SECTION 17
SUBSTATIONS

W. Bruce Dietzman

Project Engineering Manager, TXU Electric Delivery Company; Senior Member, IEEE; Past Chair, IEEE/PES Substations Committee; Past VP-Technical Activities, IEEE/PES

Philip C. Bolin

General Manager, Substation Division Mitsubishi Electric Power Products, Inc.; Fellow, IEEE; Past Chair, IEEE/PES Gas-Insulated Substations Subcommittee; Member, CIGRE Working Group 23.10 GIS

CONTENTS

17.1 AIR-INSULATED SUBSTATIONS

17.1.1 Function of Substations

Transmission and Distribution Systems. In large, modern ac power systems, the transmission and distribution systems function to deliver bulk power from generating sources to users at the load centers. Transmission systems generally include generation switchyards, interconnecting transmission lines, autotransformers, switching stations, and step-down transformers. Distribution systems include primary distribution lines or networks, transformer banks, and secondary lines or networks, all of which serve the load area.

17.1.2 Design Objectives

As an integral part of the transmission or distribution systems, the substation or switching station functions as a connection and switching point for generation sources, transmission or subtransmission lines, distribution feeders, and step-up and step-down transformers. The design objective for the substation is to provide as high a level of reliability and flexibility as possible while satisfying system requirements and minimizing total investment costs.

Voltage Levels. The selection of optimal system voltage levels depends on the load to be served and the distance between the generation source and the load. Many large power plants are located great distances from the load centers to address energy sources or fuel supplies, cooling methods, site costs and availability, and environmental concerns. For these reasons, the use of transmission voltages as high as 765 kV has occurred. Transmission system substations that provide bulk power operate at voltages from 69 to 765 kV. Common voltage classes used in the United States for major substations include 69, 115, 138, 161, and 230 kV (considered *high voltage* or *HV class*) and 345,500, and 765 kV (considered *extra high voltage* or *EHV class*). Even higher voltages which include 1100 and 1500 kV have been considered. These are referred to as *ultra high voltage* or *UHV class*. Distribution system substations operate at secondary voltage levels from 4 to 69 kV.

Design Considerations. Many factors influence the selection of the proper type of substation for a given application. This selection depends on such factors as voltage level, load capacity, environmental considerations, site space limitations, and transmission-line right-of-way requirements. While also considering the cost of equipment, labor, and land, every effort must be made to select a substation type that will satisfy all requirements at minimum costs. The major substation costs are reflected in the number of power transformers, circuit breakers, and disconnecting switches and their associated structures and foundations. Therefore, the bus layout and switching arrangement selected will determine the number of the devices that are required and in turn the overall cost. The choice of insulation levels and coordination practices also affects cost, especially at EHV. A drop of one level in basic insulation level (BIL) can reduce the cost of major electrical equipment by thousands of dollars. A careful analysis of alternative switching schemes is essential and can result in considerable savings by choosing the minimum equipment necessary to satisfy system requirements.

A number of factors must be considered in the selection of bus layouts and switching arrangements for a substation to meet system and station requirements. A substation must be safe, reliable, economical, and as simple in design as possible. The design also should provide for further expansion, flexibility of operation, and low maintenance costs.

The physical orientation of the transmission-line routes often dictates the substation's location, orientation, and bus arrangement. This requires that the selected site allow for a convenient arrangement of the lines to be accomplished.

For reliability, the substation design should reduce the probability of a total substation outage caused by faults or equipment failure and should permit rapid restoration of service after a fault or failure occurs. The layout also should consider how future additions and extensions can be accomplished without interrupting service.

Bus Schemes. The substation design or scheme selected determines the electrical and physical arrangement of the switching equipment. Different bus schemes can be selected as emphasis is shifted between the factors of safety, reliability, economy, and simplicity dictated by the function and importance of the substation.

The substation bus schemes used most often are

1. Single bus
2. Main and transfer bus
3. Double bus, single breaker
4. Double bus, double breaker
5. Ring bus
6. Breaker and a half

Some of these schemes may be modified by the addition of bus-tie breakers, bus sectionalizing devices, breaker bypass facilities, and extra transfer buses. Figures 17-1 to 17-6 show one-line diagrams for some of the typical schemes listed above.

Single Bus. The single-bus scheme (Fig. 17-1) is not normally used for major substations. Dependence on one main bus can cause a serious outage in the event of breaker or bus failure without the use of mobile equipment. The station must be deenergized in order to carry out bus maintenance or add bus extensions. Although the protective relaying is relatively simple for this scheme, the single-bus scheme is considered inflexible and subject to complete outages of extended duration.

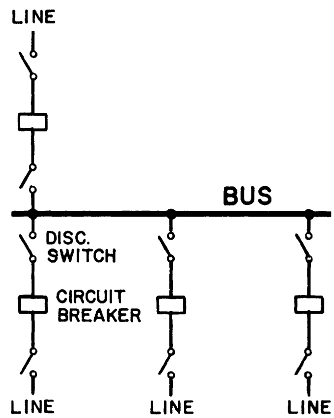


FIGURE 17-1 Single bus.

Main and Transfer Bus. The main- and transfer-bus scheme (Fig. 17-2) adds a transfer bus to the single-bus scheme. An extra bus-tie circuit breaker is provided to tie the main and transfer buses together.

When a circuit breaker is removed from service for maintenance, the bus-tie circuit breaker is used to keep that circuit energized. Unless the protective relays are also transferred, the bus-tie relaying must be capable of protecting transmission lines or generation sources. This is considered rather unsatisfactory because relaying selectivity is poor.

A satisfactory alternative consists of connecting the line and bus relaying to current transformers located on the lines rather than on the breakers. For this arrangement, line and bus relaying need not be transferred when a circuit breaker is taken out of service for maintenance, with the bus-tie breaker used to keep the circuit energized.

If the main bus is ever taken out of service for maintenance, no circuit breakers remain to protect any of the feeder circuits. Failure of any breaker or failure of the main bus can cause complete loss of service of the station.

Due to its relative complexity, disconnect-switch operation with the main- and transfer-bus scheme can lead to operator error and a possible outage. Although this scheme is low in cost and enjoys some popularity, it may not provide as high a degree of reliability and flexibility as required.

Double Bus, Single Breaker. This scheme uses two main buses, and each circuit includes two bus selector disconnect switches. A bus-tie circuit (Fig. 17-3) connects to the two main buses and, when closed, allows transfer of a feeder from one bus to the other bus without deenergizing the feeder circuit by operating the bus selector disconnect switches. The circuits may all operate from either the no. 1 or no. 2 main bus, or half the circuits may be operated off either bus. In the first case, the station

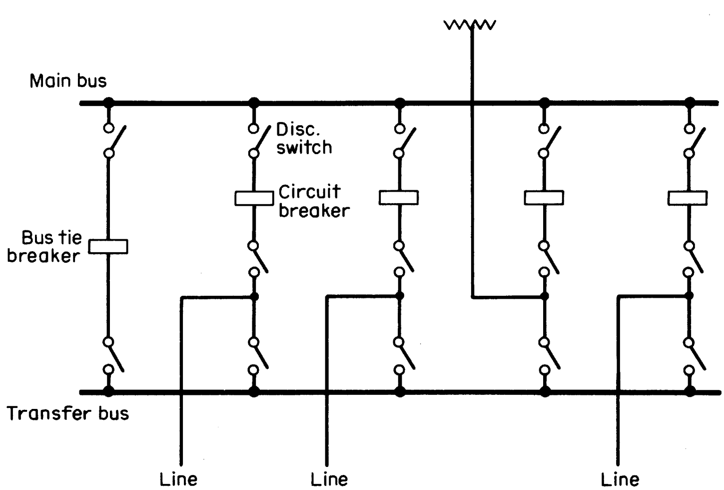


FIGURE 17-2 Main and transfer bus.

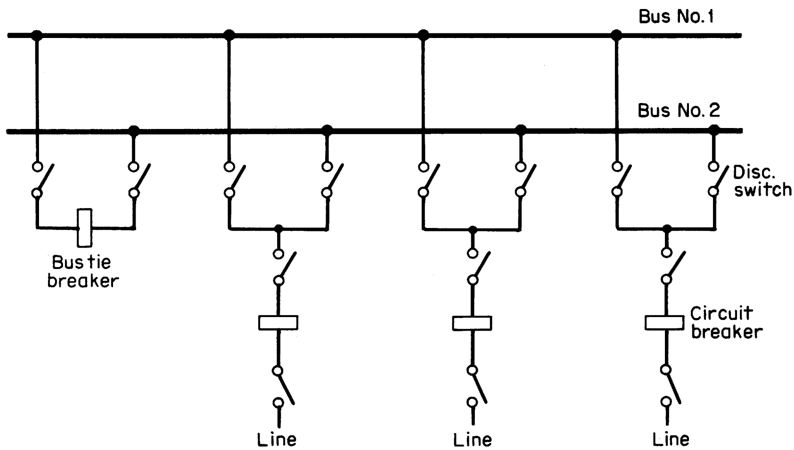


FIGURE 17-3 Double bus, single breaker.

will be out of service for bus or breaker failure. In the second case, half the circuits will be lost for bus or breaker failure.

In some cases circuits operate from both the no. 1 and no. 2 bus, and the bus-tie breaker is normally operated closed. For this type of operation, a very selective bus-protective relaying scheme is required to prevent complete loss of the station for a fault on either bus. Disconnect-switch operation becomes quite involved, with the possibility of operator error, injury, and possible outage. The double-bus, single-breaker scheme is relatively poor in reliability and is not normally used for important substations.

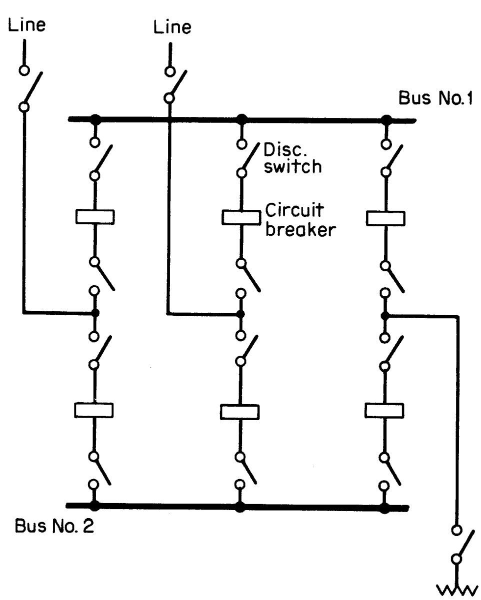


FIGURE 17-4 Double bus, double breaker.

Double Bus, Double Breaker. The double-bus, double breaker scheme (Fig. 17-4) requires two circuit breakers for each feeder circuit. Normally, each circuit is connected to both buses. In some cases, half the circuits operate on each bus. For these cases, a bus or breaker failure would cause loss of only half the circuits, which could be rapidly corrected through switching. The physical location of the two main buses must be selected in relation to each other to minimize the possibility of faults spreading to both buses. The use of two breakers per circuit makes this scheme expensive; however, it does represent a high degree of reliability.

Ring Bus. In the ring-bus scheme (Fig. 17-5), the breakers are arranged in a ring with circuits connected between breakers. There are the same number of circuits as there are breakers. During normal operation, all breakers are closed. For a circuit fault, two breakers are tripped, and in the event that one of the breakers fails to operate to clear the fault, an additional circuit will be tripped by operation of breaker-failure backup relays. During breaker maintenance, the ring is broken, but all lines remain in service.

The circuits connected to the ring are arranged so that sources are alternated with loads. For an extended circuit outage, the line-disconnect switch may be opened, and the ring can be closed. No changes to protective relays are required for any of the various operating conditions or during maintenance.

The ring-bus scheme is relatively economical in cost, has good reliability, is flexible, and is normally considered suitable for important substations up to a limit of five circuits. Protective relaying and automatic reclosing are more complex than for previously described schemes. It is common practice to build major substations initially as a ring bus; for more than five outgoing circuits, the ring bus is usually converted to the breaker-and-a-half scheme.

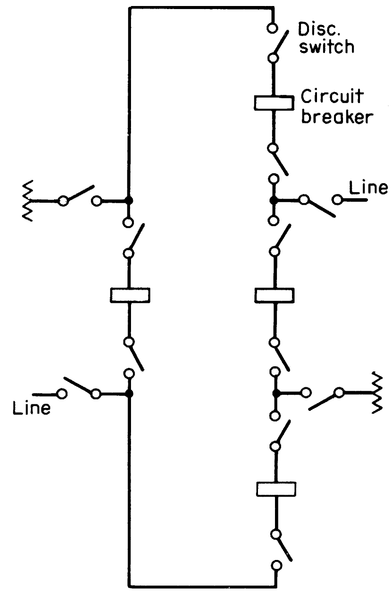


FIGURE 17-5 Ring bus.

Breaker and a Half. The breaker-and-a half scheme (Fig. 17-6), sometimes called the *three-switch scheme*, has three breakers in series between two main buses. Two circuits are connected between the three breakers, hence the term *breaker and a half*. This pattern is repeated along the main buses so that one and a half breakers are used for each circuit.

Under normal operating conditions, all breakers are closed, and both buses are energized. A circuit is tripped by opening the two associated circuit breakers. Tie-breaker failure will trip one additional circuit, but no additional circuit is lost if a line trip involves failure of a bus breaker. Either bus may be taken out of service at any time with no loss of service. With sources connected opposite to loads, it is possible to operate with both buses out of service. Breaker maintenance can be done with no loss of service, no relay changes, and simple operation of the breaker disconnects.

The breaker-and-a-half arrangement is more expensive than the other schemes, with the exception of the double-breaker, double-bus scheme, and protective relaying and automatic reclosing schemes are more complex than for other schemes. However, the breaker-and-a half scheme is superior in flexibility, reliability, and safety.

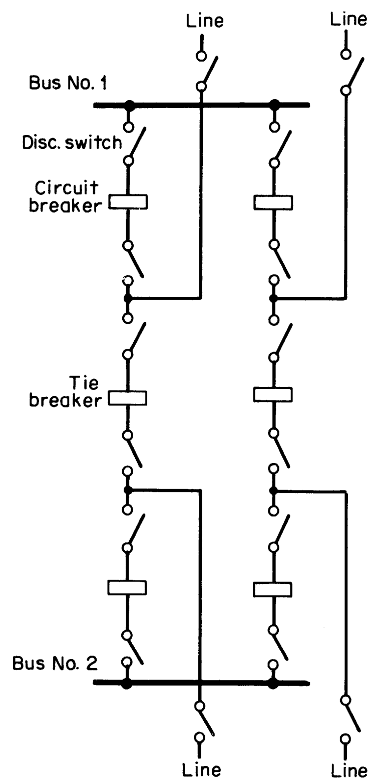


FIGURE 17-6 Breaker-and-a-half scheme.

17.1.3 Reliability Comparisons

The various schemes have been compared to emphasize their advantages and disadvantages. The basis of comparison to be employed is the economic justification of a particular degree of reliability. The determination of the degree of reliability involves an appraisal of anticipated operating conditions and the continuity of service required by the load to be served. Table 17-1 contains a summary of the comparison of switching schemes to show advantages and disadvantages.

TABLE 17-1 Summary of Comparison of Switching Schemes

Switching scheme	Advantages	Disadvantages
1. Single bus	1. Lowest cost.	1. Failure of bus or any circuit breaker results in shutdown of entire substation. 2. Difficult to do any maintenance. 3. Bus cannot be extended without completely deenergizing substation. 4. Can be used only where loads can be interrupted or have other supply arrangements.
2. Double bus, double breaker	1. Each circuit has two dedicated breakers. 2. Has flexibility in permitting feeder circuits to be connected to either bus. 3. Any breaker can be taken out of service for maintenance. 4. High reliability.	1. Most expensive. 2. Would lose half of the circuits for breaker failure if circuits are not connected to both buses.
3. Main and transfer	1. Low initial and ultimate cost. 2. Any breaker can be taken out of service for maintenance. 3. Potential devices may be used on the main bus for relaying.	1. Requires one extra breaker for the bus tie. 2. Switching is somewhat complicated when maintaining a breaker. 3. Failure of bus or any circuit breaker results in shutdown of entire substation.
4. Double bus, single breaker	1. Permits some flexibility with two operating buses. 2. Either main bus may be isolated for maintenance. 3. Circuit can be transferred readily from one bus to the other by use of bus-tie breaker and bus selector disconnect switches.	1. One extra breaker is required for the bus tie. 2. Four switches are required per circuit. 3. Bus protection scheme may cause loss of substation when it operates if all circuits are connected to that bus. 4. High exposure to bus faults. 5. Line breaker failure takes all circuits connected to that bus out of service. 6. Bus-tie breaker failure takes entire substation out of service.
5. Ring bus	1. Low initial and ultimate cost. 2. Flexible operation for breaker maintenance. 3. Any breaker can be removed for maintenance without interrupting load. 4. Requires only one breaker per circuit. 5. Does not use main bus. 6. Each circuit is fed by two breakers. 7. All switching is done with breakers.	1. If a fault occurs during a breaker maintenance period, the ring can be separated into two sections. 2. Automatic reclosing and protective relaying circuitry rather complex. 3. If a single set of relays is used, the circuit must be taken out of service to maintain the relays. (Common on all schemes.) 4. Requires potential devices on all circuits since there is no definite potential reference point. These devices may be required in all cases for synchronizing, live line, or voltage indication. 5. Breaker failure during a fault on one of the circuits causes loss of one additional circuit owing to operation of breaker-failure relaying.
6. Breaker and a half	1. Most flexible operation. 2. High reliability. 3. Breaker failure of bus side breakers removes only one circuit from service. 4. All switching is done with breakers. 5. Simple operation; no disconnect switching required for normal operation. 6. Either main bus can be taken out of service at any time for maintenance. 7. Bus failure does not remove any feeder circuits from service.	1. $1^1/_2$ breakers per circuit. 2. Relaying and automatic reclosing are somewhat involved since the middle breaker must be responsive to either of its associated circuits.

17.1.4 Arrangements and Equipment

Once a determination of the switching scheme best suited for a particular substation application is made, it is necessary to consider the station arrangement and equipment that will satisfy the many physical requirements of the design. Available to the design engineer are the following:

1. Conventional outdoor air-insulated open-type bus-and-switch arrangement substations (using either a strain bus or rigid bus design)
2. Metal-clad or metal-enclosed substations
3. Gas (sulfur hexafluoride)–insulated substations

Outdoor open-type bus-and-switch arrangements generally are used because of their lower cost, but they are larger in overall physical size. Metal-clad substations generally are limited to 38 kV. Gas-insulated substations are generally the highest in cost but smallest in size.

Substation Components. The electrical equipment in a typical substation can include the following:

Circuit breakers
Disconnecting switches
Grounding switches
Current transformers
Voltage transformers or capacitor voltage transformers
Coupling capacitors
Line traps
Surge arresters
Power transformers
Shunt reactors
Current-limiting reactors
Station buses and insulators
Grounding systems
Series capacitors
Shunt capacitors

Support Structures. In order to properly support, mount, and install the electrical equipment, structures made of steel, aluminum, wood, or concrete and associate foundations are required. The typical open-type substation requires strain structures to support the transmission-line conductors; support structures for disconnecting switches, current transformers, potential transformers, lightning arresters, and line traps, capacitor voltage transformers; and structures and supports for the strain and rigid buses in the station.

When the structures are made of steel or aluminum, they require concrete foundations; however, when they are made of wood or concrete, concrete foundations are not required. Additional work is required to design concrete foundations for supporting circuit breakers, reactors, transformers, capacitors, and any other heavy electrical equipment.

Substation-equipment support structures fabricated of steel or aluminum may consist of single wide-flange or tubular-type columns, rigid-frame structures composed of wide flanges or tubular sections, or lattice structures composed of angle members. Substation strain structures can be wood or concrete pole structures, aluminum or steel lattice-type structures, or steel A-frame structures. Aluminum, weathering steel, and concrete pole structures can be used in their natural unfinished state. Normal carbon-steel structures should have galvanized or painted finishes. Wood structures should have a thermal- or pressure-process-applied preservative finish.

