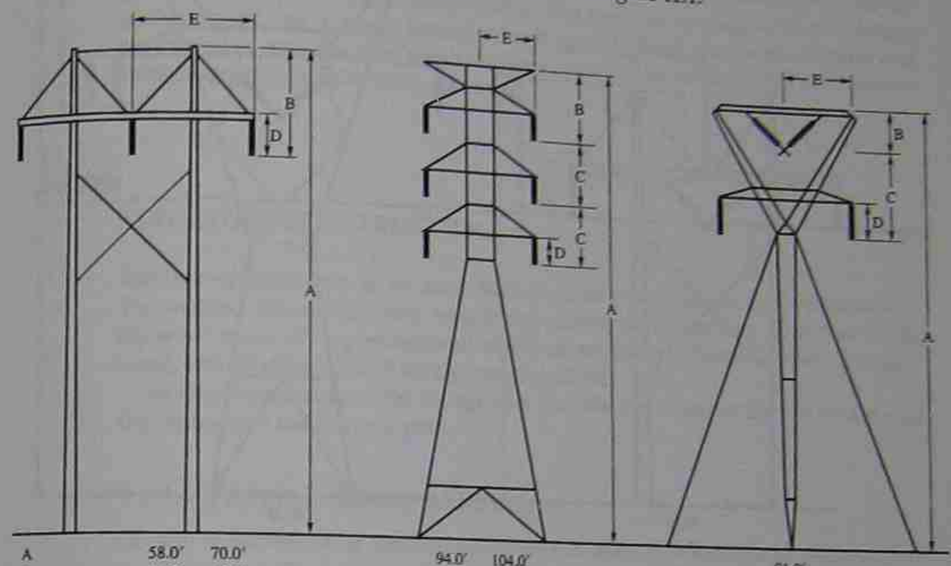
As Texas Interconnected Network developed a standard 345 kV line, the Southern Network (Georgia, Alabama, Mississippi, Louisiana, Oklahoma, Arkansas, and Tennessee), also developed a 500 kV single circuit with a bundle of three 1033 MCM ACSR per phase as their standard. Commonwealth Associates of Jackson, Michigan was selected to design and oversee this work. Now, the 500 kV lines in those states are alike. The same process has occurred in every regional power pool in the United States.

The federal government is in the electrical power business with the Tennessee Valley Authority (TVA), Bonneville, Bureau of Water Power, and the Rural Electrification Association (REA). The most readily available design books are those published by the REA, and are mandatory design guides for all borrowers of federal funds through the REA program. The REA books are available from the Bureau of Printing, and are public property.

11.2 TRANSMISSION LINE SUPPORT STRUCTURES

The transmission line support structure function is to support the conductor. The conductor is the line. The structure must support the line, but it must conform to

aesthetic requirements for an area, and must fit within the available ROW. Some available structure configurations are shown in Figure 11.1.



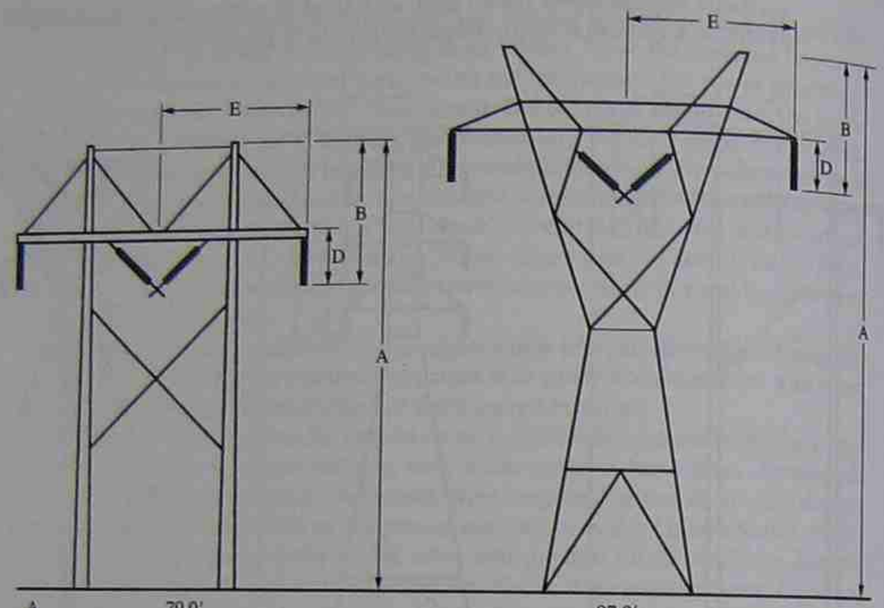
	a	b	c
A	58.0′ 70.0′	94.0′ 104.0′	91.0′
B	14.5′ 16.5′	13.0′ 15.0′	10.0′
C		13.0′ 15.0′	16.0′
D	5.0′ 7.0′	5.0′ 7.0′	7.0′
E	15.5′ 17.5′	13.0′ 14.0′	15.0′
MINIMUM R/W WIDTH	78.0′ 96.0′	86.0′ 95.0′	107.0′

FIGURE 11.1 Common transmission line support structures include: (a) 138 and 230 kV single circuit wood H-frame (b) 138 and 230 kV double circuit lattice steel (c) 230 kV single circuit guyed aluminum

We have already discussed wood poles. In transmission sizes, wood poles are southern yellow pine in lengths to about 75 feet. Poles from 80 feet to 130 feet in length are usually Douglas Fir.

Wood poles are superior for constructing transmission structures because they are readily available, inexpensive, require simple foundations, and are easily erected. Additionally, the fiber in wood poles will deflect under excessive strain without losing its integrity when strain is removed. Also, because soil foundations give under excessive strain, the wood pole will lean rather than break, and can then be inexpensively straightened.

Depending on the need, wood poles can be used in singles or in "H" structures. The advantage of the single pole structure is that the required ROW width is minimal. Limiting factors are the maximum voltage that can be placed on a single pole, conductor separation, and weight of conductors.



A	79.0'	97.0'
B	25.0'	25.0'
C	—	—
D	10.5'	11.0'
E	28.0'	30.0'
MINIMUM R.O.W.	123.0'	154.0'

d

FIGURE 11.1 (d) 345 kV single circuit wood H-frame and lattice steel

The advantages of the "H" fixture are that it is a strong rigid structure that can support the weight of a long span of large conductors, and can be used at higher voltages because of the capacity for increased conductor spacing. The disadvantage is that the ROW must be wide.

Steel poles have many of the same advantages and disadvantages that wood poles do. Steel poles can be directly imbedded in the ground just as wood poles can be. Directly imbedded poles, wood or steel, can be set with a modified foundation consisting of stabilized sand, shell, or gravel with a mixture of dry cement. While this method is preferable to natural backfill, it is not as stable as concrete. Steel poles are usually set on a reinforced concrete foundation and attached to a base plate or anchor bolts. This is a strong, but expensive, foundation. We will discuss foundations in greater detail later in the chapter.

Steel poles can be shipped in 20 to 40 foot sections, which can be shipped on trucks or a single railcar, avoiding the problem of shipping longer poles on multiple flat cars. Steel poles are always more expensive than wood, but are not limited to tree heights.

The most viable structure for strength and height capabilities greater than poles can provide is the lattice steel tower structure. The lattice steel tower provides the greatest strength-to-weight ratio available. The steel can be shipped in convenient packages, and can be easily assembled and erected. Steel towers are durable and reasonable in cost. The steel tower requires a special foundation that is not excessively expensive or difficult to construct.

11.3 STRUCTURE CONSTRUCTION

Erection of structures is an important part of transmission line construction. The method chosen may vary widely depending on: (1) terrain, (2) access roads, (3) work space, (4) experience and ability of workmen, (5) availability of equipment, and (6) allowed time for the completed job.

Terrain factors include the topography and the condition of the soil of the area through which the line will pass.

11.3.1 Factors in Choice of Structure

Certain factors must be considered, when choosing the methods of construction.

1. What type of structures are to be erected?
2. What are their natural divisions?
3. What are the dimensions of the natural divisions? (length, width, weight)
4. What are the conditions of access to ROW?
5. What are the conditions of access along the ROW?

The answer to questions 1 through 5 determine whether to use maximum equipment and minimum manpower, or minimum equipment and maximum manpower to construct the line.

If access is available for heavy equipment to and along the ROW, and if the terrain allows heavy equipment, then maximum equipment and minimum manpower is normally chosen. Whether swamp, mountains, or plains, equipment must be selected that operates in the requirements of the terrain. Heavy equipment is the preferred method of construction, and companies go to great effort to construct bridges, roads, and ferry crossings to facilitate the use of heavy equipment. When planning access, public roads are considered first; the balance of the access problems are then considered in terms of permission to use access and the cost of constructing access roads and bridges. We usually refer to these as temporary roads and bridges, because all private property is ordinarily restored to its original state.

Please follow the pattern of thinking for a particular ROW problem.

The ROW for a 138kV line is across relatively flat farm land with country roads on a near 1-mile grid. The ROW travels in an approximate diagonal across the

grid. Since the farmers will continue to use their land except during times of construction or emergency repairs, the width of the ROW is not a major factor.

Proper horizontal clearances can be obtained for voltages below 115kV by use of a single pole of wood or steel. At times, getting the poles to the site is a major financial consideration, and transportation dictates the choice of structure. Economic considerations normally dictate wood poles across farm land. Since wood poles must be handled in a single piece, poles over 75 feet must be hauled on two flat cars, and poles over 130 feet must be hauled on three flat cars. Poles over 90 feet must come from Washington or Oregon. Poles hauled by two flat cars can travel east across the Rocky Mountains by either the northern or southern route. Poles hauled by three flat cars must follow the southern route. No special permits are required to transport long poles by rail, but special permits must be obtained to haul all poles longer than about 50 feet from each state they are transported across, and in many states require a highway patrol escort. If you cannot get the poles to the job site, you cannot use them!

Many rural transmission lines are 69kV. Most 69kV rural transmission lines are supported by wood poles from 50 to 70 feet in length. The long poles are used to level out the line and to provide clearance above roads, highways, railroads, and other lines. The designers limit the longer poles to the fewest and most practical number.

Poles of 50 to 70 feet weigh between 900 and 1200 pounds. It is possible to set poles of this size and weight by manpower alone, but it is both dangerous and difficult. It does not require a large piece of equipment to set these sizes. Since poles are a single piece, they may be hoisted from a single point (the center of gravity). The balance point on a pole is closer to the butt (bottom) than it is to the top; a 50 foot pole has a balance point about 21 feet from the butt. The equipment must have the capacity to raise the pole enough to clear the ground in order to set the pole into the prepared hole. A derrick is then placed in a position so that the lift point is in excess of 21 feet high and far enough from the equipment to allow for maneuvering the pole. If the land is flat and dry, the derrick is on a truck with an "A" frame. If the ground is muddy or rough, a crawler tractor or crane may be needed.

11.3.2 Structure Construction Procedures

Each special structure and each special piece of equipment must have a particular, established procedure that accounts for the capabilities of the equipment, and the requirements of the task at hand.

An *"H" fixture* is the principal structure in rural areas for voltages between 115 kV and 500 kV. We will use a 230 kV "H" structure as an example. The procedure is as follows:

1. All pole framing material must be delivered in the ROW to exact, designated positions.
2. All structures must be assembled or framed and placed so as to be set without moving the equipment.
3. All holes are dug.

4. The setting rig must come by, set the pole and hold it until the tamping or back-fill crew can secure it.

An efficient line construction job is an assembly-line-job in which the workmen and tools move past the materials and leave behind a finished product.

Materials are brought by truck to the designated positions, where they are unloaded either by power equipment or by hand. The pole holes are marked so that the structure can be assembled in a location that allows the setting equipment maneuverability. The holes are then dug by powered drills, by some special equipment, or by blasting with dynamite.

The structure is set by whatever method has been selected. Poles are often set by an athey wagon. The athey wagon was designed during World War II for handling heavy loads. It was modified to build lines following the war. An athey wagon is essentially a trailer-mounted derrick. The athey wagon may have rubber tires for use on the plains, or a crawler for use in the coastal plains areas. The wagon is pulled by a caterpillar or a tracked tractor. The athey wagon can be pulled anywhere the caterpillar can go, but lacks maneuverability.

Because of the nature of an athey wagon, it cannot maneuver a load. It can either back the load up, or pull it forward, but it cannot swing the load from side to side. For this reason, the "H" fixture must be assembled in a position so that only one move is required. In most cases, the "H" fixture is assembled along the ROW beyond the holes. With this method, the balance point of the "H" structure is in line with the center of the ROW and the two pre-dug holes. The derrick is raised and the spreader bar (the bar between the upright plates) is attached to the poles. The structure is moved forward, until centered, over the holes and raised to the set position. The structure is lowered into the holes and held firmly until the backfill crew secures the structure. The whole process then moves forward. Figure 11.2a shows an athey wagon setting a structure.

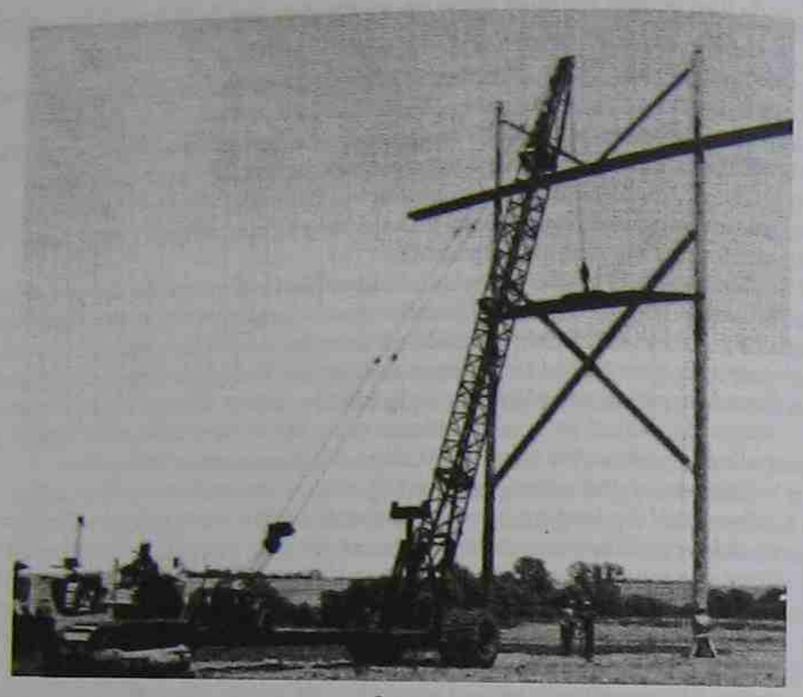
If a truck crane or a tracked crane is used, their load can be swung, allowing the structure to be framed in another position with relation to the holes. A truck crane cannot operate effectively in the mountains, or in the mud. A tracked crane is more useful than the truck crane, but is not as effective as the athey wagon. Figure 11.2b shows a free standing motor crane.

Steel towers (Fig. 11.3) are common because of their versatility and strength. The procedures are similar to the "H" frame:

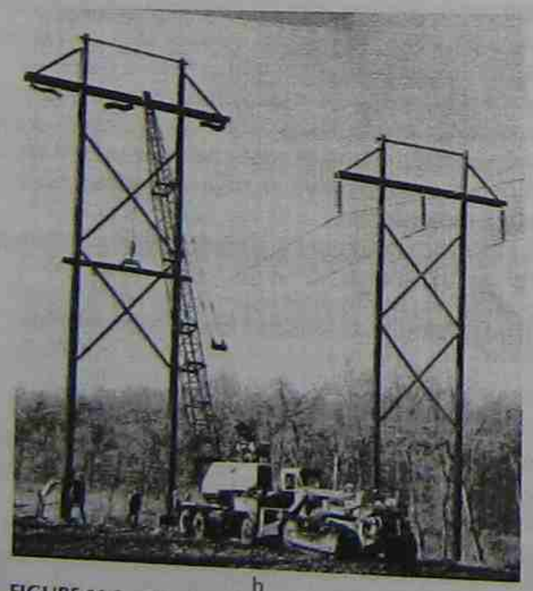
1. Prepare foundation (types of foundations and methods will follow),
2. Deliver material to site,
3. Assemble, and
4. Erect.

Since the procedure used for assembly is dictated by the chosen erection method, both are discussed together. A lattice steel tower can be set by the athey wagon, track crane, crawler crane, or gin pole.

The most common gin pole in use today is a lightweight structure that can be moved up a tower, one level at a time, in the manner of cranes on high rise buildings. The gin pole has the potential to lift approximately 2000 pounds, and swing



a



b

FIGURE 11.2 Structure setting (a) With an Athey wagon and (b) With a motor crane



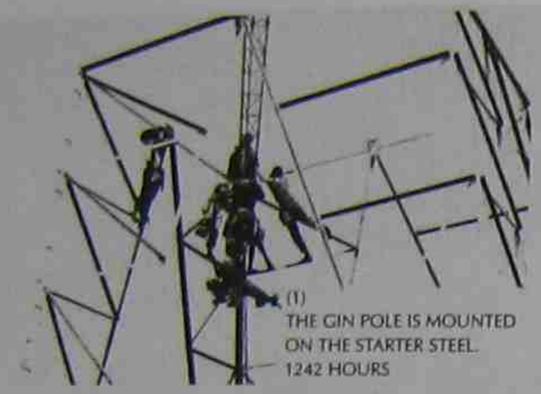
a

FIGURE 11.3 Steel tower erection (a) Materials laid out in preparation for construction

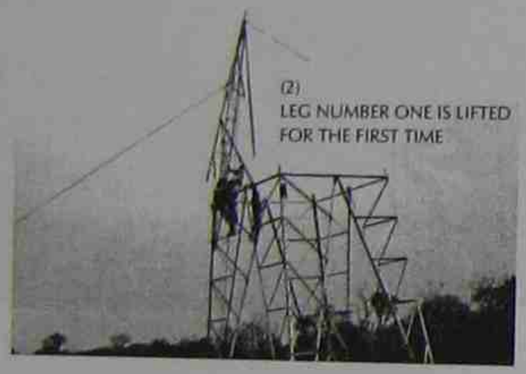
that weight to either side of the tower from its setup on each level. The crew for gin pole construction consists of a wench operator, four people on the tower, a foreman giving signals, and three people on the ground who prepare materials for the people above.

Using this method to erect towers, the tower must be paneled; meaning that sections of legs and bracing are bolted loosely together to be moved into position for final tightening.

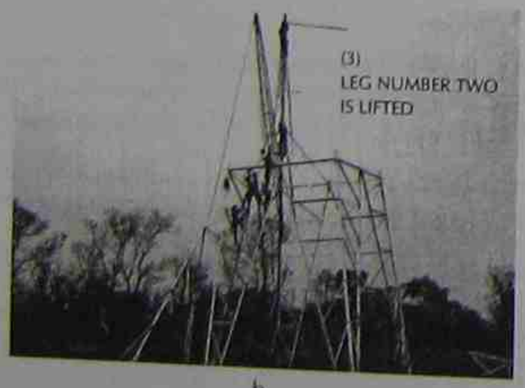
When the final assembly crew arrives, the foundation and the first section of steel are in place and leveled. The gin pole is placed inside one corner and anchored. From this position, each leg is hoisted, one at a time, and its supporting brace is swung to the anchor position and loosely bolted. Each of the four panel sections for the second level are completed and the gin pole is hoisted to the next level. Each panel to be placed from one position of the gin pole is called a "pick." When access is difficult and manpower is cheap, this is an efficient construction method. However, if it is possible, the preferred method is truck or crawler crane over gin pole.



(1)
THE GIN POLE IS MOUNTED ON THE STARTER STEEL. 1242 HOURS



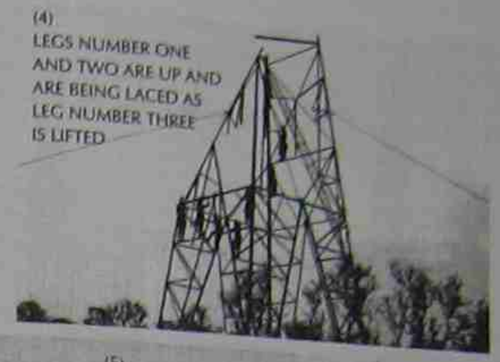
(2)
LEG NUMBER ONE IS LIFTED FOR THE FIRST TIME



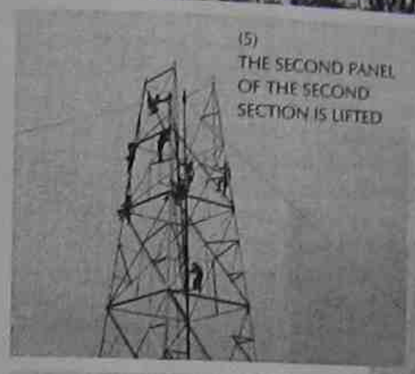
(3)
LEG NUMBER TWO IS LIFTED

b

FIGURE 11.3 (b) Construction steps



(4)
LEGS NUMBER ONE AND TWO ARE UP AND ARE BEING LACED AS LEG NUMBER THREE IS LIFTED



(5)
THE SECOND PANEL OF THE SECOND SECTION IS LIFTED



(6)
THE SECOND PANEL OF THE THIRD SECTION IS INSTALLED



(7)
INSTALLING THE PEAK

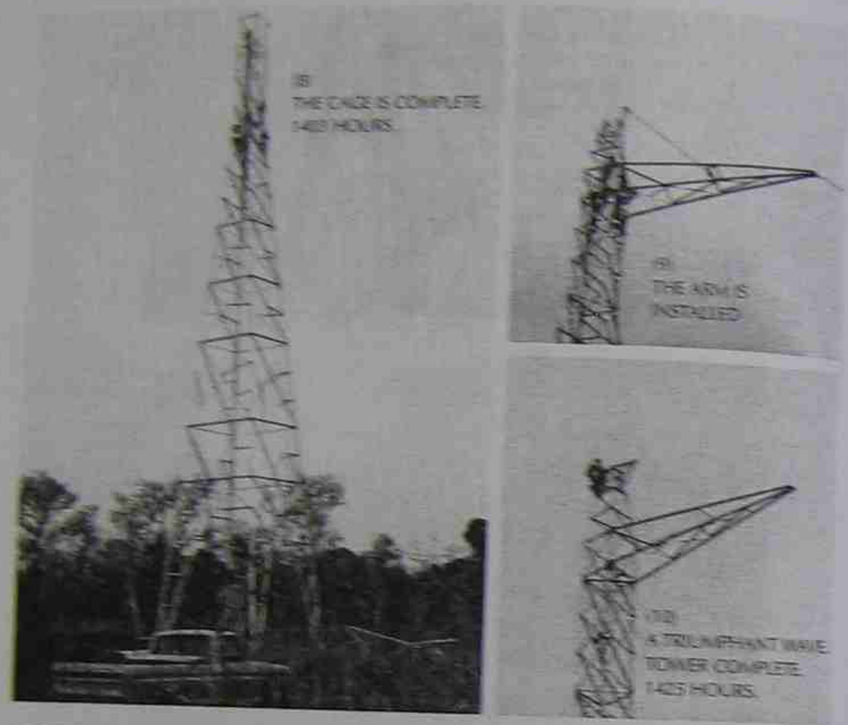


FIGURE 11.3 (b) Construction steps (contd.)

The size, weight, and rigidity of a tower, along with the size of the construction equipment, dictates whether a tower is erected in pieces or as a complete unit. A tower is designed as a unit, and it requires the entire tower structure to attain its ultimate strength. No part is designed to sustain a load alone, and often does not support its own weight. It is possible to brace a flimsy tower section for erection purposes and then remove the bracing when the tower is complete.

At times, it may be necessary to assemble towers at remote and inaccessible locations. Helicopter erection is sometimes used for this purpose. Erection by helicopter demands careful planning for optimum use. For an erection planner, there are two things to consider about each helicopter: (1) Weight lifting capability and (2) Cost of operation.

Few contractors who use helicopters own them. Because of their high operating cost, it is difficult to justify ownership. A helicopter service will furnish a four passenger helicopter for use in supervision for about $400.00 per hour of flight with a minimum of 4 hours flight time per day. A helicopter with 4000 pounds lift capacity will cost about $800.00 per hour; one with 10,000 pounds lift capacity may cost $3000 per hour; while a helicopter capable of lifting 18,000 pounds may cost $6000

per hour. Considering the costs, it is essential that the helicopter never waits on anything. Every construction phase is arranged so that the helicopters work as much as they can. All other costs fade by comparison. Towers can be sectionalized, allowing the sections to be flown in, and fastened in place to form complete towers.

11.4 TOWER AND POLE FOUNDATIONS

Because tower foundation is a large subject, here we introduce only tower compression and uplift forces. Foundations must overcome or accept these forces. Tower foundations are often constructed from bell-bottomed, drilled piers, filled with reinforced concrete, with a tower leg set into each pier. If the equipment and concrete is available, this method is economical and provides a good foundation.

In some cases, it is better to use hand or machine-dug holes, grillage foundations, and backfill. A grillage foundation consists of a tower leg, extended below grade and attached to heavy angle irons to which channel iron has been bolted, and then braces to make a grill-like unit. A force transmitted down the leg is transmitted into the soil, while an upward force is restrained by the weight of the soil backfill on top of the grillage.

A common foundation for poor soil is different types of piling with a "cap" as a transition piece. Poured slab types or floating foundations are sometimes required and used. Figure 11.4 shows some tower foundations.

11.5 TRANSMISSION LINE CONDUCTORS

The selection of a transmission line conductor and conductor size is a critical step in transmission line design. The conductor choice effects not only the cost of constructing the line, but also the cost of transmitting electric power through the line throughout its life. The conductor choice is critical.

11.5.1 Conductor Considerations

The factors that must be considered in the selection of the transmission line conductor include:

1. The required span and sag between spans
2. The tension on the conductor
3. Whether the atmosphere is corrosive
4. Whether the line will be prone to vibration
5. Power loss allowed on the line

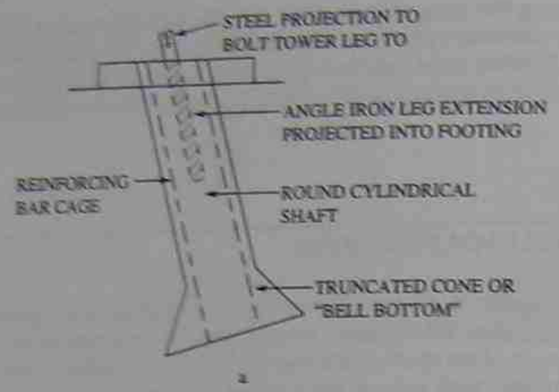


FIGURE 11.4 Tower foundation types include: (a) Bell bottom pier for use in good to medium soil (b) Grillage tower footing for use in good soil and (c) Pile and cap pier for use in very poor soil.

6. Voltage loss allowed on the line
7. Climate at the line location (for example, wind or ice loading probability and amount)

The most common types of transmission line conductor and the various considerations are discussed in the sections that follow.

