

Power Distribution Systems

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Designing a Distribution System

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Basic Principles

The best distribution system is one that will, cost-effectively and safely, supply adequate electric service to both present and future probable loads—this section is included to aid in selecting, designing and installing such a system.

The function of the electric power distribution system in a building or an installation site is to receive power at one or more supply points and to deliver it to the individual lamps, motors and all other electrically operated devices. The importance of the distribution system to the function of a building makes it almost imperative that the best system be designed and installed.

In order to design the best distribution system, the system design engineer must have information concerning the loads and a knowledge of the various types of distribution systems that are applicable. The various categories of buildings have many specific design challenges, but certain basic principles are common to all. Such principles, if followed, will provide a soundly executed design.

The basic principles or factors requiring consideration during design of the power distribution system include:

- Functions of structure, present and future
- Life and flexibility of structure
- Locations of service entrance and distribution equipment, locations and characteristics of loads, locations of unit substations
- Demand and diversity factors of loads
- Sources of power; including normal, standby and emergency (see **Tab 40**)
- Continuity and quality of power available and required (see **Tab 33**)
- Energy efficiency and management
- Distribution and utilization voltages
- Bus and/or cable feeders
- Distribution equipment and motor control
- Power and lighting panelboards and motor control centers
- Types of lighting systems
- Installation methods
- Power monitoring systems
- Electric utility requirements

Modern Electric Power Technologies

Several new factors to consider in modern power distribution systems result from two relatively recent changes. The first recent change is utility deregulation. The traditional dependence on the utility for problem analysis, energy conservation measurements and techniques, and a simplified cost structure for electricity has changed. The second change is less obvious to the designer yet will have an impact on the types of equipment and systems being designed. It is the diminishing quantity of qualified building electrical operators, maintenance departments and facility engineers.

Modern electric power technologies may be of use to the designer and building owner in addressing these new challenges. The advent of micro-processor devices (smart devices) into power distribution equipment has expanded facility owners' options and capabilities, allowing for automated communication of vital power system information (both energy data and system operation information) and electrical equipment control.

These technologies may be grouped as:

- Power monitoring and control
- Building management systems interfaces
- Lighting control
- Automated energy management
- Predictive diagnostics

Various sections of this guide cover the application and selection of such systems and components that may be incorporated into the power equipment being designed. See **Tabs 2, 3, 4, 23 and 41**.

Goals of System Design

When considering the design of an electrical distribution system for a given customer and facility, the electrical engineer must consider alternate design approaches that best fit the following overall goals.

1

1. **Safety:** The No. 1 goal is to design a power system that will not present any electrical hazard to the people who use the facility, and/or the utilization equipment fed from the electrical system. It is also important to design a system that is inherently safe for the people who are responsible for electrical equipment maintenance and upkeep.

The National Electrical Code® (NEC®), NFPA® 70 and NFPA 70E, as well as local electrical codes, provide minimum standards and requirements in the area of wiring design and protection, wiring methods and materials, as well as equipment for general use with the overall goal of providing safe electrical distribution systems and equipment.

The NEC also covers **minimum** requirements for special occupancies including hazardous locations and special use type facilities such as health care facilities, places of assembly, theaters and the like, and the equipment and systems located in these facilities. Special equipment and special conditions such as emergency systems, standby systems and communication systems are also covered in the code.

It is the responsibility of the design engineer to be familiar with the NFPA and NEC code requirements as well as the customer's facility, process and operating procedures; to design a system that protects personnel from live electrical conductors and uses adequate circuit protective devices that will selectively isolate overloaded or faulted circuits or equipment as quickly as possible.

2. **Minimum Initial Investment:** The owner's overall budget for first cost purchase and installation of the electrical distribution system and electrical utilization equipment will be a key factor in determining which of various alternate system designs are to be selected. When trying to minimize initial investment for electrical equipment, consideration should be given to the cost of installation, floor space requirements and possible extra cooling requirements as well as the initial purchase price.
3. **Maximum Service Continuity:** The degree of service continuity and reliability needed will vary depending on the type and use of the facility as well as the loads or processes being supplied by the electrical distribution system. For example, for a smaller commercial office building, a power outage of considerable time, say several hours, may be acceptable, whereas in a larger commercial building or industrial plant only a few minutes may be acceptable. In other facilities such as hospitals, many critical loads permit a maximum of 10 seconds outage and certain loads, such as real-time computers, cannot tolerate a loss of power for even a few cycles.

Typically, service continuity and reliability can be increased by:

- A. Supplying multiple utility power sources or services.
- B. Supplying multiple connection paths to the loads served.
- C. Using short-time rated power circuit breakers.
- D. Providing alternate customer-owned power sources such as generators or batteries supplying uninterruptable power supplies.
- E. Selecting the highest quality electrical equipment and conductors.
- F. Using the best installation methods.
- G. Designing appropriate system alarms, monitoring and diagnostics.
- H. Selecting preventative maintenance systems or equipment to alarm before an outage occurs.

4. **Maximum Flexibility and Expendability:** In many industrial manufacturing plants, electrical utilization loads are periodically relocated or changed requiring changes in the electrical distribution system. Consideration of the layout and design of the electrical distribution system to accommodate these changes must be considered. For example, providing many smaller transformers or loadcenters associated with a given area or specific groups of machinery may lend more flexibility for future changes than one large transformer; the use of plug-in busways to feed selected equipment in lieu of conduit and wire may facilitate future revised equipment layouts.

In addition, consideration must be given to future building expansion, and/or increased load requirements due to added utilization equipment when designing the electrical distribution system. In many cases considering transformers with increased capacity or fan cooling to serve unexpected loads as well as including spare additional protective devices and/or provision for future addition of these devices may be desirable. Also to be considered is increasing appropriate circuit capacities or quantities for future growth.

Power monitoring communication systems connected to electronic metering can provide the trending and historical data necessary for future capacity growth.

5. Maximum Electrical Efficiency (Minimum Operating Costs):

Electrical efficiency can generally be maximized by designing systems that minimize the losses in conductors, transformers and utilization equipment. Proper voltage level selection plays a key factor in this area and will be discussed later. Selecting equipment, such as transformers, with lower operating losses, generally means higher first cost and increased floor space requirements; thus, there is a balance to be considered between the owner's utility energy charge for the losses in the transformer or other equipment versus the owner's first cost budget and cost of money.

6. Minimum Maintenance Cost:

Usually the simpler the electrical system design and the simpler the electrical equipment, the less the associated maintenance costs and operator errors. As electrical systems and equipment become more complicated to provide greater service continuity or flexibility, the maintenance costs and chance for operator error increases. The systems should be designed with an alternate power circuit to take electrical equipment (requiring periodic maintenance) out of service without dropping essential loads. Use of drawout type protective devices such as breakers and combination starters can also minimize maintenance cost and out-of-service time. Utilizing sealed equipment in lieu of ventilated equipment may minimize maintenance costs and out-of-service time as well.

7. Maximum Power Quality:

The power input requirements of all utilization equipment has to be considered including the acceptable operating range of the equipment and the electrical distribution system has to be designed to meet these needs. For example, what is the required input voltage, current, power factor requirement? Consideration to whether the loads are affected by harmonics (multiples of the basic 60 Hz sine wave) or generate harmonics must be taken into account as well as transient voltage phenomena.

The above goals are interrelated and in some ways contradictory. As more redundancy is added to the electrical system design along with the best quality equipment to maximize service continuity, flexibility and expandability, and power quality, the more initial investment and maintenance are increased. Thus, the designer must weigh each factor based on the type of facility, the loads to be served, the owner's past experience and criteria.

Summary

It is to be expected that the engineer will never have complete load information available when the system is designed. The engineer will have to expand the information made available to him on the basis of experience with similar problems. Of course, it is desirable that the engineer has as much definite information as possible concerning the function, requirements, and characteristics of the utilization devices. The engineer should know whether certain loads function separately or together as a unit, the magnitude of the demand of the loads viewed separately and as units, the rated voltage and frequency of the devices, their physical location with respect to each other and with respect to the source and the probability and possibility of the relocation of load devices and addition of loads in the future.

Coupled with this information, a knowledge of the major types of electric power distribution systems equips the engineers to arrive at the best system design for the particular building.

It is beyond the scope of this guide to present a detailed discussion of loads that might be found in each of several types of buildings. Assuming that the design engineer has assembled the necessary load data, the following pages discuss some of the various types of electrical distribution systems that can be used. The description of types of systems, and the diagrams used to explain the types of systems on the following pages omits the location of utility revenue metering equipment for clarity. A discussion of short-circuit calculations, coordination, voltage selection, voltage drop, ground fault protection, motor protection and other specific equipment protection is also presented.

Voltage Classifications

ANSI and IEEE® standards define various voltage classifications for single-phase and three-phase systems. The terminology used divides voltage classes into:

- Low voltage
- Medium voltage
- High voltage
- Extra-high voltage
- Ultra-high voltage

Table 1.1-1 presents the nominal system voltages for these classifications.

Table 1.1-1. Standard Nominal System Voltages and Voltage Ranges (From IEEE Standard 141-1993)

Voltage Class	Nominal System Voltage	
	Three-Wire	Four-Wire
Low voltage	240/120	208Y/120
	240	240/120
	480	480Y/277
	600	—
	—	—
Medium voltage	2400	4160Y/2400
	4160	8320Y/4800
	4800	12000Y/6930
	6900	12470Y/7200
	13,200	13200Y/7620
	13,800	13800Y/7970
	23,000	20780Y/12000
	34,500	22860Y/13200
	46,000	24940Y/14400
	69,000	34500Y/19920
	—	—
High voltage	115,000	—
	138,000	—
	161,000	—
	230,000	—
Extra-high voltage	345,000	—
	500,000	—
	765,000	—
Ultra-high voltage	1,100,000	—

BIL—Basic Impulse Levels

ANSI standards define recommended and required BIL levels for:

- Metal-clad switchgear (typically vacuum breakers)
- Metal-enclosed switchgear (typically load interrupters, switches)
- Pad-mounted and overhead distribution switchgear
- Liquid immersed transformers
- Dry-type transformers

Table 1.1-2 through Table 1.1-6 contain those values.

Table 1.1-2. Metal-Clad Switchgear Voltage and Insulation Levels (From IEEE Std. C37.20.2-2015)

Rated Maximum Voltage (kV rms)	Impulse Withstand (kV)
4.76	60
8.25	95
15.0	95
27.0	125
38.0	150

Table 1.1-3. Metal-Enclosed Switchgear Voltage and Insulation Levels (From IEEE Std. C37.20.3-2013)

Rated Maximum Voltage (kV rms)	Impulse Withstand (kV)
4.76	60
8.25	95
15.0	95
27.0	125
38.0	150

Table 1.1-4. Pad Mounted and Overhead Distribution Switchgear, Voltage and Insulation Levels

Rated Maximum Voltage Level (kV rms)	Impulse Withstand (kV)
15.5	95
27	125
38	150

Pad Mount Switchgear (per IEEE C37.74-2014)

15.5	95
27	125
38	150

Overhead Switchgear (per IEEE C37.60-2012)

15	95
15.5	110
27	125
38	150
38	170

Table 1.1-5. Liquid-Immersed Transformers Voltage and Basic Lightning Impulse Insulation Levels (BIL) (From ANSI/IEEE C57.12.00)

Application	Nominal System Voltage (kV rms)	BIL (kV Crest) ①			
Distribution	1.2	30	—	—	—
	2.5	45	—	—	—
	5.0	60	—	—	—
	8.7	75	—	—	—
	15.0	95	—	—	—
	25.0	150	125	—	—
	34.5	200	150	125	—
	46.0	250	200	—	—
	69.0	350	250	—	—
	Power	1.2	45	30	—
2.5		60	45	—	—
5.0		75	60	—	—
8.7		95	75	—	—
15.0		110	95	—	—
25.0		150	—	—	—
34.5		200	—	—	—
46.0		250	200	—	—
69.0		350	250	—	—
115.0		550	450	350	—
138.0		650	550	450	—
161.0		750	650	550	—
230.0		900	825	750	650
345.0	1175	1050	900	—	
500.0	1675	1550	1425	1300	
765.0	2050	1925	1800	—	

① BIL values in **bold typeface** are listed as standard. Others listed are in common use.

Table 1.1-6. Dry-Type Transformers Voltage and Basic Lightning Impulse Insulation Levels (BIL)—From ANSI/IEEE C57.12.01-1998)

Nominal System Voltage (kV rms)	BIL (kV Crest) ②			
	—	10	20	30
1.2	—	20	30	45
2.5	—	30	45	60
5.0	—	45	60	95
8.7	—	—	—	—
15.0	—	60	95	110
25.0	95 ③	110	125	150
34.5	—	125 ③	150	200

② BIL values in **bold typeface** are listed as standard. Others listed are in common use. Optional higher levels used where exposure to overvoltage occurs and higher protection margins are required.

③ Lower levels where surge arrester protective devices can be applied with lower spark-over levels.

Voltage Recommendations by Motor Horsepower

Some factors affecting the selection of motor operating voltage include:

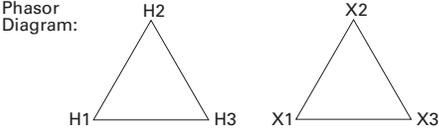
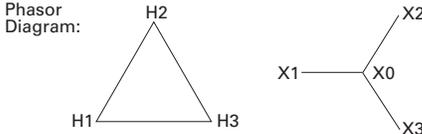
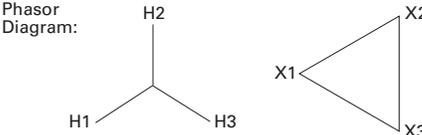
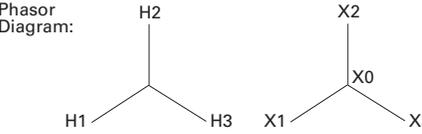
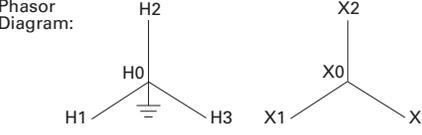
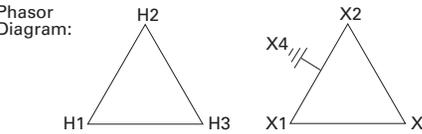
- Motor, motor starter and cable first cost
- Motor, motor starter and cable installation cost
- Motor and cable losses
- Motor availability
- Voltage drop
- Qualifications of the building operating staff; and many more

The following table is based in part on the above factors and experience. Because all the factors affecting the selection are rarely known, it is only an approximate guideline.

Table 1.1-7. Selection of Motor Horsepower Ratings as a Function of System Voltage

Motor Voltage (Volts)	Motor hp Range	System Voltage
460	up to 500	480
2300	250 to 2000	2400
4000	250 to 3000	4160
4600	250 to 3000	4800
13,200	above 2000	13,800

Table 1.1-7. Three-Phase Transformer Winding Connections

Phasor Diagram	Notes
<p>DELTA-DELTA Connection</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 0</p>	<ol style="list-style-type: none"> Suitable for both ungrounded and effectively grounded sources. Suitable for a three-wire service or a four-wire service with a mid-tap ground.
<p>DELTA-WYE Connection</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 30</p>	<ol style="list-style-type: none"> Suitable for both ungrounded and effectively grounded sources. Suitable for a three-wire service or a four-wire grounded service with XO grounded. With XO grounded, the transformer acts as a ground source for the secondary system. Fundamental and harmonic frequency zero-sequence currents in the secondary lines supplied by the transformer do not flow in the primary lines. Instead the zero sequence currents circulate in the closed delta primary windings. When supplied from an effectively grounded primary system does not see load unbalances and ground faults in the secondary system.
<p>WYE-DELTA Connection</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 30</p>	<ol style="list-style-type: none"> Suitable for both ungrounded and effectively grounded sources. Suitable for a three-wire service or a four-wire delta service with a mid-tap ground. Grounding the primary neutral of this connection would create a ground source for the primary system. This could subject the transformer to severe overloading during a primary system disturbance or load unbalance. Frequently installed with mid-tap ground on one leg when supplying combination three-phase and single-phase load where the three-phase load is much larger than single-phase load. When used in 25 kV and 35 kV three-phase four-wire primary systems, ferroresonance can occur when energizing or de-energizing the transformer using single-pole switches located at the primary terminals. With smaller kVA transformers the probability of ferroresonance is higher.
<p>WYE-WYE Connection</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 0</p>	<ol style="list-style-type: none"> Suitable for both ungrounded and effectively grounded sources. Suitable for a three-wire service only, even if XO is grounded. This connection is incapable of furnishing a stabilized neutral and its use may result in phase-to-neutral overvoltage (neutral shift) as a result of unbalanced phase-to-neutral load. If a three-phase unit is built on a three-legged core, the neutral point of the primary windings is practically locked at ground potential.
<p>GROUNDWYE-WYE Connection</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 0</p>	<ol style="list-style-type: none"> Suitable for four-wire effectively grounded source only. Suitable for a three-wire service or for four-wire grounded service with XO grounded. Three-phase transformers with this connection may experience stray flux tank heating during certain external system unbalances unless the core configuration (four or five legged) used provides a return path for the flux. Fundamental and harmonic frequency zero-sequence currents in the secondary lines supplied by the transformer also flow in the primary lines (and primary neutral conductor). Ground relay for the primary system may see load unbalances and ground faults in the secondary system. This must be considered when coordinating overcurrent protective devices. Three-phase transformers with the neutral points of the high voltage and low voltage windings connected together internally and brought out through an HOXO bushing should not be operated with the HOXO bushing ungrounded (floating). To do so can result in very high voltages in the secondary systems.
<p>DELTA-DELTA Connection with Tap</p> <p>Phasor Diagram:</p>  <p>Angular Displacement (Degrees): 0</p>	<ol style="list-style-type: none"> Suitable for both ungrounded and effectively grounded sources. Suitable for a three-wire service or a four-wire service with a mid-tap ground. When using the tap for single-phase circuits, the single-phase load kVA should not exceed 5% of the three-phase kVA rating of the transformer. The three-phase rating of the transformer is also substantially reduced.

Types of Systems

In many cases, power is supplied by the utility to a building at the utilization voltage. In these cases, the distribution of power within the building is achieved through the use of a simple radial distribution system.

In cases where the utility service voltage is at some voltage higher than the utilization voltage within the building, the system design engineer has a choice of a number of types of systems that may be used. This discussion covers several major types of distribution systems and practical modifications of them.

1. Simple radial
2. Loop-primary system—radial secondary system
3. Primary selective system—secondary radial system
4. Two-source primary—secondary selective system
5. Sparring transformer system
6. Simple spot network
7. Medium voltage distribution system design

1. Simple Radial System

The conventional simple radial system receives power at the utility supply voltage at a single substation and steps the voltage down to the utilization level. In those cases where the customer receives his supply from the primary system and owns the primary switch and transformer along with the secondary low voltage switchboard or switchgear, the equipment may take the form of a separate primary switch, separate transformer, and separate low voltage switchgear or switchboard. This equipment may be combined in the form of an outdoor pad-mounted transformer with internal primary fused switch and secondary main breaker feeding an indoor switchboard.

Another alternative would be a secondary unit substation where the primary fused switch, transformer and secondary switchgear or switchboard are designed and installed as a close-coupled single assembly.

In those cases where the utility owns the primary equipment and transformer, the supply to the customer is at the utilization voltage, and the service equipment then becomes low voltage main distribution switchgear or a switchboard.

Low voltage feeder circuits run from the switchgear or switchboard assemblies to panelboards that are located closer to their respective loads as shown in **Figure 1.1-1**.

Each feeder is connected to the switchgear or switchboard bus through a circuit breaker or other overcurrent protective device. A relatively small number of circuits are used to distribute power to the loads from the switchgear or switchboard assemblies and panelboards.

Because the entire load is served from a single source, full advantage can be taken of the diversity among the loads. This makes it possible to minimize the installed transformer capacity. However, the voltage regulation and efficiency of this system may be poor because of the low voltage feeders and single source. The cost of the low voltage-feeder circuits and their associated circuit breakers are high when the feeders are long and the peak demand is above 1000 kVA.

A fault on the secondary low voltage bus or in the source transformer will interrupt service to all loads. Service cannot be restored until the necessary repairs have been made. A low voltage feeder circuit fault will interrupt service to all loads supplied over that feeder.

A modern and improved form of the conventional simple radial system distributes power at a primary voltage. The voltage is stepped down to utilization level in the several load areas within the building typically through secondary unit substation transformers. The transformers are usually connected to their associated load bus through a circuit breaker, as shown in **Figure 1.1-2**. Each secondary unit substation is an assembled unit consisting of a three-phase, liquid-filled or air-cooled transformer, an integrally connected primary fused switch, and low voltage switchgear or switchboard with circuit breakers or fused switches. Circuits are run to the loads from these low voltage protective devices.

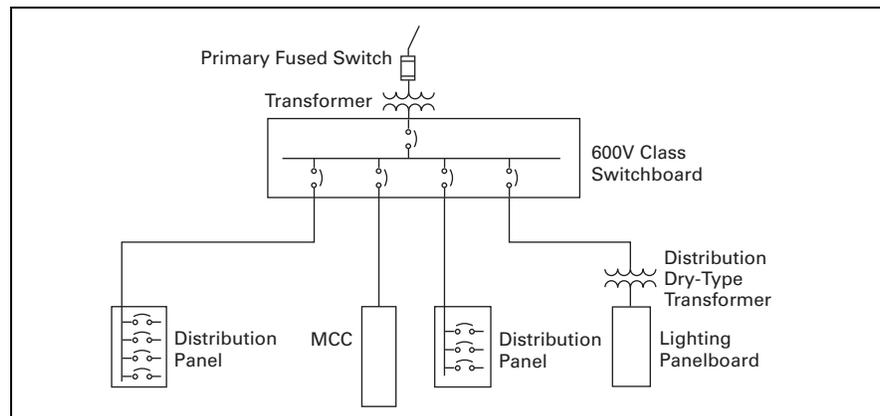


Figure 1.1-1. Simple Radial System

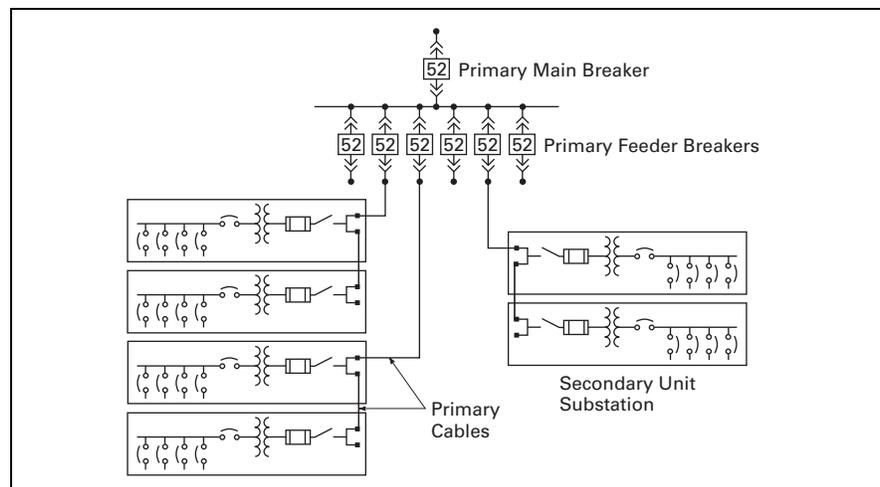


Figure 1.1-2. Primary and Secondary Simple Radial System

Because each transformer is located within a specific load area, it must have sufficient capacity to carry the peak load of that area. Consequently, if any diversity exists among the load area, this modified primary radial system requires more transformer capacity than the basic form of the simple radial system. However, because power is distributed to the load areas at a primary voltage, losses are reduced, voltage regulation is improved, feeder circuit costs are reduced substantially, and large low voltage feeder circuit breakers are eliminated. In many cases the interrupting duty imposed on the load circuit breakers is reduced.

This modern form of the simple radial system will usually be lower in initial investment than most other types of primary distribution systems for buildings in which the peak load is above 1000 kVA. A fault on a primary feeder circuit or in one transformer will cause an outage to only those secondary loads served by that feeder or transformer. In the case of a primary main bus fault or a utility service outage, service is interrupted to all loads until the trouble is eliminated.

Reducing the number of transformers per primary feeder by adding more primary feeder circuits will improve the flexibility and service continuity of this system; the ultimate being one secondary unit substation per primary feeder circuit. This of course increases the investment in the system but minimizes the extent of an outage resulting from a transformer or primary feeder fault.

Primary connections from one secondary unit substation to the next secondary unit substation can be made with "double" lugs on the unit substation primary switch as shown, or with separable connectors made in manholes or other locations.

Depending on the load kVA connected to each primary circuit and if no ground fault protection is desired for either the primary feeder conductors and transformers connected to that feeder or the main bus, the primary main and/or feeder breakers may be changed to primary fused switches. This will significantly reduce the first cost, but also decrease the level of conductor and equipment protection. Thus, should a fault or overload condition occur, downtime increases significantly and higher costs associated with increased damage levels and the need for fuse replacement is typically encountered.

In addition, if only one primary fuse on a circuit opens, the secondary loads are then single phased, causing damage to low voltage motors.

Another approach to reducing costs is to eliminate the primary feeder breakers completely, and use a single primary main breaker or fused switch for protection of a single primary feeder circuit with all secondary unit substations supplied from this circuit. Although this system results in less initial equipment cost, system reliability is reduced drastically because a single fault in any part of the primary conductor would cause an outage to all loads within the facility.

2. Loop Primary System—Radial Secondary System

This system consists of one or more "PRIMARY LOOPS" with two or more transformers connected on the loop. This system is typically most effective when two services are available from the utility as shown in **Figure 1.1-3**. Each primary loop is operated such that one of the loop sectionalizing switches is kept open to prevent parallel operation of the sources. When secondary unit substations are used, each transformer may have its own duplex (2-load break switches with load side bus connection)

sectionalizing switches and primary load break fused switch as shown in **Figure 1.1-4** or utilizing three on-off switches or a four-position sectionalizing switch and vacuum fault interrupter (VFI) internal to the transformer saving cost and reducing footprint.

When pad-mounted compartmentalized transformers are used, they are furnished with loop-feed oil-immersed gang-operated load break sectionalizing switches and Bay-O-Net expulsion fuses in series with partial range back-up current-limiting fuses. By operating the appropriate sectionalizing switches, it is possible to disconnect any section of the loop conductors from the rest of the system. In addition, it is possible to disconnect any transformer from the loop.

A key interlocking scheme is normally recommended to prevent closing all sectionalizing devices in the loop. Each primary loop sectionalizing switch and the feeder breakers to the loop are interlocked such that to be closed they require a key (which is held captive until the switch or breaker is opened) and one less key than the number of key interlock cylinders is furnished. An extra key is provided to defeat the interlock under qualified supervision.

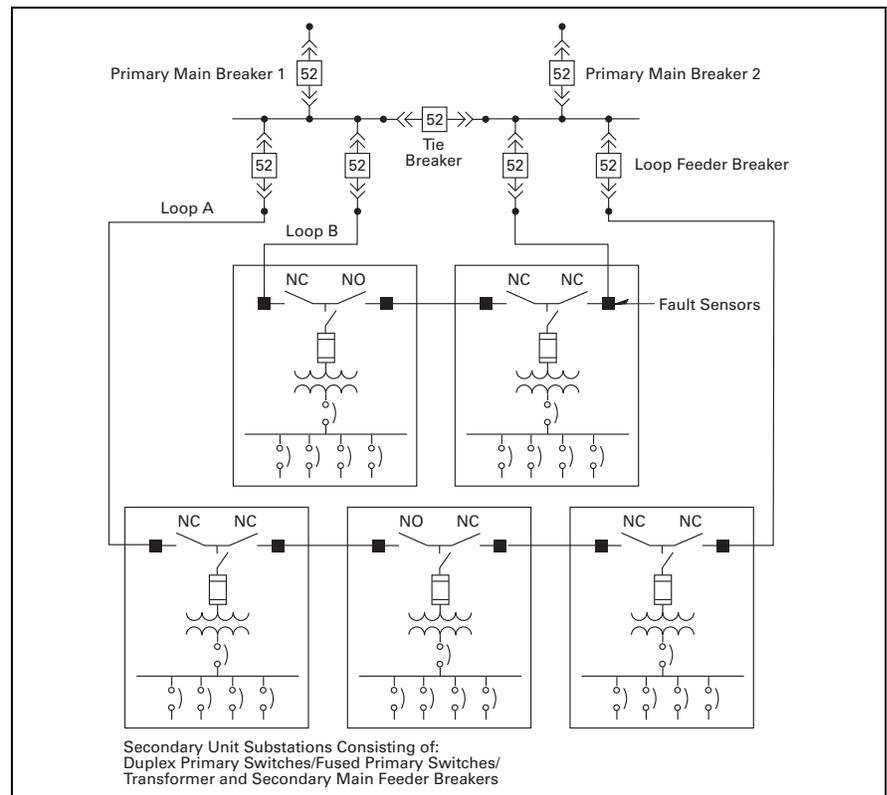


Figure 1.1-3. Loop Primary—Radial Secondary System

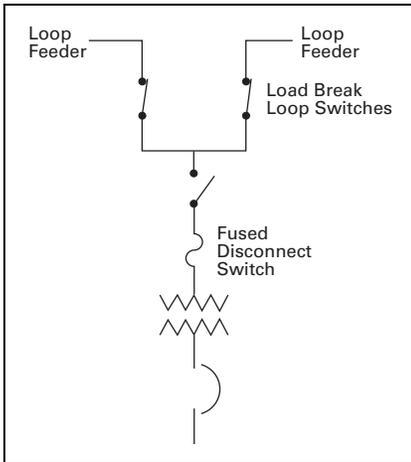


Figure 1.1-4. Secondary Unit Substation Loop Switching

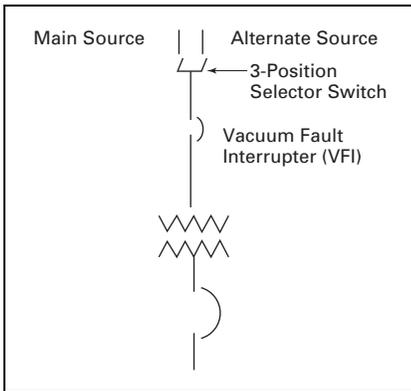


Figure 1.1-5. VFI/Selector Switch Combination

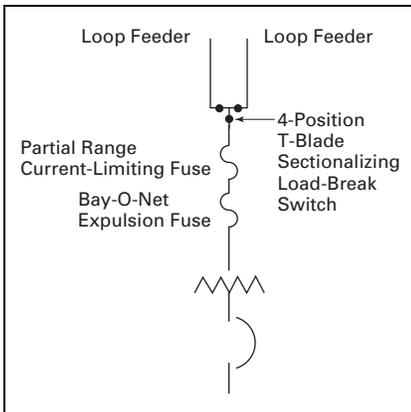


Figure 1.1-6. Pad-Mounted Transformer Loop Switching

In addition, the two primary main breakers, which are normally closed, and primary tie breaker, which is normally open, are either mechanically or electrically interlocked to prevent paralleling the incoming source lines. For slightly added cost, an automatic throw-over scheme can be added between the two main breakers and tie breaker. During the more common event of a utility outage, the automatic transfer scheme provides significantly reduced power outage time.

The system in **Figure 1.1-3** has higher costs than in **Figure 1.1-2**, but offers increased reliability and quick restoration of service when 1) a utility outage occurs, 2) a primary feeder conductor fault occurs, or 3) a transformer fault or overload occurs.

Should a utility outage occur on one of the incoming lines, the associated primary main breaker is opened and the tie breaker closed either manually or through an automatic transfer scheme.

When a primary feeder conductor fault occurs, the associated loop feeder breaker opens and interrupts service to all loads up to the normally open primary loop load break switch (typically half of the loads). Once it is determined which section of primary

cable has been faulted, the loop sectionalizing switches on each side of the faulted conductor can be opened, the loop sectionalizing switch that had been previously left open then closed and service restored to all secondary unit substations while the faulted conductor is replaced. If the fault should occur in a conductor directly on the load side of one of the loop feeder breakers, the loop feeder breaker is kept open after tripping and the next load side loop sectionalizing switch manually opened so that the faulted conductor can be sectionalized and replaced.

Note: Under this condition, all secondary unit substations are supplied through the other loop feeder circuit breaker, and thus all conductors around the loop should be sized to carry the entire load connected to the loop. Increasing the number of primary loops (two loops shown in **Figure 1.1-8**) will reduce the extent of the outage from a conductor fault, but will also increase the system investment.

When a transformer fault or overload occurs, the transformer primary fuses open, and the transformer primary switch manually opened, disconnecting the transformer from the loop, and leaving all other secondary unit substation loads unaffected.

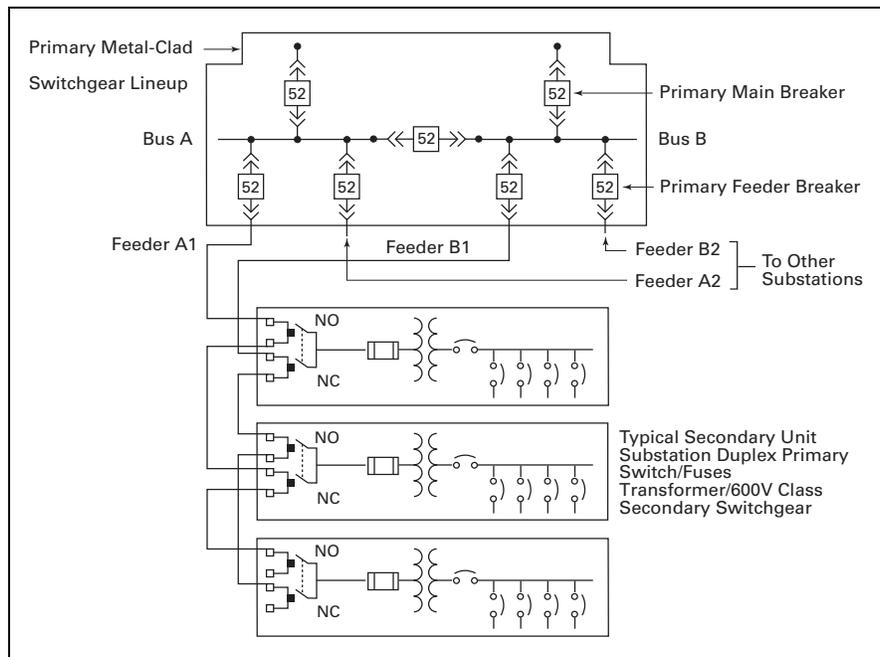


Figure 1.1-7. Basic Primary Selective—Radial Secondary System

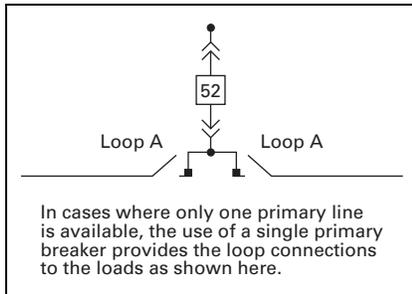


Figure 1.1-8. Single Primary Feeder—Loop System

A basic primary loop system that uses a single primary feeder breaker connected directly to two loop feeder switches which in turn then feed the loop is shown in **Figure 1.1-8**. In this basic system, the loop may be normally operated with one of the loop sectionalizing switches open as described above or with all loop sectionalizing switches closed. If a fault occurs in the basic primary loop system, the single loop feeder breaker trips, and secondary loads are lost until the faulted conductor is found and eliminated from the loop by opening the appropriate loop sectionalizing switches and then reclosing the breaker.

3. Primary Selective System—Secondary Radial System

The primary selective—secondary radial system, as shown in **Figure 1.1-7**, differs from those previously described in that it employs at least two primary feeder circuits in each load area. It is designed so that when one primary circuit is out of service, the remaining feeder or feeders have sufficient capacity to carry the total load. Half of the transformers are normally connected to each of the two feeders. When a fault occurs on one of the primary feeders, only half of the load in the building is dropped.

Duplex fused switches as shown in **Figure 1.1-7** and detailed in **Figure 1.1-9** may be utilized for this type of system. Each duplex fused switch consists of two (2) load break three-pole switches each in their own separate structure, connected together by busbars on the load side. Typically, the load break switch closest to the transformer includes a fuse assembly with fuses. Mechanical and/or key interlocking is furnished such that both switches cannot be closed at the same time (to prevent parallel operation) and interlocking such that access to either switch or fuse assembly cannot be obtained unless both switches are opened.

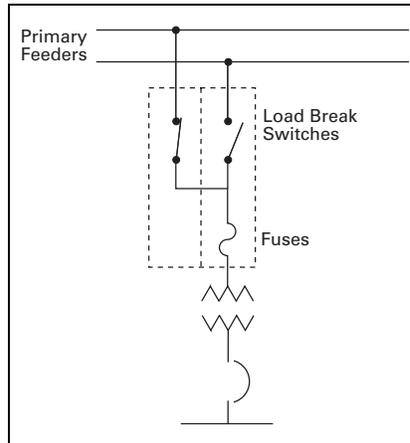


Figure 1.1-9. Duplex Fused Switch in Two Structures

One alternate to the duplex switch arrangement, a non-load break selector switch mechanically interlocked with a load break fused switch can be used as shown in **Figure 1.1-10**. The non-load break selector switch is physically located in the rear of the load break fused switch, thus only requiring one structure and a lower cost and floor space savings over the duplex arrangement. The non-load break selector switch is mechanically interlocked to prevent its operation unless the load break switch is opened. The main disadvantage of the selector switch is that conductors from both circuits are terminated in the same structure.

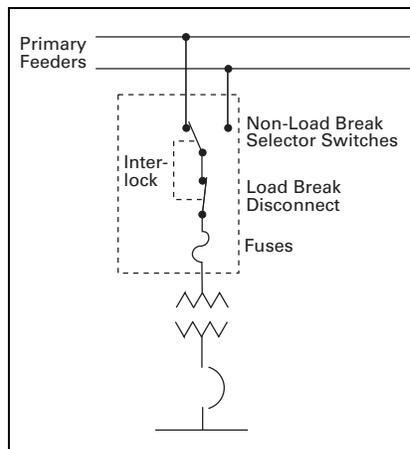


Figure 1.1-10. Fused Selector Switch in One Structure

This means limited cable space especially if double lugs are furnished for each line as shown in **Figure 1.1-7** and should a faulted primary conductor have to be changed, both lines would have to be de-energized for safe changing of the faulted conductors. A second alternative is utilizing a three-position selector switch internal to the transformer, allowing only one primary feeder to be connected to the transformer at a time without the need for any interlocking. The selector switch is rated for load-breaking. If overcurrent protection is also required, a vacuum fault interrupter (VFI), also internal to the transformer, may be utilized, reducing floor space.

In **Figure 1.1-7** when a primary feeder fault occurs, the associated feeder breaker opens and the transformers normally supplied from the faulted feeder are out of service. Then manually, each primary switch connected to the faulted line must be opened and then the alternate line primary switch can be closed connecting the transformer to the live feeder, thus restoring service to all loads. Note that each of the primary circuit conductors for Feeder A1 and B1 must be sized to handle the sum of the loads normally connected to both A1 and B1. Similar sizing of Feeders A2 and B2, etc., is required.

If a fault occurs in one transformer, the associated primary fuses blow and interrupt the service to just the load served by that transformer. Service cannot be restored to the loads normally served by the faulted transformer until the transformer is repaired or replaced.