Aluminum structures are lightweight, have an excellent strength-to-weight ratio, and require little maintenance but have a greater initial cost than steel structures. Weathering-steel structures can be field-welded without the special surface preparation and touch-up work required on galvanized or painted steel structures, and the self-forming protective corrosion oxide eliminates maintenance. In addition, the weathering-steel color blends well in natural surroundings. Galvanized- or painted-steel structures have a slightly lower initial cost than weathering-steel structures; however, they require special treatment before and after field welding and require more maintenance.

Lattice-type structures are light in weight, have a small wind-load area, and are low in cost. Single-column support structures and rigid-frame structures require little maintenance, are more aesthetically pleasing, and can be inspected more quickly than lattice structures, but they have a greater initial cost. In order to reduce erection costs, rigid-frame structures should be designed with bolted field connections.

The design of supporting structures is affected by the phase spacings and ground clearances required, by the types of insulators, by the length and weight of buses and other equipment, and by wind and ice loading. For data on wind and ice loadings, see National Electric Safety Code©, IEEE Standard C2-2002, or latest edition. For required clearances and phase spacings, see Part I, Secs. 11 and 12.

Other structural and concrete work required in the substation includes site selection and preparation, roads, control houses, manholes, conduits, ducts, drainage facilities, catch basins, oil containment, and fences.

17.1.5 Site Selection

Civil engineering work associated with the substation should be initiated as early as possible in order to ensure that the best available site is selected. This work includes a study of the topography and drainage patterns of the area together with a subsurface soil investigation. The information obtained from the subsurface soil investigation also will be used to determine the design of the substation foundations. For large substations or substations located in area with poor soils, it may be necessary to obtain additional subsurface soil tests after final selection of the substation site has been made. The additional information should fully describe the quality of the soil at the site, since the data will be used to design equipment foundations.

Open-Bus Arrangement. An air-insulated, open-bus substation arrangement consists essentially of open-bus construction using either rigid- or strain-bus design such as the breaker-and-a-half arrangement shown in Fig. 17-7; the buses are arranged to run the length of the station and are located toward the outside of the station. The transmission-line exits cross over the main bus and are dead-ended on takeoff tower structures. The line drops into the bay in the station and connects to the disconnecting switches and circuit breakers.

Use of this arrangement requires three distinct levels of bus to make the necessary crossovers and connections to each substation bay. Typical dimensions of these levels at 230 kV are 16 ft for the first level above ground, 30 ft high for the main bus location, and 57 ft for the highest level of bus (see Fig. 17-7).

This arrangement, in use since the mid-1920s and widely used by many electric utilities, has the advantage of requiring a minimum of land area per bay and relative ease of maintenance, and it is ideally suited to a transmission-line through-connection where a substation must be inserted into a transmission line.

Inverted Bus. An alternate arrangement is the inverted-bus, breaker-and-a-half scheme for EHV substations. A typical layout is outlined in Fig. 17-8. A one-line diagram of a station showing many variations of the inverted-bus scheme is presented in Fig. 17-9. With this arrangement, all outgoing circuit takeoff towers are located in the outer perimeter of the substation, eliminating the crossover of line or exit facilities. Main buses are located in the middle of the substation, with all disconnecting switches, circuit breakers, and bay equipment located outboard of the main buses. The end result of

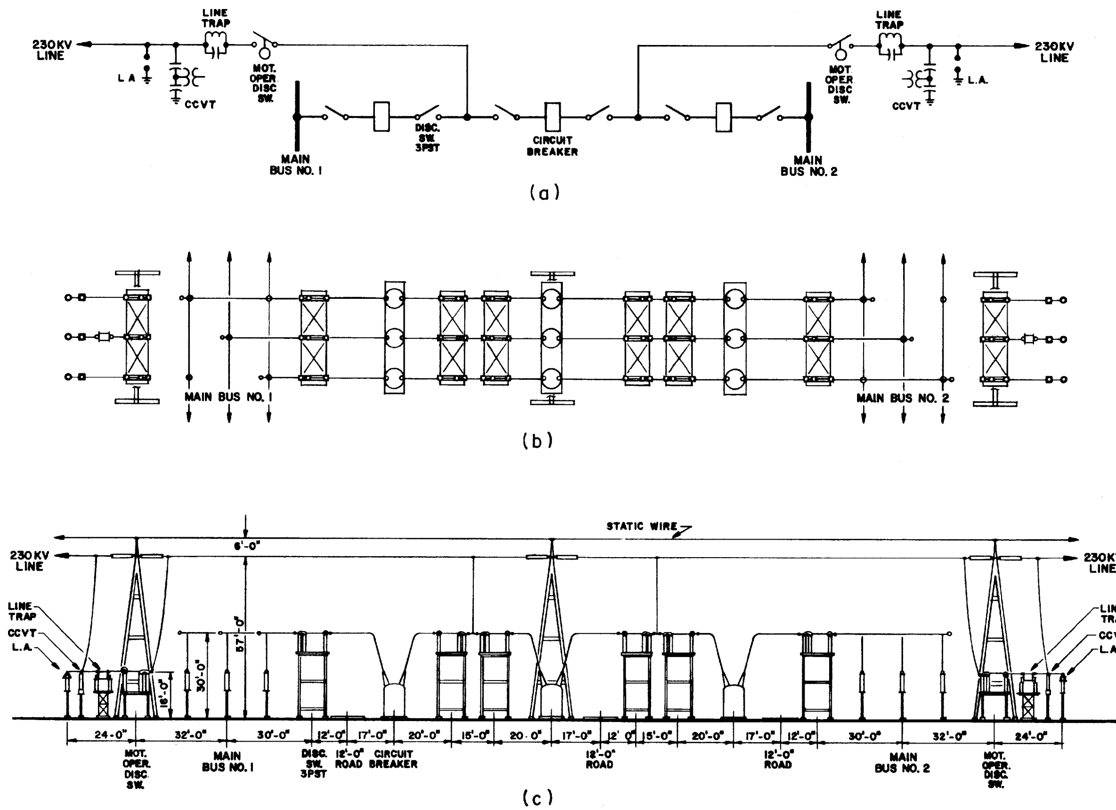


FIGURE 17-7 Typical conventional substation layout, breaker-and-a-half scheme. (*a*) Main one-line diagram; (*b*) plan; (*c*) elevation.

the inverted-bus arrangement presents a very low profile station with many advantages in areas where beauty and aesthetic qualities are a necessity for good public relations. The overall height of the highest bus in the 230-kV station just indicated reduces from a height of 57 ft above ground in the conventional arrangement to a height of only 30 ft above ground for the inverted-bus low-profile scheme.

17.1.6 Substation Buses

Substation buses are an important part of the substation because they carry electric currents in a confined space. They must be carefully designed to have sufficient structural strength to withstand the maximum stresses that may be imposed on the conductors, and in turn on the supporting structures, due to short-circuit currents, high winds, and ice loadings.

During their early development, HV class substations were usually of the strain-bus design. The strain bus is similar to a transmission line and consists of a conductor such as ACSR (aluminum cable steel reinforced), copper, or high-strength aluminum alloy strung between substation structures. EHV substations normally use the rigid-bus approach and enjoy the advantage of low station profile and ease of maintenance and operation (see Fig. 17-8). The mixing of rigid- and strain-bus construction is normally employed in the conventional arrangement shown in Fig. 17-7. Here, the main buses use rigid-bus design, and the upper buses between transmission towers are of strain-bus design. A typical design at 765 kV uses a combination of both rigid and strain buses (Fig. 17-10).

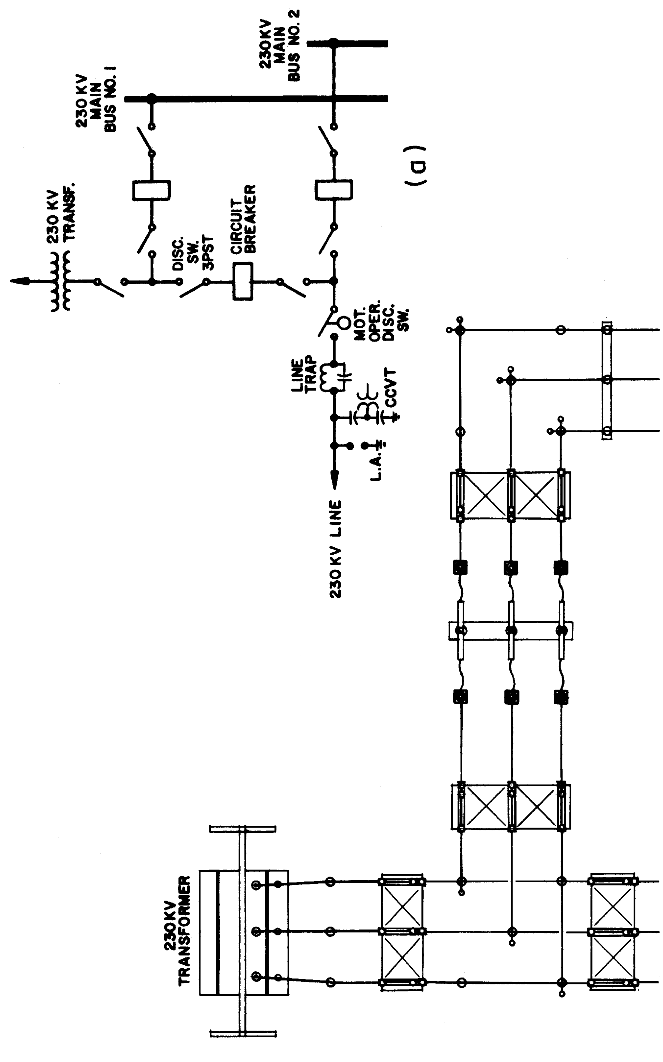


FIGURE 17-8 Typical 130-kV inverted-bus substation. (*a*) One-line diagram; (*b*) plan; (*c*) elevation.

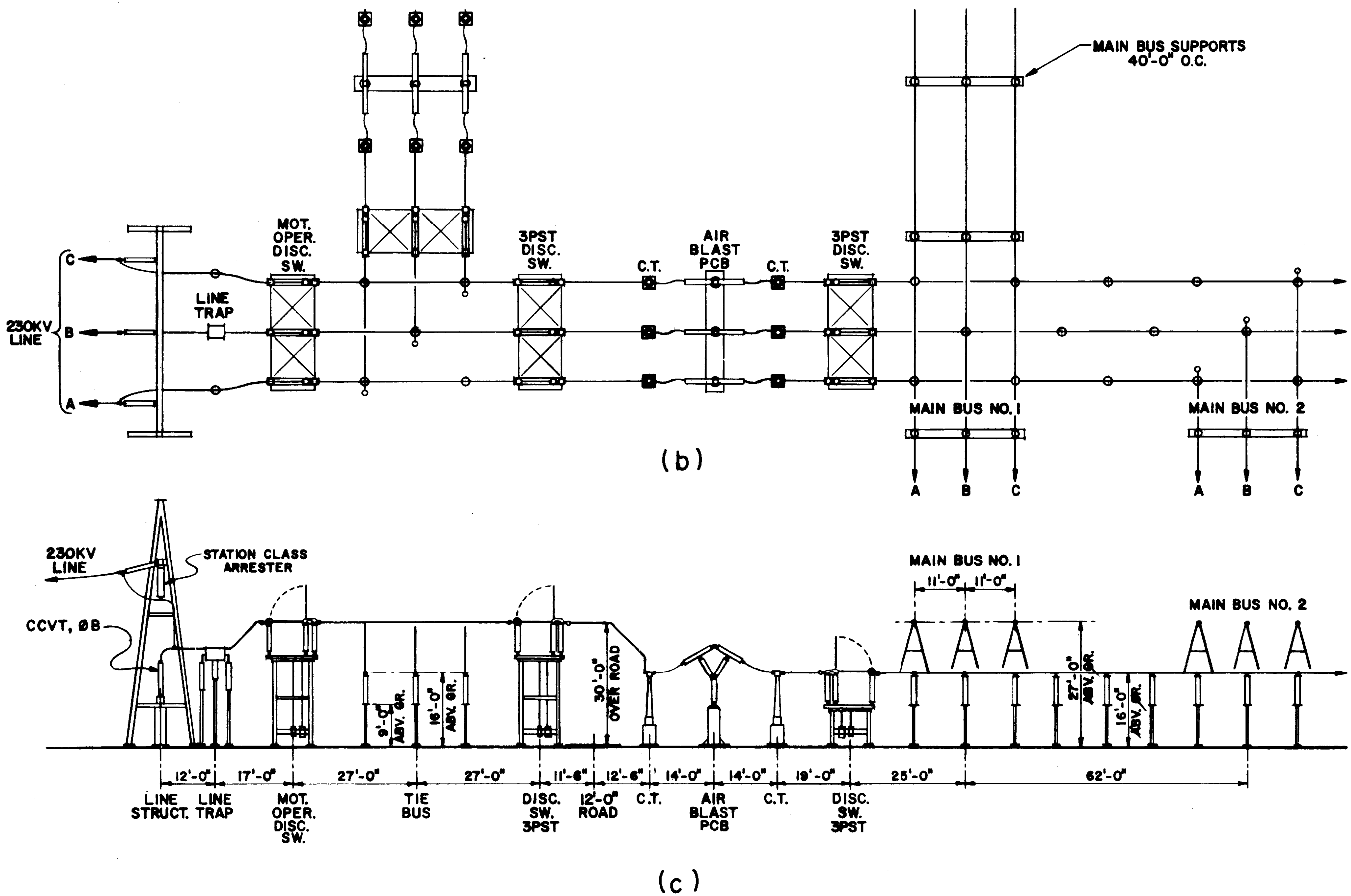


FIGURE 17-8 Typical 130-kV inverted-bus substation. (*a*) One-line diagram; (*b*) plan; (*c*) elevation.

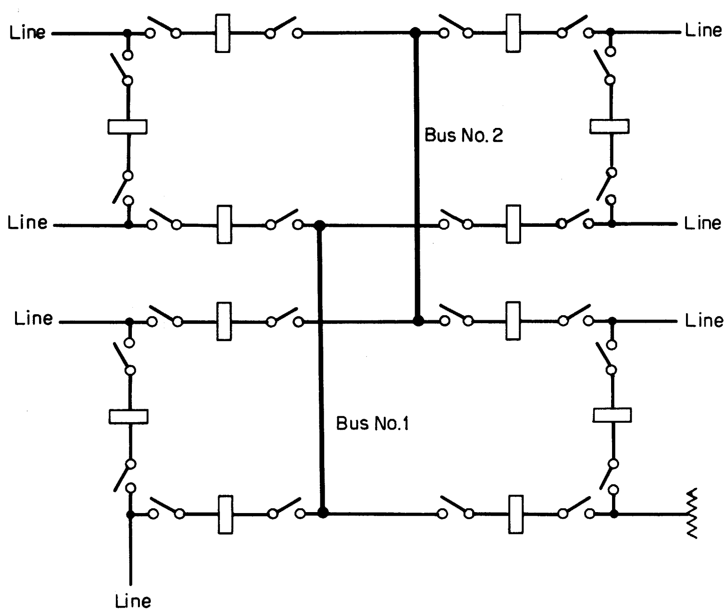


FIGURE 17-9 EHV substation, low-profile, inverted breaker-and-a-half scheme.

A comparison of rigid and strain buses indicates that careful consideration should be given to selection of the proper type of bus to use.

Rigid-bus advantages:

1. Less steel is used, and structures are of a simpler design.
2. Rigid conductors are not under constant strain.
3. Individual pedestal-mounted insulators are more accessible for cleaning.
4. The rigid bus is lower in height, has a distinct layout, and can be definitely segregated for maintenance.
5. Low profile with the rigid bus provides good visibility of the conductors and apparatus and gives a good appearance to the substation.

Rigid-bus disadvantages:

1. More insulators and supports are usually needed for rigid-bus design, thus requiring more insulators to clean.
2. The rigid bus is more sensitive to structural deflections, causing misalignment problems and possible damage to the bus.
3. The rigid bus usually requires more land area than the strain bus.
4. Rigid-bus designs are comparatively expensive.

Strain-bus advantages:

1. Comparatively lower cost than the rigid bus.
2. Substations employing the strain bus may occupy less land area than stations using the rigid bus.
3. Fewer structures are required.

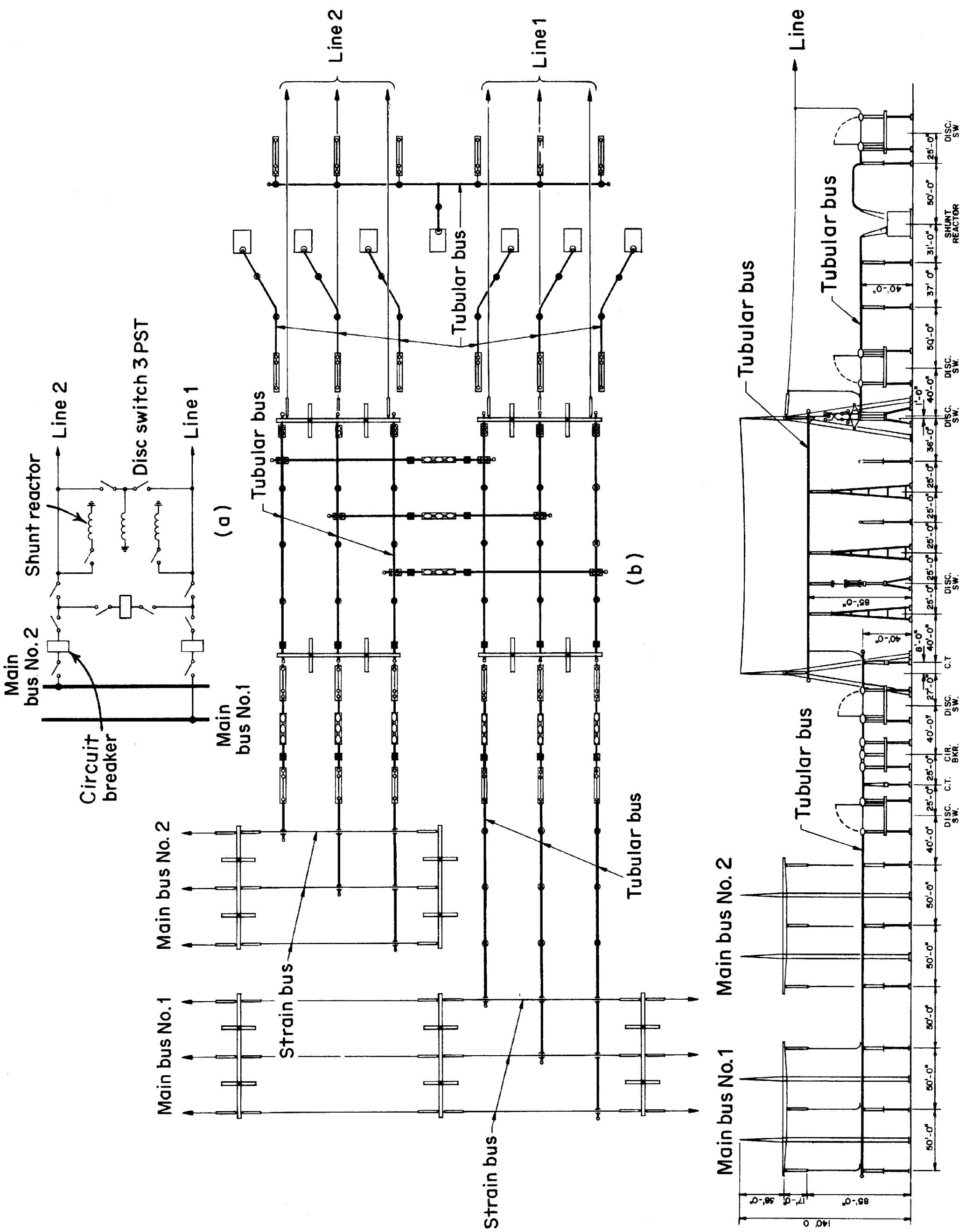


FIGURE 17-10 A 765-kV substation using both rigid- and strain-bus design. (*a*) Main one-line diagram; (*b*) plan; (*c*) elevation.