11.5.2 Conductor Types

The most commonly used transmission conductor types are listed below:

1. ACSR (Aluminum Conductor—steel reinforced)
2. ACSR/AW (Aluminum Conductor—aluminum-clad steel reinforced)
3. ACSR-SD (Aluminum Conductor—steel reinforced/self damping)
4. ACAR (Aluminum conductor—alloy reinforced)
5. AAC-1350 (Aluminum Alloy Conductor composed of #1350 aluminum alloy)
6. AAAC-201 (Aluminum Alloy Conductor composed of 6201 alloy)

A brief discussion of each conductor follows.

ACSR has designations (6/1, 26/7, 54/7): The designation of 6/1 means six aluminum #1350 strands and one strand of galvanized steel for a core. This is used only for small conductors. Experience has shown that the above combinations form a strong and tightly bound conductor. ACSR is the most common conductor used today. The #1350 aluminum is a hard drawn aluminum that has good conductivity but not much strength. The core consists of galvanized steel wire. The galvanizing is a zinc coating placed on the steel by running the steel through a vat of molten zinc. The thickness of the coating is listed as "Class A" for normal thickness, "Class B" for medium, and "Class C" for heavy duty. The degree of contamination dictates the class of galvanizing for the core.

ACSR/AW conductor is like the ACSR above, except that the core is composed of a high-strength steel clad in an aluminum coating. This conductor is more expensive than ACSR, but it is acceptable for more corrosive atmospheres than is the ACSR with class "C" galvanizing.

ACSR-SD is a conductor that consists of two layers of trapezoidal-shaped strands, or two layers of trapezoidal strands and one of round strands around a conventional steel core. The strands themselves are composed of 6201 high-strength aluminum and their internal structure makes them self damping against aeolian vibration. These conductors can be strung at very high tensions and need not have auxiliary dampers installed. They have been proven to be good conductors, but the cost of conductor, splices, dead-ends, and installation labor have kept their use from becoming widespread.

ACAR consists of strands of 1350 aluminum and a core of 6201 high-strength aluminum. It is lighter than the ACSR and is just as strong, but higher in cost. When long spans in a corrosive atmosphere are needed, ACAR must be considered.

AAC-1350 is used for any construction that requires good conductivity and when short spans can be utilized, AAC-1350 is a good conductor.

AAAC-6201 conductor is composed of 6201-T81 high-strength aluminum alloy strands. It is as strong as ACSR, is much lighter, and more expensive. AAAC-6201 is good for corrosive atmospheres and long span construction.

11.5.3 Conductor Size

Minimum size conductors are usually dictated by either required tensions for span and sag considerations, or by the breakdown voltage of air. The factors governing tensile strength will be covered later in the section on tension. The voltage per unit surface area, for instance 50 kV per square inch, is dependent upon the voltage and the circumference of the chosen conductor.

Common minimum size conductors for given voltages are as follows:

69 kV—4/0 (four ought)

138 kV—336.4 MCM

230 kV—795 MCM single conductor

345 kV—795 MCM bundle of two

500 kV—795 MCM bundle of three

750 kV—795 MCM bundle of four

Europeans have adopted a standard of 556 mm bundle of four for 500kV.

Voltage drop considerations require that not only must the conductor meet the minimum size requirements, but must transfer power at an acceptable loss. This is often expressed as a maximum voltage drop of 5% for a particular system, across the total series impedance. The total series impedance (z) on the line is equal to the maximum allowable voltage drop divided by the maximum load current.

$$Z = R + jX_L = \frac{V}{I_{max}}$$

R is inversely proportional to the area of size of the conductor.

Thermal Capacity. When sizing a phase conductor, the thermal capacity of the conductor (ampacity) must be considered. The conductor should be able to carry the maximum expected long-term load current without overheating. Generally, a conductor is assumed to be able to withstand a temperature of 75°C (167°F) without a decrease in strength. Above that temperature, the conductor strength decreases, depending upon the amount and duration of excessive heat. A conductor's ampacity depends upon the current generated heat, the heat from the sun, and the cooling of the winds. Conductor heating is generally stated as ambient temperature plus load temperature, less cooling of the wind.

Economic considerations are important factors in determining conductor size. Rarely is a conductor sized to meet the minimum requirements, as stated above, the most economical. The additional cost of a larger conductor may be more than offset by the present worth of the savings resulting from the lower losses during the entire life of the conductor. A proper economic analysis should include the following factors for each of the conductor sizes considered:

1. The total cost per kilometer or mile of building the line with the particular conductor being considered.
2. The present worth of the energy losses associated with the conductor.
3. The capital cost per kilowatt of loss of the generation, substation, and transmission facilities necessary to supply the line losses.
4. Load growth.

The results of an economic conductor analysis can often be best presented and understood when presented in a graphical form, as shown in an REA study and in Figure 11.5. At an initial load of approximately 200 MW, 1272 kcmil becomes more economical than 795 kcmil. You will notice that 954 MCM is not the most economical nor the least economical at either end of the scale.

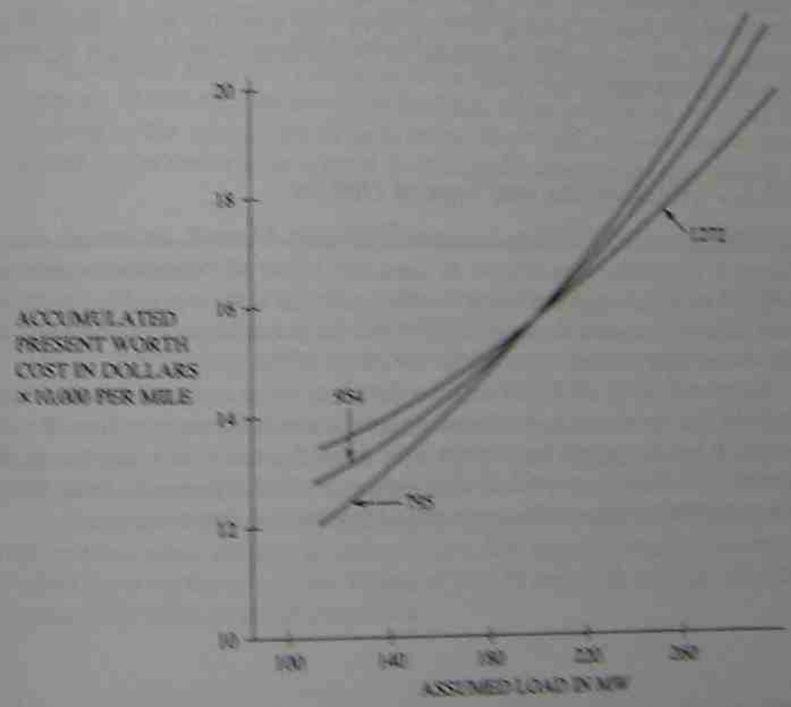


FIGURE 11.5 Results of a typical economic conductor analysis conducted by the REA.

11.5.4 Overhead Ground Wires

Overhead ground wires (OHGW) are the wires at near ground potential installed above the phase wires to protect the line from lightning, to even out the ground potential, and are sometimes used for low voltage communication. OHGW do not conduct load current, but they rapidly conduct the heavy current of a lightning strike to the ground, through their many grounded connections. Transmission

structures are all grounded and the OHGW is grounded at every structure. The types of OHGW are listed below.

High Strength or Extra High Strength Galvanized Steel Wire is used for high strength. The allowable sizes are 3/8 inch and 7/16 inch, while for extra high strength wires, the allowable sizes are 5/16 inch, 3/8 inch, and 7/16 inch. Note the 1/4 inch strand is not acceptable for use as OHGW, and neither are Siemens Martin grade wires of any size. Siemens Martin grade wire is a galvanized steel wire of low-grade steel and low stress capability, and is used only for guys to support structures.

Aluminum-clad steel strand conductor is covered with aluminum in place of galvanizing, and is a better conductor. This is the preferred conductor if the OHGW is to double as a communications circuit or if lightning is particularly heavy in the area for which this conductor is specified. This is a conductor consisting of seven strands of aluminum-coated steel with four different diameters of steel available, depending upon the current carrying need. The sizes are seven strands of 0.106 inch steel wire, normally designated as 7#.106, and seven strands of AWG steel shown as 7#9, 7#8, or 7#7.

11.5.5 Selecting Size and Type of OHGW

OHGW are sized according to current carrying demand, as stated above. The types of conductors are chosen to meet the needs of corrosion resistance. The OHGW must be capable of being installed with the same sag as the conductors, so that distance between the small OHGW and the much larger current carrying conductor remains uniform throughout the length of the span.

The specification of OHGW requires that there be no welds along their length. A weld in the metal fails in tension at a much lower temperature than the adjacent metal. A heavy current travels this wire from the point of a lightning strike to ground and if there are welds in that section, the OHGW usually fails, falling into the transmission line conductors, and putting the line out of service.

11.6 CONDUCTOR TENSION

Throughout the life of a transmission line, the conductor tension may vary between 10% and 60% or more of rated conductor strength due to change in loading and temperature. Most of the time, however, the tension varies within relatively narrow limits because ice, high winds, and extreme temperature are relatively infrequent in many areas. Normal tensions may actually be more important in determining the life of the conductor than higher tensions, which are experienced infrequently.

11.6.1 Tension Definition

The tensions shown in Table 11.1 should be approached as closely as the special conditions will allow in order to reduce the number of structures, but rarely exceeded. There are several conditions at which maximum conductor tension limits are specified.

The initial unloaded tension refers to the state of the conductor when it is initially strung and is under no ice or wind load. After a conductor has been subject to the assumed ice and wind loads, and/or long-time creep (the inelastic elongation of a conductor that occurs with time under load), it receives a permanent or inelastic stretch. The tension of the conductor in this state, when it is again unloaded, is called the *final unloaded tension*.

The loaded tension refers to the state of a conductor when it is loaded to the assumed simultaneous ice and wind loading for the National Electrical Safety Code (NESC) loading district concerned (see Table 11.1).

The vertical load on a conductor is the weight of that span of wire with its ice loading. The horizontal load is the load due to the pressure of the wind. The total loading is the vector sum of both loads. The NESC requires that a constant be added to the vector sum to reach the standard loaded tension as follows:

	Heavy	Medium	Light
Newton/meters	4.4	2.9	0.73
Pounds/foot	0.3	0.20	0.05

Extreme wind tension refers to the state of the conductor when it has a wind blowing on it of a value not less than the 50 year mean recurrence interval wind. No ice is assumed to be on the conductor.

Extreme ice tension occurs when a conductor is loaded with what is considered to be an extreme amount of ice for an area. It is assumed there is no wind blowing when ice is on the conductor. Values of 25 to 50 mm (1 to 2 inches) of radial ice are commonly used as extreme ice loads.

11.6.2 Ruling Span Tension

For a given ruling span (the reference span for a particular transmission line), usually only tension limit conditions control the design of the line, while the others conditions have relatively little significance. Stringing sags should be based on Table 11.1, limits 1, 2, and 3 only, as long as tensions at conditions 4 and 5 are satisfactory. If the conductor loading under extreme ice or wind loads is greater than under the "standard load" condition, calculated sag and tension values must meet those requirements.

TABLE 11.1 REA Standards for Maximum Conductor and Overhead Ground Wire and Temperature Limits for ACSR & 6201 AAAC

A. Temperatures		
1. Tension limits 1, 2, and 3 below must be met at the following temperatures:		
Heavy loading district	−17.8°C	(0°F)
Medium loading district	−9.4°C	(15°F)
Light loading district	−1.1°C	(30°F)
2. Limit 4 must be met at the temperature at which the extreme wind is expected.		
3. Limit 5 must be met at	0°C	(32°F).

B. Tension Limits in Percent of Conductor Rated Strength			
Tension Condition (See text for exp.)	**Phase Cond.**	**OHGW High Strength Steel**	**High Strength Steel**
1. Max. initial unloaded	33.30*	25	20
2. Max. final unloaded	25.00†	25	20
3. Standard loaded (usually NESC district loading)	50.00	50	50
4. Max. extreme wind (A)	70.00‡	80	80
5. Max. extreme ice (A)	70.00	80	80

NOTE: (A) These limits are for tension only. When conductor stringing sags are to be determined, limits 1, 2, and 3 should be considered as long as tensions at conditions 4 and 5 are satisfactory.

NOTE: Tension limits do not apply for self-damping and other special conductors.

*In areas prone to eolian vibration , a value of approximately 20 percent at the average annual minimum temperature is recommended if vibration dampers or other means of controlling vibration are not used.
†For 6201 AAAC, a value of 20 percent if recommended.
‡For ACSR only. 6201 Aluminum use 60 percent.

11.6.3 Overhead Ground Wire Tension

To avoid unnecessarily high mechanical stresses in the OHGW, supporting structures, and guys, the OHGW should not be strung with more tension than is necessary to coordinate its sags at different conditions with the phase conductors.

11.7 RULING SPAN

The ruling span is the assumed uniform design span that most closely resembles the variety of spans that are in any particular section of line. The purpose of the ruling span is to calculate the sags and clearances necessary for structure spotting and conductor stringing.

In a line where all spans are equal, the ruling span is equal to the average span. If the spans vary, the ruling span is between the longest span and shortest span in length.

11.7.1 Ruling Span Length

A satisfactory method for approximating the ruling span length is to take the average span plus two thirds of the difference between the maximum span and the average span, when the maximum span is not greatly different than the average span:

$$RS = L_{ave} + \frac{2}{3}(L_{max} - L_{ave}) \tag{11.1}$$

Where

RS = the ruling span

L_{AVE} = average span

L_{MAX} = maximum span

all in the same distance units. The exact equation calculating the ruling span is

$$RS = \left(\frac{L_1^3 + L_2^3 + L_3^3 + \ldots + L_n^3}{L_1 + L_2 + L_3 + \ldots + L_n}\right)^{1\backslash 2} \tag{11.2}$$

Example 11.1:

A line segment is 4250 feet from dead end to dead end. The individual span lengths are as follows: $L_1 = 750$ ft, $L_2 = 800$ ft, $L_3 = 1200$ ft, $L_4 = 500$ ft, and $L_5 = 1000$ ft. Calculate the ruling span by the exact and approximate methods.

Solution:

Using Equation 11.2 we obtain

$$RS = \left(\frac{750^3 + 800^3 + 1200^3 + 500^3 + 1000^3}{750 + 800 + 1200 + 500 + 1000}\right)^{1\backslash 2} \text{ ft} = 934.94 \text{ ft}$$

By the approximate method we obtain

$$RS = [850 + \frac{2}{3}(1200 - 850)] \text{ ft} = 1083.33 \text{ ft}$$

11.7.2 Limits on Lengths of Span

No span should be longer than twice the ruling span and none should be less than one half the ruling span.

By comparison to the ruling span calculated by the exact method, L_4 of Example 11.1 is close to one half of the ruling span. All spans pass the double ruling span test. This set of combinations of span lengths is acceptable.

By comparison to the ruling span calculated by the approximate method span four is under the minimum. The indicated solution to this problem is to even the spans up, if possible, and if not, to put dead ends on either side of the long span. Both solutions provide acceptable results.

11.8 DETERMINING CONDUCTOR SAG AND TENSION

Determining conductor sags and tensions, given the restraints shown in Table 11.1 and 11.7.3 listed above, and conforming to the stress-strain curves for a compound conductor such as ACSR, are complex. The best method is to use one of several computer programs written for this purpose. The computer program must:

1. Check all limiting conditions simultaneously and follow the governing parameter
2. Account for creep
3. Use average tension values (not at the support or midway).

The source most often used prior to computer calculations were manufacturers graphical methods. A good example is:

"Graphic method for sag tension calculations for ACSR and other conductors"
—Publication #8, Aluminum Company of America, 1961.

11.8.1 Sag-tension Relationship

The sag is inversely proportionate to the tension in a conductor. The maximum tension limits are set by the criteria mentioned previously. The allowable sag is a quantity that is dependent upon the length of span and the height of the supporting structure. This can be shown by the following parabolic approximate relationship:

$$S = \frac{WL^2}{8T_h} \tag{11.3}$$

Where

S = sag

W_c = weight of the conductor per unit length

T_h = tension used

L = length of span

If we pick a limiting tension for, T_h, and an acceptable sag, then we can easily calculate the length of span. If, on the other hand, the length of span is critical, the sag can be determined. All of this will be brought together in the section on the use of the sag template (section 11.11.2).

11.8.2 Equation for Sag

When any flexible conductor is supported at the ends, the conductor assumes the shape of a catenary. The formula for sag becomes:

$$S_{cat} = \frac{T_h}{W}\cosh\left(\frac{W_c L}{2T_h} - 1\right) \tag{11.4}$$

Where the sag is less then 5% of the length of span, the parabolic approximation, which has a much simpler equation, is close to that of the catenary. Only on long spans such as river crossings is it necessary to use the exact equation for sag. For others we will use the equation for the parabola, Equation 11.3.

11.8.3 Sag Calculation Example

An example calculation of sag using drake conductor and allowable tension as 25% of ultimate strength follows.

The ultimate strength of drake is listed by the NESC as 31,500 lb, T_h equals $0.25 \times 31{,}500 = 7875$ lb. W_c is 1.094 lb per ft for drake and L = 800ft is assumed.

$$S = \frac{1.094(800)^2}{8(7875)} = 11.11 \text{ ft}$$

This sag is based upon initial tension only and ignores the modulus of elasticity and temperature coefficient of expansion. A table prepared by a computer program is shown below.

Input
Conductor 477 MCM ACSR 26/7
Code name Flicker
Ruling span = 701.6 ft
Ultimate strength 17,200#
Diameter 0.846 inches
Tension limitations:
  Initial 33%
  Final 25%
  Loaded 50%
  Final temperature 60°F (ambient)
Weight factors:
  Dead weight 0.6145 lb/ft
  1/2 inch of ice 1.4517 lb/ft
  4 pounds wind 0.6153 lb/ft
  Resultant weight 1.8867 lb/ft
  Area 0.4232 in^2
  Temperature coefficient of linear expansion = 0.31
  Expansion = 0.0000108 feet per degree F
  Modulus: Final 10.3×10^6 lbs/in^2
  Initial 8.113×10^6 lbs/in^2

Output	Temp	Sag	Tension
Initial	Compatible with 1/2 of ice	15.48 ft	7500 lb.
Final	0°	12.17	3101
	30°	13.87	2722
	60°	15.48	2444
	90°	17.04	2221
	120°	18.51	2046

Calculation of initial sag by Equation 11.3 for this set of circumstances including ice and wind gives the following:

$$S = \frac{1.8867(701.6)^2}{8(7500)} = 15.48 \text{ ft}$$

This calculation shows that *if* we had a temperature that would allow for one-half inch of radial ice and a wind that produced 4 pounds per square foot wind pressure, and used a limiting factor of 7500 pounds conductor stress, a sag of 15.48 feet would be produced. This does not tell us what happens after the initial elongation of the conductor caused by applying 7500 pounds force, nor the "creep" of the conductor after time, nor does it account for changes due to temperature.

The computer program shows that if the conductors are sagged to 15.48 feet at 60°F, the tension will be 2444 pounds, and if the temperature drops to 30°F, the wire will shorten so that the tension becomes 2722 pounds, and the sag becomes 13.87 feet. Should the temperature increase to 90°F, the tension will drop to 2221 pounds and the sag will increase to 17.04 feet. It should be evident that sag calculation by computer is essential if all factors are to be considered.

11.9 CONDUCTOR VIBRATION

Overhead transmission line conductors are subject to two different types of vibration, aeolian vibration and galloping.

11.9.1 Aeolian Vibration

Aeolian vibration is a high frequency, low amplitude oscillation, generated by a low velocity, steady wind blowing across the conductors. This steady wind creates air vortices on the lee side of the conductor, which break at regular intervals, creating a force on the conductor, which is alternately upward and downward. When this frequency approaches the resonant frequency of that particular span, vibration occurs. In other words, when an integral number of vortice breaks occur within a span, vibration occurs. Wind speeds of between 8 and 15 miles per hour

cause aeolian vibration. Long spans with high tensioned conductors are especially prone to aeolian vibration. The wind conditions causing aeolian vibration usually occur in flat, open terrain. Aeolian vibration causes conductors to work harden, fracture, and break at the point of attachment to the suspension shoe. In other words, the conductor fails under fatigue.

The effects of aeolian vibration are mitigated by selection of a good suspension clamp and by installation of armor rods, or an armor grip suspension. Aeolian vibration is prevented by attaching dampers to the conductor, which act to destroy the effects of the steady wind and reinforcement of the vibration. The dampers oscillate at higher frequencies than the conductor, pull energy from the attempted aeolian vibration, and cause the damping.

11.9.2 Galloping

Galloping, or dancing, is a condition in which transmission line conductors vibrate with very large amplitudes at very low frequencies. Galloping can cause faults due to contact between phases, between a phase and a static wire, or conductor failure at a support point. The excessive stress caused by galloping has been known to cause both structure failure and excessive sag due to the conductor being stressed beyond its ultimate strength.

Galloping usually occurs when a steady, moderate, transverse wind blows over a conductor layered with ice that was deposited by freezing rain. This increases the diameter and weight of the conductor as well as the tension on the conductor.

There is one case on the Gulf Coast where a steady, moderate wind blew for 4 days before galloping was noticed. The phenomenon continued to reinforce itself until eventually several tower arms failed and the conductor lay on the ground.

On another occasion, during a hurricane at Freeport, Texas, a neoprene covered, 1000 pair, telephone cable began to gallop. Each upward swing pulled the poles from the ground a small amount. Each downward swing pushed the poles back into the ground, but not as much as they had been pulled out. This phenomenon, called "jacking," left several miles of telephone cable, with its supporting poles, on the ground.

Galloping can not be prevented but, by careful selection of span length and tension, it can be minimized.

During galloping, the conductors oscillate elliptically at frequencies under 1 Hz and amplitudes of several feet. When one loop of oscillation appears, this is called single-loop galloping, and rarely occurs in spans over 700 feet in length. Sometimes two loops appear that are superimposed on a single loop. This is called *double-loop galloping*. Double-loop galloping is common. In double-loop galloping, the point of maximum amplitude is at the quarter wave points. The shorter envelopes of motion make the problem of clearance required for double-loop galloping much less than that required for single loop.

Spans in excess of 700 feet are nearly immune to galloping as are most spans using bundled conductors. When galloping is found to occur, it can be negated by installation of aerodynamic drag dampers, or by use of interphase spacers. Galloping most likely occurs on a long span struck by winds that are funneled between mountains.

11.10 LINE PLANNING

The steps for planning the construction of a transmission line are discussed in the following section.

11.10.1 Plan-profile Drawings

Plan-profile drawings are drawings that show a topographical contour map of the terrain along and near the ROW, and a sideview profile of the line, showing elevation and towers. Figure 11.6 shows a section of a plan-profile drawing.

The transmission line plan-profile drawings serve as a worksheet, and eventually an expository sheet, which shows what is to be done and the problems involved. Initially, the drawings are prepared based on a route survey showing land ownership, the locations and elevations of all natural and man-made features to be crossed or that are adjacent to the proposed line (all affect ROW), line design, and construction. The drawings are then used to complete line design work such as structure spotting. During material procurement and construction, the drawings are used to control purchase of materials and serve as construction specification drawings. After construction, the final plan-profile drawings become the permanent record of property and ROW data, which is useful in line operation and maintenance, and in planning future modifications.

Beginning with initial preparation, accuracy, clarity, and completeness of the drawings should be maintained to ensure economical design and correct construction. All revisions made subsequent to initial preparation and transmittal of the drawings should be noted in the revision block by date and with a brief description of the revision.

Drawing preparation begins with an aerial survey followed by a ground check. The proper translation of these data to the plan-profile drawings is critical. Errors that occur during this initial stage affect line design because a graphical method is used to locate the structures and conductor. The final field check of the structure site should reveal any error. Normally, plan-profile sheets are prepared using a scale of 200 feet to the inch horizontally and 20 feet to the inch vertically. On this scale, each sheet of plan-profile can conveniently accommodate about 1 mile of line with enough overlap to connect the end span on adjacent sheets.

The sample format for a plan-profile drawing is shown by Figure 11.6 with units and stations in customary United States units. Increase in station and structure numbering usually proceeds from left to right with the profile and corresponding plan view on the same sheet.

Existing features to be crossed by the transmission line, including the height and position of power and communication lines, should be shown and noted by station and description in both the plan and profile views. The magnitude and direction of all deflection angles in the line should be given and referenced by P.I. station in plan and elevation. In rough terrain, broken lines representing

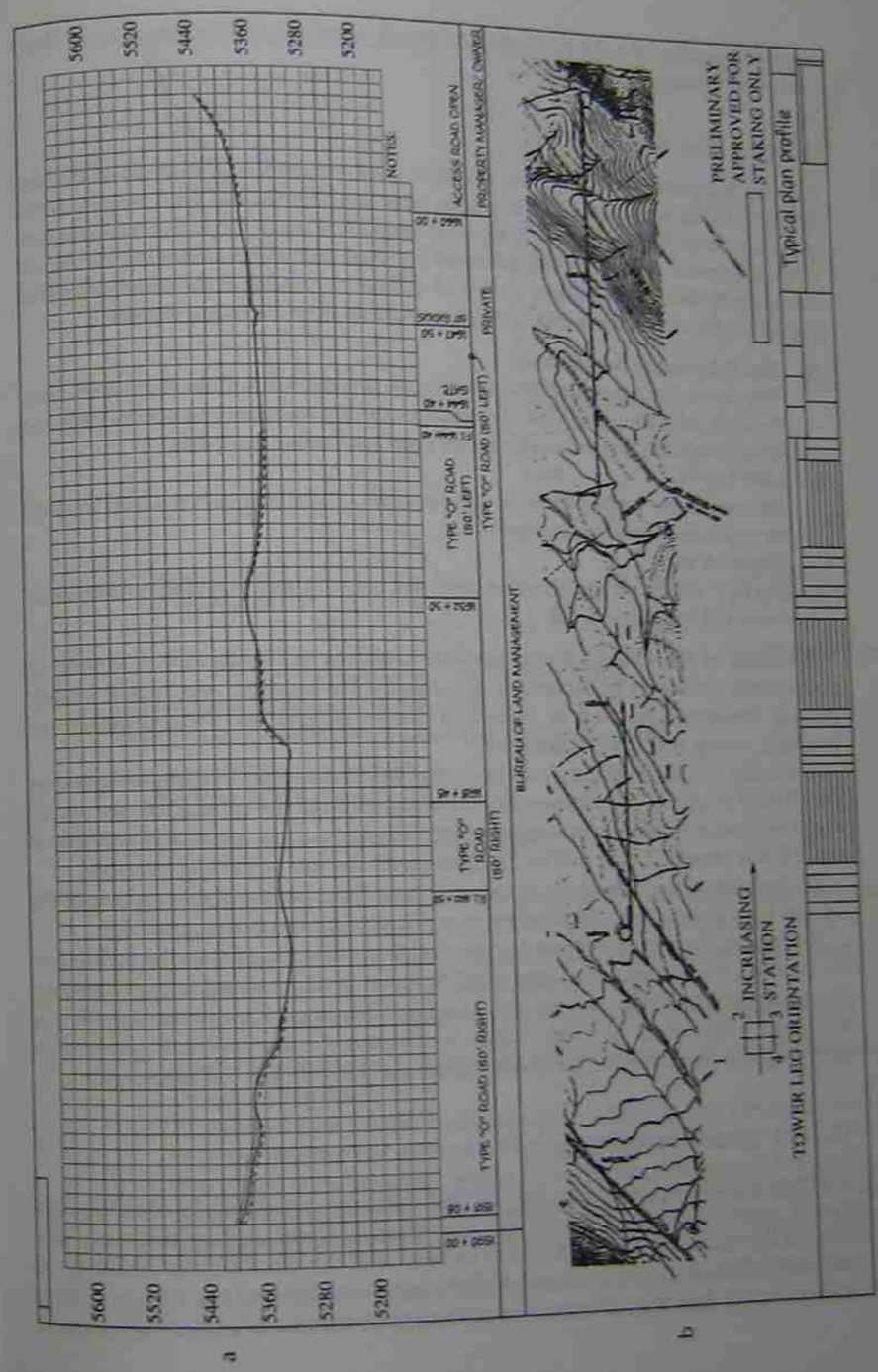


FIGURE 11.6 Plan profile drawing (a) Profile with towers spotted and (b) Contour

side-hill profiles should be plotted to assure adequate conductor–ground clearances and pole height.

