TABLE 4-4 TYPICAL BASIC INSULATION LEVELS*

Voltage class, kV	Basic insulation level, kV (standard 1.5- × 40-μs wave)	
	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.

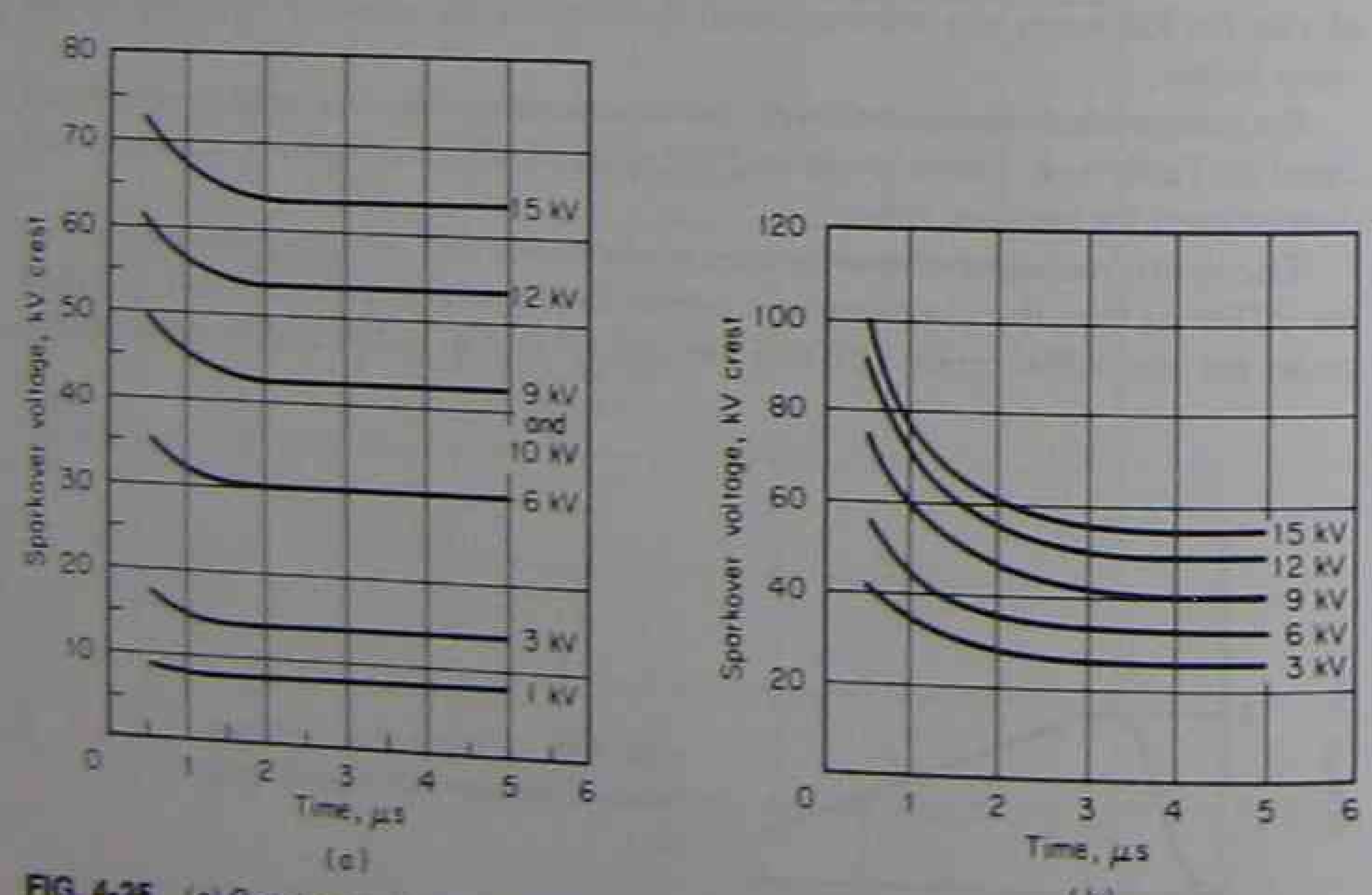


FIG. 4-25 (a) Sparkover characteristics of distribution valve arresters. (b) Sparkover characteristics of expulsion arresters. (Courtesy McGraw Edison Co.)

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:

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

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

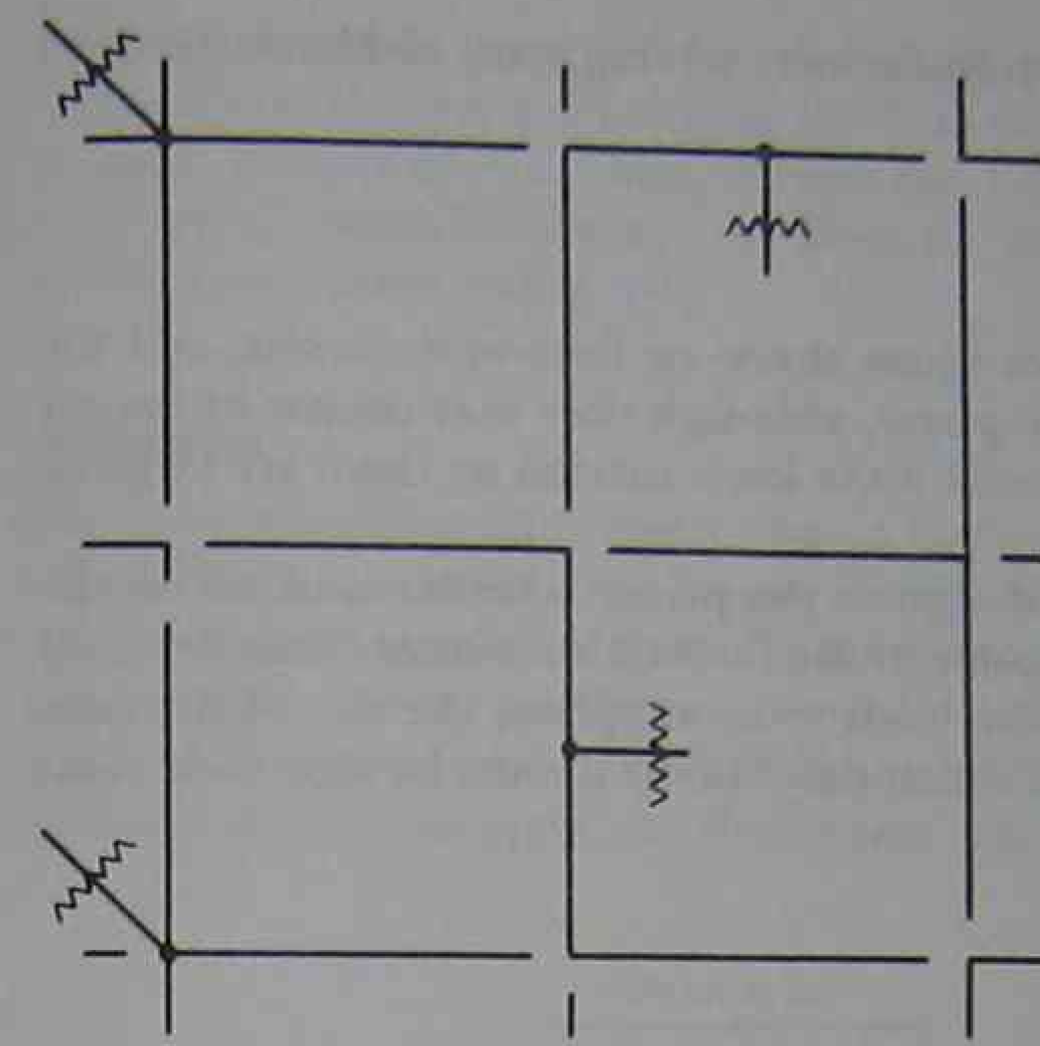


FIG. 4-2 Division of network into radial secondary circuits for design analysis.

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.

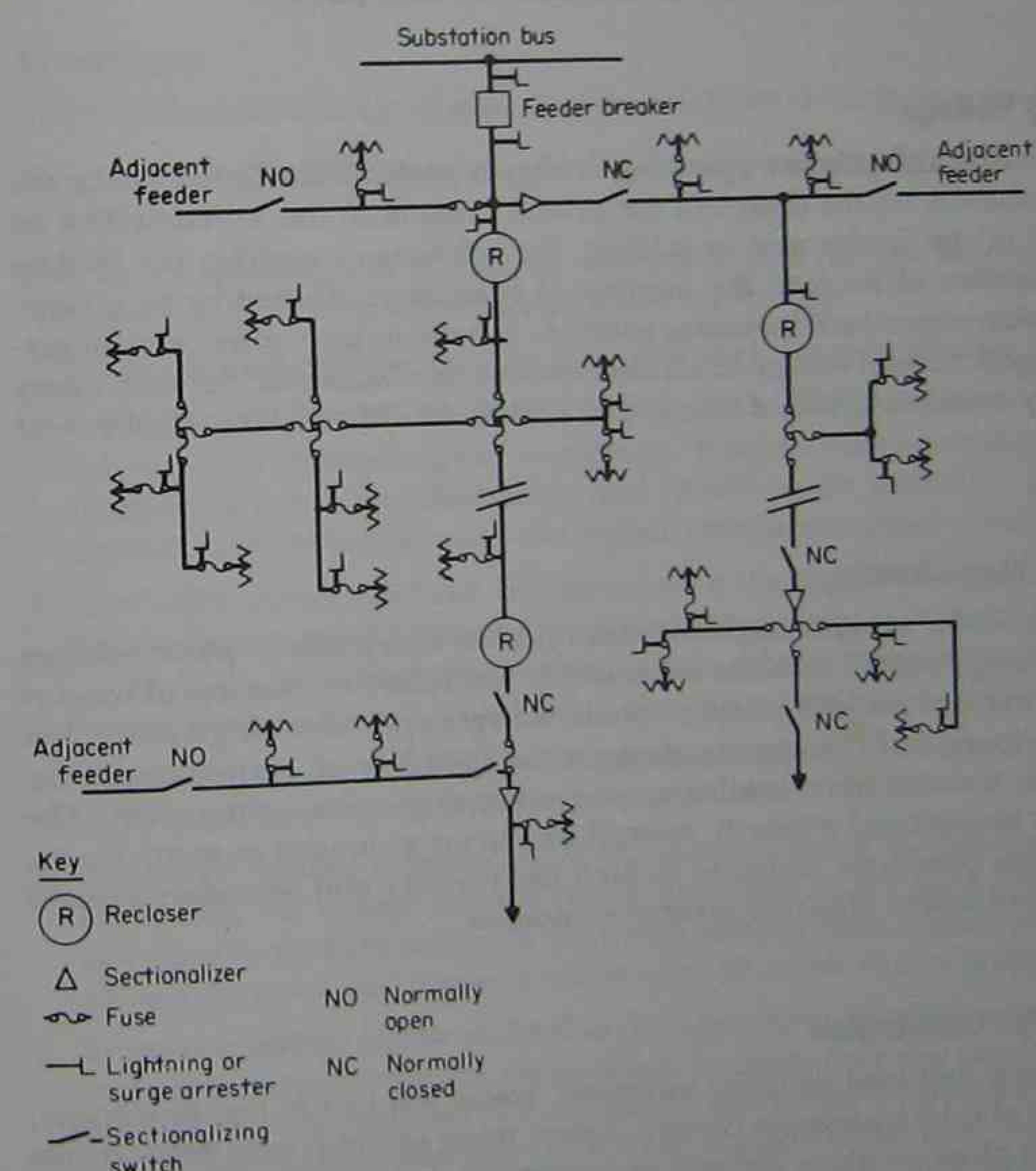


FIG. 4-3 Radial primary feeder showing location of protective devices.

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.

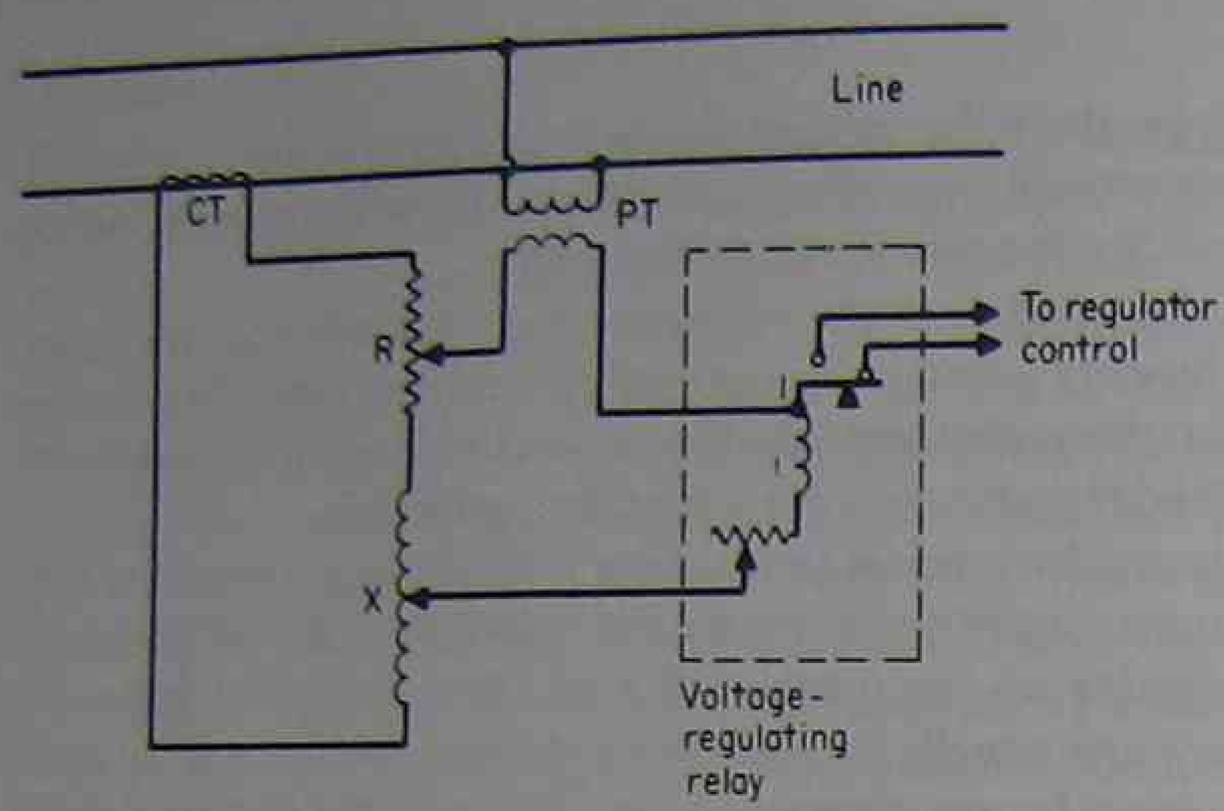


FIG. 4-4 Schematic diagram of line-drop compensator and voltage-regulating relay.

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

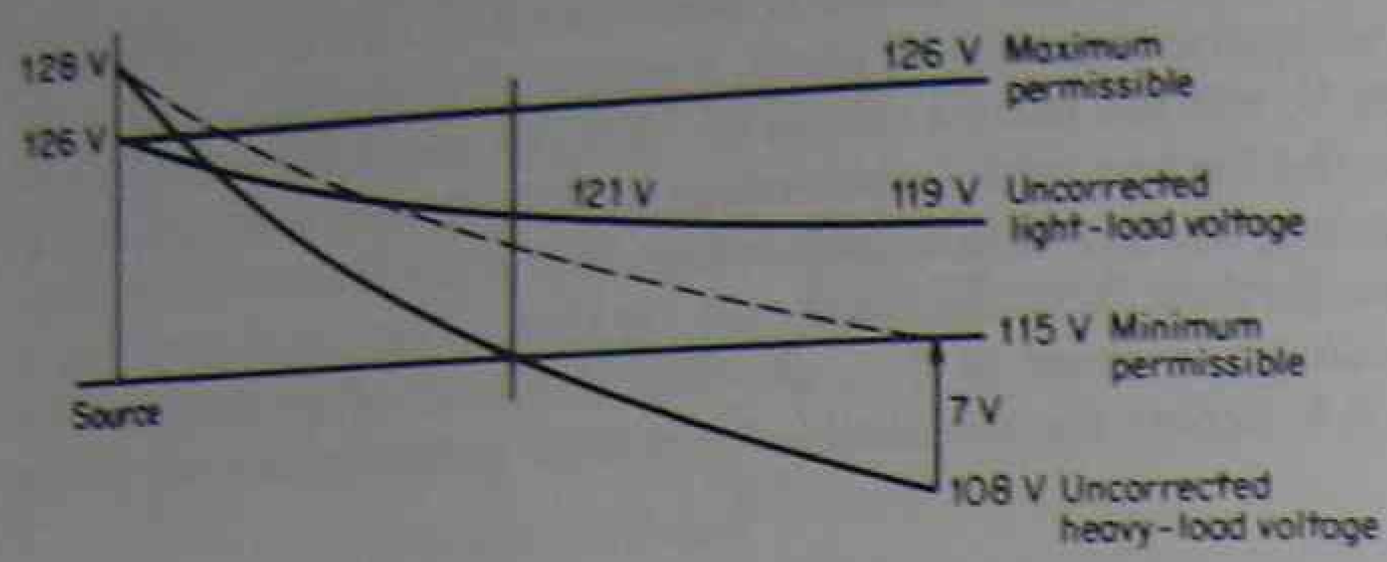


FIG. 4-5 Voltage improvement using capacitors.

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 the 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.