Strain-bus disadvantages:

1. Strain structures require larger structures and foundations.
2. Insulators are not conveniently accessible for cleaning.
3. Painting of high-steel structures is costly and hazardous.
4. Emergency conductor repairs are more difficult.

The design of station buses depends on a number of elements, which include the following:

1. Current-carrying capacity
2. Short-circuit stresses
3. Minimum electrical clearances

The current-carrying capacity of a bus is limited by the heating effects produced by the current. Buses generally are rated on the basis of the temperature rise, which can be permitted without danger of overheating equipment terminals, bus connections, and joints.

The permissible temperature rise for plain copper and aluminum buses is usually limited to 30°C above an ambient temperature of 40°C. This value is the accepted standard of IEEE, NEMA, and ANSI. This is an average temperature rise; a maximum or hot-spot temperature rise of 35°C is permissible. Many factors enter into the heating of a bus, such as the type of material used, the size and shape of the conductor, the surface area of the conductor and its condition, skin effect, proximity effect, conductor reactance, ventilation, and inductive heating caused by the proximity of magnetic materials.

Rigid-Bus Material. Rigid-bus materials in general use are aluminum and copper. Hard-drawn aluminum, especially in the tubular shape, is the most widely used material in HV and EHV open-type outdoor stations. Aluminum has the advantage of being about one-third the weight of copper and requires little maintenance. The proper use of alloys of aluminum will provide the rigidity needed to serve as a bus material. For a given current rating and for equal limiting temperatures, the required area of aluminum bus is about 133% of the area of the copper bus. Copper and aluminum tubing, as well as other special shapes, are also used for low-voltage distribution substation buses.

Skin Effect. *Skin effect* in a conductor carrying an alternating current is the tendency toward crowding of the current into the outer layer, or "skin," of the conductor due to the self-inductance of the conductor. This results in an increase in the effective resistance of the conductor and in a lower current rating for a given temperature rise. Skin effect is very important in heavy-current buses where a number of conductors are used in parallel, because it affects not only each conductor but also each group of conductors as a unit.

Tubing has less skin-effect resistance than rod or flat conductors of the same cross section, and tubing with a thin wall is affected the least by skin effect. Aluminum conductors are affected less by skin effect than copper conductors of similar cross section because of the greater resistance of aluminum.

Proximity Effect. *Proximity effect* in a bus is distortion of the current distribution caused by induction between the leaving and returning conductors. This distortion causes a concentration of current in the parts of the buses nearest together, thus increasing their effective resistance. The proximity effect must be taken into account for buses carrying alternating current. The effect is less on three-phase buses than on single-phase buses.

Tubular Bus. Tubular conductors used on alternating current have a better current distribution than any other shape of conductor of similar cross-sectional area, but they also have a relatively small surface area for dissipating heat losses. These two factors must be balanced properly in the design of a tubular bus.

TABLE 17-2 Current Ratings for Bare Copper Tubular Bus, Outdoors
(40°C ambient temperature, 98% conductivity copper, frequency 60 Hz, wind velocity 2 ft/s at 90° angle)

Nominal size	Outside diameter, in	Inside diameter, in	Current ratings, A		
			30°C rise	40°C rise	50°C rise
Standard pipe sizes					
1/2	0.840	0.625	545	615	675
3/4	1.050	0.822	675	765	850
1	1.315	1.062	850	975	1080
1 1/4	1.660	1.368	1120	1275	1415
1 1/2	1.900	1.600	1270	1445	1600
2	2.375	2.062	1570	1780	1980
2 1/2	2.875	2.500	1990	2275	2525
3	3.500	3.062	2540	2870	3225
3 1/2	4.000	3.500	3020	3465	3860
4	4.500	4.000	3365	3810	4305
Extra-heavy pipe sizes					
1/2	0.840	0.542	615	705	775
3/4	1.050	0.736	760	875	970
1	1.315	0.951	1000	1140	1255
1 1/4	1.660	1.272	1255	1445	1600
1 1/2	1.900	1.494	1445	1650	1830
2	2.375	1.933	1830	2080	2325
2 1/2	2.875	2.315	2365	2720	3020
3	3.500	2.892	2970	3365	3710
3 1/2	4.000	3.358	3380	3860	4255
4	4.500	3.818	3840	4350	4850

Note: 1 in = 25.4 mm; 1 ft/s = 0.3048 m/s.
Source: From Anderson Electric Technical Data, Table 13.

Tubing provides a relatively large cross-sectional area in minimum space and has the maximum structural strength for equivalent cross-sectional area, permitting longer distances between supports. In outdoor substations, spans of up to 40 and 50 ft with 6-in-diameter copper or aluminum tubes are considered practicable. The use of long spans reduces the number of insulator posts to a minimum. Current-carrying capacities of copper and aluminum tubular buses of different dimensions are shown in Tables 17-2 and 17-3.

Thermal Expansion. Thermal expansion and contraction of bus conductors is an important factor in bus design, particularly where high-current buses or buses of long lengths are involved. An aluminum bus will expand 0.0105 in/ft of length for a temperature rise of 38°C (100°F). In order to protect insulator supports, disconnecting switches, and equipment terminals from the stresses caused by this expansion, provisions should be made by means of expansion joints and bus-support clamps, which permit the tubing to slide.

Bus Vibration. Long tubular-bus spans have experienced vibration caused by wind blowing across the bus. Over time, this vibration can damage the bus and the equipment connected to the bus. The vibration can be eliminated or reduced by inserting a length of cable inside the tubular bus.

Bus Spacing. The spacing of buses in substations is largely a matter of design experience. However, in an attempt to arrive at some standardization of practices, minimum electrical clearances for standard basic insulation levels were established and published by the AIEE Committee on

TABLE 17-3 Current Ratings for Bare Aluminum Tubular Bus, Outdoors
(Ratings based on 30°C over 40°C ambient, frequency 60 Hz, wind velocity 2 ft/s crosswind)

Nominal size	Outside diameter, in	Inside diameter, in	Current ratings, A	
			6063-T6*	6061-T6†
ASA Schedule 40 (standard pipe size)				
1/2	0.840	0.622	405	355
3/4	1.050	0.824	495	440
1	1.315	1.049	650	575
1 1/4	1.660	1.380	810	720
1 1/2	1.900	1.610	925	820
2	2.375	2.067	1150	1020
2 1/2	2.875	2.469	1550	1370
3	3.500	3.068	1890	1670
3 1/2	4.000	3.548	2170	1920
4	4.500	4.026	2460	2180
5	5.563	5.047	3080	2730
ASA Schedule 80 (extra-heavy pipe size)				
1/2	0.840	0.546	455	400
3/4	1.050	0.742	565	500
1	1.315	0.957	740	655
1 1/4	1.660	1.278	930	825
1 1/2	1.900	1.500	1070	945
2	2.375	1.939	1350	1200
2 1/2	2.875	2.323	1780	1580
3	3.500	2.900	2190	1940
3 1/2	4.000	3.364	2530	2240
4	4.500	3.826	2880	2560
5	5.563	4.813	3640	3230

*6063-T6 = 53% IACS typical.
†6061-T6 = 40% IACS typical.
Note: 1 in = 25.4 mm.
Source: Data from Aluminum Company of America.

Substations. The data are summarized in AIEE Paper 54-80, which appeared in *Transactions* (June 1954, p. 636). This guide, shown in Table 17-4, provides minimum clearance recommendations for electric transmission systems designed for impulse-withstand levels up to and including 1175 kV BIL.

Ongoing studies attempt to extend the clearance recommendations to include the EHV range. The data published in 1954 are satisfactory to withstand anticipated switching-surge requirements of electric systems rated 161 kV and below. For systems rated 230 kV and above, more accurate determination of the switching-surge characteristics of insulation systems was required before final clearance recommendations could be made.

17.1.7 Clearance Requirements

In 1972, the Substations Committee of the IEEE published Trans. Paper T72 131-6, which established recommendations for minimum line-to-ground electrical clearances for EHV substations based on switching-surge requirements. The recommendations are based on a study of actual test data of the switching-surge strength characteristics of air gaps with various electrode configurations as reported by many investigators. The results are shown in Table 17-5 and include minimum line-to-ground clearances for EHV system voltage ratings of 345, 500, and 765 kV. The clearances given in Table 17-4 are considered adequate for both line-to-ground and phase-to-phase values for the voltage

TABLE 17-4 Minimum Electrical Clearances for Standard BIL Outdoor Alternating Current

kV class[a]	BIL level, kV withstand[b]	Minimum clearance to ground for rigid parts, in[c]	Minimum clearance between phases (or live parts) for rigid parts, in, metal to metal[d]	Minimum clearance between overhead conductors and grade for personnel safety inside substation, ft[e]	Minimum clearance between wires and roadways, inside substation enclosure, ft
7.5	95	6	7	8	20
15	110	7	12	9	20
23	150	10	15	10	22
34.5	200	13	18	10	22
46	250	17	21	10	22
69	350	25	31	11	23
115	550	42	53	12	25
138	650	50	62	13	25
161	750	58	72	14	26
230	825	65	80	15	27
230	900	71	89	15	27
	1050	83	105	16	28
	1175	94	113	17	29

[a] Coordinate kV class and BIL when choosing minimum clearances.
[b] The values above are recommended minimums but may be decreased in line with good practice, depending on local conditions, procedures, etc.
[c] The values above apply to 3300 ft above sea level. Above this elevation, the values should be increased according to IEEE Standard C37.30-1992.
[d] These recommended minimum clearances are for rigid conductors. Any structural tolerances, or allowances for conductor movement, or possible reduction in spacing by foreign objects should be added to the minimum values.
[e] These minimum clearances are intended as a guide for the installation of equipment in the field only, and not for the design of electric devices or apparatus, such as circuit breakers and transformers. 1 in = 25.4 mm; 1 ft = 0.3048 m.

classes up through 230 kV nominal system voltage where air-gap distances are dictated by impulse (BIL) withstand characteristics. The National Electric Safety Code, IEEE Standard C2-2002, also includes clearance requirements to the substation fence (Fig. 17-11).

The Substations Committee of the IEEE has an ongoing effort to review phase-to-phase air clearances and is currently balloting IEEE Standard P1427, Guide for Recommended Electrical Clearances and Insulation Levels in Air Insulated Power Substations.

Considerable information has been published by CIGRE relative to establishing phase-to-phase air clearances in EHV substations as required by switching surges. The CIGRE method is based on nearly simultaneous and equal opposite-polarity surge overvoltages in adjacent phases. The phase-to-ground surge overvoltage is multiplied by a factor of up to 1.8 (the theoretical maximum phase-to-phase voltage would be twice the phase-to-ground surge overvoltage). The estimated value of phase-to-phase overvoltage is then compared with obtained clearances. Refer to an article in CIGRE, *Electra*, no. 29, 1973, "Phase-to-Ground and Phase-to-Phase Air Clearances in Substations," by L. Paris and A. Taschini.

Suggested values of phase-to-phase clearances for EHV substations based on the CIGRE method are shown in Table 17-6. The table was formulated by choosing various phase-to-ground transient voltage values such as are used in Table 17-5. These values of phase-to-ground overvoltage were multiplied by a factor of 1.8 to arrive at a value of estimated phase-to-phase transient overvoltages. An equivalent phase-to-phase critical flashover value of voltage is next assumed by multiplying the switching-surge phase-to-phase voltage by 1.21. Finally, this value is compared with data in the CIGRE article prepared by Paris and Taschini to arrive at air-clearance values based on switching-surge impulse voltages.

EHV substation bus phase spacing is normally based on the clearance required for switching-surge impulse values plus an allowance for energized equipment projections and corona rings. This total distance may be further increased to facilitate substation maintenance.

TABLE 17-5 Minimum Electrical Clearances for EHV Substations Based on Switching Surge and Lightning Impulse Requirements
(Line to ground)

System voltage, kV		Transient voltage		SS clearances, in		BIL clearances, in	
Nom.	Max.	PU SS	Withstand SS crest, kV	Equivalent SS CFO, kV	Line to ground	Withstand BIL, kV	Line to ground
345	362	2.2	650	785	84	1050	84
		2.3	680	821	90		
		2.4	709	857	96		
		2.5	739	893	104	1300	104
		2.6	768	928	111		
		2.7	798	964	118		
		2.8	828	1000	125		
		2.9	857	1035	133		
		3.0	887	1071	140		
500	550	1.8	808	976	124	1550	124
		1.9	853	1031	132		
		2.0	898	1085	144	1800	144
		2.1	943	1139	156		
		2.2	988	1193	168		
		2.3	1033	1248	181		
		2.4	1078	1302	194		
		2.5	1123	1356	208		
		2.6	1167	1410	222		
		2.7	1212	1464	238		
		2.8	1257	1519	251		
765	800	1.5	982	1186	166	2050	167
		1.6	1047	1265	185		
		1.7	1113	1344	205		
		1.8	1178	1423	225		
		1.9	1244	1502	246		
		2.0	1309	1581	268		
		2.1	1375	1660	291		
		2.2	1440	1739	314		
		2.3	1505	1818	339		
		2.4	1571	1897	363		
		2.5	1636	1976	389		
		2.6	1702	2055	415		

Notes:

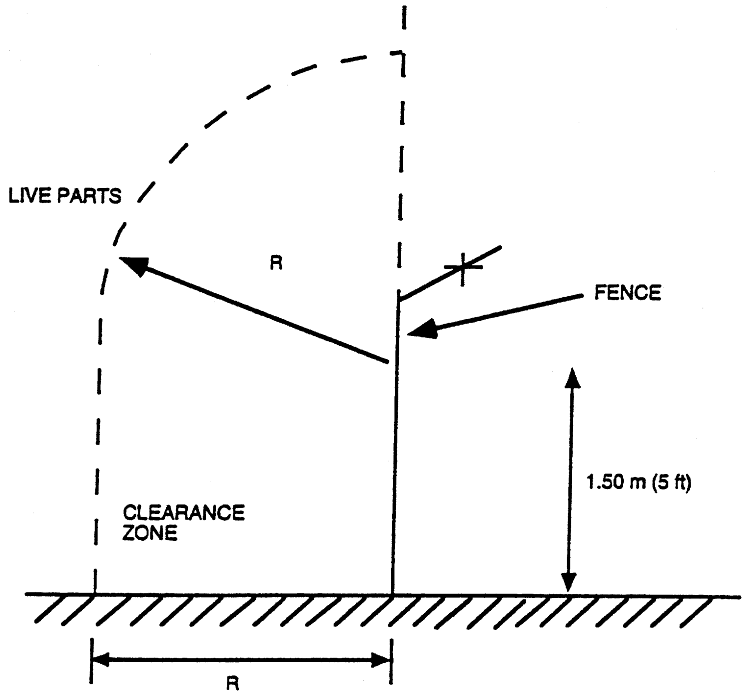
1. Minimum clearances should satisfy either maximum switching-surge or BIL duty requirement, whichever dictates the larger dimension.
2. For installations at altitudes in excess of 3300 ft elevation, it is suggested that correction factors, as provided in IEEE C37.30-1992, be applied to withstand voltages as given above.

SS: switching surge
CFO: critical flashover
1 in = 25.4 mm.

17.1.8 Mechanical and Electrical Forces

A station bus must have sufficient mechanical strength to withstand short-circuit stresses. Two factors are involved: (1) the strength of the insulators and their supporting structure and (2) the strength of the bus conductor.

A simple guide for the calculation of electromagnetic forces exerted on buses during short-circuit conditions is stated in ANSI Standard C37.32-2002, High-Voltage Switches, Bus Supports, and Accessories Schedules of Preferred Ratings, Construction Guidelines and Specifications.



Nominal voltage between phases	Typical BIL	Dimension R m	Dimension R ft
151-7200	95	3.0	10.0
13,800	110	3.1	10.1
23,000	150	3.1	10.3
34,500	200	3.2	10.6
46,000	250	3.3	10.9
69,000	350	3.5	11.6
115,000	550	4.0	13.0
138,000	650	4.2	13.7
161,000	750	4.4	14.3
230,000	825	4.5	14.9
230,000	900	4.7	15.4
345,000	1050	5.0	16.4
500,000	1175	5.3	17.3

FIGURE 17-11 Substation fence clearance requirements. *(National Electrical Safety Code, IEEE C2-2002.)*

The electromagnetic force exerted between two current-carrying conductors is a function of the current, its decrement rate, the shape and arrangement of conductors, and the natural frequencies of the complete assembly, including mounting structure, insulators, and conductors. Obviously, it is not feasible to cover each and every case with one simple equation, even if some approximations are made, because of the large number of variables involved, including the wide range of constants for support structures.

The force calculated by the following equation is that produced by the maximum peak current. In most cases, the calculated force is higher than that which actually occurs, due to inertia and flexibility

TABLE 17-6 Suggested Electrical Clearances for EHV Substations Based on Switching Surge Requirements and Including U.S. Utility Practice
(Phase to phase)

System voltage, kV		Transient voltage		SS clearances, in*		Present practice
Nom.	Max.	SS L-G PU	Withstand SS crest, kV	Equivalent L-L SS CFO, kV	Rod to rod withstand*	U.S. utility phase spacing, ft
345	362	2.2	650	1405	103	15 to 18
		2.6	768	1660	128	
		3.0	887	1915	159	
500	550	1.8	808	1745	138	20 to 35
		2.2	988	2135	190	
		2.5	1123	2425	239	
		2.8	1257	2715	294	
765	800	1.5	982	2120	189	45 to 50
		1.8	1178	2545	261	
		2.1	1375	2970	356	
		2.4	1571	3395	480	

Note: 1 in = 25.4 mm; 1 ft = 0.3048 m.
*The values of L-L switching-surge clearances are based on the use of SS L-G crest voltages multiplied by 1.8. This value of L-L SS voltage is then multiplied by 1.21 to indicate an SS CFO value of voltage used to determine the clearances. For a description of method used, refer to CIGRE report by L. Paris and A. Taschini, Phase-to-Ground and Phase-to-Phase Air Clearances in Substations, CIGRE, *Electra*, no. 29, 1973, pp. 29–44. L-G: line-to-ground; L-L: line-to-line; SS: switching surge; CFO: critical flashover.

of the systems, and this fact tends to compensate for the neglect of resonant forces. The equation, therefore, is sufficiently accurate for usual practice conditions.

$$F = M\frac{5.5 \times I^2}{S \times 10^7} \tag{17-1}$$

where F = pounds per foot of conductor
M = multiplying factor
I = short-circuit current, A (defined in Table 17-7)
S = spacing between centerlines of conductors, in

After determining the value of I, select the corresponding M factor from Table 17-7.

Structures with long spans held in tension by strain insulators cannot be calculated for stresses by the preceding procedure, but approximate estimates can be made by following the procedure generally used for calculating mechanical stresses in transmission-line conductors.

TABLE 17-7 Multiplying Factor (M) for Calculation of Electromagnetic Forces

Circuit	Amperes (I) expressed as	Multiplying factor (M)
dc	Max. peak	1.0
ac, 3-phase	Max. peak	0.866
ac, 3-phase	rms asymmetrical	$(0.866 \times 1.63^2) = 2.3$
ac, 3-phase	rms symmetrical	$(0.866 \times 2.82^2) = 6.9$
1 phase of 3 phase or 1 phase	Max peak	1.0
1 phase of 3 phase or 1 phase	rms asymmetrical	$(1.63^2) = 2.66$
1 phase of 3 phase or 1 phase	rms symmetrical	$(2.82^2) = 8.0$

The total stress in an outdoor bus is the resultant of the stresses due to the short-circuit load together with the dead, ice, and wind loads.