11.10.2 The Sag Template

The sag template is a transparent template used for graphical analysis of the best combined collection of structure locations, structure heights, and span lengths to fit a particular route with its terrain. A separate template is made for each conductor type and each tension. Each template has superimposed each of the following curves calculated with the design tension, so that all ends of curves are at the same point (The sag values for each of these conditions are available from the manufacturer.):

A. **Hot (Maximum Sag) Curve**
   The maximum operating temperature, no ice, no wind, final sag curve. Used to check for minimum vertical clearances (or if maximum sag occurs under an icing condition, this value should be used for the sag template).
B. **Cold Curve**
   The minimum temperature, no ice, no wind, initial sag curve. Used to check for uplift and insulator swing.
C. **Normal Curve**
   The 16°C (60°F), no ice, no wind, final sag curve. Used to check normal clearances and insulator swing.

A sample of the conductor sag template is shown in Figure 11.7. It is used on plan-profile drawings to determine graphically the location and height of supporting structures required to meet line design criteria for vertical clearances, insulator swing, and span limitations.

Generally, the conductor sag curves control the line design. The sag template for the OHGW is used to show its position in relationship to the conductors for special spans or change in conductor configuration. The sag curves reveal the presence of uplift if it is present. Uplift will be discussed with the use of the sag template.

The template should be made to include spans three or four times as long as the normal level ground span to allow for spotting structures on steep terrain.

The form of the template is based on the fact that at the time when the conductors are installed, the horizontal tensions must be equal in all level and inclined spans if the suspension insulators are plumb in profile. This is also approximately true at maximum temperature. To obtain values for plotting the sag curves, sag values for the ruling span are extended for spans shorter and longer than the ruling span.

11.10.3 Structure Spotting

Structure spotting is the design process that determines the height, location, and type of consecutive structures on the plan-profile sheets. Actual economy and safety of the transmission line depends on how well this final step in the design is performed. The structure spotting should closely conform to the design criteria established for the line. Constraints on structure locations and other physical

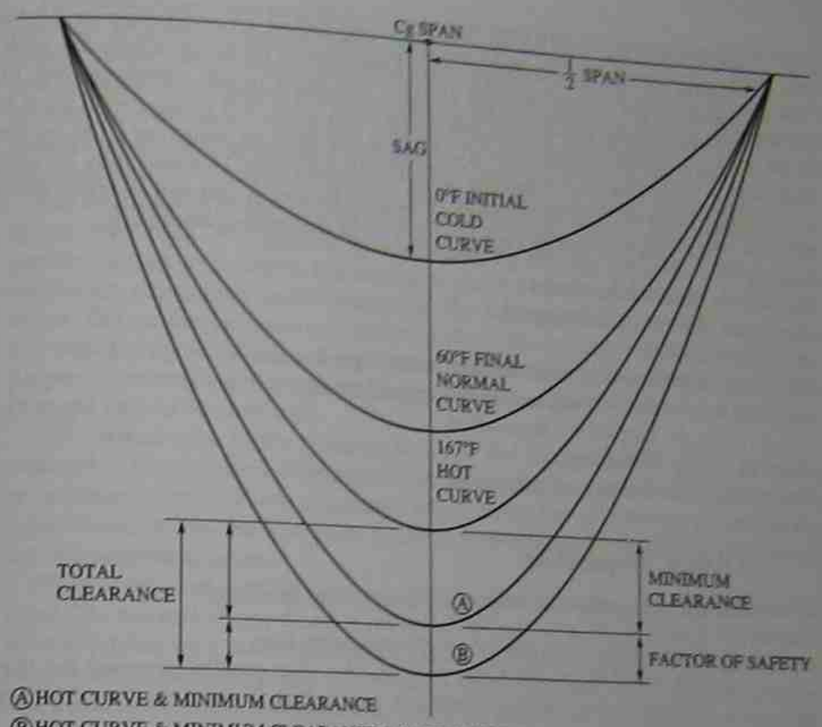


FIGURE 11.7 Typical pattern for sag template

limitations encountered may prevent spotting of structures at optimum locations. The initial effort at spotting the line must be followed by a field check to determine whether or not the structures can be placed as first laid out. Corrections or alterations are then made to accommodate the field check.

Ideally, the desired properties of a well-designed and economical line layout are:

1. Spans approximately uniform in length, equal to or slightly less than the design ruling span.
2. Maximum use of the basic structure, which is the structure and height selected as the most economical for the design condition.
3. The shape of the running conductor profile, also referred to as the grading of the line, should be smooth. If the conductor attachment points at the structure lie in a smooth-flowing curve, the loadings are equalized on successive structures.

For a generally level and straight line with few constraints on structure locations, the above stated objectives can be readily achieved. Greater skill and effort

are needed for lines on an abrupt or undulating ground profile and where constraints on structure location exist. Examples of these conditions are high or low points in the profile features such as line angle points, crossings over highway, railroad, water, power and communication lines, and ground with poor soil conditions. Structure locations and heights are often controlled or fixed by these special considerations. Alternate layouts between fixed locations may be required to determine the best arrangement based on factors of cost and effective design.

The principal design factors involved in structure spotting are:

1. Vertical clearances
2. Horizontal clearances
3. Uplift
4. Horizontal or vertical span limitations due to:
   a. Vertical sag—clearance requirement
   b. Conductor separation
   c. Galloping
   d. Strength of conductor.

11.10.4 Preparation

The following steps are required for structure spotting:

1. Plan-profile drawings of the transmission line.
2. Sag template of the same scale as the plan-profile prepared for the design temperatures, loading condition, and ruling span of the specified conductor and OHGW.
3. Table of required minimum conductor clearances over ground features and other overhead lines.
4. Insulator swing charts.
5. Horizontal and vertical span limitations due to clearance or strength requirements.

11.10.5 Process of Spotting

The process of spotting begins at a known or established conductor attachment point such as a substation take-off structure. For level terrain, when a sag template is held vertically and the ground clearance curve is held tangent to the profile, the edge of the template intersects the profile at the point where structures of the basic height should be set. This relation is illustrated for a level span in Figure 11.7. Curve No. 1 represents the actual position of the lowest conductor (hot curve), offset by the required total ground clearance, C.

The point where the normal curve intersects the profile determines the location of the next structure. The template should then be shifted and adjusted so that with opposite edge of the template held on the conductor attachment point previously located with the clearance curve again barely touching the profile. The process is repeated to establish the location of each succeeding structure. After all the structures are thus located, the structures and lowest conductor should be drawn in.

The above procedure can only be followed on lines that are approximately straight and that cross relatively flat terrain with the basic ground clearances. When line angles, broken terrain, and crossings are encountered, it may be necessary to try several different arrangements of structure locations and heights at increased clearances to determine the most satisfactory arrangement. Special considerations often fix or limit the structure locations, and it is advisable to examine the profile for several span lengths ahead for these conditions and adjust the structure spotting accordingly.

The relationship of the ground clearance and conductor curves is also used for spans other than level-ground spans by shifting the sag template until ground profile touches or is below the clearance curve with the previously established conductor attachment point (normally, the left) positioned on the conductor curve. The conductor curve would then indicate the required conductor height for any selected span. Structure height may be determined by scaling or use of the proper structure height template. Design limitations due to clearance or structure strength should be observed.

The vertical span is the distance between the conductor low points in spans adjacent to the structure. Horizontal span is the distance between the mid points on adjacent spans. Where conductor attachments are at different elevations on adjacent structures, the low point is not at mid-span and will shift its position as the temperature changes.

Where minimum vertical span or uplift is of concern, the cold curve should be used. The normal temperature is more critical and should be used if the vertical span is limited by a maximum value. Figure 11.8 shows examples of the relationship of conductor low points and vertical spans that may occur in a line profile.

If insulator swing is unacceptable, one of the following corrective steps, in order of preference, is recommended:

1. Relocate structures to adjust horizontal-vertical span ratio.
2. Increase structure height, or lower adjacent structures.
3. Use a different structure with greater allowable swing angle or a dead end structure.
4. Add weight at insulators to provide needed downward vertical force.

11.10.6 Uplift

Uplift is defined as negative vertical span and is determined by the same procedure as vertical span. On steeply inclined spans, when the cold sag curve shows the low point to be beyond the lower support structure, the conductors in the uphill span exert upward forces on the lower structure. The amount of this force at each attachment point is related to the weight of the loaded conductor from the lower support to the low point of sag. Uplift exists at a structure when the total vertical span from the ahead and back spans is negative, as shown by structure No. 4 in Figure 11.8, while no net uplift occurs at structure No. 3. Uplift must be avoided for suspension, pin-type, and post insulator construction. For structures with suspension insulators, the check for allowable insulator swing is usually the

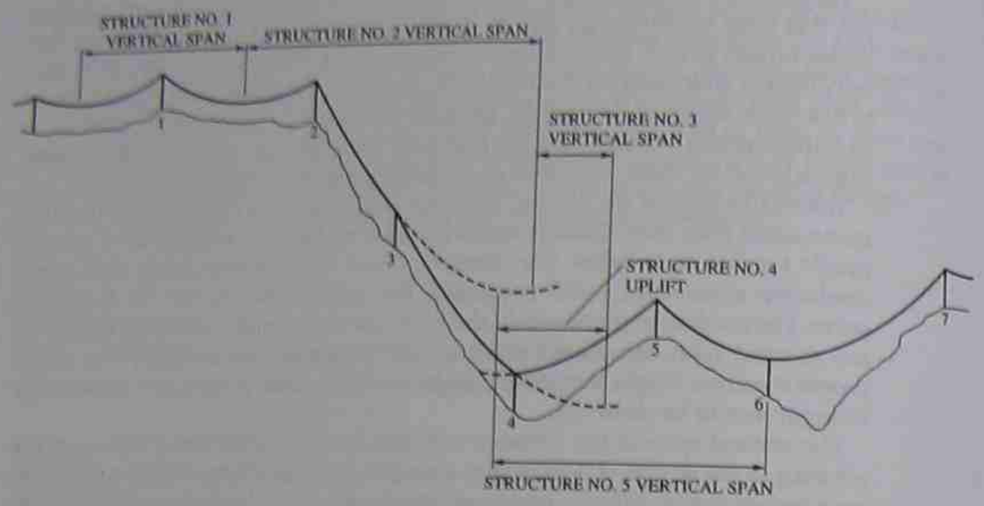


FIGURE 11.8 Sag low point, vertical spans, and uplift

controlling criteria on vertical spans. A rapid method to determine uplift is shown by Figure 11.8. There is no danger of uplift if the cold curve passes below the point of conductor support on a given structure with the curve on the point of conductor support at the two adjacent structures.

Designing for uplift or minimizing its effects is similar to the corrective measures listed for excessive insulator swing, except that adding excessive weights should be avoided. Double dead-ends and certain angle structures can have uplift as long as the total force of uplift does not approach the structure weight. If it does, hold-down guys are necessary. Care should be exercised to avoid locating structures resulting in poor line grading.

11.10.7 Final Drawings

The conductor and ground wire sizes, design tensions, ruling span, and the design loading condition should be shown on the first sheet of the plan-profile drawings. A copy of the sag template should be shown. The actual ruling spans between dead-ends should be calculated and noted on the sheets.

As conductor sags and structures are spotted on each profile sheet, the structure locations are marked on the plan view and examined to ensure that the locations are satisfactory and do not conflict with existing features or obstructions. To facilitate preparation of a structure list and the tabulation of the number of construction units, the following items, where required, should be indicated at each structure station in the profile view:

1. Structure type designation
2. Pole height and class or height of tower
3. Pole top, crossarm, or brace assemblies

4. Pole ground unit
5. Miscellaneous hardware units (vibration dampers at span locations)
6. Guying assemblies and anchors

11.10.8 Drawing Check and Review

The completed plan-profile drawings should be checked to ensure that the line meets the design requirements and criteria originally specified, adequate clearances and computed limitations have been maintained, and required strength capacities have been satisfied. The sheets should be checked for accuracy, completeness, and clarity.

11.11 LINE CONSTRUCTION EXAMPLE

Let us follow a line from inception to completion, using as models, companies such as Brazos Power or South Texas Electric Cooperative. These are both generation and transmission companies, and neither sells retail to individuals.

11.11.1 Right of Way Planning

Right of way planning begins when the need to build a new line is manifest. This need might be in relation to a new generating plant, or possibly to serve a new customer. This recently happened when Brazos Power was asked by the Texas Municipal Power Pool to provide wheeling facilities to interconnect several north and central Texas municipal power plants. The cities included Greenville, Garland, Bryan, and others.

At this juncture, the approximate amount of power to be shifted from one place to another must be determined. Maximum shifting generally occurs when a vital power plant is out of service for repairs and its load must be shared by the other municipalities.

At this time, the most suitable voltage is determined. For such a purpose, the highest approved REA design is 230 kV. Standard conductors are selected and losses checked. With this information, the most cost effective conductor size is estimated. (Computers now make these decisions easy and each company checks their transmission line designs to calculate the cost and loss per mile on each standard design they use.) Once the voltage and general class of conductors have been selected, the specific conductor and the supporting structure is chosen. If a single 795 MCM ACSR per phase is to be used, wooded "H" fixtures are the most economical.

The ROW width must now be decided. The REA dictates a standard ROW width of 100 feet unless a particular problem severely limits the available ROW. When a limiting problem exists, great effort is required to prove to REA that a narrow ROW is acceptable.

Next, a study of aerial maps determines the best transmission route. The best route is one that has the support of the courts in condemnation proceedings. The ROWs for transmission lines, as ROWs for highways, are determined to be in the public interest and therefore condemnation is allowed. To obtain a court order of condemnation, the following must be established:

1. Public need for the line must be demonstrated.
2. The selected ROW will cause the least damage to the people along it.
3. "Just compensation" must be offered for the property taken.
4. No more than the required land may be taken.

In general, it takes 2 to 10 years to obtain ROW for a line. When the ROW is finally made available, the line is laid out.

To "lay out the line," is a term adopted by this profession, which seems to have no logical translation into more commonly understood English, and is the most reasonable descriptive term for its meaning. For these reasons we will continue to use the term here. To lay out the line, the location of all angles and requirements for special structures are established, and the appropriate class of structures is selected. The structure locations are decided along with the specific structure at that location. Heights of the structures are not specified until span lengths and their required clearances are determined.

The ideal span length is established by considering the proper conductor tensions, ideal structure heights, and required ground clearance. In practice, an ideal line is laid out on ideal flat terrain to obtain the ruling span on which the conductor design is based. With these considerations met, comparison to terrain features sets the required heights and locations of all structures including the tangents, as discussed more fully in the section on spotting. All clearance and strength requirements for the construction of a safe line have been defined in the National Electric Safety Code (NESC). Recall that the NESC is a consensus construction code agreed to as appropriate and safe by all organizations in the United States who have an interest in safe electrical line construction and operation. It is published under the authority of the National Bureau of Standards.

Next, all clearances are checked and structure heights are adjusted to have required clearance above all roadways, waterways, and walkways, without excessive elevation changes. An additional check at this time is made to be sure that maximum wind loading will not allow less than minimum clearance between any phase and any possible obstruction—including trees off the ROW. One additional consideration is that tall trees (called danger trees) off the ROW must be cut. Danger trees are those that if blown over by wind would interfere with the line.

The site selection for the structures (spotting) requires the most careful judgment of the designer. If the terrain is rough, there is the possibility of uplift on a structure. Downward force is required on the insulator strings to keep them in tension, thus minimizing radio interference from the loose coupling of the insulators, and to ensure that the maximum span length and conductor tension is not exceeded. The ideal tension (and therefore the sag on the conductor) is established for the ruling span. The calculation of sag for the diverse spans and ensuring that they are properly installed is the principal problem facing the field engineer.

When a line has been designed using standard structures and a selected conductor with an accessories system approved by REA, the owner can expect 40 to 50 years of good service if the construction matches the design.

11.11.2 Conductor Stringing

Efficient wire installation is a complicated process. Wire installation, or stringing, is an art. Those capable of the art and science of being a wire engineer, usually called a sag engineer, normally move from job to job performing only wire installation.

Using the job plan, the sag engineer organizes the job so that work can progress from one end to the other. He takes a list of the wire reels, which shows the reel number and length, and selects specific reels to go to specific points. The reels are purchased in matched lengths to avoid waste. If the wire reels are 10,000 feet long, then 10,000 feet of each conductor should be installed in one operation. If the line is to be one conductor per phase, three conductors are installed from one location, or set up in two directions. If the conductor is a bundle of three, nine conductors are installed from each set-up in two directions. While wire may be ordered in 10,000 foot reels, the wire will be shipped in lengths of 10,000 feet, plus or minus 5%, labelled as to the length of wire on the spool. Unless "matched" reels are requested, much wire may be wasted.

If, for example, we check the first part of our plan and find at 10,500 feet from the starting dead end, near midspan, a level piece of ground in the ROW of sufficient size and accessability to set up all the equipment needed to begin conductor stringing, we designate that site as "wire site #1", and so mark it on our plan. The reels are checked to find nine reels as near 10,600 feet as possible (they may vary from 10,550 to 10,610 feet). These reels are assigned to "pull #1" and delivered to that wire site. At some point, 200 to 400 feet, before dead-end structure #1, a location must be found to designate as "puller site #1," and the appropriate equipment delivered to that point.

It is most effective to use the leap-frog method, and deliver the wire for pull #2 to wire site #1 so that the same equipment can be used for pull #1, turned around, and used for pull #2. The length of each pull is set by available space near midspan and the length of the available reels. The sag engineer prepares sheets similar to the ones shown in Figure 11.9 and assigns specific reels to particular wire pulls. One "set-up" is the arrangement of equipment ready to complete one pull.

The steps of a pull are as follows:

1. Install strawline from the wire site to the pull site. The strawline is a light steel line that can be dragged on the ground (to avoid damage, the conductor must never touch the ground) and is easily handled. It is mounted on a powered reel. It is strong enough to pull in the static wire also. On a standard 500 kV line, five strawlines are needed for the pull, one for each phase bundle and one for each static wire. The strawlines are put into place by setting up the five reels of straw lines at the appropriate location on the wire site, then dragging the end along the ROW to a point just beyond the first tower. The strawlines

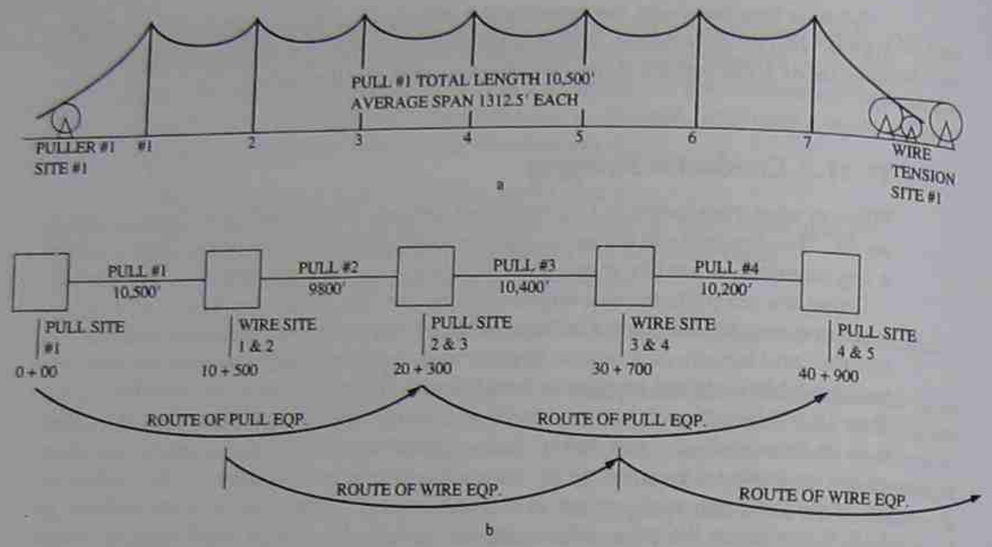
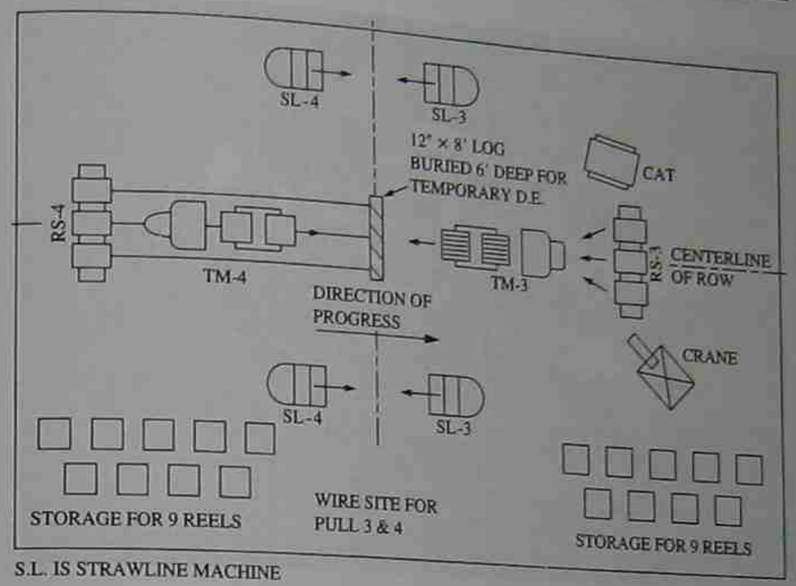


FIGURE 11.9 Conductor stringing organization (a) Seven span pull of a conductor (b) Pull organization and equipment paths

are relaxed and disconnected from the pulling CAT. One at a time, the ends are then tied to Pea lines*, and pulled into place. Now with all five strawlines in place on the first tower, they are reattached to the CAT and dragged to a point past the second tower and the process repeated until all lines are in place for the complete path of Pull #1. This is the most time consuming task in the wire stringing operation.

2. Wiresite preparation consists of setting up the conductor tensioning machine, mounting reels on the reel stands, and preparing the tools for the wire pull. Figure 11.10 shows a wire site set-up.
3. Puller site preparation consists of setting up the wire puller and the static reels on the static wire tensioner. Figure 11.11 shows the puller site set-up.
4. The two static wires are fastened to the two strawlines that were pulled into the static positions and, one after the other, the two strawlines are pulled to the wire statics in place. This leaves one strawline in place in each conductor stringing dolly. The puller is a heavy-duty machine with one reel of pulling line, which may consist of 18,000 to 20,000 feet of $\frac{3}{4}$ to $1\frac{1}{8}$ inch plough steel, anti-rotational, pulling line. One strawline is fastened to the pulling line, and the pulling line is pulled into position along the route to the wire site. The pulling line is then fastened to a pulling board, which in turn is fastened to the three conductors. This pulling board is shaped so that the pulling line

*Pea lines are small flexible lines installed when the dolly is hung. The pea line is threaded through the proper groove with two loose ends near the ground, so that the strawline can be pulled into place in the stringing dolly without someone climbing the tower.



S.L. IS STRAWLINE MACHINE
SL3 STRAWLINE MACHINE IN POSITION FOR PULL #3
SL4 STRAWLINE MACHINE IN POSITION FOR PULL #4
RS3 IS 3 CONDUCTOR REEL STAND IN PLACE FOR PULL #4 TO ALLOW THREE CONDUCTORS FOR ONE PHASE TO BE PULLED SIMULTANEOUSLY
TM3 IS 3 CONDUCTOR TENSION MACHINE IN PLACE FOR PULL #3
CRANE IS 20 TON ROUGH TERRAIN CRANE TO LOAD CONDUCTOR REELS ON REEL STAND

FIGURE 11.10 Wire site

is pulled through the stringing dolly in its proper groove, placing each of the conductors in their proper groove in the stringing dollies (which have been previously installed on the towers at the position where the conductors are attached). When the pulling line is retrieved, the first phase of conductors are in place and temporarily dead-ended by the wire crew, the remaining two phases are done, using the same procedures. The conductors are winded (brought to approximate sag) and transferred to temporary dead-ends.

The equipment is shifted to make the next pull, and the procedure is repeated. The sagging crew arrives within 72 hours to begin sagging. Figure 11.12 through 11.14 are photographs of equipment used in conductor stringing.

Timing of critical procedures and requirements for simultaneous operations require a well-orchestrated stringing effort for efficiency. The work can be done by crews of as few as 15 people, but efficiency dictates a minimum of 35 to 53 people, depending on the required rate of progress. If five pulls per week (10 miles) are desired, 53 people will work 6 days. If three pulls (6 miles)

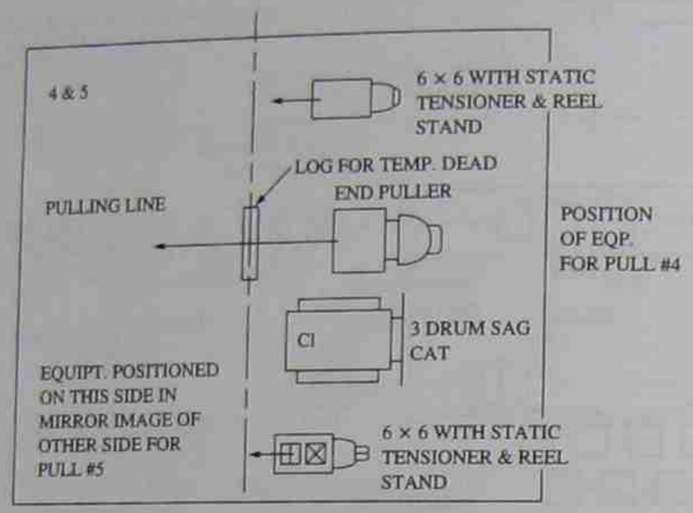


FIGURE 11.11 Puller site



FIGURE 11.12 Strawline machine and reel trailer (a) Strawline machine



FIGURE 11.12 (b) Lowboy trailer with braked reel stands for installing bundle of four conductor

are desired, they can be done in 5 days with 35 people. The fast operation requires three foremen. One foreman is responsible for all preparatory work, one is responsible for the wire pull, and one is responsible for clean-up.