Cost of the primary selective—secondary radial system is greater than that of the simple primary radial system of **Figure 1.1-1** because of the additional primary main breakers, tie breaker, two-sources, increased number of feeder breakers, the use of primary-duplex or selector switches, and the greater amount of primary feeder cable required. The benefits from the reduction in the amount of load lost when a primary feeder is faulted, plus the quick restoration of service to all or most of the loads, may more than offset the greater cost. Having two sources allows for either manual or automatic transfer of the two primary main breakers and tie breaker should one of the sources become unavailable.

The primary selective-secondary radial system, however, may be less costly or more costly than a primary loop—secondary radial system of **Figure 1.1-3** depending on the physical location of the transformers while offering comparable downtime and reliability. The cost of conductors for the two types of systems may vary greatly depending on the location of the transformers and loads within the facility and greatly override primary switching equipment cost differences between the two systems.

4. Two-Source Primary—Secondary Selective System

This system uses the same principle of duplicate sources from the power supply point using two primary main breakers and a primary tie breaker. The two primary main breakers and primary tie breaker being either manually or electrically interlocked to prevent closing all three at the same time and paralleling the sources. Upon loss of voltage on one source, a manual or automatic transfer to the alternate source line may be used to restore power to all primary loads.

Each transformer secondary is arranged in a typical double-ended unit substation arrangement as shown in **Figure 1.1-11**. The two secondary main breakers and secondary tie breaker of each unit substation are again either mechanically or electrically interlocked to prevent parallel operation. Upon loss of secondary source voltage on one side, manual or automatic transfer may be used to transfer the loads to the other side, thus restoring power to all secondary loads.

This arrangement permits quick restoration of service to all loads when a primary feeder or transformer fault occurs by opening the associated secondary main and closing the secondary tie breaker. If the loss of secondary voltage has occurred because of a primary feeder fault with the associated primary feeder breaker opening, then all secondary loads normally served by the faulted feeder would have to be transferred to the opposite primary feeder. This means each primary feeder conductor must be sized to carry the load on both sides of all the secondary buses it is serving under secondary emergency transfer

If the loss of voltage was due to a failure of one of the transformers in the double-ended unit substation, then the associated primary fuses would open taking only the failed transformer out of service, and then only the secondary loads normally served by the faulted transformer would have to be transferred to the opposite transformer. In either of the above emergency conditions, the in-service transformer of a double-ended unit substation would have to have the capability of serving the loads on both sides of the tie breaker. For this reason, transformers used in this application have equal kVA rating on each side of the double-ended unit substation and the normal operating maximum load on each transformer is typically about 2/3 base nameplate kVA rating. Typically these transformers are furnished with fan-cooling and/or lower than normal temperature rise such that under emergency conditions they can carry on a continuous basis the maximum load on both sides of the secondary tie breaker. Because of this spare transformer capacity, the voltage regulation provided by the double-ended unit substation system under normal conditions is better than that of the systems previously discussed.

The double-ended unit substation arrangement can be used in conjunction with any of the previous systems discussed, which involve two primary sources. Although not recommended, if allowed by the utility, momentary re-transfer of loads to the restored source may be made closed transition (anti-parallel interlock schemes would have to be defeated) for either the primary or secondary systems. Under this condition, all equipment interrupting and momentary ratings should be suitable for the fault current available from both sources.

For double-ended unit substations equipped with ground fault systems special consideration to transformer neutral grounding and equipment operation should be made—see “Grounding” and “Ground Fault Protection” in **Section 1.4**. Where two single-ended unit substations are connected together by external tie conductors, it is recommended that a tie breaker be furnished at each end of the tie conductors.

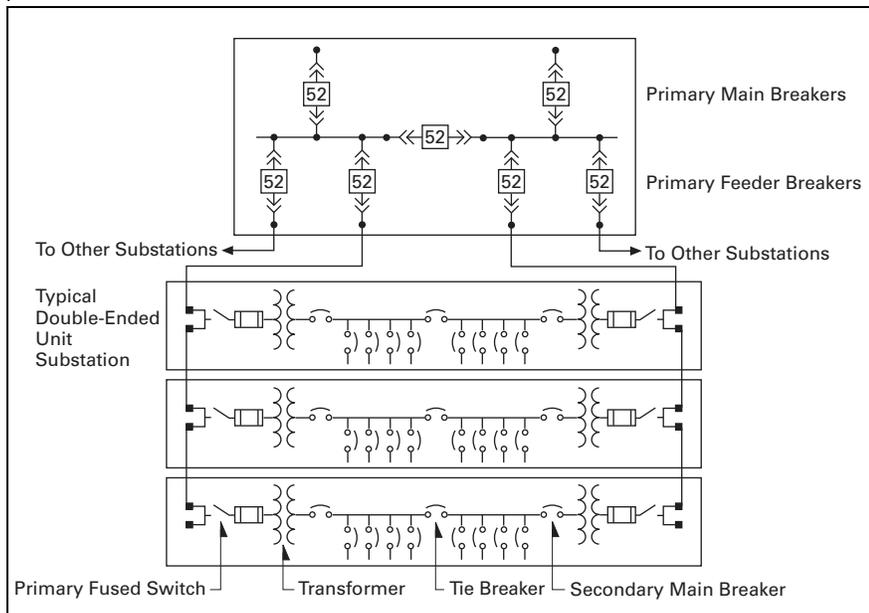


Figure 1.1-11. Two-Source Primary—Secondary Selective System

5. Sparing Transformer System

The sparing transformer system concept came into use as an alternative to the capital cost intensive double-ended secondary unit substation distribution system (see Two-Source Primary—Secondary Selective System). It essentially replaces double-ended substations with single-ended substations and one or more “sparing” transformer substations all interconnected on a common secondary bus (see Figure 1.1-12).

Generally no more than three to five single-ended substations are on a sparing loop.

The essence of this design philosophy is that conservatively designed and loaded transformers are highly reliable electrical devices and rarely fail. Therefore, this design provides a single common backup transformer for a group of transformers in lieu of a backup transformer for each and every transformer. This system design still maintains a high degree of continuity of service.

Referring to Figure 1.1-12, it is apparent that the sparing concept backs up primary switch and primary cable failure as well. Restoration of lost or failed utility power is accomplished similarly to primary selective scheme previously discussed. It is therefore important to use an automatic throwover system in a two source lineup of primary switchgear to restore utility power as discussed in the “Two-Source Primary” scheme—see Figure 1.1-11.

A major advantage of the sparing transformer system is the typically lower total base kVA of transformation. In a double-ended substation design, each transformer must be rated to carry the sum of the loads of two busses and usually requires the addition of cooling fans to accomplish this rating. In the “sparing” concept, each transformer carries only its own load, which is typically not a fan-cooled rating. Major space savings is also a benefit of this system in addition to first cost savings.

The sparing transformer system operates as follows:

- All main breakers, including the sparing main breaker, are normally closed; the tie breakers are normally open
- Once a transformer (or primary cable or primary switch/fuse) fails, the associated secondary main breaker is opened. The associated tie breaker is then closed, which restores power to the single-ended substation bus
- Schemes that require the main to be opened before the tie is closed (“open transition”), and that allow any tie to be closed before the substation main is opened, (“closed transition”) are possible

With a closed transition scheme, it is common to add a timer function that opens the tie breaker unless either main breaker is opened within a time interval.

This closed transition allows power to be transferred to the sparing transformer without interruption, such as for routine maintenance, and then back to the substation. This closed transition transfer has an advantage in some facilities; however, appropriate interrupting capacities and bus bracing must be specified suitable for the momentary parallel operation.

In facilities without qualified electrical power operators, an open transition with key interlocking is often a prudent design.

Note: Each pair of “main breaker/tie breaker” key cylinders should be uniquely keyed to prevent any paralleled source operations.

Careful sizing of these transformers as well as careful specification of the transformers is required for reliability. Low temperature rise specified with continuous overload capacity or upgraded types of transformers should be considered.

One disadvantage to this system is the external secondary tie system, see Figure 1.1-12. As shown, all single-ended substations are tied together on the secondary with a tie busway or cable system. Location of substations is therefore limited because of voltage drop and cost considerations.

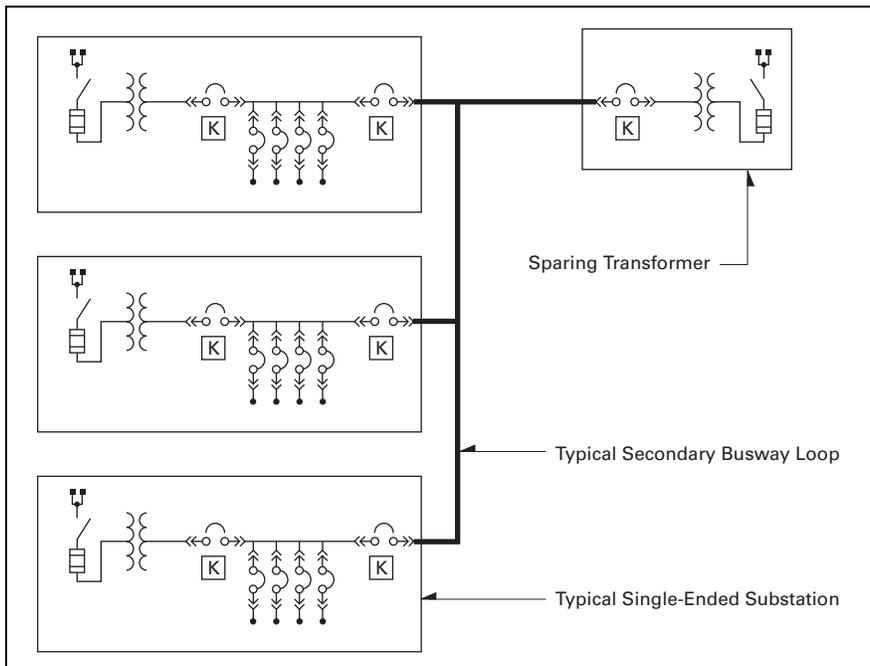


Figure 1.1-12. Sparing Transformer System

Routing of busway, if used, must be carefully laid out. It should also be noted, that a tie busway or cable fault will essentially prevent the use of the sparing transformer until it is repaired. Commonly, the single-ended substations and the sparing transformer must be clustered. This can also be an advantage, as more kVA can be supported from a more compact space layout.

6. Simple Spot Network Systems

The AC secondary network system is the system that has been used for many years to distribute electric power in the high-density, downtown areas of cities, usually in the form of utility grids. Modifications of this type of system make it applicable to serve loads within buildings.

The major advantage of the secondary network system is continuity of service. **No single fault anywhere on the primary system will interrupt service to any of the system's loads. Most faults will be cleared without interrupting service to any load.**

Another outstanding advantage that the network system offers is its flexibility to meet changing and growing load conditions at minimum cost and minimum interruption in service to other loads on the network. In addition to flexibility and service reliability, the secondary network system provides exceptionally uniform and good voltage regulation, and its high efficiency materially reduces the costs of system losses.

Three major differences between the network system and the simple radial system account for the outstanding advantages of the network. First, a network protector is connected in the secondary leads of each network transformer in place of, or in addition to, the secondary main breaker, as shown in **Figure 1.1-13**. Also, the secondaries of each transformer in a given location (spot) are connected together by a switchgear or ring bus from which the loads are served over short radial feeder circuits. Finally, the primary supply has sufficient capacity to carry the entire building load without overloading when any one primary feeder is out of service.

A network protector is a specially designed heavy-duty air power breaker, spring close with electrical motor-charged mechanism, with a network relay to control the status of the protector (tripped or closed).

The network relay is usually a solid-state microprocessor-based component integrated into the protector enclosure that functions to automatically close the protector only when the voltage conditions are such that its associated transformer will supply power to the secondary network loads, and to automatically open the protector when power flows from the secondary to the network transformer. The purpose of the network protector is to protect the integrity of the network bus voltage and the loads served from it against transformer and primary feeder faults by quickly disconnecting the defective feeder-transformer pair from the network when backfeed occurs.

The simple spot network system resembles the secondary-selective radial system in that each load area is supplied over two or more primary feeders through two or more transformers. In network systems, the transformers are connected through network protectors to a common bus, as shown in **Figure 1.1-13**, from which loads are served. Because the transformers are connected in parallel, a primary feeder or transformer fault does not cause any service interruption to the loads. The paralleled transformers supplying each load bus will normally carry equal load currents, whereas equal loading of the two separate transformers supplying a substation in the secondary-selective radial system is difficult to obtain. The interrupting duty imposed on the outgoing feeder breakers in the network will be greater with the spot network system.

The optimum size and number of primary feeders can be used in the spot network system because the loss of any primary feeder and its associated transformers does not result in the loss of any load even for an instant. In spite of the spare capacity usually supplied in network systems, savings in primary switchgear and secondary switchgear costs often result when compared to a radial system design with similar spare capacity. This occurs in many radial systems because more and smaller feeders are often used in order to minimize the extent of any outage when a primary fault event occurs.

In spot networks, when a fault occurs on a primary feeder or in a transformer, the fault is isolated from the system through the automatic tripping of the primary feeder circuit breaker and all of the network protectors associated with that feeder circuit. This operation does not interrupt service to any loads. After the necessary repairs have been made, the system can be restored to normal operating conditions by closing the primary feeder breaker. All network protectors associated with that feeder will close automatically.

The chief purpose of the network bus normally closed ties is to provide for the sharing of loads and a balancing of load currents for each primary service and transformer regardless of the condition of the primary services.

Also, the ties provide a means for isolating and sectionalizing ground fault events within the switchgear network bus, thereby saving a portion of the loads from service interruptions, yet isolating the faulted portion for corrective action.

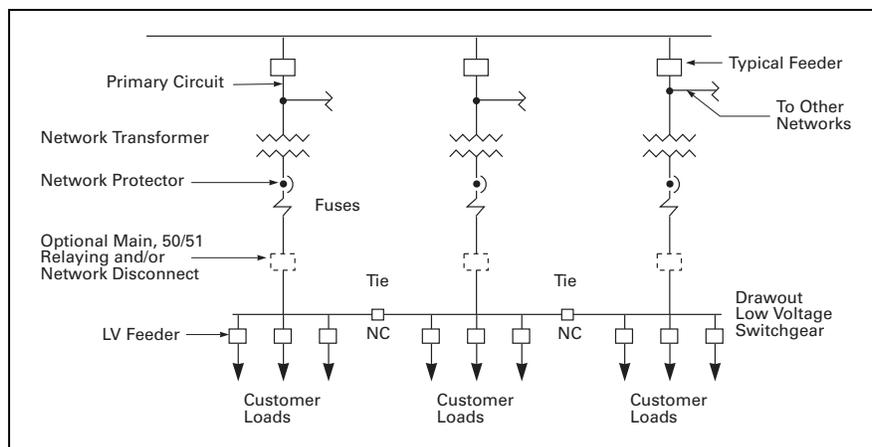


Figure 1.1-13. Three-Source Spot Network

The use of spot network systems provides users with several important advantages. First, they save transformer capacity. Spot networks permit equal loading of transformers under all conditions. Also, networks yield lower system losses and greatly improve voltage conditions. The voltage regulation on a network system is such that both lights and power can be fed from the same load bus. Much larger motors can be started across-the-line than on a simple radial system. This can result in simplified motor control and permits the use of relatively large low voltage motors with their less expensive control. Finally, network systems provide a greater degree of flexibility in adding future loads; they can be connected to the closest spot network bus.

Spot network systems are economical for buildings that have heavy concentrations of loads covering small areas, with considerable distance between areas, and light loads within the distances separating the concentrated loads. They are commonly used in hospitals, high rise office buildings, and institutional buildings where a high degree of service reliability is required from the utility sources. Spot network systems are especially economical where three or more primary feeders are available.

Principally, this is due to supplying each load bus through three or more transformers and the reduction in spare cable and transformer capacity required.

They are also economical when compared to two transformer double-ended substations with normally opened tie breakers.

Emergency power should be connected to network loads downstream from the network, or upstream at primary voltage, not at the network bus itself.

7. Medium Voltage Distribution System Design

A. Single Bus, Figure 1.1-14

The sources (utility and/or generator(s)) are connected to a single bus. All feeders are connected to the same bus.

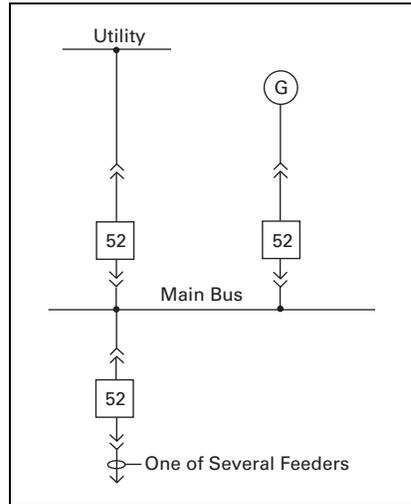


Figure 1.1-14. Single Bus

This configuration is the simplest system; however, outage of the utility results in total outage.

Normally the generator does not have adequate capacity for the entire load. A properly relayed system equipped with load shedding, automatic voltage/frequency control may be able to maintain partial system operation.

Any future addition of breaker sections to the bus will require a shutdown of the bus, because there is no tie breaker.

B. Single Bus with Two Sources from the Utility, Figure 1.1-15

Same as the single bus, except that two utility sources are available. This system is operated normally with the main breaker to one source open. Upon loss of the normal service, the transfer to the standby normally open (NO) breaker can be automatic or manual. Automatic transfer is preferred for rapid service restoration especially in unattended stations.

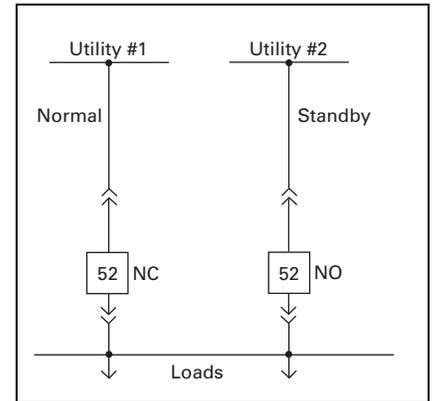


Figure 1.1-15. Single Bus with Two-Sources

Retransfer to the "Normal" can be closed transition subject to the approval of the utility. Closed transition momentarily (5–10 cycles) parallels both utility sources. **Caution:** when both sources are paralleled, the fault current available on the load side of the main device is the sum of the available fault current from each source plus the motor fault contribution. It is recommended that the short-circuit ratings of the bus, feeder breakers and all load side equipment are rated for the increased available fault current. If the utility requires open transfer, the disconnection of motors from the bus must be ensured by means of suitable time delay on reclosing as well as supervision of the bus voltage and its phase with respect to the incoming source voltage

This busing scheme does not preclude the use of cogeneration, but requires the use of sophisticated automatic synchronizing and synchronism checking controls, in addition to the previously mentioned load shedding, automatic frequency and voltage controls.

This configuration is more expensive than the scheme shown in Figure 1.1-14, but service restoration is quicker. Again, a utility outage results in total outage to the load until transfer occurs. Extension of the bus or adding breakers requires a shutdown of the bus.

If paralleling sources, reverse current, reverse power and other appropriate relaying protection should be added as requested by the utility.

C. Multiple Sources with Tie Breaker, Figure 1.1-16 and Figure 1.1-17

This configuration is similar to configuration B. It differs significantly in that both utility sources normally carry the loads and also by the incorporation of a normally open tie breaker. The outage to the system load for a utility outage is limited to half of the system. Again, the closing of the tie breaker can be manual or automatic. The statements made for the retransfer of scheme B apply to this scheme also.

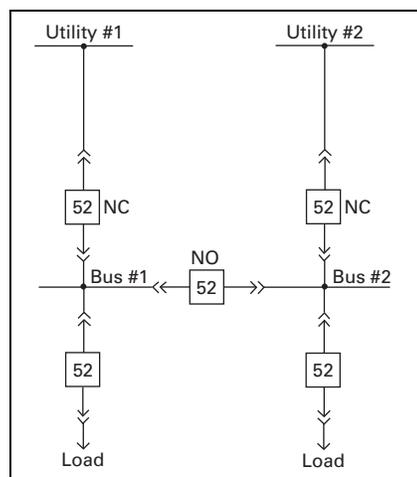


Figure 1.1-16. Two-Source Utility with Tie Breaker

If looped or primary selective distribution system for the loads is used, the buses can be extended without a shut-down by closing the tie breaker and transferring the loads to the other bus.

This configuration is more expensive than B. The system is not limited to two buses only. Another advantage is that the design may incorporate momentary paralleling of buses on retransfer after the failed line has been restored to prevent another outage. See the **Caution** for Figures 1.1-15, 1.1-16 and 1.1-17.

In **Figure 1.1-17**, closing of the tie breaker following the opening of a main breaker can be manual or automatic. However, because a bus can be fed through two tie breakers, the control scheme should be designed to make the selection.

The third tie breaker allows any bus to be fed from any utility source.

Caution for Figures 1.1-15, 1.1-16 and 1.1-17: If continuous paralleling of sources is planned, reverse current, reverse power and other appropriate relaying protection should be added. When both sources are paralleled for any amount of time, the fault current available on the load side of the main device is the sum of the available fault current from each source plus the motor fault contribution. It is required that bus bracing, feeder breakers and all load side equipment is rated for the increased available fault current.

Summary

The medium voltage system configurations shown are based on using metal-clad drawout switchgear. The service continuity required from electrical systems makes the use of single-source systems impractical.

In the design of a modern medium voltage system, the engineer should:

1. Design a system as simple as possible.
2. Limit an outage to as small a portion of the system as possible.
3. Provide means for expanding the system without major shutdowns.
4. Relay the system so that only the faulted part is removed from service, and damage to it is minimized consistent with selectivity.
5. Specify and apply all equipment within its published ratings and national standards pertaining to the equipment and its installation.

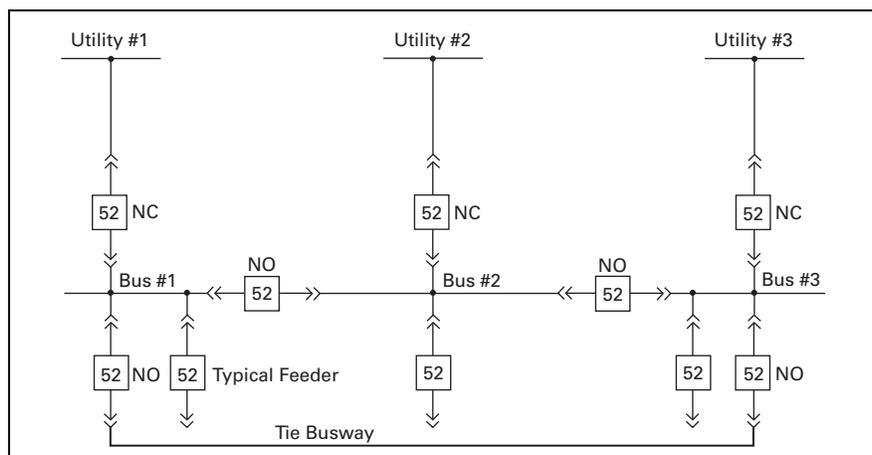


Figure 1.1-17. Triple-Ended Arrangement

Health Care Facilities

Health care facilities are defined by NFPA (National Fire Protection Agency) as “Buildings or portions of buildings in which medical, dental, psychiatric, nursing, obstetrical, or surgical care are provided.” Due to the critical nature of the care being provided at these facilities and their increasing dependence on electrical equipment for preservation of life, health care facilities have special requirements for the design of their electrical distribution systems. These requirements are typically much more stringent than commercial or industrial facilities. The following section summarizes some of the unique requirements of health care facility design.

There are several agencies and organizations that develop requirements for health care electrical distribution system design. The following is a listing of some of the specific NFPA (National Fire Protection Agency) standards that affect health care facility design and implementation:

- NFPA 37-2010—Standard for Stationary Combustion Engines and Gas Turbines
- NFPA 70-2011—National Electrical Code
- NFPA 99-2005—Health Care Facilities

- NFPA 101-2009—Life Safety Code
- NFPA 110-2010—Standard for Emergency and Standby Power Systems
- NFPA 111-2010—Standard on Stored Electrical Energy Emergency and Standby Power Systems

These NFPA guidelines represent the most industry recognized standard requirements for health care electrical design. However, the electrical design engineer should consult with the authorities having jurisdiction over the local region for specific electrical distribution requirements.

Health Care Electrical System Requirements

Health care electrical systems usually consist of two parts:

1. Non-essential or normal electrical system.
2. Essential electrical system.

All electrical power in a health care facility is important, though some loads are not critical to the safe operation of the facility. These “non-essential” or “normal” loads include things such as general lighting, general lab equipment, non-critical service equipment, patient care areas, etc. These loads are not required to be fed from an alternate source of power.

The electrical system requirements for the essential electrical system (EES) vary according to the type of health care facility. Health care facilities are categorized by NFPA 99 as Type 1, Type 2 or Type 3 facilities. Some example health care facilities, classified by type, are summarized in the following **Table 1.1-8**.

Table 1.1-8. Health Care Facilities

Description	Definition	EES Type
Hospitals	NFPA 99 Chap. 13	Type 1
Nursing homes	NFPA 99 Chap. 17	Type 2
Limited care facilities	NFPA 99 Chap. 18	Type 2
Ambulatory surgical facilities	NFPA 99 Chap. 14	Type 3 ①
Other health care facilities	NFPA 99 Chap. 14	Type 3 ①

① If electrical life support or critical care areas are present, then facility is classified as Type 1.

Type 1 Essential Electrical Systems (EES)

Type 1 essential electrical systems (EES) have the most stringent requirements for providing continuity of electrical service and will, therefore, be the focus of this section. Type 1 EES requirements meet or exceed the requirements for Type 2 and Type 3 facilities.

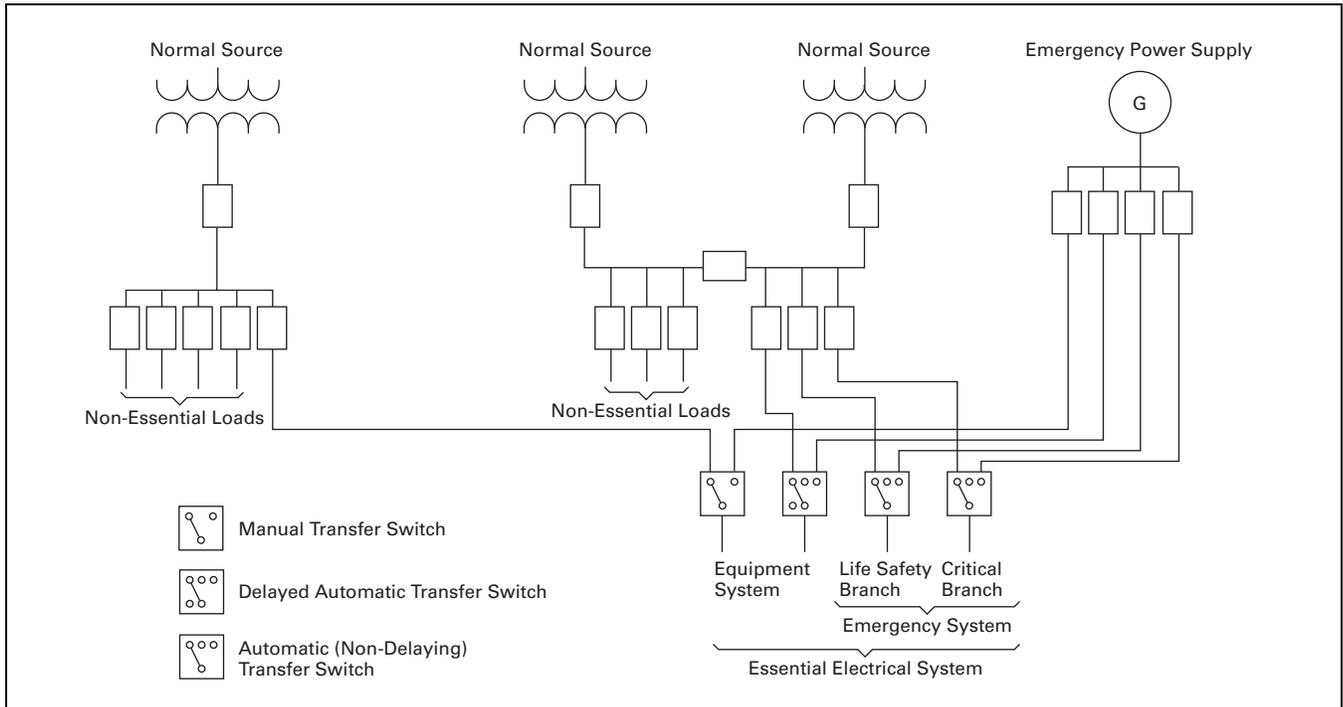


Figure 1.1-18. Typical Large Hospital Electrical System—Type 1 Facility

Sources: Type 1 systems are required to have a minimum of two independent sources of electrical power—a normal source that generally supplies the entire facility and one or more alternate sources that supply power when the normal source is interrupted. The alternate source(s) must be an on-site generator driven by a prime mover unless a generator(s) exists as the normal power source. In the case where a generator(s) is used as the normal source, it is permissible for the alternate source to be a utility feed. Alternate source generators must be classified as Type 10, Class X, Level 1 gensets per NFPA 110 Tables 4.1(a) and 4.2(b) that are capable of providing power to the load in a maximum of 10 seconds. Typically, the alternate sources of power are supplied to the loads through a series of automatic and/or manual transfer switches (see **Tab 25**). The transfer switches can be non-delayed automatic, delayed automatic or manual transfer depending on the requirements of the specific branch of the EES that they are feeding. It is permissible to feed multiple branches or systems of the EES from a single automatic transfer switch provided that the maximum demand on the EES does not exceed 150 kVA. This configuration is typically seen in smaller health care facilities that must meet Type 1 EES requirements (see **Figure 1.1-19**).

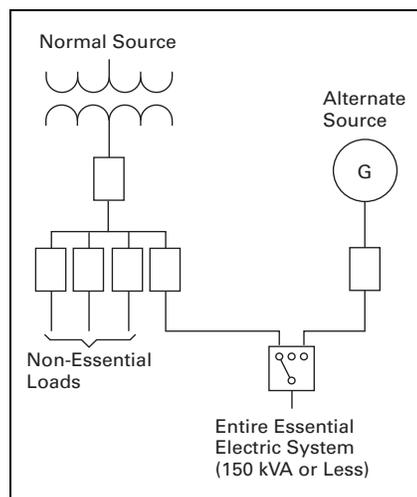


Figure 1.1-19. Small Hospital Electrical System—Single EES Transfer Switch

Table 1.1-9. Type 1 EES Applicable Codes

Description	Standard	Section
Design Sources	NFPA 99 NFPA 99	4.4.1.1.1 4.4.1.1.4 thru 4.4.4.1.1.7.2 4.4.1.1.8 (1-3)
Uses Emergency Power Supply Classification	NFPA 99 NFPA 110	 4
Distribution	NFPA 99 NEC	4.4.2 517.30

Systems and Branches of Service: The Type 1 EES consists of two separate power systems capable of supplying power considered essential for life safety and effective facility operation during an interruption of the normal power source. They are the emergency system and the equipment system.

1. Emergency system—consists of circuits essential to life safety and critical patient care.

The emergency system is an electrical sub-system that must be fed from an automatic transfer switch or series of automatic transfer switches. This emergency system consists of two mandatory branches that provide power to systems and functions essential to life safety and critical patient care.

A. Life safety branch—supplies power for lighting, receptacles and equipment to perform the following functions:

1. Illumination of means of egress.
2. Exit signs and exit direction signs.
3. Alarms and alerting systems.
4. Emergency communications systems.
5. Task illumination, battery chargers for battery powered lighting, and select receptacles at the generator.
6. Elevator lighting control, communication and signal systems.
7. Automatic doors used for egress.

These are the *only* functions permitted to be on the life safety branch. Life safety branch equipment and wiring must be entirely independent of all other loads and branches of service. This includes separation of raceways, boxes or cabinets. Power must be supplied to the life safety branch from a *non-delayed automatic transfer switch*.

B. Critical branch—supplies power for task illumination, fixed equipment, selected receptacles and selected power circuits for areas related to patient care. The purpose of the critical branch is to provide power to a limited number of receptacles and locations to reduce load and minimize the chances of fault conditions. The transfer switch(es) feeding the critical branch must be automatic type. They are permitted to have appropriate time delays that will follow the restoration of the life safety branch, but should have power restored within 10 seconds of normal source power loss. The critical branch provides power to circuits serving the following areas and functions:

1. Critical care areas.
2. Isolated power systems in special environments.
3. Task illumination and selected receptacles in the following patient care areas: infant nurseries, medication prep areas, pharmacy, selected acute nursing areas, psychiatric bed areas, ward treatment rooms, nurses' stations.
4. Specialized patient care task illumination, where needed.
5. Nurse call systems.
6. Blood, bone and tissue banks.
7. Telephone equipment rooms and closets.
8. Task illumination, selected receptacles and selected power circuits for the following: general care beds (at least one duplex receptacle), angiographic labs, cardiac catheterization labs, coronary care units, hemodialysis rooms, selected emergency room treatment areas, human physiology labs, intensive care units, selected postoperative recovery rooms.
9. Additional circuits and single-phase fraction motors as needed for effective facility operation.

Table 1.1-10. Type 1—Emergency System Applicable Codes

Description	Standard	Section
General	NFPA 99 NEC	4.4.2.2.2 517.31
Life safety branch	NFPA 99 NEC	4.4.2.2.2.2 517.32
Critical branch	NFPA 99 NEC	4.4.2.2.2.3 517.33
Wiring	NFPA 99 NEC	4.4.2.2.4 517.30(C)

2. Equipment system—consists of major electrical equipment necessary for patient care and Type 1 operation.

The equipment system is a subsystem of the EES that consists of large electrical equipment loads needed for patient care and basic hospital operation. Loads on the equipment system that are essential to generator operation are required to be fed by a *non-delayed automatic transfer switch*.

The following equipment must be arranged for *delayed automatic transfer* to the emergency power supply:

1. Central suction systems for medical and surgical functions.
2. Sump pumps and other equipment required for the safe operation of a major apparatus.
3. Compressed air systems for medical and surgical functions.
4. Smoke control and stair pressurization systems.
5. Kitchen hood supply and exhaust systems, if required to operate during a fire.

The following equipment must be arranged for *delayed automatic or manual transfer* to the emergency power supply:

1. Select heating equipment.
2. Select elevators.
3. Supply, return and exhaust ventilating systems for surgical, obstetrical, intensive care, coronary care, nurseries and emergency treatment areas.
4. Supply, return and exhaust ventilating systems for airborne infectious/isolation rooms, labs and medical areas where hazardous materials are used.
5. Hyperbaric facilities.
6. Hypobaric facilities.
7. Autoclaving equipment.
8. Controls for equipment listed above.
9. Other selected equipment in kitchens, laundries, radiology rooms and central refrigeration as selected.

Table 1.1-11. Type 1—Equipment System Applicable Codes

Description	Standard	Section
General	NFPA 99 NEC	4.4.2.2.3 517.34
Equipment	NFPA 99 NEC	4.4.2.2.3 (3-5) 517.34(A)-(B)

Any loads served by the generator that are not approved as outlined above as part of the essential electrical system must be connected through a separate transfer switch. These transfer switches must be configured such that the loads will not cause the generator to overload

and must be shed in the event the generator enters an overload condition.

Ground fault protection—per NFPA 70 NEC Article 230.95, ground fault protection is required on any feeder or service disconnect 1000 A or larger on systems with line to ground voltages of 150 V or greater and phase-to-phase voltages of 600 V or less. For health care facilities (of any type), a second level of ground fault protection is required to be on the next level of feeder downstream. This second level of ground fault is only required for feeders that serve patient care areas and equipment intended to support life. 100% selective coordination of the two levels of ground fault protection must be achieved with a minimum six-cycle separation between the upstream and downstream device.

New in the 2011 NEC, ground fault protection is now allowed between the generator(s) and the EES transfer switch(es). However, NEC 517.17(B) prohibits the installation of ground fault protection on the load side of a transfer switch feeding EES circuits (see **Figure 1.1-20**—additional level of ground fault). Careful consideration should be used in applying ground fault protection on the essential electrical system to prevent a ground fault that causes a trip of the normal source to also cause a trip on the emergency source. Such an event could result in complete power loss of both normal and emergency power sources and could not be recovered until the source of the ground fault was located and isolated from the system. To prevent this condition, NEC 700.26 removes the ground fault protection requirement for the

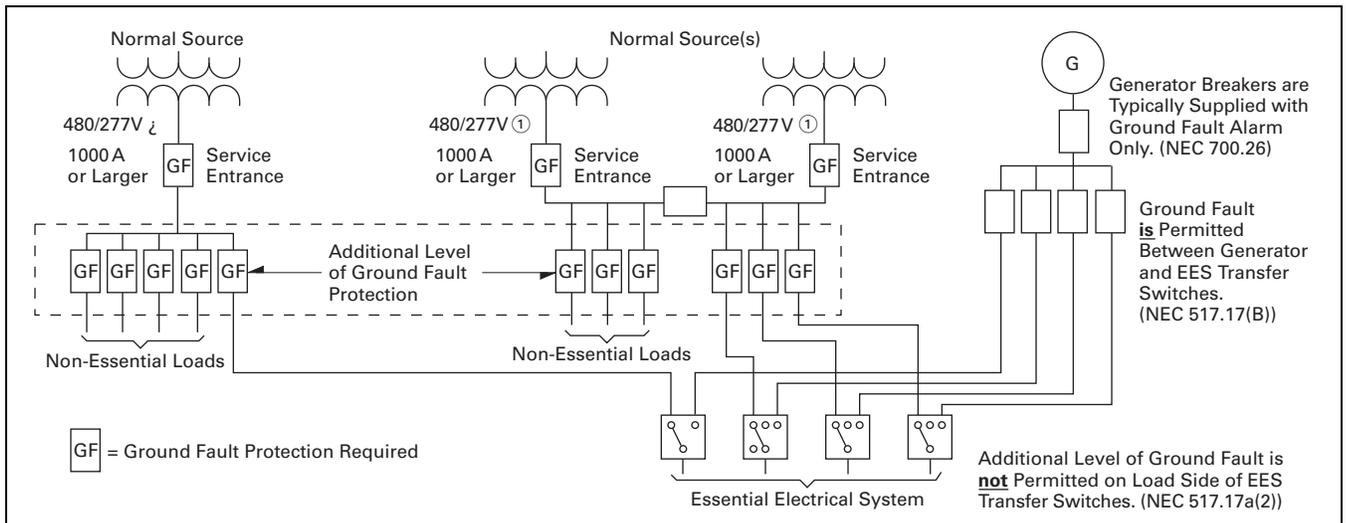


Figure 1.1-20. Additional Level of Ground Fault Protection

① Ground fault protection is required for service disconnects 1000 A and larger or systems with less than 600 V phase-to-phase and greater than 150 V to ground per NEC 230.95.

emergency system source. Typically, the emergency system generator(s) are equipped with ground fault alarms that do not automatically disconnect power during a ground fault.

Table 1.1-12. Ground Fault Protection Applicable Codes

Description	Standard	Section
Services Feeders	NEC	230.95
	NEC	215.10
Additional level	NEC	517.17
	NFPA 99	4.3.2.5
Alternate source	NEC	700.26
	NEC	701.26

Wet procedure locations—A wet procedure location in a health care facility is any patient care area that is normally subject to wet conditions while patients are present. Typical wet procedure locations can include operating rooms, anesthetizing locations, dialysis locations, etc. (Patient beds, toilets and sinks are not considered wet locations.) These wet procedure locations require special protection to guard against electric shock. The ground fault current in these areas must be limited to not exceed 6 mA.