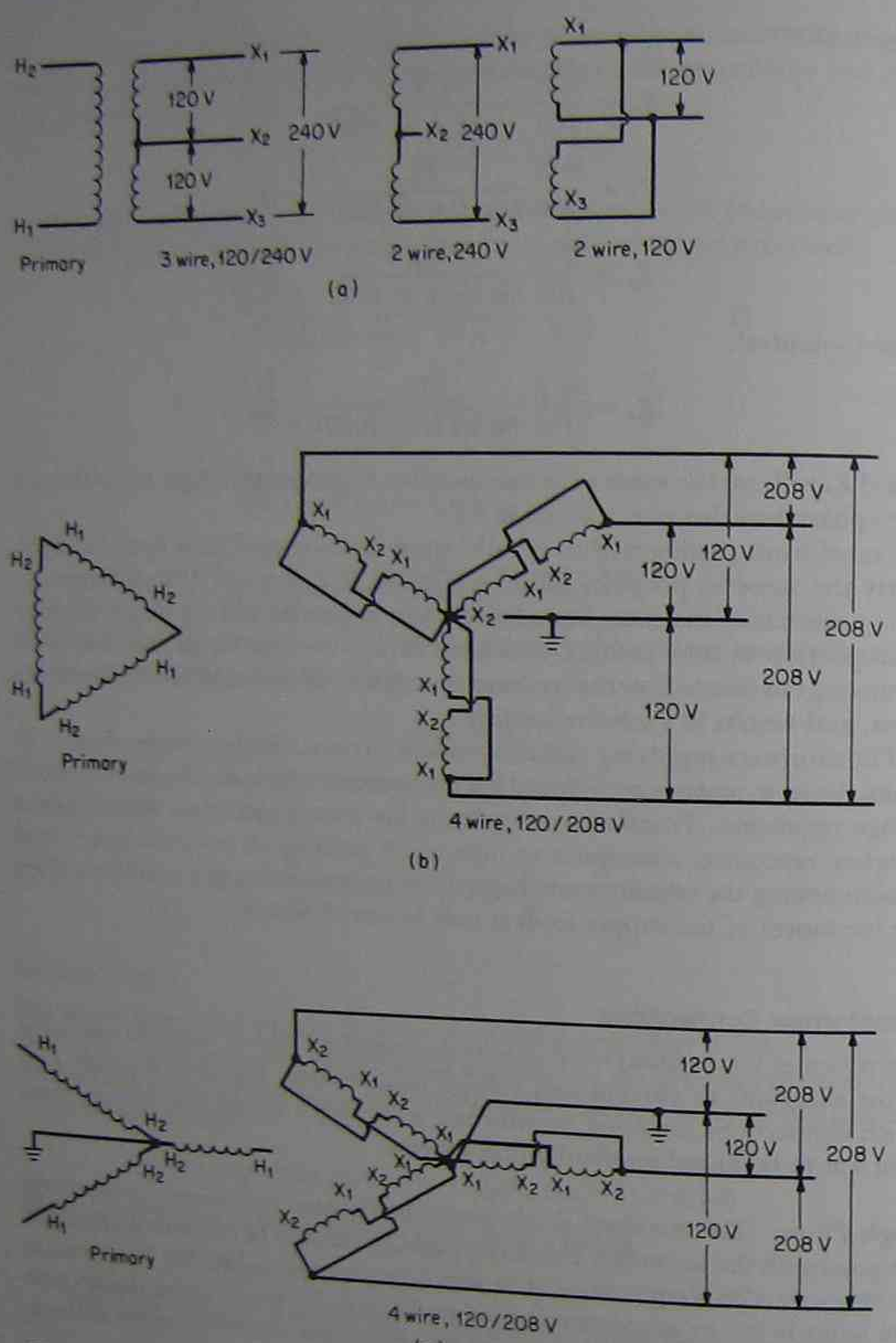
Transformers supplying radial secondary circuits, whether single-phase or in banks, have a reactance of from 3 to 5 percent, which results in reasonable voltage regulation. Transformers supplying low-voltage secondary networks have a higher reactance, sometimes as high as 10 percent, to ensure a better 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



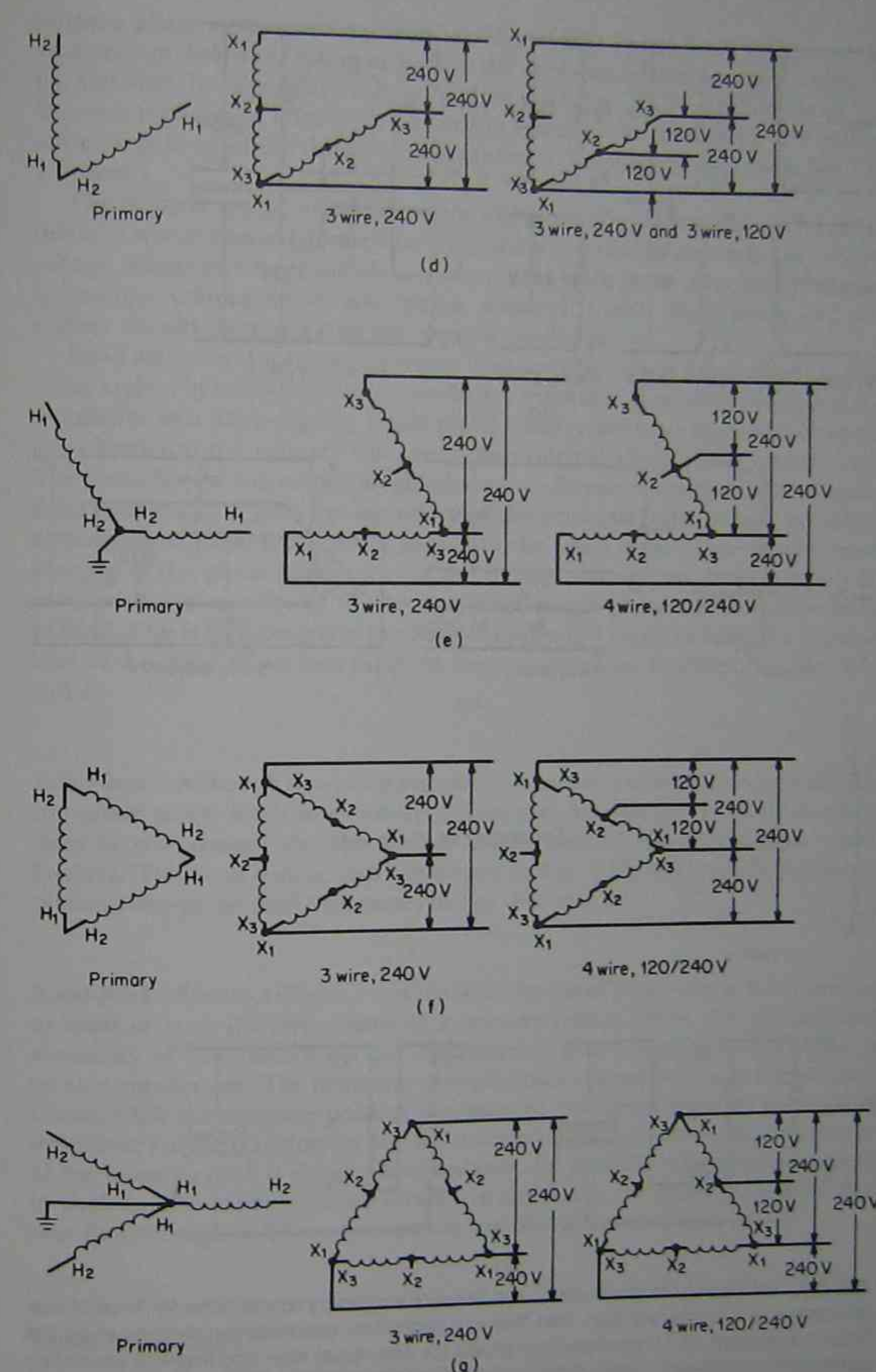


FIG. 4-6 (a) Single-phase two- and three-wire secondary connections. (b) Three-phase delta-to-wye four-wire secondary connection. (c) Three-phase wye-to-wye four-wire secondary connection. (d) Three-phase open delta three- and four-wire secondary connections. (e) Three-phase open wye–open delta three-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

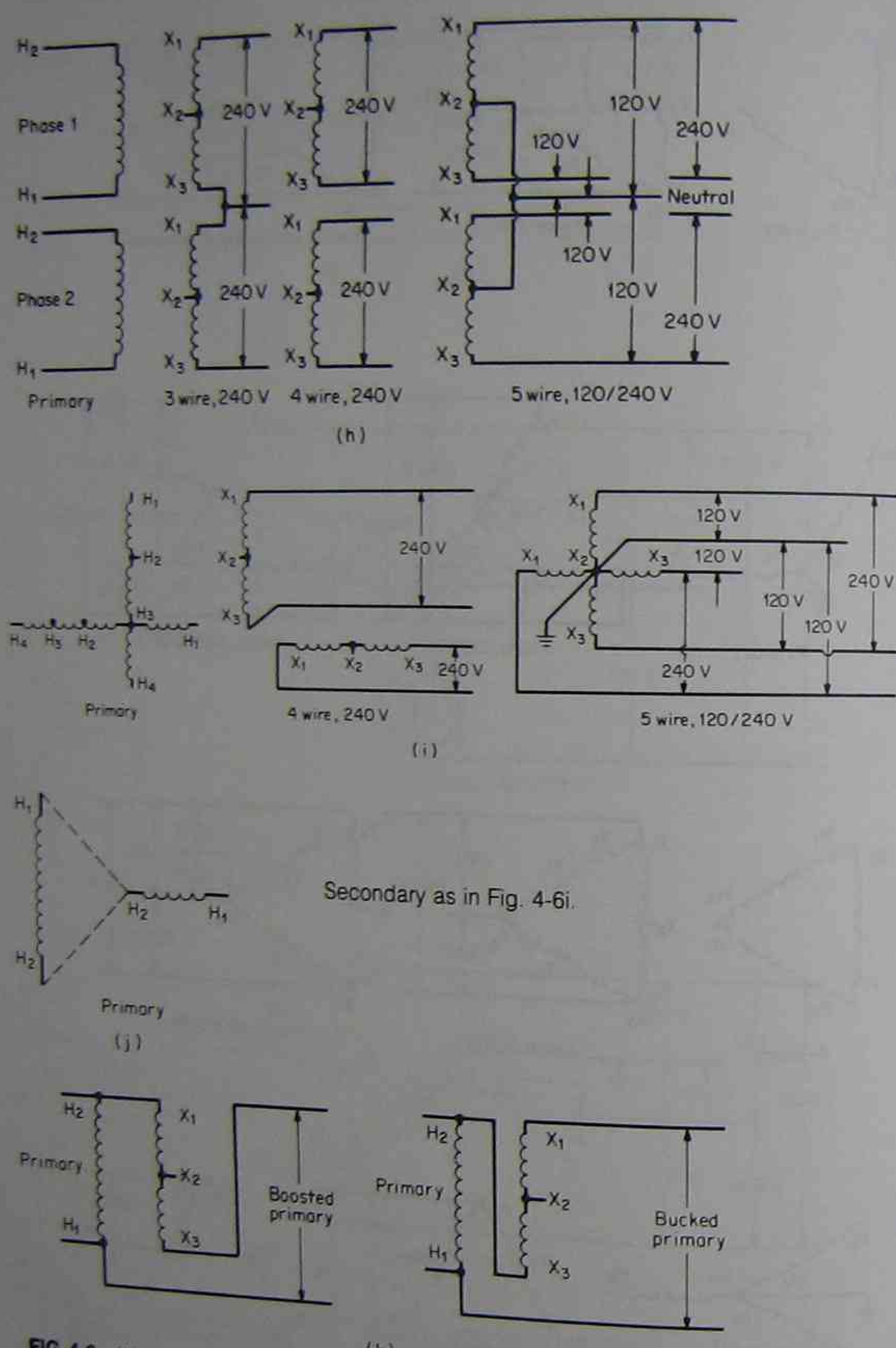


FIG. 4-6 (*h*) Two-phase three-, four-, and five-wire secondary connections. (*i*) Three-phase/two-phase (or vice versa) four- and five-wire secondary connections (also known as the Scott connection). (*j*) Three-phase/two-phase (or vice versa) four- and five-wire secondary connection. Secondary connections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

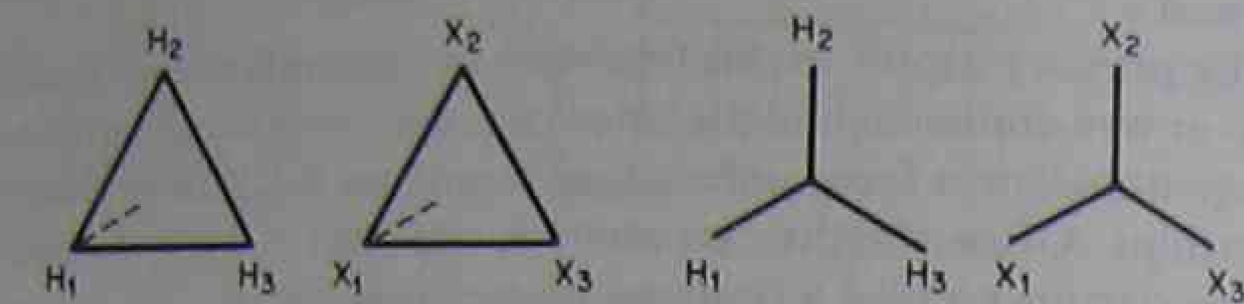
Three-Phase Units

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

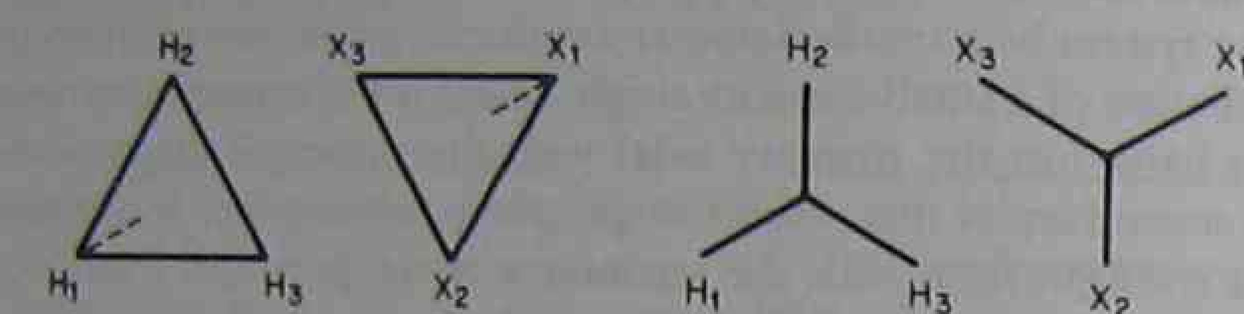
TABLE 4-2 IEEE CLASSIFICATION OF POLARITIES OF THREE-PHASE TRANSFORMERS

Three-phase transformers without taps

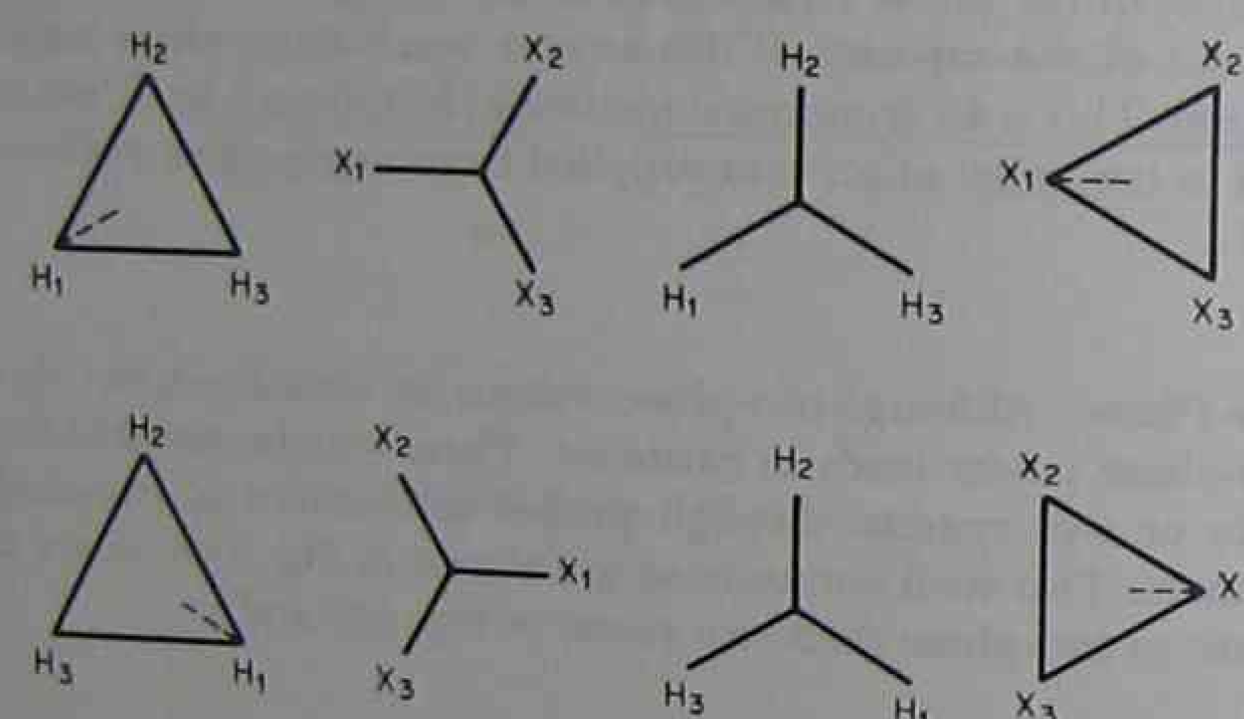
Group 1:
angular
displacement
0°



Group 2:
angular
displacement
180°

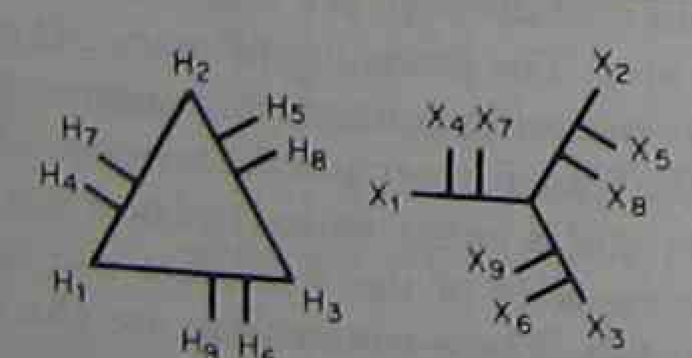


Group 3:
angular
displacement
30°



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

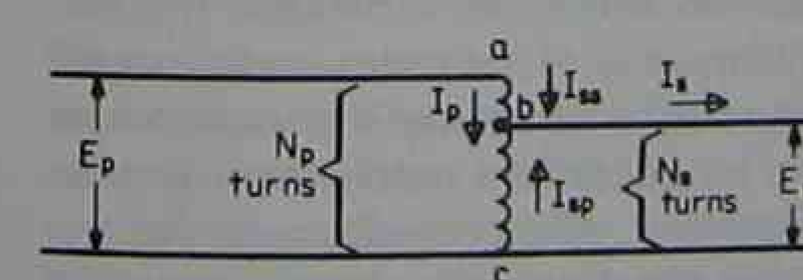


FIG. 4-7 Autotransformer.