1. *Buses up to 161 kV.* The distance between phases and the character of the bus supports and their spacing are such that wind loading usually may be neglected. Ice load of $^1/_2$ in is usually considered.
2. *Buses for 230 kV and higher voltages.* The spacing between phases is usually so large that the mechanical effects of short-circuit currents may not be the determining factor, and such buses, when designed properly for the mechanical loads only, may be found to also satisfy the electrical short-circuit current requirements. However, short-circuit duties on modern systems continue to rise, and the electrical forces should be checked by Eq. (17-1).

Deflections and stresses on aluminum buses can be determined by referring to Tables 17-8 and 17-9. All loads are assumed to be uniformly distributed. Loading includes the dead load of the bus and, in addition, includes ice loadings of $^1/_2$- and 1-in coating on the bus. Wind loads are assumed to be 8 lb/ft^2 of the projected area of tubing including $^1/_2$ in of ice. Large deflections should be avoided even if the maximum bending stress is found to be within safe limits. It is generally satisfactory, in approximation of bus diameter, to allow 1 in of bus outside diameter for every 10 ft of bus span. Refer to the foot notes below Tables 17-8 and 17-9 for the method of support and number of spans.

Stresses on disconnecting switches under short-circuit conditions may be sufficient to open them, with disastrous results; therefore, modern switch designs embody locks, or overtoggle mechanisms, to prevent this from occurring. The force on the switchblade varies as the square of the current. This force will be increased if the return circuit passes behind the switch and will vary inversely with the distance from the center of the switchblade to the center of the return conductor.

Bus supports are designed for definite cantilever strength, expressed in inch pounds and measured at the cap supporting the conductor clamp. Ample margin of safety with regard to insulation and structural strength should be provided, manufacturers' data should be checked carefully, and units should be so selected that allowable values for the particular units are not exceeded. Good practice recommends that the working load must not exceed 40% of the published rating, and short-circuit loads must not exceed the insulator published rating. These loads should include forces for ultimate short-circuit growth and worst mechanical loading.

17.1.9 Overvoltage and Overcurrent Protection

Protective Relaying. A substation can employ many relaying systems to protect the equipment associated with the station; the most important of these are

1. Transmission and distribution lines emanating from the station
2. Step-up and step-down transformers
3. Station buses
4. Breakers
5. Shunt and series reactors
6. Shunt and series capacitors

Substations serving bulk transmission system circuits must provide a high order of reliability and security in order to provide continuity of service to the system. More and more emphasis is being placed on very sophisticated relaying systems which must function reliably and at high speeds to clear line and station faults while minimizing false tripping.

Most EHV and UHV systems now use two sets of protective relays for lines, buses, and transformers. Many utilities use one set of electromechanical relays for transmission-line protection, with a completely separate, redundant set of solid-state relays to provide a second protective relaying package or two completely separate redundant sets of solid-state relays. The use of two separate sets of relays, operating from separate potential and current transformers and from separate station batteries, allows for the testing of relays without the necessity of removing the protected line or bus from service. For more difficult relaying applications, such as EHV lines using series

TABLE 17-8 Aluminum Round Tubular Bus bar Deflections and Stresses
(Standard iron pipe sizes)

		Span, ft													
		20		25		30		35		40		45		50	
IPS size, in	Loading	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2	Deflection, in	Stress, lb/in^2
1¼	Bare	1.45	2010	3.54	3135										
	½″ ice	3.94	5445	9.61	8510										
	½″ ice + 8 lb wind	5.12	7090	12.51	11075										
	1″ ice	7.57	10470	18.48	16360										
1½	Bare	1.09	1725	2.66	2700										
	½″ ice	2.83	4475	6.90	6990										
	½″ ice + 8 lb wind	3.61	5715	8.81	8930										
	1″ ice	5.28	8365	12.90	13070										
2	Bare	0.68	1350	1.67	2110	3.45	3040								
	½″ ice	1.65	3265	4.03	5100	8.35	7345								
	½″ ice + 8 lb wind	2.05	4055	5.00	6340	10.38	9125								
	1″ ice	2.95	5845	7.21	9135	14.95	13150								
2½	Bare	0.47	1130	1.15	1765	2.38	2540	4.42	3455						
	½″ ice	0.96	2310	2.36	3610	4.89	5200	9.05	7080						
	½″ ice + 8 lb wind	1.14	2730	2.78	4270	5.77	6150	10.70	8370						
	1″ ice	1.61	3845	3.92	6010	8.13	8655	15.06	11780						
3	Bare	0.31	910	0.76	1425	1.58	2050	2.93	2790	5.00	3640				
	½″ ice	0.61	1775	1.49	2775	3.08	3995	5.71	5440	9.74	7105				
	½″ ice + 8 lb wind	0.71	2060	1.72	3220	3.58	4635	6.62	6310	11.30	8240				
	1″ ice	0.98	2860	2.39	4465	4.96	6430	9.19	8755	15.68	11435				
3½	Bare	0.24	790	0.58	1230	1.20	1775	2.22	2415	3.79	3155	6.06	3995		
	½″ ice	0.45	1490	1.09	2330	2.26	3355	4.19	4565	7.15	5960	11.46	7545		
	½″ ice + 8 lb wind	0.51	1710	1.25	2670	2.59	3845	4.81	5230	8.20	6835	13.14	8650		
	1″ ice	0.70	2350	1.72	3670	3.57	5280	6.61	7190	11.27	9390	18.05	11885		

4	Bare	0.19	695	0.45	1090	0.94	1565	1.74	2130	2.97	2785	4.76	3525	7.25	4350
	$^1/_2''$ ice	0.34	1275	0.83	1995	1.72	2870	3.19	3910	5.45	5105	8.72	6465	13.30	7980
	$^1/_2''$ ice + 8 lb wind	0.39	1450	0.94	2265	1.96	3260	3.62	4435	6.18	5795	9.90	7335	15.09	9055
	$1''$ ice	0.53	1975	1.28	3085	2.66	4440	4.93	6045	8.42	7895	13.49	9990	20.55	12330
$4^1/_2$	Bare	0.15	620	0.36	970	0.76	1400	1.40	1905	2.39	2490	3.83	3150	5.83	3890
	$^1/_2''$ ice	0.27	1115	0.65	1740	1.35	2505	2.51	3410	4.28	4455	6.85	5640	10.44	6960
	$^1/_2''$ ice + 8 lb wind	0.30	1255	0.73	1960	1.52	2820	2.82	3840	4.81	5015	7.71	6345	11.75	7835
	$1''$ ice	0.41	1695	0.99	2650	2.06	3810	3.81	5190	6.51	6780	10.42	8580	15.89	10590
5	Bare	0.12	555	0.29	870	0.61	1250	1.12	1705	1.92	2225	3.07	2815	4.69	3475
	$^1/_2''$ ice	0.21	970	0.51	1520	1.06	2185	1.96	2975	3.35	3885	5.37	4920	8.18	6070
	$^1/_2''$ ice + 8 lb wind	0.23	1085	0.57	1695	1.18	2440	2.19	3320	3.74	4335	5.99	5490	9.13	6775
	$1''$ ice	0.31	1455	0.77	2275	1.59	3275	2.94	4455	5.02	5820	8.04	7365	12.26	9095
6	Bare	0.08	465	0.20	725	0.42	1040	0.79	1420	1.34	1850	2.15	2345	3.28	2895
	$^1/_2''$ ice	0.14	775	0.34	1210	0.71	1745	1.32	2375	2.25	3105	3.60	3930	5.49	4850
	$^1/_2''$ ice + 8 lb wind	0.15	855	0.38	1335	0.78	1925	1.45	2615	2.48	3420	3.97	4325	6.05	5340
	$1''$ ice	0.21	1135	0.50	1770	1.04	2550	1.92	3470	3.28	4530	5.26	5735	8.02	7080

Note: The tabulated deflections are for single-span, simply supported buses. Deflections for fixed-end buses are one-fifth of the values given above, and the deflections for continuous buses for the center spans are also one-fifth of the values above. The deflections for the end spans are two-fifths of the values given. The stresses given in the above table are the stresses in the outer fibers as calculated for simply supported beams with a uniformly distributed load. 1 in = 25.4 mm; 1 ft = 0.3048 m; 1 lb = 0.4536 kg; 1 lb/in^2 = 6.895 kPa.

Source: From *Kaiser Aluminum Electrical Conductor Technical Manual*.

TABLE 17-9 Aluminum Round Tubular Bus bar Deflections and Stresses
(Extra-heavy pipe sizes)

		Span, ft													
		20		25		30		35		40		45		50	
IPS size, in	Loading	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²	Deflection, in	Stress, lb/in²
1¼	Bare	1.54	2130												
	½″ ice	3.54	4900												
	½″ ice + 8 lb wind	4.42	6110												
	1″ ice	6.47	8945												
1½	Bare	1.15	1825	2.82	2855										
	½″ ice	2.53	4005	6.17	6255										
	½″ ice + 8 lb wind	3.09	4895	7.55	7645										
	1″ ice	4.47	7085	10.92	11070										
2	Bare	0.72	1425	1.76	2225										
	½″ ice	1.46	2890	3.57	4520										
	½″ ice + 8 lb wind	1.73	3430	4.23	5360										
	1″ ice	2.46	4870	6.01	7610										
2½	Bare	0.49	1185	1.21	1850	2.50	2665								
	½″ ice	0.89	2125	2.17	3320	4.49	4780								
	½″ ice + 8 lb wind	1.01	2420	2.46	3780	5.11	5440								
	1″ ice	1.40	3345	3.41	5225	7.07	7525								
3	Bare	0.33	955	0.80	1495	1.66	2150	3.07	2925						
	½″ ice	0.56	1625	1.36	2540	2.82	3660	5.23	4980						
	½″ ice + 8 lb wind	0.62	1815	1.52	2840	3.15	4085	5.84	5560						
	½″ ice	0.85	2465	2.06	3850	4.28	5545	7.93	7550						
3½	Bare	0.25	825	0.60	1290	1.25	1860	2.32	2530	3.96	3305				
	½″ ice	0.41	1360	1.00	2125	2.07	3060	3.83	4165	6.53	5440				
	½″ ice + 8 lb wind	0.45	1500	1.10	2345	2.28	3380	4.23	4600	7.21	6010				
	1″ ice	0.60	2015	1.48	3145	3.06	4530	5.67	6170	9.67	8055				

4	Bare	0.19	725	0.47	1135	0.98	1635	1.82	2230	3.10	2910	4.97	3680	7.58	4545
	1/2″ ice	0.31	1165	0.76	1820	1.57	2620	2.91	3565	4.97	4655	7.96	5895	12.13	7275
	1/2″ ice + 8 lb wind	0.34	1270	0.83	1990	1.72	2865	3.18	3900	5.43	5095	8.70	6445	13.26	7955
	1″ ice	0.45	1690	1.10	2640	2.28	3800	4.22	5170	7.20	6755	11.54	8550	17.59	10555
4 1/2	Bare	0.16	650	0.38	1015	0.79	1460	1.46	1990	2.49	2600	4.00	3290	6.09	4060
	1/2″ ice	0.24	1015	0.59	1585	1.23	2285	2.28	3110	3.90	4060	6.24	5135	9.51	6340
	1/2″ ice + 8 lb wind	0.26	1100	0.65	1720	1.34	2475	2.48	3370	4.23	4405	6.77	5575	10.32	6880
	1″ ice	0.35	1445	0.85	2260	1.76	3255	3.26	4430	5.55	5785	8.90	7320	13.56	9040
5	Bare	0.13	580	0.31	905	0.63	1305	1.17	1775	2.00	2320	3.20	2935	4.88	3625
	1/2″ ice	0.19	885	0.47	1380	0.97	1990	1.79	2710	3.05	3535	4.89	4475	7.45	5525
	1/2″ ice + 8 lb wind	0.21	950	0.50	1490	1.04	2140	1.93	2915	3.29	3810	5.26	4820	8.02	5950
	1″ ice	0.27	1240	0.65	1935	1.35	2785	2.51	3795	4.28	4955	6.85	6270	10.44	7745
6	Bare	0.09	485	0.21	755	0.44	1090	0.82	1485	1.40	1940	2.25	2455	3.43	3030
	1/2″ ice	0.13	700	0.31	1095	0.64	1580	1.19	2150	2.04	2810	3.26	3555	4.97	4390
	1/2″ ice + 8 lb wind	0.13	745	0.33	1165	0.68	1675	1.27	2280	2.16	2980	3.46	3775	5.27	4660
	1″ ice	0.17	950	0.42	1485	0.87	2140	1.61	2910	2.75	3800	4.41	4810	6.72	5940

Note: The tabulated deflections are for single-span, simply supported buses. Deflections for fixed-end buses are one-fifth of the values given above, and the deflections for continuous buses for the center spans are also one-fifth of the values above. The deflections for the end spans are two-fifths of the values given. The stresses given in the above table are the stresses in the outer fibers as calculated for simply supported beams with a uniformly distributed load. 1 in = 25.4 mm; 1 ft = 0.3048 m; 1 lb = 0.4536 kg; 1 lb/in^2 = 6.895 kPa.

Source: From *Kaiser Aluminum Electrical Conductor Technical Manual.*

capacitors in the line, some companies always use two sets of solid-state relays to provide the protection systems.

Transmission-line relay terminals are located at the substation and employ many different types of relaying schemes that include the following:

1. Pilot wire
2. Direct underreaching
3. Permissive underreaching
4. Permissive overreaching
5. Directional comparison
6. Phase comparison

Pilot-Wire Relaying. Pilot-wire relaying is an adaptation of the principle of differential relaying to line protection and functions to provide high-speed clearing of the line for faults anywhere on the line. Pilots include wire pilot (using a two-wire pair between the ends of the line), carrier-current pilots, microwave pilots, fiber-optics pilots, and the use of audio-tone equipment over wire, carrier, fiber-optics, or microwave. The transmission lines may have two or more terminals each with circuit breakers for disconnecting the line from the rest of the power system. All the relaying systems described can be used on two-terminal or multiterminal lines. The relaying systems program the automatic operation of the circuit breakers during power-system faults.

Direct Underreaching Fault Relays. These relays (Fig. 17-12) at each terminal of the protected line sense fault power flow into the line. Their zones of operation must overlap but not overreach any remote terminals. The operation of the relays at any terminal initiates both the opening of the local breaker and the transmission of a continuous remote tripping signal to effect instantaneous operation of all remote breakers. For example, in Fig. 17-12, for a line fault near bus *A*, the fault relays at *A* open (trip) breaker *A* directly and send a transfer trip signal to *B*. The reception of this trip signal at *B* trips breaker *B*.

Permissive Underreaching Relays. The operation and equipment for this system are the same as those of the direct underreaching system, with the addition of fault-detector units at each terminal. The fault detectors must overreach all remote terminals. They are used to provide added security by supervising remote tripping. Thus, the fault relays operate as shown in Fig. 17-12 and the fault detectors as shown in Fig. 17-13. As an example, for a fault near *A* in Fig. 17-12, the fault relays at *A* trip breaker *A* directly and send a transfer trip signal to *B*. The reception of the trip signal plus the operation of the fault detector relays at *B* (Fig. 17-13) trip breaker *B*.

Permissive Overreaching Relays. Fault relays at each terminal of the protected line sense fault power flow into the line, with their zones of operation overreaching all remote terminals. Both the

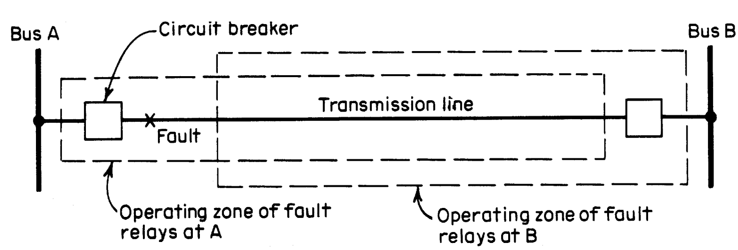


FIGURE 17-12 Fault-relay operating zones for the underreaching transfer trip transmission-line pilot relaying system.

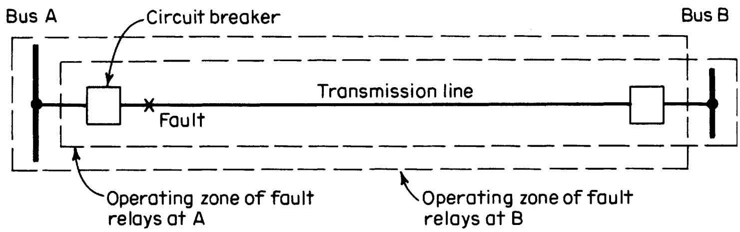


FIGURE 17-13 Fault-relay operating zones for the overreaching transmission-line pilot relaying system.

operation of the local fault relays and a transfer trip signal from all the remote terminals are required to trip any breaker. Thus, in the example of Fig. 17-13 for the line fault near *A*, fault relays at *A* operate and transmit a trip signal to *B*. Similarly, the relays at *B* operate and transmit a trip signal to *A*. Breaker *A* is tripped by the operation of the fault relay *A* plus the remote trip signal from *B*. Likewise, breaker *B* is tripped by the operation of fault relay *B* plus the remote trip signal from *A*.

Directional-Comparison Relays. The channel signal in these systems (Fig. 17-14) is used to block tripping in contrast to its use to initiate tripping in the preceding three systems. Fault relays at each terminal of the protected line section sense fault power flow into the line. Their zones of operation must overreach all remote terminals. Additional fault-detecting units are required at each terminal to initiate the channel-blocking signal. Their operating zones must extend further or be set more sensitively than the fault relays at the far terminals. For example, in Fig. 17-13 the blocking zone at *B* must extend further behind breaker *B* (to the right) than the operating zone of the fault relays at *A*. Correspondingly, the blocking zone at *A* must extend further out into the system (to the left) than the operating zone of the fault relays at *B*.

For an internal fault on line *AB*, no channel signal is transmitted (or if transmitted, it is cut off by the fault relays) from any terminal. In this absence of any channel signal, fault relays at *A* instantly trip breaker *A*, and fault relays at *B* instantly trip breaker *B*. For the external fault to the right of *B* as shown in Fig. 17-13, the blocking zone relays at *B* transmit a blocking channel signal to prevent the fault relays at *A* from tripping breaker *A*. Breaker *B* is not tripped because the *B* operating zone does not see this fault.

Phase-Comparison Relays. The three line currents at each end of the protected line are converted into a proportional single-phase voltage. The phase angles of the voltages are compared by permitting

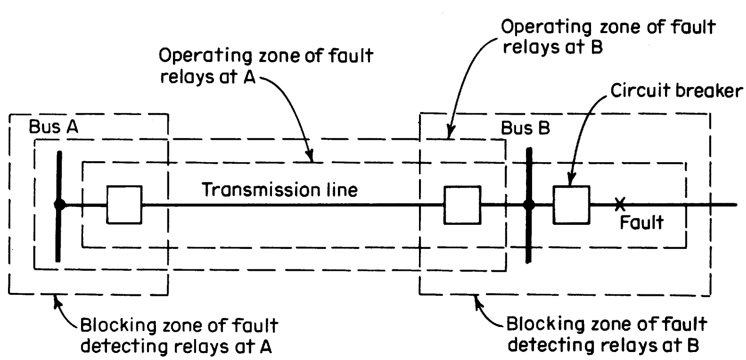


FIGURE 17-14 Fault and blocking relay operating zones for the directional-comparison transmission-line pilot relay system.

the positive half-cycle of the voltage to transmit a half-wave signal block over the pilot channel. For external faults, these blocks are out of phase so that alternately the local and then the remote signal provide essentially a continuous signal to block or prevent tripping. For internal faults, the local and remote signals are essentially in phase so that approximately a half-cycle of no channel signal exists. This is used to permit the fault relays at each terminal to trip their respective breakers.

Station Bus Protection. Station bus protection deserves very careful attention because bus failures are, as a rule, the most serious that can occur to an electrical system. Unless properly isolated, a bus fault could result in complete shutdown of a station. Many methods are employed to protect the station buses. Among them are the use of overcurrent relays, backup protection by relays of adjacent protective zones, directional-comparison schemes, and so forth. By far, the most effective and preferred method used to protect buses consists of percentage differential relaying, using either current or voltage differential relays. Differential relaying is preferred because it is fast, selective, and sensitive.