In areas where the interruption of power is permissible, ground fault circuit interrupters (GFCI) can be employed. GFCIs will interrupt a circuit when ground fault current exceeds 5 mA (± 1 mA).

In areas where the interruption of power cannot be tolerated, protection from ground fault currents is accomplished through the use of an isolated power system. Isolated power systems provide power to an area that is isolated from ground (or ungrounded). This type of system limits the amount of current that flows to ground in the event of a single line-to-ground fault and maintains circuit continuity. Electronic line isolation monitors (LIM) are used to monitor and display leakage currents to ground. When leakage current thresholds are exceeded, visible and/or audible alarms are initiated to alert occupants of a possible hazardous condition. This alarm occurs without interrupting power to allow for the safe conclusion of critical procedures.

Table 1.1-13. Wet Procedure Location Applicable Codes

Description	Standard	Section
General	NFPA 99	4.3.2.2.9
	NEC	517.20
Isolated power systems	NFPA 99	4.3.2.6
	NEC	517.160

Maintenance and Testing

Regular maintenance and testing of the electrical distribution system in a health care facility is necessary to ensure proper operation in an emergency and, in some cases, to maintain government accreditation. Any health care facility receiving Medicare or Medicaid reimbursement from the government must be accredited by the Joint Commission on Accreditation of Health Care Organizations (JCAHO). JCAHO has established a group of standards called the Environment of Care, which must be met for health care facility accreditation. Included in these standards is the regular testing of the emergency (alternate) power system(s). Diesel-powered EPS installations must be tested monthly in accordance with NFPA 110 *Standard for Emergency and Standby Power Systems*. Generators must be tested for a minimum of 30 minutes under the criteria defined in NFPA 110.

One method to automate the task of monthly generator tests is through the use of Power Xpert® communications. With the Power Xpert integrated metering, monitoring and control system, a facility maintenance director can initiate a generator test, control/monitor loads, meter/monitor generator test points and create a JCAHO compliant report automatically from a central PC. The report contains all metered values, test results, date/time information, etc. necessary to satisfy JCAHO requirements. This automated generator testing procedure reduces the labor, training and inaccuracies that occur during manual emergency power system tests. (See **Power Monitoring Tab 2.**)

Table 1.1-14. Maintenance and Testing Applicable Codes

Description	Standard	Section
Grounding	NFPA 99	4.3.3.1
Emergency power system	NFPA 99	4.4.4.1.1
	JCAHO	EC.2.14(d)
Generator	NFPA 110	8.4
Transfer switches	NFPA 110	8.3.5, 8.4.6
Breakers	NFPA 99	4.4.4.1.2
	NFPA 110	8.4.7

Routine maintenance should be performed on circuit breakers, transfer switches, switchgear, generator equipment, etc. by trained professionals to ensure the most reliable electrical system possible. See **Tab 41** for Eaton's Electrical Services & Systems (EESS), which provides engineers,

trained in development and execution of annual preventative maintenance procedures of health care facility electrical distribution systems.

Paralleling Emergency Generators

Without Utility Paralleling

In many health care facilities (and other large facilities with critical loads), the demand for standby emergency power is large enough to require multiple generator sets to power all of the required essential electrical system (EES) loads. In many cases, it becomes more flexible and easier to operate the required multiple generators from a single location using generator paralleling switchgear.

Figure 1.1-21 on **Page 1.1-19** shows an example of a typical one-line for a paralleling switchgear lineup feeding the EES.

A typical abbreviated sequence of operation for a multiple emergency generator and ATS system follows. Note that other modes of operation such as generator demand priority and automated testing modes are available but are not included below. (Reference **Tab 41** for complete detailed sequences of operation.)

1. Entering emergency mode
 - a. Upon loss of normal source, automatic transfer switches send generator control system a run request.
 - b. All available generators are started. The first generator up to voltage and frequency is closed to the bus.
 - c. Unsheddable loads and load shed Priority 1 loads are powered in less than 10 seconds.
 - d. The remaining generators are synchronized and paralleled to the bus as they come up to voltage and frequency.
 - e. As additional generators are paralleled to the emergency bus, load shed priority levels are added, powering their associated loads.
 - f. The system is now in emergency mode.
2. Exit from emergency mode
 - a. Automatic transfer switches sense the utility source is within acceptable operational tolerances for a time duration set at the automatic transfer switch.

- b. As each automatic transfer switch transfers back to utility power, it removes its run request from the generator plant.
- c. When the last automatic transfer switch has retransferred to the utility and all run requests have been removed from the generator plant, all generator circuit breakers are opened.
- d. The generators are allowed to run for their programmed cool-down period.
- e. The system is now back in automatic/standby mode.

With Utility Paralleling

Today, many utilities are offering their customers excellent financial incentives to use their on-site generation capacity to remove load from the utility grid. These incentives are sometimes referred to as limited interruptible rates (LIP). Under these incentives, utilities will greatly reduce or eliminate kWhr or kW demand charges to their customers with on-site generation capabilities. In exchange, during times of peak loading of the utility grid, the utility can ask their LIP rate customers to drop load from the grid by using their on-site generation capabilities.

Health care facilities are ideally suited to take advantage of these programs because they already have significant on-site generation capabilities due to the code requirements described.

Many health care facilities are taking advantage of these utility incentives by adding generator capacity over and above the NFPA requirements. **Figure 1.1-22 on Page 1.1-20** shows an example one-line of a health care facility with complete generator backup and utility interconnect.

NFPA 110 requirements state that the normal and emergency sources must be separated by a fire-rated wall.

The intent of this requirement is so that a fire in one location cannot take out both sources of power. To meet this requirement, the paralleling switchgear must be split into separate sections with a tie bus through a fire-rated wall. For more information on generator paralleling switchgear, see **Tab 40**.

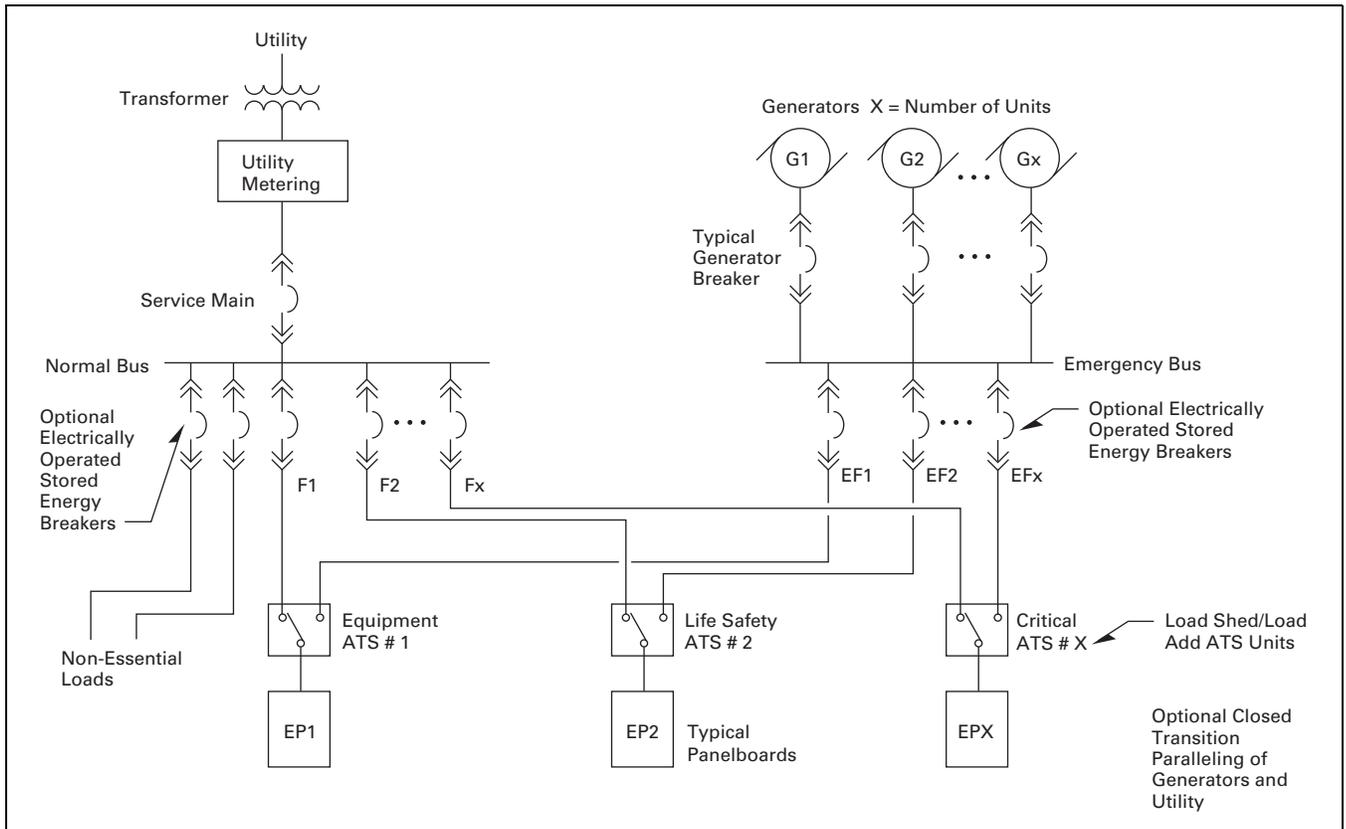


Figure 1.1-21. Typical One-Line for a Paralleling Switchgear Lineup Feeding the Essential Electrical System (EES)

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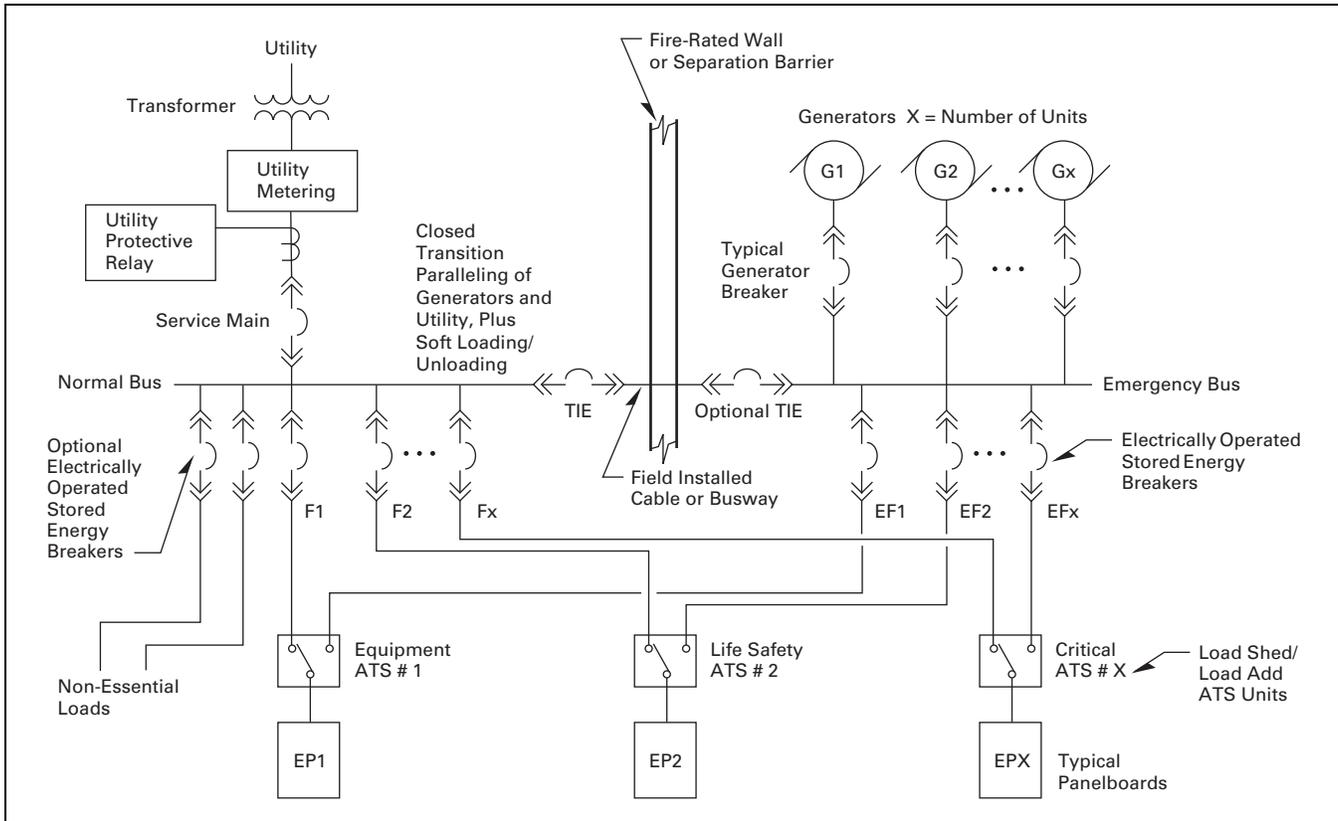
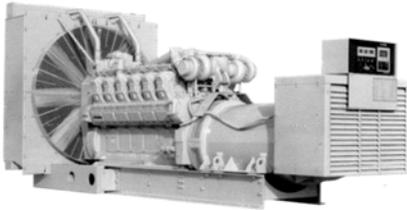


Figure 1.1-22. Typical One-Line Health Care Facility with Complete Generator Backup and Utility Interconnect

Generators and Generator Systems



Typical Diesel Genset—Caterpillar

Introduction

The selection and application of generators into the electrical distribution system will depend on the particular application. There are many factors to consider, including code requirements, environmental constraints, fuel sources, control complexity, utility requirements and load requirements. The health care requirements for legally required emergency standby generation systems are described starting on **Page 1.1-15**. Systems described in this section are applicable to health care requirements, as well as other facilities that may require a high degree of reliability. The electrical supply for data centers, financial institutions, telecommunications, government and public utilities also require high reliability. Threats of disaster or terror attacks have prompted many facilities to require complete self-sufficiency for continuous operation.

2011 NEC Changes Related to Generator Systems

Article 250.30—Grounding Separately Derived AC Systems—has been completely rewritten for clarity and for usability. Most notably, the term *equipment bonding jumper* was changed to *supply-side bonding jumper* (see 250.30(A)(2)). This was necessary to ensure proper identification and installation of bonding conductors within or on the supply side of service equipment and between the source of a separately derived system and the first disconnecting means. The other requirements for grounded systems were renumbered to accommodate the 250.30(A)(2) change. 250.30(B)(3)—Ungrounded Systems—has been added, and this language requires

a supply-side bonding jumper to be installed from the source of a separately derived system to the first disconnecting means in accordance with 250.30(A)(2). Another new requirement, 250.30(C)—Outdoor Source—has been added, and requires a grounding electrode connection at the source location when the separately derived system is located outside of the building or the structure being supplied.

Article 445.19—Generators Supplying Multiple Loads—has been revised to require that the generator have overcurrent protection per 240.15(A) when using individual enclosures tapped from a single feeder.

Article 517.17(B)—Feeder GFP (Health Care Facilities)—now allows, but does not require, multiple levels of GFPE upstream of the transfer switch when the choice is made to provide GFPE on the alternate power source (i.e., generator).

Article 701.6(D)—Signals (Legally Required Standby Systems)—now requires ground fault indication for legally required standby systems of more than 150 V to ground and OCPDs rated 1000 A or more.

Types of Engines

Many generator sets are relatively small in size, typically ranging from several kilowatts to several megawatts. These units are often required to come online and operate quickly. They need to have the capacity to run for an extended period of time. The internal combustion engine is an excellent choice as the prime mover for the majority of these applications. Turbines may also be used. Diesel-fueled engines are the most common, but other fuels used include natural gas, digester gas, landfill gas, propane, biodiesel, crude oil, steam and others.

Some campuses and industrial facilities use and produce steam for heating and other processes. These facilities may find it economically feasible to produce electricity as a byproduct of the steam production. These installations would typically be classified as a cogeneration facility producing a fairly constant power output and operating in parallel with the electric utility system.

Types of Generators

Generators can be either synchronous or asynchronous. Asynchronous generators are also referred to as induction generators. The construction is essentially the same as an induction motor. It has a squirrel-cage rotor and wound stator. An induction generator is a motor driven above its designed synchronous speed thus generating power. It will operate as a motor if it is running below synchronous speed. The induction generator does not have an exciter and must operate in parallel with the utility or another source. The induction generator requires VARs from an external source for it to generate power. The induction generator operates at a slip frequency so its output frequency is automatically locked in with the utility's frequency.

An induction generator is a popular choice for use when designing cogeneration systems, where it will operate in parallel with the utility. This type of generator offers certain advantages over a synchronous generator. For example, voltage and frequency are controlled by the utility; thus voltage and frequency regulators are not required. In addition, the generator construction offers high reliability and little maintenance. Also, a minimum of protective relays and controls are required. Its major disadvantages are that it requires VARs from the system and it normally cannot operate as a standby/emergency generator.

Synchronous generators, however, are the most common. Their output is determined by their field and governor controls. Varying the current in the DC field windings controls the voltage output. The frequency is controlled by the speed of rotation. The torque applied to the generator shaft by the driving engine controls the power output. In this manner, the synchronous generator offers precise control over the power it can generate. In cogeneration applications, it can be used to improve the power factor of the system.

Generator Systems

Emergency Standby Generator System

There are primarily three types of generator systems. The first and simplest type is a single generator that operates independently from the electric utility power grid. This is typically referred to as an emergency standby generator system. **Figure 1.2-1** shows a single standby generator, utility source and a transfer switch. In this case, the load is either supplied from the utility or the generator. The generator and the utility are never continuously connected together. This simple radial system has few requirements for protection and control. It also has the least impact on the complete electric power distribution system. It should be noted that this type of generator system improves overall electrical reliability but does not provide the redundancy that some facilities require if the generator fails to start or is out for maintenance.

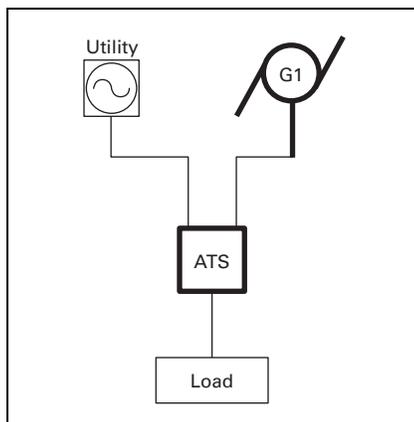


Figure 1.2-1. Emergency Standby Generator System

Multiple Isolated Standby Generators

The second type of generator system is a multiple isolated set of standby generators. **Figure 1.2-2** shows multiple generators connected to a paralleling bus feeding multiple transfer switches. The utility is the normal source for the transfer switches. The generators and the utility are never continuously connected together in this scheme. Multiple generators may be required to meet the load requirements (N system). Generators may be applied in an N+1 or a 2N system for improved system reliability.

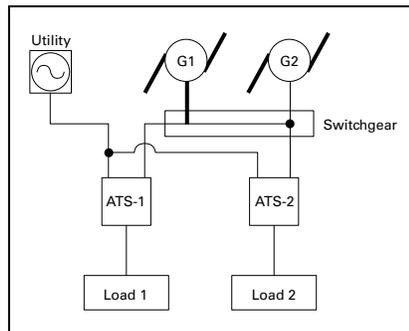


Figure 1.2-2. Multiple Isolated Set of Standby Generators

In an N system, where N is the number of generators required to carry the load; if a generator fails or is out for maintenance, then the load may be dropped. This is unacceptable for most critical 24/7 operations. In an N + 1 system, N is the number of generators needed to carry the load and 1 is an extra generator for redundancy. If one generator fails to start or is out for maintenance, it will not affect the load. In a 2N system, there is complete 100% redundancy in the standby generation system such that the failure of one complete set of generators will not affect the load.

Multiple generator systems have a more complex control and protection requirement as the units have to be synchronized and paralleled together. The generators are required to share the load proportionally without swings or prolonged hunting in voltage or frequency for load sharing. They may also require multiple levels of load shedding and/or load restoration schemes to match generation capacity.

Multiple Generators Operating in Parallel with Utility System

The third type of system is either one with a single or multiple generators that operate in parallel with the utility system. **Figure 1.2-3** shows two generators and a utility source feeding a switchgear lineup feeding multiple loads. This system typically requires generator capacity sufficient to carry the entire load or sophisticated load shedding schemes. This system will require a complete and complex protection and control scheme. The electric utility may have very stringent and costly protection requirements for the system. IEEE standard 1547 describes the interconnection requirements for paralleling to the utility.

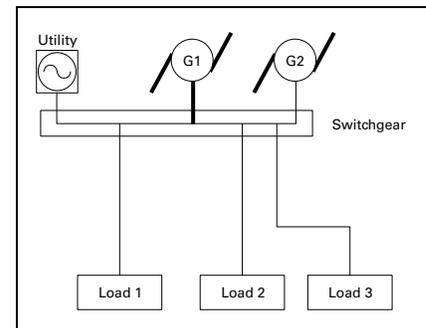


Figure 1.2-3. Multiple Generators Operating in Parallel with Utility System

Generator Fundamentals

A generator consists of two primary components, a prime mover and an alternator. The prime mover is the energy source used to turn the rotor of the alternator. It is typically a diesel combustion engine for most emergency or standby systems. In cogeneration applications, the prime mover may come from a steam driven turbine or other source. On diesel units, a governor and voltage regulator are used to control the speed and power output.

The alternator is typically a synchronous machine driven by the prime mover. A voltage regulator controls its voltage output by adjusting the field. The output of a single generator or multiple paralleled generator sets is controlled by these two inputs. The alternator is designed to operate at a specified speed for the required output frequency, typically 60 or 50 Hz. The voltage regulator and engine governor along with other systems define the generator's response to dynamic load changes and motor starting characteristics.

Generators are rated in power and voltage output. Most generators are designed to operate at a 0.8 power factor. For example, a 2000 kW generator at 277/480 V would have a kVA rating of 2500 kVA (2000 kW/0.8 pf) and a continuous current rating of 3007A (2500 kVA/480V $\sqrt{3}$).

Typical synchronous generators for industrial and commercial power systems range in size from 100–3000 kVA and from 208 V–13,800 V. Other ratings are available and these discussions are applicable to those ratings as well.

Generators must be considered in the short-circuit and coordination study as they may greatly impact the rating of the electrical distribution system. This is especially common on large installations with multiple generators and systems that parallel with the utility source. Short-circuit current contribution from a generator typically ranges from 8 to 12 times full load amperes.

The application of generators requires special protection requirements. The size, voltage class, importance and dollar investment will influence the protection scheme associated with the generator(s). Mode of operation will influence the utility company's interface protection requirements. Paralleling with the electric utility is the most complicated of the utility inter-tie requirements. IEEE ANSI 1547 provides recommended practices.

Generator Grounding and Bonding (Ref. NEC 2011, Article 250.30(A)(1) and (2))

Generator grounding methods need to be considered and may affect the distribution equipment and ratings. Generators may be connected in delta or wye, but wye is the most typical connection. A wye-connected generator can be solidly grounded, low impedance grounded, high impedance grounded or ungrounded. **Section 1.4** discusses general grounding schemes, benefits of each and protection considerations.

A solidly grounded generator may have a lower zero sequence impedance than its positive sequence impedance. In this case, the equipment will need to be rated for the larger available ground fault current. The generator's neutral may be connected to the system-neutral; if it is, the generator is not a separately derived system and a three-pole transfer switch is used. If the generator's neutral is bonded to ground separate from the system-neutral, it is a separately

derived system and a four-pole transfer switch is required or ground fault relays could misoperate and unbalanced neutral current may be carried on ground conductors.

An IEEE working group has studied the practice of low resistance grounding of medium voltage generators within the general industry. This "working group" found that, for internal generator ground faults, the vast majority of the damage is done after the generator breaker is tripped offline, and the field and turbine are tripped. This is due to the stored energy in the generator flux that takes several seconds to dissipate after the generator is tripped offline. It is during this time that the low resistance ground allows significant amounts of fault current to flow into the ground fault. Because the large fault currents can damage the generator's winding, application of an alternate protection method is desirable during this time period. One of the solutions set forth by this "working group" is a hybrid high resistance grounding (HHRG) scheme as shown in **Figure 1.2-4**. In the HHRG scheme, the low resistance ground (LRG) is quickly tripped offline when the generator protection senses the ground fault. The LRG is cleared at the same time that the generator breaker clears, leaving the high resistance ground portion connected to control the transient overvoltages during the coast-down phase of the generator, thereby all but eliminating generator damage.

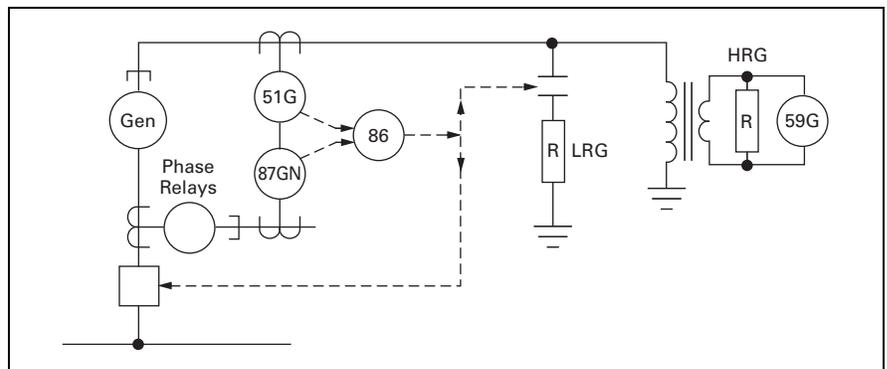


Figure 1.2-4. Hybrid High Resistance Grounding Scheme

Generator Controls

The engine generator set has controls to maintain the output frequency (speed) and voltage. These controls consist of a governor and voltage regulator. As loads change on the system, the frequency and voltage will change. The speed control will then adjust the governor to correct for the load (kW) change. The voltage regulator will change the field current to adjust the voltage to the desired voltage value. These are the basic controls found on all synchronous generators.

Multiple generator systems require more sophisticated controls. Generators are paralleled in a multi-generator system and they must share the load. These systems often have a load shed scheme, which adds to the complexity.

Multiple generator schemes need a master controller to prevent units from being connected out-of-phase. The sequence of operation is to send a start signal to all generators simultaneously. The first unit up to frequency and voltage will be permitted to close its respective breaker and energize the paralleling bus. Breakers for the other generators are held open, not permitted to close, until certain conditions are met. Once the paralleling bus is energized, the remaining generators must be synchronized to it before the generators can be paralleled. Synchronization compares the voltage phasor's angle and magnitude. Both generators must be operating at the same frequency and phase-matched within typically 5 to 10 degrees with each other. The voltage magnitude typically must be within 20 to 24%.

A synch-scope is typically supplied on paralleling gear. The synch-scope displays the relative relationship between voltage phasors on the generator to be paralleled and the bus. If the generator is running slower than the bus (less than 60 Hz) then the needle on the scope will spin in the counterclockwise direction. If it is running faster, then it will rotate in the clockwise direction. The greater the frequency difference, the faster is the rotation. It is important that the generators are in phase before they are paralleled. Severe damage will occur if generators are paralleled out-of-phase.

Generator Short-Circuit Characteristics

If a short circuit is applied directly to the output terminals of a synchronous generator, it will produce an extremely high current initially, gradually decaying to a steady-state value. This change is represented by a varying reactive impedance. Three specific reactances are used for short-circuit fault currents. They are:

- Subtransient reactance X_d'' , which is used to determine the fault current during the first 1 to 5 cycles
- Transient reactance X_d' , which is used to determine the fault current during the next 5 to 200 cycles
- Synchronous reactance X_d , which is used to determine the steady-state fault current

The subtransient reactance X_d'' will range from a minimum of approximately 9% for a two-pole, wound-rotor machine to approximately 32% for a low-speed, salient-pole, hydro-generator. The initial symmetrical fault current can be as much as 12 times full load current.

Depending on the generator type, the zero sequence impedance may be less than the subtransient reactance and the ground fault current substantially higher than the three-phase short-circuit current. For example, a 2500 kVA, 480/277 V, four-pole, 2/3 pitch standby generator has a 0.1411 per unit subtransient reactance X_d'' and a 0.033 per unit zero sequence X_0 reactance. The ground current is approximately a third larger than the three-phase fault current. The ground fault current can be reduced to the three-phase level by simply adding a small reactance between the generator neutral and ground while still being considered solidly grounded.

The electric power system analysis must be performed based on the worst-case operating conditions. Typically this is when all sources are paralleled. If the system can operate with both the utility supply and generators in parallel, then the equipment must be rated for the combined fault current plus motor contribution. If the generator and utility will not be paralleled, then both cases will need to be looked at independently and the worst case used for selecting the equipment ratings.

Generator Protection

Generator protection will vary and depend on the size of the generator, type of system and importance of the generator. Generator sizes are defined as: small—1000 kVA maximum up to 600 V (500 kVA maximum when above 600 V); medium over 1000 kVA to 12,500 kVA maximum regardless of voltage; large—from 12,500–50,000 kVA. The simplest is a single generator system used to feed emergency and/or standby loads. In this case, the generator is the only source available when it is operating and it must keep operating until the normal source returns.

Figure 1.2-5 Part (A) shows minimum recommended protection for a single generator used as an emergency or standby system. Phase and ground time overcurrent protection (Device 51 and 51G) will provide protection for external faults. For medium voltage generators, a voltage controlled time overcurrent relay (Device 51V) is recommended for the phase protection as it can be set more sensitive than standard overcurrent relays and is less likely to false operate on normal overloads. This scheme may not provide adequate protection for internal generator faults when no other power source exists. Local generator controllers may offer additional protection for voltage and frequency conditions outside the generator’s capabilities.

Figure 1.2-5 Part (B) shows the recommended protection for multiple, isolated, medium voltage, small generators. Additional protection may be desired and could include generator differential, reverse power, and loss of field protection. Differential protection (Device 87) can be accomplished with either a self-balancing set of CTs as in **Figure 1.2-6** or with a percentage differential scheme as in **Figure 1.2-7** on **Page 1.2-6**. The percentage differential scheme offers the advantage of reducing the possibility for false tripping due to CT saturation. The self-balancing scheme offers the advantages of increased sensitivity, needing three current transformers in lieu of six, and the elimination of current transformer external wiring from the generator location to the generator switchgear location.

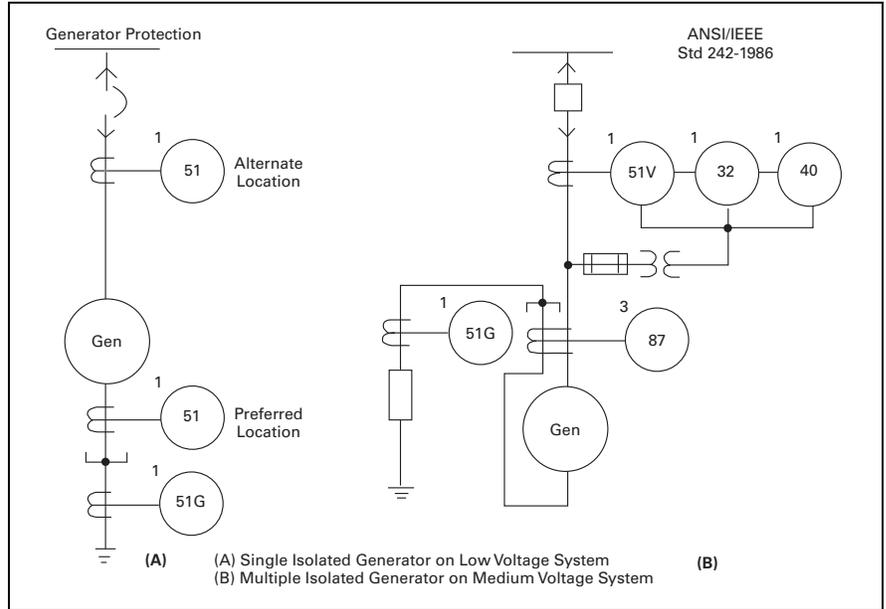


Figure 1.2-5. Typical Protective Relaying Scheme for Small Generators

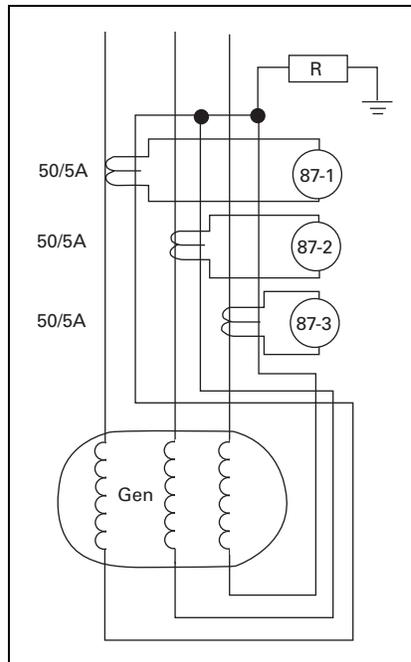


Figure 1.2-6. Self-Balancing Generator Differential Relay Scheme

1

Reverse power protection (Device 32) is used to prevent the generator from being motored. Motoring could damage (with other hazards) the prime mover. A steam turbine could overheat and fail. A diesel or gas engine could either catch fire or explode. A steam turbine can typically withstand approximately 3% reverse power where a diesel engine can withstand up to 25% reverse power.

Loss of field protection (Device 40) is needed when generators are operating in parallel with one another or the power grid. When a synchronous generator loses its field, it will continue to generate power as an induction generator obtaining its excitation from the other machines on the system. During this condition, the rotor will quickly overheat due to the slip frequency currents induced in it. Loss of excitation in one machine could jeopardize the operation of the other machines beyond their capability and the entire system.

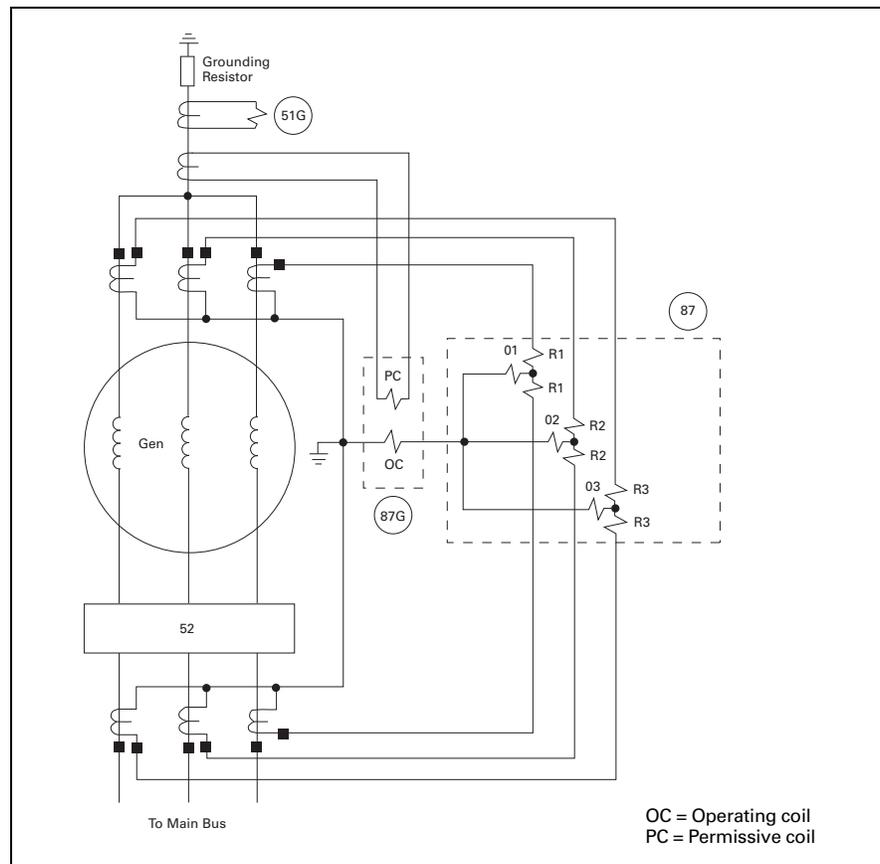


Figure 1.2-7. Generator Percentage Differential Relay (Phase Scheme) and Ground Differential Scheme Using a Directional Relay

Typical protection for larger generators is shown in **Figure 1.2-8**. It adds phase unbalance and field ground fault protection. Phase unbalance (Device 46) or negative sequence overcurrent protection prevents the generator's rotor from overheating damage. Unbalanced loads, fault conditions or open phasing will produce a negative sequence current to flow. The unbalanced currents induce double system frequency currents in the rotor, which quickly causes rotor overheating. Serious damage will occur to the generator if the unbalance is allowed to persist.

Other protection functions such as under/overvoltage (Device 27/59) could be applied to any size generator. The voltage regulator typically maintains the output voltage within its desired output range. This protection can provide backup protection in case the voltage regulator fails. Under/over frequency protection (Device 81U/81O) could be used for backup protection for the speed control. Sync check relays (Device 25) are typically applied as a breaker permissive close function where generators are paralleled.

Many modern protective relays are microprocessor-based and provide a full complement of generator protection functions in a single package. The cost per protection function has been drastically reduced such that it is feasible to provide more complete protection even to smaller generators.

IEEE ANSI 1547 provides recommended practices for utility inter-tie protection. If the system has closed-transition or paralleling capability, additional protection may be required by the utility. Typically, no additional protection is required if the generator is paralleled to the utility for a maximum of 100 msec or less. Systems that offer soft transfer, peak shaving or co-generation will require additional utility inter-tie protection. The protection could include directional overcurrent and power relays and even transfer trip schemes. Please consult your local utility for specific requirements.