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 transformer 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*,

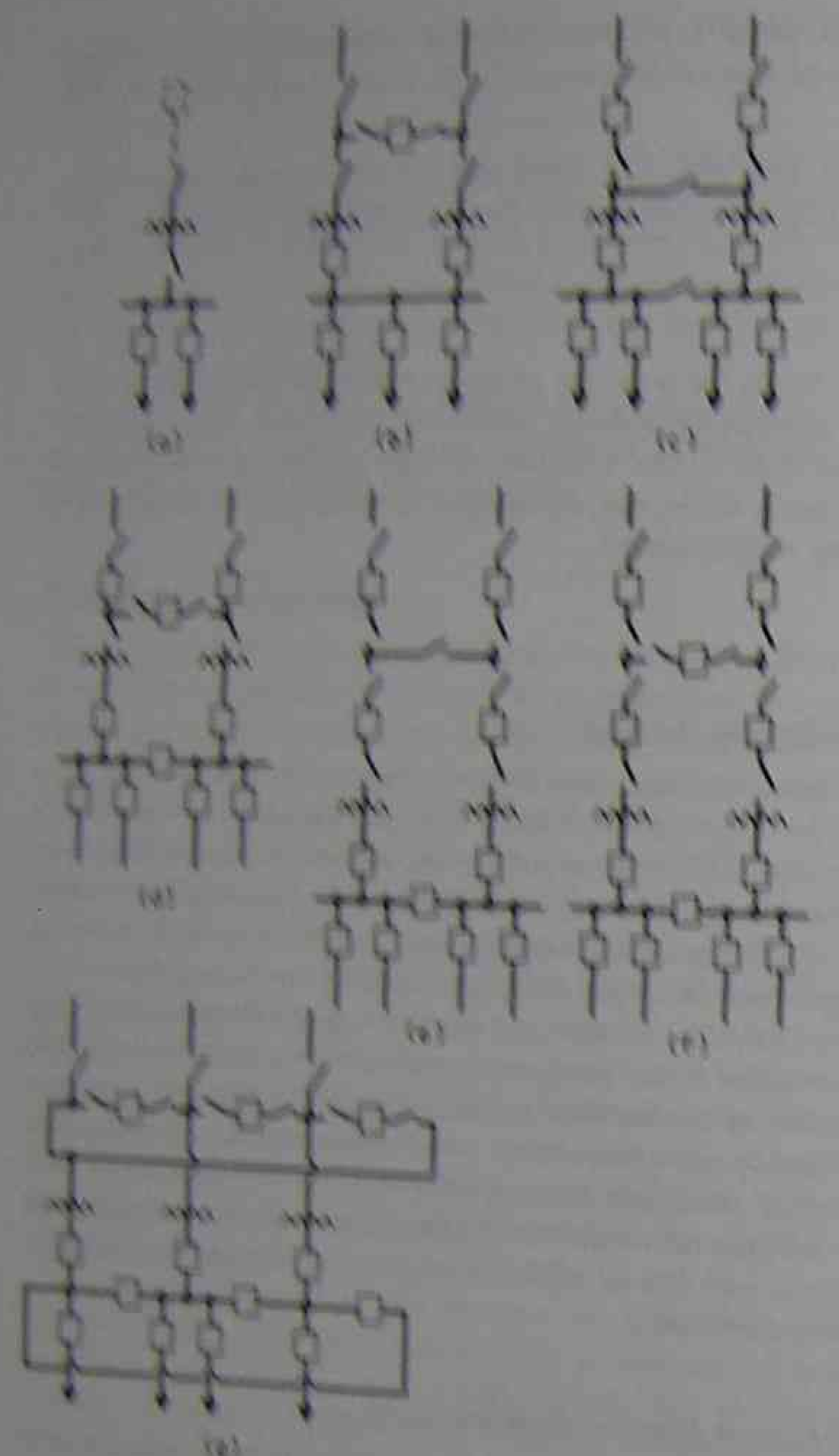


FIG. 4-8 Incoming feeder circuit breaker arrangements.

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, 33-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

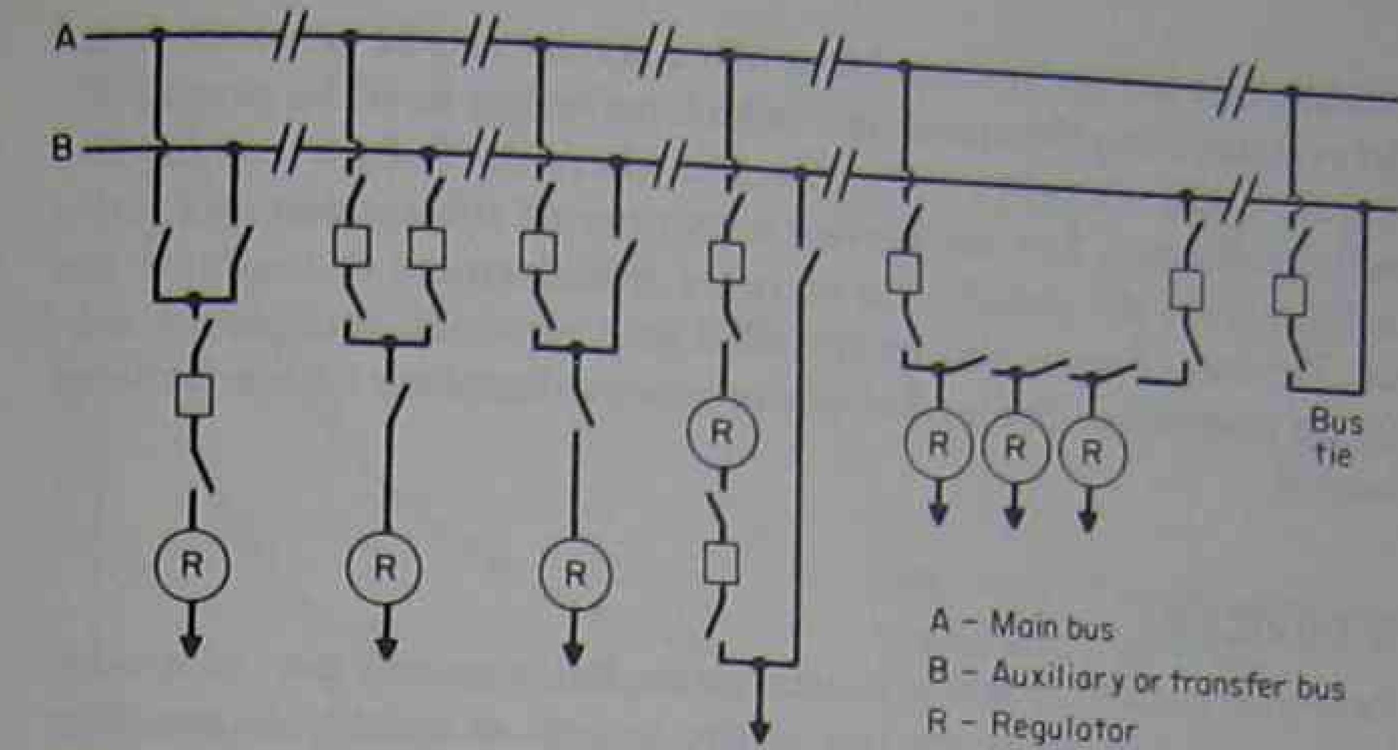


FIG. 4-9 Arrangement of distribution feeder buses at substations (see also Fig. 4-8).

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

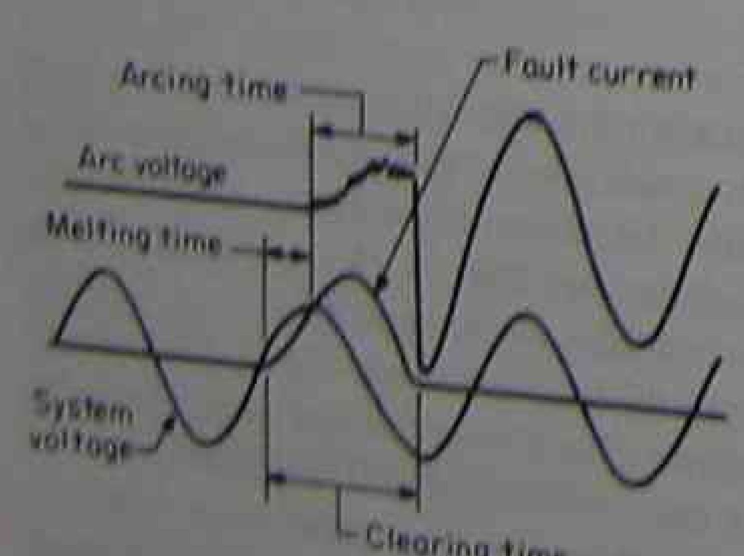


FIG. 4-10 Oscillogram of link melting and fault current interruption. *(Courtesy McGraw Edison Co.)*

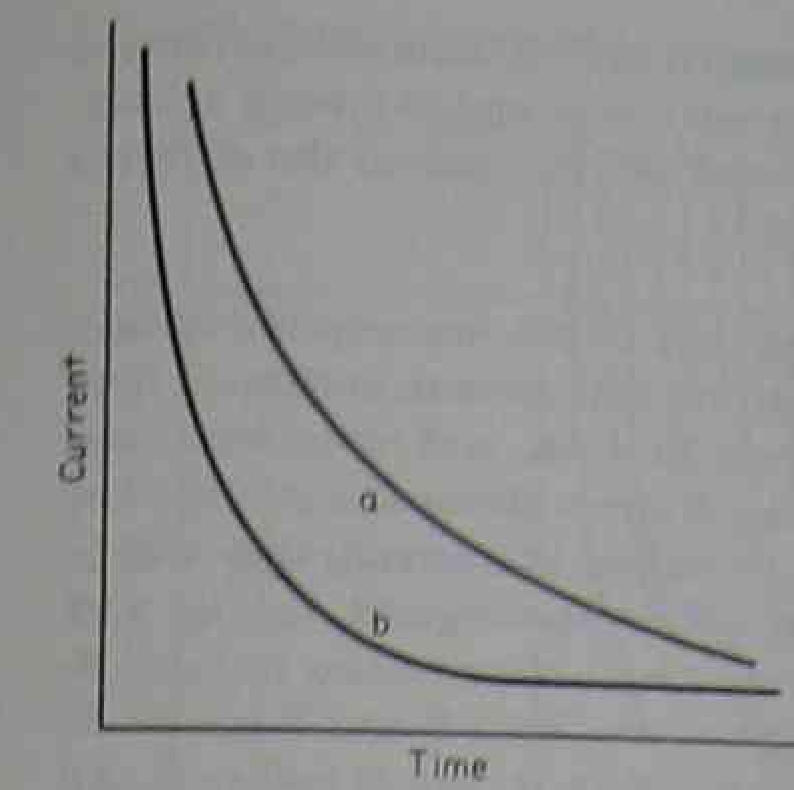


FIG. 4-11 Typical time-current characteristic for fuses.

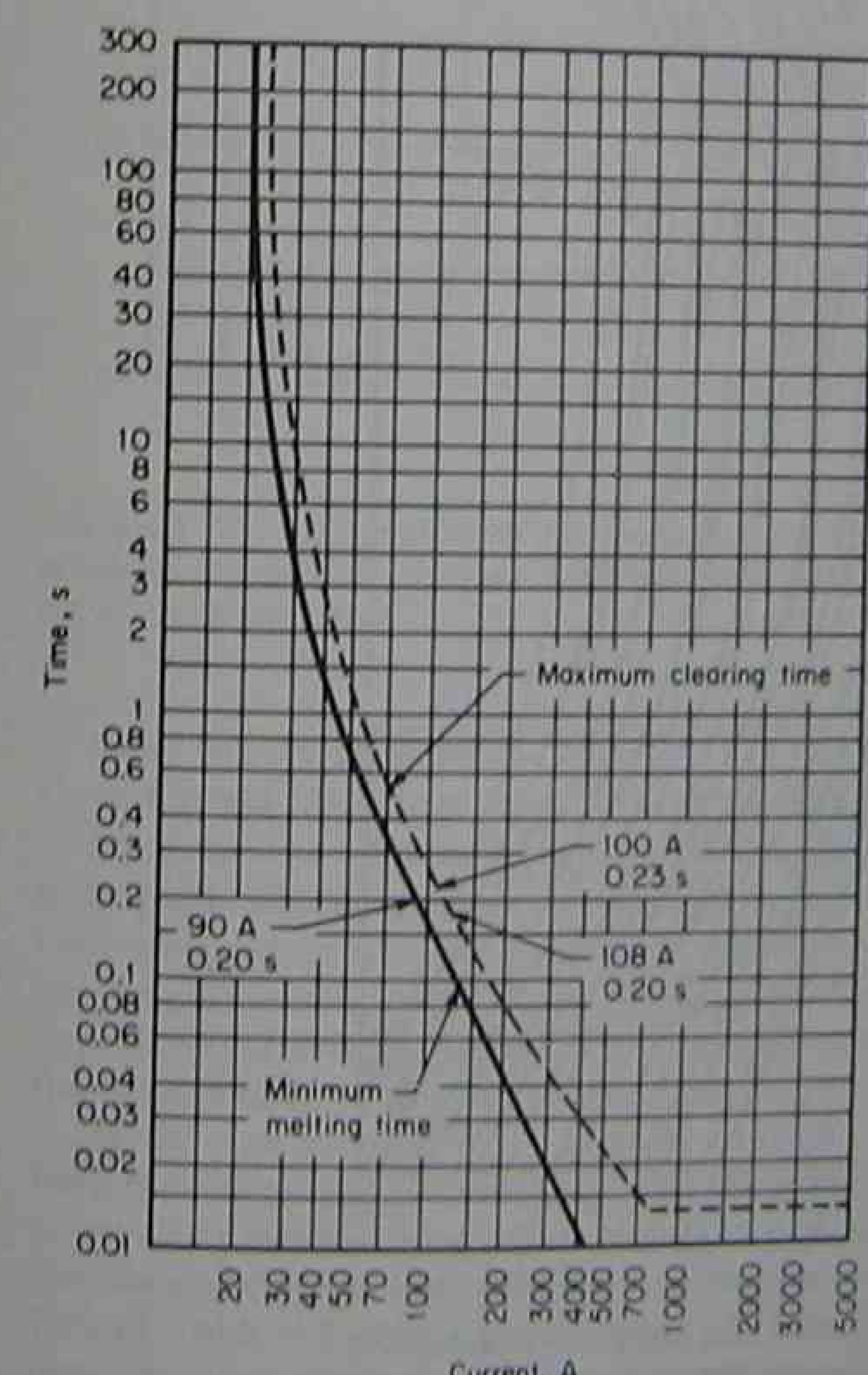


FIG. 4-12 Typical time-current characteristic for a 10-K fuse link. *(Courtesy McGraw Edison Co.)*