Preparatory, or front end work, before the pull, consists of the following tasks:

a. Roads are prepared, puller sites cleared and leveled.
b. Material is hauled to proper sites. This includes wire, support hardware, insulators, splicing materials, and stringing dollies. Sufficient stringing dollies for both the conductors and static wires for the three longest pulls are required. As soon as the wire has been clipped in pull #1, a crew must retrieve the stringing dollies used in pull #1 and haul them to pull #2 for installation there. These procedures are repeated in sequence throughout the job.
c. All insulators are washed and hung, and insulator hardware installed with the stringing dolly in position. When this procedure is complete for the length of the pull, the job is ready for the wire crew and their procedures, which have been discussed. When the wire crew completes their work, the job is passed to the clean-up crew.

The initial task for the clean-up crew is sagging. Wire is sagged between temporary or permanent dead-ends, whichever is required. The sag is started at the dead-end on one end and carried through to the other. On any sag in excess of five spans, the sag on three spans must be checked. The sagger selects a span near each end and one near the center, as close to the length of the ruling span as possible, and calculates the sags for those spans. On level

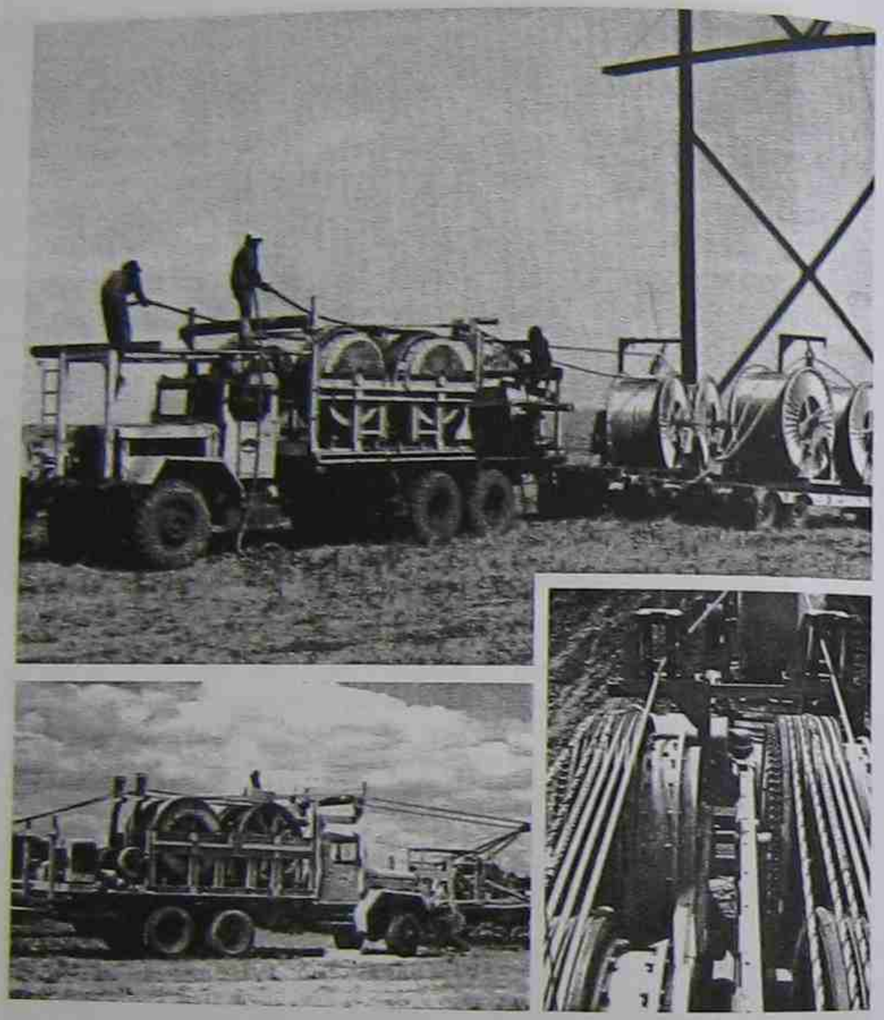


FIGURE 11.13 Views of a tensioner for bundle of two stringing

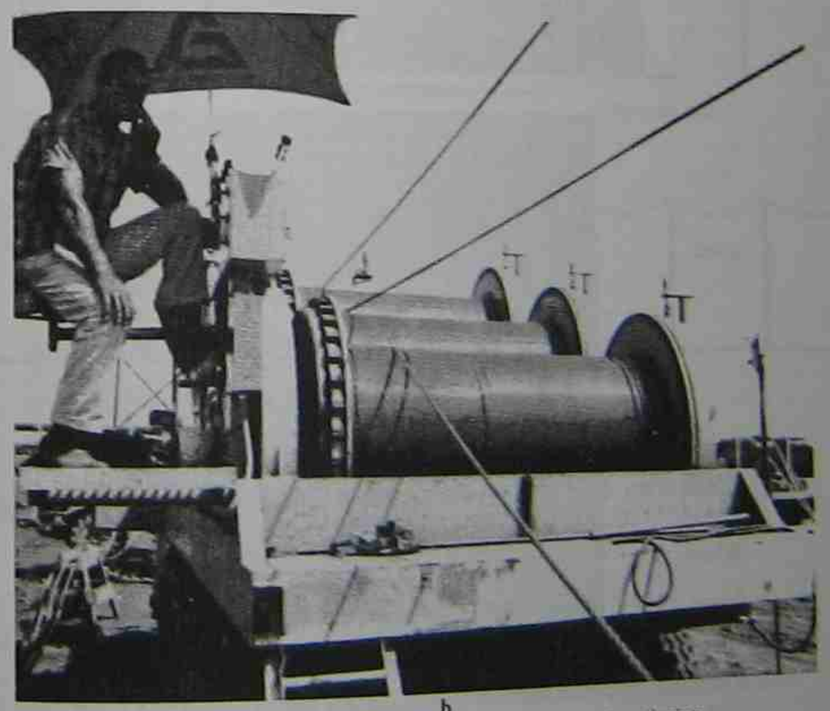
ground, sags are determined by mounting a target on one structure and a transit on the other so that proper sag in the low point of the catenary of the wire and the line between target and transit can be determined, as shown in Figure 11.15a. The stopwatch method of conductor sagging has become the method of choice for most sag engineers, and will be described in Appendix.

Sag for any span can be calculated by the following equation that references sag of a span to that of the ruling span.

$$S_{REFRS} = \frac{L^2}{L_{RS}} S_{RS} \qquad (10.5)$$

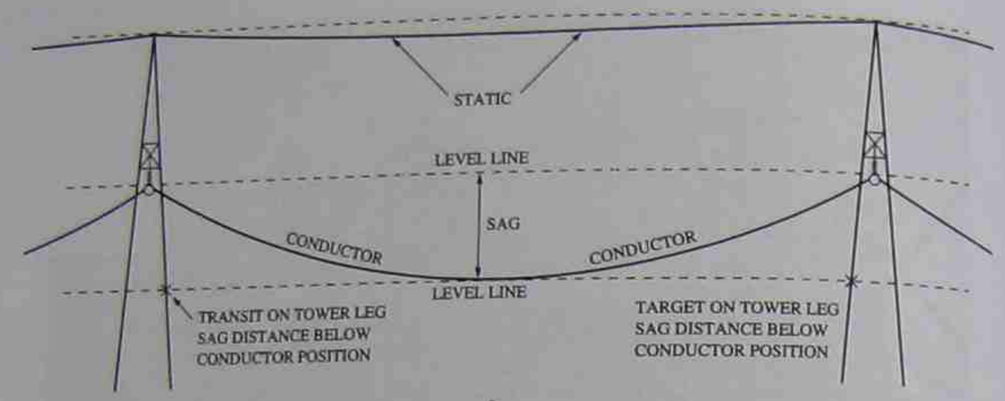


a

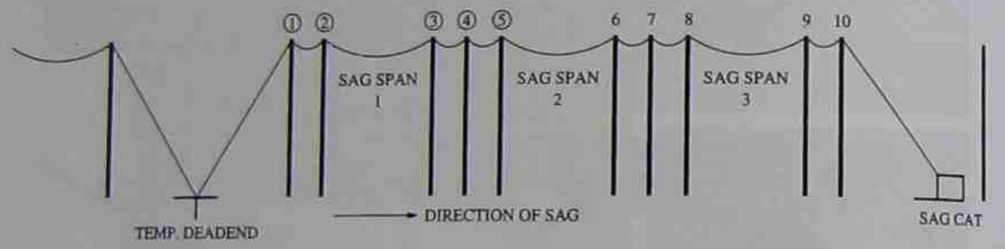


b

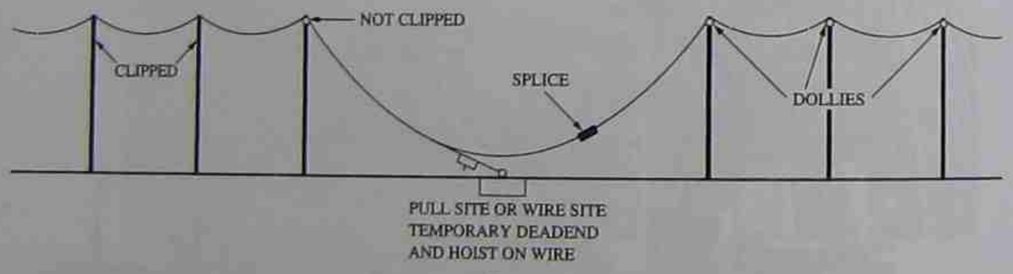
Figure 11.14 Two views of a three drum wire puller for tension wire stringing



a



b



c

FIGURE 11.15 Conductor sagging (a) Sag measurement (b) Sag pull and (c) Clipping

Where

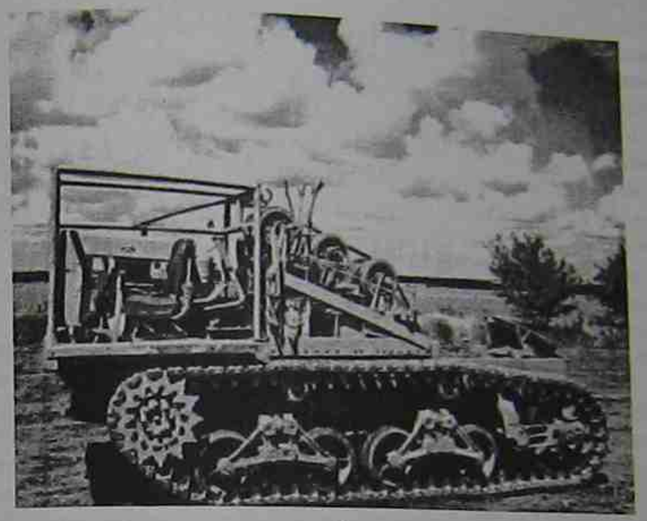
$S_{REF\,RS}$ = sag in any span of interest other than the ruling span

S_{RS} = sag in the ruling span

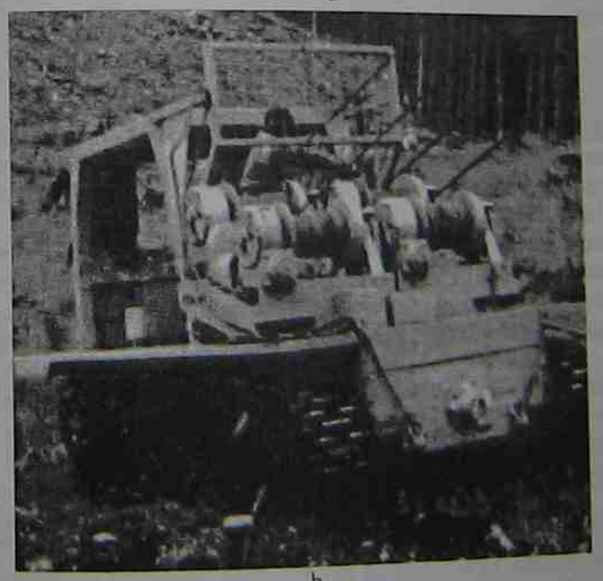
L = length of span of interest

L_{RS} = length of the ruling span

Sagging procedure is illustrated in Figure 11.15b and c. A caterpillar is used to pull conductor to near sag, then the wire is transferred to a temporary dead-end with hand-operated hoists, which are used to complete the sag. Figure 11.16 shows a sagging CAT.



a



b

FIGURE 11.16 Sag cat (a) M-5 equipped with three winches for sagging bundle of three conductor (b) M-5 equipped with four winches for sagging bundle of four conductor

The span nearest to the temporary dead-end reaches its proper sag last, so both the second and third sag spans are brought to a little above their proper sag to bring span #1 into proper sag. Then, tension is relaxed to allow spans #3 and #2 to return to proper sag. The conductor is left in sag for 1 hour to allow any conductor creep to settle. The wire is then *clipped* (transferred from the pulling dolly to the permanent support) at all spans except at the last structure sagged.

The second wire set-up, which is already in place, is sagged just as the first set, except that the second pull conductor is spliced to the first pull conductor, and the tension is applied by the caterpillar. When the tension in the second pull is approximately equal to the first, the last structure conductors are clipped, the hand hoists are removed, and the sagging continues. An observer is stationed to watch the last structure clipped. When the sag is correct, the bells on that structure are perpendicular. Three people with transits verify the sag. Sagging is usually done on each set-up, but it can be delayed and done on two set-ups at a time. A delay causes lost clipping time, and requires extra stringing dollies, which are quite expensive.

The next task the clean-up crew performs is clipping the tangent structures. Clipping consists of raising the weight of the wire with a hand-operated chain hoist called a coffin hoist, removing the stringing dolly and lowering it to the ground, straightening the string of insulators to ensure that they are vertical, and transferring the conductors to the conductor support hardware previously attached to the string of insulators. Figure 11.17 shows clipping in progress. Ideally, there should be enough clipping crews to clip one set-up during the time one pull is made. This is called one turn around. If one set-up is to be pulled per day, then every other task must be done within the same time frame. In this way, each person repeats the same task daily, becomes adept at it, and maximum efficiency is obtained. A crew reaches maximum efficiency by the fourth or fifth pull.

The next task for the clean-up crew is the "dead-end" work. If the line has many dead-ends, a separate crew is organized to install all the dead-ends and jumpers of a pull during the same period that one pull can be made. Otherwise this phase of the work falls behind.

After the clean-up crew finishes the line installation, true clean-up begins. The ROW is cleaned of all debris, and the equipment sites are returned to normal. Temporary gates are removed and fences closed. Temporary bridges and roads are removed and the complete ROW restored to a condition satisfactory to the land owner.

The job is now complete.

11.12 SUMMARY

Considerations for transmission line design are power loss, voltage drop, reactance, thermal overload, wheeling needs, total load, and cost. Additional considerations



FIGURE 11.17 Conductor clipping with a high-reach

for transmission line design are ROW, terrain, weather, skilled labor and equipment availability, and their cost. When possible a utility will develop standard support structure and line designs for commonly used voltages and terrain and will depart from them only for special situations. Experience with a particular design results in fewer construction and maintenance errors, and the stocking of fewer maintenance parts results in both convenience and savings. The REA has published successful distribution and transmission design specifications that have resulted from REA financed projects. The REA specifications are good starting points for line design. Additionally fittings, conductors, and hardware have been standardized by the Electrical Manufacturers Association.

The most used support structures are wood, which is least expensive, steel poles, which work well and can be shipped in sections but are more expensive than wood poles, and lattice steel structures, which have the greatest strength-to-weight ratio and are reasonable in cost. Wood poles are usually arranged as "H"

fixtures for transmission applications, and lattice steel is used for erecting towers. Each type of structure—wood, steel, and lattice steel—has associated with it recommended foundation requirements and construction practices.

ACSR is the most commonly used conductor for transmission lines, but other conductors are used for specialized requirement. Tension and ice loading and span length as well as the electrical loading are factors in the choice of transmission line conductors. The OHGW are normally high strength galvanized steel or aluminum clad steel stranded conductors.

A typical span, called the ruling span, is used for the nominal design of a line. Adjustments are made in the design as the span must be varied from ruling to accommodate varied terrain. Typical conductor tension is calculated for the ruling span. Conductor sag is an important factor in setting the ultimate tension of the line. Too little sag results in too much tension, and too much sag in too little ground clearance. Lines must be sufficiently damped that aeolian vibration (a resonance induced from steady cross winds) does not occur, and to minimize galloping, which is a low frequency vibration induced by the lift from icing conditions and steady cross wind. Both types of vibration can cause catastrophic outages.

Line design requires the preparation of a plan profile which is an outline of the topography of the terrain along and near the ROW. The location of the towers is decided on and the proper sag calculated. The plan profile in uneven terrain is carefully checked to see that no tower experiences negative sag or uplift under any expected line tension. The final drawings are then prepared, and the construction phase can begin.

Construction consists of several steps, often occurring simultaneously at different locations along the line path. The heavy equipment needed for each phase of the construction must be arranged for and access to the ROW for the equipment must be secured. The conductor, tower parts, and fittings must be ordered for the line and transported to the correct location on the ROW at the proper time. The ROW must be cleared, foundations set, poles set or towers constructed, and line must be strung. Final inspection and connection to the substations, which must have the proper instrument transformers and protection equipment installed, precedes line energization. Finally, it must all be paid for.

11.13 QUESTIONS

1. Few transmission lines are designed from scratch. Why?
2. State the advantages of standard lines.
3. List the major advantages of wood, steel, and steel lattice transmission line support structures.
4. List the factors that influence the method the transmission line support structure.
5. List the steps in transmission line structure construction.
6. Why must steel lattice towers sometimes be braced during construction?

7. State the prime consideration in helicopter tower construction.
8. List the major factors that influence the selection of the transmission conductor diameter.
9. Why must there be no welds in the OHGW?
10. What factors affect the choice of tension for the transmission line conductor?
11. Define ruling span.
12. Calculate, by both the approximate and exact equation, the ruling span for the following span lengths:
    L1 = 900 ft, L2 = 1400 ft, L3 = 1100 ft, L4 = 1000 ft, L5 = 1500 ft.
13. State the accepted limits on span length relative to ruling span.
14. Calculate the sag for a 1000 foot span of Drake conductor if the allowable tension is 30% of the ultimate conductor strength.
15. Define aeolian vibration.
16. What is galloping?
17. Why are plan-profile drawings important?
18. What is meant by the term "structure spotting"?
19. State the source and effects of uplift.
20. What are the major factors considered in ROW condemnation proceedings?
21. List the steps in conductor stringing.
22. Describe the steps performed in "clipping a conductor."

APPENDIX A

Three-phase Power Flow Constancy

We noted in Chapter 2 that balanced three-phase power is constant over time. Let

$V_A = V_P \cos\omega t$

$I_A = I_P \cos(\omega t + \theta)$

then

$P_A = I_P V_P \cos(\omega t + \theta)\cos\omega t$

noting that

$\cos A \cos B = (1/2)\cos(A - B) + (1/2)\cos(A + B)$

we see

$$\cos(\omega t + \theta)\cos\omega t = (1/2)\cos(\omega t + \theta - \omega t) + (1/2)\cos(\omega t + \theta + \omega t)$$
$$= (1/2)[\cos\theta + \cos(2\omega t + \theta)]$$

therefore

$$P_A = \frac{I_P V_P}{2}[\cos(2\omega t + \theta) + \cos\theta]$$

For the other two phases, B and C at $\omega t + 120°$ and $\omega t + 240°$ respectively

$$P_B = \frac{V_P I_P}{2}[\cos(2\omega t + 240° + \theta) + \cos\theta]$$

$$P_C = \frac{V_P I_P}{2}[\cos(2\omega t + 480° + \theta) + \cos\theta]$$

Note now that

$\cos(2\omega t + \theta) + \cos(2\omega t + 240° + \theta) + \cos(2\omega t + 480° + \theta) = 0$

For example let $2\omega t + \theta = \pi$

$\cos\pi = -1$

$\cos(180° + 240°) = 0.5$

$\cos(180° + 480°) = 0.5$

$-1 + 0.5 + 0.5 = 0$

Now let $2\omega t + \theta = \frac{\pi}{2}$

$\cos\frac{\pi}{2} = 0$

$\cos(\frac{\pi}{2} + 240°) = 0.866$

$\cos(\frac{\pi}{2} + 480°) = -0.866$

Thus total three-phase instantaneous power is

$P_T = P_A + P_B + P_C = (3/2) I_P V_P \cos\theta$

Which is a constant.

APPENDIX B

Sample REA Specifications

REA publications are public domain. The REA provides a valuable service in developing and making available construction specifications such as these. They are used as guidelines throughout the United States.

Specifications for Construction

1. *General*

All construction work shall be done in accordance with the staking sheets, plans and specifications, and the construction drawings.

The 1981 or latest edition of the National Electrical Safety Code (NESC), ANSI C2, shall be followed except where local regulations are more stringent, in which case local regulations shall govern.

2. *Distribution of Poles*

In distributing the poles, large, choice, dense poles shall be used at transformer, dead-end, angle, and corner locations.

3. *Pole Setting*

The minimum depth for setting poles shall be as follows:

Length of Pole (Feet)	Setting in Soil (Feet)	Setting in All Solid Rock (Feet)
20	4.0	3.0
25	5.0	3.5
30	5.5	3.5
35	6.0	4.0
40	6.0	4.0
45	6.5	4.5
50	7.0	4.5
55	7.5	5.0
60	8.0	5.0

"Setting in Soil" depths shall apply:

a. Where poles are to be set in soil.

b. Where there is a layer of soil of more than two (2) feet in depth over solid rock.

c. Where the hole in solid rock is not substantially vertical or the diameter of the hole at the surface of the rock exceeds approximately twice the diameter of the pole at the same level.

"Setting in All Solid Rock" depths shall apply where poles are to be set in solid rock and where the hole is substantially vertical, approximately uniform in diameter and large enough to permit the use of tamping bars the full depth of the hole.

Where there is a layer of soil two (2) feet or less in depth over solid rock, the depth of the hole shall be the depth of the soil in addition to the depth specified under "Setting in All Solid Rock" provided, however, that such depth shall not exceed the depth specified under "Setting in Soil."

On sloping ground, the depth of the hole shall be measured from the low side of the hole.

Poles shall be set so that alternate crossarm gains face in opposite directions, except at terminals and dead ends where the gains of the last two (2) poles shall be on the side facing the terminal or dead end. On unusually long spans, the poles shall be set so that the crossarm is located on the side of the pole away from the long span. Where pole top insulator brackets or pole top pins are used, they shall be located on the opposite side of the pole from the gain.

Poles shall be set in alignment and plumb, except at corners, terminals, angles, junctions, or other points of strain, where they shall be set and raked against the strain so that the conductors are in line.

Poles shall be raked against the conductor strain not less than 1-inch for each 10 feet of pole length nor more than 2 inches for each 10 feet of pole length after conductors are installed at the required tension.

Pole backfill shall be thoroughly tamped in full depth. Excess dirt shall be banked around the pole.

Poles which have been in storage for more than 1 year from the date of treatment shall be ground line treated when installed.

4. *Grading of Line*

When using high poles to clear obstacles such as buildings, foreign wire crossings, railroads, etc., there shall be no upstrain on pin-type or post-type insulators in grading the line each way to lower poles.

5. *Guys and Anchors*

Guys shall be placed before the conductors are strung and shall be attached to the pole as shown in the construction drawings.

All anchors and rods shall be in line with the strain and shall be installed so that approximately 6 inches of the rod remain out of the ground. In cultivated fields or other locations, as deemed necessary, the projection of the anchor rod above earth may be increased to a maximum of 12 inches to prevent burial of the rod eye. The backfill of all anchor holes must be thoroughly tamped the full depth.

After a cone anchor has been set in place, the hole shall be backfilled with coarse crushed rock for 2 feet above the anchor tamping during the filling. The remainder of the hole shall be backfilled and tamped with dirt.

6. *Locknuts*

A locknut shall be installed with each nut, eyenut or other fastener on all bolts or threaded hardware such as insulator pins and studs, upset bolts, double arming bolts, etc.

7. *Conductors*

Conductors must be handled with care. Conductors shall neither be trampled on nor run over by vehicles. Each reel shall be examined and the wire shall be inspected for cuts, kinks, or other injuries. Injured portions shall be cut out and the conductor spliced. The conductors shall be pulled over suitable rollers or stringing blocks properly mounted on the pole or crossarm if necessary to prevent binding while stringing.

The neutral conductor should be maintained on one side of the pole (preferably the road side) for tangent construction and for angles not exceeding 20°.

With pin-type or post-type insulators, the conductors shall be tied in the top groove of the insulator on tangent poles and on the side of the insulator away from the strain at angles. Pin-type and post-type insulators shall be tight on the pins and brackets, respectively, and the top groove must be in line with the conductor after tying.

For line angles of 0° to 5° in locations known to be subject to considerable conductor vibration, insulated brackets (material item da) may be substituted for the single and double upset bolts used for supporting the neutral and secondary conductors.

All conductors shall be cleaned thoroughly by wirebrushing before splicing or installing connectors or clamps. A suitable inhibitor shall be used before splicing or applying connectors over aluminum conductor.

8. *Splices and Dead Ends*

Conductors shall be spliced and dead-ended as shown on the construction drawings. There shall be not more than one splice per conductor in any span and splices shall be located at least 10 feet from the conductor support. No splices shall be located in Grade B crossing spans and preferably not in the adjacent spans. Splices shall be installed in accordance with the manufacturer's recommendations.

9. *Taps and Jumpers*

Jumpers and other leads connected to line conductors shall have sufficient slack to allow free movement of the conductors. Where slack is not shown on the construction drawings, it will be provided by at least two (2) bends in a vertical plane, or one (1) in a horizontal plane, or the equivalent. In areas where aeolian vibration occurs, special measures to minimize the effects of jumper breaks shall be used as specified.

All leads on equipment such as transformers, reclosers, etc., shall be a minimum of #6 copper conductivity. Where aluminum jumpers are used, a connection to an unplated bronze terminal shall be made by splicing a short stub of copper to the aluminum jumper using a compression connector suitable for the bimetallic connection.

10. *Hot-Line Clamps and Connectors*

Connectors and hot-line clamps suitable for the purpose shall be installed as shown on the guide drawings. On all hot-line clamp installations, the clamp and jumper shall be installed so that they are permanently bonded to the load side of the line, allowing the jumper to be de-energized when the clamp is disconnected.

11. *Surge Arrester Gap Settings*

The external gap electrodes of surge arresters, combination arrester cutout units, and transformer mounted arresters shall be adjusted to the manufacturer's

recommended spacing. Care shall be taken that the adjusted gap is not disturbed when the equipment is installed.

12. *Conductor Ties*

Hand-formed ties shall be in accordance with construction drawings. Factory-formed ties shall be installed in accordance with the manufacturer's recommendations.