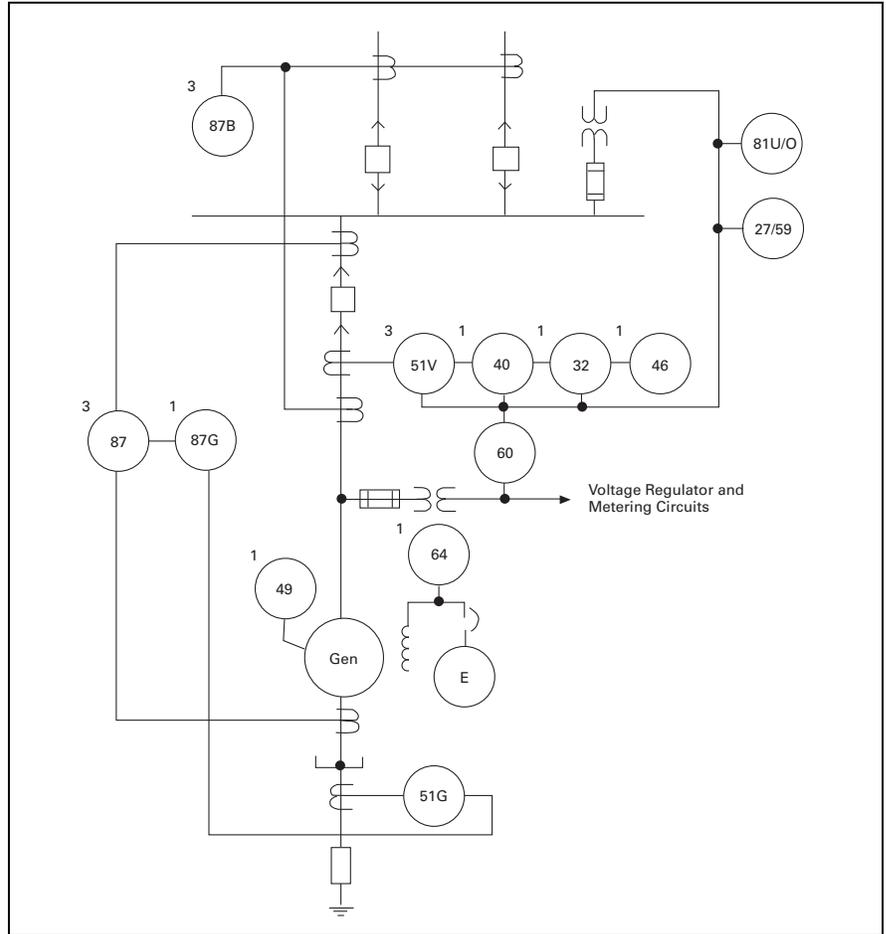


Figure 1.2-8. Typical Protective Relaying Scheme for Large Generator

Generator Set Sizing and Ratings

Many factors must be considered when determining the proper size or electrical rating of an electrical power generator set. **The engine or prime mover is sized to provide the actual or real power in kW**, as well as speed (frequency) control through the use of an engine governor. **The generator is sized to supply the kVA needed** at startup and during normal running operation and it also provides voltage control using a brushless exciter and voltage regulator. Together the engine and generator provide the energy necessary to supply electrical loads in many different applications encountered in today's society.

The generator set must be able to supply the starting and running electrical load. It must be able to pick up and start all motor loads and low power factor loads, and recover without excessive voltage dip or extended recovery time. Nonlinear loads like variable frequency drives, uninterruptible power supply (UPS) systems and switching power supplies also require attention because the SCR switching causes voltage and current waveform distortion and harmonics. The harmonics generate additional heat in the generator windings, and the generator may need to be upsized to accommodate this. The type of fuel (diesel, natural gas, propane, etc.) used is important as it is a factor in determining generator set transient response. It is also necessary to determine the load factor or average power consumption of the generator set. This is typically defined as the load (kW) x time (hrs. while under that particular load) / total running time. When this load factor or average power is taken into consideration with peak demand requirements and the other operating parameters mentioned above, the overall electrical rating of the genset can be determined. Other items to consider include the unique installation, ambient, and site requirements of the project. These will help to determine the physical configuration of the overall system.

Typical rating definitions for diesel gensets are: standby, prime plus 10, continuous and load management (paralleled with or isolated from utility). Any diesel genset can have several electrical ratings depending on the number of hours of operation per year and the ratio of electrical load/genset rating when in operation. The same diesel genset can have a standby rating of 2000 kW at 0.8 power factor (pf) and a continuous rating of 1825 kW at 0.8 pf. The lower continuous rating is due to the additional hours of operation and higher load that the continuous genset must carry. These additional requirements put more stress on the engine and generator and therefore the rating is decreased to maintain longevity of the equipment.

Different generator set manufacturers use basically the same diesel genset electrical rating definitions and these are based on international diesel fuel stop power standards from organizations like ISO, DIN and others. A standby diesel genset rating is typically defined as supplying varying electrical loads for the duration of a power outage with the load normally connected to utility, genset operating <100 hours per year and no overload capability. A prime plus 10 rating is typically defined as supplying varying electrical loads for the duration of a power outage with the load normally connected to utility, genset operating 500 hours per year and overload capability of 10% above its rating for 1 hour out of 12. A continuous rating is typically defined as supplying unvarying electrical loads (i.e., base loaded) for an unlimited time. The load management ratings apply to gensets in parallel operation with the utility or isolated/islanded from utility and these ratings vary in usability from <200 hours per year to unlimited usage. Refer to generator set manufacturers for further definitions on load management ratings, load factor or average power consumption, peak demand and how these ratings are typically applied. Even though there is some standardization of these ratings across the manufacturers, there also exists some uniqueness with regard to how each manufacturer applies their generator sets.

Electrical rating definitions for natural gas powered gensets are typically defined as standby or continuous with definitions similar to those mentioned above for diesels. **Natural gas gensets recover more slowly than diesel gensets when subjected to block loads.** Diesel engines have a much more direct path from the engine governor and fuel delivery system to the combustion chamber and this results in a very responsive engine-generator. A natural gas engine is challenged with air-fuel flow dynamics and a much more indirect path from the engine governor (throttle actuator) and fuel delivery system (natural gas pressure regulator, fuel valve and actuator, carburetor mixer, aftercooler, intake manifold) to the combustion chamber and this results in a less responsive engine-generator. **Diesel gensets recover about twice as fast as natural gas gensets.**

For the actual calculations involved for sizing a genset, there are readily accessible computer software programs that are available on the genset manufacturer's Internet sites or from the manufacturer's dealers or distributors. These programs are used to quickly and accurately size generator sets for their application. The programs take into consideration the many different parameters discussed above, including the size and type of the electrical loads (resistive, inductive, SCR, etc.), reduced voltage soft starting devices (RVSS), motor types, voltage, fuel type, site conditions, ambient conditions and other variables. The software will optimize the starting sequences of the motors for the least amount of voltage dip and determine the starting kVA needed from the genset. It also provides transient response data, including voltage dip magnitude and recovery duration. If the transient response is unacceptable, then design changes can be considered, including oversizing the generator to handle the additional kvar load, adding RVSS devices to reduce the inrush current, improving system power factor and other methods. The computer software programs are quite flexible in that they allow changes to the many different variables and parameters to achieve an optimum design. The software allows, for example, minimizing voltage dips or using paralleled gensets vs. a single genset.

Genset Sizing Guidelines

Some conservative rules of thumb for genset sizing include:

1. Oversize genset 20–25% for reserve capacity and for motor starting.
2. Oversize gensets for unbalanced loading or low power factor running loads.
3. Use 1/2 hp per kW for motor loads.
4. For variable frequency drives, oversize the genset by at least 40%.
5. For UPS systems, oversize the genset by 40% for 6 pulse and 15% for 6 pulse with input filters or 12 pulse.
6. Always start the largest motor first when stepping loads.

For basic sizing of a generator system, the following example could be used:

Step 1: Calculate Running Amperes

- Motor loads:
 - 200 hp motor156 A
 - 100 hp motor78 A
 - 60 hp motor48 A
- Lighting load68 A
- Miscellaneous loads95 A
- Running amperes**445 A**

Step 2: Calculating Starting Amperes Using 1.25 Multiplier

- Motor loads:
 -195 A
 -98 A
 -60 A
- Lighting load68 A
- Miscellaneous loads95 A
- Starting amperes**516 A**

Step 3: Selecting kVA of Generator

- Running kVA =
(445 A x 480 V x 1.732)/
1000 = 370 kVA
- Starting kVA =
(516 A x 480 V x 1.732)/
1000 = 428 kVA

Solution

Generator must have a minimum starting capability of 428 kVA and minimum running capability of 370 kVA.

Also, please see section “Factors Governing Voltage Drop” on **Page 1.3-21** for further discussion on generator loading and reduced voltage starting techniques for motors.

Generator Set Installation and Site Considerations

There are many different installation parameters and site conditions that must be considered to have a successful generator set installation. The following is a partial list of areas to consider when conducting this design. Some of these installation parameters include:

- Foundation type (crushed rock, concrete, dirt, wood, separate concrete inertia pad, etc.)
- Foundation to genset vibration dampening (spring type, cork and rubber, etc.)
- Noise attenuation (radiator fan mechanical noise, exhaust noise, air intake noise)
- Combustion and cooling air requirements
- Exhaust backpressure requirements
- Emissions permitting
- Delivery and rigging requirements
- Genset derating due to high altitudes or excessive ambient temperatures

- Hazardous waste considerations for fuel, antifreeze, engine oil
- Meeting local building and electrical codes
- Genset exposure (coastal conditions, dust, chemicals, etc.)
- Properly sized starting systems (compressed air, batteries and charger)
- Allowing adequate space for installation of the genset and for maintenance (i.e., air filter removal, oil changing, general genset inspection, etc...)
- Flex connections on all systems that are attached to the genset and a rigid structure (fuel piping, foundation vibration isolators, exhaust, air intake, control wiring, power cables, radiator flanges/duct work, etc.)
- Diesel fuel day tank systems (pumps, return piping)
- Fuel storage tank (double walled, fire codes) and other parameters

Please see the generator set manufacturer’s application and installation guidelines for proper application and operation of their equipment.

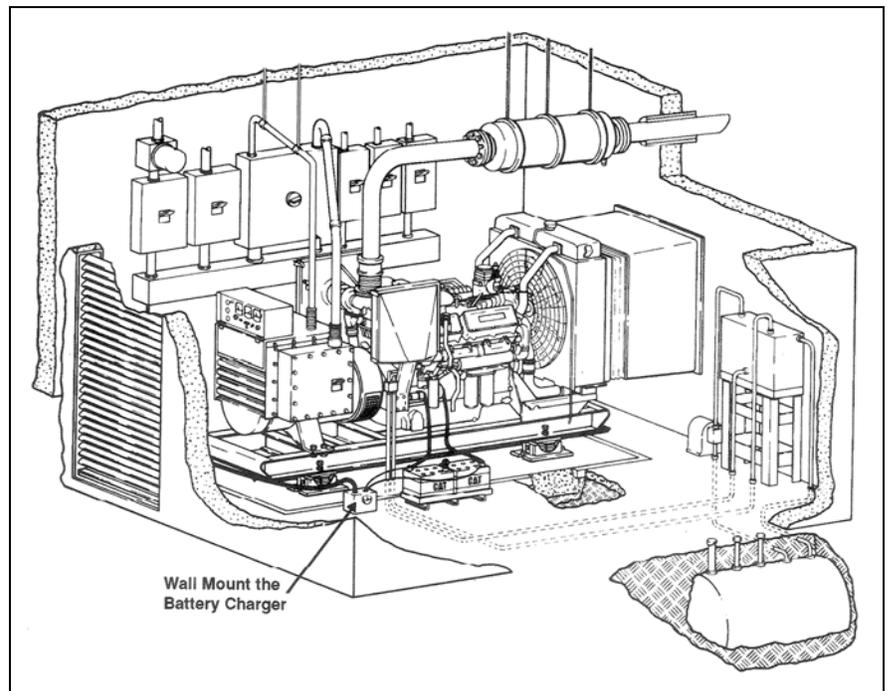


Figure 1.2-9. Typical Genset Installation
Note: Courtesy of Caterpillar, Inc.

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Systems Analysis

A major consideration in the design of a distribution system is to ensure that it provides the required quality of service to the various loads. This includes serving each load under normal conditions and, under abnormal conditions, providing the desired protection to service and system apparatus so that interruptions of service are minimized consistent with good economic and mechanical design.

Under normal conditions, the important technical factors include voltage profile, losses, load flow, effects of motor starting, service continuity and reliability. The prime considerations under faulted conditions are apparatus protection, fault isolation and service continuity. During the system preliminary planning stage, before selection of the distribution apparatus, several distribution systems should be analyzed and evaluated, including both economic and technical factors. During this stage, if system size or complexity warrant, it may be appropriate to provide a thorough review of each system under both normal and abnormal conditions.

The principal types of computer programs used to provide system studies include:

- Short circuit—identify three-phase and line-to-ground fault currents and system impedances
- Arc flash—calculates arc flash energy levels, which leads to the selection of personal protective equipment (PPE)
- Circuit breaker duty—identify asymmetrical fault current based on X/R ratio
- Protective device coordination—determine characteristics and settings of medium voltage protective relays and fuses, and entire low voltage circuit breaker and fuse coordination
- Load flow—simulate normal load conditions of system voltages, power factor, line and transformer loadings
- Motor starting—identify system voltages, motor terminal voltage, motor accelerating torque, and motor accelerating time when starting large motors

Short-circuit calculations define momentary and steady-state fault currents for LV and MV breaker and fuse duty and bus bracings at any selected location in the system, and also determine the effect on the system after removal of utility power due to breaker operation or scheduled power outages. Computer software programs can identify the fault current at any bus, in every line or source connected to the faulted bus, or to it and every adjacent bus, or to it and every bus that is one and two buses away, or currents in every line or source in the system. The results of these calculations permit optimizing service to the loads while properly applying distribution apparatus within their intended limits.

The following additional studies should be considered depending upon the type and complexity of the distribution system, the type of facility and the type of loads to be connected to the system:

- Harmonic analysis
- Transient stability
- Insulation coordination
- Grounding study
- Switching transient

Eaton's Electrical Services & Systems division can provide the studies enumerated above.

Short-Circuit Currents— General

The amount of current available in a short-circuit fault is determined by the capacity of the system voltage sources and the impedances of the system, including the fault. Voltage sources include the power supply (utility or on-site generation) plus all rotating machines connected to the system at the time of the fault. A fault may be either an arcing or bolted fault. In an arcing fault, part of the circuit voltage is consumed across the fault and the total fault current is somewhat smaller than for a bolted fault, so the latter is the worst condition, and therefore is the value sought in the fault calculations.

Basically, the short-circuit current is determined by applying Ohm's Law to an equivalent circuit consisting of a constant voltage source and a time-varying impedance. A time-varying impedance is used in order to account for the changes in the effective voltages of the rotating machines during the fault. In an AC system, the resulting short-circuit current starts out higher in magnitude than the final steady-state value and asymmetrical (due to the DC offset) about the X-axis. The current then decays toward a lower symmetrical steady-state value. The time-varying characteristic of the impedance accounts for the symmetrical decay in current. The ratio of the reactive and resistive components (X/R ratio) accounts for the DC decay, see **Figure 1.3-1**. The fault current consists of an exponentially decreasing direct-current component superimposed upon a decaying alternating-current. The rate of decay of both the DC and AC components depends upon the ratio of reactance to resistance (X/R) of the circuit. The greater this ratio, the longer the current remains higher than the steady-state value that it would eventually reach.

The total fault current is not symmetrical with respect to the time-axis because of the direct-current component, hence it is called asymmetrical current. The DC component depends on the point on the voltage wave at which the fault is initiated.

See **Table 1.3-2** for multiplying factors that relate the rms asymmetrical value of total current to the rms symmetrical value, and the peak asymmetrical value of total current to the rms symmetrical value.

The AC component is not constant if rotating machines are connected to the system because the impedance of this apparatus is not constant. The rapid variation of motor and generator impedance is due to these factors:

Subtransient reactance (x_d''), determines fault current during the first cycle, and after about 6 cycles this value increases to the transient reactance. It is used for the calculation of the momentary interrupting and/or momentary withstand duties of equipment and/or system.

Transient reactance (x_d'), which determines fault current after about 6 cycles and this value in 1/2 to 2 seconds increases to the value of the synchronous reactance. It is used in the setting of the phase OC relays of generators and medium voltage circuit breakers.

Synchronous reactance (x_d), which determines fault current after steady-state condition is reached. It has no effect as far as short-circuit calculations are concerned, but is useful in the determination of relay settings.

Transformer impedance, in percent, is defined as that percent of rated primary voltage that must be applied to the transformer to produce rated current flowing in the secondary, with secondary shorted through zero resistance. Therefore, assuming the primary voltage can be sustained (generally referred to as an infinite or unlimited supply), the maximum current a transformer can deliver to a fault condition is the quantity of (100 divided by percent impedance) times the transformer rated

secondary current. Limiting the power source fault capacity will thereby reduce the maximum fault current from the transformer.

The electric network that determines the short-circuit current consists of an AC driving voltage equal to the pre-fault system voltage and an impedance corresponding to that observed when looking back into the system from the fault location. In medium and high voltage work, it is generally satisfactory to regard reactance as the entire impedance; resistance may be neglected. However, this is normally permissible only if the X/R ratio of the medium voltage system is equal to or more than 25. In low voltage (1000 V and below) calculations, it is usually worthwhile to attempt greater accuracy by including resistance with reactance in dealing with impedance. It is for this reason, plus ease of manipulating the various impedances of cables and buses and transformers of the low voltage circuits, that computer studies are recommended before final selection of apparatus and system arrangements.

When evaluating the adequacy of short-circuit ratings of medium voltage circuit breakers and fuses, both the rms symmetrical value and asymmetrical value of the short-circuit current should be determined.

For low voltage circuit breakers and fuses, the rms symmetrical value should be determined along with either: the X/R ratio of the fault at the device or the asymmetrical short-circuit current.

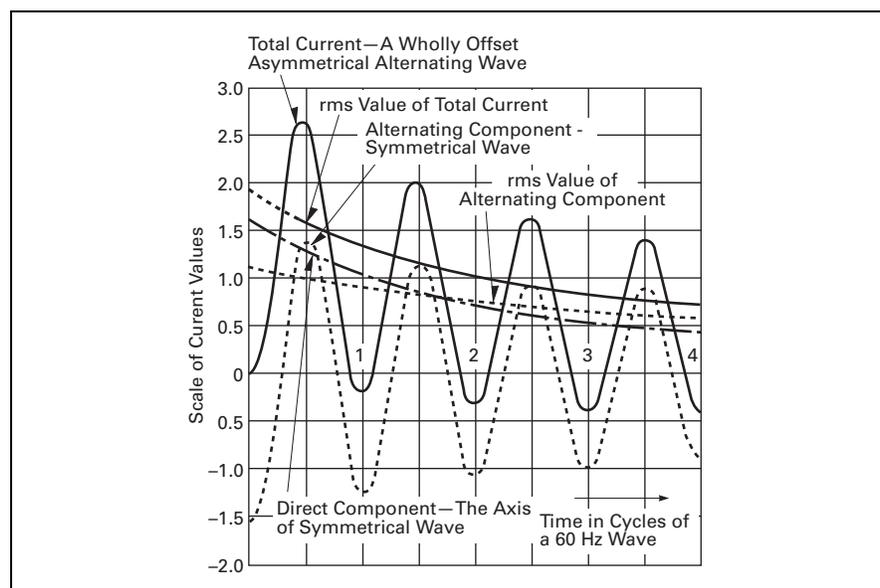


Figure 1.3-1. Structure of an Asymmetrical Current Wave

Fault Current Waveform Relationships

The following **Figure 1.3-2** describes the relationship between fault current peak values, rms symmetrical values and rms asymmetrical values depending on the calculated X/R ratio. The table is based on the following general formulas:

Based on a 60 Hz system and t = 1/2 cycle (ANSI/IEEE C37.13.1990/10.1.4)

$$\text{Peak multiplication factor} = \frac{I_p}{I} = \sqrt{2} \left(1 + e^{\frac{-2\pi 60}{120} \frac{X}{R}} \right) = \sqrt{2} \left(1 + e^{\frac{-\pi}{X/R}} \right)$$

$$\text{rms multiplication factor} = \frac{I_{\text{rms asym}}}{I} = \sqrt{1 + 2e^{\frac{(-2)(2\pi 60)}{120} \frac{X}{R}}} = \sqrt{1 + 2e^{\frac{-2\pi}{X/R}}}$$

$$1. \quad I_p = I\sqrt{2} \left(1 + e^{\frac{-\omega t}{X/R}} \right)$$

$$2. \quad I_{\text{rms asym}} = I\sqrt{1 + 2e^{\frac{-2\omega t}{X/R}}}$$

Example for X/R = 15

$$\text{Peak mf} = \sqrt{2} \left(1 + e^{\frac{-\pi}{15}} \right) = 2.5612$$

$$\text{rms mf} = \sqrt{1 + 2e^{\frac{-2\pi}{15}}} = 1.5217$$

Where:

- I = Symmetrical rms current
- I_p = Peak current
- e = 2.718
- ω = 2 π f
- f = Frequency in Hz
- t = Time in seconds

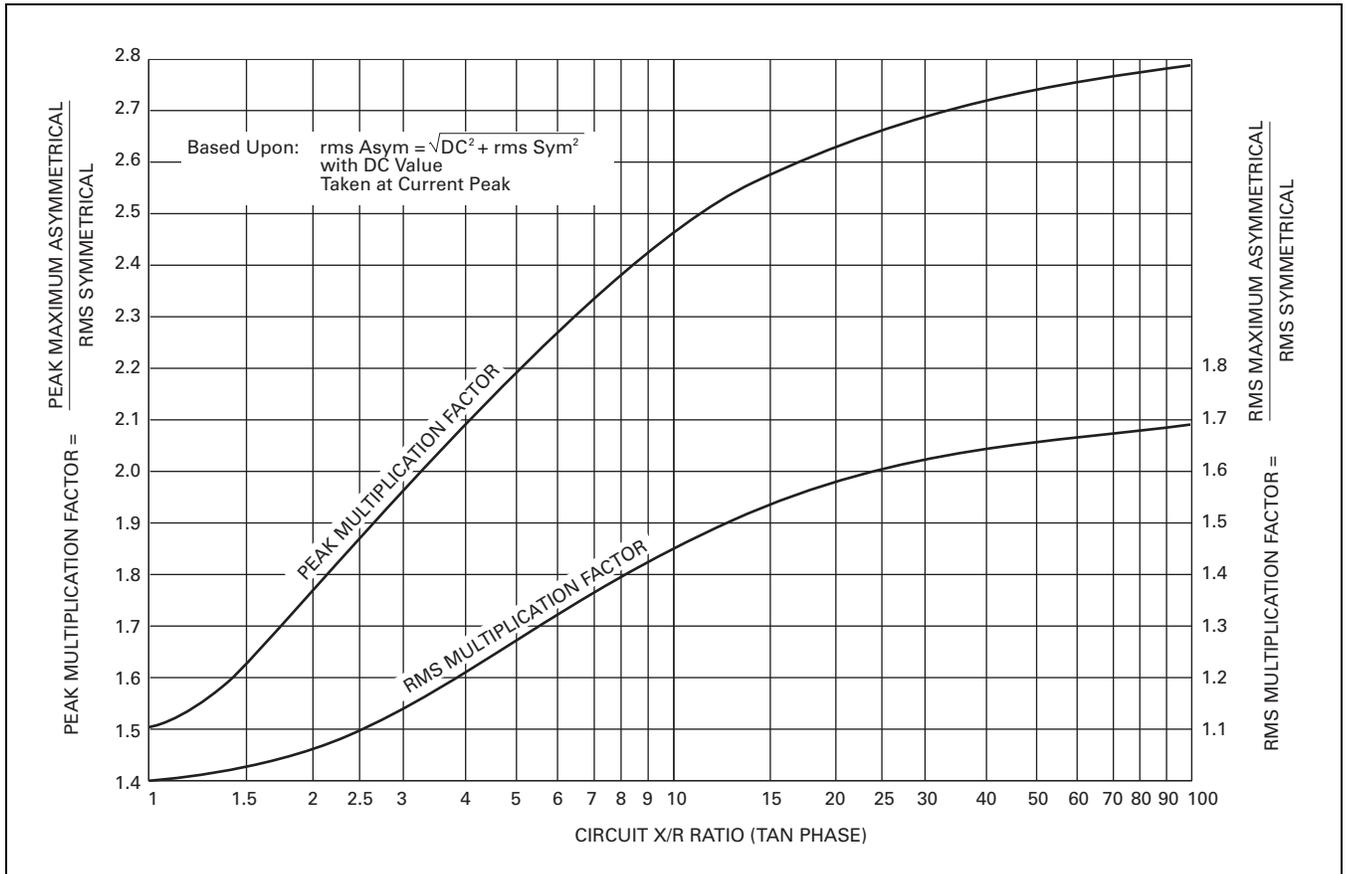


Figure 1.3-2. Relation of X/R Ratio to Multiplication Factor

Fault Current Calculations

The calculation of asymmetrical currents is a laborious procedure since the degree of asymmetry is not the same on all three phases. It is common practice for medium voltage systems, to calculate the rms symmetrical fault current, with the assumption being made that the DC component has decayed to zero, and then apply a multiplying factor to obtain the first half-cycle rms asymmetrical current, which is called the "momentary current." For medium voltage systems (defined by IEEE as greater than 1000 V up to 69,000 V) the multiplying factor is established by NEMA® and ANSI standards depending upon the operating speed of the breaker. For low voltage systems, short-circuit study software usually calculates the symmetrical fault current and the faulted system X/R ratio using ANSI guidelines. If the X/R ratio is within the standard, and the breaker interrupting current is under the symmetrical fault value, the breaker is properly rated. If the X/R ratio is higher than ANSI standards, the study applies a multiplying factor to the symmetrical calculated value (based on the X/R value of the system fault) and compares that value to the breaker symmetrical value to assess if it is properly rated. In the past, especially using manual calculations, a multiplying factor of 1.17 (based on the use of an X/R ratio of 6.6 representing a source short-circuit power factor of 15%) was used to calculate the asymmetrical current. These values take into account that medium voltage breakers are rated on maximum asymmetry and low voltage breakers are rated average asymmetry.

To determine the motor contribution during the first half-cycle fault current, when individual motor horsepower load is *known*, the subtransient reactances found in the IEEE Red Book should be used in the calculations. When the system motor load is *unknown*, the following assumptions generally are made:

Induction motors—use 4.0 times motor full load current (impedance value of 25%).

Note: For motors fed through adjustable frequency drives or solid-state soft starters, there is no contribution to fault current, unless
1) they have an internal run contactor or
2) they have a bypass contactor.

Synchronous motors—use 5.0 times motor full load current (impedance value of 20%).

When the motor load is not known, the following assumptions generally are made:

208Y/120 V Systems

- Assume 50% lighting and 50% motor load

or

- Assume motor feedback contribution of twice full load current of transformer

or

240/480/600 V Three-Phase, Three-Wire or Four-Wire Systems

- Assume 100% motor load

or

- Assume motors 25% synchronous and 75% induction

or

- Assume motor feedback contribution of four times full load current of transformer

480Y/277 V Systems in Commercial Buildings

- Assume 50% induction motor load

or

- Assume motor feedback contribution of two times full load current of transformer or source

Medium Voltage Motors

If known, use actual values otherwise use the values indicated for the same type of motor.

Calculation Methods

The following pages describe various methods of calculating short-circuit currents for both medium and low voltage systems. A summary of the types of methods and types of calculations is as follows:

- Medium voltage switchgear—exact method **Page 1.3-5**
- Medium voltage switchgear—quick check table **Page 1.3-7**
- Medium voltage switchgear Example 1—verify ratings of breakers . . . **Page 1.3-8**
- Medium voltage switchgear Example 2—verify ratings of breakers with rotating loads. **Page 1.3-9**
- Medium voltage switchgear Example 3—verify ratings of breakers with generators **Page 1.3-10**
- Medium voltage fuses—exact method . . **Page 1.3-11**
- Power breakers—asymmetry derating factors **Page 1.3-11**
- Molded-case breakers—asymmetry derating factors **Page 1.3-12**
- Short-circuit calculations—short cut method for a system **Page 1.3-13**
- Short-circuit calculations—short cut method for end of cable **Page 1.3-15**
- Short-circuit calculations—short cut method for end of cable chart method **Page 1.3-16**
- Short-circuit currents—chart of transformers 300–3750 kVA. **Page 1.5-9**

Fault Current Calculations for Specific Equipment—Exact Method

The purpose of the fault current calculations is to determine the fault current at the location of a circuit breaker, fuse or other fault interrupting device in order to select a device adequate for the calculated fault current or to check the thermal and momentary ratings of non-interrupting devices. When the devices to be used are ANSI-rated devices, the fault current must be calculated and the device selected as per ANSI standards.

The calculation of available fault current and system X/R rating is also used to verify adequate busbar bracing and momentary withstand ratings of devices such as contactors.

Medium Voltage VCP-W Metal-Clad Switchgear

The applicable ANSI Standards, C37 is the latest applicable edition. The following is a review of the meaning of the ratings. (See **Tab 5, Section 5.4.**)

The Rated Maximum Voltage

This designates the upper limit of design and operation of a circuit breaker. For example, a circuit breaker with a 4.76 kV rated maximum voltage cannot be used in a 4.8 kV system.

K-Rated Voltage Factor

The rated voltage divided by this factor determines the system kV a breaker can be applied up to the short-circuit kVA rating calculated by the formula

$$\sqrt{3} \times \text{Rated SC Current} \times \text{Rated Max. Voltage}$$

Note: Interrupting capabilities of some of today's vacuum breakers may have K = 1, whereby the interrupting current is constant across its entire operating range.

Rated Short-Circuit Current

This is the symmetrical rms value of current that the breaker can interrupt at rated maximum voltage. It should be noted that the product $\sqrt{3} \times 4.76 \times 29,000 = 239,092$ kVA is less than the nominal 250,000 kVA listed. This rating (29,000 A) is also the base quantity that all the "related" capabilities are referred to.

Maximum Symmetrical Interrupting Capability

This is expressed in rms symmetrical amperes or kiloamperes and is $K \times I$ rated; $29,000 \times 1.24 = 35,960$ rounded to 36 kA.

This is the rms symmetrical current that the breaker can interrupt down to

a voltage = maximum rated voltage divided by K (for example, $4.76/1.24 = 3.85$). If this breaker is applied in a system rated at 2.4 kV, the calculated fault current must be less than 36 kA.

For example, consider the following case:

Assume a 12.47 kV system with 20,000 A symmetrical available. In order to determine if an Eaton Type 150 VCP-W 500 vacuum breaker is suitable for this application, check the following:

From **Table 5.4-1B** in **Tab 5, Section 5.4** under column "Rated Maximum Voltage" $V = 15$ kV, under column "Rated short-circuit Current" $I = 18$ kA, "Rated Voltage Range Factor" $K = 1.3$.

Test 1 for $V/V_0 \times I$ or $15 \text{ kV}/12.47 \text{ kV} \times 18 \text{ kA} = 21.65$; also check $K \times I$ (which is shown in the column headed "Maximum Symmetrical Interrupting Capability") or $1.3 \times 18 \text{ kA} = 23.4 \text{ kA}$. Because both of these numbers are

greater than the available system fault current of 20,000 A, the breaker is acceptable (assumes the breaker's momentary and fault close rating is also acceptable).

Note: If the system available fault current were 22,000 A symmetrical, this breaker could not be used even though the "Maximum Symmetrical Interrupting Capability" is greater than 22,000 because Test 1 calculation is not satisfied.

For approximate calculations, **Table 1.3-1** provides typical values of % reactance (X) and X/R values for various rotating equipment and transformers. For simplification purposes, the transformer impedance (Z) has been assumed to be primarily reactance (X). In addition, the resistance (R) for these simplified calculations has been ignored. For detailed calculations, the values from the IEEE Red Book Standard 141, for rotating machines, and ANSI C57 and/or C37 for transformers should be used.

Table 1.3-1. Reactance X

System Component	Reactance X Used for		Typical Values and Range on Component Base	
	Short-Circuit Duty	Close and Latch (Momentary)	% Reactance	X/R Ratio
Two-pole turbo generator	X	X	9 (7–14)	80 (40–120)
Four-pole turbo generator	X	X	15 (12–17)	80 (40–120)
Hydro generator with damper wedges and synchronous condensers	X	X	20 (13–32)	30 (10–60)
Hydro generator without damper windings	0.75X	0.75X	16 (16–50)	30 (10–60)
All synchronous motors	1.5X	1.0X	20 (13–35)	30 (10–60)
Induction motors above 1000 hp, 1800 rpm and above 250 hp, 3600 rpm	1.5X	1.0X	17 (15–25)	30 (15–40)
All other induction motors 50 hp and above	3.0X	1.2X	17 (15–25)	15 (2–40)
Induction motors below 50 hp and all single-phase motors	Neglect	Neglect	—	—
Distribution system from remote transformers	X	X	As specified or calculated	15 (5–15)
Current limiting reactors	X	X	As specified or calculated	80 (40–120)

Transformers

OA to 10 MVA, 69 kV	X	X	8.0	18 (7–24)
OA to 10 MVA, above 69 kV	X	X	8.0 to 10.5 Depends on primary windings BIL rating	18 (7–24)
FOA 12–30 MVA	X	X		20 (7–30)
FOA 40–100 MVA	X	X		38 (32–44)

Table 1.3-2. Typical System X/R Ratio Range (for Estimating Purposes)

Type of Circuit	X/R Range
Remote generation through other types of circuits such as transformers rated 10 MVA or smaller for each three-phase bank, transmission lines, distribution feeders, etc.	15 or less
Remote generation connected through transformer rated 10 MVA to 100 MVA for each three-phase bank, where the transformers provide 90% or more of the total equivalent impedance to the fault point	15–40
Remote generation connected through transformers rated 100 MVA or larger for each three-phase bank where the transformers provide 90% or more of the total equivalent impedance to the fault point	30–50
Synchronous machines connected through transformers rated 25–100 MVA for each three-phase bank	30–50
Synchronous machines connected through transformers rated 100 MVA and larger	40–60
Synchronous machines connected directly to the bus or through reactors	40–120

The Close and Latch Capability

This is also a related quantity expressed in rms asymmetrical amperes by $1.6 \times$ maximum symmetrical interrupting capability. For example, $1.6 \times 36 = 57.6$ or 58 kA, or $1.6 K \times$ rated short-circuit current.

Another way of expressing the close and latch rating is in terms of the peak current, which is the instantaneous value of the current at the crest. ANSI Standard C37.09 indicates that the ratio of the peak to rms asymmetrical value for any asymmetry of 100% to 20% (percent asymmetry is defined as the ratio of DC component of the fault in per unit to $\sqrt{2}$) varies not more than $\pm 2\%$ from a ratio of 1.69. Therefore, the close and latch current expressed in terms of the peak amperes is $= 1.6 \times 1.69 \times K \times$ rated short-circuit current.

In the calculation of faults for the purposes of breaker selection, the rotating machine impedances specified in ANSI Standard C37.010 Article 5.4.1 should be used. The value of the impedances and their X/R ratios should be obtained from the equipment manufacturer. At initial short-circuit studies, data from manufacturers is not available. Typical values of impedances and their X/R ratios are given in **Table 1.3-1**.

The ANSI Standard C37.010 allows the use of the X values only in determining the E/X value of a fault current. The R values are used to determine the X/R ratio, in order to apply the proper multiplying factor, to account for the total fault clearing time, asymmetry, and decrement of the fault current.

The steps in the calculation of fault currents and breaker selection are described hereinafter:

Step 1: Collect the X and R data of the circuit elements. Convert to a common kVA and voltage base. If the reactances and resistances are given either in ohms or per unit on a different voltage or kVA base, all should be changed to the same kVA and voltage base. This caution does not apply where the base voltages are the same as the transformation ratio.

Step 2: Construct the sequence networks and connect properly for the type of fault under consideration. Use the X values required by ANSI Standard C37.010 for the "interrupting" duty value of the short-circuit current.

Step 3: Reduce the reactance network to an equivalent reactance. Call this reactance X_I .

Step 4: Set up the same network for resistance values.

Step 5: Reduce the resistance network to an equivalent resistance. Call this resistance R_I . The above calculations of X_I and R_I may be calculated by several computer programs.

Step 6: Calculate the E/X_I value, where E is the pre-fault value of the voltage at the point of fault nominally assumed 1.0 pu.

Step 7: Determine $X/R = \frac{X_I}{R_I}$ as previously calculated.

Step 8: Go to the proper curve for the type of fault under consideration (three-phase, phase-to-phase, phase-to-ground), type of breaker at the location (2, 3, 5 or 8 cycles), and contact parting time to determine the multiplier to the calculated E/X_I .

See **Figures 1.3-3, 1.3-4 and 1.3-5** for 5-cycle breaker multiplying factors. Use **Figure 1.3-5** if the short circuit is fed predominantly from generators removed from the fault by two or more

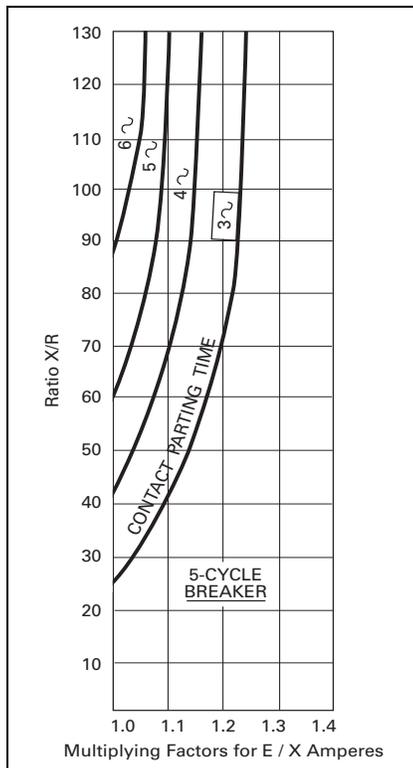


Figure 1.3-3. Three-phase Fault Multiplying Factors that Include Effects of AC and DC Decrement

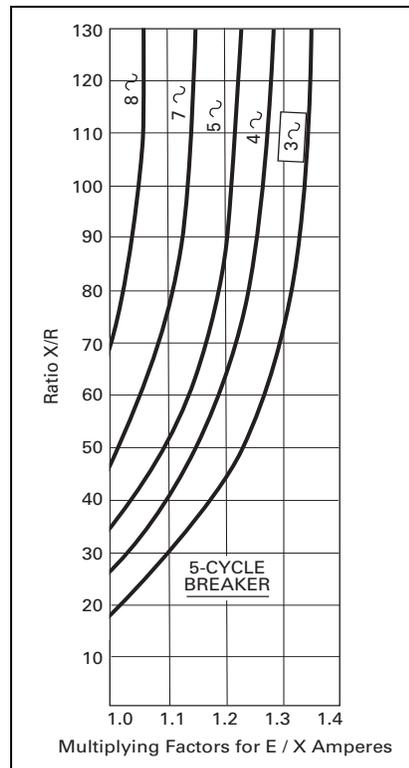


Figure 1.3-4. Line-to-Ground Fault Multiplying Factors that Include Effects of AC and DC Decrement

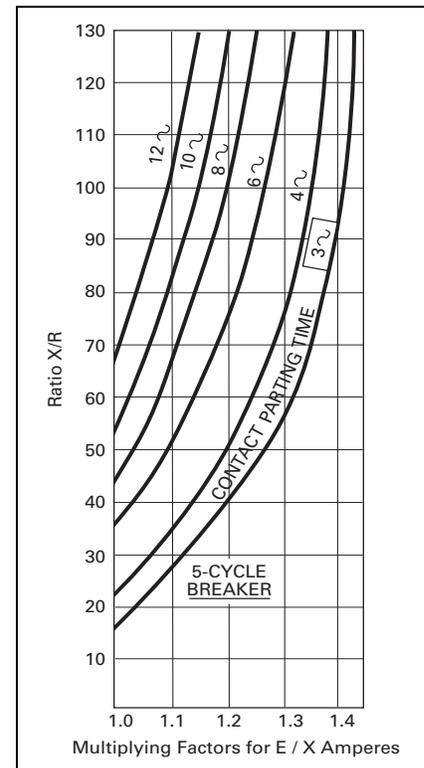


Figure 1.3-5. Three-phase and Line-to-Ground Fault Multiplying Factors that Include Effects of DC Decrement Only

transformations or the per unit reactance external to the generation is 1.5 times or more than the subtransient reactance of the generation on a common base. Also use **Figure 1.3-5** where the fault is supplied by a utility only.

Step 9: Interrupting duty short-circuit current = $E/X_1 \times MF_X = E/X_2$.

Step 10: Construct the sequence (positive, negative and zero) networks properly connected for the type of fault under consideration. Use the X values required by ANSI Standard C37.010 for the "Close and Latch" duty value of the short-circuit current.