The relays are available in either electromechanical or solid-state form, with the solid-state units featuring somewhat higher speeds and sensitivity than are available in the electromechanical models. Operating times of 5 to 8 ms can be achieved with solid-state bus differential relays.

Because of the high magnitude of currents encountered during bus faults, current transformers may saturate and thus cause false tripping during external faults. The possibility of ac and dc saturation during faults makes it mandatory that current transformers used for bus differential protection be accurate and of the best quality possible. Also, current transformers should be matched to provide similar ratios and characteristics.

Some bus differential relays developed in solid-state form in Europe have been designed to function correctly even when using current transformers of inferior quality and different ratios. However, it is considered good practice to provide the best possible current transformers for use in bus differential relay applications. For a sensitive bus differential scheme using current percentage differential relays, refer to Fig. 17-15. For a percentage differential scheme using high-impedance-voltage differential relays, refer to Fig. 17-16.

Because the effective resistance of the voltage relay coil circuit is so high, of the order of 3000 Ω, a voltage-limiting element must be connected in parallel with the rectifier branch in order to prevent the CT secondary voltage from being excessive. The overcurrent relay in series with the voltage limiter provides high-speed operation for bus faults of high currents. All current-transformer leads are paralleled at a junction point in the substation near the circuit breakers, and only one set of leads is required to be run into the control house where the relay is normally located.

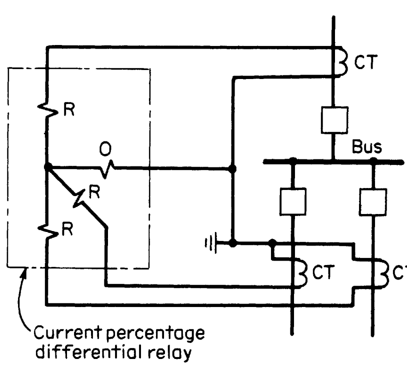


FIGURE 17-15 Bus differential protection using current percentage differential relays (CT, current transformer; O, operating coil; R, restraining coil).

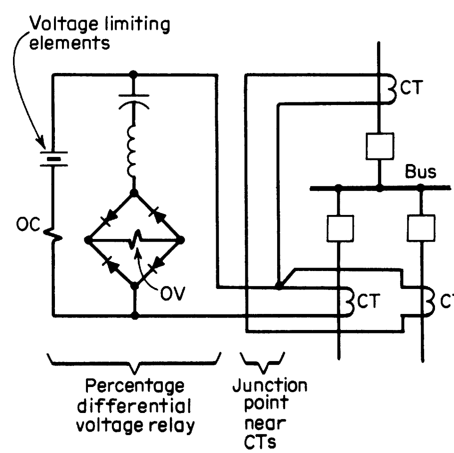


FIGURE 17-16 Bus differential protection using voltage differential relays; (OC, high set overcurrent relays; OV, voltage element; CT, current transformer).

Transformer Protection. Transformers may be subjected to short circuits between phase and ground, open circuits, turn-to-turn short circuits, and overheating. Interphase short circuits are rare and seldom develop as such initially, since the phase windings are usually well separated in a three-phase transformer. Faults usually begin as turn-to-turn failures and frequently develop into faults involving ground.

It is highly desirable to isolate transformers with faulty windings as quickly as possible to reduce the possibility of oil fires, with the attendant resulting cost for replacement. Differential protection is the preferred type of transformer protection due to its simplicity, sensitivity, selectivity, and speed of operation. If the current-transformer ratios are not perfectly matched, taking into account the voltage ratios of the transformer, autotransformers or auxiliary current transformers are required in the current-transformer secondary circuits to match the units properly so that no appreciable current will flow in the relay operating coil, except for internal fault conditions.

In applying differential protection to transformers, somewhat less sensitivity in the relays is usually required, as compared with generator relays, since they must remain nonoperative for the maximum transformer tap changes that might be used. It is also necessary to take into account the transformer exciting inrush current that may flow in only one circuit when the transformer is energized by closing one of its circuit breakers. As a rule, incorrect relay operation can be avoided by imposing a slight time delay for this condition.

Voltage-load tap-changing (LTC) transformers may be protected by differential relays. The same principles of applying differential protection to other transformers hold here as well. It is important that the differential relay be selected carefully so that the unbalance in the current-transformer secondary circuits will not in any case be sufficient to operate the relay under normal conditions. It is suggested that the current transformers be matched at the midpoint of the tap-changing range. The current-transformer error will then be a minimum for the maximum tap position in either direction.

Current-transformer and relay connections for various types of differential protection are indicated (1) in Fig. 17-17 for a Y-delta transformer and (2) in Fig. 17-18 for a three-winding Y-delta-Y transformer. Two rules, frequently used in laying out the wiring for differential protection of transformers whose main windings are connected in Y and delta, are

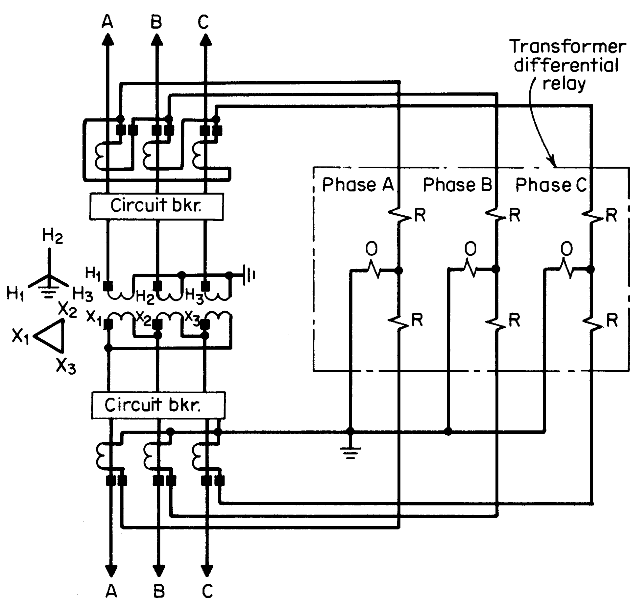


FIGURE 17-17 Transformer differential protection for a Y-Δ transformer.

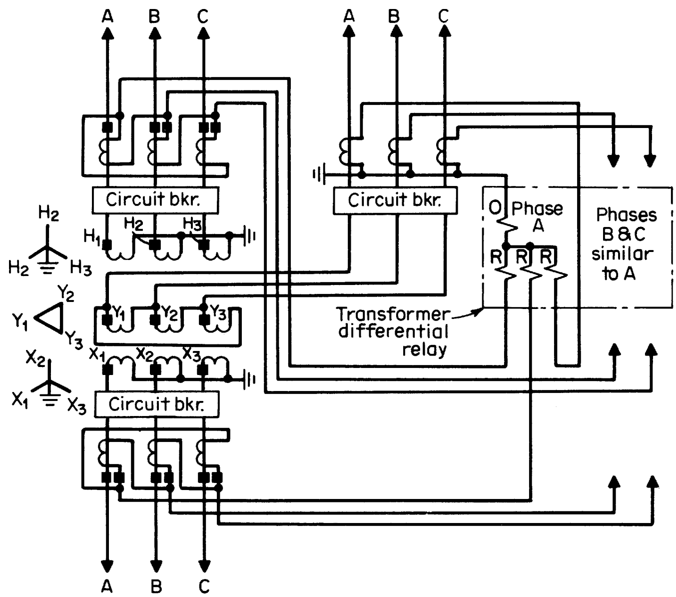


FIGURE 17-18 Transformer differential protection for a Y-Δ Y transformer.

1. The current transformers in the leads to the Y-connected winding should be connected in delta; current transformers in the leads to a delta-connected winding should be connected in Y.
2. The delta connection of the current transformers should be a replica of the delta connection of the power transformers; the Y connection of the current transformers should be a replica of the Y connection of the power transformers.

Current transformers that will give approximately 5-A secondary current at full load on the transformer should be chosen. This will not be possible in all cases, particularly for transformers having three or more windings, since the kVA ratings may vary widely and may not be proportional to the voltage ratings.

Overcurrent protection should be applied to transformers as the primary protection where a differential scheme cannot be justified or as "backup" protection if differential is used. Frequently, faster relaying may be obtained for power flow from one direction by the use of power-directional relays.

Transformer overheating protection is sometimes provided to give an indication of overtemperature, rarely to trip automatically. Overload relays of the replica type may be connected in the current-transformer circuits to detect overloading of the unit. Others operate on top-oil temperature, and still others operate on top-oil temperature supplemented with heat from an adjacent resistor connected to a current transformer in the circuit. A recently developed sensor using a glass chip sensitive to temperature changes employs fiber-optics techniques to measure winding hot-spot temperatures.

Gas- or oil-pressure relays are available for attachment to the top or side of transformer tanks to indicate winding faults, which produce gas or sudden pressure waves in the oil. Rapid collection of gas or pressure waves in the oil, due to short circuits in the winding, will produce fast operation. New, more sophisticated methods to detect incipient failures by frequent monitoring of gas samples are being developed.

Circuit-Breaker Protection. In recent years, great emphasis has been placed on the need to provide backup protection in the event of failure of a circuit breaker to clear a fault following receipt of a trip command from protective relays. For any fault, the protective relays operate to trip the necessary circuit breakers. In addition, these same protective relays, together with breaker-failure fault-detector relays, will energize a timer to start the breaker-failure backup scheme. If any breaker fails to clear the fault, the protective relays will remain picked up, permitting the timer to time-out and trip the necessary other breakers to clear the fault.

Circuit-breaker failure can be caused by loss of dc trip supply, blown trip fuses, trip-coil failure, failure of breaker trip linkages, or failure of the breaker current-interrupting mechanism. The two basic types of failures are (1) mechanical failure and (2) electrical failure of the breaker to clear the fault. Mechanical failure occurs when the breaker does not move following receipt of a trip command because of loss of dc trip supply, trip coil failure, or trip linkage failure. Electrical failure occurs when the breaker moves in an attempt to clear a fault on receipt of the trip command but fails to break the fault current because of misoperation of the current interrupter itself.

In order to clear faults for these two types of breaker failures, two different schemes of protection can be employed. The more conventional breaker-failure schemes consist of using instantaneous current-operated fault detectors which pick up to start a timer when fault relays operate. If the breaker fails to operate to clear the fault, the timer times out and trips necessary breakers to clear the fault. However, if the breaker operates correctly to clear the fault, enough time must be allowed in the timer setting to ensure reset of the fault-detector relay. Total clearing times at EHV using this scheme are quite fast and usually take 10 to 12 cycles from the time of fault until the fault is cleared.

For those faults where mechanical failure of the breakers occurs, an even faster scheme is in use. This scheme depends on a breaker auxiliary switch (normally open type 52-A contact) to initiate a fast timer. The auxiliary switch is specially located to operate from breaker trip linkages to sense actual movement of the breaker mechanism. If the breaker failure is mechanical, the breaker-failure timer is actuated through the auxiliary switch when the protective relays operate. The advantage of using the auxiliary switch is the extremely fast reset time of the breaker-failure timer that can be realized when the breaker operates correctly. Schemes in use with the fast breaker-failure circuit can attain total clearing times of 7.5 cycles when a breaker failure occurs.

Shielding and Grounding Practices for Control Cables. For several years, the increased application of solid-state devices for protective relaying and control and for electronic equipment, such as audio tones, carrier and microwave equipment, event recorders, and supervisory control equipment, in EHV substations has resulted in many equipment failures. Many of these failures have been attributed to transients or surges in the control circuits connected to the solid-state devices. Failures due to transients or surges have been experienced even with conventional electromechanical devices.

The failures being experienced are attributed to the use of EHV (345 kV and higher voltage levels) as well as the presence of unusually high short-circuit currents. One of the major sources of transient voltages is the switching of capacitances, for example, the operation of a disconnect switch which generates high-magnitude, high-frequency oscillatory surge currents. The transient magnetic fields associated with these high-frequency surge currents are both electrostatically and magnetically coupled to cables in the area. Induced voltages have been reported to be as high as 10 kV in cables without shielding, and the frequencies of these induced voltages have been reported to be as high as 3 MHz.

In order to avoid insulation breakdown at 10-kV crest and possible false operation of relays, it is important that station design includes necessary precautions to limit the undesirable surges and control circuit transients to an acceptable minimum.

In any station design there are several precautions that can be taken. All cable circuits that are used in a substation should be run radially, with each circuit separated from any other circuit and with both supply and return conductors contained within the same cable. If a conductor is routed from the control house to a point in the switchyard with the return circuits following different paths, loops may be formed that are inductive and are subject to magnetically induced voltages. However, when the two conductors involved are both affected by the same field, the voltage appearing between them at the open end should be essentially zero.

Because of ground-mat potential differences and longitudinally induced voltages in the radial circuits, proper cable shielding is necessary to maintain lowest possible voltages on the cable leads. The cables that require shielding include control, current, and potential transformer circuits. The shield should be of as low resistance as possible, and it should be connected to the ground grid at least at both ends. To reduce penetration of a magnetic flux through the nonferrous shield (lead, copper, bronze, etc.), a current must flow in the shield to produce a counterflux, which opposes the applied flux. Ground-grid conductors should be placed in parallel to and in close proximity to the shield to maintain as low a resistance between the ends as possible and also to form a small loop to reduce the reactance between ground and the shield. Without close coupling of the conductor and ground shield, the propagation time of the two paths could differ so that a voltage impulse could arrive at the receiving end with a time difference, hence causing an unwanted voltage difference.

All control, potential-transformer, and current-transformer cables should be shielded, with the shield grounded at the switchyard end and at the control-house end. In addition, each group or run of conduits and cables should be installed with a separate No. 4/0 bare stranded copper cable buried directly in the ground and grounded and bonded to the control-cable shield at each end of each cable. The bare copper cable should run as closely as possible to the cable run. The heavy cable functions to provide a low-resistance path in an attempt to prevent heavy fault currents from flowing in the shield and to reduce reactance between ground and shield.

In order to limit induced voltages, the control-cable runs should be installed, where possible, at right angles to high-voltage buses. Where it is necessary to run parallel to a high-voltage bus for any appreciable distance, the spacing between cables and high-voltage buses should be made as great as possible. Distances of at least 50 ft should be maintained.

It is further considered good practice to have both current-transformer and potential-transformer leads installed with the ground for the secondary wye neutral made at the control-house end rather than at the switchyard end. Any rise due to induced voltages will be concentrated at the switchyard and will ensure operator safety at the control switchboard in the control house.

The shield can be grounded by using a flexible tinned copper braid of from $^1/_2$ to 1 in wide. The shielded-cable outer insulation is peeled back, exposing the sheath. The 1-in braid is wrapped around the sheath and soldered carefully to it. The other end of the braid is connected to a lug, and solder should be run over the lug to the braid connection. The lug is then bolted securely to the ground bus bar. The flexible copper braid circuits should be kept as short as possible and should be run directly to the ground bus without any bends, if possible.

It should be pointed out that the shields should be grounded at multiple points rather than at a single point, because of the tendency to lose any advantage from single-point grounding at 50 kHz and above. As an example, assume that one input and one output terminal of a system are grounded, each at different points on a common ground plane. A small noise voltage will usually exist across these ground points because of currents flowing in the finitely conductive ground plane. If either the load or source ground is lifted, a ground loop is no longer formed, and coupling of unwanted signals is minimized. This is the advantage of having one physical ground.

Removal of one of the ground connections achieves a single-point ground only for dc and low-frequency signals. At higher frequencies, ground loops will be created by capacitance coupling. Frequencies below 50 kHz are considered the arbitrary crossover point for single-point grounding. At EHV, the transient voltages above 50 kHz represent the more serious problem; for this reason, all cable shields should be grounded at least at two points. It should be noted that shielding of control cables is normally provided for substations operating at voltage levels of 138 kV and above.

17.1.10 Substation Grounding

Grounding at substations is highly important. The functions of a grounding system are listed below:

1. Provide the ground connection for the grounded neutral for transformers, reactors, and capacitors
2. Provide the discharge path for lightning rods, arresters, gaps, and similar devices
3. Ensure safety to operating personnel by limiting potential differences, which can exist in a substation
4. Provide a means of discharging and deenergizing equipment in order to proceed with maintenance on the equipment
5. Provide a sufficiently low-resistance path to ground to minimize rise in ground potential with respect to remote ground

Substation safety requirements call for the grounding of all exposed metal parts of switches, structures, transformer tanks, metal walkways, fences, steelwork of buildings, switchboards, instrument-transformer secondaries, etc. so that a person touching or near any of this equipment cannot receive a dangerous shock if a high-tension conductor flashes to or comes in contact with any of the equipment listed. This function in general is satisfied if all metalwork between which a person can complete contact or which a person can touch when standing on the ground is so bonded and grounded that dangerous potentials cannot exist. This means that each individual piece of equipment, each structural column, etc., must have its own connection to the station grounding mat.

A most useful source of information concerning substation grounding is contained in the comprehensive guide IEEE Standard 80-1986, IEEE Guide for Safety in AC Substation Grounding Period. Much of the following information is based on recommendations stated in the IEEE Standard 80.

The basic substation ground system used by most utilities takes the form of a grid of horizontally buried conductors. The reason that the grid or mat is so effective is attributed to the following:

1. In systems where the maximum ground current may be very high, it is seldom possible to obtain a ground resistance so low as to ensure that the total rise of the grounding system potential will not reach values unsafe for human contact. This being the case, the hazard can be corrected only by control of local potentials. A grid is usually the most practical way to do this.
2. In HV and EHV substations, no ordinary single electrode is adequate to provide needed conductivity and current-carrying capacity. However, when several are connected to each other and to structures, equipment frames, and circuit neutrals which are to be grounded, the result is necessarily a grid, regardless of original objectives. If this grounding network is buried in soil of reasonably good conductivity, this network provides an excellent grounding system.

The first step in the practical design of a grid or mat consists of inspecting the layout plan of equipment and structures. A continuous cable should surround the grid perimeter to enclose as much ground as practical and to avoid current concentration and hence high gradients at projecting ground cable ends. Within the grid, cables should be laid in parallel lines and at reasonably uniform spacing. They should be located, where practical, along rows of structures or equipment to facilitate the making of ground connections. The preliminary design should be adjusted so that the total length of buried conductor, including cross connections and rods, is at least equal to that required to keep local potential differences within acceptable limits.

A typical grid system for a substation might comprise 4/0 bare stranded copper cable buried 12 to 18 in below grade and spaced in a grid pattern of about 10 by 20 ft. (Other conductor sizes, burial depths, and grid conductor spacings, however, are frequently used.) At each junction of 4/0 cable, the cables would be securely bonded together, and there might also be connected a driven copper-covered steel rod approximately $^5/_8$ in. in diameter and approximately 8 ft long. In very high-resistance soils it might be desirable to drive the rods deeper. (Lengths approaching 100 ft are recorded.) A typical grid system usually extends over the entire substation yard and sometimes a few feet beyond the fence, which surrounds the building and equipment. Figure 17-19 shows a grounding plan for a typical EHV substation operating at 345 kV.

In order to ensure that all ground potentials around the station are equalized, the various ground cables or buses in the yard and in the substation building should be bonded together by heavy multiple connections and tied into the main station ground. This is necessary in order that appreciable voltage differences to ground may not exist between the ends of cables which may run from the switchyard to the substation building.

Heavy ground currents, such as those that may flow in a transformer neutral during ground faults, should not be localized in ground connections (mats or groups of rods) of small area in order to minimize potential gradients in the area around the ground connections. Such areas should have reinforced wire sizes where necessary to handle adequately the most severe condition of fault-current magnitude and duration.