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

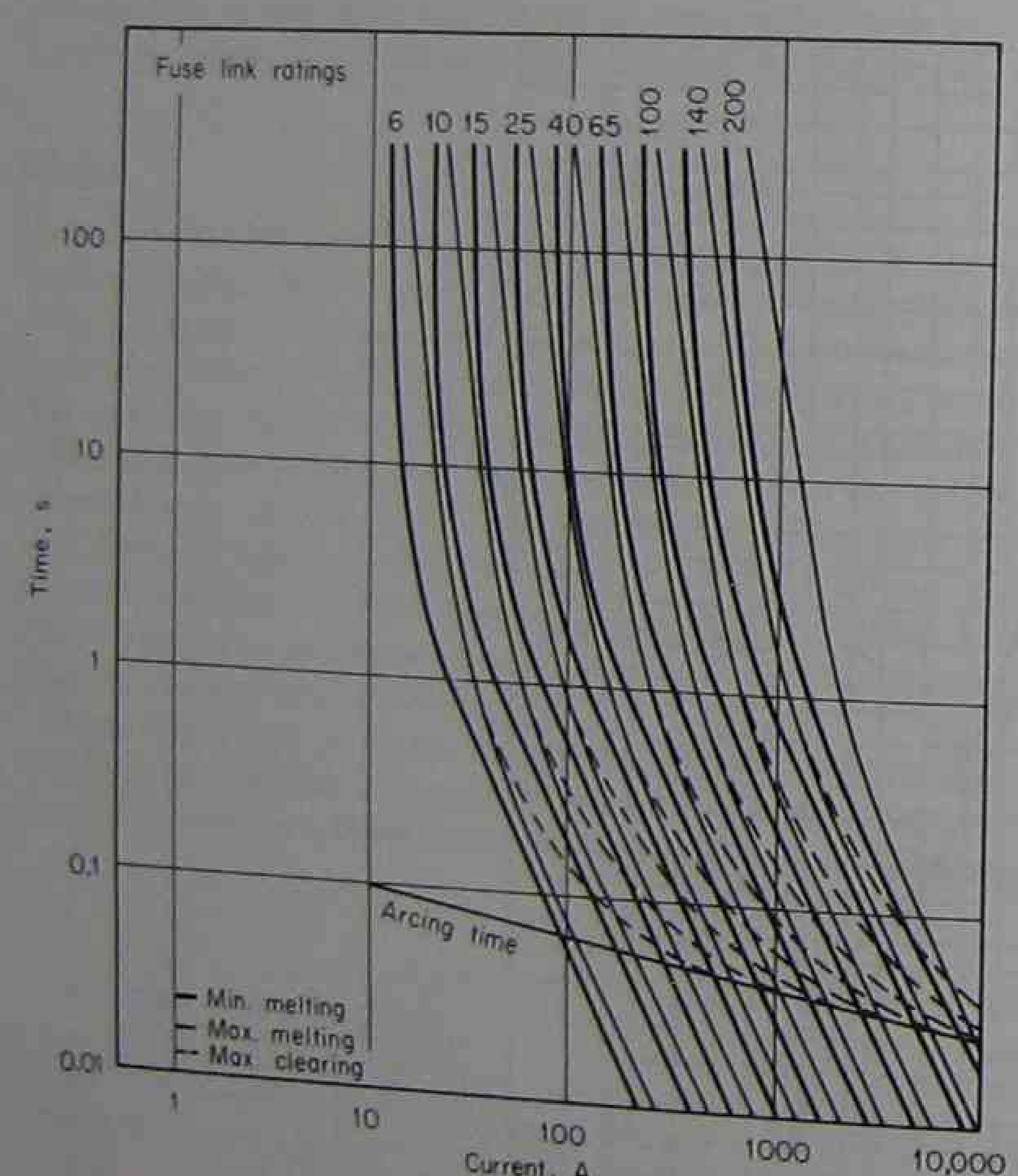


FIG. 4-13 (a) "Representative" minimum and maximum time-current characteristic curves for EEI-NEMA type K (fast) fuse links. *(Courtesy Westinghouse Electric Co.)*

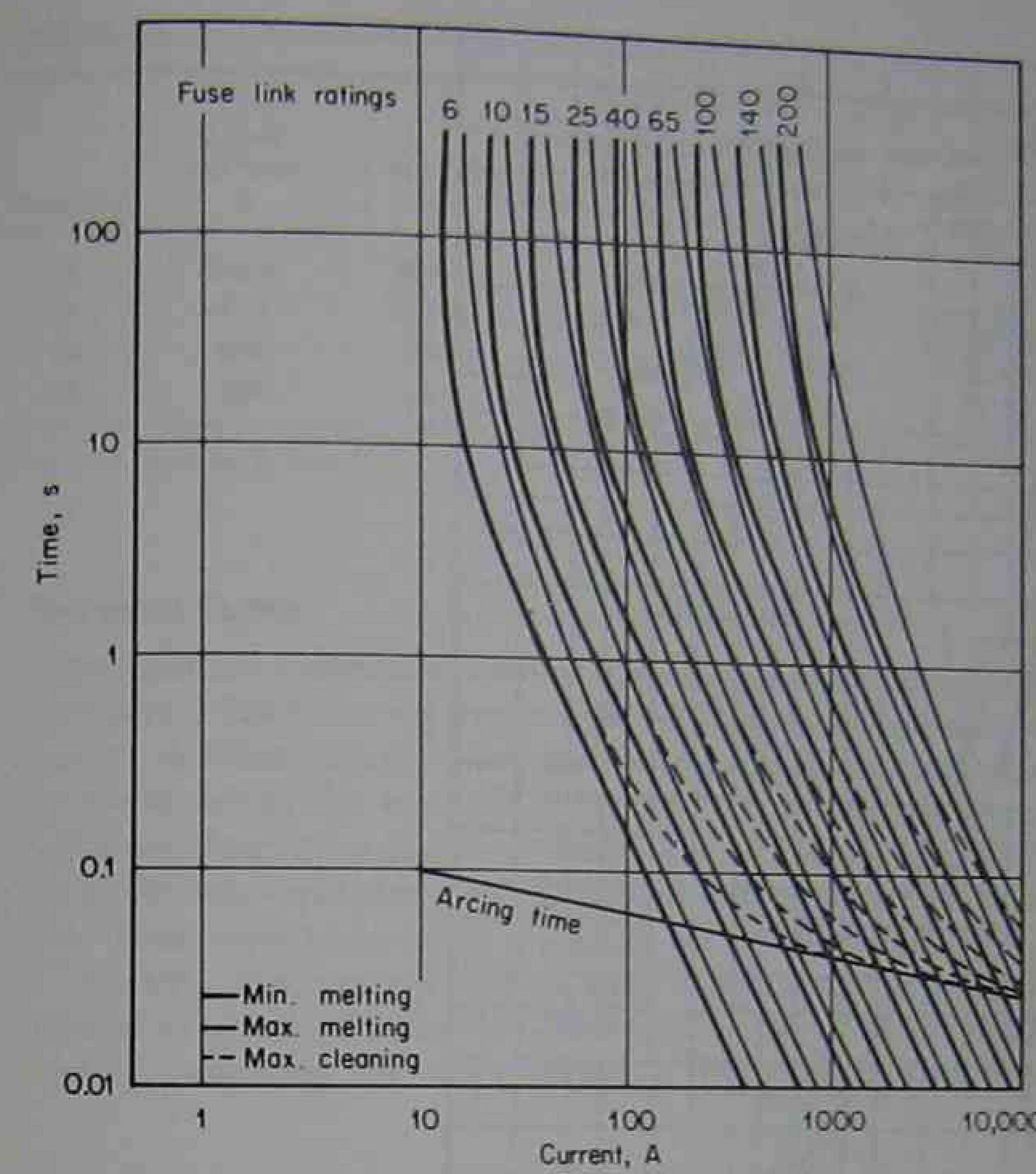


FIG. 4-13 (*b*) "Representative" minimum and maximum time-current characteristic curves for EEI-NEMA type T (slow) fuse links. *(Courtesy Westinghouse Electric Co.)*

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.

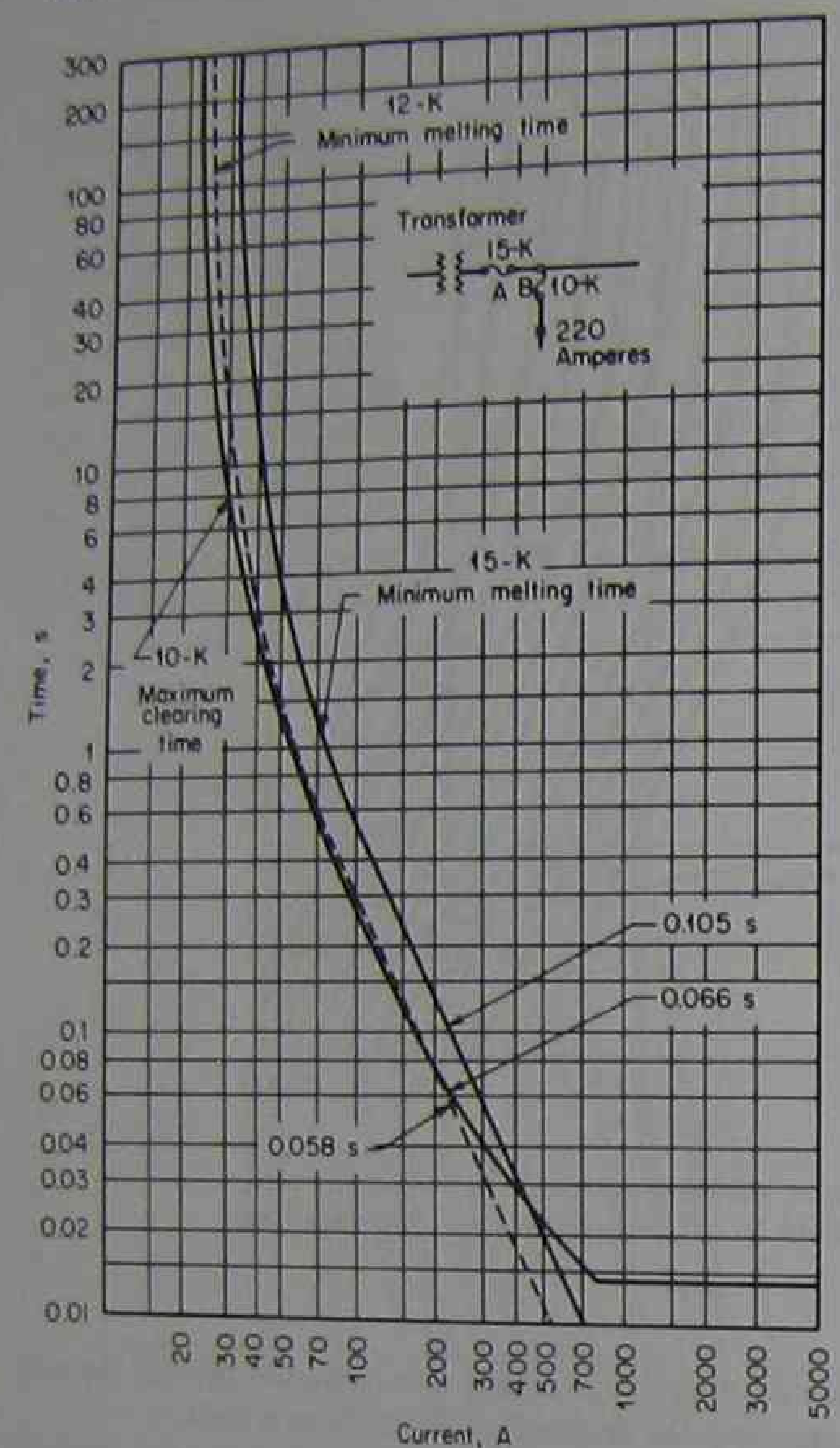


FIG. 4-14 Coordination by time-current curves. *(Courtesy McGraw Edison Co.)*

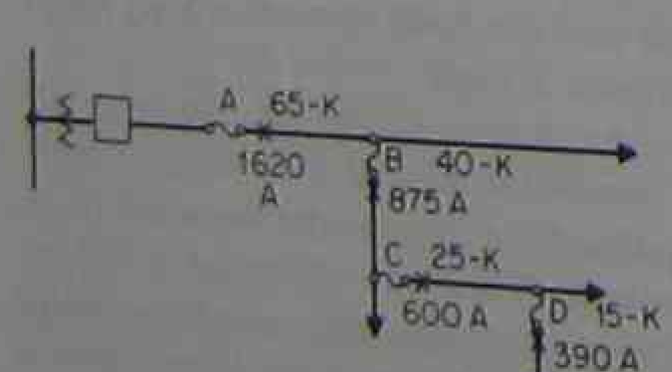


FIG. 4-15 Example of fuse-coordinated system.

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.

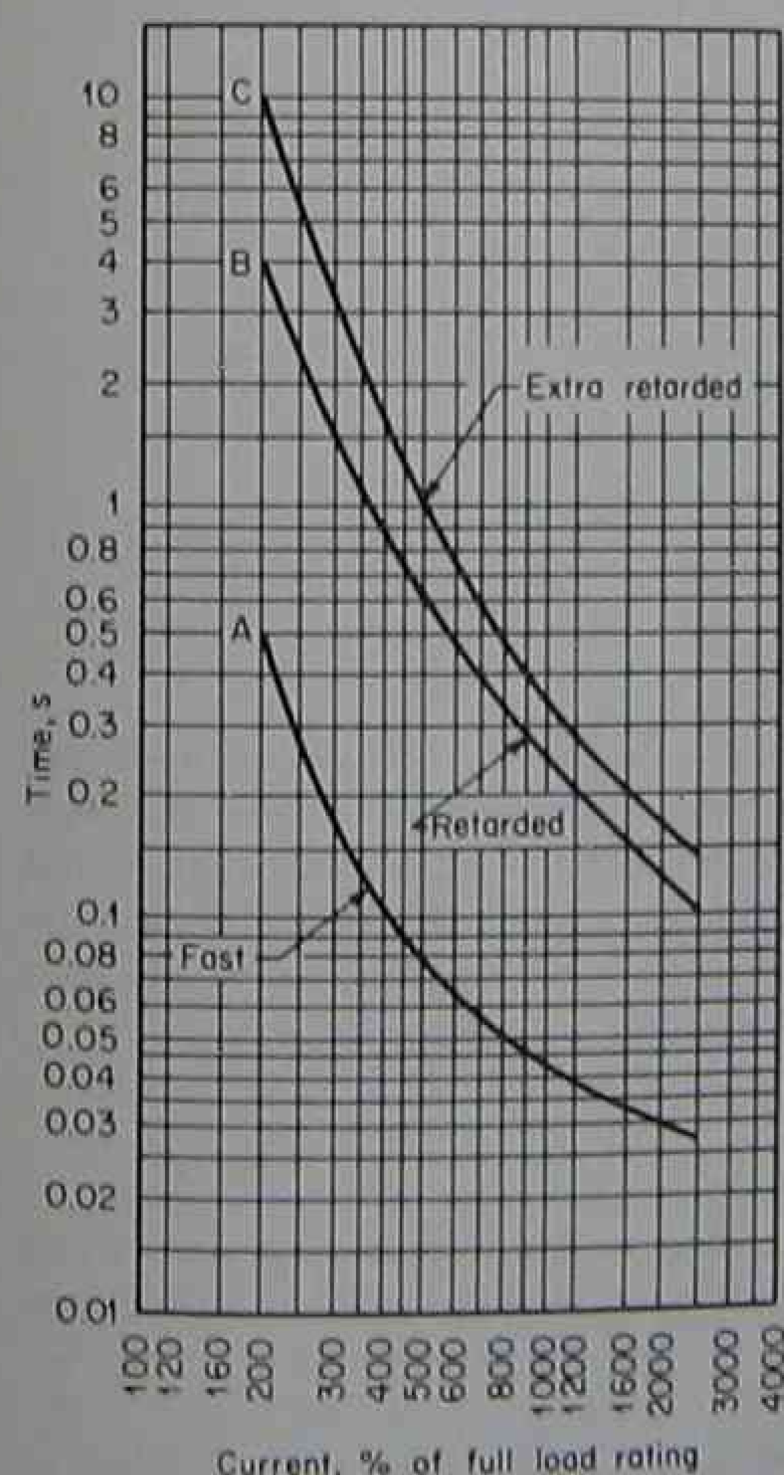


FIG. 4-16 Time-current curves of standard-duty reclosers. *(Courtesy McGraw Edison Co.)*

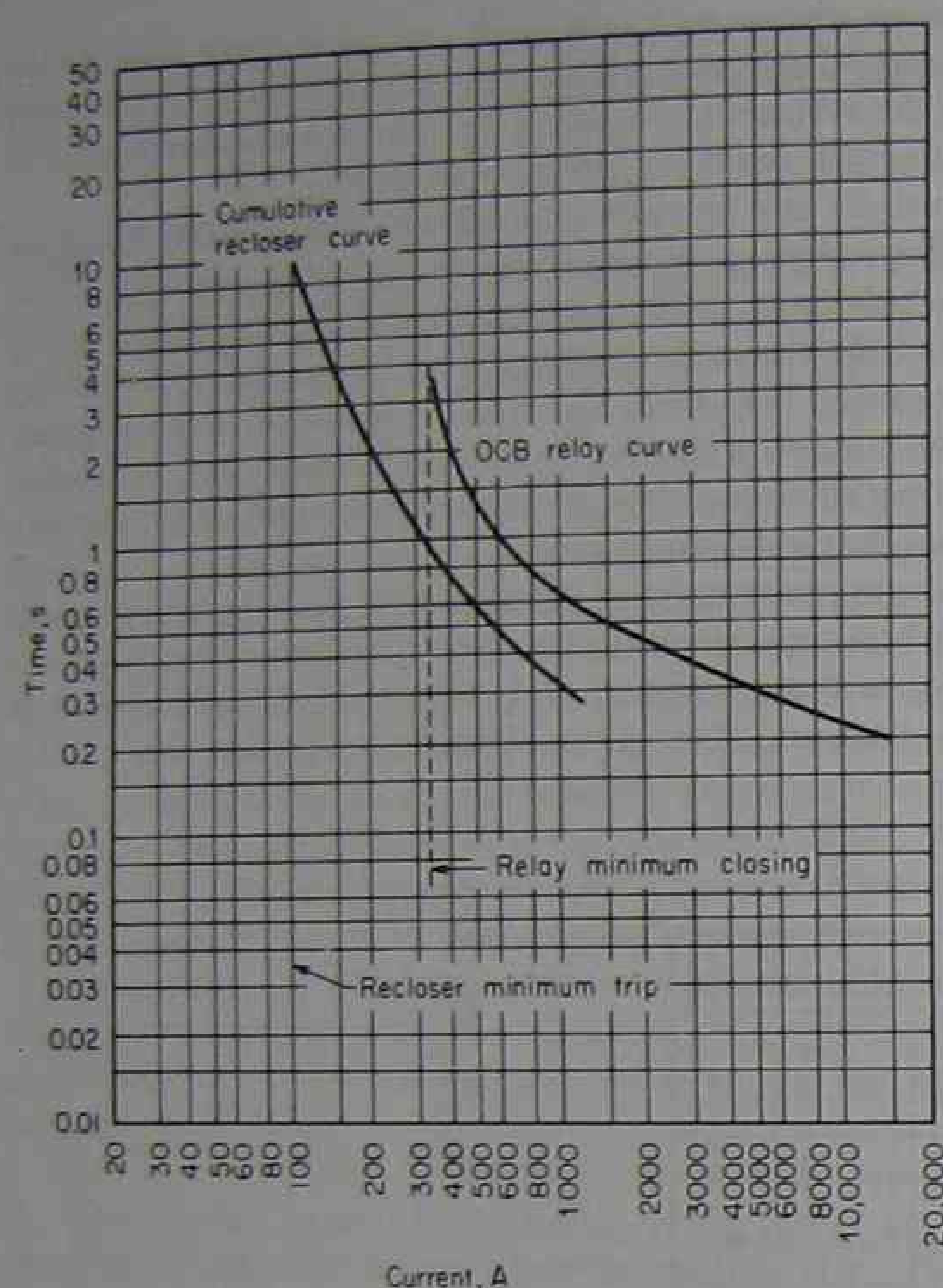


FIG. 4-17 Coordination of OCB relay and recloser. *(Courtesy McGraw Edison Co.)*

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.