Step 11: Reduce the network to an equivalent reactance. Call the reactance X. Calculate $E/X \times 1.6$ if the breaker close and latch capability is given in rms amperes or $E/X \times 2.7$ if the breaker close and latch capability is given in peak or crest amperes.

Step 12: Select a breaker whose:

- a. Maximum voltage rating exceeds the operating voltage of the system:
- b.
$$\frac{E}{X_2} \leq I \times \frac{V_{max}}{V_o} \leq KI$$

See **Table 6.0-1, Tab 6.**

Where:

I = Rated short-circuit current

V_{max} = Rated maximum voltage of the breaker

VD = Actual system voltage

KI = Maximum symmetrical interrupting capacity

- c. $E/X \times 1.6 \leq$ rms closing and latching capability of the breaker
and/or

$E/X \times 2.7 \leq$ Crest closing and latching capability of the breaker.

The ANSI standards do not require the inclusion of resistances in the calculation of the required interrupting and close and latch capabilities. Thus the calculated values are conservative. However, when the capabilities of existing switchgears are investigated, the resistances should be included.

For single line-to-ground faults, the symmetrical interrupting capability is 1.15 x the symmetrical interrupting capability at any operating voltage, but not to exceed the maximum symmetrical capability of the breaker.

Section 5 of ANSI C37 provides further guidance for medium voltage breaker application.

Reclosing Duty

ANSI Standard C37.010 indicates the reduction factors to use when circuit breakers are used as reclosers. Eaton VCP-W breakers are listed at 100% rating factor for reclosing.

Application Quick Check Table

For application of circuit breakers in a radial system supplied from a single source transformer. Short-circuit duty was determined using E/X amperes and 1.0 multiplying factor for X/R ratio of 15 or less and 1.25 multiplying factor for X/R ratios in the range of 15 to 40.

Application Above 3,300 ft (1,000 m)

The rated one-minute power frequency withstand voltage, the impulse withstand voltage, the continuous current rating, and the maximum voltage rating must be multiplied by the appropriate correction factors below to obtain modified ratings that must equal or exceed the application requirements.

Note: Intermediate values may be obtained by interpolation.

Table 1.3-3. Altitude Derating

Altitude in Feet (Meters)	Correction Factor	
	Current	Voltage
3300 (1006) (and below)	1.00	1.00
5000 (1524)	0.99	0.95
10,000 (3048)	0.96	0.80

Table 1.3-4. Application Quick Check Table

Source Transformer MVA Rating	Operating Voltage kV						
	Motor Load		2.4	4.16	6.6	12	13.8
	100%	0%					
1	1.5	50 VCP-W 250 12 kA	50 VCP-W 250 10.1 kA	150 VCP-W 500 23 kA	150 VCP-W 500 22.5 kA	150 VCP-W 500 19.6 kA	
1.5	2						
2	2.5						
2.5	3						
3	3.75						
3.75	5						
5	7.5						
7.5	10						
10 ①	10						
10	12 ①						
12	15	50 VCP-W 350 46.9 kA	75 VCP-W 500 41.3 kA				
15	20	Breaker Type and symmetrical interrupting capacity at the operating voltage				150 VCP-W 750 35 kA	150 VCP-W 750 30.4 kA
20 ①	20					150 VCP-W 1000 46.3 kA	150 VCP-W 1000 40.2 kA
	25						
	30						
	50 ①						

① Transformer impedance 6.5% or more, all other transformer impedances are 5.5% or more.

Application on Symmetrical Current Rating Basis

Example 1—Fault Calculations

Given a circuit breaker interrupting and momentary rating in the table below, verify the adequacy of the ratings for a system without motor loads, as shown.

Table 1.3-5. Short-Circuit Duty

Type Breaker	V Max.	Three-Phase Symmetrical Interrupting Capability			Close and Latch or Momentary
		at V Max.	Max. KI	at 4.16 kV Oper. Voltage	
50VCP-W250	4.76 kV	29 kA	36 kA	$\left[\frac{4.76}{4.16}\right] (29) = 33.2 \text{ kA } I_1$	58 kA I_3
		LG symmetrical interrupting capability			
		—	36 kA	$1.15 (33.2) = 38.2 \text{ kA } I_2$	

Note: Interrupting capabilities I_1 and I_2 at operating voltage must not exceed maximum symmetrical interrupting capability KI.

Check capabilities I_1 , I_2 and I_3 on the following utility system where there is no motor contribution to short circuit.

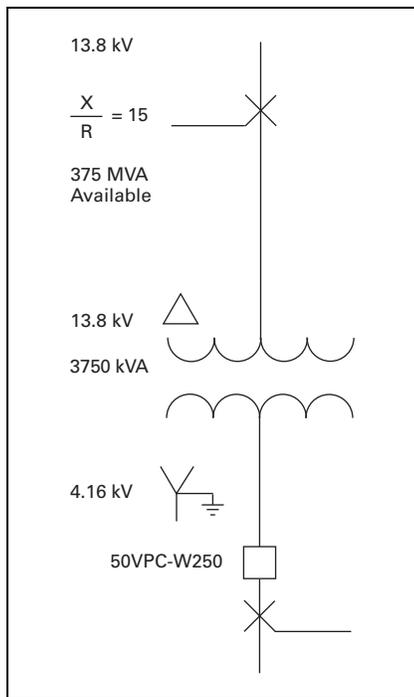


Figure 1.3-6. Example 1—One-Line Diagram

From transformer losses per unit or percent R is calculated

31,000 Watts Full Load
 - 6,800 Watts No Load
 24,200 Watts Load Losses

$$R = \frac{24.2 \text{ kW}}{3750 \text{ kVA}} = 0.0065 \text{ pu or } 0.65\%$$

$$\text{Transformer } X = \sqrt{Z^2 - R^2} = \sqrt{(5.09)^2 - (0.65)^2} = \sqrt{25.91 - 0.42} = \sqrt{25.48}$$

$$X = 5.05\%$$

	X	R	X/R
13.8 kV System	0.99%	0.066%	15
Transformer	5.05%	0.65%	8
System Total	6.04%	0.716%	9
or	0.0604 pu	0.00716 pu	

On 13.8 kV System, 3.75 MVA Base

$$Z = \frac{3.75 \text{ MVA}}{375 \text{ MVA}} = 0.01 \text{ pu or } 1\%$$

$$Z^2 = X^2 + R^2 = R^2 \left(\frac{X^2}{R^2} + 1 \right)$$

$$R = \frac{Z}{\sqrt{\frac{X^2}{R^2} + 1}} = \frac{1}{\sqrt{266}} = \frac{1}{15.03} = 0.066\%$$

$$X = \frac{X}{R} (R) = 15 (0.066) = .99\%$$

Transformer Standard 5.5% Impedance has a $\pm 7.5\%$ Manufacturing Tolerance

$$\text{Transformer } Z = \frac{5.50 \text{ Standard Impedance} - 0.41 (-7.5\% \text{ Tolerance})}{5.09\%}$$

For Three-Phase Fault

$$I_{3\text{-Phase}} = \frac{E}{X}$$

where X is ohms per phase and E is the highest typical line-to-neutral operating voltage or

$$I_{3\text{-Phase}} = \frac{I_B}{X}$$

where X is per unit reactance

I_B is base current

$$\text{Base current } I_B = \frac{3.75 \text{ MVA}}{\sqrt{3}(4.16 \text{ kV})} = 0.52 \text{ kA}$$

$$I_{3\text{-Phase}} = \frac{I_1}{X} = \frac{0.52}{0.0604} = 8.6 \text{ kA Sym.}$$

System $\frac{X}{R} = 9$ (is less than 15)

would use 1.0 multiplying factor for short-circuit duty, therefore, short-circuit duty is 8.6 kA sym. for three-phase fault I_1 and momentary duty is $8.6 \times 1.6 = 13.7 \text{ kA } I_3$.

For Line-to-Ground Fault

$$I_{LG} = \frac{3E}{2X_1 + X_0} = \frac{3I_B}{2X_1 + X_0}$$

For this system, X_0 is the zero sequence reactance of the transformer, which is equal to the transformer positive sequence reactance and X_1 is the positive sequence reactance of the system.

Therefore,

$$I_{LG} = \frac{3(0.52)}{2(0.0604) + 0.0505} = 9.1 \text{ kA Sym.}$$

Using 1.0 multiplying factor (see **Table 1.3-6**), short-circuit duty = 9.1 kA Sym. LG (I_2)

Answer

The 50VCP-W250 breaker capabilities exceed the duty requirements and may be applied.

With this application, shortcuts could have been taken for a quicker check of the application. If we assume unlimited short circuit available at 13.8 kV and that Trans. $Z = X$

$$\text{Then } I_{3\text{-Phase}} = \frac{I_B}{X} = \frac{0.52}{0.055} = 9.5 \text{ kA Sym.}$$

X/R ratio 15 or less multiplying factor is 1.0 for short-circuit duty.

The short-circuit duty is then 9.5 kA Sym. (I_1 , I_2) and momentary duty is $9.5 \times 1.6 \text{ kA} = 15.2 \text{ kA } (I_3)$.

Example 2—Fault Calculations

Given the system shown with motor loads, calculate the fault currents and determine proper circuit breaker selection.

All calculations on per unit basis.
7.5 MVA base

$$\text{Base Current } I_B = \frac{7.5 \text{ MVA}}{\sqrt{3} \cdot 6.9 \text{ kV}} = 0.628 \text{ kA}$$

	X	R	X/R
13.8 kV System			
$X = \frac{0.628 (6.9)}{21 (13.8)}$	0.015	0.015	0.001
Transformer	0.055	0.0055	10
Total Source Transformer	0.070 pu	0.0065 pu	11

3000 hp Synchronous Motor

$$X = 0.20 \left(\frac{0.628}{0.197} \right) = 0.638 \text{ pu at 7.5 MVA Base}$$

2500 hp Ind. Motor

$$X = 0.25 \left(\frac{0.628}{0.173} \right) = 0.908 \text{ pu at 7.5 MVA Base}$$

$$I_{3-Ph} = \frac{E}{X} = \frac{I_B}{X} \text{ where X on per unit base}$$

Table 1.3-6. Multiplying Factor for E/X Amperes (ANSI C37.010, 1979, Figures 1.1-8, 1.1-9 and 1.1-10)

System X/R	Type VCP-W Vacuum Circuit Breaker Rated Interrupting Time, 5-Cycle		
	Type of Fault		
Ratio	Three-Phase	LG	Three-Phase and LG
	Source of Short Circuit		
	Local	Remote	
1	1.00	1.00	1.00
15 ①	1.00	1.00	1.00
20	1.00	1.02	1.05
25	1.00	1.06	1.10
30	1.04	1.10	1.13
36	1.06	1.14	1.17
40	1.08	1.16	1.22
45	1.12	1.19	1.25
50	1.13	1.22	1.27
55	1.14	1.25	1.30
60	1.16	1.26	1.32
65	1.17	1.28	1.33
70	1.19	1.29	1.35
75	1.20	1.30	1.36
80	1.21	1.31	1.37
85	—	—	1.38
90	1.22	1.32	1.39
95	—	—	1.40
100	1.23	1.33	1.41
100	1.24	1.34	1.42
120	1.24	1.35	1.43
130	1.24	1.35	1.43

① Where system X/R ratio is 15 or less, the multiplying factor is 1.0.

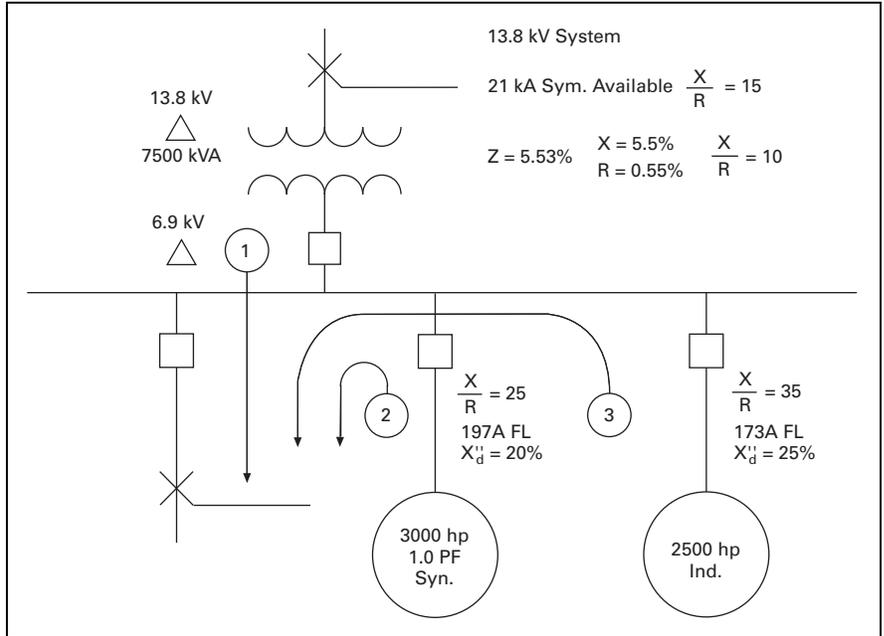


Figure 1.3-7. Example 2—One-Line Diagram

Source of Short-Circuit Current	Interrupting E/X Amperes	Momentary E/X Amperes	X/R	X (1) / R (X)	1/R
I_3 Source Transformer	$\frac{0.628}{0.070} = 8.971$	$\frac{0.628}{0.070} = 8.971$	11	$\frac{11}{0.070}$	= 157
I_1 3000 hp Syn. Motor	$\frac{0.628}{(1.5) 0.638} = 0.656$	$\frac{0.628}{0.638} = 0.984$	25	$\frac{25}{0.638}$	= 39
I_1 2500 hp Syn. Motor	$\frac{0.628}{(1.5) 0.908} = 0.461$	$\frac{0.628}{0.908} = 0.691$	35	$\frac{35}{0.908}$	= 39
$I_{3F} = \frac{10.088}{\text{or } 10.1 \text{ kA}}$			Total 1/R = 235		
			$\frac{10.647}{\times 1.6}$ 17.0 kA Momentary Duty		

$$\text{Total X} = \frac{I_B}{I_{3F}} = \frac{0.628}{10.1} = 0.062$$

System $\frac{X}{R} = 0.062 (235) = 14.5$ is a Multiplying Factor of 1.0 from **Table 1.3-6**

Table 1.3-7. Short-Circuit Duty = 10.1 kA

Breaker Type	V Max.	Three-Phase Symmetrical Interrupting Capability			Close and Latch or Momentary
		at V Max.	Max. KI	at 6.9 kV Oper. Voltage	
75VCP-W500	8.25 kV	33 kA	41 kA	$\frac{8.25}{6.9} (33) = 39.5 \text{ kA}$	66 kA
150VCP-W500	15 kV	18 kA	23 kA	$\frac{15 (18)}{6.9} (39.1) = 23 \text{ kA}$ (But not to exceed KI)	37 kA

Answer

Either breaker could be properly applied, but price will make the type 150VCP-W500 the more economical selection.

Example 3—Fault Calculations

Check breaker application or generator bus for the system of generators shown.

Each generator is 7.5 MVA, 4.16 kV 1040 A full load, $I_B = 1.04$ kA

Sub transient reactance $X_d'' = 11\%$ or, $X = 0.11$ pu

1

Gen $\frac{X}{R}$ ratio is 30

$$\frac{1}{X_S} = \frac{1}{X} + \frac{1}{X} + \frac{1}{X} = \frac{3}{X} \text{ and } \frac{1}{R_S} = \frac{1}{R} + \frac{1}{R} + \frac{1}{R} = \frac{3}{R}$$

or $X_S = \frac{X}{3}$ and $R_S = \frac{R}{3}$ Therefore, System $\frac{X_S}{R_S} = \frac{X}{R} = \text{Gen } \frac{X}{R} = 30$

Since generator neutral grounding reactors are used to limit the I_{LG} to $I_{3\text{-phase}}$ or below, we need only check the I_3 short-circuit duty.

$$I_{B\text{Phase}} = \frac{I_B}{X} + \frac{I_B}{X} + \frac{I_B}{X} + \frac{3I_B}{X} = \frac{3(1.04)}{0.11} = 28.4 \text{ kA Symmetrical E/X amperes}$$

System $\frac{X}{R}$ of 30 is a Multiplying Factor of 1.04 from **Table 1.3-6**.

Short-circuit duty is $28.4 (1.04) = 29.5$ kA Symmetrical

Three-Phase Symmetrical Interrupting Capability

Breaker Type	V Max.	at V Max.	Max. KI	at 4.16 kV Oper. Voltage
50VCP-W250	4.76 kV	29 kA	36 kA	4.76 4.16 (29) = 33.2 kA

Answer

The 50VCP-W250 breaker could be applied.

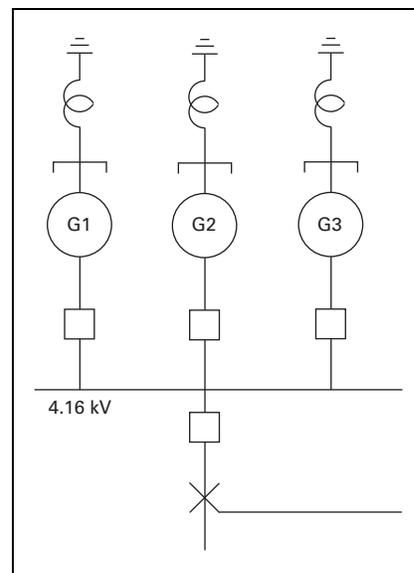


Figure 1.3-8. Example 3—One-Line Diagram

Medium Voltage Fuses— Fault Calculations

There are two basic types of medium voltage fuses. The following definitions are taken from ANSI Standard C37.40.

Expulsion Fuse (Unit)

A vented fuse (unit) in which the expulsion effect of the gases produced by internal arcing, either alone or aided by other mechanisms, results in current interruption.

Current-Limiting Fuse (Unit)

A fuse unit that, when its current-responsive element is melted by a current within the fuse's specified current-limiting range, abruptly introduces a high resistance to reduce current magnitude and duration, resulting in subsequent current interruption.

There are two classes of fuses; power and distribution. They are distinguished from each other by the current ratings and minimum melting type characteristics.

The current-limiting ability of a current-limiting fuse is specified by its threshold ratio, peak let-through current and I^2t characteristics.

Interrupting Ratings of Fuses

Modern fuses are rated in amperes rms symmetrical. They also have a listed asymmetrical rms rating that is 1.6 x the symmetrical rating.

Refer to ANSI/IEEE C37.48 for fuse interrupting duty guidelines.

Calculation of the Fuse Required Interrupting Rating:

Step 1—Convert the fault from the utility to percent or per unit on a convenient voltage and kVA base.

Step 2—Collect the X and R data of all the other circuit elements and convert to a percent or per unit on a convenient kVA and voltage base same as that used in Step 1. Use the subtransient X and R for all generators and motors.

Step 3—Construct the sequence networks using reactances and connect properly for the type of fault under consideration and reduce to a single equivalent reactance.

Step 4—Construct the sequence networks using resistances and connect properly for the type of fault under consideration and reduce to a single equivalent resistance.

Step 5—Calculate the E/X_1 value, where E is the prefault value of the voltage at the point of fault normally assumed 1.0 in pu. For three-phase faults E/X_1 is the fault current to be used in determining the required interrupting capability of the fuse.

Note: It is not necessary to calculate a single phase-to-phase fault current. This current is very nearly $\sqrt{3}/2$ x three-phase fault. The line-to-ground fault may exceed the three-phase fault for fuses located in generating stations with solidly grounded neutral generators, or in delta-wye transformers with the wye solidly grounded, where the sum of the positive and negative sequence impedances on the high voltage side (delta) is smaller than the impedance of the transformer.

For single line-to-ground fault:

$$X_1 = X_{1(+)} + X_{1(-)} + X_{1(0)}$$

$$I_f = \frac{E}{X_1} \times 3$$

Step 6—Select a fuse whose published interrupting rating exceeds the calculated fault current.

Figure 1.3-2 should be used where older fuses asymmetrically rated are involved.

The voltage rating of power fuses used on three-phase systems should equal or exceed the maximum line-to-line voltage rating of the system. Current limiting fuses for three-phase systems should be so applied that the fuse voltage rating is equal to or less than 1.41 x nominal system voltage.

Low Voltage Power Circuit Breakers—Fault Calculations

The steps for calculating the fault current for the selection of a low voltage power circuit breaker are the same as those used for medium voltage circuit breakers except that where the connected loads to the low voltage bus

includes induction and synchronous motor loads. The assumption is made that in 208Y/120 V systems the contribution from motors is two times the full load current of step-down transformer. This corresponds to an assumed 50% motor aggregate impedance on a kVA base equal to the transformer kVA rating or 50% motor load. For 480 V, 480Y/277 V and 600 V systems, the assumption is made that the contribution from the motors is four times the full load current of the step-down transformer, which corresponds to an assumed 25% aggregate motor impedance on a kVA base equal to the transformer kVA rating or 100% motor load.

In low voltage systems that contain generators, the subtransient reactance should be used.

If the X/R to the point of fault is greater than 6.6, a derating multiplying factor (MF) must be applied. The X/R ratio is calculated in the same manner as that for medium voltage circuit breakers.

Calculated symmetrical amperes x MF δ breaker interrupting rating.

The multiplying factor MF can be calculated by the formula:

$$MF = \frac{\sqrt{2}[1 + 2.718^{-(\pi)/(X/R)}]}{2.29}$$

If the X/R of system feeding the breaker is not known, use X/R = 15.

For fused breakers by the formula:

$$MF = \frac{\sqrt{1 + 2 \times (2.718)^{-(2\pi)/(X/R)}}}{1.25}$$

If the X/R of the system feeding the breaker is not known, use X/R = 20.

Refer to **Table 1.3-8** for the standard ranges of X/R and power factors used in testing and rating low voltage breakers. Refer to **Table 1.3-9** for the circuit breaker interrupting rating multiplying factors to be used when the calculated X/R ratio or power factor at the point the breaker is to be applied in the power distribution system falls outside of the **Table 1.3-8** X/R or power factors used in testing and rating the circuit breakers. MF is always greater than 1.0.

Molded-Case Breakers and Insulated Case Circuit Breakers—Fault Calculations

The method of fault calculation is the same as that for low voltage power circuit breakers. Again, the calculated fault current x MF ÷ breaker interrupting capacity. Because molded case breakers are tested at lower X/R ratios, the MFs are different than those for low voltage power circuit breakers.

$$MF = \frac{1 + 2.718^{-\pi/\left(\frac{X_2}{R_2}\right)}}{1 + 2.718^{-\pi/\left(\frac{X_1}{R_1}\right)}}$$

$X_1 \cdot R_1$ = test X/R value

$X_2 \cdot R_2$ = X/R at point where breaker is applied

Low Voltage Circuit Breaker Interrupting Derating Factors

Refer to **Table 1.3-8** for the standard ranges of X/R and power factors used in testing and rating low voltage breakers. Refer to **Table 1.3-9** for the circuit breaker interrupting rating de-rating factors to be used when the calculated X/R ratio or power factor at the point the breaker is to be applied in the power distribution system falls outside of the **Table 1.3-8** X/R or power factors used in testing and rating the circuit breakers.

Normally the short-circuit power factor or X/R ratio of a distribution system need not be considered in applying low voltage circuit breakers. This is because the ratings established in the applicable standard are based on power factor values that apply cover most applications.

Established standard values include the following:

Table 1.3-8. Standard Test Power Factors

Interrupting Rating in kA	Power Factor Test Range	X/R Test Range
Molded Case Circuit Breaker		
10 or Less	0.45–0.50	1.98–1.73
Over 10 to 20	0.25–0.030	3.87–3.18
Over 20	0.15–0.20	6.6–4.9
Low Voltage Power Circuit Breaker		
All	0.15 Maximum	6.6 Minimum

For distribution systems where the calculated short-circuit current X/R ratio differs from the standard values given in the above table, circuit breaker interrupting rating derating factors from **Table 1.3-9** table should be applied.

Table 1.3-9. Circuit Breaker Interrupting Rating Derating Factors

% P.F.	X/R	Interrupting Rating				
		Molded Case or Insulated Case			Power Circuit Breaker	
		≤/ = 10 kA	>10 kA ≤/ = 20 kA	>20 kA	Unfused	Fused
50	1.73	1.000	1.000	1.000	1.000	1.000
30	3.18	0.847	1.000	1.000	1.000	1.000
25	3.87	0.805	0.950	1.000	1.000	1.000
20	4.90	0.762	0.899	1.000	1.000	1.000
15	6.59	0.718	0.847	0.942	1.000	0.939
12	8.27	0.691	0.815	0.907	0.962	0.898
10	9.95	0.673	0.794	0.883	0.937	0.870
8.5	11.72	0.659	0.778	0.865	0.918	0.849
7	14.25	0.645	0.761	0.847	0.899	0.827
5	19.97	0.627	0.740	0.823	0.874	0.797

Note: These are derating factors applied to the breaker and are the inverse of MF.

Short-Circuit Calculations—Shortcut Method

Determination of Short-Circuit Current

Note 1: Transformer impedance generally relates to self-ventilated rating (e.g., with OA/FA/FOA transformer use OA base).

Note 2: kV refers to line-to-line voltage in kilovolts.

Note 3: Z refers to line-to-neutral impedance of system to fault where $R + jX = Z$.

Note 4: When totaling the components of system Z, arithmetic combining of impedances as “ohms Z,” “per unit Z,” etc., is considered a shortcut or approximate method; proper combining of impedances (e.g., source, cables transformers, conductors, etc.) should use individual R and X components. This Total Z = Total R + j Total X (see IEEE “Red Book” Standard No. 141).

1

1. Select convenient kVA base for system to be studied.
2. Change per unit, or percent, impedance from one kVA base to another:
 - (a) Per unit = pu impedance kVA base 2 = $\frac{\text{kVA base 2}}{\text{kVA base 1}} \times (\text{pu impedance on kVA base 1})$
 - (b) Percent = % impedance kVA base 2 = $\frac{\text{kVA base 2}}{\text{kVA base 1}} \times (\% \text{ impedance on kVA base 1})$
3. Change ohms, or percent or per unit, etc.:
 - (a) Per unit impedance = pu Z = $\frac{\text{percent impedance}}{100} = \frac{(\text{ohms impedance})(\text{kVA base})}{(\text{kV})^2 (1000)}$
 - (b) % impedance = % Z = $\frac{(\text{ohms impedance})(\text{kVA base})}{(\text{kV})^2 (10)}$
 - (c) Ohms impedance = $\frac{(\% \text{ impedance})(\text{kV})^2 (10)}{\text{kVA base}}$
4. Change power-source impedance to per unit or percent impedance on kVA base as selected for this study:
 - (a) —if utility fault capacity given in kVA
Per-unit impedance = pu Z = $\frac{\text{kVA base in study}}{\text{power-source kVA fault capacity}}$
 - (b) —if utility fault capacity given in rms symmetrical short circuit amperes
Per-unit impedance = pu Z = $\frac{\text{kVA base in study}}{(\text{short-circuit current})(\sqrt{3})(\text{kV of source})}$
5. Change motor rating to kVA:
 - (a) —motor kVA = $(\sqrt{3})(\text{kV})(\text{I})$ where I = motor nameplate full-load amperes
 - (b) —if 1.0 power factor synchronous motor kVA = (0.8) (hp)
 - (c) —if 0.8 power factor synchronous motor kVA = (1.0) (hp)
 - (d) —if induction motor kVA = (1.0) (hp)
6. Determine symmetrical short-circuit current:
 - (a) Base current = I Base = $\frac{\text{Three-phase kVA}}{(\sqrt{3})(\text{kV})}$ or $\frac{\text{Single-phase kVA}}{\text{kV line-to-neutral}}$
 - (b) Per unit $I_{SC} = \frac{1.0}{\text{puZ}}$
 - (c) rms Symmetrical current = $I_{SC} = (\text{pu } I_{SC})(I_{\text{Base}} \text{ Amperes})$
 - (d) rms Symmetrical current = Amperes = $\frac{\text{Three-phase KVA base}}{(\text{puZ})(\sqrt{3})(\text{kV})}$ or $\frac{\text{Single-phase KVA base}}{(\text{puZ})(\text{kV})}$
 - (e) = $\frac{(\text{Three-phase kVA base})(100)}{(\%Z)(\sqrt{3})(\text{kV})}$ or $\frac{\text{Single-phase kVA base}(100)}{(\%Z)(\text{kV})}$
 - (g) = $\frac{(\text{kV})(1000)}{\sqrt{3}(\text{ohms } Z)}$
7. Determine symmetrical short-circuit kVA:
 - (a) Symmetrical short-circuit kVA = $\frac{\text{kVA base}}{(\text{puZ})} = \frac{(\text{kVA base})(100)}{\%Z} = \frac{(\text{kV})^2(1000)}{\text{ohms } Z}$
 - (b) = $\frac{3(\text{line-to-neutral kV})^2(1000)}{(\text{ohms } Z)}$
8. Determine line-to-line short-circuit current:
 - (a) —from three-phase transformer—approx. 86% of three-phase current
 - (b) —three single-phase transformers (e.g., 75 kVA, Z = 2%) calculate same as one three-phase unit (i.e., 3 x 75 kVA = 225 kVA, Z = 2%).
 - (c) —from single-phase transformer—see **Page 1.3-15**.
9. Determine motor contribution (or feedback) as source of fault current:
 - (a) —synchronous motor—5 times motor full load current (impedance 20%)
 - (b) —induction motor—4 times motor full-load current (impedance 25%)
 - (c) —motor loads not individually identified, use contribution from group of motors as follows:
 - on 208Y/120 V systems—2.0 times transformer full-load current
 - on 240-480-600 V three-phase, three-wire systems—4.0 times transformer full-load current
 - on 480Y/277 V three-phase, four-wire systems
 - In commercial buildings, 2.0 times transformers full-load current (50% motor load)
 - In industrial plants, 4.0 times transformer full-load current (100% motor load)

} See IEEE Standard No. 141

Example Number 1

How to Calculate Short-Circuit Currents at Ends of Conductors

1

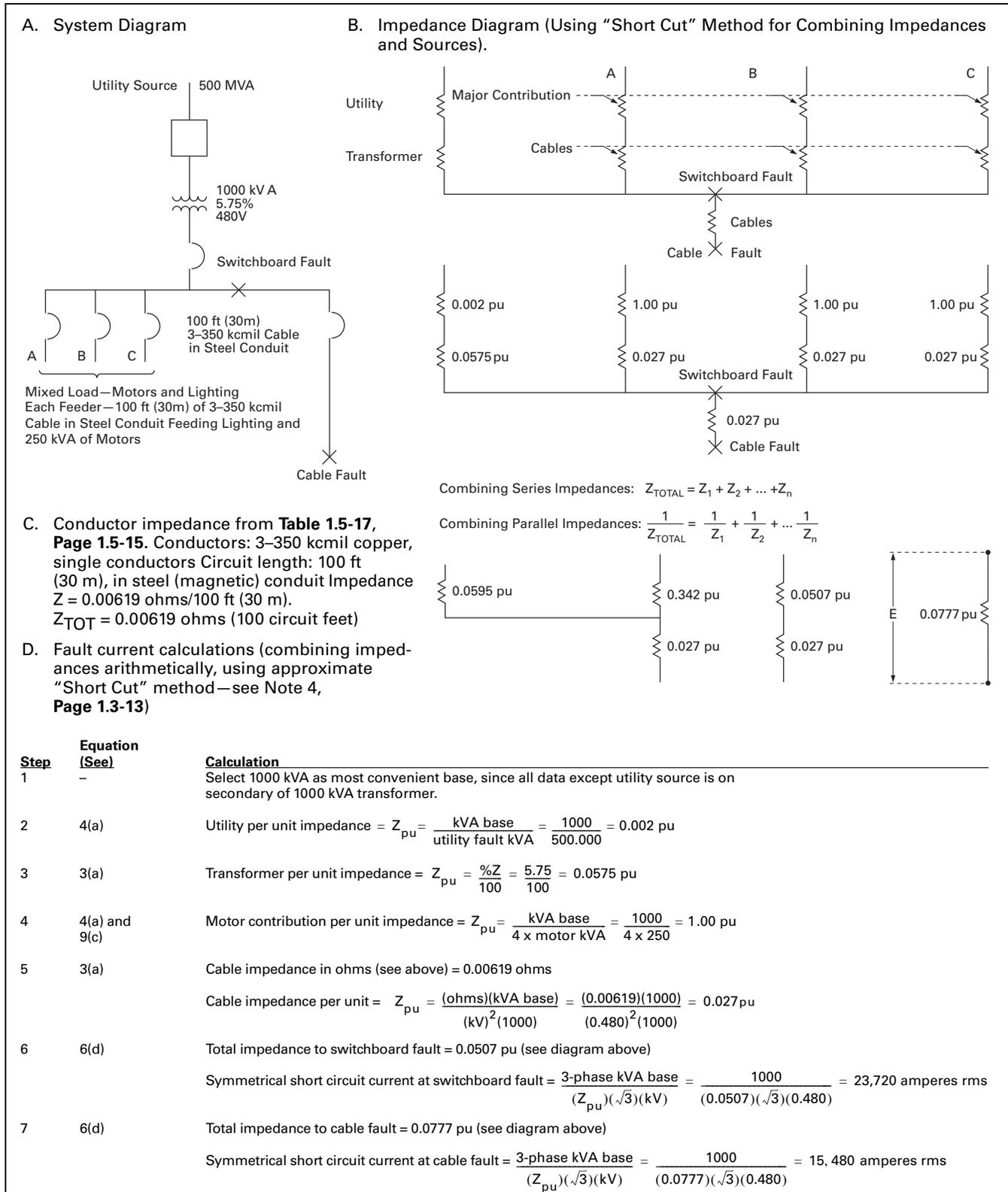


Figure 1.3-9. Example Number 1

Example Number 2

Fault Calculation—Secondary Side of Single-Phase Transformer

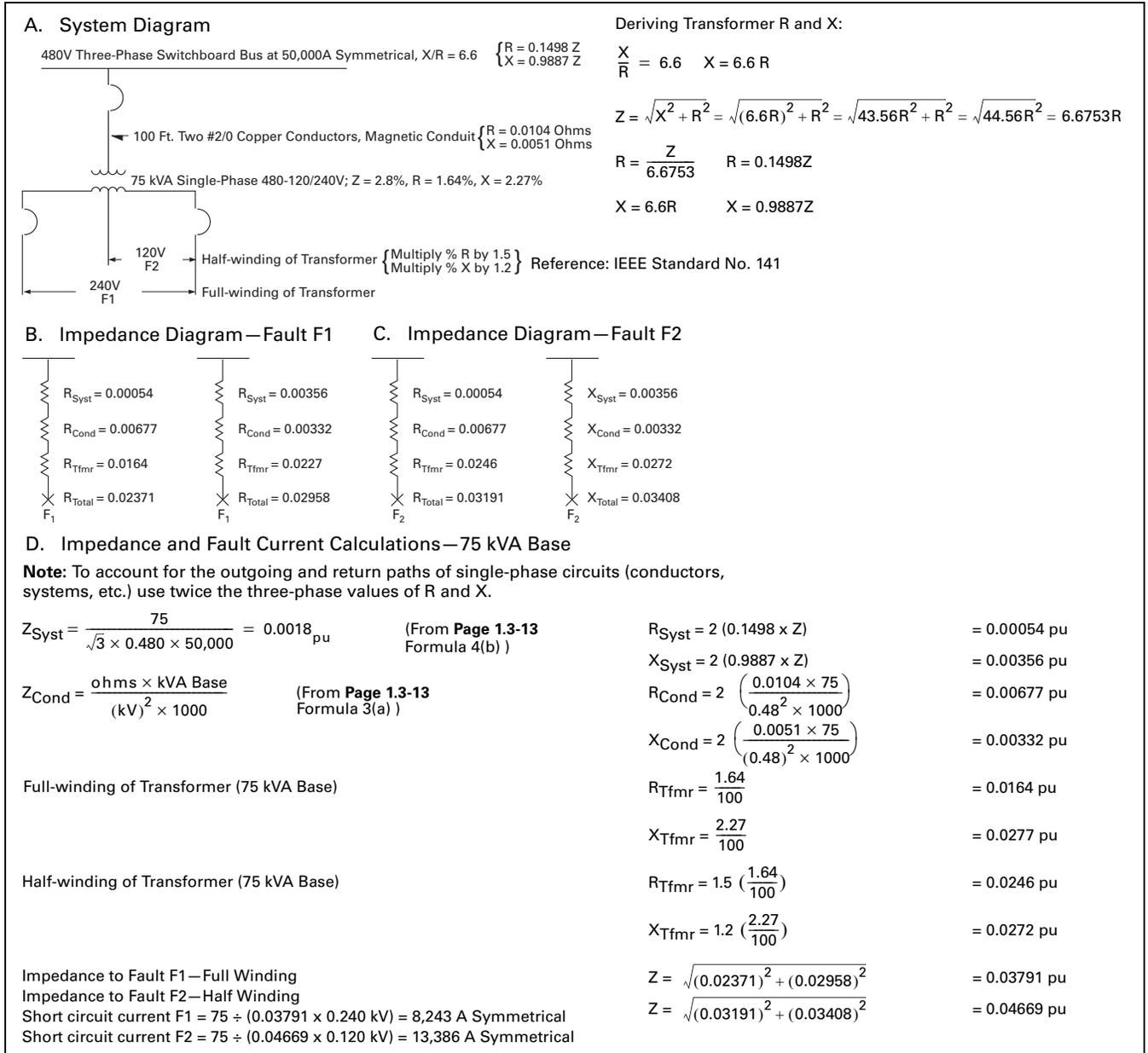


Figure 1.3-10. Example Number 2

Method 1: Shortcut Methods—End of Cable

This method uses the approximation of adding Zs instead of the accurate method of Rs and Xs.

For Example: For a 480/277 V system with 30,000 A symmetrical available at the line side of a conductor run of 100 ft (30 m) of 2–500 kcmil per phase and neutral, the approximate fault current

at the load side end of the conductors can be calculated as follows.

277 V/30,000 A = 0.00923 ohms (source impedance)

Conductor ohms for 500 kcmil conductor from reference data in this section in magnetic conduit is 0.00551 ohms per 100 ft (30 m). For 100 ft (30 m) and two conductors per phase we have:

0.00551/2 = 0.00273 ohms (conductor impedance)

Add source and conductor impedance or 0.00923 + 0.00273 = 0.01196 total ohms

Next, 277 V/0.01196 ohms = 23,160 A rms at load side of conductors

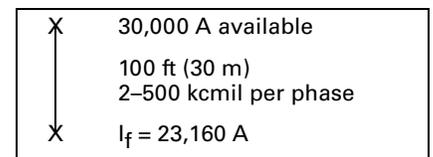


Figure 1.3-11. Short-Circuit Diagram

Method 2: Chart Approximate Method

The chart method is based on the following:

Motor Contribution

For system voltages of 120/208 V, it is reasonable to assume that the connected load consists of 50% motor load, and that the motors will contribute four times their full load current into a fault. For system voltages of 240 and 480 V, it is reasonable to assume that the connected load consists of 100% motor load, and that the motors will contribute four times their full load current into a fault. These motor contributions have been factored into each curve as if all motors were connected to the transformer terminals.