Copper cables or straps are usually employed for equipment-frame ground connections. However, transformer tanks are sometimes used as part of the ground path for lightning arresters mounted thereon. Similarly, steel structures may be used as part of the path to ground if it can be established that the conductivity, including that of any joints, is and can be maintained as equivalent

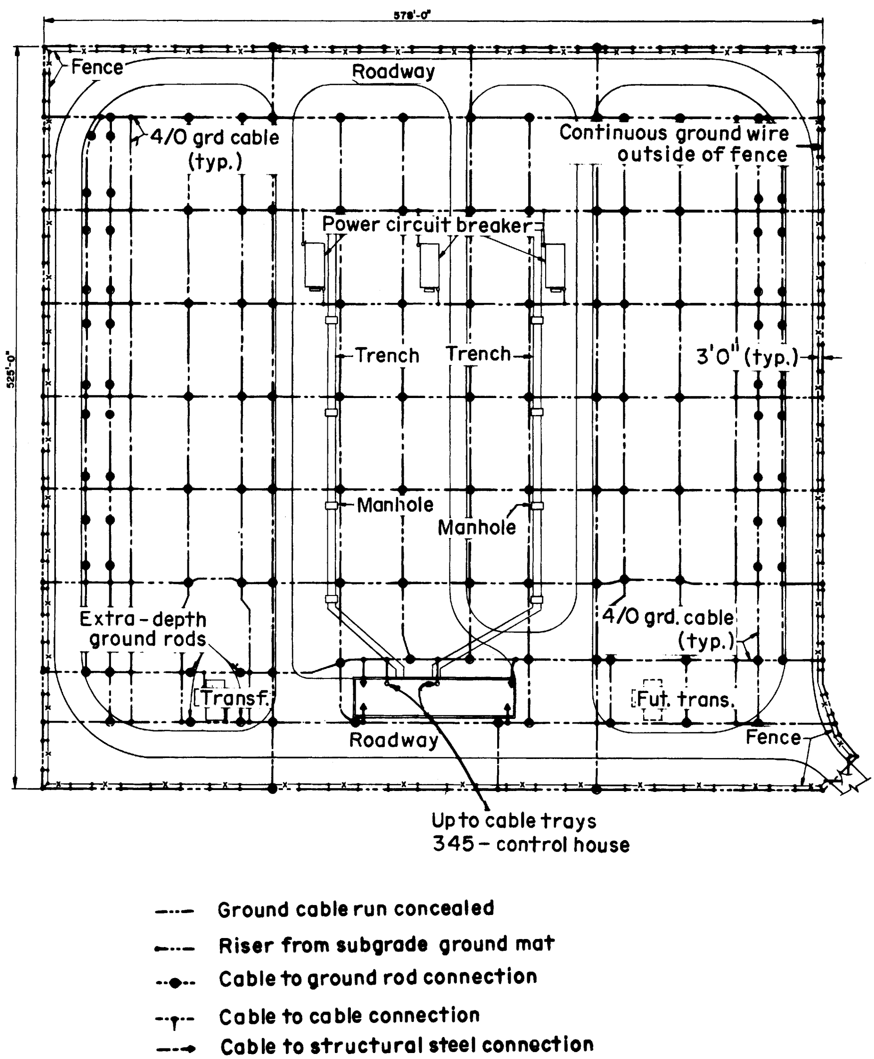


FIGURE 17-19 Grounding plan for a 345-kV substation.

to the copper conductor that would otherwise be required. Studies by some utilities have led to their successful use of steel structures as part of the path to the ground mat from overhead ground wires, lightning arresters, etc. Where this practice is followed, any paint films, which might otherwise introduce a high-resistance joint should be removed and a suitable joint compound applied or other effective means taken to prevent subsequent deterioration of the joint from oxidation.

Connections between the various ground leads and the cable grid and connections within the cable grid are usually clamped, welded, or brazed. Ordinary soldered connections are to be avoided because of possible failure under high fault currents or because of galvanic corrosion.

Each element of the ground system (including grid proper, connecting ground leads, and electrodes) should be so designed that it will

1. Resist fusing and deterioration of electric joints under the most adverse combination of fault-current magnitude and fault duration to which it might be subjected.
2. Be mechanically rugged to a high degree, especially in locations exposed to physical damage.
3. Have sufficient conductivity so that it will not contribute substantially to dangerous local potential differences.

Adequacy of a copper conductor and its joints against fusing can be determined from Table 17-10 and by referring to Fig. 17-20.

If the switchyard is on soil of high resistivity so that it is impossible to obtain suitably low resistance from rods driven within the station, it is possible to reduce the resistance by extending the main ground grid outside the enclosed substation area to a secondary ground mat located adjacent to the substation. The effective resistance of the complete grounding system can be lowered appreciably by the use of a more extensive grid area and of additional grid conductor length. An important reason for trying to lower grid resistance is to minimize ground-potential rise with respect to remote ground during ground faults.

TABLE 17-10 Minimum Copper Conductor Sizes to Avoid Fusing

Time duration of fault, s	Circular mils per ampere: Cable only	Circular mils per ampere: With brazed joints	Circular mils per ampere: With bolted joints
30	40	50	65
4	14	20	24
1	7	10	12
0.5	5	6.5	8.5

Ground-potential rise depends on fault-current magnitude, system voltage, and ground-system resistance. The current through the ground system multiplied by its resistance measured from a point remote from the substation determines the ground-potential rise with respect to remote ground. The current through the grid is usually considered to be the maximum available line-to-ground fault current. For example, a ground fault of 15,000 A flowing into a ground grid with a value of 0.5 Ω resistance to absolute earth would cause an *IR* drop of 7500 V. The 7500-V *IR* drop due to the fault current could cause serious trouble to communications lines entering the station if the communications facilities are not properly insulated or neutralized.

Low-resistance station grounds are frequently difficult to obtain. In such cases, the use of driven grounds will provide the most convenient means of obtaining a suitable ground connection. The arrangement and number of driven grounds will depend on the station size and the nature of the soil. The ground mat of Fig. 17-19 has a value measured to be on the order of 0.5 Ω. The best soils for ground mats are wet and marshy, with clay or clay loam as the next best. Sand and sandy soils are of higher resistance, making it difficult to obtain low-resistance ground connections.

The size of the rods used is determined mainly by the depth to which they must be driven, although small rods can be driven to considerable depths by the use of driving collars. Figure 17-21 shows the relationship between rod size and resistance obtained. Driving more rods in a given space will help reduce resistance, but the reduced resistance

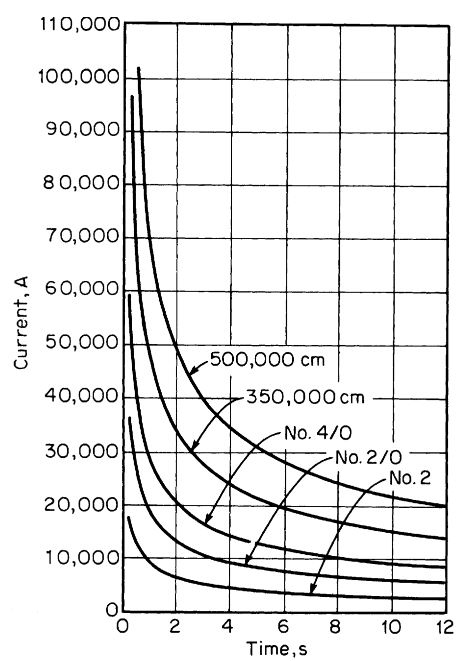


FIGURE 17-20 Short-time fusing curves for copper cable.

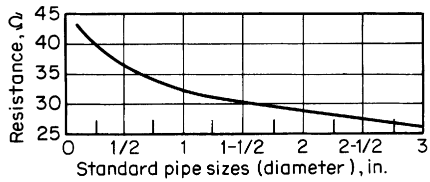


FIGURE 17-21 Relation between pipe diameter and ground resistance. *(NBS Technologic Paper No. 108, June 1918.)*

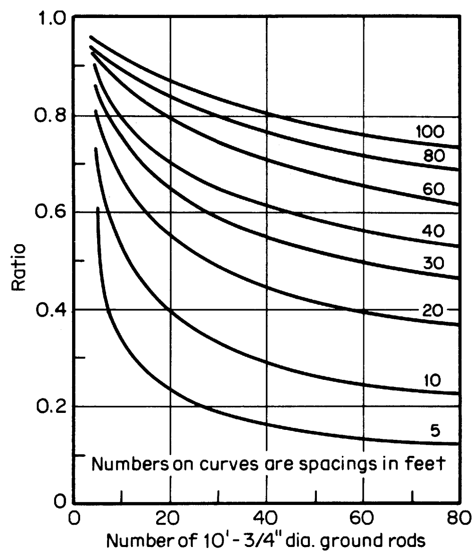


FIGURE 17-22 Ratio of conductivity of ground rods in parallel on an area to that of isolated rods. *(H. B. Dwight, Trans. AIEE, vol. 55, p. 1936.)*

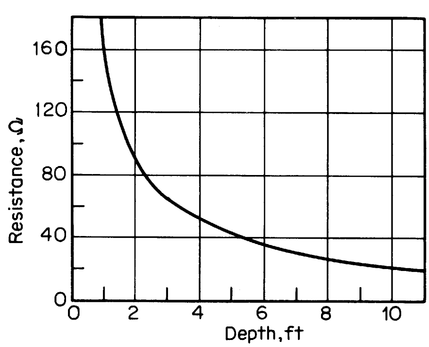


FIGURE 17-23 Variation of resistance of driven pipes with depth. Soil fairly wet. External diameter of pipe is 24.9 mm (1.02 in). *(NBS Technologic Paper No. 108, June 1918.)*

is not a function of the number of rods. Figure 17-22 shows the effect on resistance of spacing and number of rods in square areas. These curves apply to $^3/_4$-in by 10-ft rods. The rods or pipes for permanent stations should be of noncorroding materials. Figure 17-23 shows the effect of increased length of rods in uniform soil. Usually the improvement is much greater than indicated because the rods penetrate into better-conducting earth as they are driven deeper. In addition, where the ground can become frozen, rods must be driven below the frost line to obtain low resistance.

In general, it is advisable to obtain reduced ground resistance by the use of a more extensive mat and more ground rods rather than by treating the earth around the rods with salt because of the impermanence of the treatment. However, treatment of the soil is sometimes the only means whereby suitable resistance can be obtained.

It is not possible to describe all methods of obtaining ground connections of suitably low resistance. The problem sometimes presents great difficulties and calls for considerable extra expense. Substations should not be located on solid rock with little or no topsoil, since the cost of obtaining a low-resistance ground would be excessive. Such a ground would require the use of an extensive counterpoise system with many drilled "wells," in which electrodes would be inserted in treated filling, with provision made for renewing the treatment.

Measuring Ground Resistance. The measurement of ground resistance is necessary both at the time of initial energization of a substation and at periodic intervals thereafter to ensure that the value of ground resistance does not increase appreciably. The measurement of the resistance of a ground connection with respect to absolute earth is somewhat difficult. All results are approximations and require careful application of the test equipment and selection of reference ground points.

There are several methods of testing ground resistance, but all of them are similar in that two reference ground connections are used and a suitable source of current is required for the test. Some form of alternating current is circulated through the ground under test in amounts from a few milliamperes, as in bridge methods and with some of the patented ground testers, up to 100 A or more. The amount of current used depends on the method, and methods using very small currents will give results as accurate as methods using heavy currents if the ground under test is one for which the test method is suitable.

Methods of testing ground resistance fall into three general groups:

1. *Triangulation or three-point methods*, in which two auxiliary test grounds and the point to be measured are arranged in a triangular configuration. The series resistance of each pair of ground points in the triangle is determined by measuring the voltage across and the current through the ground resistance being measured. Resistance measurements are made by the voltmeter-ammeter method or by means of a suitable bridge. For accurate results, the resistance of the auxiliary grounds and the ground under test should be of the same order of magnitude, and results may be meaningless if the test grounds have more than 10 times the resistance of the ground under test. This method is suitable for measuring the resistance of tower footings, isolated ground rods, or small grounding installations. It is not suitable for measurement of low-resistance grounds such as the ground grid at large substations.
2. *Ratio methods,* in which the series resistance R of the ground under test and a test probe is measured by means of a bridge which operates on the null-balance principle. A calibrated slide-wire potentiometer is connected to the two ground connections, with the slider of the potentiometer connected to a second test probe. The potential of the slider to ground is adjusted to zero or null. If D is the total slide-wire resistance and d_1 is the resistance from the slider to the ground under test, the resistance R of the ground under test is $(d_1/D) \times R$. The vibrometer and the groundometer, self-contained test instruments, make use of this principle. This method is much more satisfactory than triangulation methods, since ratios of test-probe resistance to the resistance of the ground under test run as high as 300:1 with test instruments such as the groundometer. Although this method has its limitations in testing low-resistance grounds of large areas, suitable readings can be obtained by locating the test probes in a straight line, in a direction 90° from the substation fence, and with the distance of the farthest probe twice the width of the substation. Best accuracy can be attained by taking measurements at the greatest possible distance from the ground grid being measured.
3. *Fall-of-potential methods,* which include methods using close-in reference grounds, usually less than 1000 ft from the ground under test. The principle of the fall-of-potential method using close-in reference grounds is illustrated by Fig. 17-24. A fixed probe is driven in the ground at point C_2 with a movable probe P_2 set at various points in a straight line between C_2 and the ground mat G

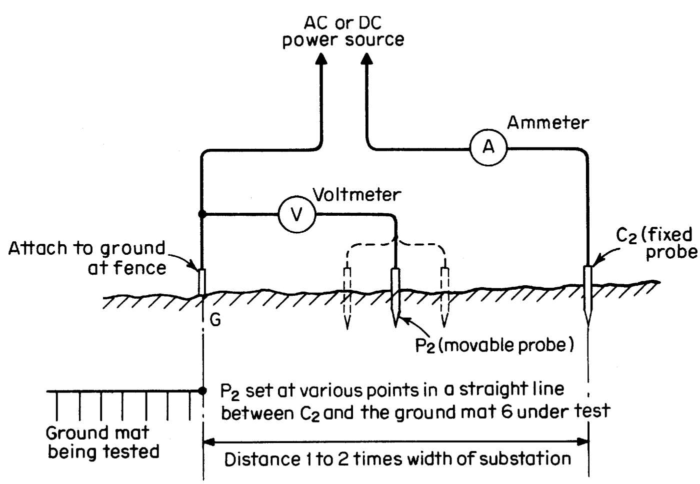


FIGURE 17-24 Field setup for making ground-resistance tests by means of the fall-of-potential method.

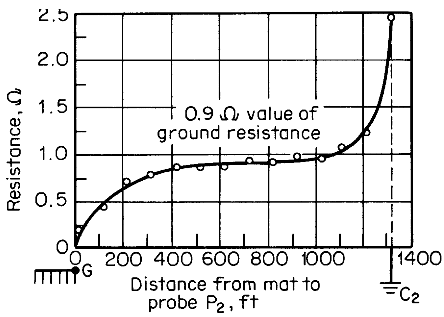


FIGURE 17-25 Ground-resistance curve for a substation ground mat.

under test. Either alternating current or direct current is circulated through ground G and fixed test probe C_2. A voltmeter is connected between point G and probe P_2, and an ammeter is connected to observe current flow through probe C_2. Voltmeter readings E are taken simultaneously with ammeter readings I. The reading E/I, which equals the resistance in ohms, is plotted in Fig. 17-25. The resistance shown on the flat part of the curve or at the point of inflection is taken as the resistance of the ground. This method may be subject to considerable error if stray currents are present. It is normally applied by using several test-probe readings at 10% intervals of the distance from G to C_2, with the test probe located midway between G and C_2. Self-contained test instruments which make use of this method are available; among them are the ground ohmer and Megger ground tester. These instruments give better results than the voltmeter-ammeter method, since they are designed to eliminate the effects of stray currents.

In recent years, considerable emphasis has been placed on the use of computer programs to calculate the design parameters of substation ground systems. These programs normally employ methods detailed in IEEE Guide 80. Normal input data required to run a typical program consist of the following:

1. System voltage, symmetric rms single-phase-to-ground fault currents, and the clearing time of faults
2. Length and width of substation area
3. Estimated value of ground resistivity in ohm-meters
4. Assumed value of ground conductor length
5. Cross section of conductors available

The following typical information is derived from the program:

1. Size, total length, and number of strands of copper ground conductor
2. Spacing of main grid configuration along width and length
3. Expected ground-mat resistance
4. Depth of grid below ground level
5. Tolerable limits and maximum values of step and touch potentials

It should be noted that the step and touch potentials are defined as follows:

E_{step} is the tolerable potential difference between any two points on the ground surface, which can be touched simultaneously by the feet.

E_{touch} is the tolerable potential difference between any point on the ground where a person may stand and any point which can be touched simultaneously with either hand.

17.1.11 Transformers

Transformers Connections. *Delta-delta–connected* transformers are used mainly on the lower transmission voltages. This is due to the fact that the complete winding must be insulated for full line-to-line voltage; for voltages above 73 kV, the cost increase is appreciable over Y-connected transformers with graded insulation. The delta-delta–connected transformers have one advantage in that the bank can be operated open delta at 86.6% of the capacity of the two remaining transformers.

The delta-star connection is in common use for both step-up and step-down purposes. When used as a step-up transformer, the high-tension winding is Y-connected; when used for step-down purposes, the low-tension winding is usually Y-connected in order to provide a grounded neutral for secondary transmission or for primary distribution.

Delta-connected high-tension windings, however, are seldom used for transmission voltages of 138 kV and above. The delta-Y connection almost completely suppresses the triple harmonics with the neutral solidly grounded. Triple harmonics, which can appear on power systems are the third and its odd multiples. Y-connected windings on the higher voltages are usually provided with graded insulation, the neutral-end turns of which may have very little insulation if the neutral is solidly grounded. If neutral impedance (reactor or resistor) is used, neutral insulation must be equal to or greater than the maximum *IZ* drop of the neutral impedance. If the neutral is to be left ungrounded on either grounded neutral systems or ungrounded neutral systems, the neutral insulation should be the same as it is on the line side to avoid traveling-wave troubles.

Star-star–connected (Y-Y) transformers are used infrequently on high-voltage transmission systems. When used with both neutrals grounded, if single-phase or three-phase shell type, they must be used with Y-connected generators, and a solid neutral connection must be provided between the generator, or generators, and the low-tension transformer neutral in order to minimize triple-harmonic troubles. The various types of Y-Y–connected transformers can be used with both neutrals ungrounded with satisfactory results or with neutrals grounded if of the three-phase core type. The triple harmonics are nearly suppressed in three-phase core-type transformers.

Star-star–connected transformers with a delta-connected third winding (tertiary) overcome the difficulties of the simple Y-Y connection. The tertiary winding may be for the suppression of harmonics only, in which case no connections are brought out with three-phase transformers. Y-delta-Y transformers are frequently used to supply two distribution voltages or a distribution voltage and a secondary-transmission voltage. If the service supplied from the delta-connected winding is four-wire three-phase, the neutral must be obtained from a separate grounding transformer. A common use for the tertiary winding is to provide substation station-service power to operate station auxiliary equipment. Three-winding transformers, all windings of which are used, are frequently rated with two outputs: (1) the individual output of each secondary winding alone with the other secondary winding carrying no load and (2) a simultaneous loading rating in which each secondary winding is given a rated loading with the primary-winding loading the resultant of the two secondary loadings.

Autotransformers are generally used for transforming from one transmission voltage to another when the ratio is 3:1 or less. Such transformers are normally connected in Y with the neutral solidly grounded and when so connected should be provided with a closed delta tertiary winding of adequate capacity for the suppression of harmonics, for ground-fault duty, and to provide station-service power. The tertiary is frequently used to provide a supply of distribution voltage. Autotransformers are superior to separate-winding transformers owing to their lower cost, greater efficiency, smaller size and weight, and better regulation. Autotransformers also may be obtained with zigzag-connected windings or with delta-connected windings. Both these types are free from triple-harmonic troubles but in general are more expensive.