13. *Sagging of Conductors*

Conductors shall be sagged in accordance with the conductor manufacturer's recommendations. All conductors shall be sagged evenly. The air temperature at the time and place of sagging shall be determined by a certified thermometer.

The sag of all conductors after stringing shall be in accordance with the engineer's instructions.

14. *Secondaries and Service Drops*

Secondary conductors may be bare or covered wire or multi-conductor service cable. The conductors shall be sagged in accordance with the manufacturer's recommendations.

Conductors for secondary underbuild on primary lines will normally be bare, except in those instances where prevailing conditions may limit primary span lengths to the extent that covered wires or service cables may be used. Service drops shall be covered wire or service cable.

Secondaries and service drops shall be so installed as not to obstruct climbing space. There shall not be more than one splice per conductor in any span, and splices shall be located at least 10 feet from the conductor support. Where the same covered conductors or service cables are to be used for the secondary and service drop, they may be installed in one continuous run.

15. *Grounds*

Ground rods shall be driven full length in undisturbed earth in accordance with the construction drawings. The top shall be at least 12 inches below the surface of the earth. The ground wire shall be attached to the rod with a clamp and shall be secured to the pole with staples. The staples on the ground wire shall be spaced 2 feet apart, except for a distance of 8 feet above the ground and 8 feet down from the top of the pole where they shall be 6 inches apart.

All equipment shall have at least two (2) connections from the frame, case or tank to the multi-grounded neutral conductor.

The equipment ground, neutral wires, and surge-protection equipment shall be interconnected and attached to a common ground wire.

16. *Clearing Right-of-Way*

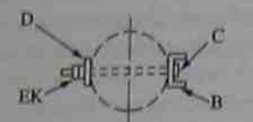
The right-of-way shall be prepared by removing trees, clearing underbrush, and trimming trees so that the right-of-way is cleared close to the ground and

is the width specified, except that low growing shrubs which will not interfere with the operation or maintenance of the line shall be left undisturbed if so directed by the owner. Slash may be chipped and blown on the right-of-way. The landowner's written permission shall be received prior to cutting trees outside the right-of-way. Trees fronting each side of the right-of-way shall be trimmed symmetrically unless otherwise specified. Dead trees beyond the right-of-way which would strike the line in falling shall be removed. Leaning trees beyond the right-of-way, which would strike the line in falling and which would require topping if not removed, shall either be removed or topped, except that shade, fruit, or ornamental trees shall be trimmed and not removed, unless otherwise authorized.

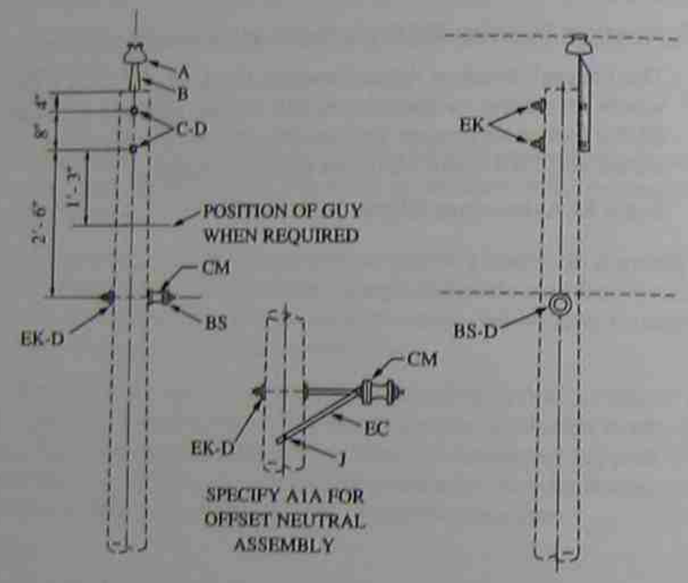
17. *Structures Exceeding 200 Feet in Height and Structures in the Vicinity of Airports*

The Federal Aviation Administration (FAA) requires (14 CFR 77) that in cases where structures or conductors will exceed a height of 200 feet, or are within 20,000 feet of an airport, the nearest regional or area office of the FAA be contacted and FAA Form 7460-1 be filed if necessary.

Some REA drawings follow.



POLE TOP PIN ASSEMBLY



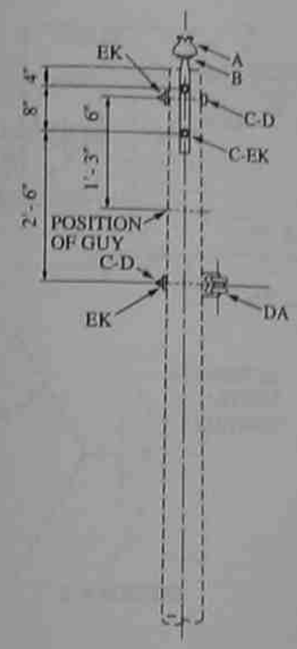
SPECIFY A1A FOR
OFFSET NEUTRAL
ASSEMBLY

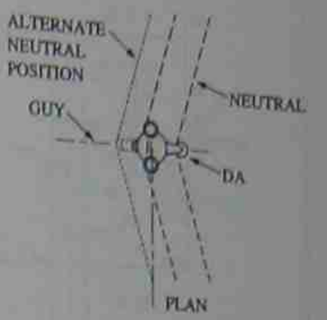
ITEM	NO.	MATERIAL
A	1	INSULATOR, PIN TYPE
B	1	PIN, POLE TOP, 20°
C	2	BOLT, MACHINE, ⅝" × REQ'D. LENGTH
J	2	SCREW, LAG, ½" × 4" (A1A ONLY)
EK		LOCKNUTS, AS REQUIRED
CM	1	SPOOL INSULATOR

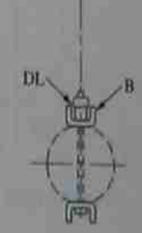
ITEM	NO.	MATERIAL
D	3	WASHER, SQUARE, 2¼"
BS	1	BOLT, SINGLE UPSET, (A1 ONLY)
EC	1	BRACKET, OFFSET, NEUTRAL, (A1A ONLY)

DESIGN LIMITS	12.5/7.2kV PRIMARY, 1-PHASE, SINGLE PRIMARY SUPPORT	
MAX. TRANSVERSE LOAD: 500 LBS. PER CONDUCTOR MAX. LINE ANGLE WITHIN LOAD LIMITS: 5°	APR., 1983	A1, A1A

FIGURE B.1







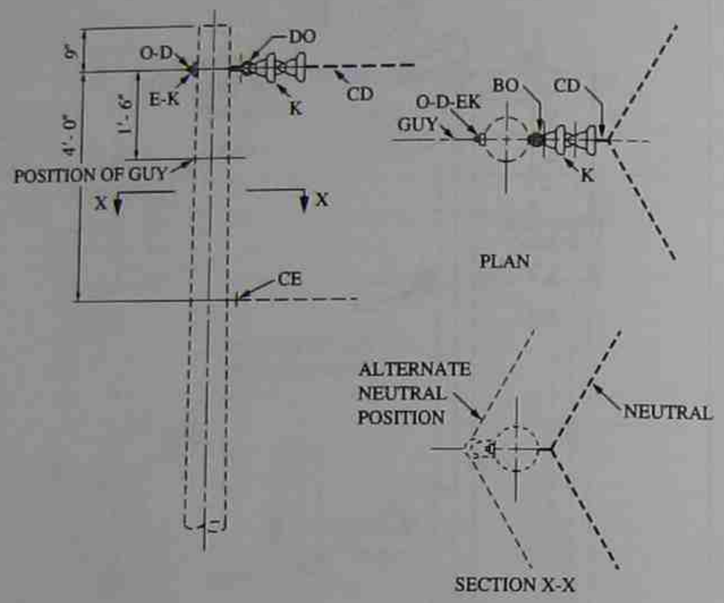
POLE TOP PIN ASSEMBLY

ITEM	NO.	MATERIAL
A	2	INSULATOR, PIN TYPE
B	2	PIN, POLE TOP, 20°
C	4	BOLT, MACHINE, ⅝" × REQ'D. LENGTH
D	3	WASHER, 2¼" × 2¼" × ⅝", 13/16" HOLE

ITEM	NO.	MATERIAL
DA	1	BRACKET, INSULATED
DL	2	PIPE SPACER, ⅝" DIA. × 1½"
EK		LOCKNUTS, AS REQUIRED

DESIGN LIMITS	12.5/7.2 kV 1-PHASE DOUBLE PRIMARY SUPPORTS	
MAX. TRANSVERSE LOAD: 1000 LBS. PER CONDUCTOR MAX. LINE ANGLE WITHIN LOAD LIMITS: 20°	APR., 1983	A2

FIGURE B.2



NOTE: ITEMS CD AND CE ARE SHOWN ON ASSEMBLY DRAWINGS M41-1 AND M41-10

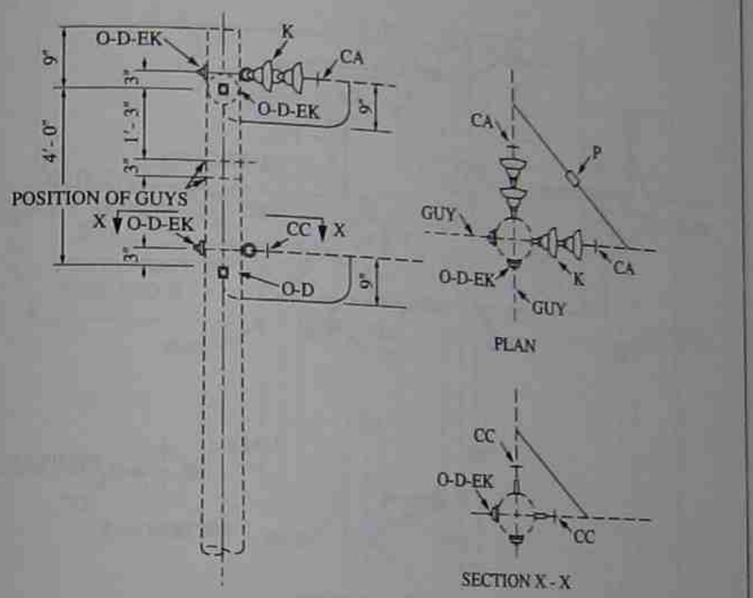
ITEM	NO. REQ'D	MATERIAL		ITEM	NO. REQ'D	MATERIAL
				BO	1	SHACKLE, ANCHOR
D	2	WASHER, 2¼" × 2¼" × 3/16", 13/16" HOLE		CD	1	ANGLE ASSEMBLY, PRIMARY
K	4	INSULATOR, SUSPENSION		CE	1	ANGLE ASSEMBLY, NEUTRAL
O	3	BOLT, EYE, ⅝" × REQ'D LENGTH		EK		LOCKNUT, AS REQUIRED

DESIGN LIMITS
MAX. TRANSVERSE LOAD: 4000 LBS. PER CONDUCTOR
ANGLE: 20° - 60°

12.5/7.2 kV PRIMARY I-PHASE

APR., 1983 | A3

FIGURE B.3



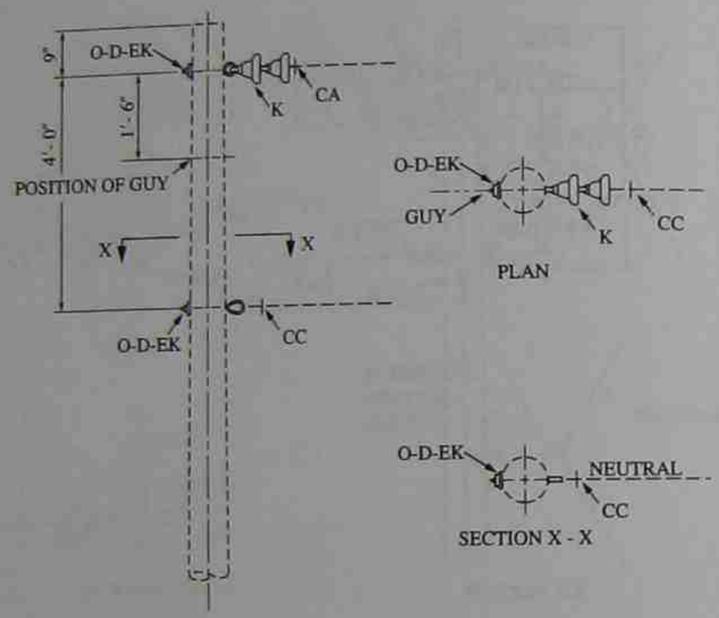
NOTE: ITEMS CA AND CC ARE SHOWN ON ASSEMBLY DRAWINGS M42-3, M42-11, M42-13 AND M42-21

ITEM	NO.	MATERIAL		ITEM	NO.	MATERIAL
D	4	WASHER, 2¼" × 2¼" × 3/16", 13/16" HOLE		CA	2	DEADEND ASSEMBLY, PRIMARY
K	4	INSULATOR, SUSPENSION		CC	2	DEADEND ASSEMBLY, NEUTRAL
O	4	BOLT, EYE, ⅝" × REQ'D LENGTH		EK		LOCKNUTS, AS REQUIRED
P		CONNECTORS, AS REQUIRED				

12.5/7.2 kV PRIMARY, I-PHASE
60° TO 90° ANGLE

APR., 1983 | A4

FIGURE B.4



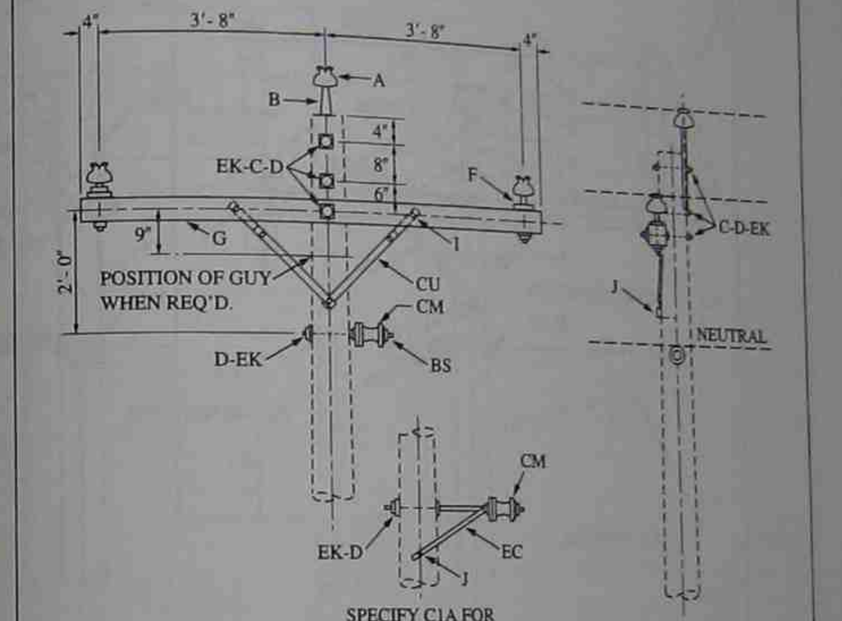
NOTE: ITEMS CA AND CC ARE SHOWN ON ASSEMBLY DRAWINGS M42-3, M42-11, M42-13 AND M42-21

ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
D	2	WASHER, SQUARE, 2½"	CC	1	DEADEND ASSEMBLY, NEUTRAL
K	2	INSULATOR, SUSPENSION	EK		LOCKNUTS, AS REQUIRED
O	2	BOLT, EYE, ⅝" × REQ'D. LENGTH			
CA	1	DEADEND ASSEMBLY, PRIMARY			

12.5/7.2 kV PRIMARY, 1-PHASE DEADEND (SINGLE)

APR., 1983 — A5

FIGURE B.5



SPECIFY C1A FOR OFFSET NEUTRAL ASSEMBLY

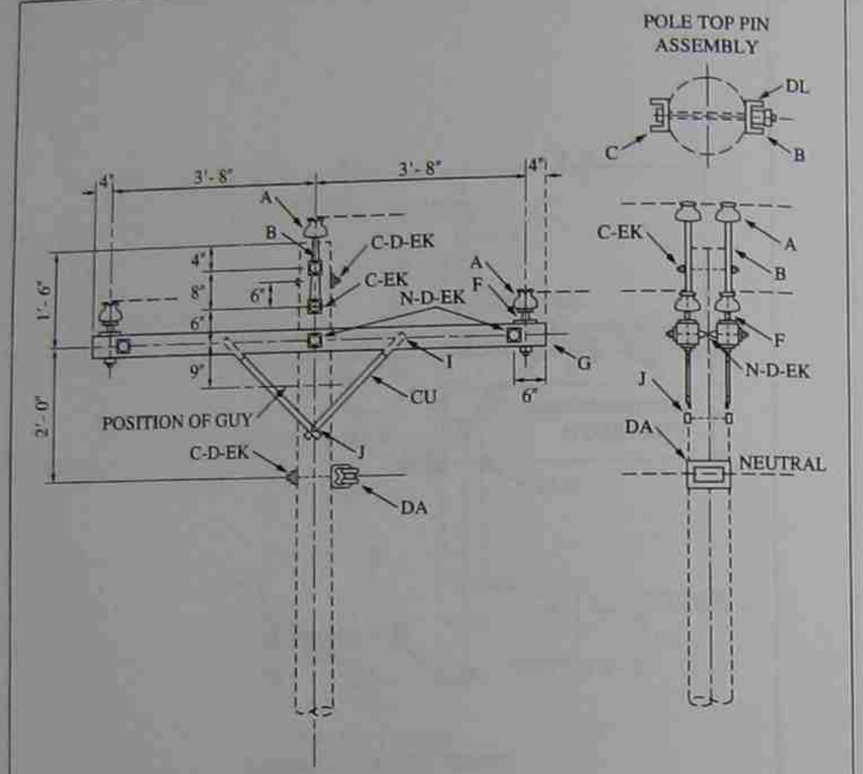
ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
A	3	INSULATOR, PIN TYPE	CU	2	BRACE, WOOD, 28"
B	1	PIN, POLE TOP, 20"	I	2	BOLT, CARRIAGE, ⅜" × 4½"
C	3	BOLT, MACHINE, ⅝" × REQ'D. LENGTH	J	1	SCREW, LAG, ½" × 4" (C1 ONLY)
D	5	WASHER, 2¼" × 2¼" × 5/16", 5/16" HOLE	BS	1	BOLT, SINGLE UPSET, (C1 ONLY)
F	2	PIN, CROSSARM, STEEL, ⅝" × 10¾"	EC	1	BRACKET, OFFSET NEUTRAL (C1A ONLY)
G	1	CROSSARM, 3⅜" × 4½" × 8'-0"	J	3	SCREW, LAG, ½" × 4" (C1A ONLY)
EK		LOCKNUTS, AS REQUIRED			
CM	1	SPOOL INSULATOR			

DESIGN LIMITS
MAX. TRANSVERSE LOAD: 500 LBS. PER CONDUCTOR
MAX. LINE ANGLE WITHIN LOAD LIMITS: 5°

12.5/7.2 kV
3-PHASE CROSSARM CONSTRUCTION
SINGLE PRIMARY SUPPORT

APR., 1983 — C1, C1A

FIGURE B.6

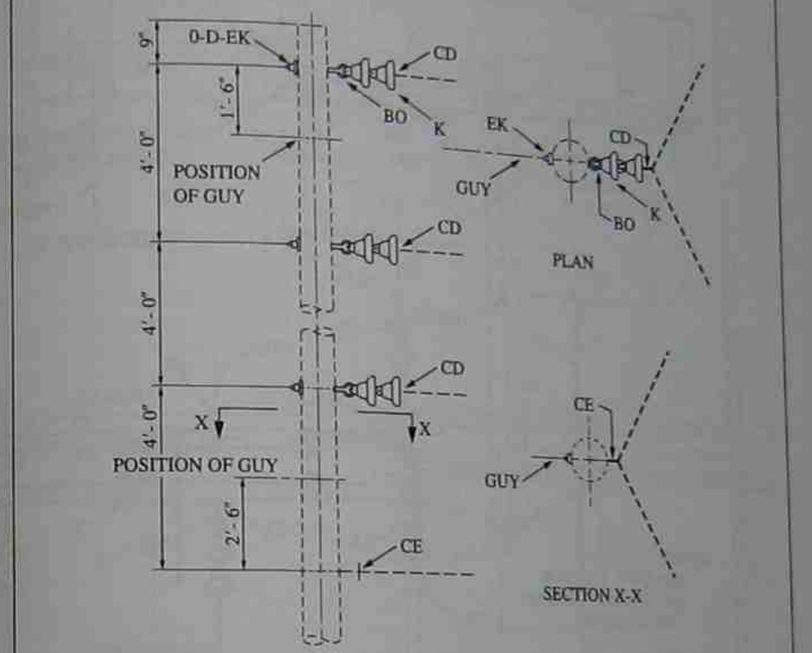


NOTE: WHEN THE TRANSVERSE LOAD IS MORE THAN 1000 POUNDS, SUBSTITUTE C2-1 OR C2-2 AS REQUIRED

ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
A	6	INSULATOR, PIN TYPE	I	4	BOLT, CARRIAGE, ⅜" × 4½"
B	2	PIN, POLE TOP, 20'	J	2	SCREW, LAG, ½" × 4"
C	4	BOLT, MACHINE, ⅝" × REQ'D. LENGTH	N	3	BOLT, DOUBLE ARMING, ⅝" × REQ'D. L'GTH
D	13	WASHER, 2¼" × 2¼" × ⅛", 13/16" HOLE	DA	1	BRACKET, INSULATED
F	4	PIN, CROSSARM, STEEL, ⅝" × 10¾"	DL	2	PIPE, SPACER, ¾" DIA. × 1½"
G	2	CROSSARM, 3½" × 4½" × 8 - 0"	EK		LOCKNUTS, AS REQUIRED
CU	4	BRACE, WOOD, 28"			

DESIGN LIMITS	12.5/7.2 kV 3-PHASE CROSSARM CONSTR. DOUBLE PRIMARY SUPPORT	
MAX. TRANSVERSE LOAD: 1000 LBS. PER CONDUCTOR MAX. LINE ANGLE WITHIN LOAD LIMITS: 20°	APR., 1983	C2

FIGURE B.7

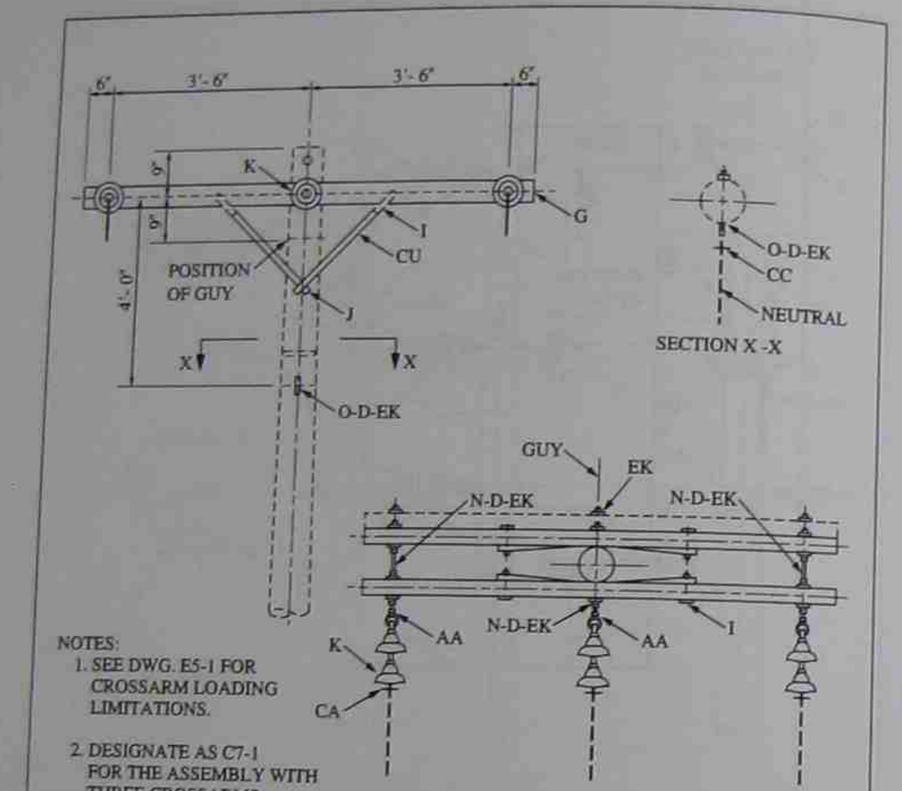


NOTE: ITEMS CD AND CE ARE SHOWN ON ASSEMBLY DRAWINGS M41-1, AND M42-10

ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
			BO	3	SHACKLE, ANCHOR
D	3	WASHER, 2¼" × 2¼" × 5/16", 13/16" HOLE	CD	3	ANGLE ASSEMBLY, PRIMARY
K	6	INSULATOR, SUSPENSION	CE	1	ANGLE ASSEMBLY, NEUTRAL
O	3	BOLT, EYE, ⅝" × REQ'D. LENGTH	EK		LOCKNUTS, AS REQUIRED

DESIGN LIMITS	12.5/7.2 kV - THREE PHASE VERTICAL CONSTRUCTION	
MAX. TRANSVERSE LOAD: 4000 LBS. PER CONDUCTOR ANGLE: 20° - 60°	APR., 1983	C3

FIGURE B.8

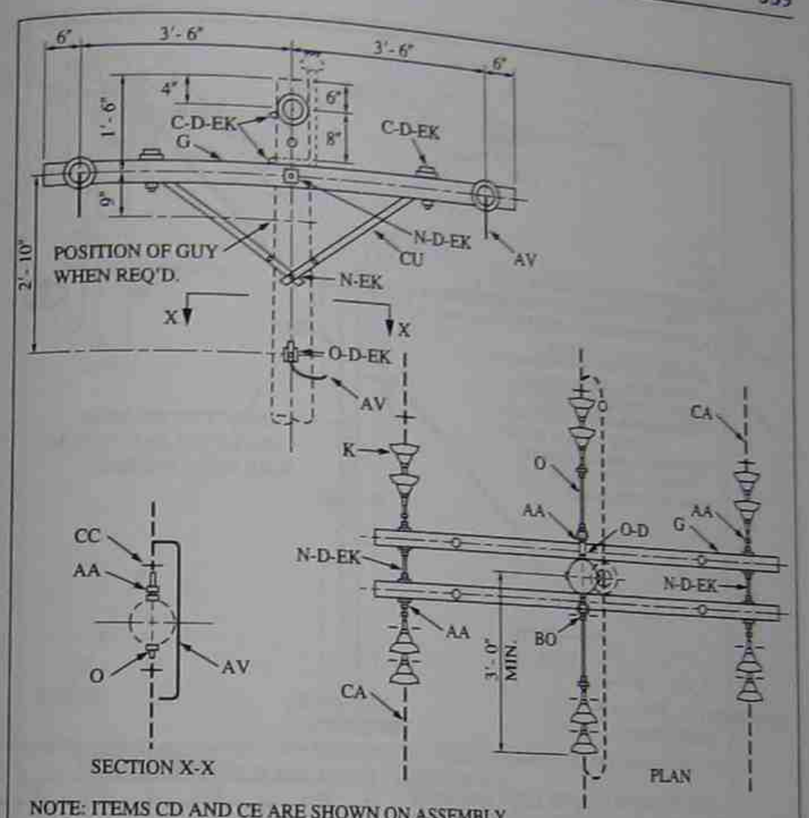


NOTES:
1. SEE DWG. E5-1 FOR CROSSARM LOADING LIMITATIONS.
2. DESIGNATE AS C7-1 FOR THE ASSEMBLY WITH THREE CROSSARMS.
3. ITEMS CA AND CC ARE SHOWN ON ASSEMBLY DRAWINGS M42-3, M42-11, M42-13, AND M42-21.

ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
D	11	WASHER, 2¼" × 2¼" × 5/16", 13/16" HOLE	N	3	BOLT, DOUBLE ARMING, ¾" × REQ'D. L'GTH
G	2	CROSSARM, 3½" × 4½" × 8'-0"	O	1	BOLT, EYE, ⅝" × REQ'D. LENGTH
CU	4	BRACE, WOOD, 28"	AA	3	NUT, EYE, ⅝"
I	4	BOLT, CARRIAGE, ⅝" × 4½"	CA	3	DEADEND ASSEMBLY, PRIMARY
J	2	SCREW, LAG, ½" × 4"	CC	1	DEADEND ASSEMBLY, NEUTRAL
K	6	INSULATOR, SUSPENSION	EK		LOCKNUTS, AS REQUIRED

	12.5/7.2 kV, 3 - PHASE CROSSARM CONSTRUCTION DEAD END (SINGLE)	
	APR., 1983	C7, C7-1

FIGURE B.9

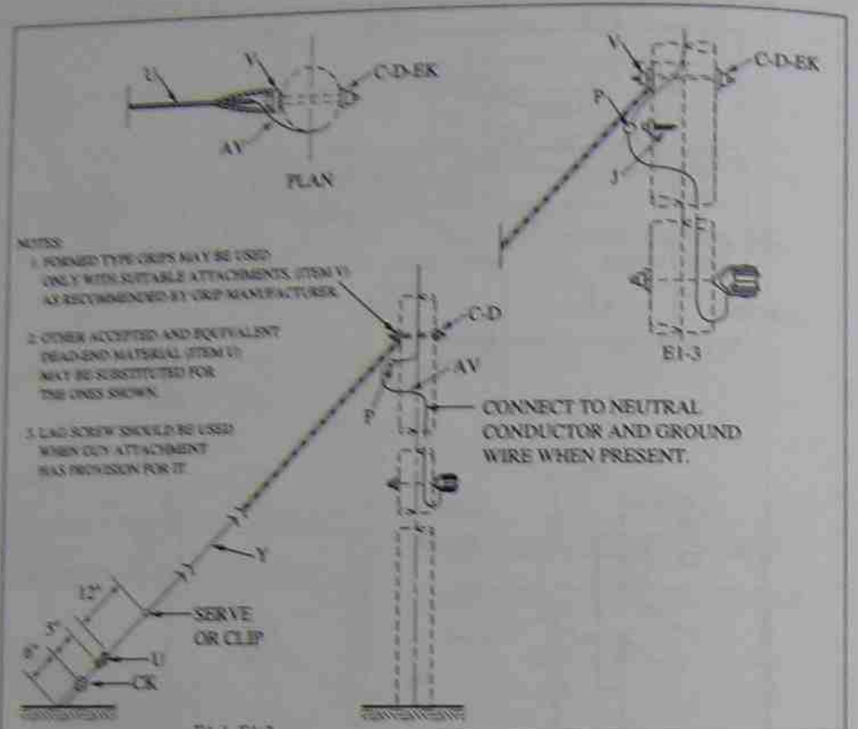


NOTE: ITEMS CD AND CE ARE SHOWN ON ASSEMBLY DRAWINGS M42-3, M42-11, M42-13 AND M42-21

ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
			O	4	BOLT, EYE, ⅝" × REQ'D. LENGTH
			P		CONNECTORS, AS REQ'D.
C	4	BOLT, MACHINE, ½" × REQ'D. LENGTH	AA	8	NUT, EYE, ⅝"
D	14	WASHER, 2¼" × 2¼" × 5/16", 13/16" HOLE	AV		JUMPERS AND LEADS AS REQ'D
D	4	WASHER, ROUND, 1⅜" DIA., 9/16" HOLE	BO	2	SHACKLE, ANCHOR
			CA	6	DEADEND, ASSEMBLY, PRIMARY
G	2	CROSSARM, 3½" × 4½" × 8'-0"	CC	2	DEADEND, ASSEMBLY, NEUTRAL
K	12	INSULATOR, SUSPENSION	CU	2	BRACE, WOOD, 60" SPAN
N	4	BOLT, DOUBLE ARMING, ¾" × REQ'D. LENGTH	EK		LOCKNUTS, AS REQUIRED

	12.5/7.2 kV, 3-PHASE CROSSARM CONSTRUCTION, DEADEND (DOUBLE)	
	APR., 1983	C8

FIGURE B.10



SEE GUIDE DRAWINGS M30-1 AND M30-2

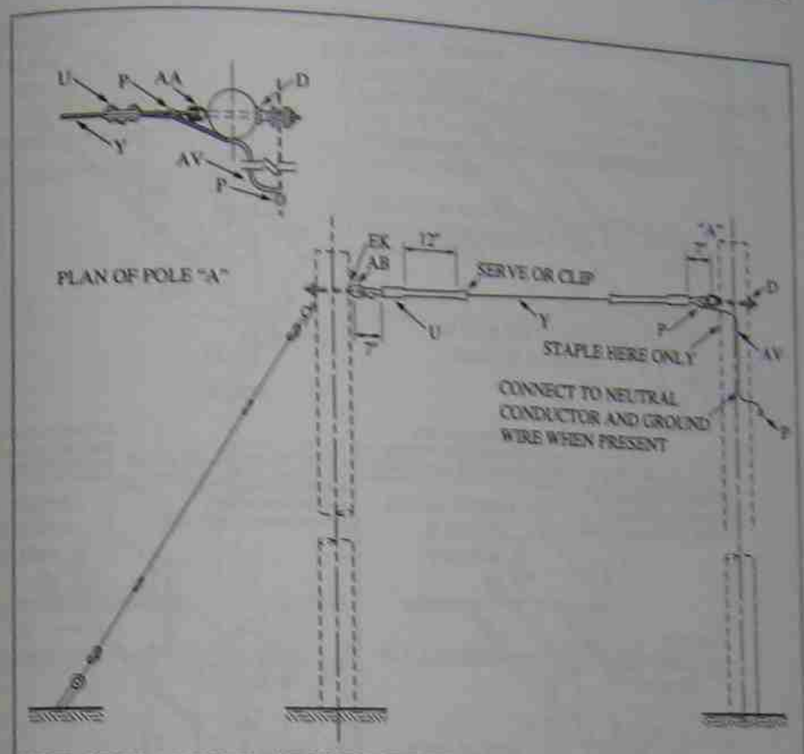
		ASSEMBLY UNIT		
		E1-1	E1-2	E1-3
ITEM	MATERIAL	NO. REQ'D.	NO. REQ'D.	NO. REQ'D.
C	BOLT, MACHINE, ⅝" x REQUIRED LENGTH	1	1	1
D	WASHER, CURVED	1-2¼" x 2¼"	1-3" x 3"	1-4" x 4"
J	SCREW, LAG, ½" x 4"			
P	CONNECTORS	AS REQ'D.	AS REQ'D.	AS REQ'D.
U	DEADEND FOR GUY STRAND	2	2	2
X	GUY ATTACHMENT (RATING)	1-(5200 LBS.)	1-(5200 LBS.)	1-(6000 LBS.)
Y	GUY WIRE, S.M., 7 STRAND REQ'D. LENGTH	⅜"	⅜"	⅜"
AV	JUMPER, NO. 4 STRANDED AL. ALLOY OR EQUIV.	REQ'D. LENGTH	REQ'D. LENGTH	REQ'D. LENGTH
CK	CLAMP, ANCHOR ROD BONDING	1	1	1
EK	LOCKNUTS, AS REQUIRED			

12.5/7.2 kV
SINGLE DOWN GUY, THROUGH BOLT TYPE

APR., 1983

E1-1, E1-2, E1-3

FIGURE B.11



NOTE: OTHER ACCEPTED AND EQUIVALENT ITEMS OF DEADEND MATERIAL MAY BE SUBSTITUTED FOR THE 3-BOLT CLAMP SHOWN.

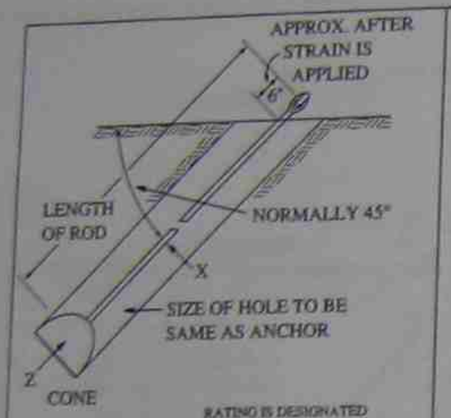
		ASSEMBLY UNIT		
		E2-1	E2-2	E2-3
ITEM	MATERIAL	NO. REQ'D.	NO. REQ'D.	NO. REQ'D.
D	WASHER, CURVED	1-2¼" x 2¼"	1-3" x 3"	1-4" x 4"
U	DEADEND FOR GUY STRAND	LIGHT DUTY (2)	HEAVY DUTY (2)	HEAVY DUTY (2)
Y	GUY WIRE, 7 STRAND S.M. REQ'D. LENGTH	⅜"	⅜"	⅜"
AB	NUT, THIMBLE TYPE EYE, ⅝"	1	1	1
AA	BOLT, THIMBLEYE, ⅝" x REQ'D. LENGTH BT	1	1	1
AV	JUMPER, #4 STRANDED AL. ALLOY OR EQUIV.	1	1	1
P	CONNECTORS, AS REQ'D.			
EK	LOCKNUTS, AS REQUIRED			

12.5/7.2 kV
SINGLE OVERHEAD GUY, THROUGH BOLT TYPE

APR., 1983

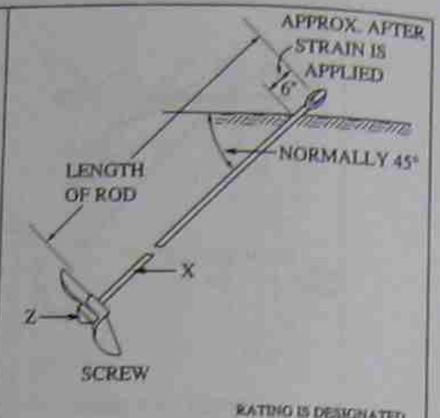
E2-1, E2-2, E2-3

FIGURE B.12



RATING IS DESIGNATED MAXIMUM HOLDING POWER IN HARDPAN AND ROCKY SOIL

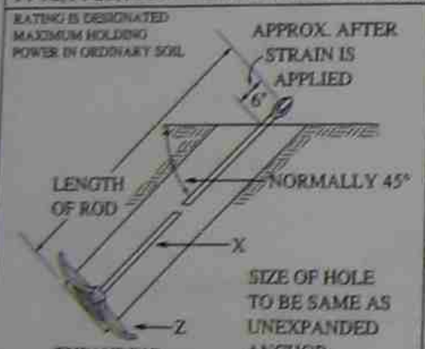
F1-1C, F1-2C, F1-3C



RATING IS DESIGNATED MAXIMUM HOLDING POWER IN ORDINARY SOIL.

F1-1S, F1-2S, F1-3S, F1-4S

RATING IS DESIGNATED MAXIMUM HOLDING POWER IN ORDINARY SOIL



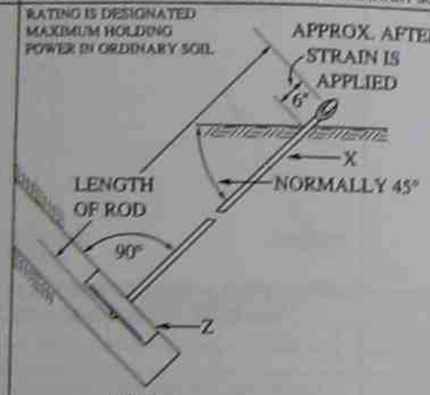
EXPANDING

F1-1, F1-2, F1-3, F1-4

SIZE OF HOLE TO BE SAME AS UNEXPANDED ANCHOR.

NOTE: PROJECTION OF ANCHOR RODS ABOVE EARTH MAY BE INCREASED TO A MAX. OF 12" IN CULTIVATED FIELDS OR OTHER LOCATIONS WHERE NECESSARY TO PREVENT BURYING OF THE ROD EYE.

RATING IS DESIGNATED MAXIMUM HOLDING POWER IN ORDINARY SOIL



PLATE

F1-1P, F1-2P, F1-3P, F1-4P

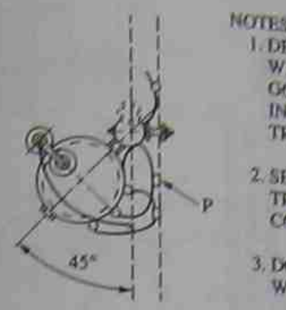
	ASSEMBLY UNIT							
	F1-1		F1-2		F1-3		F1-4	
RATING (POUNDS)	6000		8000		10,000		12,000	
ITEM MATERIAL	NO.		NO.		NO.		NO.	
X ROD, ANCHOR, THIMBLE EYE	1	¾" x 7'-0"	1	¾" x 7'-0"				
Y ROD, ANCHOR, TWIN EYE					1	¾" x 8'-0"	1	¾" x 8'-0"
Z ANCHOR ..... TYPE	1		1		1		1	

LINE ANCHOR ASSEMBLIES

APR., 1983

F1-1 TO F1-4

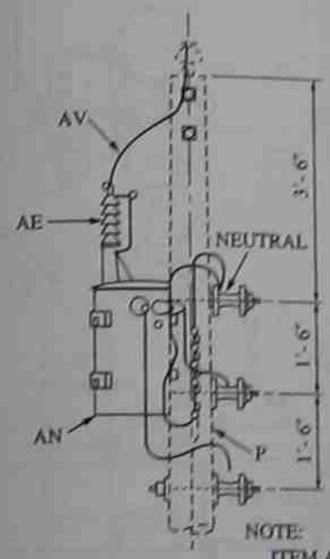
FIGURE B.13

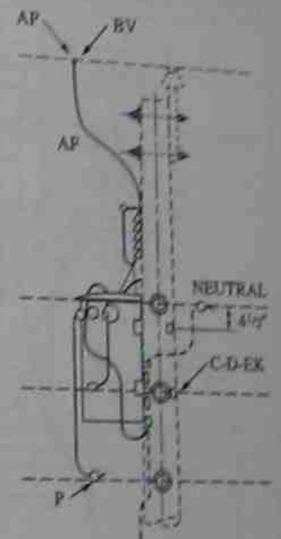


PLAN

NOTES:

1. DESIGNATE G9 FOR CONVENTIONAL TRANSFORMER WITH TANK MOUNTED CUTOUT AND ARRESTER. G6S FOR TRANSFORMER WITH DOUBLE GAP AND INTERNAL FUSE. G10S FOR SELF PROTECTED TRANSFORMER.
2. SEE GUIDE DRAWINGS FOR DETAILS OF TRANSFORMER SECONDARY AND SERVICE CONNECTIONS.
3. DO NOT DISCONNECT TRANSFORMER NEUTRAL WITHOUT FIRST DISCONNECTING PRIMARY.





NOTE:
ITEM AX MAY BE SUBSTITUTED FOR ITEMS AE AND AF.

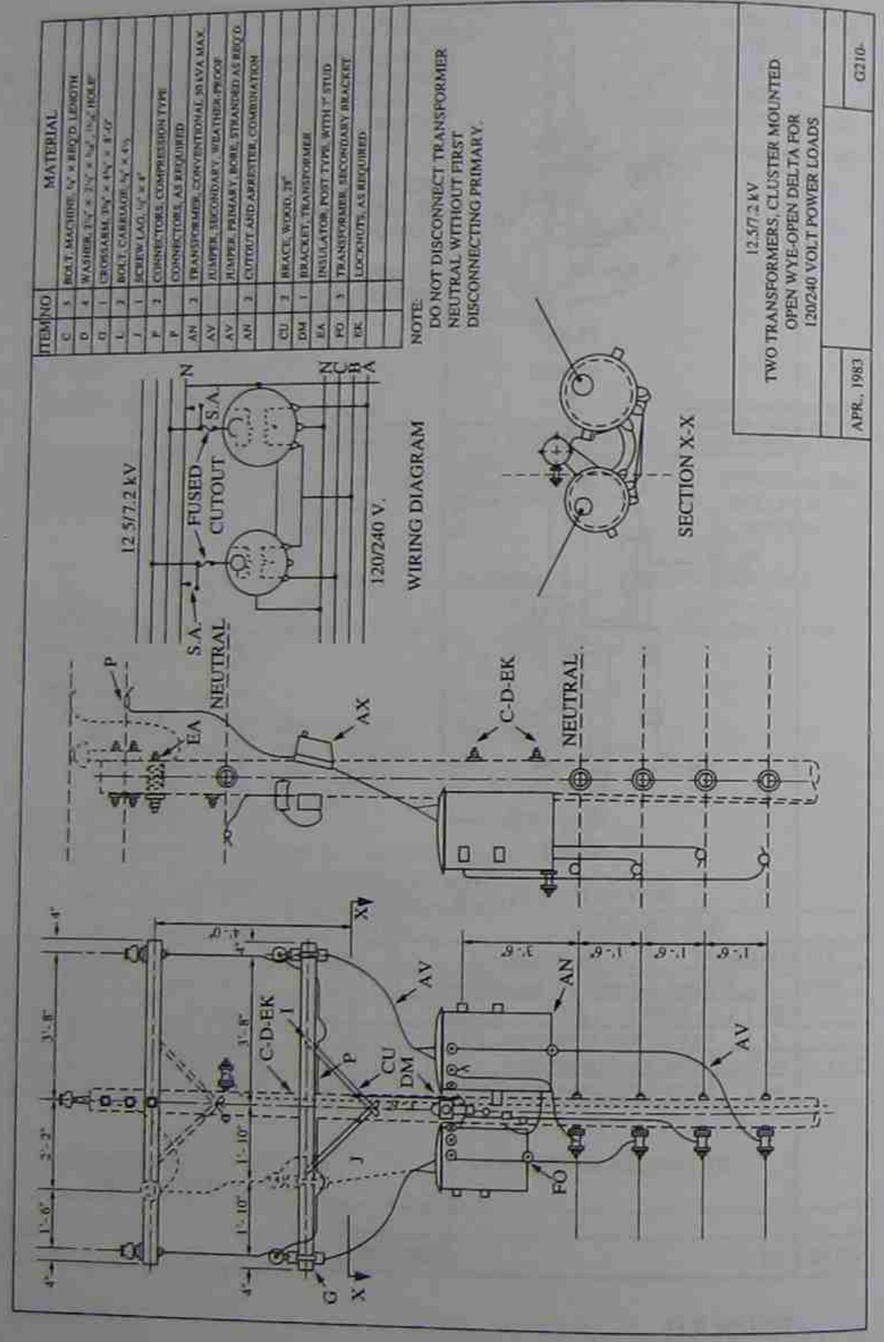
ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
C	2	BOLT, MACHINE, ⅝" x REQ'D. LENGTH	AX	1	TRANSFORMER
D	2	WASHER, 2½" x 2½" x ⅝", 1⅛" HOLE	AP	1	CLAMP, HOT LINE, TAP ASSEMBLY
P		CONNECTORS, AS REQUIRED	AV		JUMPERS, STRANDED AS REQUIRED
AE		SURGE ARRESTER (G9 ONLY)	BV	1	RODS, ARMOR
AF		CUTOUT, FUSE, OPEN LINK (G9 ONLY)	EK		LOCKNUTS, AS REQ'D.

12.5/7.2 kV,
SINGLE PHASE TRANSFORMER
AT 1 - PHASE TANGENT

APR., 1983

G9-, G6S-, G10S

FIGURE B.14



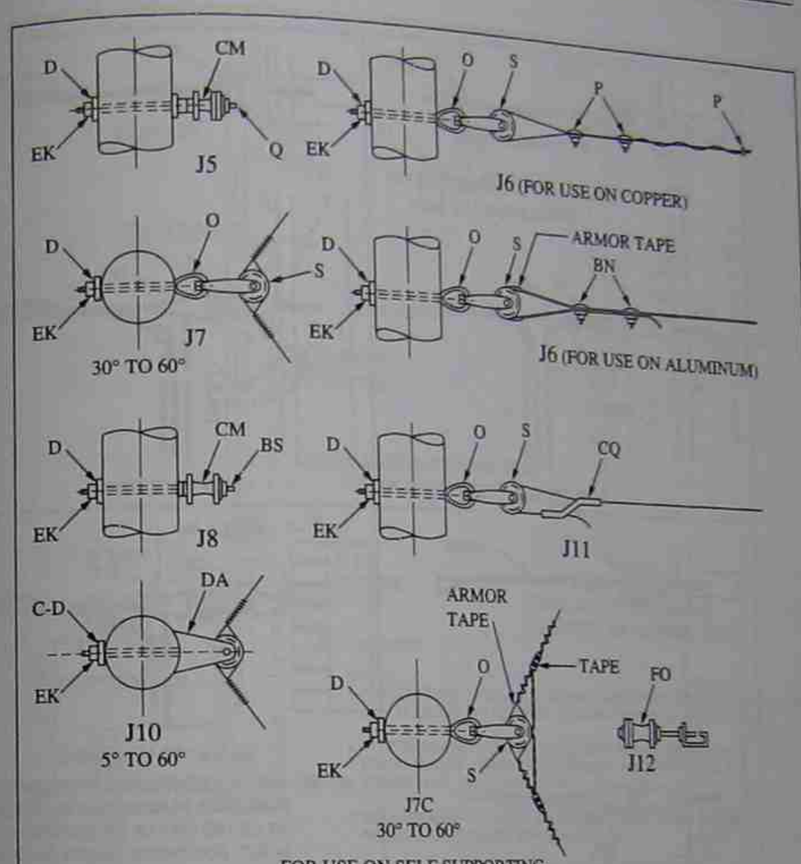
ITEM	NO	MATERIAL
C	1	BOLT, MACHINE, ⅝" × REQ'D. LENGTH
D	4	WASHER, 2¼" × 2¼" × 13/16" HOLE
O	1	CROSSARM 3½" × 4½" × 8'-0"
L	2	BOLT, CARRIAGE, ⅝" × 4½
J	1	SCREW LAG, ½" × 4"
P	2	CONNECTORS, COMPRESSION TYPE
P	2	CONNECTORS, AS REQUIRED
AN	3	TRANSFORMER, CONVENTIONAL 30 kVA MAX
AV	3	JUMPER, SECONDARY, WEATHERPROOF
AV	1	JUMPER, PRIMARY, BARE, STRANDED AS REQ'D.
AN	3	CUTOUT AND ARRESTER, COMBINATION
CU	3	BRACE, WOOD, 28"
DM	1	BRACKET, TRANSFORMER
EA	1	INSULATOR, POST TYPE, WITH ¾" STUD
FO	3	TRANSFORMER, SECONDARY BRACKET
EK		LOCKNUTS, AS REQUIRED

NOTE:
DO NOT DISCONNECT TRANSFORMER NEUTRAL WITHOUT FIRST DISCONNECTING PRIMARY.

12.5/7.2 kV
TWO TRANSFORMERS, CLUSTER MOUNTED
OPEN WYE-OPEN DELTA FOR
120/240 VOLT POWER LOADS

APR., 1983 | G210-

FIGURE B.15

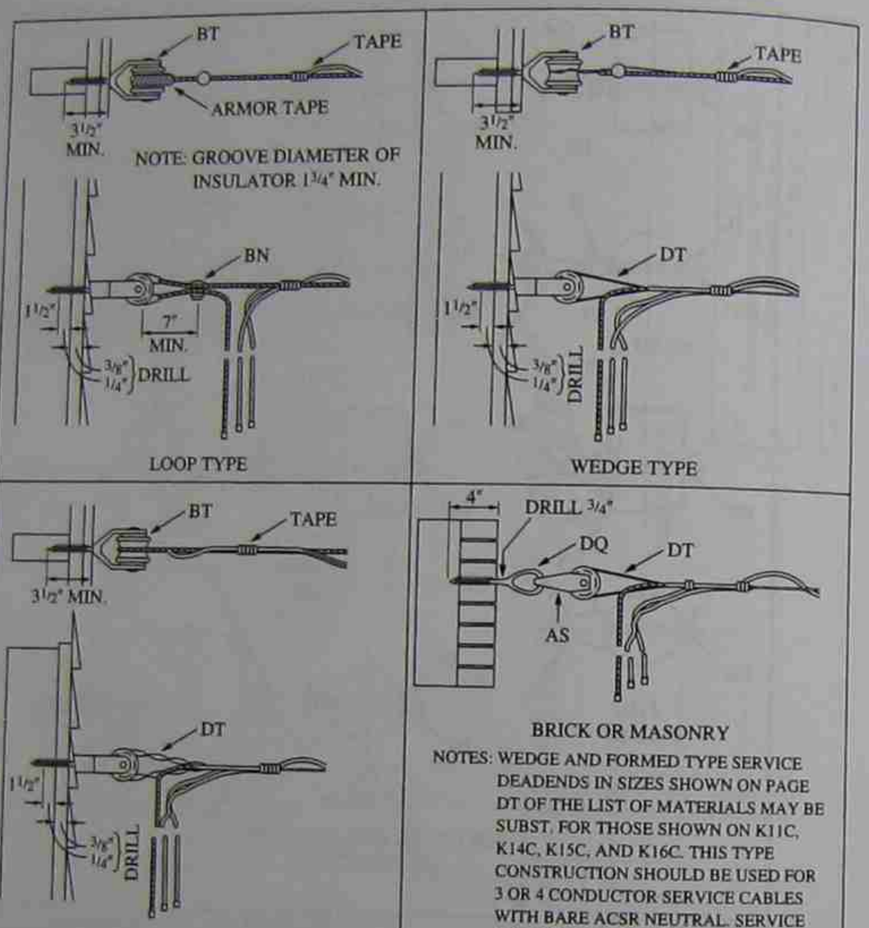


ITEM	NO.	MATERIAL	ITEM	NO.	MATERIAL
C		BOLT, MACHINE, ⅝" × REQUIRED LENGTH	BS		BOLT, SINGLE UPSET
D		WASHER, 2¼" × 2¼" × 13/16" HOLE	BN		CLAMP, LOOP, DEADEND
O		BOLT, EYE, ⅝" × REQUIRED LENGTH	CQ		SLEEVE, OFFSET, SPLICING
P		CONNECTORS, AS REQUIRED	DA		BRACKET, INSULATED
Q		BOLT, DOUBLE UPSET	FO		TRANSFORMER SECONDARY BRACKET
S		CLEVIS, SECONDARY, SWINGING, INSULATED	EK		LOCKNUTS AS REQUIRED
CM		INSULATOR SPOOL			

SECONDARY ASSEMBLIES

APR., 1983 | J5 TO J12

FIGURE B.16



NOTES: WEDGE AND FORMED TYPE SERVICE DEADENDS IN SIZES SHOWN ON PAGE DT OF THE LIST OF MATERIALS MAY BE SUBST. FOR THOSE SHOWN ON K11C, K14C, K15C, AND K16C. THIS TYPE CONSTRUCTION SHOULD BE USED FOR 3 OR 4 CONDUCTOR SERVICE CABLES WITH BARE ACSR NEUTRAL. SERVICE CONNECTORS TO BE INSULATED COMPRESSION TYPE.