Feeder Conductors

The conductor sizes most commonly used for feeders from molded case circuit breakers are shown. For conductor sizes not shown, the following table has been included for conversion to equivalent arrangements. In some cases it may be necessary to interpolate for unusual feeder ratings. **Table 1.3-10** is based on using copper conductor.

Table 1.3-10. Conductor Conversion (Based on Using Copper Conductor)

If Your Conductor is:	Use Equivalent Arrangement
3-No. 4/0 cables 4-No. 2/0 cables	2-500 kcmil
3-2000 kcmil cables 5-400 kcmil cables 6-300 kcmil cables	4-750 kcmil
800 A busway 1000 A busway 1600 A busway	2-500 kcmil 2-500 kcmil 4-750 kcmil

Short-Circuit Current Readout

The readout obtained from the charts is the rms symmetrical amperes available at the given distance from the transformer. The circuit breaker should have an interrupting capacity at least as large as this value.

How to Use the Short-Circuit Charts**Step One**

Obtain the following data:

1. System voltage
2. Transformer kVA rating (from transformer nameplate)
3. Transformer impedance (from transformer nameplate)
4. Primary source fault energy available in kVA (from electric utility or distribution system engineers)

Step Two

Select the applicable chart from the following pages. The charts are grouped by secondary system voltage, which is listed with each transformer. Within each group, the chart for the lowest kVA transformer is shown first, followed in ascending order to the highest rated transformer.

Step Three

Select the family of curves that is closest to the "available source kVA." The black line family of curves is for a source of 500,000 kVA. The lower value line (in red) family of curves is for a source of 50,000 kVA. You may interpolate between curves if necessary, but for values above 100,000 kVA it is appropriate to use the 500,000 kVA curves.

Step Four

Select the specific curve for the conductor size being used. If your conductor size is something other than the sizes shown on the chart, refer to the conductor conversion **Table 1.3-10**.

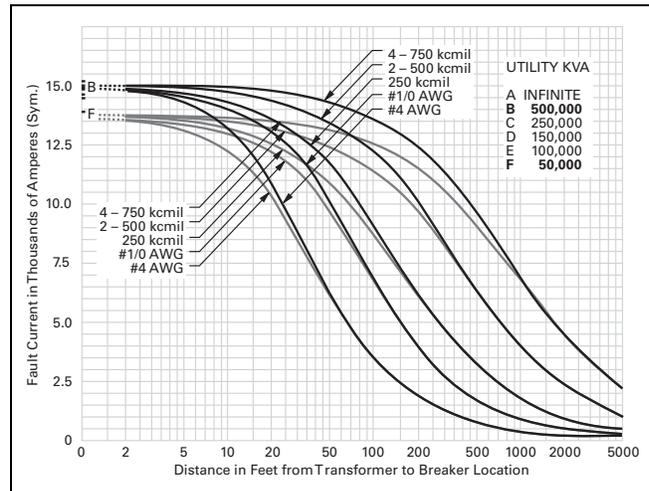
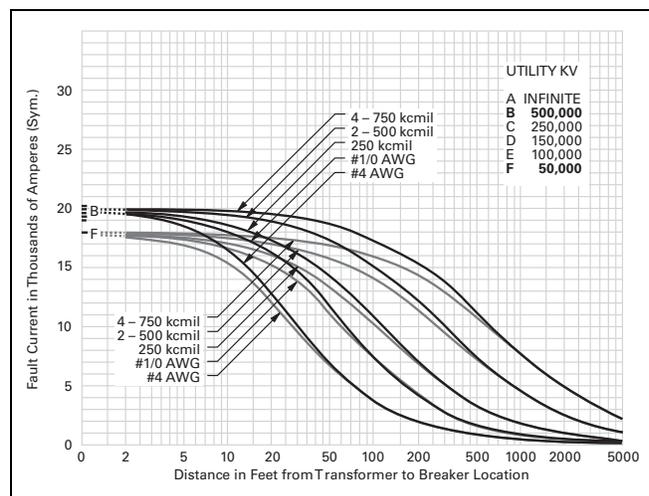
Step Five

Enter the chart along the bottom horizontal scale with the distance (in feet) from the transformer to the fault point. Draw a vertical line up the chart to the point where it intersects the selected curve. Then draw a horizontal line to the left from this point to the scale along the left side of the chart.

Step Six

The value obtained from the left-hand vertical scale is the fault current (in thousands of amperes) available at the fault point.

For a more exact determination, see the formula method. It should be noted that even the most exact methods for calculating fault energy use some approximations and some assumptions. Therefore, it is appropriate to select a method which is sufficiently accurate for the purpose, but not more burdensome than is justified. The charts that follow make use of simplifications that are reasonable under most circumstances and will almost certainly yield answers that are on the safe side. This may, in some cases, lead to application of circuit breakers having interrupting ratings higher than necessary, but should eliminate the possibility of applying units which will not be safe for the possible fault duty.

**Figure 1.3-12. 225 kVA Transformer/4.5% Impedance/208 V****Figure 1.3-13. 300 kVA Transformer/4.5% Impedance/208 V**

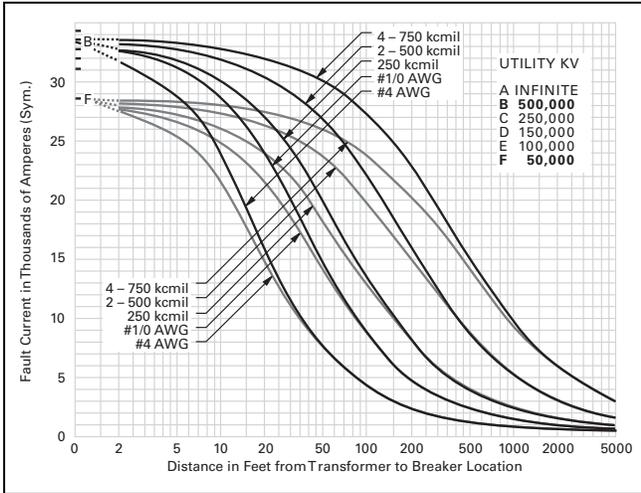


Figure 1.3-14. 500 kVA Transformer/4.5% Impedance/208 V

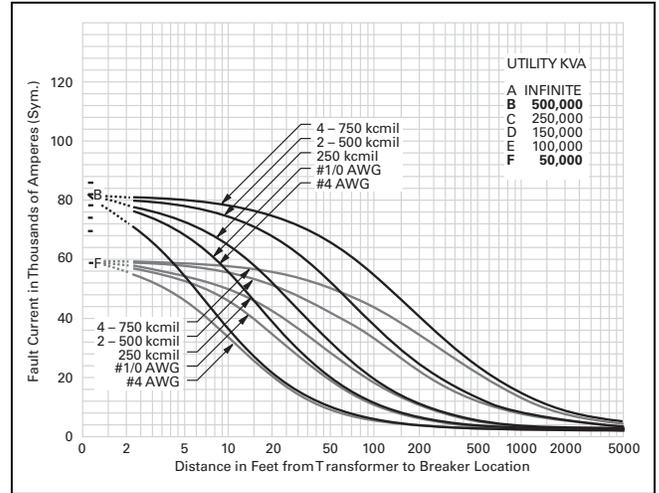


Figure 1.3-17. 1500 kVA Transformer/5.5% Impedance/208 V

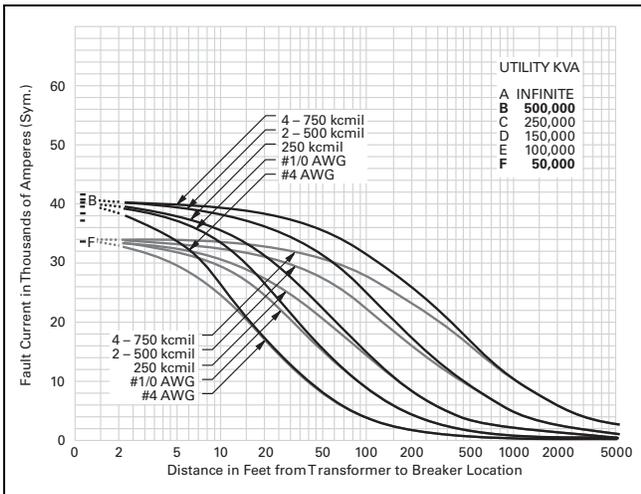


Figure 1.3-15. 750 kVA Transformer/5.5% Impedance/208 V

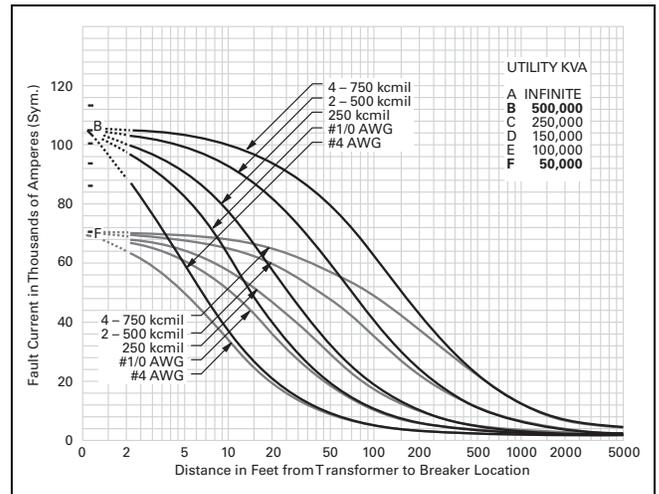


Figure 1.3-18. 2000 kVA Transformer/5.5% Impedance/208 V

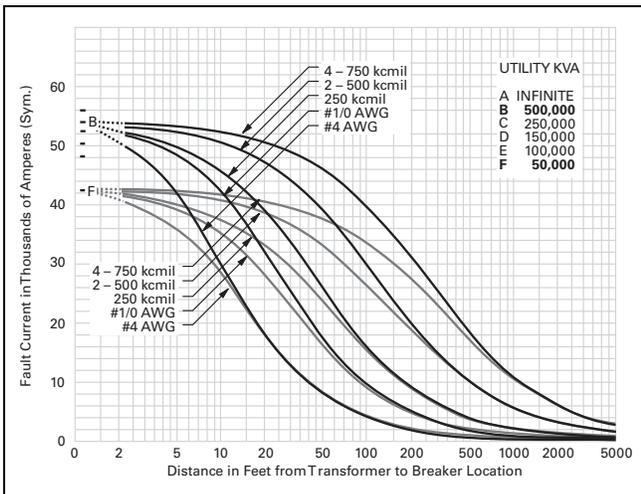


Figure 1.3-16. 1000 kVA Transformer/5.5% Impedance/208 V

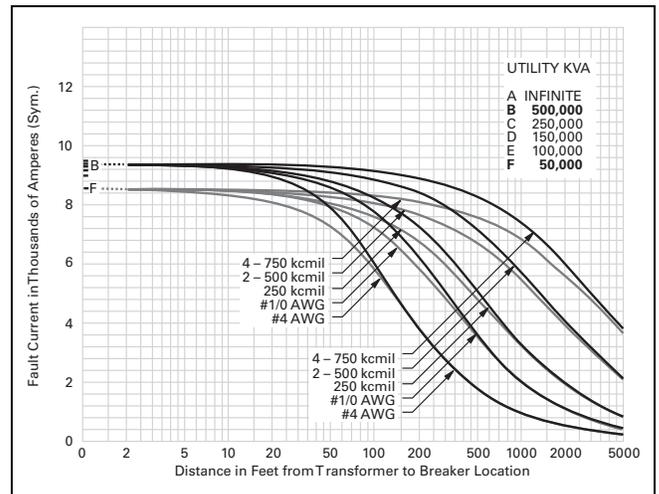


Figure 1.3-19. 300 kVA Transformer/4.5% Impedance/480 V

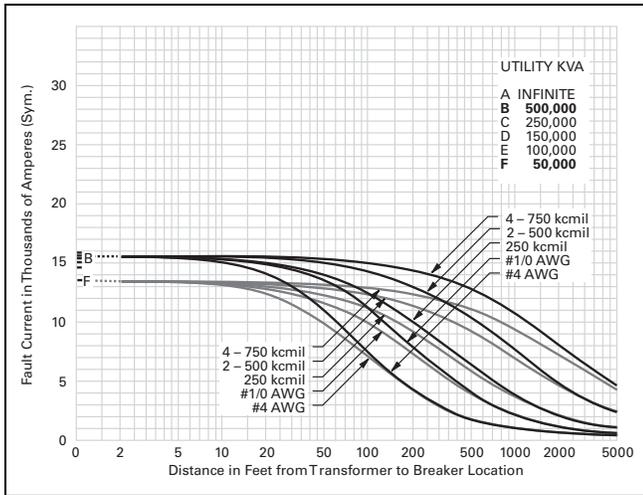


Figure 1.3-20. 500 kVA Transformer/4.5% Impedance/480 V

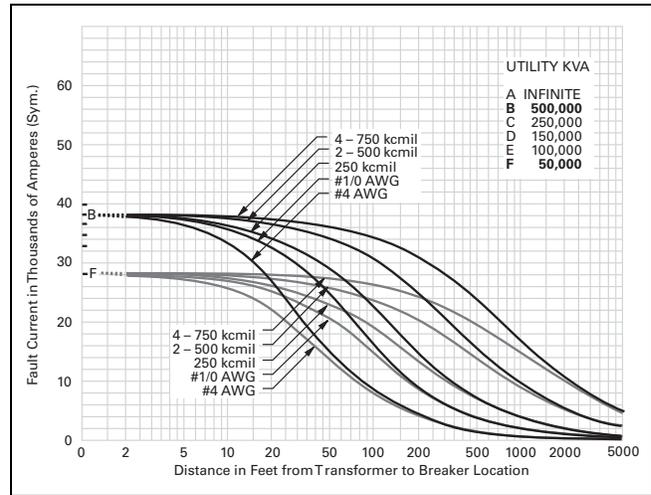


Figure 1.3-23. 1500 kVA Transformer/5.5% Impedance/480 V

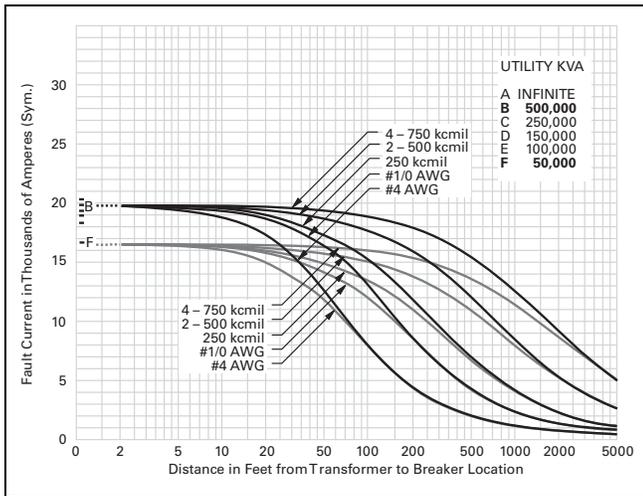


Figure 1.3-21. 750 kVA Transformer/5.5% Impedance/480 V

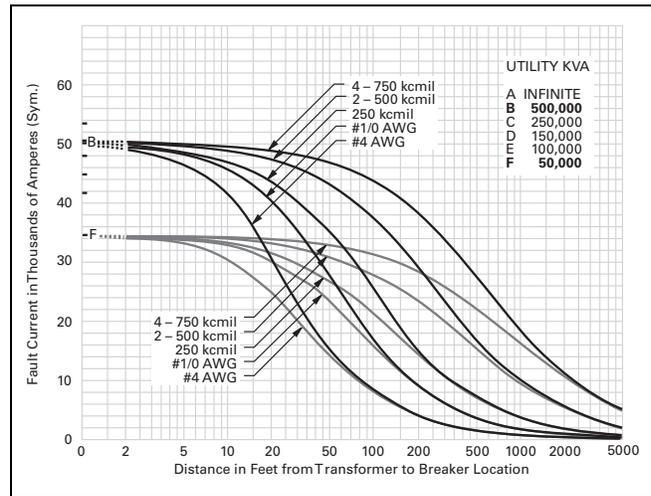


Figure 1.3-24. 2000 kVA Transformer/5.5% Impedance/480 V

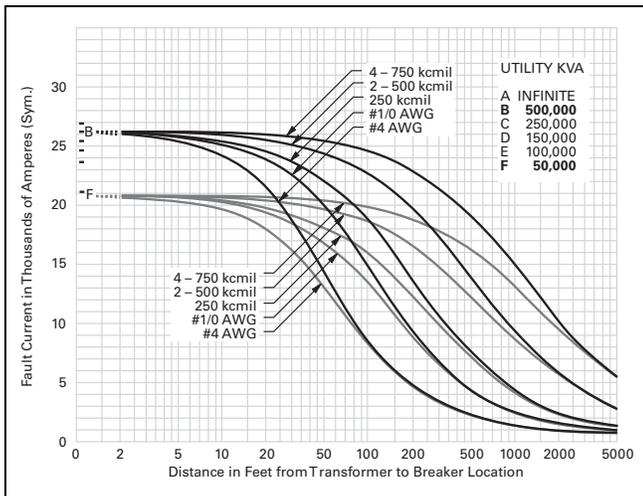


Figure 1.3-22. 1000 kVA Transformer/5.5% Impedance/480 V

Determining X and R Values from Transformer Loss Data

Method 1:

Given a 500 kVA, 5.5% Z transformer with 9000W total loss; 1700W no-load loss; 7300W load loss and primary voltage of 480 V.

$$3 \times \left(\frac{500}{\sqrt{3} \times 0.480} \right)^2 \times R = 7300 \text{ W}$$

$$\%R = 0.0067 \text{ ohms}$$

$$\%R = \frac{0.0067 \times 500}{10 \times 0.48^2} = 1.46\%$$

$$\%X = \sqrt{5.5^2 - 1.46^2} = 5.30\%$$

Method 2:

Using same values above.

$$\%R = \frac{I^2 R \text{ Losses}}{10 \times \text{kVA}}$$

$$\frac{7300}{10 \times 500} = 1.46$$

$$\%X = \sqrt{5.5^2 - 1.46^2} = 5.30\%$$

How to Estimate Short-Circuit Currents at Transformer Secondaries:

Method 1:

To obtain three-phase rms symmetrical short-circuit current available at transformer secondary terminals, use the formula:

$$I_{SC} = I_{FLC} \times \frac{100}{\%Z}$$

where %Z is the transformer impedance in percent, from **Tables 1.5-6** through **1.5-11, Page 1.5-11**.

This is the maximum three-phase symmetrical bolted-fault current, assuming sustained primary voltage during fault, i.e., an infinite or unlimited primary power source (zero source impedance). Because the power source must always have some impedance, this is a conservative value; actual fault current will be somewhat less.

Note: This will not include motor short-circuit contribution.

Method 2:

Refer to **Page 1.5-9** in the Reference section, and use appropriate row of data based on transformer kVA and primary short-circuit current available. This will yield more accurate results and allow for including motor short-circuit contribution.

Voltage Drop Considerations

The first consideration for voltage drop is that under the steady-state conditions of normal load, the voltage at the utilization equipment must be adequate. Fine-print notes in the NEC recommend sizing feeders and branch circuits so that the maximum voltage drop in either does not exceed 3%, with the total voltage drop for feeders and branch circuits not to exceed 5%, for efficiency of operation. (Fine print notes in the NEC are not mandatory.)

In addition to steady-state conditions, voltage drop under transient conditions, with sudden high-current, short-time loads, must be considered. The most common loads of this type are motor inrush currents during starting. These loads cause a voltage dip on the system as a result of the voltage drop in conductors, transformers and generators under the high current. This voltage dip can have numerous adverse effects on equipment in the system, and equipment and conductors must be designed and sized to minimize these problems. In many cases, reduced-voltage starting of motors to reduce inrush current will be necessary.

Recommended Limits of Voltage Variation

General Illumination: Flicker in incandescent lighting from voltage dip can be severe; lumen output drops about three times as much as the voltage dips. That is, a 10% drop in voltage will result in a 30% drop in light output. While the lumen output drop in fluorescent lamps is roughly proportional to voltage drop, if the voltage dips about 25%, the lamp will go out momentarily and then restrike. For high-intensity discharge (HID) lamps such as mercury vapor, high-pressure sodium or metal halide, if the lamp goes out because of an excessive voltage dip, it will not restrike until it has cooled. This will require several minutes. These lighting flicker effects can be annoying, and in the case of HID lamps, sometimes serious. In areas where close work is being done, such as drafting rooms, precision assembly plants, and the like, even a slight variation, if repeated, can be very annoying, and reduce efficiency. Voltage variation in such areas should be held to 2 or 3% under motor-starting or other transient conditions.

Computer Equipment: With the proliferation of data-processing and computer- or microprocessor-controlled manufacturing, the sensitivity of computers to voltage has become an important consideration. Severe dips of short duration can cause a computer to “crash”—shut down completely, and other voltage transients caused by starting and stopping motors can cause data-processing errors. While voltage drops must be held to a minimum, in many cases computers will require special power-conditioning equipment to operate properly.

Industrial Plants: Where large motors exist, and unit substation transformers are relatively limited in size, voltage dips of as much as 20% may be permissible in some cases, if they do not occur too frequently. Lighting is often supplied from separate transformers, and is minimally affected by voltage dips in the power systems. However, it is usually best to limit dips to between 5 and 10% at most. One critical consideration is that a large voltage dip can cause a dropout (opening) of magnetic motor contactors and control relays. The actual dropout voltage varies considerably among starters of different manufacturers. The only standard that exists is that of NEMA, which states that a starter must *not* drop out at 85% of its nominal coil voltage, allowing only a 15% dip. While most starters will tolerate considerably more voltage dip before dropping out, limiting dip to 15% is the only way to ensure continuity of operation in all cases.

X-Ray Equipment: Medical x-ray and similar diagnostic equipment, such as CAT-scanners, are extremely sensitive to low voltage. They present a small, steady load to the system until the instant the x-ray tube is “fired.” This presents a brief but extremely high instantaneous momentary load. In some modern x-ray equipment, the firing is repeated rapidly to create multiple images. The voltage regulation must be maintained within the manufacturer’s limits, usually 2 to 3%, under these momentary loads, to ensure proper x-ray exposure.

Motor Starting

Motor inrush on starting must be limited to minimize voltage dips. **Table 1.3-11** on the next page will help select the proper type of motor starter for various motors, and to select generators of adequate size to limit voltage dip. See **Tab 29** for additional data on reduced voltage motor starting.

Utility Systems

Where the power is supplied by a utility network, the motor inrush can be assumed to be small compared to the system capacity, and voltage at the source can be assumed to be constant during motor starting. Voltage dip resulting from motor starting can be calculated on the basis of the voltage drop in the conductors between the power source and the motor resulting from the inrush current. Where the utility system is limited, the utility will often specify the maximum permissible inrush current or the maximum hp motor they will permit to be started across-the-line.

Transformer Considerations

If the power source is a transformer, and the inrush kVA or current of the motor being started is small compared to the full-rated kVA or current of the transformer, the transformer voltage dip will be small and may be ignored. As the motor inrush becomes a significant percentage of the transformer full-load rating, an estimate of the transformer voltage drop must be added to the conductor voltage drop to obtain the total voltage drop to the motor. Accurate voltage drop calculation would be complex and depend upon transformer and conductor resistance, reactance and impedance, as well as motor inrush current and power factor. However, an approximation can be made on the basis of the low power-factor motor inrush current (30–40%) and impedance of the transformer.

For example, if a 480 V transformer has an impedance of 5%, and the motor inrush current is 25% of the transformer full-load current (FLC), then the worst case voltage drop will be 0.25 x 5%, or 1.25%.

The allowable motor inrush current is determined by the total permissible voltage drop in transformer and conductors.

Table 1.3-11. Factors Governing Voltage Drop

Type of Motor ①	Starting Torque	Starting Current ②	How Started	Starting Current % Full-Load ③	Starting Torque per Unit of Full Load Torque			Full-Load Amperes per kVA Generator Capacity for Each 1% Voltage Drop
					Motor Rpm			
					1750	1150 ③	850	
Design A	Normal	Normal	Across-the-line resistance autotransformer	600–700	1.5	1.35	1.25	0.0109–.00936 0.0136–.0117 0.0170–.0146
				480–560 ② 375–450 ②	0.96 0.96	0.87 0.87	0.80 0.80	
Design B	Normal	Low	Across-the-line resistance autotransformer	500–600	1.5	1.35	1.25	0.0131–.0109 0.0164–.01365 0.0205–.0170
				400–480 ② 320–400 ②	0.96 0.96	0.87 0.87	0.80 0.80	
Design C	High	Low	Across-the-line resistance autotransformer	500–600	—	0.2 to 2.5	—	0.0131–.0109 0.0164–.01365 0.0205–.0170
				400–480 ②	—	1.28 to 1.6	—	
				320–400 ②	—	1.28 to 1.6	—	
Wound Rotor	High	Low	Secondary controller	100% current for 100% torque	—	—	—	— — 0.0655
Synchronous (for compressors)	Low	—	Across-the-line	300	40% Starting, 40% Pull-In			0.0218
Synchronous (for centrifugal pumps)	Low	—	Across-the-line Autotransformer	450–550 288–350 ④	60% Starting, 110% Pull-In 38% Starting, 110% Pull-In			0.0145–.0118 0.0228–.0197

① Consult NEMA MG-1 sections 1 and 12 for the exact definition of the design letter.
 ② In each case, a solid-state reduced voltage starter can be adjusted and controlled to provide the required inrush current and torque characteristics.
 ③ Where accuracy is important, request the code letter of the the motor and starting and breakdown torques from the motor vendor.
 ④ Using 80% taps.

Engine Generator Systems

With an engine generator as the source of power, the type of starter that will limit the inrush depends on the characteristics of the generator. Although automatic voltage regulators are usually used with all AC engine-generators, the initial dip in voltage is caused by the inherent regulation of the generator and occurs too rapidly for the voltage regulator to respond. It will occur whether or not a regulator is installed. Consequently, the percent of initial voltage drop depends on the ratio of the starting kVA taken by the motor to the generator capacity, the inherent regulation of the generator, the power-factor of the load thrown on the generator, and the percentage load carried by the generator.

A standard 80% power-factor engine-type generator (which would be used where power is to be supplied to motor loads) has an inherent regulation of approximately 40% from no-load to full-load. This means that a 50% variation in load would cause approximately 20% variation in voltage (50% x 40% = 20%).

Assume that a 100 kVA, 80% PF engine-type generator is supplying the power and that the voltage drop should not exceed 10%. Can a 7-1/2 hp, 220 V, 1750 rpm, three-phase, squirrel-cage motor be started without exceeding this voltage drop?

Starting ratio =

$$\frac{\text{Percent voltage drop} \times \text{gen. kVA} \times 1000}{\text{F.L. amperes} \times \text{volts} \times \sqrt{3} \times \text{reg. of gen.}}$$

From the nameplate data on the motor, the full-load amperes of a 7-1/2 hp, 220 V, 1750 rpm, three-phase, squirrel-cage motor is 19.0 A. Therefore:

$$\text{Starting current (\%FL.)} = \frac{10 \times 100 \times 1000}{19.0 \times 220 \times \sqrt{3} \times 0.40} = 3.45 \text{ or } 345\%$$

From **Table 1.3-11**, a NEMA design C or NEMA design D motor with an autotransformer starter gives approximately this starting ratio. It could also be obtained from a properly set solid-state adjustable reduced voltage starter.

The choice will depend upon the torque requirements of the load since the use of an autotransformer starter reduces the starting torque in direct proportion to the reduction in starting current. In other words, a NEMA design C motor with an autotransformer would have a starting torque of approximately full-load (see **Table 1.3-11**) whereas the NEMA design D motor under the same conditions would have a starting torque of approximately 1-1/2 times full-load.

Note: If a resistance starter were used for the same motor terminal voltage, the starting torque would be the same as that obtained with autotransformer type, but the starting current would be higher, as shown.

Shortcut Method

Column 7 in **Table 1.3-11** has been worked out to simplify checking. The figures were obtained by using the formula above and assuming 1 kVA generator capacity and 1% voltage drop.

Example:

Assuming a project having a 1000 kVA generator, where the voltage variation must not exceed 10%. Can a 75 hp, 1750 rpm, 220 V, three-phase, squirrel-cage motor be started without objectionable lamp flicker (or 10% voltage drop)?

From tables in the circuit protective devices reference section, the full-load amperes of this size and type of motor is 158 A. To convert to same basis as column 7, 158 A must be divided by the generator capacity and % voltage drop, or:

$$\frac{158}{1000 \times 10} = 0.0158 \text{ A per kVA per } 1\% \text{ voltage drop}$$

Checking against the table, 0.0158 falls within the 0.0170–0.0146 range. This indicates that a general-purpose motor with autotransformer starting can be used.

Note: Designers may obtain calculated information from engine generator manufacturers.

The calculation results in conservative results. The engineer should provide to the engine-generator vendor the starting kVA of all motors connected to the generator and their starting sequence. The engineer should also specify the maximum allowable drop. The engineer should request that the engine-generator vendor consider the proper generator size when closed-transition autotransformer reduced voltage starters, and soft-start solid-state starter are used; so the most economical method of installation is obtained.

Voltage Drop Formulas

Approximate Method

Voltage Drop

$$E_{VD} = IR \cos\theta + IX \sin\theta$$

where abbreviations are same as below "Exact Method."

Exact Methods

Voltage drop

Exact Method 1—If sending end voltage and load PF are known.

$$E_{VD} = E_S + IR \cos\theta + IX \sin\theta - \sqrt{E_S^2 - (IX \cos\theta - IR \sin\theta)^2}$$

where:

E_{VD} = Voltage drop, line-to-neutral, volts

E_S = Source voltage, line-to-neutral, volts

I = Line (Load) current, amperes

R = Circuit (branch, feeder) resistance, ohms

X = Circuit (branch, feeder) reactance, ohms

$\cos\theta$ = Power factor of load, decimal

$\sin\theta$ = Reactive factor of load, decimal

If the receiving end voltage, load current and power factor (PF) are known.

$$E_{VD} = \sqrt{(E_R \cos\theta + I_R)^2 + (E_R \sin\theta + I_X)^2} - E_R$$

E_R is the receiving end voltage.

Exact Method 2—If receiving or sending mVA and its power factor are known at a known sending or receiving voltage.

$$E_S^2 = E_R^2 + \frac{(ZMVA_R)^2}{E_R^2} + 2ZMVA_R \cos(\gamma - \theta_R)$$

or

$$E_R^2 = E_S^2 + \frac{(ZMVA_R)^2}{E_S^2} - 2ZMVA_S \cos(\gamma - \theta_S)$$

where:

E_R = Receiving line-line voltage in kV

E_S = Sending line-line voltage in kV

MVA_R = Receiving three-phase mVA

MVA_S = Sending three-phase mVA

Z = Impedance between and receiving ends

γ = The angle of impedance Z

θ_R = Receiving end PF

θ_S = Sending end PF, positive when lagging

Voltage Drop

Voltage Drop Tables

Note: Busway voltage drop tables are shown in **Tab 24** of this catalog.

Tables for calculating voltage drop for copper and aluminum conductors, in either magnetic (steel) or nonmagnetic (aluminum or non-metallic) conduit, appear on **Page 1.3-24**. These tables give voltage drop per ampere per 100 ft (30 m) of circuit length. The circuit length is from the beginning point to the end point of the circuit regardless of the number of conductors.

Tables are based on the following conditions:

- Three or four single conductors in a conduit, random lay. For three-conductor cable, actual voltage drop will be approximately the same for small conductor sizes and high power factors. Actual voltage drop will be from 10 to 15% lower for larger conductor sizes and lower power factors.
- Voltage drops are phase-to-phase, for three-phase, three-wire or three-phase, four-wire 60 Hz circuits. For other circuits, multiply voltage drop given in the tables by the following correction factors:

Three-phase, four-wire, phase-to-neutral	x 0.577
Single-phase, two-wire	x 1.155
Single-phase, three-wire, phase-to-phase	x 1.155
Single-phase, three-wire, phase-to-neutral	x 0.577
- Voltage drops are for a conductor temperature of 75 °C. They may be used for conductor temperatures between 60 °C and 90 °C with reasonable accuracy (within ±5%). However, correction factors in **Table 1.3-12** can be applied if desired. The values in the table are in *percent of total voltage drop*.

For conductor temperature of 60 °C—**SUBTRACT** the percentage from **Table 1.3-12**.

For conductor temperature of 90 °C—**ADD** the percentage from **Table 1.3-12**.

Table 1.3-12. Temperature Correction Factors for Voltage Drop

Conductor Size	Percent Correction				
	Power Factors %				
	100	90	80	70	60
No. 14 to No. 4	5.0	4.7	4.7	4.6	4.6
No. 2 to 3/0	5.0	4.2	3.7	3.5	3.2
4/0 to 500 kcmil	5.0	3.1	2.6	2.3	1.9
600 to 1000 kcmil	5.0	2.6	2.1	1.5	1.3

Calculations

To calculate voltage drop:

- Multiply current in amperes by the length of the circuit in feet to get ampere-feet. Circuit length is the distance from the point of origin to the load end of the circuit.
- Divide by 100.
- Multiply by proper voltage drop value in tables. Result is voltage drop.

Example:

A 460 V, 100 hp motor, running at 80% PF, draws 124 A full-load current. It is fed by three 2/0 copper conductors in steel conduit. The feeder length is 150 ft (46 m). What is the voltage drop in the feeder? What is the percentage voltage drop?

- 124 A x 150 ft (46 m) = 18,600 A-ft
- Divided by 100 = 186
- Table: 2/0 copper, magnetic conduit, 80% PF = 0.0187
 186 x 0.0187 = 3.48 V drop
 $\frac{3.48}{460} \times 100 = 0.76\%$ drop
- Conclusion: 0.76% voltage drop is very acceptable. (See NEC 2005 Article 215, which suggests that a voltage drop of 3% or less on a feeder is acceptable.)

To select minimum conductor size:

- Determine maximum desired voltage drop, in volts.
- Divide voltage drop by (amperes x circuit feet).
- Multiply by 100.
- Find nearest *lower* voltage drop value in tables, in correct column for type of conductor, conduit and power factor. Read conductor size for that value.
- Where this results in an oversized cable, verify cable lug sizes for molded case breakers and fusible switches. Where lug size available is exceeded, go to next higher rating.**

Example:

A three-phase, four-wire lighting feeder on a 208 V circuit is 250 ft (76.2 m) long. The load is 175 A at 90% PF. It is desired to use aluminum conductors in aluminum conduit. What size conductor is required to limit the voltage drop to 2% phase-to-phase?

- $VD = \frac{2}{100} \times 208 = 4.16 \text{ V}$
- $\frac{4.16}{175 \times 250} = 0.0000951$
- $0.0000951 \times 100 = 0.00951$
- In table, under aluminum conductors, nonmagnetic conduit, 90% PF, the nearest lower value is 0.0091. Conductor required is 500 kcmil. (Size 4/0 THW would have adequate ampacity, but the voltage drop would be excessive.)

Table 1.3-13. Voltage Drop—Volts per Ampere per 100 Feet (30 m); Three-Phase, Phase-to-Phase

Conductor Size AWG or kcmil	Magnetic Conduit (Steel)					Nonmagnetic Conduit (Aluminum or Nonmetallic)				
	Load Power Factor, %					Load Power Factor, %				
	60	70	80	90	100	60	70	80	90	100
Copper Conductors										
14	0.3390	0.3910	0.4430	0.4940	0.5410	0.3370	0.3900	0.4410	0.4930	0.5410
12	0.2170	0.2490	0.2810	0.3130	0.3410	0.2150	0.2480	0.2800	0.3120	0.3410
10	0.1390	0.1590	0.1790	0.1980	0.2150	0.1370	0.1580	0.1780	0.1970	0.2150
8	0.0905	0.1030	0.1150	0.1260	0.1350	0.0888	0.1010	0.1140	0.1250	0.1350
6	0.0595	0.0670	0.0742	0.0809	0.0850	0.0579	0.0656	0.0730	0.0800	0.0849
4	0.0399	0.0443	0.0485	0.0522	0.0534	0.0384	0.0430	0.0473	0.0513	0.0533
2	0.0275	0.0300	0.0323	0.0342	0.0336	0.0260	0.0287	0.0312	0.0333	0.0335
1	0.0233	0.0251	0.0267	0.0279	0.0267	0.0218	0.0238	0.0256	0.0270	0.0266
1/0	0.0198	0.0211	0.0222	0.0229	0.0213	0.0183	0.0198	0.0211	0.0220	0.0211
2/0	0.0171	0.0180	0.0187	0.0190	0.0170	0.0156	0.0167	0.0176	0.0181	0.0169
3/0	0.0148	0.0154	0.0158	0.0158	0.0136	0.0134	0.0141	0.0147	0.0149	0.0134
4/0	0.0130	0.0134	0.0136	0.0133	0.0109	0.0116	0.0121	0.0124	0.0124	0.0107
250	0.0122	0.0124	0.0124	0.0120	0.0094	0.0107	0.0111	0.0112	0.0110	0.0091
300	0.0111	0.0112	0.0111	0.0106	0.0080	0.0097	0.0099	0.0099	0.0096	0.0077
350	0.0104	0.0104	0.0102	0.0096	0.0069	0.0090	0.0091	0.0091	0.0087	0.0066
500	0.0100	0.0091	0.0087	0.0080	0.0053	0.0078	0.0077	0.0075	0.0070	0.0049
600	0.0088	0.0086	0.0082	0.0074	0.0046	0.0074	0.0072	0.0070	0.0064	0.0042
750	0.0084	0.0081	0.0077	0.0069	0.0040	0.0069	0.0067	0.0064	0.0058	0.0035
1000	0.0080	0.0077	0.0072	0.0063	0.0035	0.0064	0.0062	0.0058	0.0052	0.0029
Aluminum Conductors										
12	0.3296	0.3811	0.4349	0.4848	0.5330	0.3312	0.3802	0.4328	0.4848	0.5331
10	0.2133	0.2429	0.2741	0.3180	0.3363	0.2090	0.2410	0.2740	0.3052	0.3363
8	0.1305	0.1552	0.1758	0.1951	0.2106	0.1286	0.1534	0.1745	0.1933	0.2115
6	0.0898	0.1018	0.1142	0.1254	0.1349	0.0887	0.1011	0.1127	0.1249	0.1361
4	0.0595	0.0660	0.0747	0.0809	0.0862	0.0583	0.0654	0.0719	0.0800	0.0849
2	0.0403	0.0443	0.0483	0.0523	0.0535	0.0389	0.0435	0.0473	0.0514	0.0544
1	0.0332	0.0357	0.0396	0.0423	0.0428	0.0318	0.0349	0.0391	0.0411	0.0428
1/0	0.0286	0.0305	0.0334	0.0350	0.0341	0.0263	0.0287	0.0322	0.0337	0.0339
2/0	0.0234	0.0246	0.0275	0.0284	0.0274	0.0227	0.0244	0.0264	0.0274	0.0273
3/0	0.0209	0.0220	0.0231	0.0241	0.0217	0.0160	0.0171	0.0218	0.0233	0.0222
4/0	0.0172	0.0174	0.0179	0.0177	0.0170	0.0152	0.0159	0.0171	0.0179	0.0172
250	0.0158	0.0163	0.0162	0.0159	0.0145	0.0138	0.0144	0.0147	0.0155	0.0138
300	0.0137	0.0139	0.0143	0.0144	0.0122	0.0126	0.0128	0.0133	0.0132	0.0125
350	0.0130	0.0133	0.0128	0.0131	0.0100	0.0122	0.0123	0.0119	0.0120	0.0101
500	0.0112	0.0111	0.0114	0.0099	0.0076	0.0093	0.0094	0.0094	0.0091	0.0072
600	0.0101	0.0106	0.0097	0.0090	0.0063	0.0084	0.0085	0.0085	0.0081	0.0060
750	0.0095	0.0094	0.0090	0.0084	0.0056	0.0081	0.0080	0.0078	0.0072	0.0051
1000	0.0085	0.0082	0.0078	0.0071	0.0043	0.0069	0.0068	0.0065	0.0058	0.0038

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Capacitors

Capacitors and Power Factor

Capacitor General Application Considerations

Additional application information is available in **Tab 35** regarding capacitors and harmonic filters as follows:

- Capacitor selection
- Where to install capacitors in a plant distribution system
- Locating capacitors on reduced voltage and multi-speed starters
- Harmonic considerations
- Eliminating harmonic problems
- National Electrical Code requirements

Medium Voltage Capacitor Switching

Capacitance switching constitutes severe operating duty for a circuit breaker. At the time the breaker opens at near current zero, the capacitor is fully charged. After interruption, when the alternating voltage on the source side of the breaker reaches its opposite maximum, the voltage that appears across the contacts of the open breaker is at least twice the normal peak line-to-neutral voltage of the circuit. If a breakdown occurs across the open contact, the arc is re-established. Due to the circuit constants on the supply side of the breaker, the voltage across the open contact can reach three times the normal line-to-neutral voltage. After it is interrupted and with subsequent alternation of the supply side voltage, the voltage across the open contact is even higher.