Delta-connected autotransformers have a possible disadvantage in that they insert a phase shift into the transformation, which means that the system being served must be radial or else it must be served by similar transformations at other points.

Transformer Loading Practice. Because of the varying load cycle of most transformers, it is customary to permit loading considerably in excess of the transformer nameplate rating. There may be limitations on the transformer imposed by bushings, leads, tap changers, cables, disconnecting switches, circuit breakers, etc. Good engineering design, however, will permit operation without these limitations.

The increase in transformer loading is limited by the effect of temperature on insulation life. High temperature decreases the mechanical strength and increases the brittleness of fibrous insulation and makes transformer failure increasingly likely even though the dielectric strength of the insulation may not be seriously decreased. Overloading should be limited then by giving consideration to the

TABLE 17-11 Percent Daily Peak Load for Normal Life Expectancy with 30°C Cooling Air

Duration of peak load, h	Self-cooled with % load before peak of			Forced-air-cooled up to 133% of self-cooled rating, with % load before peak of			Forced-air-cooled over 133% of self-cooled rating, or forced-oil-cooled, with % load before peak of		
	50%	70%	90%	50%	70%	90%	50%	70%	90%
0.5	189	178	164	182	174	161	165	158	150
1	158	149	139	150	143	135	138	133	128
2	137	132	124	129	126	121	122	119	117
4	119	117	113	115	113	111	111	110	109
8	108	107	106	107	107	106	106	106	105

effect on insulation life and transformer life. For recurring loads, such as the daily load cycles, the transformer would be operated for normal life expectancy. For emergencies, either planned or accidental, loading would be based on some percentage loss of life.

In a typical case for a failure of part of the electrical system, a 2.5% loss of life per day for a transformer may be acceptable. Loading recommendations based on the evaluation of the loss of insulation life as affected by temperature are contained in ANSI Standard C57.91-1995, Institute of Electrical and Electronics Engineers Guide for Loading Mineral-Oil-Immersed Transformers. NEMA Publ. TR98-1964 contains corresponding recommendations for loading power transformers with 65°C average winding rise insulation systems. ANSI Standard C57.91-1995 states that an average loss of life of 1% per year or 5% in any one emergency operation is considered reasonable.

Daily overload cycles consistent with normal life expectancy for air-cooled power transformers at 30°C ambient temperature are given in Table 17-11, which is a condensation of data taken from ANSI Standard C57.91-1995. For a listing of transformer loading above normal with some sacrifice of life expectancy, data given in NEMA Publ. TR98-1964, Part 3, are condensed in Table 17-12.

Ambient temperature affects load capacity by an amount depending on the type of cooling as shown in Tables 17-11 and 17-12. For changes from this average ambient temperature, transformer ratings may be adjusted as shown in Table 17-13. The table applies to both the 55°C and the 65°C average winding-temperature-rise transformers. For the ambient temperature of air-cooled transformers, use the average value over a 24-h period or 10°C under the maximum during the 24-h period, whichever is higher.

The following temperatures and load limitations are generally applied to transformers. The temperature of the top oil should never exceed 100°C. The maximum hot-spot winding temperature should not exceed 150°C for 55°C rise transformers or 180°C for 65°C rise transformers. Short-time peak loading for $^1/_2$ h or more should not exceed 200% rating. At abnormally high temperatures it may be necessary to remove some oil in order to avoid overflow or excessive pressure.

17.1.12 Surge Protection

A substation should be designed to include safeguards against the hazards of abnormally high voltage surges that can appear across the insulation of electrical equipment in the station. The most severe overvoltages are caused by lightning strokes and by switching surges. The main methods to prevent these overvoltages from causing insulation failures include:

1. Use of surge arresters
2. Equipment neutral grounding
3. Proper selection of equipment impulse insulation level

TABLE 17-12 Allowable Peak Loads (in Multiples of Maximum Nameplate Rating) for Moderate Sacrifice of Life Expectancy with 30°C Cooling Air

Duration of peak load, h	Hottest-spot temperature reached, °C	Life loss in percent not more than	Self-cooled (OA) with % load before peak of				Forced-air-cooled (OA/FA) up to 133% of self-cooled rating with % load before peak of				Forced-air-cooled (OA/FA/FA) over 133% of self-cooled rating or forced-oil-cooled (FOA or OA/FOA/FOA) with % load before peak of			
			50%	70%	90%	100%	50%	70%	90%	100%	50%	70%	90%	100%
½	171	0.25	2.00	2.00	2.00	1.96	2.00	1.95	1.85	1.80	1.64	1.60	1.54	1.51
	180	0.50	2.00	2.00	2.00	2.00	2.00	2.00	1.95	1.90	1.69	1.66	1.60	1.57
1	163	0.25	1.96	1.89	1.80	1.74	1.77	1.72	1.65	1.61	1.47	1.45	1.49	1.39
	180	1.00	2.00	2.00	1.99	1.94	1.93	1.88	1.81	1.78	1.57	1.55	1.52	1.50
2	155	0.25	1.68	1.63	1.57	1.53	1.53	1.50	1.47	1.44	1.33	1.32	1.31	1.30
	171	1.00	1.83	1.79	1.71	1.64	1.66	1.64	1.60	1.58	1.42	1.41	1.39	1.39
	180	2.00	1.91	1.83	1.71	1.64	1.74	1.71	1.65	1.61	1.47	1.46	1.44	1.43
4	147	0.25	1.44	1.41	1.39	1.37	1.35	1.34	1.33	1.32	1.24	1.23	1.23	1.23
	163	1.00	1.55	1.52	1.47	1.44	1.47	1.46	1.45	1.45	1.32	1.32	1.32	1.32
	180	4.00	1.55	1.52	1.47	1.44	1.51	1.50	1.47	1.46	1.40	1.40	1.39	1.39
8	139	0.25	1.28	1.27	1.27	1.26	1.24	1.24	1.24	1.24	1.18	1.18	1.18	1.18
	155	1.00	1.38	1.37	1.36	1.36	1.36	1.36	1.36	1.36	1.27	1.27	1.27	1.27
	171	4.00	1.38	1.37	1.36	1.36	1.42	1.42	1.41	1.41	1.35	1.35	1.35	1.35

Note: For forced-air-cooled transformers, the peak loads are calculated on the basis of all cooling being in use during the period preceding the peak load. When operating without fans, use the tables for OA transformers. Differences in cooling methods used with forced-oil-cooled transformers result in differences in peak-load-carrying ability. Consult the manufacturer before applying loads above the values given in the table.

Source: Based on capability tables in *NEMA Publ.* TR98, Part 3.

TABLE 17-13 Effect of Ambient Temperature on kVA Capacity

Type of cooling	% of rated kVA decrease in capacity for each °C increase over 30°C air	% of rated kVA increase in capacity for each °C decrease under 30°C
Self-cooled—OA	1.5	1.0
Forced-air-cooled—OA/FA, OA/FA/FA	1.0	0.75
Forced-air-cooled—FOA, OA/FOA/FOA	1.0	0.75

4. Proper selection and coordination of equipment basic insulation levels

5. Careful study of switching-surge levels that can appear in the substation

The main device used to prevent dangerous overvoltages, flashovers, and serious damage to equipment is the surge arrester. The surge arrester conducts high surge currents, such as can be caused by a lightning stroke, harmlessly to ground and thus prevents excessive overvoltages from appearing across equipment insulation. For a detailed description of the characteristics and application of arresters, refer to Sec. 27.

The important consideration in applying surge arresters and in selecting equipment insulation levels depends greatly on the method of grounding used. Systems are considered to be effectively grounded when the coefficient of grounding does not exceed 80%. Similarly, systems are noneffectively grounded or ungrounded when the coefficient of grounding exceeds 80%.

A value not exceeding 80% is obtained approximately when, for all system conditions, the ratio of zero sequence reactance to positive sequence reactance (X_0/X_1) is positive and less than 3 and the ratio of zero sequence resistance to positive sequence reactance (R_0/X_1) is positive and less than 1. What this says in effect is that if neutrals are grounded solidly everywhere and if a ground occurs on one of the conductors, then the voltage that can appear on the healthy phases cannot exceed 80% of normal phase-to-phase voltage.

Thus, the *coefficient of grounding* is defined as the ratio of maximum sustained line-to-ground voltage during faults to the maximum operating line-to-line voltage. On many HV and EHV systems, the coefficient of grounding may be as low as 70%.

Surge-arrester ratings are normally selected on the basis of the coefficient of grounding; thus, for effectively grounded systems, the 80% arrester is selected when using the conventional gap-type arrester. When using the gapless metal oxide arrester, a lower-value arrester may be selected based on the maximum continuous operating voltage (MCOV) equal to the maximum normal line-to-neutral voltage. For example, a 115-kV system (maximum operating voltage equals 121 kV) can use a 97-kV conventional arrester, that is, 80% of 121 kV, when operating on a solidly grounded system, and can use a gapless-type metal oxide arrester rated 70 kV. It should be noted that other factors, such as resonant conditions and system switching, could increase the value of the coefficient of grounding and thus should be studied in each individual system.

The impulse insulation level of a piece of equipment is a measure of its ability to withstand impulse voltage. It is the crest value, in kilovolts, of the wave of impulse voltage that the equipment must withstand. However, at EHV, the switching-surge insulation level may be lower than the corresponding impulse level, and thus the switching-surge level becomes the dominant factor in establishing insulation levels.

Basically, the coordination of insulation in a substation means the use of no higher-rated arrester than required to withstand the 60-Hz voltage and the choice of equipment insulation levels that can be protected by the arrester. Careful study of switching-surge levels that can occur at the substation as determined, for example, by transient network analyzer studies also can be used to determine and coordinate proper impulse insulation and switching-surge strength required in a substation electrical equipment.

REFERENCES ON AIR-INSULATED SUBSTATIONS

Books

Alcoa Aluminum Bus Conductor Handbook. Pittsburgh, Pa., Aluminum Company of America, 1957.

Applied Protective Relaying. Newark, N.J., Westinghouse Electric Corporation.

Blume, L. F., Boyajian, A., Camilli, G., Lennox, T. S., Minneci, S., and Montsinger, V. M.: *Transformer Engineering.* New York, John Wiley & Sons, 1951.

Electrical Transmission and Distribution Reference Book. East Pittsburgh, Pa., Westinghouse Electric Corporation, 1950.

Mason, C. R.: *The Art and Science of Protective Relaying.* New York, John Wiley & Sons, 1967.

Van C. Warrington, A. R.: *Protective Relays, Their Theory and Practice,* vol. 1. London, Chapman & Hall, 1971.

Van C. Warrington, A. R.: *Protective Relays, Their Theory and Practice,* vol. 2. London, Chapman & Hall, 1974.

Station Design

AIEE Committee Report: A Guide for Minimum Electrical Clearances for Standard Basic Insulation Levels, *Trans. AIEE, Power Appar. Syst.,* June 1954, vol. 73, pp. 636–641.

AIEE Committee Report: Basic Structural Design for Transmission Substations Including Light Metals, *Electr. Eng.,* April 1952, vol. 71, pp. 344–350.

Colombo, A., Sartorio, G., and Taschini, A.: Phase to Phase Air Clearances in EHV Substations as Required by Switching Surges, *CIGRE Paper* 33-11, 1972.

Committee Report: Design Standardization Methods and Techniques for Substation Facilities (Bibliogr.), *Trans. AIEE, Power Appar. Syst.,* October 1964, vol. 83, pp. 1029–1034.

Committee Report: 500 kV AC Substation Design Criteria, Summary of Industry Practices, *IEEE Trans., Power Appar. Syst.,* 1969, vol. 88, pp. 854–861.

Committee Report: Minimum Line-to-Ground Electrical Clearances for EHV Substations Based on Switching Surge Requirement, *IEEE Trans., Power Appar. Syst.,* 1972, vol. 91, pp. 1924–1930.

Committee Report: 700/765 kV AC Substation Design Criteria, A Summary of Industry Practices, *IEEE Trans., Power Appar. Syst.,* 1970, vol. 89, pp. 1521–1524.

Dolan, P. R., and Peat, A. J.: Design of the First 500 kV Substations on the Southern California Edison Company System, *IEEE Trans., Power Appar. Syst.,* 1967, vol. 86, pp. 531–539.

Hertig, G. E.: High- and Extra-High-Voltage Substation Design and Economic Comparisons, *Trans. AIEE,* 1963, vol. 81, pp. 832–840.

IEEE Standard C2-1997, National Electrical Safety Code.

Paris, L., and Taschini, A.: Phase-to-Ground and Phase-to-Phase Air Clearances in Substations, *CIGRE, Electra,* 1973, no. 29. (Recommended by CIGRE S.C. 23 and CIGRE S.C. 33.)

Scherer, H. N.: 765 kV Station Design, *IEEE Trans. Power Appar. Syst.,* 1969, vol. 88, pp. 1372–1376.

Bus Construction

Attri, N. S., and Edgar, J. N.: Response of Bus Bars on Elastic Supports Subjected to a Suddenly Applied Force, *IEEE Trans., Power Appar. Syst.,* 1967, vol. 86, pp. 636–650.

Committee Report: Use of Aluminum for Substation Busses, *IEEE Trans., Power Appar. Syst.,* 1963, vol. 82, pp. 72–102.

Dwight, H. B.: Skin Effect and Proximity Effect in Tubular Conductors, *Trans. AIEE,* February 1922, pp. 189–198.

Fischer, E. G.: Seismic Design of Bus Runs and Supports, *IEEE Trans., Power Appar. Syst*., 1973, vol. 92, pp. 1493–1500.

Foti, A.: Design and Application of EHV Disconnecting Switches, *Trans. AIEE, Power Appar. Syst.,* October 1965, vol. 84, pp. 868–876.

Higgins, T. J.: Formulas for Calculating Short Circuit Forces between Conductors of Structural Shape, *Trans. AIEE,* October 1943, vol. 62, pp. 659–663.

Higgins, T. J.: Formulas for Calculating Short Circuit Stresses for Bus Supports for Rectangular Tubular Conductors, *Trans. AIEE,* August 1942, vol. 61, pp. 578–580.

IEEE Standard C37.30-1992, Requirements for High Voltage Air Switches.

IEEE Standard C37.32-1992 (American National Standard for Switchgear, High-Voltage Air Switches, Bus Supports, and Switch Accessories), Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

Milton, R. M., and Chambers, F.: Behavior of High-Voltage Busses and Insulators during Short Circuits, *Trans. AIEE,* August 1955, vol. 74, pp. 742–749.

NEMA Standard SG6-1995, Power Switching Equipment.

Rayleigh, J. W. S.: *Aeolian Tones.* New York, Cambridge University Press, 1920.

Schurig, O. R., and Sayre, M. F.: Mechanical Stresses in Bus Bar Supports During Short Circuits, *J. AIEE,* April 1925, vol. 44, pp. 365–372.

Taylor, D. W., and Stuehler, C. M.: Short Circuit Tests on 138 kV Busses, *Trans. AIEE,* August 1956, vol. 75, pp. 739–747.

Temple, G., and Brickley, W. G.: *Rayleigh's Principle.* New York, Oxford University Press, 1933.

Wagner, C. F.: Current Distribution in Multi Conductor Single Phase Buses, *Electr. World,* March 18, 1922, vol. 79, no. 11.

System Protection

Blackburn, J. L.: Future Automatic Switching of EHV Transmission Lines—Development and Application of Solid-State Relays, *Proc. Am. Power Conf.,* 1965, vol. 27, pp. 998–1008.

Boyaris, E., and Guyot, W. S.: Experience with Fault Pressure Relaying and Combustible Gas Detection in Power Transformers, *Proc. Am. Power Conf.,* 1971, vol. 33, pp. 1116–1126.

Chadwick, J. W., and Goff, L. E.: Development of a Static Single-pole Relaying Scheme for the TVA 500-kV System, *Proc. Am. Power Conf.,* 1971, vol. 33, pp. 1127–1133.

Committee Report: Relaying the Keystone 500 kV System, *IEEE Trans.,* June 1968, vol. 87, no. 5, no. 6, pp. 1434–1439.

Elmore, W. A.: Some Guidelines for Selecting a Solid-State Transmission Line Relaying System, *Westinghouse Eng.,* March 1972, vol. 32, no. 2, pp. 50–59.

Emanuel, A. E., and Vora, J. P.: Sensor Coil for Internal Fault Protection of Shunt Reactors, *IEEE Trans.,* November-December 1974, vol. 93, no. 6, pp. 1917–1926.

Forford, T., and Linders, J. R.: A Half Cycle Bus Differential Relay and Its Applications, *IEEE Trans.,* July-August 1974, vol. 93, no. 4, pp. 1110–1120.

Horowitz, S. H., and Seeley, H. T.: Relaying the AEP 765 kV System, *IEEE Trans.,* September 1969, vol. PAS-88, no. 9, pp. 1382–1389.

IEEE Committee Report: Bibliography of Relay Literature 1995.

IEEE Committee Report: Ground Relaying Practices and Problems: A Power System Relaying Committee Survey, *IEEE Trans., Power Appar. Syst.,* May 1966, vol. PAS-85, no. 5, pp. 524–532.

IEEE Standard C37.90-1-1989, Guide for Surge Withstand Capability (SWC) Tests.

IEEE Standard C37.90-1989, Relays and Relay Systems Associated with Electric Power Apparatus.

IEEE Standard C37.91-1985, Guide for Protective Relay Applications to Power Transformers.

Korponay, N., and Ungrad, H.: The Requirements Made of Current Transformers by High-Speed Protective Relays, *Brown Boveri Rev.,* June 1968, vol. 55, no. 6, pp. 289–297.

Narayan, V.: Distance Protection of H. V. and E. H. V. Transmission Lines, *Brown Boveri Rev.,* July 1971, vol. 58, no. 7, pp. 276–286.

Rockefeller, G. D.: What Are the Prospects for Substation-Computer Relaying? *Westinghouse Eng.,* September 1972, vol. 32, no. 5, pp. 152–156.

Schumm, G. P.: The Philosophy of Protective Relaying in the United States and Europe, *Proc. Am. Power Conf.,* 1971, vol. 33, pp. 1105–1115.

Sutton, H. J.: The Application of Relaying on an EHV System, *IEEE Trans.,* April 1967, vol. 86, no. 4, pp. 408–415.

Sykes, J. A., and Morrison, I. F.: A Proposed Method of Harmonic Restraint Differential Protection of Transformers by Digital Computer, *IEEE Trans.,* May-June 1972, vol. 91, no. 3, pp. 1266–1272.

Ungrad, H.: Back-up Protection, *Brown Boveri Rev.,* June 1968, vol. 55, no. 6, pp. 297–305.

Ungrad, H.: Distance Relays with Signal Transmission for Main and Backup Protection, *Brown Boveri Rev.,* July 1971, vol. 58, no. 7, pp. 293–304.

Vanderleck, J. M.: Measurement of Composite Error of Relay-type Current Transformers, *Ontario Hydro Res. Q.,* 1967, vol. 19, no. 3, pp. 15–18.

Shielding of Control Cables

Dietrick, R. E., Ramberg, H. C., and Barber, J. C.: BPA Experience with EMI Measurements and Shielding in EHV Substations, *Proc. Am. Power Conf.,* 1970, vol. 32, pp. 1054–1061.

Kotheimer, W. C.: Control Circuit Transients, Pt. 1, *Power Eng.,* January 1969, vol. 73, no. 1, pp. 42–46.

Kotheimer, W. C.: Control Circuit Transients, Pt. 2, *Power Eng.,* February 1969, vol. 73, no. 2, pp. 54–56.

Sutton, H. J.: Transients Induced in Control Cables Located in EHV Substation, *IEEE Trans.,* July-August 1970, vol. 89, no. 6, p. 1069.

Grounding

AIEE Committee Report: Application Guide on Methods of Substation Grounding, *Trans. AIEE, Power Appar. Syst.*, April 1954, vol. 73, pp. 271–275.

Bellasi, P. L.: Impulse and 60-Cycle Characteristics of Driven Grounds, *Trans. AIEE,* March 1941, vol. 60, pp. 123–128.