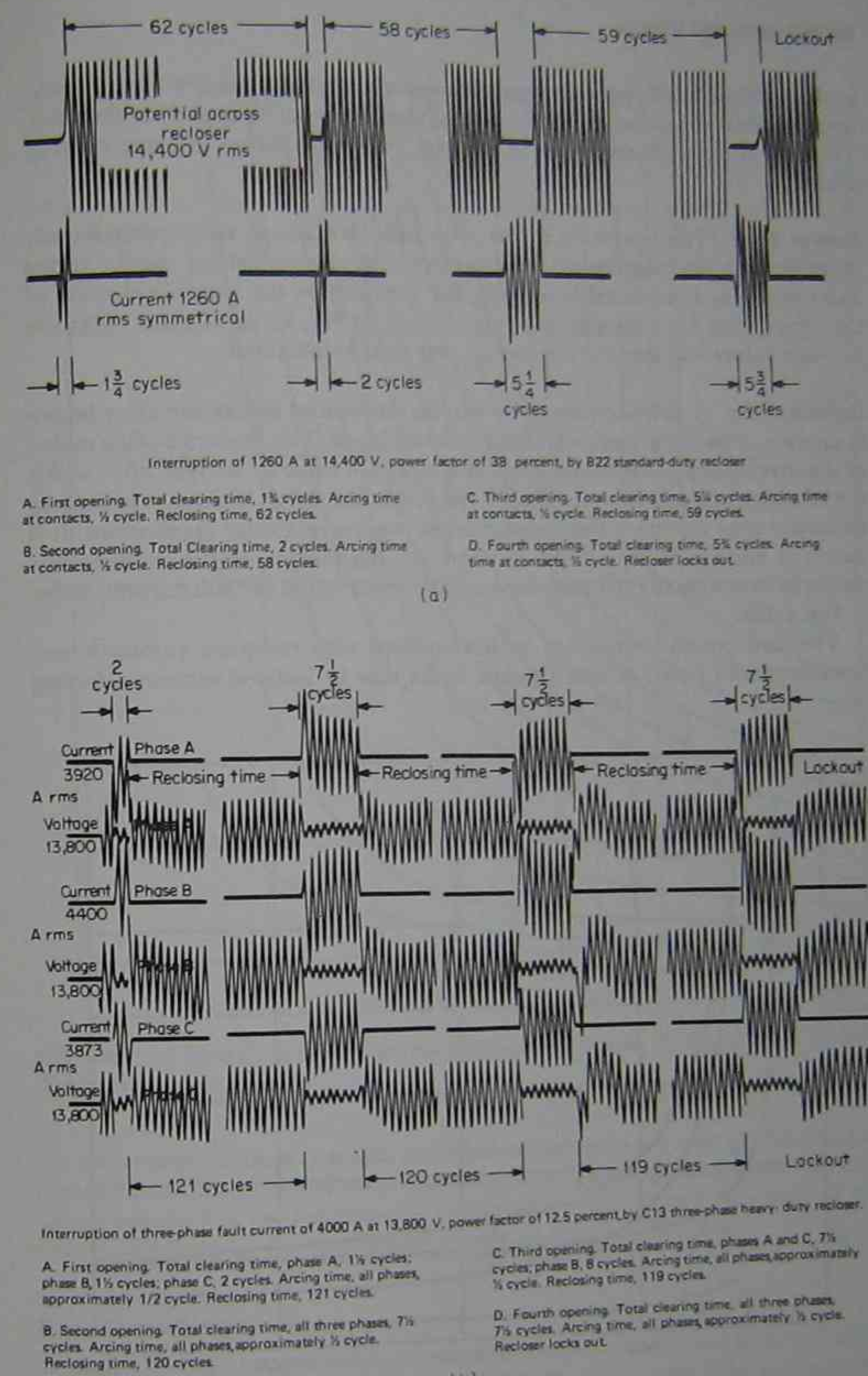


FIG. 4-18 (*a*) Typical oscillogram of recloser operation. (*b*) Typical oscillogram of three-phase fault interruption by heavy-duty recloser. *(Courtesy McGraw Edison Co.)*

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

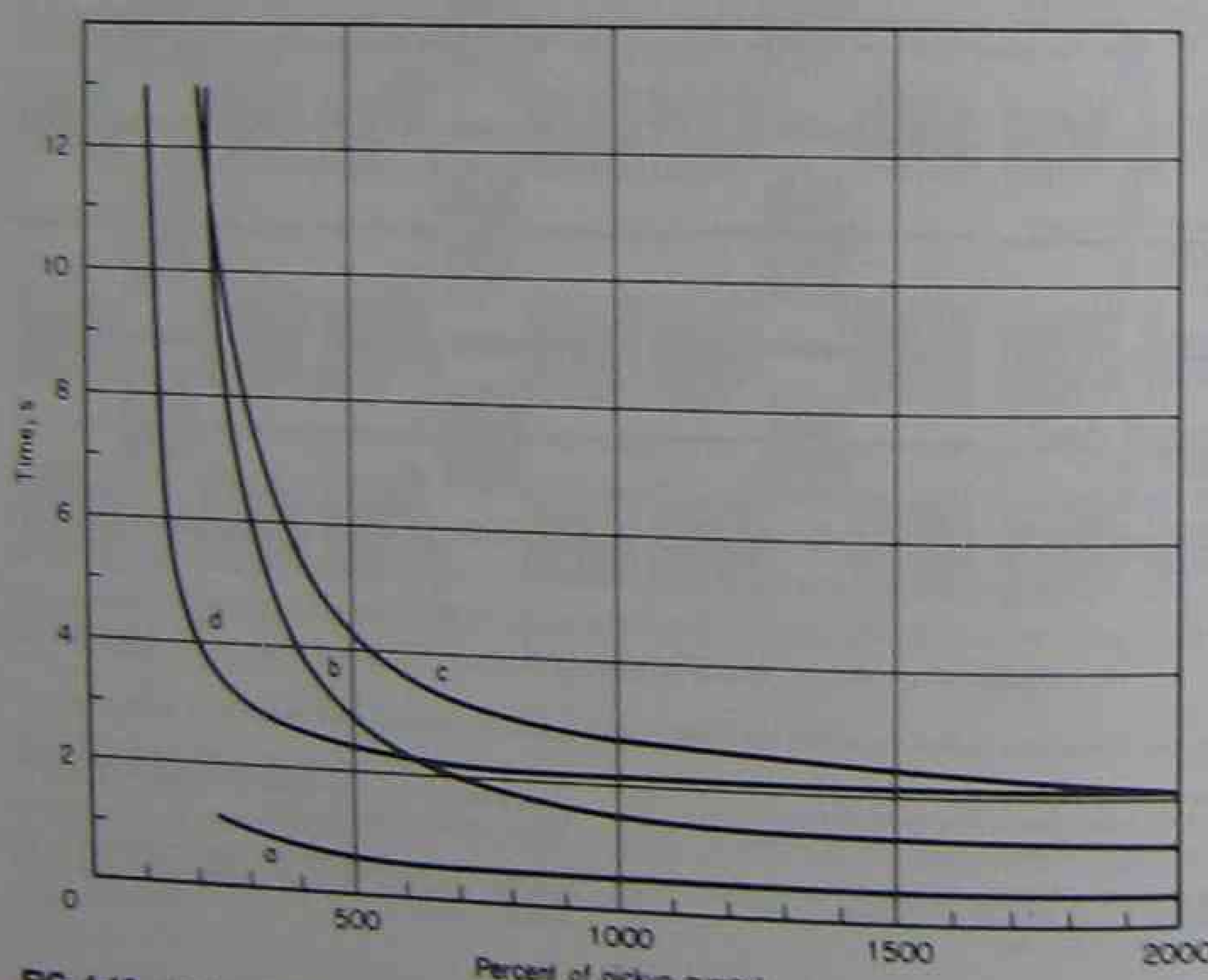


FIG. 4-19 (*a*) A collection of time curves. These are representative of the various types of time curves which are used on overcurrent relays.

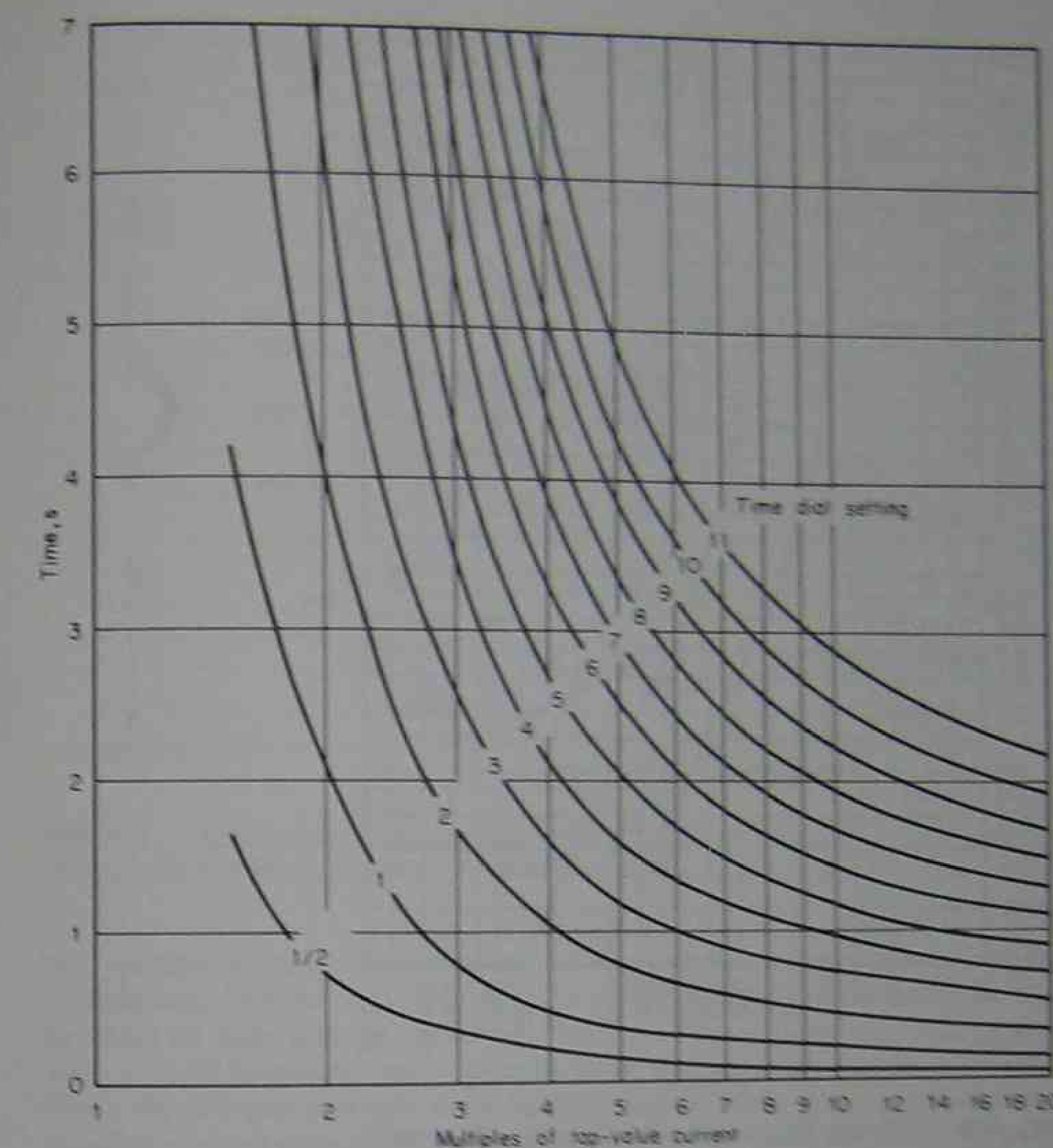


FIG. 4-19 (*b*) Type CO-8 overcurrent relay time-current curves, 50–60 cycles. (*Courtesy Westinghouse Electric Co.*)

the entire circuit; fuses are also provided on the primary side of distribution transformers. The definite time characteristic of the relay associated with the 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