ANSI Standard C37.06 (indoor oilless circuit breakers) indicates the preferred ratings of Eaton's Type VCP-W vacuum breaker. For capacitor switching, careful attention should be paid to the notes accompanying the table. The definition of the terms are in ANSI Standard C37.04 Article 5.13 (for the latest edition). The application guide ANSI/IEEE Standard C37.012 covers the method of calculation of the quantities covered by C37.06 Standard.

Note that the definitions in C37.04 make the switching of two capacitors banks in close proximity to the switchgear bus a back-to-back mode of switching. This classification requires a definite purpose circuit breaker (breakers specifically designed for capacitance switching).

We recommend that such application be referred to Eaton.

A breaker specified for capacitor switching should include as applicable:

1. Rated maximum voltage.
2. Rated frequency.
3. Rated open wire line charging switching current.
4. Rated isolated cable charging and shunt capacitor switching current.
5. Rated back-to-back cable charging and back-to-back capacitor switching current.
6. Rated transient overvoltage factor.
7. Rated transient inrush current and its frequency.
8. Rated interrupting time.
9. Rated capacitive current switching life.
10. Grounding of system and capacitor bank.

Load break interrupter switches are permitted by ANSI/IEEE Standard C37.30 to switch capacitance, but they must have tested ratings for the purpose. Refer to Eaton Type MVS ratings.

Low Voltage Capacitor Switching

Circuit breakers and switches for use with a capacitor must have a current rating in excess of rated capacitor current to provide for overcurrent from overvoltages at fundamental frequency and harmonic currents. The following percent of the capacitor-rated current should be used as a general guideline:

- Fused and unfused switches. . . . 165%
- Molded case breaker or equivalent 150%
- DSII power circuit breakers 135%
- Magnum DS power circuit breaker 135%
- Contactors:
- Open type. 135%
- Enclosed type. 150%

The NEC, Section 460.8(C), requires the disconnecting means to be rated not less than 135% of the rated capacitor current (for 600 V and below).

See **Tab 35** for switching device ampere ratings. They are based on percentage of capacitor-rated current as indicated (above). The interrupting rating of the switch must be selected to match the system fault current available at the point of capacitor application. Whenever a capacitor bank is purchased with less than the ultimate kvar capacity of the rack or enclosure, the switch rating should be selected based on the ultimate kvar capacity—not the initial installed capacity.

Refer to Tab 35 for recommended selection of capacitor switching devices; recommended maximum capacitor ratings for various motor types and voltages; and for required multipliers to determine capacitor kvar required for power factor correction.

Capacitors

Motor Power Factor Correction

See **Tab 35** containing **suggested maximum** capacitor ratings for induction motors switched with the capacitor. The data is general in nature and representative of general purpose induction motors of standard design. The preferable means to select capacitor ratings is based on the "maximum recommended kvar" information available from the motor manufacturer. If this is not possible or feasible, the tables can be used.

An important point to remember is that if the capacitor used with the motor is too large, self-excitation may cause a motor-damaging over-voltage when the motor and capacitor combination is disconnected from the line. In addition, high transient torques capable of damaging the motor shaft or coupling can occur if the motor is reconnected to the line while rotating and still generating a voltage of self-excitation.

Definitions

kvar—rating of the capacitor in reactive kilovolt-amperes. This value is approximately equal to the motor no-load magnetizing kilovars.

% AR—percent reduction in line current due to the capacitor. A capacitor located on the motor side of the overload relay reduces line current through the relay. Therefore, a different overload relay and/or setting may be necessary. The reduction in line current may be determined by measuring line current with and without the capacitor or by calculation as follows:

$$\% \text{ AR} = 100 - 100 \times \frac{(\text{Original PF})}{(\text{Improved PF})}$$

If a capacitor is used with a lower kvar rating than listed in tables, the % AR can be calculated as follows:

$$\% \text{ AR} = \text{Listed \% AR} \times \frac{\text{Actual kvar}}{\text{kvar in Table}}$$

The tables can also be used for other motor ratings as follows:

- A. For standard 60 Hz motors operating at 50 Hz:
kvar = 1.7–1.4 of kvar listed
% AR = 1.8–1.35 of % AR listed
- B. For standard 50 Hz motors operating at 50 Hz:
kvar = 1.4–1.1 of kvar listed
% AR = 1.4–1.05 of % AR listed
- C. For standard 60 Hz wound-rotor motors:
kvar = 1.1 of kvar listed
% AR = 1.05 of % AR listed

Note: For A, B, C, the larger multipliers apply for motors of higher speeds; i.e., 3600 rpm = 1.7 mult., 1800 rpm = 1.65 mult., etc.

To derate a capacitor used on a system voltage lower than the capacitor voltage rating, such as a 240 V capacitor used on a 208 V system, use the following formula:

$$\text{Actual kvar} =$$

$$\text{Nameplate kvar} \times \frac{(\text{Applied Voltage})^2}{(\text{Nameplate Voltage})^2}$$

For the kVAC required to correct the power factor from a given value of COS ϕ_1 to COS ϕ_2 , the formula is:

$$\text{kVAC} = \text{kW} (\tan \text{phase}_1 - \tan \text{phase}_2)$$

Capacitors cause a voltage rise.

At light load periods the capacitive voltage rise can raise the voltage at the location of the capacitors to an unacceptable level. This voltage rise can be calculated approximately by the formula:

$$\% \text{ VR} = \frac{\text{MVA}_R}{\text{MVA}_{SC}}$$

MVA_R is the capacitor rating and MVA_{SC} is the system short-circuit capacity.

With the introduction of variable speed drives and other harmonic current generating loads, the capacitor impedance value determined must not be resonant with the inductive reactances of the system.

Overcurrent Protection and Coordination

Overcurrents in a power distribution system can occur as a result of both normal (motor starting, transformer inrush, etc.) and abnormal (overloads, ground fault, line-to-line fault, etc.) conditions. In either case, the fundamental purposes of current-sensing protective devices are to detect the abnormal overcurrent and with proper coordination, to operate selectively to protect equipment, property and personnel while minimizing the outage of the remainder of the system. With the increase in electric power consumption over the past few decades, dependence on the continued supply of this power has also increased so that the direct costs of power outages have risen significantly. Power outages can create dangerous and unsafe conditions as a result of failure of lighting, elevators, ventilation, fire pumps, security systems, communications systems, and the like. In addition, economic loss from outages can be extremely high as a result of computer downtime, or, especially in industrial process plants, interruption of production.

Protective equipment must be adjusted and maintained in order to function properly when an overcurrent occurs, but coordination begins during power system design with the knowledgeable analysis and selection and application of each overcurrent protective device in the series circuit from the power source(s) to each load apparatus. The objective of coordination is to localize the overcurrent disturbance so that the protective device closest to the fault on the power-source side has the first chance to operate; but each preceding protective device upstream toward the power source should be capable, within its designed settings of current and time, to provide backup and de-energize the circuit if the fault persists. Sensitivity of coordination is the degree to which the protective devices can minimize the damage to the faulted equipment.

To study and accomplish coordination requires (a) a one-line diagram, the roadmap of the power distribution system, showing all protective devices and the major or important distribution and utilization apparatus, (b) identification of desired degrees of power continuity or criticality of loads throughout system, (c) definition of operating-current characteristics (normal, peak, starting) of each utilization circuit, (d) equipment

damage or withstand characteristics, (e) calculation of maximum short-circuit currents (and ground fault currents if ground fault protection is included) available at each protective device location, (f) understanding of operating characteristics and available adjustments of each protective device, (g) any special overcurrent protection requirements including utility limitations. Refer to **Figure 1.4-1**.

To ensure complete coordination, the time-trip characteristics of all devices in series should be plotted on a single sheet of standard log-log paper. Devices of different-voltage systems can be plotted on the same sheet by converting their current scales, using the voltage ratios, to the same voltage-basis. Such a coordination plot is shown in **Figure 1.4-1**. In this manner, primary fuses and circuit breaker relays on the primary side of a

substation transformer can be coordinated with the low voltage breakers. Transformer damage points, based on ANSI standards, and low voltage cable heating limits can be plotted on this set of curves to ensure that apparatus limitations are not exceeded.

Ground-fault curves may also be included in the coordination study if ground-fault protection is provided, but care must be used in interpreting their meaning.

Standard definitions have been established for overcurrent protective devices covering ratings, operation and application systems.

M—Motor (100 hp). Dashed line shows initial inrush current, starting current during 9-sec. acceleration, and drop to 124 A normal running current, all well below CBA trip curve.

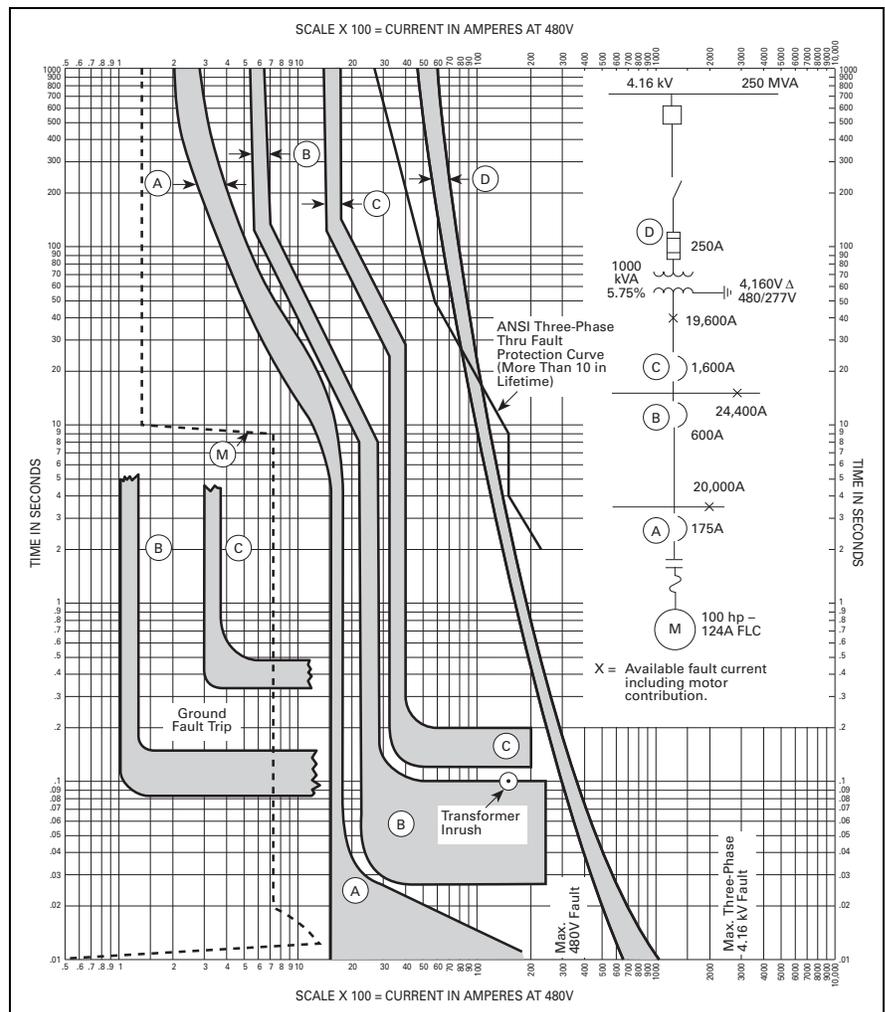


Figure 1.4-1. Time-Current Characteristic Curves for Typical Power Distribution System Protective Devices Coordination Analysis

Protection and Coordination

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A—CB (175 A) coordinates selectively with motor M on starting and running and with all upstream devices, except that CB B will trip first on low level ground faults.

B—CB (600 A) coordinates selectively with all upstream and downstream devices, except will trip before A on limited ground faults, since A has no ground fault trips.

C—Main CB (1600 A) coordinates selectively with all downstream devices and with primary fuse D, for all faults on load side of CB.

D—Primary fuse (250 A, 4160 V) coordinates selectively with all secondary protective devices. Curve converted to 480 V basis. Clears transformer inrush point (12 x FLC for 0.1 sec.), indicating that fuse will not blow on inrush. Fuse is underneath right-half of ANSI three-phase withstand curve, indicating fuse will protect transformer for high-magnitude faults up to ANSI rating.

Delta-wye secondary side short circuit is not reflected to the primary by the relation

$$I_P = \frac{V_S}{V_P} \times I_S$$

for L-L and L-G faults. For line-to-line fault, the secondary (low voltage) side fault current is $0.866 \times I$ three-phase fault current.

However, the primary (high voltage) side fault is the same as if the secondary fault was a three-phase fault. Therefore in coordination studies, the knee of the short-time pickup setting on the secondary breaker should be multiplied by

$$\frac{1}{0.866} \text{ or } 1.1547$$

before it is compared to the minimum melting time of the upstream primary fuse curve. In the example shown, the knee is at 4000 A 30 sec., and the 30-sec. trip time should be compared to the MMT (minimum melt time) of the fuse curve at $4000 \times 1.1547 = 4619$ A. In this case, there is adequate clearance to the fuse curve.

In the example shown, the ANSI three-phase through fault protection curve must be multiplied by 0.577 and replotted in order to determine the protection given by the primary for a single line to ground fault in the secondary.

Maximum 480 V three-phase fault indicated on the horizontal current axis.

Maximum 4160 V three-phase fault indicated, converted to 480 V basis.

$$I_{480V} = I_{4160V} \times \frac{4160}{480}$$

The ANSI protection curves are specified in ANSI C57.109 for liquid-filled transformers and C57.12.59 for dry-type transformers.

Illustrative examples such as shown here start the coordination study from the lowest rated device proceeding upstream. In practice, the setting or rating of the utility's protective device sets the upper limit. Even in cases where the customer owns the medium voltage or higher distribution system, the setting or rating of the lowest set protective device at the source determines the settings of the downstream devices and the coordination.

Therefore the coordination study should start at the present setting or rating of the upstream device and work toward the lowest rated device. If this procedure results in unacceptable settings, the setting or rating of the upstream device should be reviewed. Where the utility is the sole source, they should be consulted. Where the owner has its own medium or higher voltage distribution, the settings or ratings of all upstream devices should be checked.

If perfect coordination is not feasible, then lack of coordination should be limited to the smallest part of the system.

Application data is available for all protective equipment to permit systems to be designed for adequate overcurrent protection and coordination. For circuit breakers of all types, time-current curves permit selection of instantaneous and inverse-time trips. For more complex circuit breakers, with solid-state trip units, trip curves include long- and short-time delays, as well as ground-fault tripping, with a wide range of settings and features to provide selectivity and coordination. For current-limiting circuit breakers, fuses, and circuit breakers with integral fuses, not only are time-current characteristic curves available, but also data on current-limiting performance and protection for downstream devices.

In a fully rated system, all circuit breakers must have an interrupting capacity adequate for the maximum

available fault current at their point of application. All breakers are equipped with long-time-delay (and possibly short delay) and instantaneous overcurrent trip devices. A main breaker may have short time-delay tripping to allow a feeder breaker to isolate the fault while power is maintained to all the remaining feeders.

A selective or fully coordinated system permits maximum service continuity. The tripping characteristics of each overcurrent device in the system must be selected and set so that the breaker nearest the fault opens to isolate the faulted circuit, while all other breakers remain closed, continuing power to the entire unfaulted part of the system.

The National Electrical Code^① contains specific requirements for designing certain circuits with selective coordination. Article 100 defines selective coordination: Coordination (Selective), the following definition: "Localization of an overcurrent condition to restrict outages to the circuit or equipment affected, accomplished by the choice of overcurrent protective devices and their ratings or settings."

① NEC 2011 NFPA 70: National Electrical Code International Electrical Code Series.

Article 620.62 (elevators, dumbwaiters, escalators, moving walks, wheelchair lifts, and stairway chair lifts) requires "Where more than one driving machine disconnecting means is supplied by a single feeder, the overcurrent protective devices in each disconnecting means shall be selectively coordinated with any other supply side overcurrent protective device." A similar requirement under Article 700.27 is as follows: "Emergency system(s) overcurrent devices shall be selectively coordinated with all supply side overcurrent protective devices." Article 701.27 states that "Legally required standby system(s) overcurrent devices shall be selectively coordinated with all supply side overcurrent devices."

Exception: Selective coordination shall not be required between two overcurrent devices located in series if no loads are connected in parallel with the downstream device.

In addition, for health care facilities, Article 517.26, Application of Other Articles requires that "The essential electrical system shall meet the requirements of Article 700, except as amended by Article 517."

Protection and Coordination

All breakers must have an interrupting capacity not less than the maximum available short-circuit current at their point of application. A selective system is a fully rated system with tripping devices chosen and adjusted to provide the desired selectivity. The tripping characteristics of each overcurrent device should not overlap, but should maintain a minimum time interval for devices in series (to allow for normal operating tolerances) at all current values. Generally, a maximum of four low voltage circuit breakers can be operated selectively in series, with the feeder or branch breaker downstream furthest from the source.

Specify true rms sensing devices in order to avoid false trips due to rapid currents or spikes. Specify tripping elements with I^2t or I^4t feature for improved coordination with other devices having I^2t or I^4t (such as OPTIM™ trip units) characteristics and fuses.

In general for systems such as shown in the example:

1. The settings or ratings of the primary side fuse and main breaker must not exceed the settings allowed by NEC Article 450.
2. At $12 \times I_{FL}$ the minimum melting time characteristic of the fuse should be higher than 0.1 second.
3. The primary fuse should be to the left of the transformer damage curve as much as possible. The correction factor for a single line-to-ground factor must be applied to the damage curve.
4. The setting of the short-time delay element must be checked against the fuse MMT after it is corrected for line-to-line faults.
5. The maximum fault current must be indicated at the load side of each protective device.
6. The setting of a feeder protective device must comply with Article 240 and Article 430 of the NEC. It also must allow the starting and acceleration of the largest motor on the feeder while carrying all the other loads on the feeder.

Protection of Conductors (Excerpts from NFPA 70-2011, Article 240.4)

Conductors, other than flexible cords and fixture wires, shall be protected against overcurrent in accordance with their ampacities as specified in Section 310.15, unless otherwise permitted or required in (A) through (G).

A. **Power Loss Hazard.** Conductor overload protection shall not be required where the interruption of the circuit would create a hazard, such as in a material handling magnet circuit or fire pump circuit. Short-circuit protection shall be provided.

Note: FPN See NFPA 20-2003, standard for the Installation of Stationary Pumps for Fire Protection.

B. **Devices Rated 800 A or Less.** The next higher standard overcurrent device rating (above the ampacity of the conductors being protected) shall be permitted to be used, provided all of the following conditions are met.

1. The conductors being protected are not part of a branch circuit supplying more than one receptacle for cord-and-plug-connected portable loads.
2. The ampacity of the conductors does not correspond with the standard ampere rating of a fuse or a circuit breaker without overload trip adjustments above its rating (but that shall be permitted to have other trip or rating adjustments).
3. The next higher standard rating selected does not exceed 800 A.

C. **Overcurrent Devices Rated Over 800 A.** Where the overcurrent device is rated over 800 A, the ampacity of the conductors it protects shall be equal to or greater than the rating of the overcurrent device as defined in Section 240.6.

D. **Small Conductors.** Unless specifically permitted in 240.4(E) or 240.4(G), the overcurrent protection shall not exceed 15 A for 14 AWG, 20 A for 12 AWG, and 30 A for 10 AWG copper; or 15 A for 12 AWG and 25 A for 10 AWG aluminum and copper-clad aluminum after any correction factors for ambient temperature and number of conductors have been applied.

E. **Tap Conductors.** Tap conductors shall be permitted to be protected against overcurrent in accordance with the following:

1. 210.19(A)(3) and (A)(4) Household Ranges and Cooking Appliances and Other Loads.
2. 240.5(B)(2) Fixture Wire.
3. 240.21 Location in Circuit.
4. 368.17(B) Reduction in Ampacity Size of Busway.
5. 368.17(C) Feeder or Branch Circuits (busway taps).
6. 430.53(D) Single Motor Taps.

Circuit Breaker Cable Temperature Ratings

UL listed circuit breakers rated 125 A or less shall be marked as being suitable for 60 °C (140°F), 75 °C (167 °F) only or 60/75 °C (140/167°F) wire. All Eaton breakers rated 125 A or less are marked 60/75 °C (140/167 °F). All UL listed circuit breakers rated over 125 A are suitable for 75 °C conductors. Conductors rated for higher temperatures may be used, but must not be loaded to carry more current than the 75 °C ampacity of that size conductor for equipment marked or rated 75 °C or the 60 °C ampacity of that size conductor for equipment marked or rated 60 °C. However, when applying derated factors, so long as the actual load does not exceed the lower of the derated ampacity or the 75 °C or 60 °C ampacity that applies.

Zone Selective Interlocking

Trip elements equipped with zone selective interlocking, trip without intentional time delay unless a restraint signal is received from a protective device downstream. Breakers equipped with this feature reduce the damage at the point of fault if the fault occurs at a location between the zone of protection.

The upstream breaker upon receipt of the restraint signal will not trip until its time-delay setting times out. If the breaker immediately downstream of the fault does not open, then after timing out, the upstream breaker will trip.

Breakers equipped with ground fault trip elements should also be specified to include zone interlocking for the ground fault trip element.

Protection and Coordination

1

Ground Fault Protection

Article 230.95 of NEC requires ground-fault protection of equipment shall be provided for solidly grounded wye electrical services of more than 150 V to ground, but not exceeding 600 V phase-to-phase for each service disconnect rated 1000 A or more.

The rating of the service disconnect shall be considered to be the rating of the largest fuse that can be installed or the highest continuous current trip setting for which the actual overcurrent device installed in a circuit breaker is rated or can be adjusted.

The maximum allowable settings are: 1200 A pickup, 1 second or less trip delay at currents of 3000 A or greater.

The characteristics of the ground-fault trip elements create coordination problems with downstream devices not equipped with ground fault protection. The National Electrical Code exempts fire pumps and continuous industrial processes from this requirement.

It is recommended that in solidly grounded 480/277 V systems where main breakers are specified to be equipped with ground fault trip elements that the feeder breakers be specified to be equipped with ground fault trip elements as well.

Suggested Ground Fault Settings**For the main devices:**

A ground fault pickup setting equal to 20–30% of the main breaker rating but not to exceed 1200 A, and a time delay equal to the delay of the short-time element, but not to exceed 1 second.

For the feeder ground fault setting:

A setting equal to 20–30% of the feeder ampacity and a time delay to coordinate with the setting of the main (at least 6 cycles below the main).

If the desire to selectively coordinate ground fault devices results in settings that do not offer adequate damage protection against arcing single line-ground faults, the design engineer should decide between coordination and damage limitation.

For low voltage systems with high-magnitude available short-circuit currents, common in urban areas and large industrial installations, several solutions are available. High interrupting Series C[®] molded case breakers, current-limiting circuit breakers, or current-limiting fuses, limiters integral with molded-case circuit breakers (TRI-PAC[®]) or mounted on power circuit breakers (MDSL) can be used to handle these large fault currents. To provide current limiting, these devices must clear the fault completely within the first half-cycle, limiting the peak current (I_p) and heat energy (I^2t) let-through to considerably less than what would have occurred without the device. For a fully fusible system, rule-of-thumb fuse ratios or more accurate I^2t curves can be used to provide selectivity and coordination. For fuse-breaker combinations, the fuse should be selected (coordinated) so as to permit the breaker to handle those overloads and faults within its capacity; the fuse should operate before or with the breaker only on large faults, approaching the interrupting capacity of the breaker, to minimize fuse blowing. Recently, unfused, truly current-limiting circuit breakers with interrupting ratings adequate for the largest systems (Type Series C, FDC, JDC, KDC, LDC and NDC frames or Type Current Limit-R[®]) have become available.

The Series G high performance, current-limiting circuit breaker series offers interrupting ratings to 200 kA. Frames are EGC, EGU, EGX, JGC, JGU, JGX, LGC, LGU and LGX.

Any of these current-limiting devices—fuses, fused breakers or current-limiting breakers—cannot only clear these large faults safely, but also will limit the I_p and I^2t let-through significantly to prevent damage to apparatus downstream, extending their zone of protection. Without the current limitation of the upstream device, the fault current could exceed the withstand capability of the downstream equipment. Underwriters Laboratories tests and lists these series combinations. Application information is available for combinations that have been tested and UL[®]-listed for safe operation downstream from MDSL, TRI-PAC, and Current Limit-R, or Series C breakers of various ratings, under high available fault currents.

Protective devices in electrical distribution systems may be properly coordinated when the systems are designed and built, but that is no guarantee that they will remain coordinated. System changes and additions, plus power source changes, frequently modify the protection requirements, sometimes causing loss of coordination and even increasing fault currents beyond the ratings of some devices. Consequently, periodic study of protective-device settings and ratings is as important for safety and preventing power outages as is periodic maintenance of the distribution system.

Grounding

Grounding encompasses several different but interrelated aspects of electrical distribution system design and construction, all of which are essential to the safety and proper operation of the system and equipment supplied by it. Among these are equipment grounding, system grounding, static and lightning protection, and connection to earth as a reference (zero) potential.

1. Equipment Grounding

Equipment grounding is essential to safety of personnel. Its function is to ensure that all exposed noncurrent-carrying metallic parts of all structures and equipment in or near the electrical distribution system are at the same potential, and that this is the zero reference potential of the earth. Equipment grounding is required by both the National Electrical Code (Article 250) and the National Electrical Safety Code regardless of how the power system is grounded. Equipment grounding also provides a return path for ground fault currents, permitting protective devices to operate. Accidental contact of an energized conductor of the system with an improperly grounded noncurrent-carry metallic part of the system (such as a motor frame or panelboard enclosure) would raise the potential of the metal object

above ground potential. Any person coming in contact with such an object while grounded could be seriously injured or killed. In addition, current flow from the accidental grounding of an energized part of the system could generate sufficient heat (often with arcing) to start a fire. To prevent the establishment of such unsafe potential difference requires that (1) the equipment grounding conductor provide a return path for ground fault currents of sufficiently low impedance to prevent unsafe voltage drop, and (2) the equipment grounding conductor be large enough to carry the maximum ground fault current, without burning off, for sufficient time to permit protective devices (ground fault relays, circuit breakers, fuses) to clear the fault. The grounded conductor of the system (usually the neutral conductor), although grounded at the source, must not be used for equipment grounding.

The equipment grounding conductor may be the metallic conduit or raceway of the wiring system, or a separate equipment grounding conductor, run with the circuit conductors, as permitted by NEC. If a separate equipment grounding conductor is used, it may be bare or insulated; if insulated, the insulation must be green, green with yellow stripe or green tape. Conductors with green insulation may not be used for any purpose other than for equipment grounding.

The equipment grounding system must be bonded to the grounding electrode at the source or service; however, it may be also connected to ground at many other points. This will not cause problems with the safe operation of the electrical distribution system. Where computers, data processing, or microprocessor-based industrial process control systems are installed, the equipment grounding system must be designed to minimize interference with their proper operation. Often, isolated grounding of this equipment, or isolated electrical supply systems are required to protect microprocessors from power system “noise” that does not in any way affect motors or other electrical equipment. Such systems must use single-point ground concept to minimize “noise” and still meet the NEC requirements. Any separate isolated ground mat must be tied to the rest of the facility ground mat system for NEC compliance.

2. System Grounding

System grounding connects the electrical supply, from the utility, from transformer secondary windings, or from a generator, to ground. A system can be solidly grounded (no intentional impedance to ground), impedance grounded (through a resistance or reactance), or ungrounded (with no intentional connection to ground).

3. Medium Voltage System: Grounding

Table 1.4-1. Features of Ungrounded and Grounded Systems (from ANSI C62.92)

Description	A Ungrounded	B Solidly Grounded	C Reactance Grounded	D Resistance Grounded	E Resonant Grounded
(1) Apparatus insulation	Fully insulated	Lowest	Partially graded	Partially graded	Partially graded
(2) Fault to ground current	Usually low	Maximum value rarely higher than three-phase short circuit current	Cannot satisfactorily be reduced below one-half or one-third of values for solid grounding	Low	Negligible except when Petersen coil is short circuited for relay purposes when it may compare with solidly grounded systems
(3) Stability	Usually unimportant	Lower than with other methods but can be made satisfactory by use of high-speed breakers	Improved over solid grounding particularly if used at receiving end of system	Improved over solid grounding particularly if used at receiving end of system	Is eliminated from consideration during single line-to-ground faults unless neutralizer is short circuited to isolate fault by relays
(4) Relaying	Difficult	Satisfactory	Satisfactory	Satisfactory	Requires special provisions but can be made satisfactory
(5) Arcing grounds	Likely	Unlikely	Possible if reactance is excessive	Unlikely	Unlikely
(6) Localizing faults	Effect of fault transmitted as excess voltage on sound phases to all parts of conductively connected network	Effect of faults localized to system or part of system where they occur	Effect of faults localized to system or part of system where they occur unless reactance is quite high	Effect of faults transmitted as excess voltage on sound phases to all parts of conductively connected network	Effect of faults transmitted as excess voltage on sound phases to all parts of conductively connected network
(7) Double faults	Likely	Likely	Unlikely unless reactance is quite high and insulation weak	Unlikely unless resistance is quite high and insulation weak	Seem to be more likely but conclusive information not available

Grounding/Ground Fault Protection

Table 1.4-1. Features of Ungrounded and Grounded Systems (Continued)

Description	A Ungrounded	B Solidly Grounded	C Reactance Grounded	D Resistance Grounded	E Resonant Grounded
(8) Lightning protection	Ungrounded neutral service arresters must be applied at sacrifice in cost and efficiency	Highest efficiency and lowest cost	If reactance is very high arresters for ungrounded neutral service must be applied at sacrifice in cost and efficiency	Arresters for ungrounded, neutral service usually must be applied at sacrifice in cost and efficiency	Ungrounded neutral service arresters must be applied at sacrifice in cost and efficiency
(9) Telephone interference	Will usually be low except in cases of double faults or electrostatic induction with neutral displaced but duration may be great	Will be greatest in magnitude due to higher fault currents but can be quickly cleared particularly with high speed breakers	Will be reduced from solidly grounded values	Will be reduced from solidly grounded values	Will be low in magnitude except in cases of double faults or series resonance at harmonic frequencies, but duration may be great
(10) Radio interference	May be quite high during faults or when neutral is displaced	Minimum	Greater than for solidly grounded, when faults occur	Greater than for solidly grounded, when faults occur	May be high during faults
(11) Line availability	Will inherently clear themselves if total length of interconnected line is low and require isolation from system in increasing percentages as length becomes greater	Must be isolated for each fault	Must be isolated for each fault	Must be isolated for each fault	Need not be isolated but will inherently clear itself in about 60 to 80 percent of faults
(12) Adaptability to interconnection	Cannot be interconnected unless interconnecting system is ungrounded or isolating transformers are used	Satisfactory indefinitely with reactance-grounded systems	Satisfactory indefinitely with solidly-grounded systems	Satisfactory with solidly- or reactance-grounded systems with proper attention to relaying	Cannot be interconnected unless interconnected system is resonant grounded or isolating transformers are used. Requires coordination between interconnected systems in neutralizer settings
(13) Circuit breakers	Interrupting capacity determined by three-phase conditions	Same interrupting capacity as required for three-phase short circuit will practically always be satisfactory	Interrupting capacity determined by three-phase fault conditions	Interrupting capacity determined by three-phase fault conditions	Interrupting capacity determined by three-phase fault conditions
(14) Operating procedure	Ordinarily simple but possibility of double faults introduces complication in times of trouble	Simple	Simple	Simple	Taps on neutralizers must be changed when major system switching is performed and difficulty may arise in interconnected systems. Difficult to tell where faults are located
(15) Total cost	High, unless conditions are such that arc tends to extinguish itself, when transmission circuits may be eliminated, reducing total cost	Lowest	Intermediate	Intermediate	Highest unless the arc suppressing characteristic is relied on to eliminate transmission circuits when it may be lowest for the particular types of service

Because the method of grounding affects the voltage rise of the unfaulted phases above ground, ANSI C62.92 classifies systems from the point of view of grounding in terms of a coefficient of grounding

$$COG = \frac{\text{Highest Power Frequency rms Line - Ground Voltage}}{\text{rms Line - Line Voltage at Fault Location with the Fault Removed}}$$

This same standard also defines systems as effectively grounded when $COG \geq .8$ such a system would have $X_0/X_1 \geq 3.0$ and $R_0/X_1 \geq 1.0$. Any other grounding means that does not satisfy these conditions at any point in a system is not effectively grounded.

The aforementioned definition is of significance in medium voltage distribution systems with long lines and with grounded sources removed during light load periods so that in some locations in the system the X_0/X_1 , R_0/X_1 may exceed the defining limits. Other standards (cable and lightning arrester) allow the use of 100% rated cables and arresters selected on the basis of an effectively grounded system only where the criteria in the above are met. In effectively grounded system the line-to-ground fault current is high and there is no significant voltage rise in the unfaulted phases.

With selective ground fault isolation the fault current should be at least 60%

of the three-phase current at the point of fault. Damage to cable shields must be checked. Although this fact is not a problem except in small cables, it is a good idea to supplement the cable shields returns of ground fault current to prevent damage, by installing an equipment grounding conductor.

The burdens on the current transformers must be checked also (for saturation considerations), where residually connected ground relays are used and the current transformers supply current to phase relays and meters.

If ground sensor current transformers (zero sequence type) are used they must be of high burden capacity.

Table 1.4-2 taken from ANSI-C62.92 indicates the characteristics of the various methods of grounding.

Reactance Grounding

It is generally used in the grounding of the neutrals of generators directly connected to the distribution system bus, in order to limit the line-to-ground fault to somewhat less than the three-phase fault at the generator terminals. If the reactor is so sized, in all probability the system will remain effectively grounded.

Resistance Grounded

Medium voltage systems in general should be low resistance grounded. The ground fault is typically limited to about 200–400 A but less than 1000 A (a cable shield consideration). With a properly sized resistor and relaying application, selective fault isolation is feasible. The fault limit provided has a bearing on whether residually connected relays are used or ground sensor current transformers are used for ground fault relaying.

In general, where residually connected ground relays are used (51N), the fault current at each grounded source

should not be limited to less than the current transformers rating of the source. This rule will provide sensitive differential protection for wye-connected generators and transformers against line-to-ground faults near the neutral. Of course, if the installation of ground fault differential protection is feasible, or ground sensor current transformers are used, sensitive differential relaying in resistance grounded system with greater fault limitation is feasible. In general, ground sensor current transformers (zero sequence) do not have high burden capacity. Resistance grounded systems limit the circulating currents of triple harmonics and limit the damage at the point of fault. This method of grounding is not suitable for line-to-neutral connection of loads.

On medium voltage systems, 100% cable insulation is rated for phase-to-neutral voltage. If continued operation with one phase faulted to ground is desired, increased insulation thickness is required. For 100% insulation, fault clearance is recommended within one minute; for 133% insulation, one hour is acceptable; for indefinite operation, as long as necessary, 173% insulation is required.

Grounding Point

The most commonly used grounding point is the neutral of the system or the neutral point created by means of a zigzag or a wye-broken delta grounding transformer in a system that was operating as an ungrounded delta system.

In general, it is a good practice that all source neutrals be grounded with the same grounding impedance magnitude. However, neutrals should not be tied together to a single resistor. Where one of the medium voltage sources is the utility, their consent for impedance grounding must be obtained.

The neutral impedance must have a voltage rating at least equal to the rated line-to-neutral voltage class of the system. It must have at least a 10-second rating equal to the maximum future line-to-ground fault current and a continuous rating to accommodate the triple harmonics that may be present.

4. Low Voltage System: Grounding

Solidly grounded three-phase systems (Figure 1.4-2) are usually wye-connected, with the neutral point grounded. Less common is the “red-leg” or high-leg delta, a 240 V system supplied by some utilities with one winding center-tapped to provide 120 V to ground for lighting. This 240 V, three-phase, four-wire system is used where 120 V lighting load is small compared to 240 V power load, because the installation is low in cost to the utility. A corner-grounded three-phase delta system is sometimes found, with one phase grounded to stabilize all voltages to ground. Better solutions are available for new installations.

Table 1.4-2. Characteristics of Grounding

Grounding Classes and Means	Ratios of Symmetrical Component Parameters ①			Percent Fault Current	Per Unit Transient LG Voltage
	X_0/X_1	R_0/X_1	R_0/X_0	②	③
A. Effectively ④					
1. Effective	0-3	0-1	—	>60	δ2
2. Very effective	0-1	0-0.1	—	>95	<1.5
B. Noneffectively					
1. Inductance					
a. Low inductance	3-10	0-1	—	>25	<2.3
b. High inductance	>10	—	<2	<25	δ2.73 ⑥
2. Resistance					
a. Low resistance	0-10	—	Š2	<25	<2.5
b. High resistance	—	>100	δ(-1)	<1	δ2.73
3. Inductance and resistance	>10	—	>2	<10	δ2.73
4. Resonant	⑤	—	—	<1	δ2.73
5. Ungrounded/capacitance					
a. Range A	-x to -40 ⑥	—	—	<8	δ3 ⑦
b. Range B	-40 to 0	—	—	>8	>3 ⑦⑧

- ① Values of the coefficient of grounding (expressed as a percentage of maximum phase-to-phase voltage) corresponding to various combinations of these ratios are shown in the ANSI C62.92 Appendix figures. Coefficient of grounding affects the selection of arrester ratings.
- ② Ground-fault current in percentage of the three-phase short-circuit value.
- ③ Transient line-to-ground voltage, following the sudden initiation of a fault in per unit of the crest of the prefault line-to-ground operating voltage for a simple, linear circuit.
- ④ In linear circuits, Class A1 limits the fundamental line-to-ground voltage on an unfaulted phase to 138% of the prefault voltage; Class A2 to less than 110%.
- ⑤ See ANSI 62.92 para. 7.3 and precautions given in application sections.
- ⑥ Usual isolated neutral (ungrounded) system for which the zero-sequence reactance is capacitive (negative).
- ⑦ Same as NOTE (6) and refer to ANSI 62.92 para. 7.4. Each case should be treated on its own merit.
- ⑧ Under restriking arcing ground fault conditions (e.g., vacuum breaker interrupter operation), this value can approach 500%.
- ⑨ Under arcing ground fault conditions, this value can easily reach 700%, but is essentially unlimited.