Committee Report: Principles and Practices in Grounding, *Edison Electr. Inst. Ser. Rep.* D9, October 1936.

Eaton, J. R.: Grounding Electric Circuits Effectively, I, II, III, *Gen. Electr. Rev.,* June, July, and August 1941.

EPRI Final Report EL-2682: Analysis Techniques for Power Substation Grounding Systems, vol. 1, Design Methodology and Tests.

IEEE Standard 80-1986, IEEE Guide for Safety in AC Substation Grounding.

IEEE Standard 81-1983, Recommended Guide for Measuring Ground Resistance and Potential Gradients in the Earth.

IEEE Standard 142-1991, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems.

Kinyon, A. L.: Earth Resistivity Measurements for Grounding Grids, Trans. *AIEE, Power Appar. Syst.,* December 1961, vol. 80, pp. 795–800.

17.2 GAS-INSULATED SUBSTATIONS

By Philip Bolin

17.2.1 Introduction

High-voltage gas-insulated substations have been in service since the early 1960s. Operation of 800-kV equipment has proved successful since the end of 1979. Prototype testing of 1100 through 1600-kV substation equipment proved the feasibility of this equipment at the next generation of voltage levels.

17.2.2 General Characteristics

The basic principle of gas-insulated equipment is that the high-voltage current-carrying parts are within a metal enclosure and are held in a concentric configuration by cast epoxy spacer insulators. The space between the conductor and the enclosure is filled with sulfur hexafluoride gas under moderate pressure.

Medium-voltage to 170-kV equipment is available in three phases in one enclosure; for higher voltages, it is generally in a single-phase enclosure arrangement. The equipment can be installed indoors or outdoors, and it can be designed for any bus scheme. Depending on the voltage level, bus scheme, and whether connecting lines are installed underground or overhead, the land area required for gas-insulated equipment is 10% for 800 kV to 20% for 145 kV of the space required for comparable air-insulated equipment. Because of its smaller size and enclosed current-carrying parts, this equipment is excellently suited for installation where real estate is at a premium, where the environmental constraints dictate a minimum of visual exposure, and where the continuity of service may be threatened by airborne contamination. Typical section and five-bay substation layouts are shown in Figs. 17-26 and 17-27.

The dielectric medium is the sulfur hexafluoride (SF_6) gas, which became commercially available in 1947. SF_6 has been used as an insulating medium in electronic devices, power apparatus, and HVDC converter stations. Its excellent properties make it ideally suited both as an insulating and as an arc-quenching agent. SF_6 gas is colorless, odorless, chemically inert, nontoxic, nonflammable, and noncorrosive. Its dielectric strength is greatly superior to that of air, and it is close to 100 times as effective as air in quenching an electric arc. These characteristics are illustrated in Figs. 17-28 and 17-29, respectively.

Pure SF_6 is heavier than air, which causes it to settle in low areas, thus diluting oxygen in air. It is therefore necessary to learn proper safety rules before entering any area where pockets of SF_6 could accumulate. Although the gas is self-restoring, during its exposure to an electric arc it will yield decomposition by-products. In the presence of moisture, which is especially the case in failed and ruptured equipment, these by-products will hydrolyze, and all resulting reaction products must be considered hazardous.

The level of gas pressure at which the equipment will operate to meet specified ratings is a function of the relationship between diameters of the conductor and the enclosure (the size of the gap), and the temperature at which the equipment will operate. At the higher pressures, the gas would liquefy at higher temperatures, as indicated in Fig. 17-30. At lower pressures, dielectric strength and arc-quenching qualities of the gas would be reduced. Therefore, the gas-insulated equipment operating pressure is usually between 0.35 and 0.52 MPa (50 and 75 lb/in^2, gage).

Environmental effects of SF_6 that might be released to the atmosphere from GIS have been thoroughly studied. SF_6 does not affect the earth's ozone layer, but it is a strong greenhouse gas. Relative to CO_2, it has a global warming potential of 23,400 due to its infrared absorption and emission characteristics and very long life in the atmosphere (half-life is projected to be 3200 years). Fortunately, the concentration of SF_6 in the atmosphere is very low, and with proper handling, leak checking, and recycling, the contribution of SF_6 to anthropogenic global warming due to its use in electrical equipment can be kept below 0.1%.

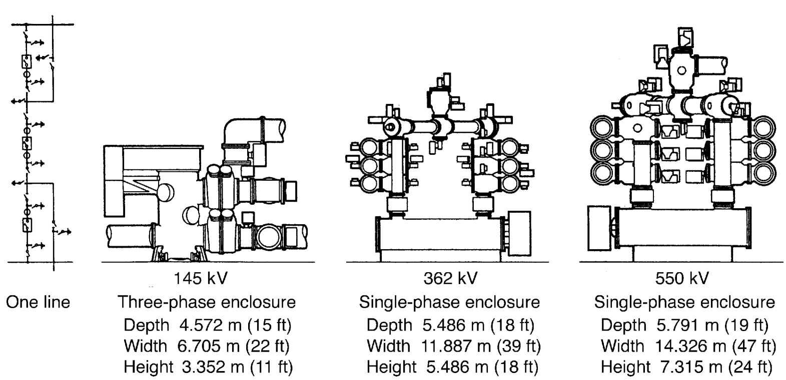


FIGURE 17-26 Typical breaker section for breaker-and-a-half scheme.

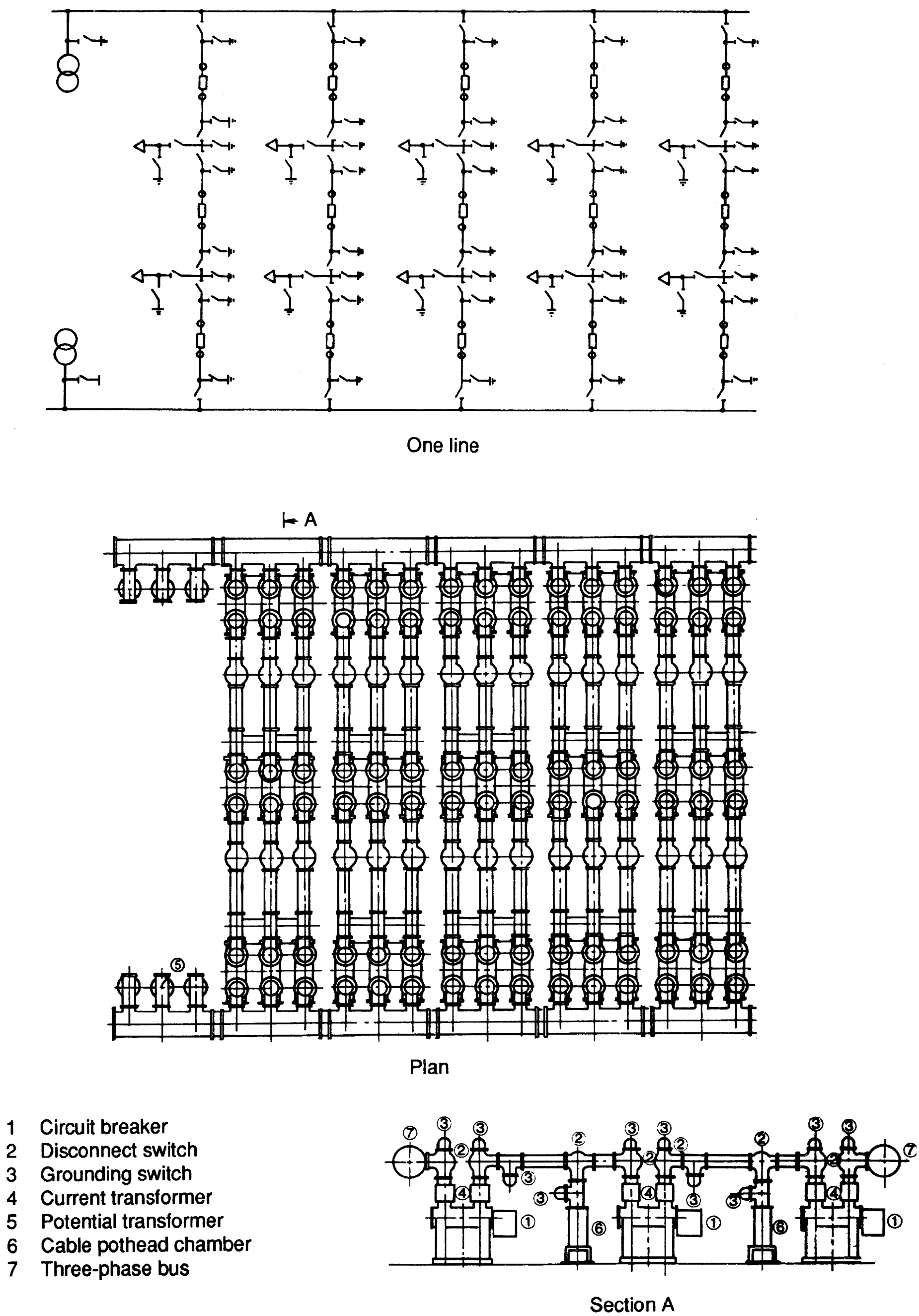


FIGURE 17-27 Typical layout for five-bay breaker-and-a-half scheme.

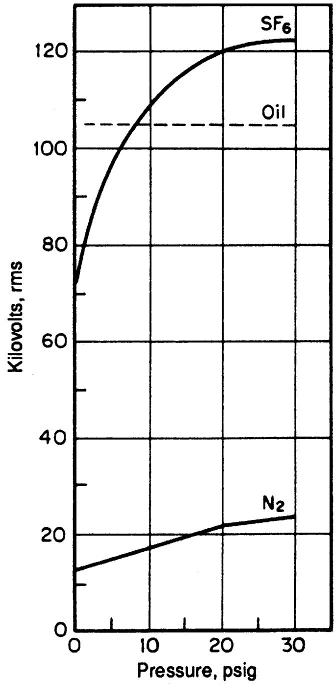


FIGURE 17-28 Power-frequency dielectric strength of SF_6.

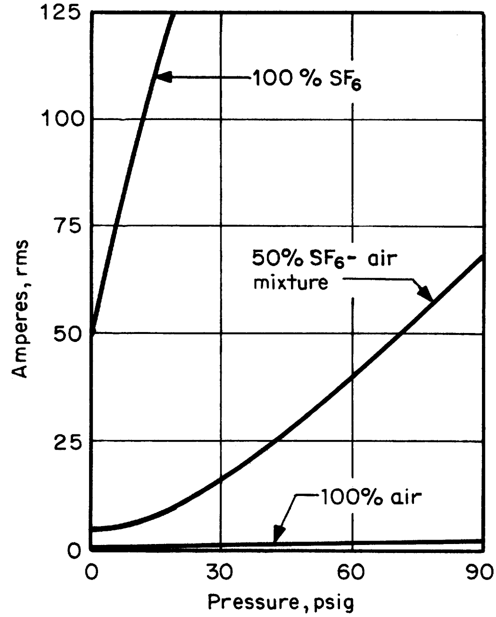


FIGURE 17-29 Arc-quenching ability of SF_6.

17.2.3 Equipment

The tubular conductor is made of aluminum or copper, and the enclosure can be of aluminum, steel, or stainless steel. The conductor connections are made by plug-in contacts, and the enclosure is joined by bolted flanges. In order to provide for proper gas seal, the flanges are constructed with O-ring gaskets. Conductor support insulators are of two types. Barrier insulators are used to isolate gas compartments; they must be capable of withstanding 1.5 times the operating pressure on one side and vacuum on the other side. Nonbarrier insulators permit the gas pressure to equalize between the compartments.

The circuit breakers are of dead-tank design and are the same as those installed in air-insulated substations, except that they are connected to the gas-insulated bus. They have standard ratings.

The rating of the disconnecting switches is established by standards; they must be capable of interrupting associated bus charging current. External indicators provide for switchblade position; however, visual verification is required by some users. This is done through a viewport in the enclosure directly over the contact-making area.

Maintenance and fault-closing grounding switches are the two most common types of grounding devices used with gas-insulated equipment. The first is used to provide grounding connection for maintenance purposes and is generally manually operated. The fault-closing grounding switch, in addition to providing for the maintenance function, has the capability of closing into a fault at least twice without damage. It is generally motor-operated. Both types may be furnished with a low-voltage test provision which permits voltage application to the conductor. This can be achieved without removal of the dielectric and without disassembly, except for ground shunt straps, which must be disconnected. Contact position indication can be the same as for disconnecting switches.

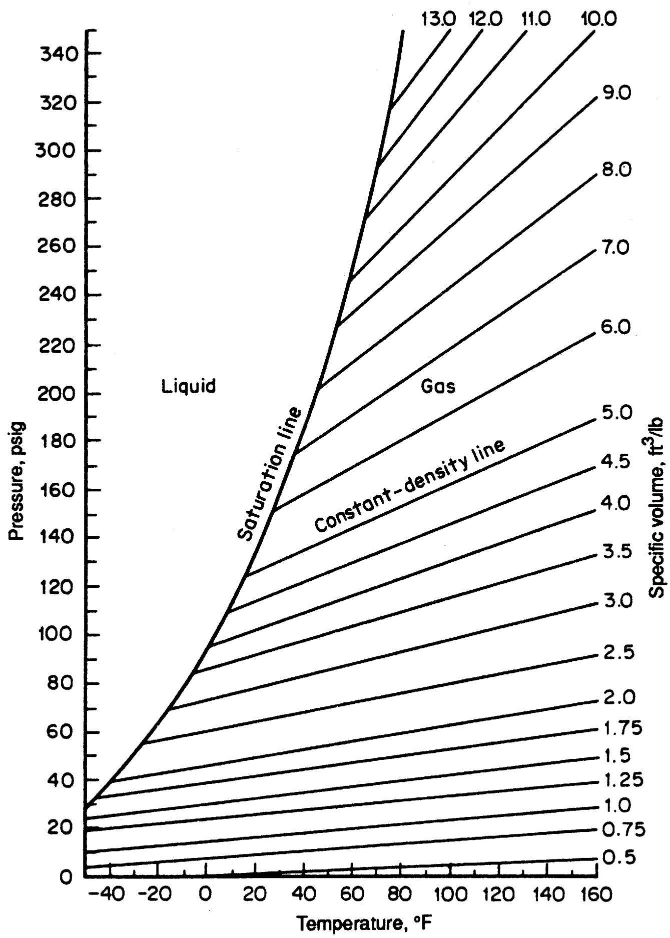


FIGURE 17-30 Pressure variation of SF_6 at constant specific volume.

Current transformers should be positioned so that the current in the enclosure does not affect the accuracy and ratio of the device and does not distort the conductor current being measured. Inductive and capacitive voltage transformers and surge arresters must be provided with disconnecting means for system dielectric tests. The surge-arrester ground connection must be isolated from the enclosure in order to permit monitoring of the leakage current.

The connections from the gas-insulated equipment to transmission lines, transformers, and reactors can be made by SF_6-to-air or SF_6-to-oil bushings. For overhead connection, the SF_6-to-air bushing is usually a hollow porcelain or composite insulator filled with pressurized SF_6 gas. There are two types of SF_6-to-oil bushings: one is for the transformer and the reactor and consists of an expanded bus section that totally encloses the bushing. Provision is made, for both the conductor and the enclosure, to minimize the transfer of transformer or reactor vibrations. The other type of SF_6-to-oil bushing is the power-cable pothead termination into the bus. This bushing must allow for power-cable disconnection from the gas-insulated bus to permit cable dc field testing. Both SF_6-to-oil bushings are provided with barriers which prevent oil migration into the switchgear. Bushings are also available for termination of a solid-dielectric cable into the GIS.

Particle Traps. Any loose conductive particles left within the enclosure can, when the equipment is energized, produce a flashover. When voltage is applied, these particles are moved by the alternating field in a random mode along the lower part of the enclosure. Eventually they reach a particle trap and through its slots fall into the zero-field region where they become permanently trapped and are rendered harmless. Particle traps are placed at the support insulators.

Pressure-Relief Devices. The enclosure is designed so that overpressure caused by internal faults is limited by pressure-relief devices. The location of these devices is such that when activated, the escaping ionized gases do not pose a hazard to personnel. The bursting pressure is coordinated with the rated gas pressure and the pressure rise caused by arcing. If the enclosure material or volume is sufficient to withstand expected overpressure during an internal fault, the pressure-relief devices may not be required.

Desiccant. Depending on the composition of the metal, insulators, and other materials within the equipment and expected moisture content of the dielectric, desiccant may be placed in selected locations to maintain the total moisture content at acceptable levels. It may be contained in especially designed canisters or may be built into spaces of the equipment. The desiccant is also useful in absorbing arcing-related gas by-products.

Expansion. Expansion joints provide for installation alignment and compensate for thermal expansion. If they are to facilitate alignment, they are locked in place when alignment is completed. If they are to compensate for thermal expansion, they are to have means to preserve mechanical integrity of the enclosure and the conductor.

Gas System. For maintenance and monitoring and to restrict damage and contamination in case of a fault, the gas system is divided by means of gas-barrier insulators into basic compartments: each circuit breaker, each terminal compartment, and each main bus section. Each gas compartment has a monitoring system for gas-density with two sets of contacts. Electrically independent contacts operate in two stages: an alarm to refill the gas, normally 5% to 10% below normal, and an alarm to indicate that the pressure has reached minimum level to support equipment ratings. By weight, the individual compartments are not to experience more than 1% leakage per year. The compartments are connected with external gas piping. The piping, which is made of corrosion-resistant material, must be isolated to prevent circulating currents. At each compartment, provisions are made for connecting moisture measurement instrumentation and the gas service cart.

Access. To facilitate maintenance, handholes or manholes, depending on the equipment size, are provided in the enclosure at locations where maintenance-prone devices are located. These gastight accesses are entered only after the dielectric has been evacuated and the compartment thoroughly ventilated.

Associated Systems. Most of the protective and control practices for air-insulated substations apply also for gas-insulated equipment. The principal difference is the requirement for online gas-density alarms for the gas-insulated substations. Another significant difference is that circuit-breaker reclosing is blocked for faults detected anywhere within gas-insulated equipment and its associated gas-insulated transmission-line exits.

In considering the grounding of the gas-insulated equipment, it is essential that the enclosure be bonded so as to present a continuous current path. The current in the conductor induces a voltage in its single-phase enclosure, which causes a longitudinal current flow. When the loads are balanced, this current returns through the enclosure of the adjacent phase. A discontinuity in the enclosure would generate circulating currents and most likely higher-than-desired touch potential.

Field testing of gas-insulated substations requires tests, which may not be required for the conventional equipment. These tests are leak detection, moisture content in the dielectric, and power-frequency testing. In addition to verifying the integrity of the installation, the power-high-voltage frequency test also will reveal the presence of any free conducting particles which may be present.

REFERENCES ON SF_6 GAS-INSULATED SUBSTATIONS

Bennett, A. I., Carlson, G. L., and Lee, A.: Characterization of ARC By-Products of Sulfur Hexafluoride and Polymeric Construction Materials, *EPRI Final Report* EL-5089, April 1987.

Boggs, S., Chu, F. Y., and Fujimoto, J., ed.: *Gas-Insulated Substations—Technology and Practices.* New York: Pergamon Press, 1986.

CIGRE Working Group 23-02 Report: Handling of SF_6 and Its Decomposition Products in Gas-Insulated Switchgear, CIGRE, *Electra,* no. 136, June 1991, part 1, and no. 137, August 1991, part 2.

CIGRE Working Group 23.10: A Twenty-Five-Year Review of Experience with SF_6 Gas-Insulated Substations (GIS), CIGRE Paper 23.101, 1992.

CIGRE Working Group 23.10-01 Report 117: SF_6 Recycling Guide, August 1997.

IEEE C37.122-1993, IEEE Standard for Gas Insulated Substations.

IEEE C37.123-1996, IEEE Guide to Specifications for Gas-Insulated Substations Equipment.

IEEE C37.38-1989, IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.