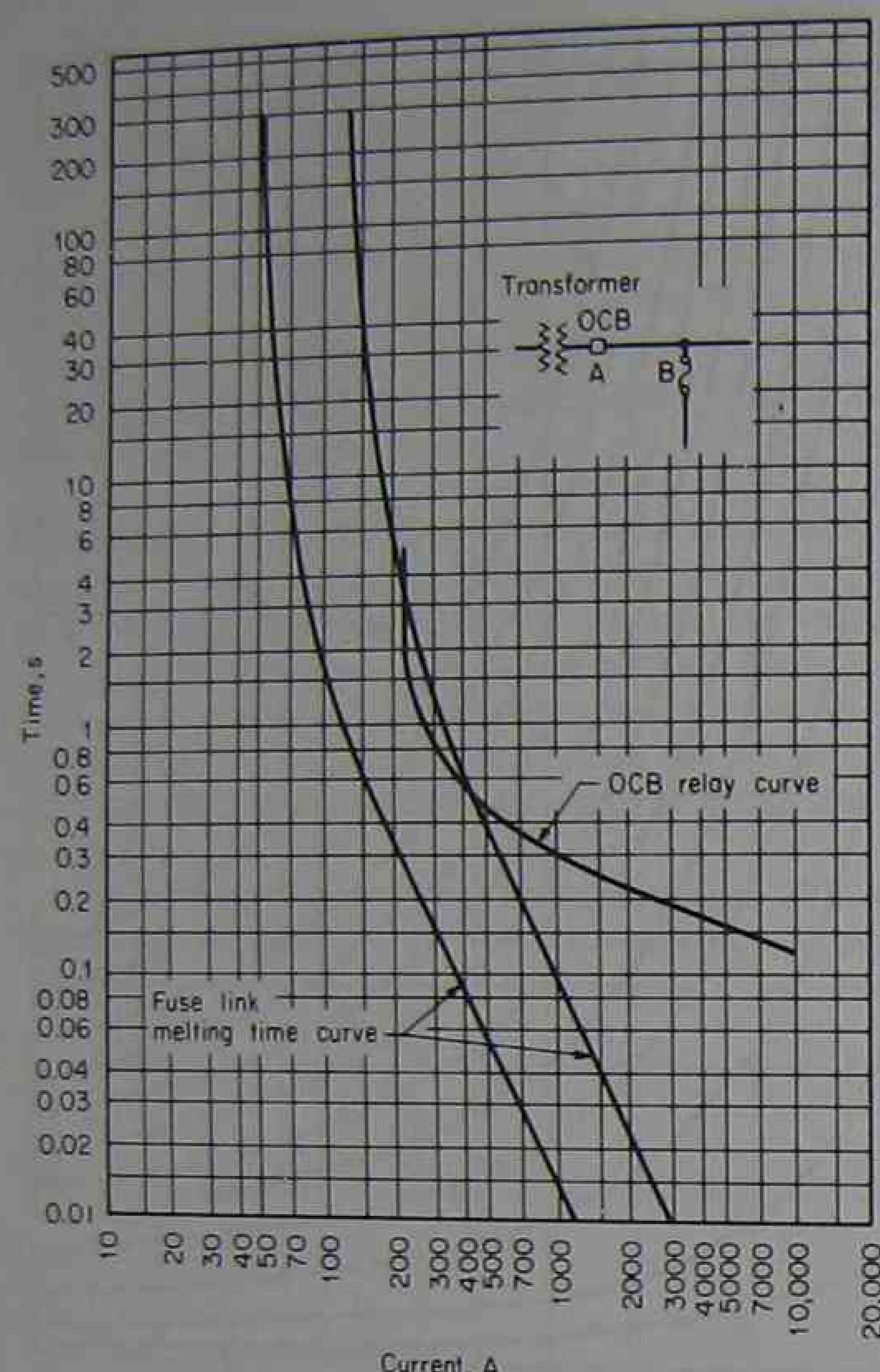


FIG. 4-20 OCB-fuse link coordination. *(Courtesy McGraw Edison Co.)*

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

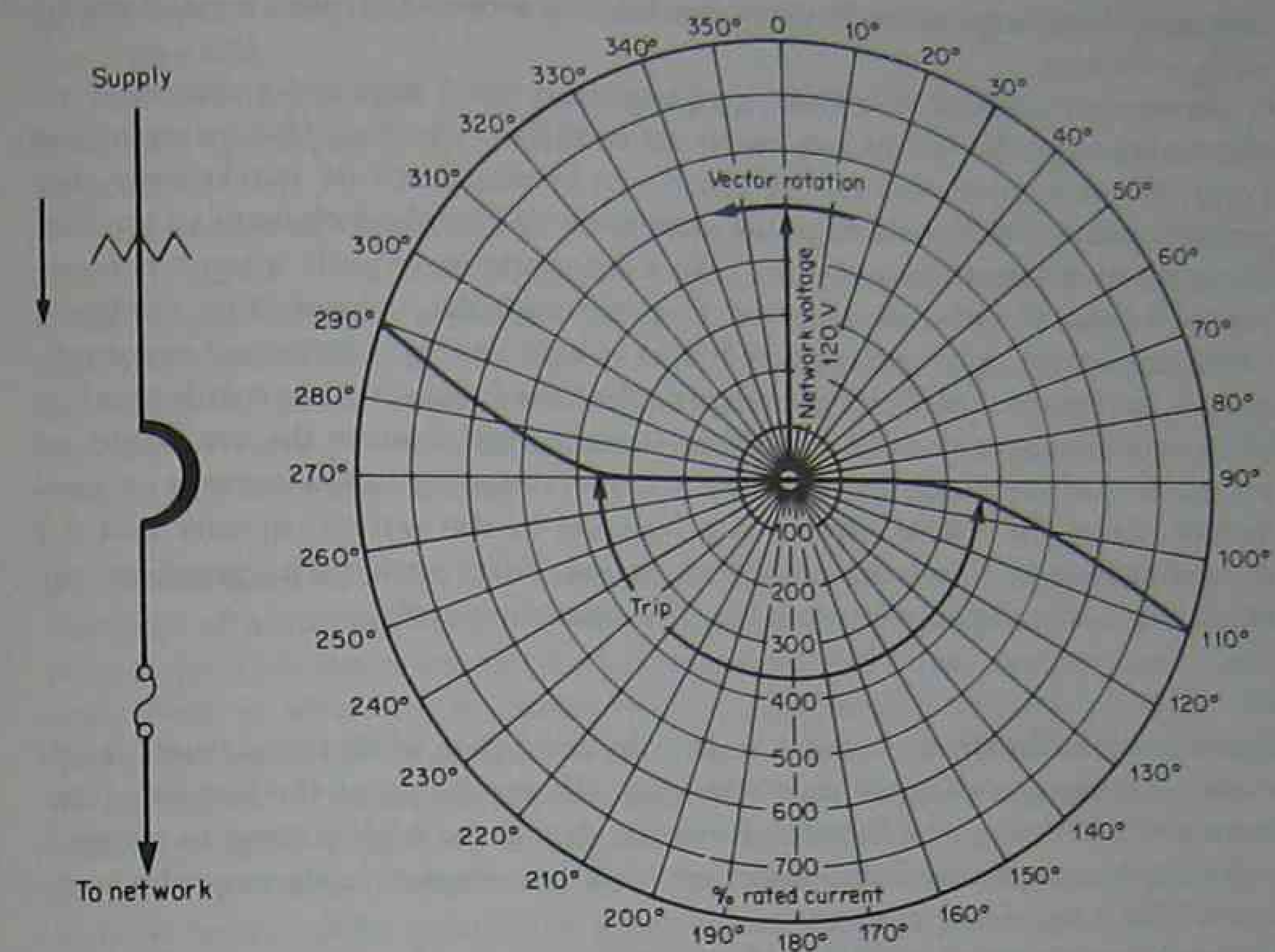


FIG. 4-21 Typical tripping characteristic of the CN-33 network master relay under balanced three-phase conditions. *(Courtesy Westinghouse Electric Co.)*

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.

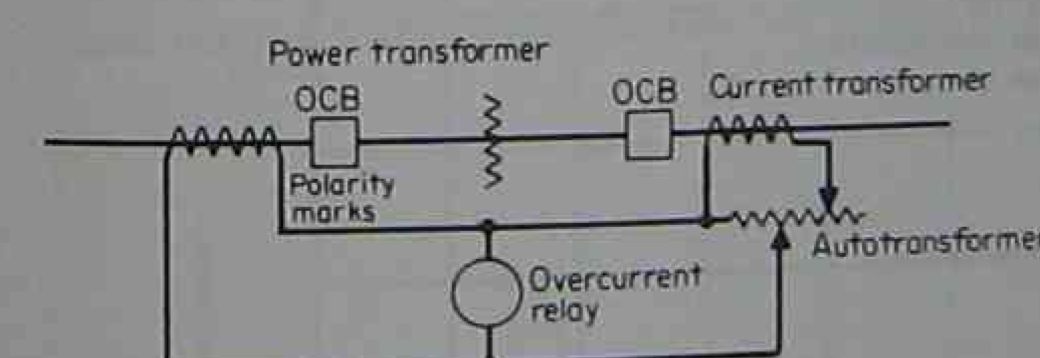


FIG. 4-22 One-line diagram of current-differential protection.

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

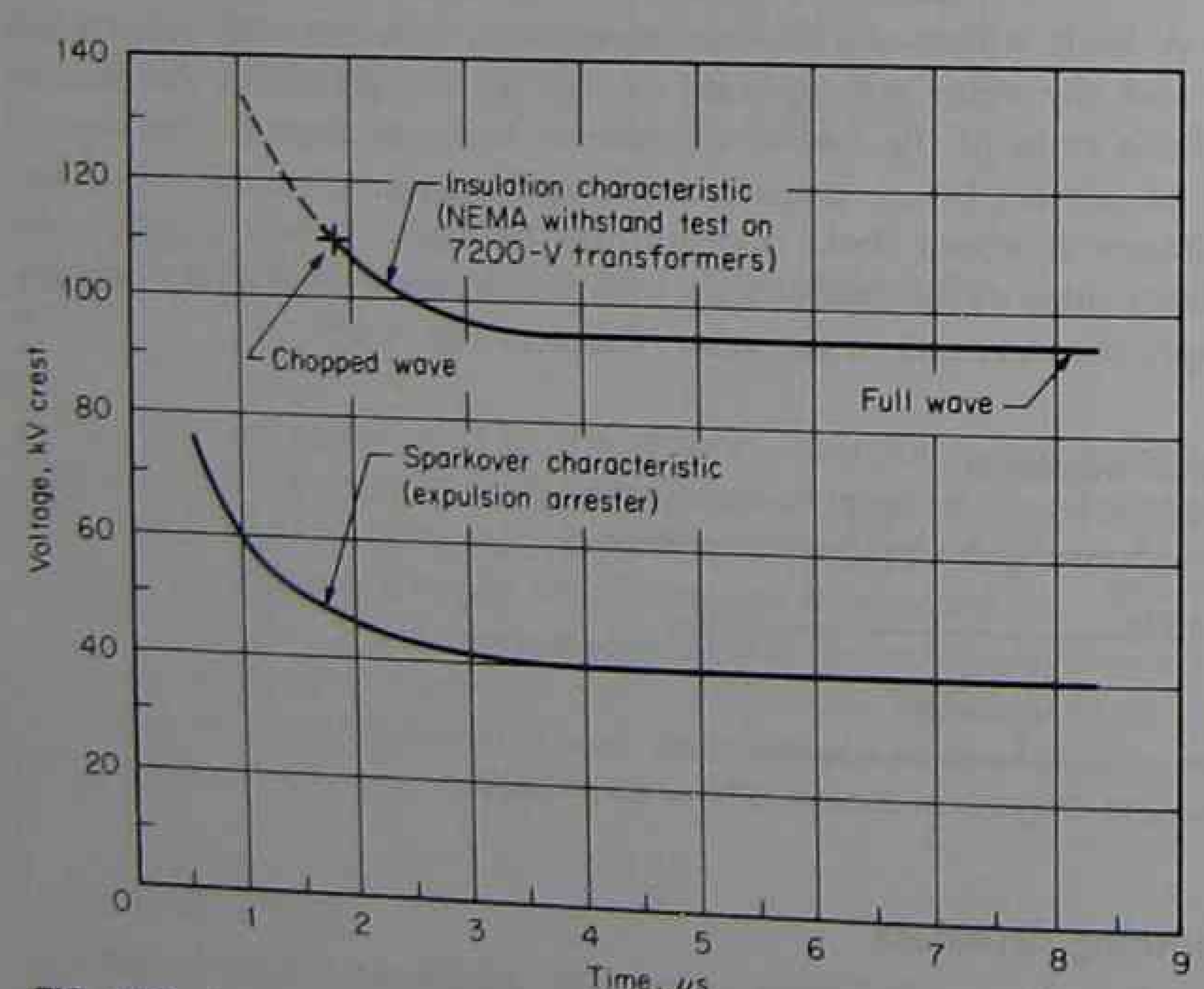


FIG. 4-23 Insulation coordination. *(Courtesy McGraw Edison Co.)*

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.

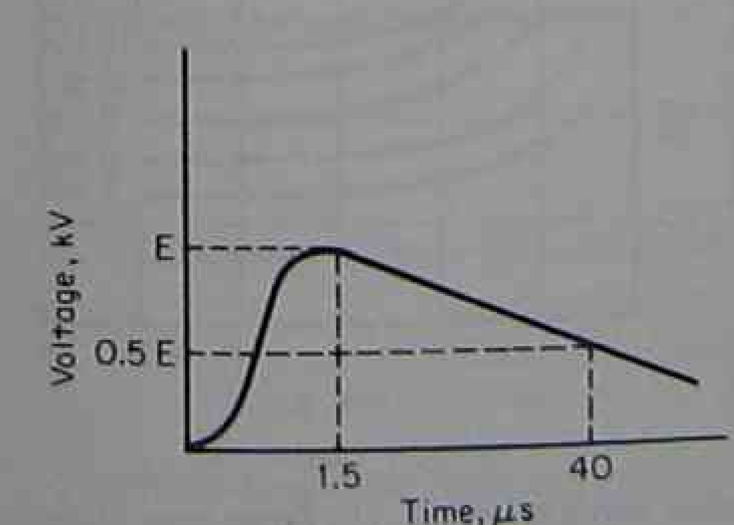


FIG. 4-24 1.5- by 40-μs voltage wave *(Courtesy McGraw Edison Co.)*

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.

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

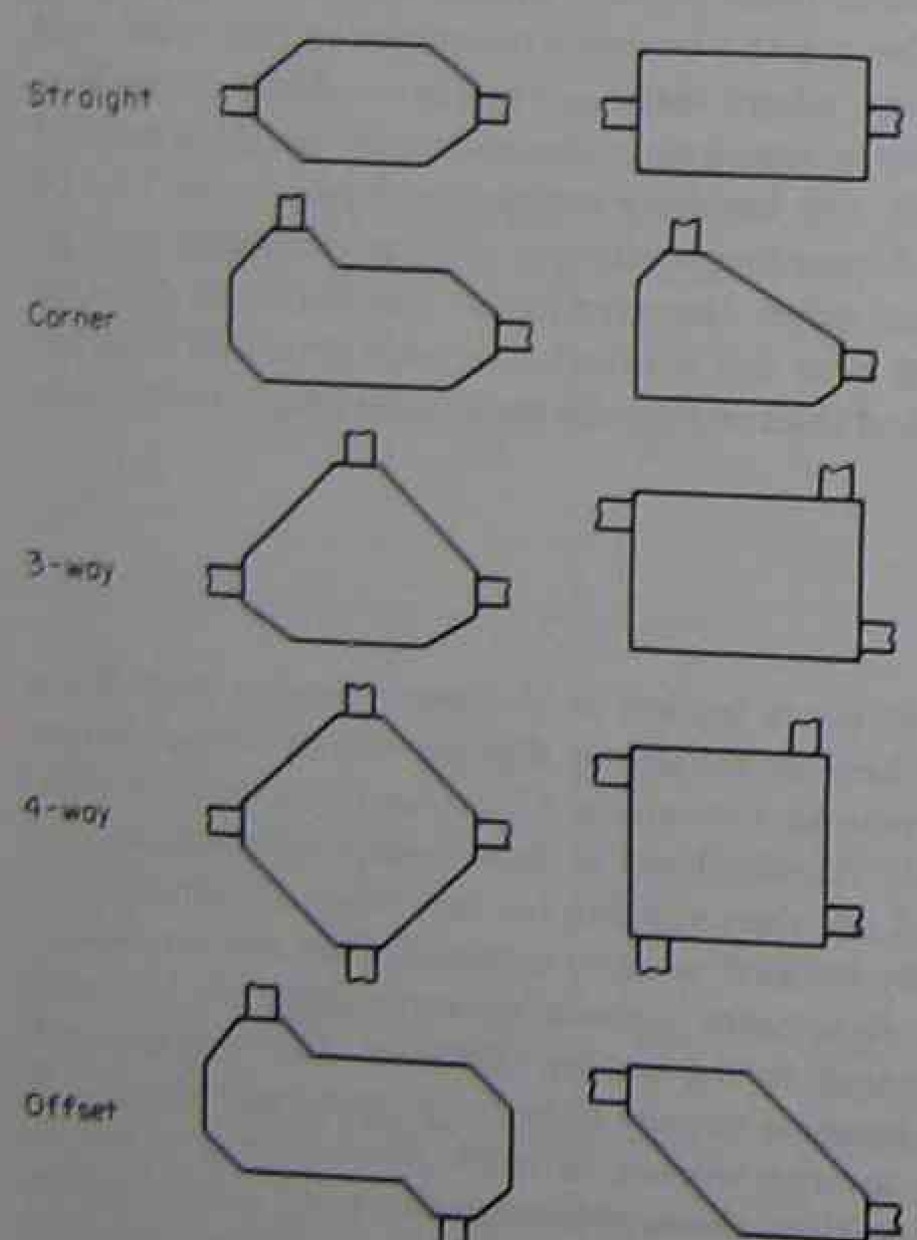


FIG. 6-3 Typical shapes of cable manholes. *(From EEI Underground Systems Reference Book.)*

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

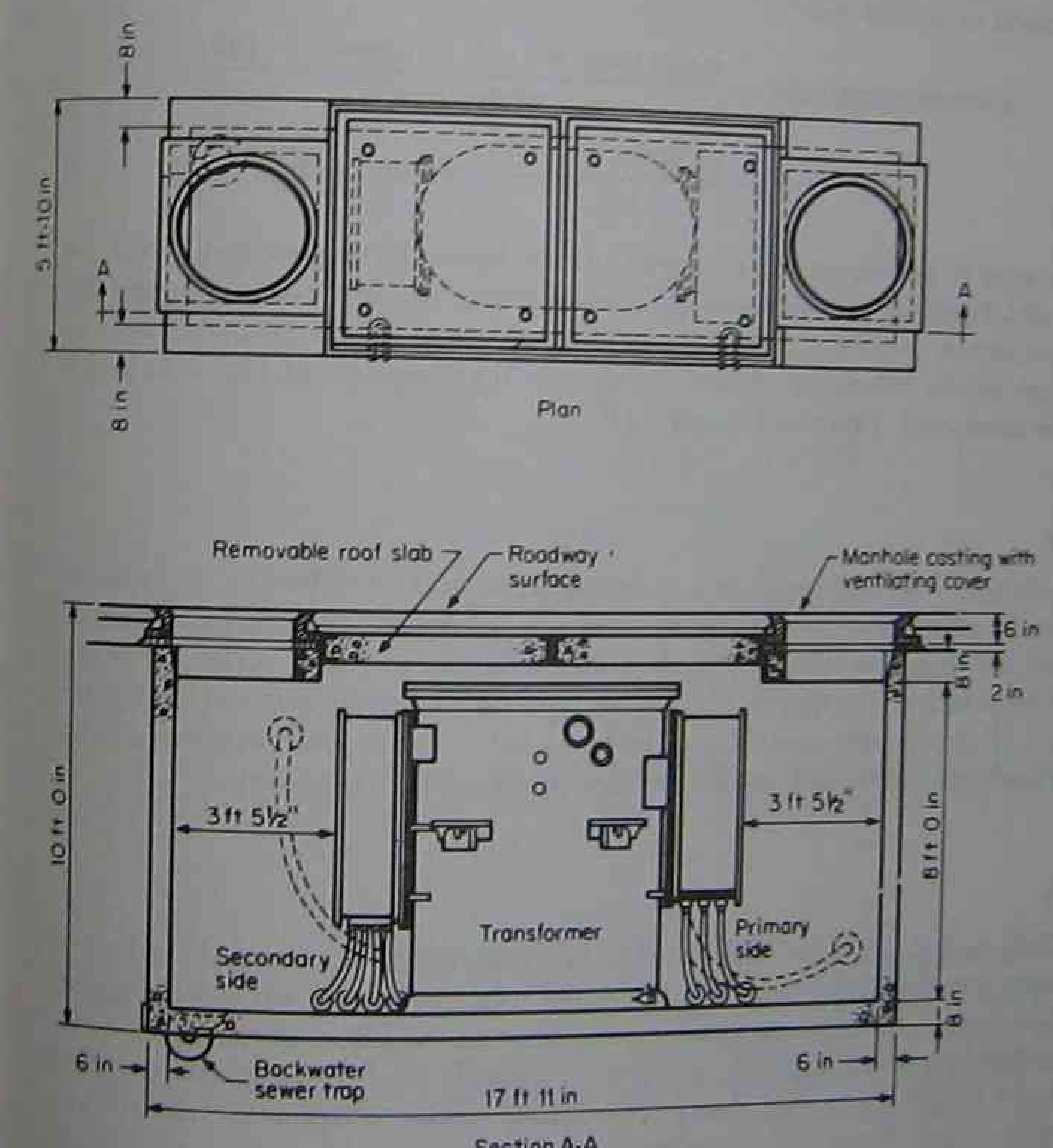


FIG. 6-4 Transformer manhole under roadway, with removable roof slab. *(Adapted from EEI Underground Systems Reference Book.)*

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 ft², are also considered. The concentrated load may then be as much as 63,000 lb/ft²:

$$\text{Concentrated load} = \frac{\text{wheel load} \times (1 + \%\ \text{impact} \div 100)}{\text{wheel area}}$$

$$= \frac{21{,}000(1 + 0.5)}{0.5} = 63{,}000\ \text{lb/ft}^2$$

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/ft²; it appears to be constant at lower depths.