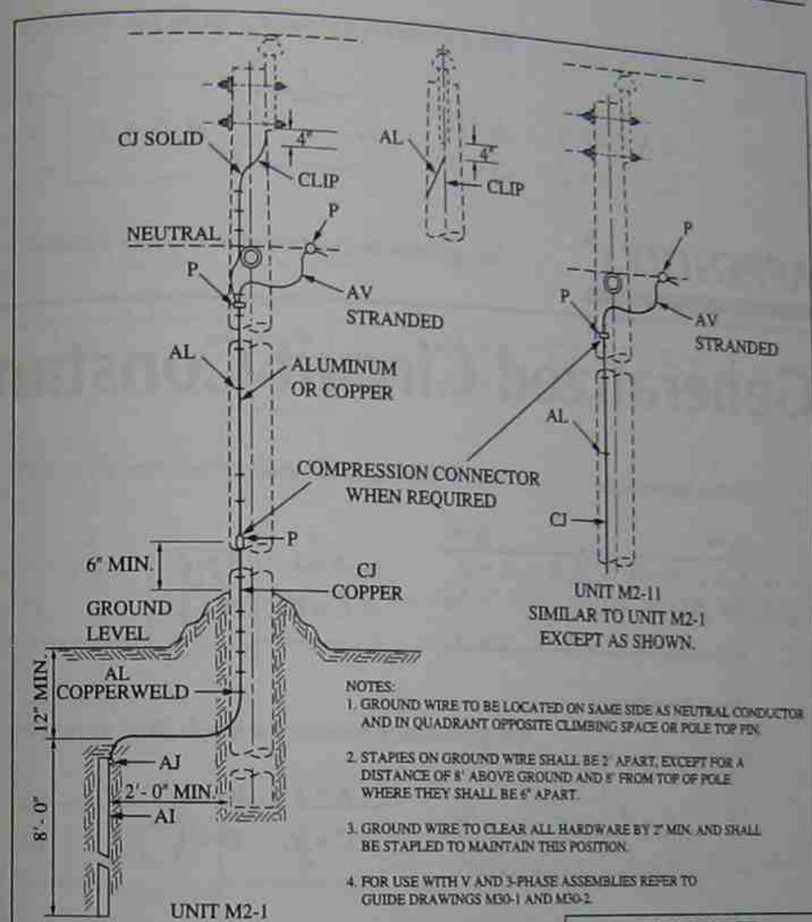
ITEM	NO.	MATERIAL
BT		WIREHOLDER, CLEVIS TYPE, INSULATED
		#24 WOODSCREW.
P		CONNECTORS, AS REQUIRED
BN		CLAMP, LOOP, DEADEND
AS		CLEVIS, SERVICE, INSULATED

ITEM	NO.	MATERIAL
DT		SERVICE DEADEND, WEDGE TYPE.
DT		SERVICE DEADEND, PREFORMED TYPE
DQ		EYE SCREW, ELLIPTICAL, ½" × 6"
		¾" × 3½ EXPANSION SHIELD

SERVICE ASSEMBLIES, CABLE

APR., 1983 — K10C

FIGURE B.17



NOTES:
1. GROUND WIRE TO BE LOCATED ON SAME SIDE AS NEUTRAL CONDUCTOR AND IN QUADRANT OPPOSITE CLIMBING SPACE OR POLE TOP PIN.
2. STAPLES ON GROUND WIRE SHALL BE 2" APART, EXCEPT FOR A DISTANCE OF 8' ABOVE GROUND AND 8" FROM TOP OF POLE WHERE THEY SHALL BE 6" APART.
3. GROUND WIRE TO CLEAR ALL HARDWARE BY 2" MIN. AND SHALL BE STAPLED TO MAINTAIN THIS POSITION.
4. FOR USE WITH V AND 3-PHASE ASSEMBLIES REFER TO GUIDE DRAWINGS M30-1 AND M30-2.

ITEM	MATERIAL	ASSEMBLY UNIT M2-1	ASSEMBLY UNIT M2-11
P	CONNECTOR, COMPRESSION	AS REQ'D.	AS REQ'D.
AI	ROD, GROUND, ⅝" MINIMUM DIAMETER	1	1
AI	CLAMP, GROUND ROD WIRE	1	1
AL	STAPLES, GROUND WIRE (COPPER OR STEEL TO MATCH GROUND WIRE)	AS REQ'D.	AS REQ'D.
AL	GROUND WIRE CLIP	1	
CJ	GROUND WIRE, MINIMUM NO. 6 COPPER OR EQUIV. CONDUCTIVITY	AS REQ'D.	AS REQ'D.
AV	JUMPER, STRANDED MIN. NO. 6 COPPER OR EQUIV. CONDUCTIVITY	AS REQ'D.	AS REQ'D.

12.5/7.2 kV
GROUNDING ASSEMBLY - GROUND ROD TYPE

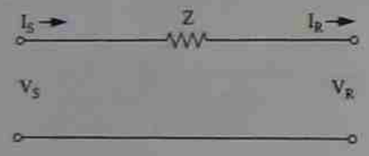
APR., 1983 — M2-1 TO M2-11

FIGURE B.18

APPENDIX C

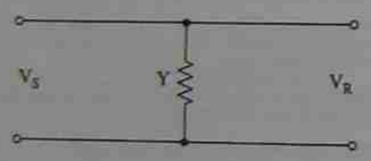
Generalized Circuit Constants

Series Impedance



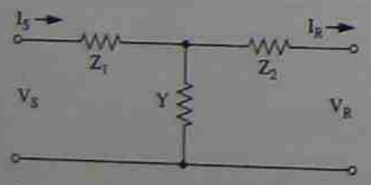
$A = 1 \quad B = Z$
$C = 0 \quad D = 1$

Shunt Admittance



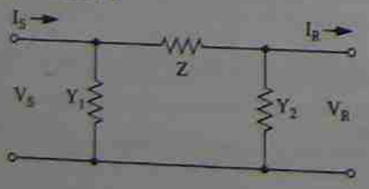
$A = 1 \quad B = 0$
$C = Y \quad D = 1$

General T



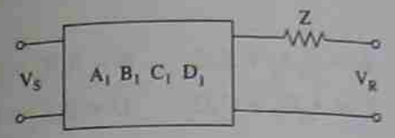
$A = 1 + YZ_1 \quad B = Z_1 + Z_2 + YZ_1$
$C = Y \quad D = 1 + YZ_2$

General TT



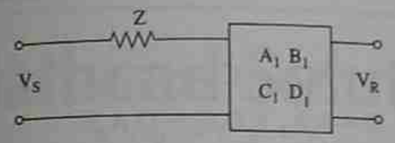
$A = 1 + Y_2Z \quad B = Z$
$C = Y_1 + Y_2 + ZY_1Y_2 \quad D = 1 + Y_1Z$

Network and series impedance at receiving end



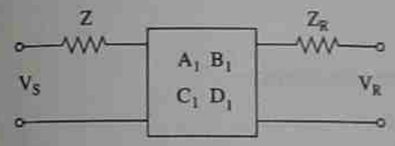
$A = A_1 \quad B = B_1 + A_1Z$
$C = C_1 \quad D = D_1 + C_1Z$

Network and series impedance at sending end



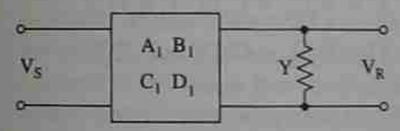
$A = A_1 + C_1Z \quad B = B_1 + D_1Z$
$C = C_1 \quad D = D_1$

Network with series impedance at both ends



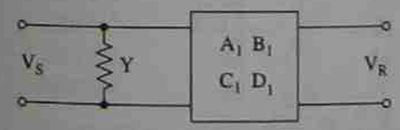
$A = A_1 + C_1Z_S \quad B = B_1 + A_1Z_R + D_1Z_S + C_1Z_RZ_S$
$C = C_1 \quad D = D_1 + C_1Z_R$

Network with shunt admittance at receiving end



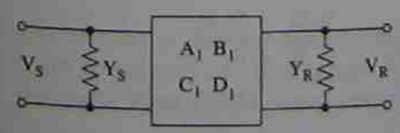
$A = A_1 + B_1Y \quad B = B_1$
$C = C_1 + D_1Y \quad D = D_1$

Network with shunt admittance at sending end



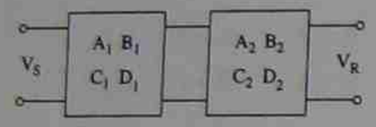
$A = A_1 \quad B = B_1$
$C = C_1 + A_1Y \quad D = D_1 + B_1Y$

Network with shunt admittance at both ends



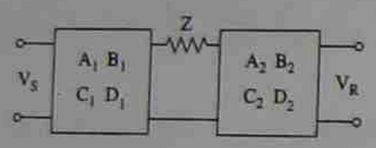
$A = A_1 + B_1Y_R \quad B = B_1$
$C = C_1 + A_1Y_S + D_1Y_R + B_1Y_RY_S \quad D = D_1 + B_1Y_S$

Two networks in series



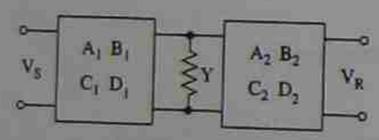
$$A = A_1A_2 + B_1C_2 \qquad B = A_1B_2 + B_1D_2$$
$$C = A_2C_1 + C_2D_1 \qquad D = B_2C_1 + D_1D_2$$

Two networks in series with intermediate impedance



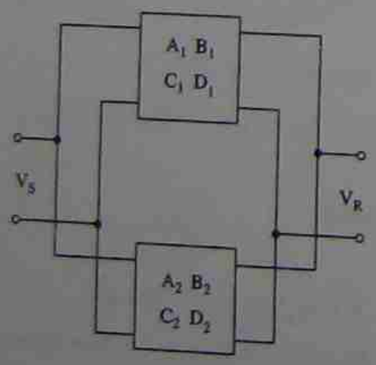
$$A = A_1A_2 + C_1B_2 + C_1A_2Z$$
$$B = B_1A_2 + D_1B_2 + D_1A_2Z$$
$$C = A_1C_2 + C_1D_2 + C_1C_2Z$$
$$D = B_1C_2 + D_1D_2 + D_1C_2Z$$

Two networks in series with intermediate admittance



$$A = A_1A_2 + C_1B_2 + A_1B_2Y$$
$$B = B_1A_2 + D_1B_2 + B_1B_2Y$$
$$C = A_1C_2 + C_1D_2 + A_1D_2Y$$
$$D = B_1C_2 + D_1D_2 + B_1D_2Y$$

Two networks in parallel



$$A = \frac{A_1B_2 + B_1A_2}{B_1 + B_2}$$

$$B = \frac{B_1B_2}{B_1 + B_2}$$

$$C = \frac{C_1 + C_2 + (A_1 - A_2)(D_2 - D_1)}{B_1 + B_2}$$

$$D = \frac{B_1D_2 - D_1B_2}{B_1 + B_2}$$

APPENDIX D

Mathcad Solution to Example 9.11

by
Jeff Gallihugh

Problem Statement: Calculate the line power loss for 50, 100, and 200 mile lines for each line to line voltage 69 kV, 138 kV, 345 kV, and 500 kV using LINNET conductor at 50°C with phase spacing and bundle distances as shown below. The load Current is 100 amps per conductor at .8 PF lagging. The 345 kV is to use a bundle of two conductors per phase and the 500 kV is to use a bundle of three conductors per phase. Use both the medium length and long line equivalent circuits.

Common line spacing in feet:

69 kV	10	10	20	
138 kV	14	14	28	
345 kV	22	22	44	1.5 bundle of two spacing
500 kV	30	30	60	1.5 bundle of three spacing

LINNET Conductor Characteristics

R = 56.932 micro Ω/ft
radius = 0.030 ft
Ds = 0.0243 ft

Calculation of the conductor single phase inductance and single phase capacitance to neutral per unit length for a three phase transmission line requires that the equivalent GMD (Deq) and GMR for the inductance (Dsl) and capacitance

(Dsc) using the bundling distance and the phase spacing distance be determined. The following equations are used.

$$D_{eq} = (D_{ab} \cdot D_{ac} \cdot D_{bc})^{\frac{1}{3}} \qquad D_{sl} = (d^{n-1} \cdot D_s)^{\frac{1}{n}} \qquad D_{sc} = (d^{n-1} \cdot r)^{\frac{1}{n}}$$

Such that:

D = phase distance in feet
Ds = GMR in feet
r = conductor radius in feet
d = bundling distance in feet where d must be = 1 for single conductor
n = number of conductors per bundle
f = frequency of conductor in hertz
L = conductor length in miles

To calculate the per phase inductive reactance per unit length and capacitive reactance to neutral per unit length for bundled conductors up to a bundle of three the following equations are used, and are a function of Deq, Dsl, and Dsc.

For units set mi := 1

$$x_l = .1213 \cdot \ln\left(\frac{D_{eq}}{D_{sl}}\right) \cdot j \cdot \frac{\Omega}{mi} \qquad x_{cn} = 2.965 \cdot 10^4 \cdot \ln\left(\frac{D_{eq}}{D_{sc}}\right) \cdot -j \cdot \Omega \cdot mi$$

$$D_{eq}(D_{ab},D_{ac},D_{bc}) := (D_{ab} \cdot D_{ac} \cdot D_{bc})^{\frac{1}{3}} \cdot ft \qquad D_{sl}(d,n,D_s) := [d^{(n-1)} \cdot D_s]^{\frac{1}{n}} \cdot ft$$

$$D_{sc}(d,n,r) := [d^{(n-1)} \cdot r]^{\frac{1}{n}} \cdot ft \qquad R_{eq}(R,n) := \frac{R}{n} \cdot \frac{\Omega}{mi}$$

To calculate the inductance and capacitance per unit length of the line and the series impedance and shunt admittance per unit length the following equations are used. To avoid units errors the dependencies of the equation are in parentheses. The dependencies are not necessary for the program to work properly.

$$x_l(D_{ab},D_{ac},D_{bc},d,n,D_s) := .1213 \cdot \ln\left(\frac{D_{eq}(D_{ab},D_{ac},D_{bc})}{D_{sl}(d,n,D_s)}\right) \cdot j \cdot \frac{\Omega}{mi}$$

$$x_{cn}(D_{ab},D_{ac},D_{bc},d,n,r) := 2.965 \cdot 10^4 \cdot \ln\left(\frac{D_{eq}(D_{ab},D_{ac},D_{bc})}{D_{sc}(d,n,r)}\right) \cdot -j \cdot \Omega \cdot mi$$

$$y(D_{ab},D_{ac},D_{bc},d,n,r) := \frac{1}{x_{cn}(D_{ab},D_{ac},D_{bc},d,n,r)}$$

$$z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) := (R_{eq}(R,n) + x_l(D_{ab},D_{ac},D_{bc},d,n,D_s))$$

The long line equivalent circuit the generalized circuit constants need to be developed from the unit length impedance and admittance which yields the line characteristic impedance, Zc, and the line propagation constant, γ.

$$Z_c = \sqrt{\frac{z}{y}} \text{ and } \gamma = \sqrt{z \cdot y} \text{ therefore } \quad A_a = D_d = \cosh(\gamma \cdot 1) \quad B_b = Z_c \cdot \sinh(\gamma \cdot 1) \quad C_c = \frac{\sinh(\gamma \cdot 1)}{Z_c}$$

$$Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) := \sqrt{\frac{z(R,D_{ab},D_{ac},D_{bc},d,n,D_s)}{y(D_{ab},D_{ac},D_{bc},d,n,r)}}$$

$$\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \sqrt{z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) \cdot y(D_{ab},D_{ac},D_{bc},d,n,r)}$$

$$A_a(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \cosh(\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) \cdot 1)$$

$$B_b(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) := Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) \cdot \sinh(\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) \cdot 1)$$

$$C_c(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \frac{\sinh(\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) \cdot 1)}{Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)}$$

$$D_d(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \cosh(\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) \cdot 1)$$

To develop the medium length lumped parameter equivalent circuit the generalized circuit constants need to be calculated from the unit length impedance and admittance from the conductor length. The equations are:

$$Z = z \cdot 1 \qquad Y = y \cdot 1 \qquad A = D = \frac{Z \cdot Y}{2} + 1 \qquad B = Z \qquad C = Y \cdot \left(1 + \frac{Z \cdot Y}{4}\right)$$

$$Z(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s) := z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) \cdot 1$$

$$Y(1,D_{ab},D_{ac},D_{bc},d,n,r) := y(D_{ab},D_{ac},D_{bc},d,n,r) \cdot 1$$

$$A(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \frac{Z(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s) \cdot Y(1,D_{ab},D_{ac},D_{bc},d,n,r)}{2} + 1$$

$$B(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s) := Z(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s)$$

$$C(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := Y(1,D_{ab},D_{ac},D_{bc},d,n,r) \cdot \left(1 + \frac{Z(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s) \cdot Y(1,D_{ab},D_{ac},D_{bc},d,n,r)}{4}\right)$$

$$D(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) := \frac{Z(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s) \cdot Y(1,D_{ab},D_{ac},D_{bc},d,n,r)}{2} + 1$$

To calculate the source voltage and current the following equations are used.

Long Line Equivalent	Medium Line Equivalent
$V_s = V_r \cdot A_a + I_r \cdot B_b$	$V_s = V_r \cdot A + I_r \cdot B$
$\frac{(V_s - I_r \cdot B_b)}{A_a} = V_r$	$\frac{(V_s - I_r \cdot B)}{A} = V_r$
$I_s = I_r \cdot D_d + V_r \cdot C_c$	$I_s = V_r \cdot C + I_r \cdot D$
$\frac{(I_s - V_r \cdot C_c)}{D_d} = I_r$	$\frac{(I_s - V_r \cdot C)}{D} = I_r$

Enter the conductor variables and phase spacing and bundle spacing without units to calculate conductor physical parameters. An equation test with dummy variables follows.

$D_{ab} := 1$ ft $D_{ac} := 1$ ft $D_{bc} := 1$ ft $D_s := .1$ ft $r := .1$ ft

$n := 1$ $d := 1$ ft $f := 60$ Hz $R := 100$ Ω/mile

The program now calculates the line impedance, characteristic impedance, admittance, and propagation constant.

$D_{eq}(D_{ab},D_{ac},D_{bc}) = 1.0000 \cdot ft$ $D_{sl}(d,n,D_s) = 0.1 \cdot ft$ $D_{sc}(d,n,r) = 0.1000 \cdot ft$

$x_l(D_{ab},D_{ac},D_{bc},d,n,D_s) = 0.2793j \cdot \frac{\Omega}{mi}$

$y(D_{ab},D_{ac},D_{bc},d,n,r) = 1.4647 \cdot 10^{-5}j \cdot \frac{siemens}{mi}$

$x_{cn}(D_{ab},D_{ac},D_{bc},d,n,r) = -6.8272 \cdot 10^{4}j \cdot \Omega \cdot mi$

$\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) = 0.0270 + 0.0271j \cdot \frac{1}{mi}$

$z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) = 100.0000 + 0.2793j \cdot \frac{\Omega}{mi}$

$Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) = 1.8502 \cdot 10^{3} - 1.8450 \cdot 10^{3}j \cdot \Omega$

Input the load terminal line to line voltage, voltage phase angle, load line current, and power factor angle without units in the values shown:

$v_{rl} := 1$ kV $\delta_{rl} := 0$ deg $i_{rl} := 1$ kA $\theta_{rl} := 0$

Calculated load terminal phase voltage

$V_{rl} := \frac{v_{rl}}{\sqrt{3}} \cdot e^{j \cdot \delta_{rl} \cdot deg} \cdot kV$

$V_{rl} = 0.5774 \cdot kV$

Calculated load phase current

$I_{rl} := i_{rl} \cdot e^{j \cdot \theta_{rl} \cdot deg} \cdot kA$

$I_{rl} = 1.0000 \cdot kA$

The long line supply voltage and current are calculated as:

$V_{sLL}(l) := V_{rl} \cdot A_a(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{rl} \cdot B_b(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r)$

$I_{sLL}(l) := I_{rl} \cdot D_d(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{rl} \cdot C_c(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The medium line supply voltage and current are calculated as:

$V_{sML}(l) := V_{rl} \cdot A(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{rl} \cdot B(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s)$

$I_{sML}(l) := I_{rl} \cdot D(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{rl} \cdot C(l,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The transmission line power loss is calculated by entering the transmission length in miles without units, and subtracting received power from sending power:

Long Line Equivalent $l := 1$	Medium Line Equivalent
$V_{sLL}(l \cdot mi) = 100.5772 + 0.3041j \cdot kV$	$V_{sML}(l \cdot mi) = 100.5773 + 0.2797j \cdot kV$
$\lvert V_{sLL}(l \cdot mi)\rvert = 100.5777 \cdot kV$	$\lvert V_{sML}(l \cdot mi)\rvert = 100.5777 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 0.1733 \cdot deg$	$\arg(V_{sML}(l \cdot mi)) = 0.1594 \cdot deg$
$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$	$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$
$S_{sLL} = 1.0058 \cdot 10^{5} + 229.6278j \cdot VA$	$S_{sML} = 1.0058 \cdot 10^{5} + 205.2156j \cdot VA$
$P_{sLL} := 3 \cdot Re(S_{sLL})$	$P_{sML} := 3 \cdot Re(S_{sML})$
$S_{rLL} := V_{rl} \cdot \overline{I_{rl}}$	$S_{rML} := V_{rl} \cdot \overline{I_{rl}}$
$P_{rLL} := 3 \cdot Re(S_{rLL})$	$P_{rML} := 3 \cdot Re(S_{rML})$
$P_{lossLL} := P_{sLL} - P_{rLL}$	$P_{lossML} := P_{sML} - P_{rML}$
$P_{lossLL} = 3.0000 \cdot 10^{5} \cdot kW$	$P_{lossML} = 3.0000 \cdot 10^{5} \cdot kW$

Now the line loss will be calculated.

69 kV

For 69 kV load and 10 ft, 10 ft, 20 ft phase spacing and ft. bundle spacing for single conductor per phase

Enter the conductor variables and phase spacing and bundle spacing without units to calculate conductor physical parameters:

$D_{ab} := 10$ ft $D_{ac} := 10$ ft $D_{bc} := 20$ ft $D_s := 0.0243$ ft $r := 0.0300$ ft

$n := 1$ $d := 1$ ft $f := 60$ Hz $R := .3006$ Ω/mile

Which calculates the line impedance, characteristic impedance, admittance, and propagation constant.