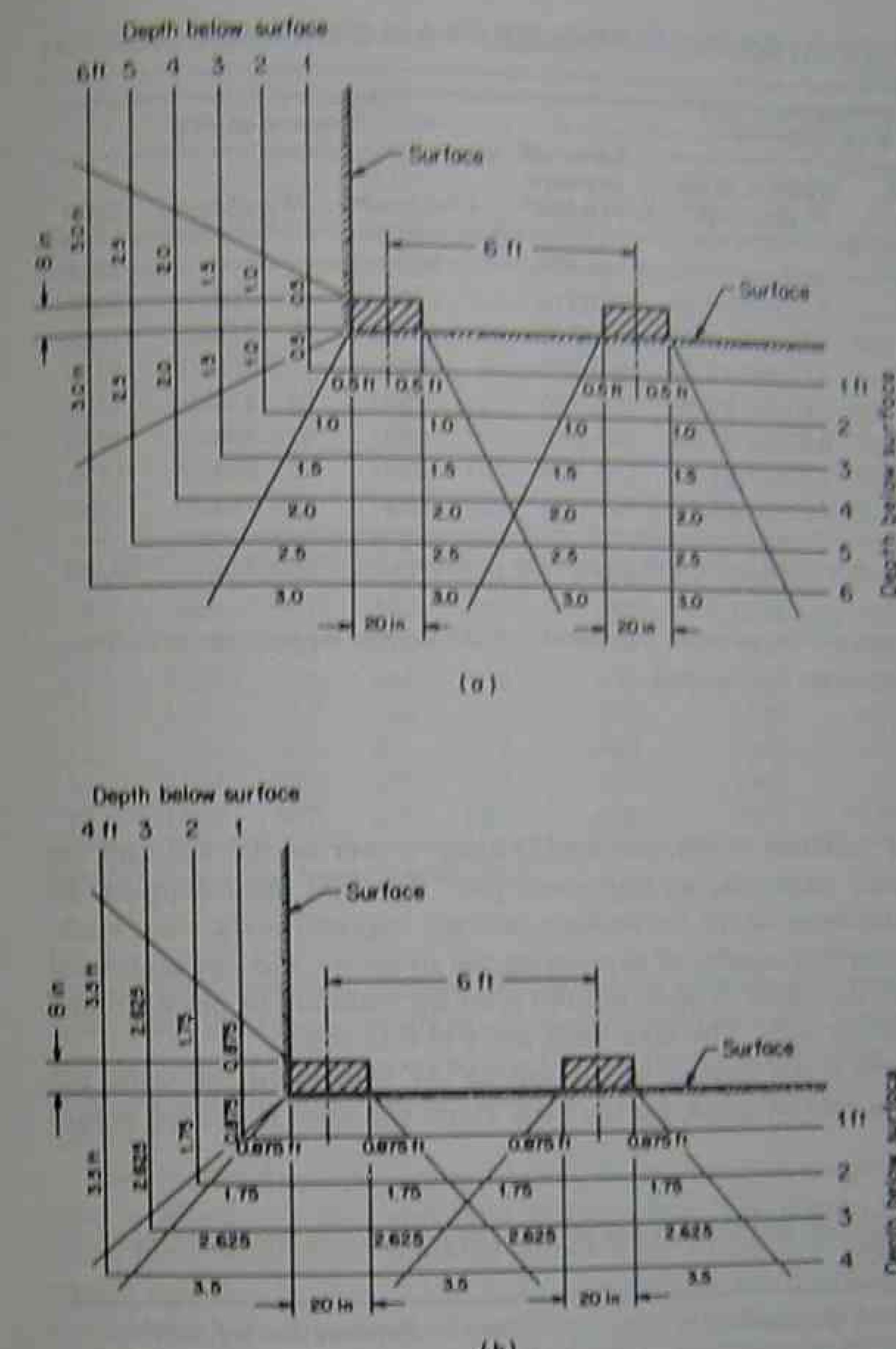


FIG. 6-5 Diagram showing area of spread of wheel loads (a) based on 1:1 spread and (b) based on 1¾:1 spread. *(From EEI Underground Systems Reference Book.)*

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_{av} 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 $P_{av}W/6$.

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_{av} 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 $P_{av}W/6$.

From *EEI Underground Systems Reference Book.*

TABLE 6-2 HORIZONTAL EARTH PRESSURES AT VARIOUS DEPTHS

	No live load				*Live and dead loads*				
		Horizontal pressure, lb/ft²					*Horizontal pressure, lb/ft²*		
Depth	*Dead load*	*25%*	*30%*	*35%*	*Live load 1½:1*	*Total live and dead load*	*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.

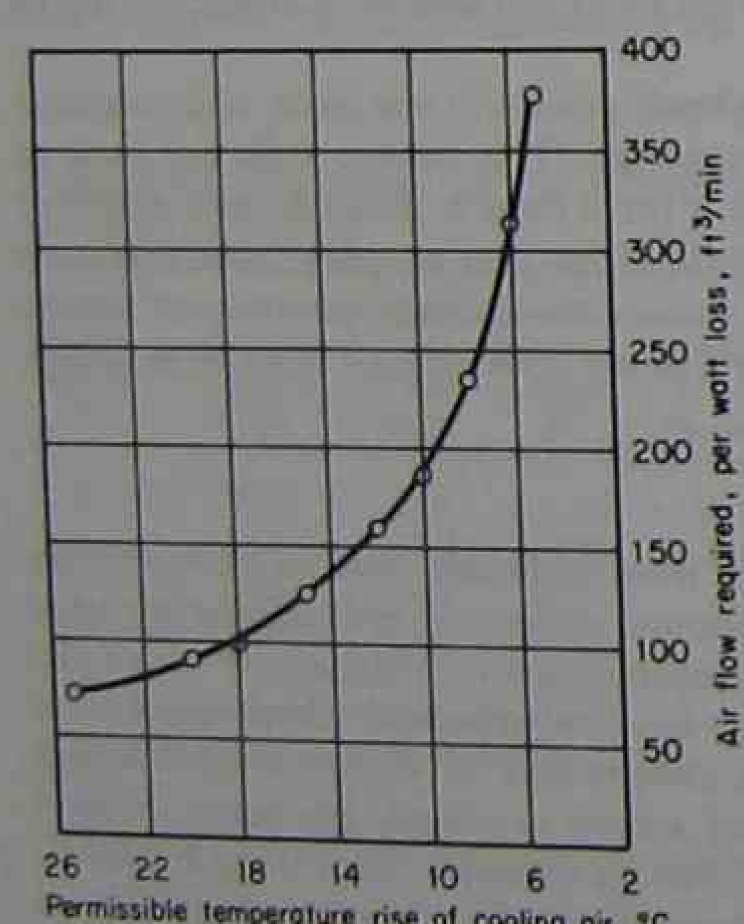


FIG. 6-6 Airflow requirements for limiting temperature rise in transformer vaults. *(From EEI Underground Systems Reference Book.)*

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.

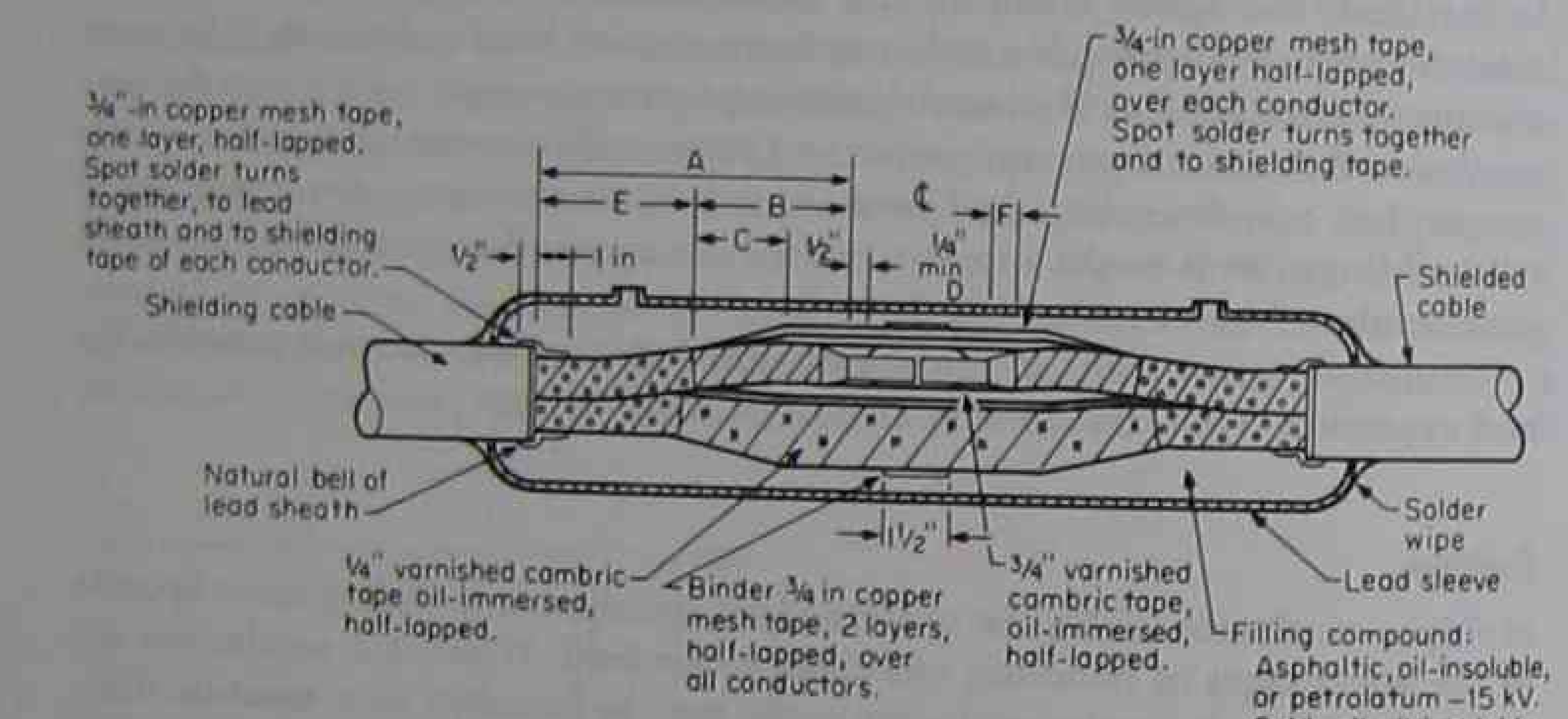
Cable Insulation For both primary and secondary cables, plastics such as cross-linked polyethylene are now almost exclusively used; some oil-impregnated paper is still installed in special cases where much of that kind of insulation exists. Varnished cambric and rubber, for primary, and rubber, for secondary 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.

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	VC	E*	F**
15	9-11	6	3	3/8	7/16	3-5	3/4
27	11-13	8	4	9/16	3/4	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.

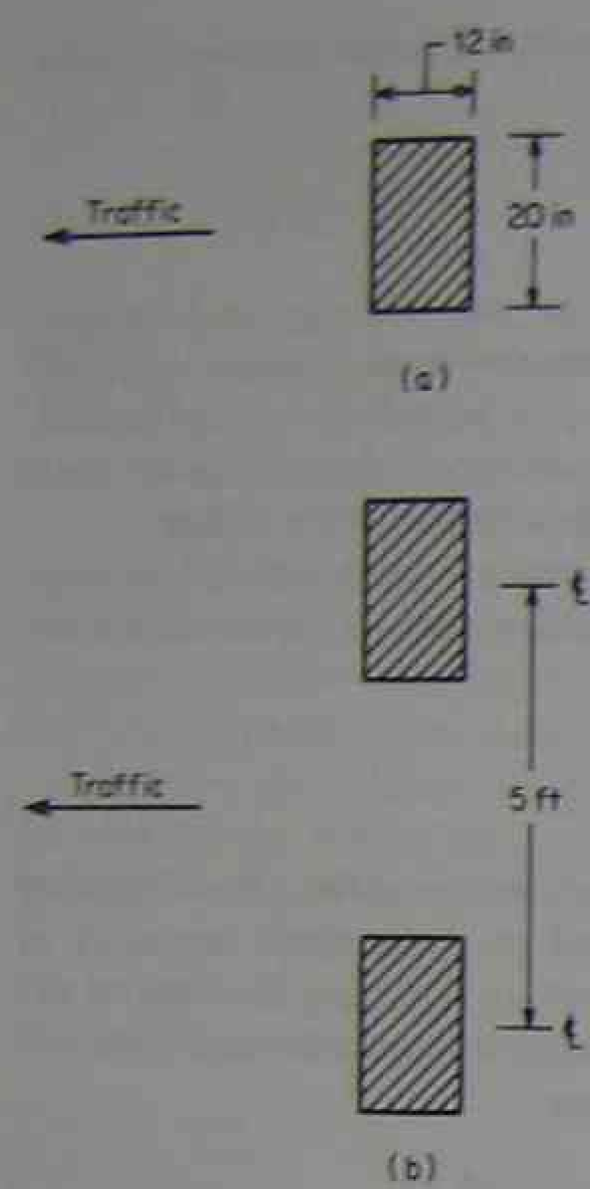


FIG. 6-8 Multiple wheel load. *(a)* H20 (HS-20) wheel load. *(b)* Multiple wheel load. *(Courtesy Consolidated Edison Co.)*

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

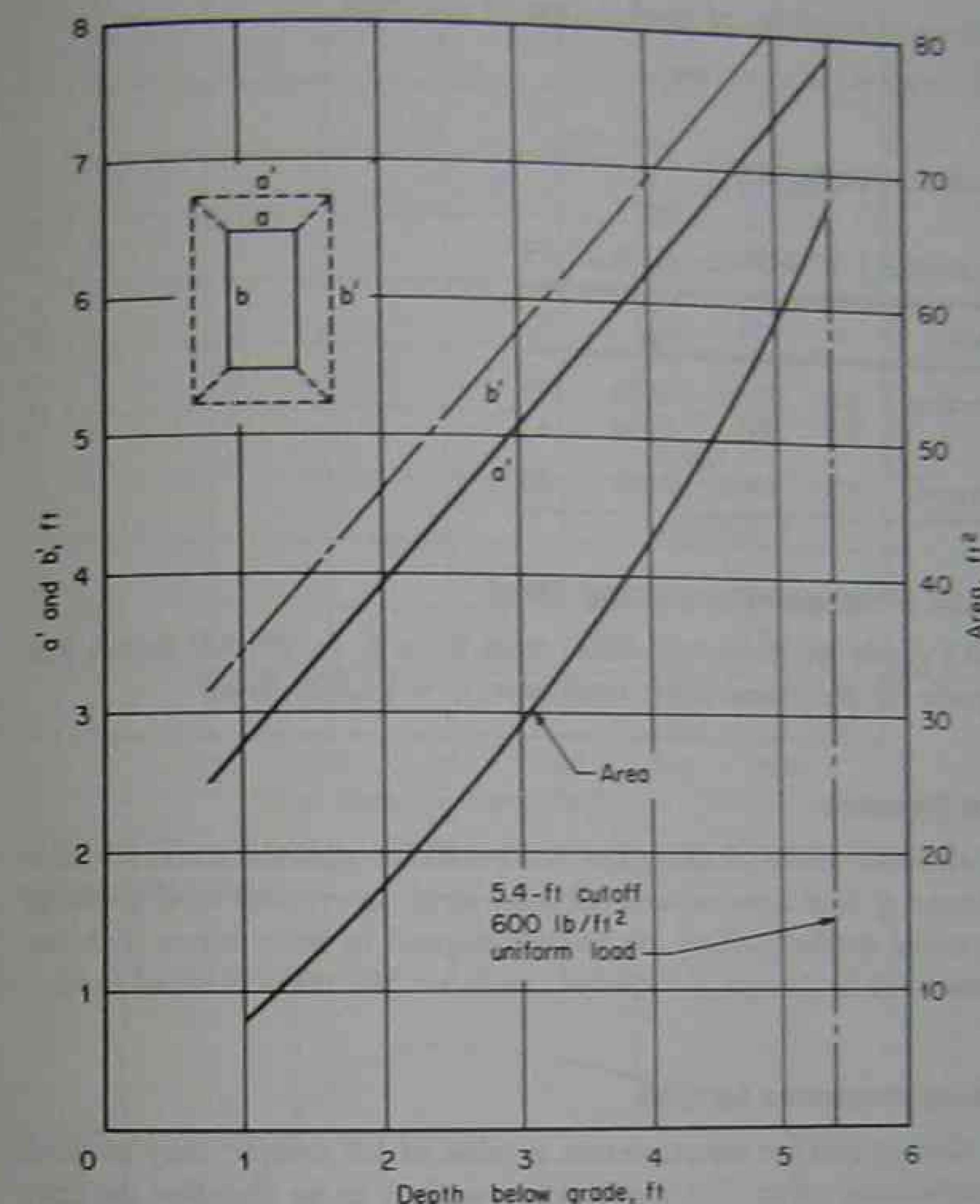


FIG. 6-9 Spread of wheel for 9-in pavement. *(Courtesy Consolidated Edison Co.)*

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/in². For ASTM A615 grade 60 deformed-billet steel bars, f_s = 24,000 lb/in².