$D_{eq}(D_{ab},D_{ac},D_{bc}) = 12.5992 \cdot ft$ $D_{sl}(d,n,D_s) = 0.0243 \cdot ft$ $D_{sc}(d,n,r) = 0.0300 \cdot ft$

$$z(D_{ab}, D_{ac}, D_{bc}, d, n, D_s) = 0.7982 \cdot \frac{\Omega}{mi}$$

$$y(D_{ab}, D_{ac}, D_{bc}, d, n, r) = 5.8087 \cdot 10^{-6} \cdot \frac{siemens}{mi}$$

$$z_c(D_{ab}, D_{ac}, D_{bc}, d, n, r) = 1.7908 \cdot 10^{-3} \cdot \Omega \cdot mi$$

$$y(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) = 4.0036 \cdot 10^{-6} + 0.0020i \cdot \frac{1}{mi}$$

$$z(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s) = 0.3006 + 0.7982i \cdot \frac{\Omega}{mi}$$

$$Z_c(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, R, r) = 375.4128 - 71.7010i \cdot \Omega$$

Input the load terminal line to line voltage, voltage phase angle, load line current, and power factor angle without units in the values shown:

$v_c := 66 \cdot kV$ $\delta_c := 0 \cdot deg$ $i_c := 100 \cdot kA$ $\theta_c := -36.87 \cdot deg$

Calculated load terminal phase voltage

$$V_c := \frac{v_c}{\sqrt{3}} \cdot e^{i \cdot \delta_c} = 66 \cdot kV$$

$V_c = 38.8372 \cdot kV$

Calculated load phase current

$$I_c := i_c \cdot e^{i \cdot \theta_c} = 80 \cdot kA$$

$I_c = 0.0800 - 0.0600i \cdot kA$

The long line supply voltage and current are calculated as:

$V_{acl}(l) := V_c \cdot A_l(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + I_c \cdot B_l(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, R, r)$

$I_{acl}(l) := I_c \cdot D_l(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + V_c \cdot C_l(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r)$

The medium line supply voltage and current are calculated as:

$V_{acm}(l) := V_c \cdot A(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + I_c \cdot B(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s)$

$I_{acm}(l) := I_c \cdot D(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + V_c \cdot C(l, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r)$

The transmission line power loss is calculated by entering the transmission length in miles without units as:

At 50 miles

Long Line Equivalent $l := 50$

$V_{acl}(l \cdot mi) = 45.0960 + 2.2332i \cdot kV$

$|V_{acl}(l \cdot mi)| = 45.1528 \cdot kV$

$arg(V_{acl}(l \cdot mi)) = 2.8944 \cdot deg$

$S_{acl} := V_{acl}(l \cdot mi) \cdot \overline{I_{acl}(l)}$

$S_{acl} = 3.5274 \cdot 10^3 + 2.2625 \cdot 10^3 i \cdot VA$

$P_{acl} := 3 \cdot Re(S_{acl})$

$S_{acl} := V_c \cdot \overline{I_c}$

$P_{acl} := 3 \cdot Re(S_{acl})$

$P_{lossl} := P_{acl} - P_{acl}$

$P_{lossl} = 421.2125 \cdot kW$

Medium Line Equivalent

$V_{acm}(l \cdot mi) = 45.1035 + 2.2147i \cdot kV$

$|V_{acm}(l \cdot mi)| = 45.1603 \cdot kV$

$arg(V_{acm}(l \cdot mi)) = 2.9414 \cdot deg$

$S_{acm} := V_{acm}(l \cdot mi) \cdot \overline{I_{acm}(l)}$

$S_{acm} = 3.5277 \cdot 10^3 + 2.2657 \cdot 10^3 i \cdot VA$

$P_{acm} := 3 \cdot Re(S_{acm})$

$S_{acm} := V_c \cdot \overline{I_c}$

$P_{acm} := 3 \cdot Re(S_{acm})$

$P_{lossm} := P_{acm} - P_{acm}$

$P_{lossm} = 422.2049 \cdot kW$

$P_{acl} := 3 \cdot Re(S_{acl})$

$S_{acl} := V_c \cdot \overline{I_c}$

$P_{acl} := 3 \cdot Re(S_{acl})$

$P_{lossl} := P_{acl} - P_{acl}$

$P_{lossl} = 421.2125 \cdot kW$

$P_{acm} := 3 \cdot Re(S_{acm})$

$S_{acm} := V_c \cdot \overline{I_c}$

$P_{acm} := 3 \cdot Re(S_{acm})$

$P_{lossm} := P_{acm} - P_{acm}$

$P_{lossm} = 422.2049 \cdot kW$

At 100 miles

$l := 100$

$V_{acl}(l \cdot mi) = 45.8897 + 4.5836i \cdot kV$

$|V_{acl}(l \cdot mi)| = 46.1161 \cdot kV$

$arg(V_{acl}(l \cdot mi)) = 5.7039 \cdot deg$

$S_{acl} := V_{acl}(l \cdot mi) \cdot \overline{I_{acl}(l)}$

$S_{acl} = 3.4489 \cdot 10^3 + 2.0121 \cdot 10^3 i \cdot VA$

$P_{acl} := 3 \cdot Re(S_{acl})$

$S_{acl} := V_c \cdot \overline{I_c}$

$P_{acl} := 3 \cdot Re(S_{acl})$

$P_{lossl} := P_{acl} - P_{acl}$

$P_{lossl} = 785.7140 \cdot kW$

$V_{acm}(l \cdot mi) = 45.9467 + 4.5969i \cdot kV$

$|V_{acm}(l \cdot mi)| = 46.1774 \cdot kV$

$arg(V_{acm}(l \cdot mi)) = 5.7128 \cdot deg$

$S_{acm} := V_{acm}(l \cdot mi) \cdot \overline{I_{acm}(l)}$

$S_{acm} = 3.4582 \cdot 10^3 + 2.0183 \cdot 10^3 i \cdot VA$

$P_{acm} := 3 \cdot Re(S_{acm})$

$S_{acm} := V_c \cdot \overline{I_c}$

$P_{acm} := 3 \cdot Re(S_{acm})$

$P_{lossm} := P_{acm} - P_{acm}$

$P_{lossm} = 782.5870 \cdot kW$

At 200 miles

$l := 200$

$V_{acl}(l \cdot mi) = 49.9288 + 9.7385i \cdot kV$

$|V_{acl}(l \cdot mi)| = 50.8697 \cdot kV$

$arg(V_{acl}(l \cdot mi)) = 11.0369 \cdot deg$

$S_{acl} := V_{acl}(l \cdot mi) \cdot \overline{I_{acl}(l)}$

$S_{acl} = 3.6445 \cdot 10^3 + 1.1940 \cdot 10^3 i \cdot VA$

$P_{acl} := 3 \cdot Re(S_{acl})$

$S_{acl} := V_c \cdot \overline{I_c}$

$P_{acl} := 3 \cdot Re(S_{acl})$

$P_{lossl} := P_{acl} - P_{acl}$

$P_{lossl} = 1.5726 \cdot 10^3 \cdot kW$

$V_{acm}(l \cdot mi) = 50.5726 + 9.8619i \cdot kV$

$|V_{acm}(l \cdot mi)| = 51.5287 \cdot kV$

$arg(V_{acm}(l \cdot mi)) = 11.0772 \cdot deg$

$S_{acm} := V_{acm}(l \cdot mi) \cdot \overline{I_{acm}(l)}$

$S_{acm} = 3.6574 \cdot 10^3 + 1.2167 \cdot 10^3 i \cdot VA$

$P_{acm} := 3 \cdot Re(S_{acm})$

$S_{acm} := V_c \cdot \overline{I_c}$

$P_{acm} := 3 \cdot Re(S_{acm})$

$P_{lossm} := P_{acm} - P_{acm}$

$P_{lossm} = 1.4034 \cdot 10^3 \cdot kW$

138 kV

For 138 kV load and 14 ft, 14 ft, 28 ft phase spacing for single conductor per phase

Enter the conductor variables and phase spacing and bundle spacing without units to calculate conductor physical parameters:

$D_{ab} := 14\ ft \quad D_{ac} := 14\ ft \quad D_{bc} := 28\ ft \quad D_s := 0.0243\ ft \quad r := 0.0600\ ft$

$n := 1 \quad d := 1\ ft \quad f := 60\ Hz \quad R := .3006\ \Omega/mile$

Which calculates the line impedance, characteristic impedance, admittance, and propagation constant.

$D_{eq}(D_{ab},D_{ac},D_{bc}) = 17.6389 \cdot ft \quad D_{sl}(d,n,D_s) = 0.0243 \cdot ft \quad D_{sc}(d,n,r) = 0.0300 \cdot ft$

$x_l(D_{ab},D_{ac},D_{bc},d,n,D_s) = 0.7990j \cdot \frac{\Omega}{mi}$

$y(D_{ab},D_{ac},D_{bc},d,n,r) = 5.2891 \cdot 10^{-6}j \cdot \frac{siemens}{mi}$

$x_{cn}(D_{ab},D_{ac},D_{bc},d,n,r) = -1.8907 \cdot 10^{5}j \cdot \Omega \cdot mi$

$\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) = 3.8024 \cdot 10^{-4} + 0.0021j \cdot \frac{1}{mi}$

$z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) = 0.3006 + 0.7990j \cdot \frac{\Omega}{mi}$

$Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) = 395.2761 - 71.8914j \cdot \Omega$

Input the load terminal line to line voltage, voltage phase angle, load line current, and power factor angle without units in the values shown:

$v_{rl} := 138\ kV \quad \delta_{rl} := 0\ deg \quad i_{rl} := .100\ kA \quad \theta_{rl} := -36.87\ deg$

Calculated load terminal phase voltage

$V_{rl} := \frac{v_{rl}}{\sqrt{3}} \cdot e^{j \cdot \delta_{rl} \cdot deg} \cdot kV$

$V_{rl} = 79.6743 \cdot kV$

Calculated load phase current

$I_{rl} := i_{rl} \cdot e^{j \cdot \theta_{rl} \cdot deg} \cdot kA$

$I_{rl} = 0.0800 - 0.0600j \cdot kA$

The long line supply voltage and current are calculated as:

$V_{sLL}(1) := V_{rl} \cdot A_a(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{rl} \cdot B_b(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r)$

$I_{sLL}(1) := I_{rl} \cdot D_d(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{rl} \cdot C_c(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The medium line supply voltage and current are calculated as:

$V_{sML}(1) := V_{rl} \cdot A(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{rl} \cdot B(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s)$

$I_{sML}(1) := I_{rl} \cdot D(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{rl} \cdot C(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The transmission line power loss is calculated by entering the transmission length in miles without units as:

At 50 miles

$l := 50$

Long Line Equivalent	Medium Line Equivalent
$V_{sLL}(l \cdot mi) = 82.8454 + 2.4508j \cdot kV$	$V_{sML}(l \cdot mi) = 82.8530 + 2.4527j \cdot kV$
$\lvert V_{sLL}(l \cdot mi)\rvert = 82.8817 \cdot kV$	$\lvert V_{sML}(l \cdot mi)\rvert = 82.8893 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 1.6945 \cdot deg$	$\arg(V_{sML}(l \cdot mi)) = 1.6957 \cdot deg$
$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$	$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$
$S_{sLL} = 6.5070 \cdot 10^3 + 3.3841 \cdot 10^3 j \cdot VA$	$S_{sML} = 6.5069 \cdot 10^3 + 3.3861 \cdot 10^3 j \cdot VA$
$P_{sLL} := 3 \cdot Re(S_{sLL})$	$P_{sML} := 3 \cdot Re(S_{sML})$
$S_{rLL} := V_{rl} \cdot \overline{I_{rl}}$	$S_{rML} := V_{rl} \cdot \overline{I_{rl}}$
$P_{rLL} := 3 \cdot Re(S_{rLL})$	$P_{rML} := 3 \cdot Re(S_{rML})$
$P_{lossLL} := P_{sLL} - P_{rLL}$	$P_{lossML} := P_{sML} - P_{rML}$
$P_{lossLL} = 399.2212 \cdot kW$	$P_{lossML} = 398.9008 \cdot kW$

At 100 miles

$l := 100$

$V_{sLL}(1 \cdot mi) = 85.1322 + 5.2044j \cdot kV$	$V_{sML}(l \cdot mi) = 85.1898 + 5.2222j \cdot kV$
$\lvert V_{sLL}(l \cdot mi)\rvert = 85.2911 \cdot kV$	$\lvert V_{sML}(l \cdot mi)\rvert = 85.3497 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 3.4983 \cdot deg$	$\arg(V_{sML}(l \cdot mi)) = 3.5079 \cdot deg$
$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$	$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$
$S_{sLL} = 6.6133 \cdot 10^3 + 1.7937 \cdot 10^3 j \cdot VA$	$S_{sML} = 6.6119 \cdot 10^3 + 1.8078 \cdot 10^3 j \cdot VA$
$P_{sLL} := 3 \cdot Re(S_{sLL})$	$P_{sML} := 3 \cdot Re(S_{sML})$
$S_{rLL} := V_{rl} \cdot \overline{I_{rl}}$	$S_{rML} := V_{rl} \cdot \overline{I_{rl}}$
$P_{rLL} := 3 \cdot Re(S_{rLL})$	$P_{rML} := 3 \cdot Re(S_{rML})$
$P_{lossLL} := P_{sLL} - P_{rLL}$	$P_{lossML} := P_{sML} - P_{rML}$
$P_{lossLL} = 718.1223 \cdot kW$	$P_{lossML} = 713.8214 \cdot kW$

At 200 miles

$l := 200$

$V_{sLL}(l \cdot mi) = 86.9208 + 11.5336j \cdot kV$
$|V_{sLL}(l \cdot mi)| = 87.6827 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 7.5585 \cdot deg$
$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$
$S_{sLL} = 6.7970 \cdot 10^3 + 1.6992 \cdot 10^3 j \cdot VA$
$P_{sLL} := 3 \cdot Re(S_{sLL})$
$S_{rLL} := V_{ri} \cdot \overline{I_{ri}}$
$P_{rLL} := 3 \cdot Re(S_{rLL})$
$P_{lossLL} := P_{sLL} - P_{rLL}$
$P_{lossLL} = 1.2692 \cdot 10^3 \cdot kW$

$V_{sML}(l \cdot mi) = 87.3381 + 11.7111j \cdot kV$
$|V_{sML}(l \cdot mi)| = 88.1197 \cdot kV$
$\arg(V_{sML}(l \cdot mi)) = 7.6372 \cdot deg$
$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$
$S_{sML} = 6.7779 \cdot 10^3 - 1.6103 \cdot 10^3 j \cdot VA$
$P_{sML} := 3 \cdot Re(S_{sML})$
$S_{rML} := V_{ri} \cdot \overline{I_{ri}}$
$P_{rML} := 3 \cdot Re(S_{rML})$
$P_{lossML} := P_{sML} - P_{rML}$
$P_{lossML} = 1.2118 \cdot 10^3 \cdot kW$

345 kV

For 345 kV load and 22 ft, 22 ft, 44 ft phase spacing and 1.5 ft bundle spacing for two conductor bundle per phase

Enter the conductor variables and phase spacing and bundle spacing without units to calculate conductor physical parameters:

$D_{ab} := 22 ft$ $D_{ac} := 22 ft$ $D_{bc} := 44 ft$ $D_s := 0.0243 ft$ $r := 0.0300 ft$
$n := 2$ $d := 1.5 ft$ $f := 60 Hz$ $R := .3006 \Omega/mile$

Which calculates the line impedance, characteristic impedance, admittance, and propagation constant.

$D_{eq}(D_{ab},D_{ac},D_{bc}) = 27.7183 \cdot ft$ $D_{sl}(d,n,D_s) = 0.1909 \cdot ft$ $D_{sc}(d,n,r) = 0.2121 \cdot ft$

$x_l(D_{ab},D_{ac},D_{bc},d,n,D_s) = 0.6038j \cdot \frac{\Omega}{mi}$

$y(D_{ab},D_{ac},D_{bc},d,n,r) = 6.9217 \cdot 10^{-6} j \cdot \frac{siemens}{mi}$

$x_{cn}(D_{ab},D_{ac},D_{bc},d,n,r) = -1.4447 \cdot 10^5 j \cdot \Omega \cdot mi$

$\gamma(R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) = 2.5252 \cdot 10^{-4} + 0.0021j \cdot \frac{1}{mi}$

$z(R,D_{ab},D_{ac},D_{bc},d,n,D_s) = 0.1503 + 0.6038j \cdot \frac{\Omega}{mi}$

$Z_c(R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r) = 297.6049 - 36.4819j \cdot \Omega$

Input the load terminal line to line voltage, voltage phase angle, load line current, and power factor angle without units in the values shown:

$v_{ri} := 345 kV$ $\delta_{ri} := 0 deg$ $i_{ri} := .100 kA$ $\theta_{ri} := -36.87 deg$

Calculated load terminal phase voltage

$V_{ri} := \frac{v_{ri}}{\sqrt{3}} \cdot e^{j \cdot \delta_{ri} \cdot deg} \cdot kV$

$V_{ri} = 199.1858 \cdot kV$

Calculated load phase current

$I_{ri} := i_{ri} \cdot e^{j \cdot \theta_{ri} \cdot deg} \cdot kA$

$I_{ri} = 0.0800 - 0.0600j \cdot kA$

The long line supply voltage and current are calculated as:

$V_{sLL}(1) := V_{ri} \cdot A_a(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{ri} \cdot B_b(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,R,r)$
$I_{sLL}(1) := I_{ri} \cdot D_d(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{ri} \cdot C_c(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The medium line supply voltage and current are calculated as:

$V_{sML}(1) := V_{ri} \cdot A(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + I_{ri} \cdot B(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s)$
$I_{sML}(1) := I_{ri} \cdot D(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r) + V_{ri} \cdot C(1,R,D_{ab},D_{ac},D_{bc},d,n,D_s,r)$

The transmission line power loss is calculated by entering the transmission length in miles without units as:

At 50 miles

$l := 50$

Long Line Equivalent

$V_{sLL}(l \cdot mi) = 200.5537 + 2.2206j \cdot kV$
$|V_{sLL}(l \cdot mi)| = 200.5660 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 0.6344 \cdot deg$
$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$
$S_{sLL} = 1.5991 \cdot 10^4 - 1.6747 \cdot 10^3 j \cdot VA$
$P_{sLL} := 3 \cdot Re(S_{sLL})$
$S_{rLL} := V_{ri} \cdot \overline{I_{ri}}$
$P_{rLL} := 3 \cdot Re(S_{rLL})$
$P_{lossLL} := P_{sLL} - P_{rLL}$
$P_{lossLL} = 167.4330 \cdot kW$

Medium Line Equivalent

$V_{sML}(l \cdot mi) = 200.5579 + 2.2234j \cdot kV$
$|V_{sML}(l \cdot mi)| = 200.5702 \cdot kV$
$\arg(V_{sML}(l \cdot mi)) = 0.6352 \cdot deg$
$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$
$S_{sML} = 1.5988 \cdot 10^4 - 1.6625 \cdot 10^3 j \cdot VA$
$P_{sML} := 3 \cdot Re(S_{sML})$
$S_{rML} := V_{ri} \cdot \overline{I_{ri}}$
$P_{rML} := 3 \cdot Re(S_{rML})$
$P_{lossML} := P_{sML} - P_{rML}$
$P_{lossML} = 158.9851 \cdot kW$

At 100 miles

$l := 100$

$V_{sLL}(l \cdot mi) = 199.8220 + 4.9387j \cdot kV$
$|V_{sLL}(l \cdot mi)| = 199.8830 \cdot kV$
$\arg(V_{sLL}(l \cdot mi)) = 1.4158 \cdot deg$

$V_{sML}(l \cdot mi) = 199.8487 + 4.9649j \cdot kV$
$|V_{sML}(l \cdot mi)| = 199.9104 \cdot kV$
$\arg(V_{sML}(l \cdot mi)) = 1.4231 \cdot deg$

$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$

$S_{sLL} = 1.6055 \cdot 10^4 - 1.5314 \cdot 10^4 j \cdot VA$

$P_{sLL} := 3 \cdot Re(S_{sLL})$

$S_{rLL} := V_{rl} \cdot \overline{I_{rl}}$

$P_{rLL} := 3 \cdot Re(S_{rLL})$

$P_{lossLL} := P_{sLL} - P_{rLL}$

$P_{lossLL} = 361.0161 \cdot kW$

$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$

$S_{sML} = 1.6032 \cdot 10^4 - 1.5219 \cdot 10^4 j \cdot VA$

$P_{sML} := 3 \cdot Re(S_{sML})$

$S_{rML} := V_{rl} \cdot \overline{I_{rl}}$

$P_{rML} := 3 \cdot Re(S_{rML})$

$P_{lossML} := P_{sML} - P_{rML}$

$P_{lossML} = 292.1748 \cdot kW$

At 200 miles

$l := 200$

$V_{sLL}(l \cdot mi) = 192.0827 + 11.7361j \cdot kV$

$|V_{sLL}(l \cdot mi)| = 192.4409 \cdot kV$

$\arg(V_{sLL}(l \cdot mi)) = 3.4964 \cdot deg$

$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$

$S_{sLL} = 1.6490 \cdot 10^4 - 4.0384 \cdot 10^4 j \cdot VA$

$P_{sLL} := 3 \cdot Re(S_{sLL})$

$S_{rLL} := V_{rl} \cdot \overline{I_{rl}}$

$P_{rLL} := 3 \cdot Re(S_{rLL})$

$P_{lossLL} := P_{sLL} - P_{rLL}$

$P_{lossLL} = 1.6664 \cdot 10^3 \cdot kW$

$V_{sML}(l \cdot mi) = 192.1866 + 12.0021j \cdot kV$

$|V_{sML}(l \cdot mi)| = 192.5610 \cdot kV$

$\arg(V_{sML}(l \cdot mi)) = 3.5735 \cdot deg$

$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$

$S_{sML} = 1.6310 \cdot 10^4 - 3.9671 \cdot 10^4 j \cdot VA$

$P_{sML} := 3 \cdot Re(S_{sML})$

$S_{rML} := V_{rl} \cdot \overline{I_{rl}}$

$P_{rML} := 3 \cdot Re(S_{rML})$

$P_{lossML} := P_{sML} - P_{rML}$

$P_{lossML} = 1.1240 \cdot 10^3 \cdot kW$

500 kV

For 500 kV load and 30 ft, 30 ft, 60 ft phase spacing and 1.5 ft bundle spacing for a three conductor bundle per phase

Therefore enter the conductor variables and phase spacing and bundle spacing without units to calculate conductor physical parameters:

$D_{ab} := 30\ ft$ $D_{ac} := 30\ ft$ $D_{bc} := 60\ ft$ $D_s := 0.0243\ ft$ $r := 0.0300\ ft$

$n := 3$ $d := 1.5\ ft$ $f := 60\ Hz$ $R := .3006\ \Omega/mile$

Which calculates the line impedance, characteristic impedance, admittance, and propagation constant.

$D_{eq}(D_{ab}, D_{ac}, D_{bc}) = 37.7976 \cdot ft$ $D_{sl}(d,n,D_s) = 0.3795 \cdot ft$ $D_{sc}(d,n,r) = 0.4072 \cdot ft$

$x_l(D_{ab}, D_{ac}, D_{bc}, d, n, D_s) = 0.5581j \cdot \frac{\Omega}{mi}$

$y(D_{ab}, D_{ac}, D_{bc}, d, n, r) = 7.4439 \cdot 10^{-6} j \cdot \frac{siemens}{mi}$

$x_{cn}(D_{ab}, D_{ac}, D_{bc}, d, n, r) = -1.3434 \cdot 10^5 j \cdot \Omega \cdot mi$

$\gamma(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) = 1.8224 \cdot 10^{-4} + 0.0020j \cdot \frac{1}{mi}$

$z(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s) = 0.1002 + 0.5581j \cdot \frac{\Omega}{mi}$

$Z_c(R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, R, r) = 274.9073 - 24.4822j \cdot \Omega$

Input the load terminal line to line voltage, voltage phase angle, load line current, and power factor angle without units in the values shown:

$v_{rl} := 500\ kV$ $\delta_{rl} := 0\ deg$ $i_{rl} := .100\ kA$ $\theta_{rl} := -36.87\ deg$

Calculated load terminal phase voltage

$V_{rl} := \frac{v_{rl}}{\sqrt{3}} \cdot e^{j \cdot \delta_{rl} \cdot deg} \cdot kV$

$V_{rl} = 288.6751 \cdot kV$

Calculated load phase current

$I_{rl} := i_{rl} \cdot e^{j \cdot \theta_{rl} \cdot deg} \cdot kA$

$I_{rl} = 0.0800 - 0.0600j \cdot kA$

The long line supply voltage and current are calculated as:

$V_{sLL}(1) := V_{rl} \cdot A_a(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + I_{rl} \cdot B_b(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, R, r)$

$I_{sLL}(1) := I_{rl} \cdot D_d(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + V_{rl} \cdot C_c(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r)$

The medium line supply voltage and current are calculated as:

$V_{sML}(1) := V_{rl} \cdot A(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + I_{rl} \cdot B(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s)$

$I_{sML}(1) := I_{rl} \cdot D(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r) + V_{rl} \cdot C(1, R, D_{ab}, D_{ac}, D_{bc}, d, n, D_s, r)$

The transmission line power loss is calculated by entering the transmission length in miles without units as:

At 50 miles

Long Line Equivalent $l := 50$

$V_{sLL}(l \cdot mi) = 289.2482 + 2.1978j \cdot kV$

$|V_{sLL}(l \cdot mi)| = 289.2565 \cdot kV$

$\arg(V_{sLL}(l \cdot mi)) = 0.4353 \cdot deg$

$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$

Medium Line Equivalent

$V_{sML}(l \cdot mi) = 289.2511 + 2.2010j \cdot kV$

$|V_{sML}(l \cdot mi)| = 289.2595 \cdot kV$

$\arg(V_{sML}(l \cdot mi)) = 0.4360 \cdot deg$

$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$

$S_{sLL} = 2.3131 \cdot 10^4 - 1.3606 \cdot 10^4 j \cdot VA$

$P_{sLL} := 3 \cdot Re(S_{sLL})$

$S_{rLL} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rLL} := 3 \cdot Re(S_{rLL})$

$P_{lossLL} := P_{sLL} - P_{rLL}$

$P_{lossLL} = 110.9790 \cdot kW$

$S_{sML} = 2.3126 \cdot 10^4 - 1.3579 \cdot 10^4 j \cdot VA$

$P_{sML} := 3 \cdot Re(S_{sML})$

$S_{rML} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rML} := 3 \cdot Re(S_{rML})$

$P_{lossML} := P_{sML} - P_{rML}$

$P_{lossML} = 96.7842 \cdot kW$

At 100 miles

$l := 100$

$V_{sLL}(l \cdot mi) = 286.8155 + 4.9112j \cdot kV$

$|V_{sLL}(l \cdot mi)| = 286.8575 \cdot kV$

$\arg(V_{sLL}(l \cdot mi)) = 0.9810 \cdot deg$

$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$

$S_{sLL} = 2.3219 \cdot 10^4 - 4.4055 \cdot 10^4 j \cdot VA$

$P_{sLL} := 3 \cdot Re(S_{sLL})$

$S_{rLL} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rLL} := 3 \cdot Re(S_{rLL})$

$P_{lossLL} := P_{sLL} - P_{rLL}$

$P_{lossLL} = 373.7367 \cdot kW$

$V_{sML}(l \cdot mi) = 286.8289 + 4.9402j \cdot kV$

$|V_{sML}(l \cdot mi)| = 286.8714 \cdot kV$

$\arg(V_{sML}(l \cdot mi)) = 0.9867 \cdot deg$

$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$

$S_{sML} = 2.3181 \cdot 10^4 - 4.3843 \cdot 10^4 j \cdot VA$

$P_{sML} := 3 \cdot Re(S_{sML})$

$S_{rML} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rML} := 3 \cdot Re(S_{rML})$

$P_{lossML} := P_{sML} - P_{rML}$

$P_{lossML} = 260.0452 \cdot kW$

At 200 miles

$l := 200$

$V_{sLL}(l \cdot mi) = 273.0436 + 11.7436j \cdot kV$

$|V_{sLL}(l \cdot mi)| = 273.2961 \cdot kV$

$\arg(V_{sLL}(l \cdot mi)) = 2.4628 \cdot deg$

$S_{sLL} := V_{sLL}(l \cdot mi) \cdot \overline{I_{sLL}(1)}$

$S_{sLL} = 2.3992 \cdot 10^4 - 9.8552 \cdot 10^4 j \cdot VA$

$P_{sLL} := 3 \cdot Re(S_{sLL})$

$S_{rLL} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rLL} := 3 \cdot Re(S_{rLL})$

$P_{lossLL} := P_{sLL} - P_{rLL}$

$V_{sML}(l \cdot mi) = 272.9897 + 12.0336j \cdot kV$

$|V_{sML}(l \cdot mi)| = 273.2548 \cdot kV$

$\arg(V_{sML}(l \cdot mi)) = 2.5240 \cdot deg$

$S_{sML} := V_{sML}(l \cdot mi) \cdot \overline{I_{sML}(1)}$

$S_{sML} = 2.3703 \cdot 10^4 - 9.6902 \cdot 10^4 j \cdot VA$

$P_{sML} := 3 \cdot Re(S_{sML})$

$S_{rML} := V_{ri} \cdot \overline{I_{ri}}$

$P_{rML} := 3 \cdot Re(S_{rML})$

$P_{lossML} := P_{sML} - P_{rML}$

$P_{lossLL} = 2.6932 \cdot 10^3 \cdot kW$

$P_{lossML} = 1.8270 \cdot 10^3 \cdot kW$

Note from authors:

Notice first that as the lines get longer the long line equivalent circuit yields answers that depart significantly from medium length line approximations. Otherwise the long line equivalent circuit would not be necessary.

Notice also that the losses at 200 miles at 345 kV and 500 kV at a receiving current of 100 A are higher than the losses at 200 miles at lower voltages. The additional capacitance at the higher voltages with bundled conductors causes incremental current increases along the line that cause higher losses. Doing the problem over with the receiving current at 300 A (a simple procedure using the Mathcad program, just change the value of $I_{receiving}$) results in losses that are lowest at the highest voltages at any distance in the problem as the table below shows. 300 A is too high for this conductor at the lower voltages, but this illustrates the principle.

Line losses with the receiving current = 300 A

Voltage	Line length (mil)	Long Line Equivalent (kW)	Medium Line Equivalent (kW)
69 kV	50	3965	3970
	100	7663	7666
	200	14120	14877
138 kV	50	3880	3892
	100	7838	7472
	200	13215	13817
345 kV	50	1779	1776
	100	3184	3153
	200	5698	5354
500 kV	50	1116	1105
	100	1982	1890
	200	4333	3536

LMF & WC

APPENDIX E

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