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/ft² 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-

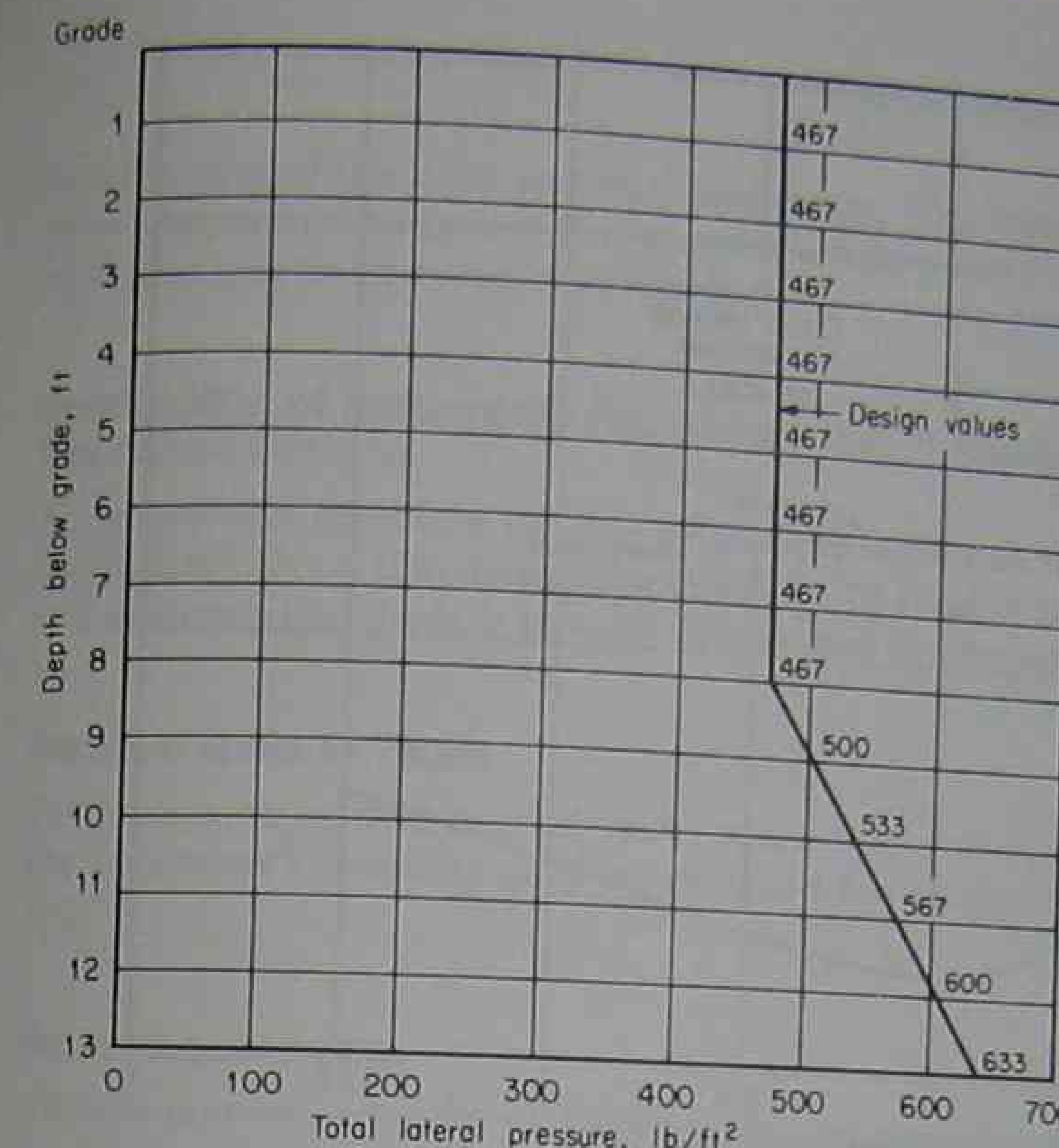


FIG. 6-10 Design chart—lateral pressures on walls. *(Courtesy Consolidated Edison Co.)*

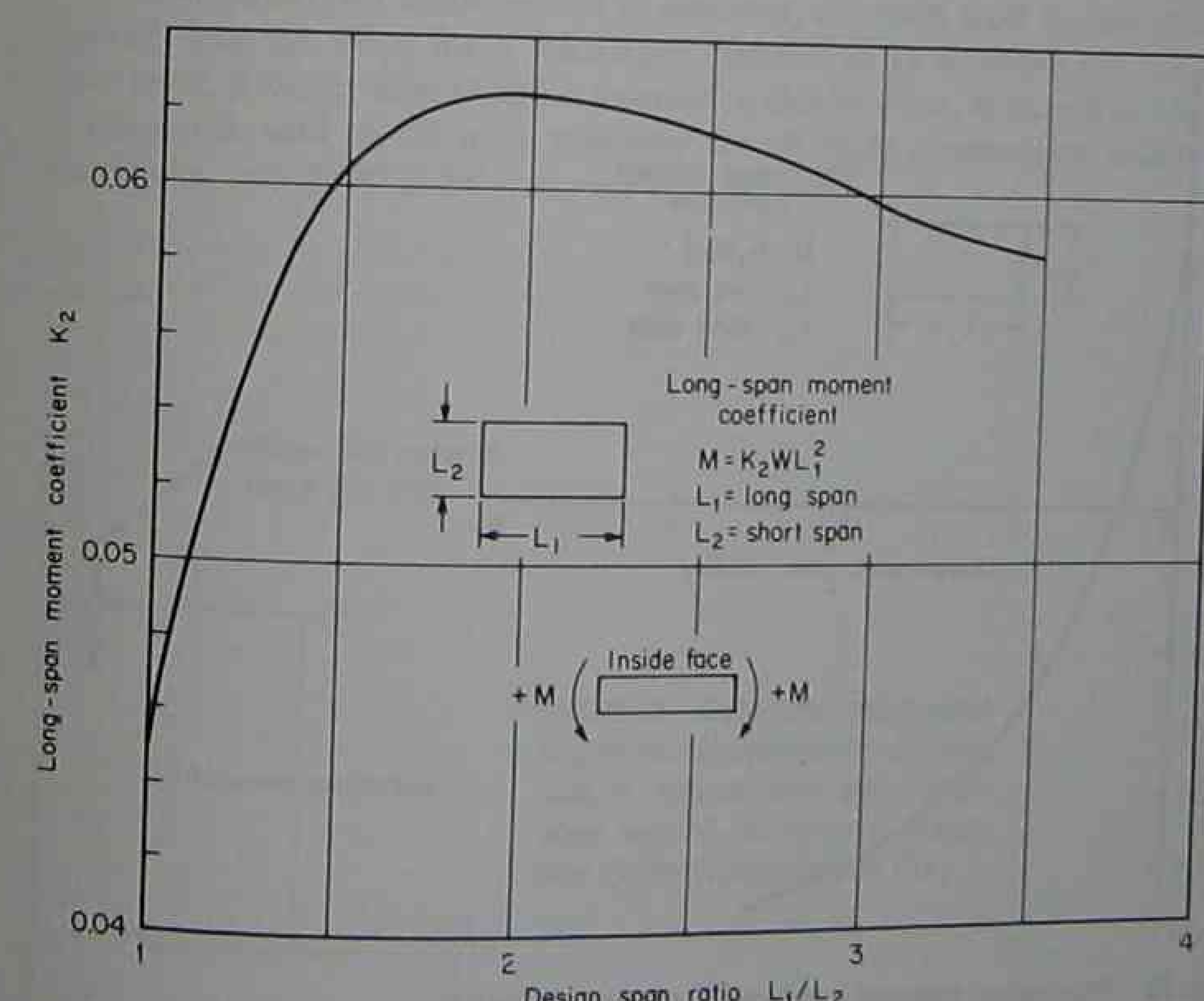


FIG. 6-11 Long-span moment coefficient. *(Courtesy Consolidated Edison Co.)*

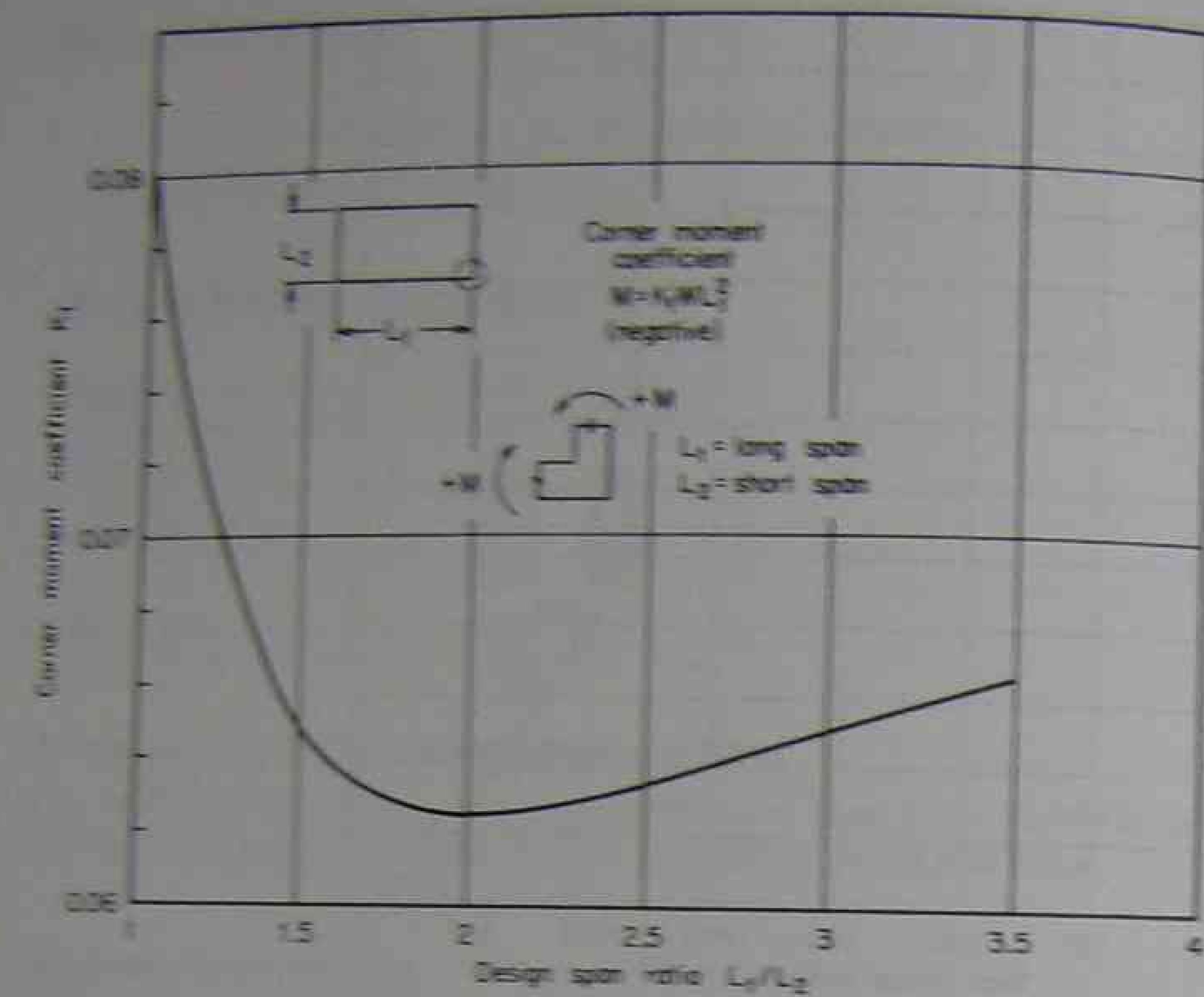


FIG. 6-12 Corner moment coefficient. *(Courtesy Consolidated Edison Co.)*

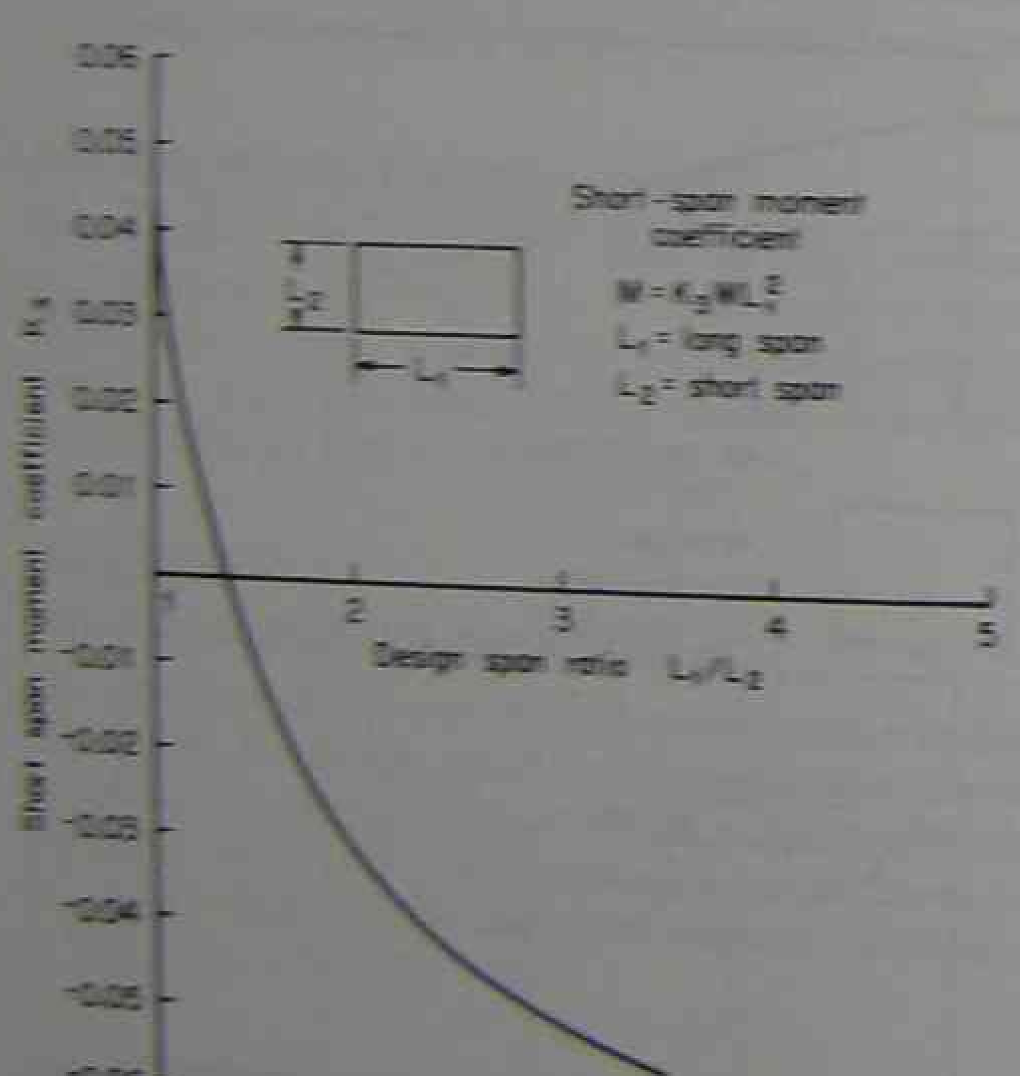


FIG. 6-13 Short-span moment coefficient. *(Courtesy Consolidated Edison Co.)*

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.

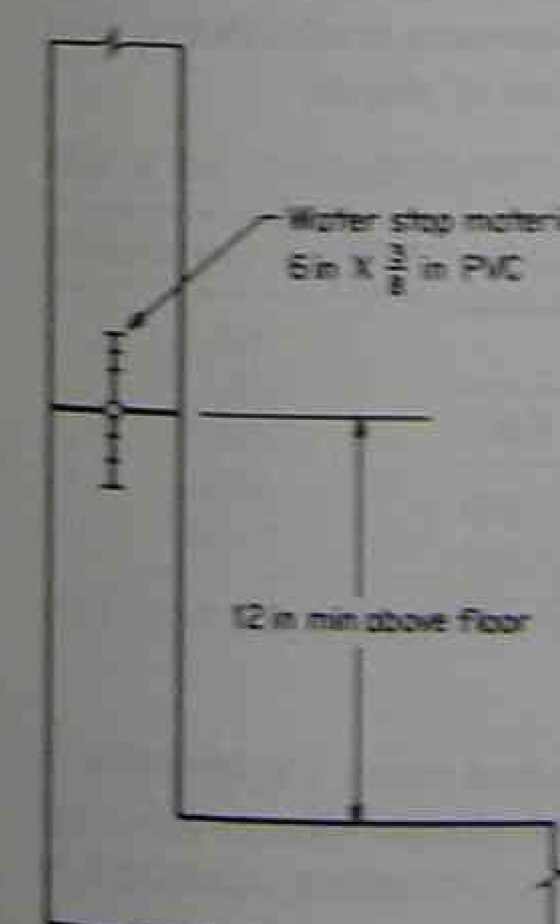


FIG. 6-14 Water stop detail; water stop to be lap-spliced 4 in on each side of vertical joints and continuous around all corners. *(Courtesy Consolidated Edison Co.)*

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