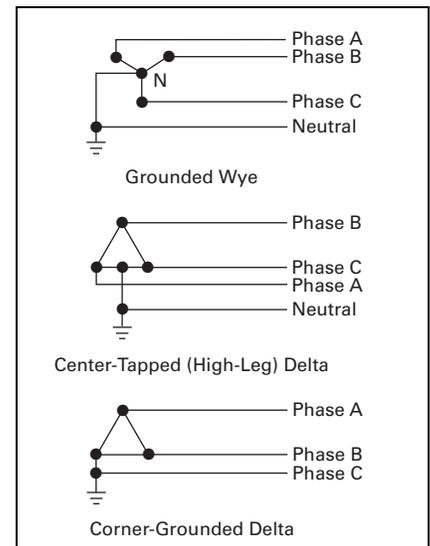


Figure 1.4-2. Solidly Grounded Systems

Grounding/Ground Fault Protection

1

Ungrounded systems (Figure 1.4-3) can be either wye or delta, although the ungrounded delta system is far more common.

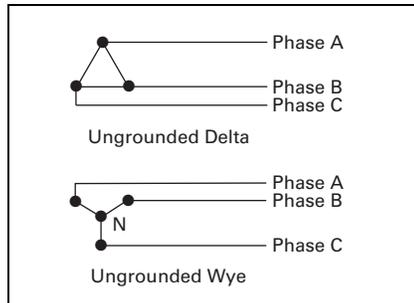


Figure 1.4-3. Ungrounded Systems

Resistance-grounded systems (Figure 1.4-4) are simplest with a wye connection, grounding the neutral point directly through the resistor. Delta systems can be grounded by means of a zig-zag or other grounding transformer. Wye broken delta transformer banks may also be used.

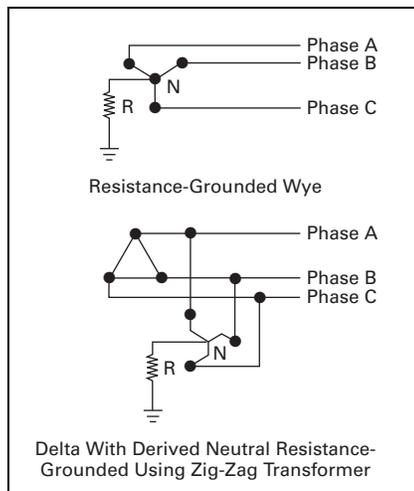


Figure 1.4-4. Resistance-Grounded Systems

This derives a neutral point, which can be either solidly or impedance-grounded. If the grounding transformer has sufficient capacity, the neutral created can be solidly grounded and used as part of a three-phase, four-wire system. Most transformer-supplied systems are either solidly grounded or resistance grounded. Generator neutrals are often grounded through a reactor, to limit ground fault (zero sequence) currents to values the generator can withstand.

Selecting the Low Voltage System Grounding Method

There is no one “best” distribution system for all applications. In choosing among solidly grounded, resistance grounded, or ungrounded power distribution, the characteristics of the system must be weighed against the requirements of power loads, lighting loads, continuity of service, safety and cost.

Under ground fault conditions, each system behaves very differently. A solidly grounded system produces high fault currents, usually with arcing, and the faulted circuit must be cleared on the first fault within a fraction of a second to minimize damage. An ungrounded system will pass limited current into the first ground fault—only the charging current of the system, caused by the distributed capacitance to ground of the system wiring and equipment. In low voltage systems, this is rarely more than 1 or 2 A. Therefore, on first ground fault, an ungrounded system can continue in service, making it desirable where power outages cannot be tolerated. However, if the ground fault is intermittent, sputtering or arcing, a high voltage—as much as 6 to 8 times phase voltage—can be built up across the system capacitance, from the phase conductors to ground. Similar high voltages can occur as a result of resonance between system capacitance and the inductances of transformers and motors in the system. The phase-to-phase voltage is not affected. This high transient phase-to-ground voltage can puncture insulation at weak points, such as motor windings, and is a frequent cause of multiple motor failures on ungrounded systems. Locating a first fault on an ungrounded system can be difficult. If, before the first fault is cleared, a second ground fault occurs on a different phase, even on a different, remote feeder, it is a high-current phase-to-ground-to-phase fault, usually arcing, that can cause severe damage if at least one of the grounds is not cleared immediately. If the second circuit is remote, enough current may not flow to cause protection to operate. This can leave high voltages and stray currents on structures and jeopardize personnel.

In general, where loads will be connected line-to-neutral, solidly grounded systems are used. High resistance grounded systems are

used as substitutes for ungrounded systems where high system availability is required.

With one phase grounded, the voltage to ground of the other two phases rises 73%, to full phase-to-phase voltage. In low voltage systems this is not important, since conductors are insulated for 600 V.

A low voltage resistance grounded system is normally grounded so that the single line-to-ground fault current exceeds the capacitive charging current of the system. If data for the charging current is not available, use 40–50 ohm resistor in the neutral of the transformer.

In **commercial and institutional** installations, such as office buildings, shopping centers, schools and hospitals, lighting loads are often 50% or more of the total load. In addition, a feeder outage on first ground fault is seldom crucial—even in hospitals, that have emergency power in critical areas. For these reasons, a **solidly grounded wye** distribution, with the neutral used for lighting circuits, is usually the most economical, effective and convenient design. In some instances, it is an NEC requirement.

In **industrial installations**, the effect of a shutdown caused by a single ground fault could be disastrous. An interrupted process could cause the loss of all the materials involved, often ruin the process equipment itself, and sometimes create extremely dangerous situations for operating personnel. On the other hand, lighting is usually only a small fraction of the total industrial electrical load. A solidly grounded neutral circuit conductor is not imperative and, when required, can be obtained from inexpensive lighting transformers.

Because of the ability to continue in operation with one ground fault on the system, many existing industrial plants use **ungrounded** delta distribution. Today, new installations can have all the advantages of service continuity of the ungrounded delta, yet minimize the problems of the system, such as the difficulty of locating the first ground fault, risk of damage from a second ground fault, and damage transient overvoltages. A **high-resistance grounded wye** distribution can continue in operation with a ground fault on the system and will not develop transient overvoltages.

And, because the ground point is established, locating a ground fault is less difficult than on an ungrounded system especially when a “pulsing contactor” design is applied. When combined with sensitive ground-fault protection, damage from a second ground fault can be nearly eliminated. **Ungrounded delta** systems can be converted to high-resistance grounded systems, using a zig-zag or other grounding transformer to derive a neutral, with similar benefits, see **Tab 36**. While the majority of manufacturing plants use solidly grounded systems, in many instances, the high-resistance grounded distribution will be the most advantageous.

Ground Fault Protection

A ground fault normally occurs in one of two ways: by accidental contact of an energized conductor with normally grounded metal, or as a result of an insulation failure of an energized conductor. When an insulation failure occurs, the energized conductor contacts normally noncurrent-carrying grounded metal, which is bonded to or part of the equipment grounding conductor. In a solidly grounded system, the fault current returns to the source primarily along the equipment grounding conductors, with a small part using parallel paths such as building steel or piping. If the ground return impedance was as low as that of the circuit conductors, ground fault currents would be high, and the normal phase overcurrent protection would clear them with little damage. Unfortunately, the impedance of the ground return path is usually higher, the fault itself is usually arcing and the impedance of the arc further reduces the fault current. In a 480Y/277 V system, the voltage drop across the arc can be from 70 to 140 V. The resulting ground fault current is rarely enough to cause the phase overcurrent protection device to open instantaneously and prevent damage. Sometimes, the ground fault is below the trip setting of the protective device and it does not trip at all until the fault escalates and extensive damage is done. For these reasons, low level ground protection devices with minimum time delay settings are required to rapidly clear ground faults. This is emphasized by the NEC requirement that a ground fault relay on a service shall have a maximum delay of one second for faults of 3000 A or more.

The NEC (Sec. 230.95) requires that ground fault protection, set at no more than 1200 A, be provided for each service

disconnecting means rated 1000 A or more on solidly grounded wye services of more than 150 V to ground, but not exceeding 600 V phase-to-phase. Practically, this makes ground fault protection mandatory on 480Y/277 V services, but not on 208Y/120 V services. On a 208 V system, the voltage to ground is 120 V. If a ground fault occurs, the arc goes out at current zero, and the voltage to ground is often too low to cause it to restrike. Therefore, arcing ground faults on 208 V systems tend to be self-extinguishing. On a 480 V system, with 277 V to ground, restrike usually takes place after current zero, and the arc tends to be self-sustaining, causing severe and increasing damage, until the fault is cleared by a protective device.

The NEC requires ground fault protection on the service disconnecting means. This protection works so fast that for ground faults on feeders, or even branch circuits, it will often open the service disconnect before the feeder or branch circuit overcurrent device can operate. This is highly undesirable, and in the NEC (230.95) a Fine Print Note (FPN) states that additional ground fault protective equipment will be needed on feeders and branch circuits where maximum continuity of electric service is necessary. Unless it is acceptable to disconnect the entire service on a ground fault almost anywhere in the system, such additional stages of ground fault protection must be provided. At least two stages of protection are mandatory in health care facilities (NEC Sec. 517.17).

Overcurrent protection is designed to protect conductors and equipment against currents that exceed their ampacity or rating under prescribed time values. An overcurrent can result from an overload, short circuit or (high level) ground fault condition. When currents flow outside the normal current path to ground, supplementary ground fault protection equipment will be required to sense low-level ground fault currents and initiate the protection required. Normal phase overcurrent protection devices provide no protection against low-level ground faults.

There are three basic means of sensing ground faults. The most simple and direct method is the ground return method as illustrated in **Figure 1.4-5**. This sensing method is based on the fact that all currents supplied by a transformer must return to that transformer.

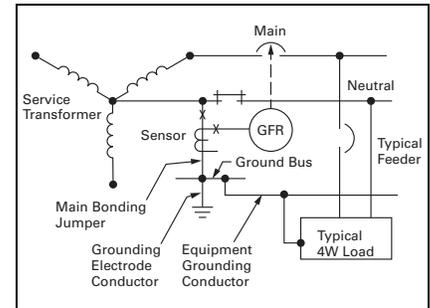


Figure 1.4-5. Ground Return Sensing Method

When an energized conductor faults to grounded metal, the fault current returns along the ground return path to the neutral of the source transformer. This path includes the main bonding jumper as shown in **Figure 1.4-5**.

A current sensor on this conductor (which can be a conventional bar-type or window type CT) will respond to ground fault currents only. Normal neutral currents resulting from unbalanced loads will return along the neutral conductor and will not be detected by the ground return sensor.

This is an inexpensive method of sensing ground faults where protection per NEC (230.95) is desired. For it to operate properly, the neutral must be grounded in only one place as indicated in **Figure 1.4-5**. In many installations, the servicing utility grounds the neutral at the transformer and additional grounding is required in the service equipment per NEC (250.24(A)(2)). In such cases, and others including multiple source with multiple, interconnected neutral ground points, residual or zero sequence ground sensing methods should be employed.

A second method of detecting ground faults involves the use of a zero sequence sensing method, as illustrated in **Figure 1.4-6**. This sensing method requires a single, specially designed sensor either of a toroidal or rectangular shaped configuration. This core balance current transformer surrounds all the phase and neutral conductors in a typical three-phase, four-wire distribution system. The sensing method is based on the fact that the vectorial sum of the phase and neutral currents in any distribution circuit will equal zero unless a ground fault condition exists downstream from the sensor. All currents that flow only in the circuit conductors, including balanced or unbalanced phase-to-phase and phase-to-neutral normal or fault currents, and harmonic currents, will result in zero sensor output.

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However, should any conductor become grounded, the fault current will return along the ground path—not the normal circuit conductors—and the sensor will have an unbalanced magnetic flux condition, and a sensor output will be generated to actuate the ground fault relay.

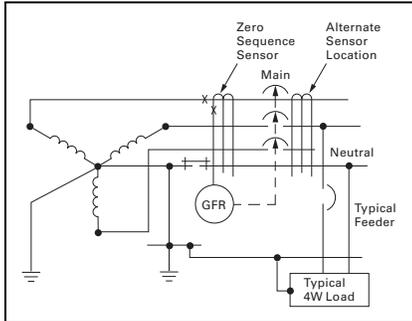


Figure 1.4-6. Zero Sequence Sensing Method

Zero sequence sensors are available with various window openings for circuits with small or large conductors, and even with large rectangular windows to fit over busbars or multiple large size conductors in parallel. Some sensors have split cores for installation over existing conductors without disturbing the connections.

This method of sensing ground faults can be employed on the main disconnect where protection per NEC (230.95) is desired. It can also be easily employed in multi-tier systems where additional levels of ground fault protection are desired for added service continuity. Additional grounding points may be employed upstream of the sensor, but not on the load side.

Ground fault protection employing ground return or zero sequence sensing methods can be accomplished by the use of separate ground fault relays (GFRs) and disconnects equipped with standard shunt trip devices or by circuit breakers with integral ground fault protection with external connections arranged for these modes of sensing. In some cases, a reliable source of control power is needed.

The third basic method of detecting ground faults involves the use of multiple current sensors connected in a residual sensing method as illustrated in Figure 1.4-7. This is a very common sensing method used with circuit breakers equipped with electronic trip units, current sensors and integral ground fault protection. The three-phase sensors are required for normal phase overcurrent protection. Ground fault sensing is obtained with the addition of an identically rated sensor mounted on the

neutral. In a residual sensing scheme, the relationship of the polarity markings—as noted by the “X” on each sensor—is critical. Because the vectorial sum of the currents in all the conductors will total zero under normal, non-ground faulted conditions, it is imperative that proper polarity connections are employed to reflect this condition.

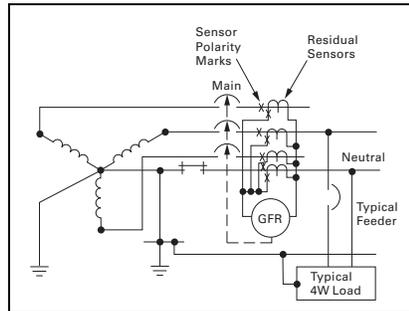


Figure 1.4-7. Residual Sensing Method

As with the zero sequence sensing method, the resultant residual sensor output to the ground fault relay or integral ground fault tripping circuit will be zero if all currents flow only in the circuit conductors. Should a ground fault occur, the current from the faulted conductor will return along the ground path, rather than on the other circuit conductors, and the residual sum of the sensor outputs will not be zero. When the level of ground fault current exceeds the pre-set current and time delay settings, a ground fault tripping action will be initiated.

This method of sensing ground faults can be economically applied on main service disconnects where circuit breakers with integral ground fault protection are provided. It can be used in protection schemes per NEC (230.95) or in multi-tier schemes where additional

levels of ground fault protection are desired for added service continuity. Additional grounding points may be employed upstream of the residual sensors, but not on the load side.

Both the zero sequence and residual sensing methods have been commonly referred to as “vectorial summation” methods.

Most distribution systems can use either of the three sensing methods exclusively or a combination of the sensing methods depending upon the complexity of the system and the degree of service continuity and selective coordination desired. Different methods will be required depending upon the number of supply sources, and the number and location of system grounding points.

As an example, one of the more frequently used systems where continuity of service to critical loads is a factor is the dual source system illustrated in Figure 1.4-8. This system uses tie-point grounding as permitted under NEC Sec. 250.24(A)(3). The use of this grounding method is limited to services that are dual fed (double-ended) in a common enclosure or grouped together in separate enclosures, employing a secondary tie.

This scheme uses individual sensors connected in ground return fashion. Under tie breaker closed operating conditions, either the M1 sensor or M2 sensor could see neutral unbalance currents and possibly initiate an improper tripping operation. However, with the polarity arrangements of these two sensors along with the tie breaker auxiliary switch (T/a) and interconnections as shown, this possibility is eliminated.

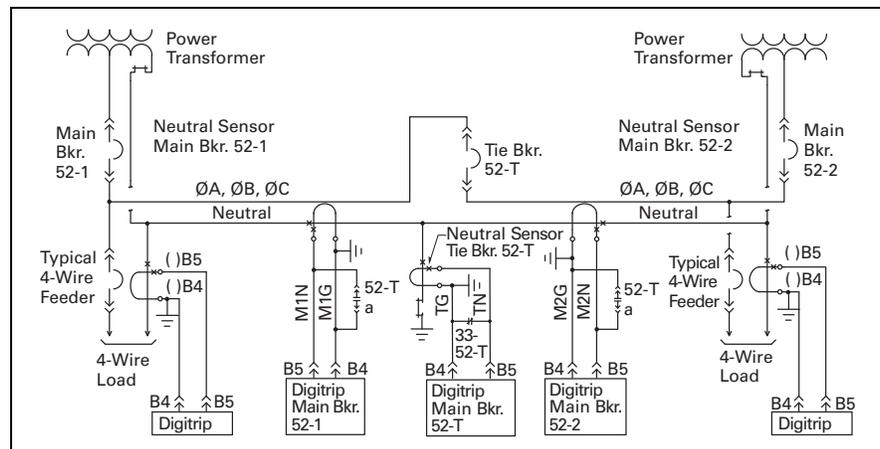


Figure 1.4-8. Dual Source System—Single Point Grounding

Note: This GF scheme requires trip units to be set to source ground sensing.

Selective ground fault tripping coordination between the tie breaker and the two main circuit breakers is achieved by pre-set current pickup and time delay settings between devices GFR/1, GFR/2 and GFR/T.

The advantages of increased service continuity offered by this system can only be effectively used if additional levels of ground fault protection are added on each downstream feeder. Some users prefer individual grounding of the transformer neutrals. In such cases, a partial differential ground fault scheme should be used for the mains and tie breaker.

An example of a residual partial differential scheme is shown in **Figure 1.4-9**. The scheme typically relies upon the vector sum of at least two neutral sensors in combination with each breakers' three-phase sensors. To reduce the complexity of the drawing, each of the breakers' three-phase sensors have not been shown. It is absolutely critical that the sensors' polarities are supplied as shown, the neutral sensor ratings of the mains and tie are the same, and that there are no other grounds on the neutral bus made downstream of points shown.

An infinite number of ground fault protection schemes can be developed depending upon the number of alternate sources, the number of grounding points and system interconnections involved. Depending upon the individual system configuration, either mode of sensing

or a combination of all types may be employed to accomplish the desired end results.

Because the NEC (230.95) limits the maximum setting of the ground fault protection used on service equipment to 1200 A (and timed tripping at 3000 A for one second), to prevent tripping of the main service disconnect on a feeder ground fault, ground fault protection must be provided on all the feeders. To maintain maximum service continuity, more than two levels (zones) of ground fault protection will be required, so that ground fault outages can be localized and service interruption minimized. To obtain selectivity between different levels of ground fault relays, time delay settings should be employed with the GFR furthest downstream having the minimum time delay. This will allow the GFR nearest the fault to operate first. With several levels of protection, this will reduce the level of protection for faults within the upstream GFR zones. Zone interlocking was developed for GFRs to overcome this problem.

GFRs (or circuit breakers with integral ground fault protection) with zone interlocking are coordinated in a system to operate in a time delayed mode for ground faults occurring most remote from the source. However, this time delayed mode is only actuated when the GFR next upstream from the fault sends a restraining signal to the upstream GFRs. The absence of a restraining signal from a downstream

GFR is an indication that any occurring ground fault is within the zone of the GFR next upstream from the fault and that device will operate instantaneously to clear the fault with minimum damage and maximum service continuity. This operating mode permits all GFRs to operate instantaneously for a fault within their zone and still provide complete selectivity between zones. The National Electrical Manufacturers Association (NEMA) states, in their application guide for ground fault protection, that zone interlocking is necessary to minimize damage from ground faults. A two-wire connection is required to carry the restraining signal from the GFRs in one zone to the GFRs in the next zone.

Circuit breakers with integral ground fault protection and standard circuit breakers with shunt trips activated by the ground fault relay are ideal for ground fault protection. Many fused switches over 1200 A, and Eaton Type FDP fusible switches with ratings from 400 to 1200 A, are listed by UL as suitable for ground fault protection. Fusible switches so listed must be equipped with a shunt trip, and be able to open safely on faults up to 12 times their rating.

Power distribution systems differ widely from each other, depending upon the requirements of each user, and total system overcurrent protection, including ground fault currents, must be individually designed to meet these needs. Experienced and knowledgeable engineers must consider the power sources (utility or on-site), the effects of outages and costs of downtime, safety for people and equipment, initial and lifecycle costs, and many other factors. They must apply protective devices, analyzing the time-current characteristics, fault interrupting capacity, and selectivity and coordination methods to provide the most safe and cost-effective distribution system.

Further Information

- PRSC-4E—System Neutral Grounding and Ground Fault Protection (ABB Publication)
- PB 2.2—NEMA Application Guide for Ground Fault Protective Devices for Equipment
- IEEE Standard 142—Grounding of Industrial and Commercial Power Systems (Green Book)
- IEEE Emerald Book (Standard 1100)
- UL 96A, Installation Requirements for Lightning Protection Systems

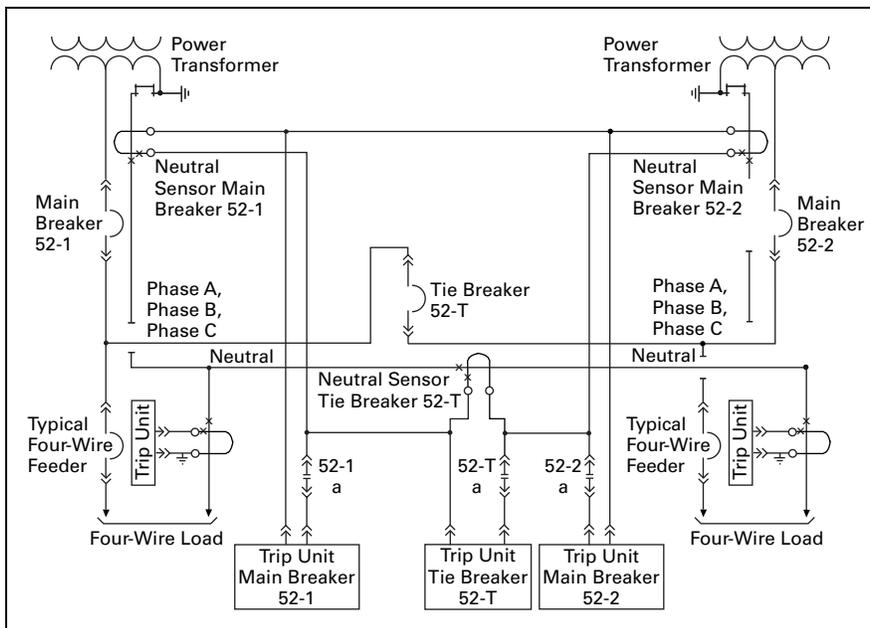


Figure 1.4-9. Dual Source System—Multiple Point Grounding

Lightning and Surge Protection

Physical protection of buildings from direct damage from lightning is beyond the scope of this section. Requirements will vary with geographic location, building type and environment, and many other factors (see IEEE/ANSI Standard 142, Grounding of Industrial and Commercial Power Systems). Any lightning protection system must be grounded, and the lightning protection ground must be bonded to the electrical equipment grounding system.

Grounding Electrodes

At some point, the equipment and system grounds must be connected to the earth by means of a grounding electrode system.

Outdoor substations usually use a ground grid, consisting of a number of ground rods driven into the earth and bonded together by buried copper conductors. The required grounding electrode system for a building is spelled out in the NEC Article 250.

The preferred grounding electrode is a metal underground water pipe in direct contact with the earth for at least 10 ft (3 m). However, because underground water piping is often plastic outside the building, or may later be replaced by plastic piping, the NEC requires this electrode to be supplemented by and bonded to at least one other grounding electrode, such as the effectively grounded metal frame of the building, a concrete-encased electrode, a copper conductor ground ring encircling the building, or a made electrode such as one or more driven ground rods or a buried plate. Where any of these electrodes are present, they must be bonded together into one grounding electrode system.

One of the most effective grounding electrodes is the concrete-encased electrode, sometimes called the Ufer ground, named after the man who developed it. It consists of at least 20 ft (6 m) of steel reinforcing bars or rods not less than 1/2 inches (12.7 mm) in diameter, or at least 20 ft (6 m) of bare copper conductor, size No. 4 AWG or larger, encased in at least 2 inches (50.8 mm) of concrete. It must be located within and near the bottom of a concrete foundation or footing that is in direct contact with the earth. Tests have shown this electrode to provide a low-resistance earth ground even in poor soil conditions.

The electrical distribution system and equipment ground must be connected to this grounding electrode system by a grounding electrode conductor. All other grounding electrodes, such as those for the lightning protection system, the telephone system, television antenna and cable TV system grounds, and computer systems, must be bonded to this grounding electrode system.

Medium Voltage Equipment Surge Protection Considerations

Transformers

If the voltage withstand/BIL rating of the transformer is less than that of the switchgear feeding the transformer, surge protection is recommended at the transformer terminals, in line with established practices. In addition, consideration should be given to using surge arresters and/or surge capacitors for transformers having equal or greater withstand/BIL ratings than that of the switchgear feeding the transformer for distribution systems where reflected voltage waves and/or resonant conditions may occur. Typically incoming voltage surges are reflected at the transformer primary terminals (because of the change in impedance) resulting in voltages at the ends of the transformer primary terminals/windings of up to two times the incoming voltage wave. System capacitance and inductance values combined with the transformer impedance values can cause resonant conditions resulting in amplified reflected waves. Surge arresters/capacitors when required, should be located as close to the transformer primary terminals as practical.

Motors

Surge capacitors and, where appropriate, surge arresters should be applied at the motor terminals.

Generators

Surge capacitors and station class surge arresters at the machine terminals.

Surge Protection

Eaton's VacClad-W metal-clad switchgear is applied over a broad range of circuits, and is one of the many types of equipment in the total system. The distribution system can be subject to voltage transients caused by lighting or switching surges.

Recognizing that distribution system can be subject to voltage transients caused by lighting or switching, the industry has developed standards to provide guidelines for surge protection of electrical equipment. Those guidelines should be used in design and protection of electrical distribution systems independent of the circuit breaker interrupting medium. The industry standards are:

ANSI C62

Guides and Standards for Surge Protection

IEEE 242—Buff Book

IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE 141—Red Book

Recommended Practice for Electric Power Distribution for Industrial Plants

IEEE C37.20.2

Standards for Metal-Clad Switchgear

Eaton's medium voltage metal-clad and metal-enclosed switchgear that uses vacuum circuit breakers is applied over a broad range of circuits. It is one of the many types of equipment in the total distribution system. Whenever a switching device is opened or closed, certain interactions of the power system elements with the switching device can cause high frequency voltage transients in the system. Due to the wide range of applications and variety of ratings used for different elements in the power systems, a given circuit may or may not require surge protection. Therefore, Eaton does not include surge protection as standard with its metal-clad or metal-enclosed medium voltage switchgear. The user exercises the options as to the type and extent of the surge protection necessary depending on the individual circuit characteristics and cost considerations.

The following are Eaton's recommendations for surge protection of medium voltage equipment. **Please note these recommendations are valid when using Eaton's vacuum breakers only.**

Surge Protection Recommendations

Note: The abbreviation ZORC[®] used in the text below refers to Surge Protection Device manufactured by Strike Technology (Pty) Ltd. An equivalent device offered by other manufacturers, such as Type EHZ by ABB, and Protec Z by Northern Technologies SA can also be used.

1. For circuits exposed to lightning, surge arresters should be applied in line with Industry standard practices.
2. Transformers
 - a. Close-Coupled to medium voltage primary breaker: Provide transients surge protection, such as Surge Arrester in parallel with RC Snubber, or ZORC. The surge protection device selected should be located and connected at the transformer primary terminals or it can be located inside the switchgear and connected on the transformer side of the primary breaker.
 - b. Cable-Connected to medium voltage primary breaker: Provide transient surge protection, such as Surge Arrester in parallel with RC Snubber, or ZORC for transformers connected by cables with lengths up to 75 feet. The surge protection device should be located and connected at the transformer terminals. No surge protection is needed for transformers with lightning impulse withstand ratings equal to that of the switchgear and connected to the switchgear by cables at least 75 feet or longer. For transformers with lower BIL, provide surge arrester in parallel with RC Snubber or ZORC.

RC Snubber and/or ZORC damp internal transformer resonance:

The natural frequency of transformer windings can under some circumstances be excited to resonate. Transformer windings in resonance can produce elevated internal voltages that produce insulation damage or failure. An RC Snubber or a ZORC applied at the transformer terminals as indicated above can damp internal winding resonance and prevent the production of damaging elevated internal voltages. This is typically required where rectifiers, UPS or similar electronic equipment is on the transformer secondary.

3. Arc-Furnace Transformers— Provide Surge Arrester in parallel with RC Snubber, or ZORC at the transformer terminals.
4. Motors— Provide Surge Arrester in parallel with RC Snubber, or ZORC at the motor terminals. For those motors using VFDs, surge protection should be applied and precede the VFD devices as well.
5. Generators— Provide station class Surge Arrester in parallel with RC Snubber, or ZORC at the generator terminals.

6. Capacitor Switching— No surge protection is required. Make sure that the capacitor's lightning impulse withstand rating is equal to that of the switchgear.
7. Shunt Reactor Switching— Provide Surge Arrester in parallel with RC Snubber, or ZORC at the reactor terminals.
8. Motor Starting Reactors or Reduced Voltage Auto-Transformers— Provide Surge Arrester in parallel with RC Snubber, or ZORC at the reactor or RVAT terminals.
9. Switching Underground Cables— Surge protection not needed.

Types of Surge Protection Devices

Generally surge protective devices should be located as closely as possible to the circuit component(s) that require protection from the transients, and connected directly to the terminals of the component with conductors that are as short and flat as possible to minimize the inductance. It is also important that surge protection devices should be properly grounded for effectively shunting high frequency transients to ground.

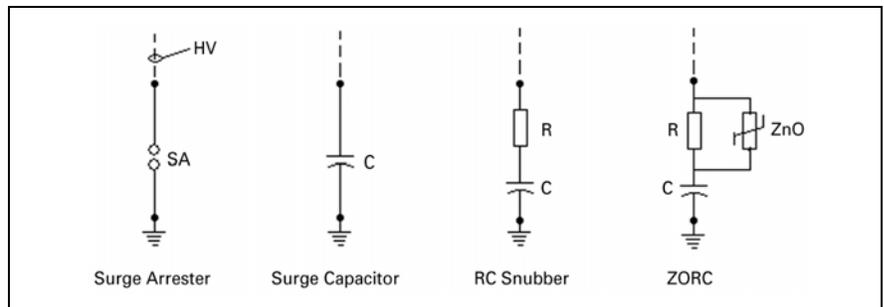


Figure 1.4-10. Surge Protection Devices

Grounding/Ground Fault Protection

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Surge Arresters

The modern metal-oxide surge arresters are recommended because this latest advance in arrester design ensures better performance and high reliability of surge protection schemes. Manufacturer's technical data must be consulted for correct application of a given type of surge arrester. Notice that published arrester MCOV (Maximum Continuous Operating Voltage) ratings are based on 40° or 45 °C ambient temperature. In general, the following guidelines are recommended for arrester selections, when installed inside Eaton's medium voltage switchgear:

- A. Solidly Grounded Systems:
Arrester MCOV rating should be equal to $1.05 \times V_{LL} / (1.732 \times T)$, where V_{LL} is nominal line-to-line service voltage, 1.05 factor allows for +5% voltage variation above the nominal voltage according to ANSI C84.1, and T is derating factor to allow for operation at 55 °C switchgear ambient, which should be obtained from the arrester manufacturer for the type of arrester under consideration. Typical values of T are: 0.946 to 1.0.
- B. Low Resistant Grounded Systems (systems grounded through resistor rated for 10 seconds):
Arrester 10-second MCOV capability at 60 °C, which is obtained from manufacturer's data, should be equal to $1.05 \times V_{LL}$, where V_{LL} is nominal line-to-line service voltage, and 1.05 factor allows for +5% voltage variation above the nominal voltage.
- C. Ungrounded or Systems Grounded through impedance other than 10-second resistor:
Arrester MCOV rating should be equal to $1.05 \times V_{LL} / T$, where V_{LL} and T are as defined above.

Refer to **Table 1.4-3** for recommended ratings for metal-oxide surge arresters that are sized in accordance with the above guidelines, when located in Eaton's switchgear.

Surge Capacitors

Metal-oxide surge arresters limit the magnitude of prospective surge overvoltage, but are ineffective in controlling its rate of rise. Specially designed surge capacitors with low internal inductance are used to limit the rate of rise of this surge overvoltage to protect turn-to-turn insulation. Recommended values for surge capacitors are: 0.5 μ f on 5 and 7.5 kV, 0.25 μ f on 15 kV, and 0.13 μ f on systems operating at 24 kV and higher.

RC Snubber

A RC Snubber device consists of a non-inductive resistor R sized to match surge impedance of the load cables, typically 20 to 30 ohms, and connected in series with a Surge Capacitor C. The Surge Capacitor is typically sized to be 0.15 to 0.25 microfarad. Under normal operating conditions, impedance of the capacitor is very high, effectively "isolating" the resistor R from the system at normal power frequencies, and minimizing heat dissipation during normal operation. Under high frequency transient conditions, the capacitor offers very low impedance, thus effectively "inserting" the resistor R in the power system as cable terminating resistor, thus minimizing reflection of the steep wave-fronts of the voltage transients and prevents voltage doubling of the traveling wave. The RC Snubber provides protection against high frequency transients by absorbing and damping and the transients. Please note RC Snubber is most effective in mitigating fast-rising transient voltages, and in attenuating reflections and resonances before they have a chance to build up, but does not limit the peak magnitude of the transient. Therefore, the RC Snubber alone may not provide adequate protection. To limit peak magnitude of the transient, application of surge arrester should also be considered.

ZORC

A ZORC device consists of parallel combination of Resistor (R) and Zinc Oxide Voltage Suppressor (ZnO), connected in series with a Surge Capacitor. The resistor R is sized to match surge impedance of the load cables, typically 20 to 30 ohms. The ZnO is a gapless metal-oxide nonlinear arrester, set to trigger at 1 to 2 PU voltage, where $1 \text{ PU} = 1.412 \times (V_{LL} / 1.732)$. The Surge Capacitor is typically sized to be 0.15 to 0.25 microfarad. As with RC Snubber, under normal operating conditions, impedance of the capacitor is very high, effectively "isolating" the resistor R and ZnO from the system at normal power frequencies, and minimizing heat dissipation during normal operation. Under high frequency transient conditions, the capacitor offers very low impedance, thus effectively "inserting" the resistor R and ZnO in the power system as cable terminating network, thus minimizing reflection of the steep wave-fronts of the voltage transients and prevents voltage doubling of the traveling wave. The ZnO element limits the peak voltage magnitudes. The combined effects of R, ZnO, and Capacitor of the ZORC device provides optimum protection against high frequency transients by absorbing, damping, and by limiting the peak amplitude of the voltage wave-fronts. Please note that the ZORC is not a lightning protection device. If lightning can occur or be induced in the electrical system, a properly rated and applied surge arrester must precede the ZORC.

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Surge Protection Summary

Minimum protection: Surge Arrester for protection from high overvoltage peaks, or Surge Capacitor for protection from fast-rising transient. Please note that the surge arresters or surge capacitor alone may not provide adequate surge protection from escalating voltages caused by circuit resonance. Note that when applying surge capacitors on both sides of a circuit breaker, surge capacitor on one side of the breaker must be RC Snubber or ZORC, to mitigate possible virtual current chopping.

Good protection: Surge Arrester in parallel with Surge Capacitor for protection from high overvoltage peaks and fast rising transient. This option may not provide adequate surge protection from escalating voltages caused by circuit resonance. When applying surge capacitors on both sides of a circuit breaker, surge capacitor on one side of the breaker must be RC Snubber or ZORC, to mitigate possible virtual current chopping.

Better protection: RC Snubber in parallel with Surge Arrester for protection from high frequency transients and voltage peaks.

Best protection: ZORC, plus proper surge arrester preceding ZORC where needed for protection against lightning. ZORC provides protection from high frequency voltage transients and limits peak magnitude of the transient to 1 to 2 PU (see ZORC description on **Page 1.4-16** for more detail). Surge arrester provides protection from higher voltage peaks resulting from lightning surges.

Further Information

- IEEE/ANSI Standard 142—Grounding Industrial and Commercial Power Systems (Green Book)
- IEEE Standard 241—Electric Power Systems in Commercial Buildings (Gray Book)
- IEEE Standard 141—Electric Power Distribution for Industrial Plants (Red Book)

Table 1.4-3. Surge Arrester Selections—Recommended Ratings

Service Voltage Line-to-Line kV	Distribution Class Arresters						Station Class Arresters					
	Solidly Grounded System		Low Resistance Grounded System		High Resistance or Ungrounded System		Solidly Grounded System		Low Resistance Grounded System		High Resistance or Ungrounded System	
	Arrester Ratings kV											
	Nominal	MCOV	Nominal	MCOV	Nominal	MCOV	Nominal	MCOV	Nominal	MCOV	Nominal	MCOV
2.30	3	2.55	3	2.55	3	2.55	3	2.55	3	2.55	3	2.55
2.40	3	2.55	3	2.55	6	5.10	3	2.55	3	2.55	6	5.10
3.30	3	2.55	3	2.55	6	5.10	3	2.55	3	2.55	6	5.10
4.00	3	2.55	6	5.10	6	5.10	3	2.55	6	5.10	6	5.10
4.16	6	5.10	6	5.10	6	5.10	6	5.10	6	5.10	6	5.10
4.76	6	5.10	6	5.10	9	7.65	6	5.10	6	5.10	9	7.65
4.80	6	5.10	6	5.10	9	7.65	6	5.10	6	5.10	9	7.65
6.60	6	5.10	6	5.10	9	7.65	6	5.10	6	5.10	9	7.65
6.90	6	5.10	6	5.10	9	7.65	6	5.10	9	7.65	9	7.65
7.20	6	5.10	6	5.10	10	8.40	6	5.10	9	7.65	10	8.40
8.32	9	7.65	9	7.65	12	10.20	9	7.65	9	7.65	12	10.20
8.40	9	7.65	9	7.65	12	10.20	9	7.65	9	7.65	12	10.20
11.00	9	7.65	9	7.65	15	12.70	9	7.65	10	8.40	15	12.70
11.50	9	7.65	10	8.40	18	15.30	9	7.65	12	10.20	18	15.30
12.00	10	8.40	10	8.40	18	15.30	10	8.40	12	10.20	18	15.30
12.47	10	8.40	12	10.20	18	15.30	10	8.40	12	10.20	18	15.30
13.20	12	10.20	12	10.20	18	15.30	12	10.20	12	10.20	18	15.30
13.80	12	10.20	12	10.20	18	15.30	12	10.20	15	12.70	18	15.30
14.40	12	10.20	12	10.20	21	17.00	12	10.20	15	12.70	21	17.00
18.00	15	12.70	15	12.70	27	22.00	15	12.70	18	15.30	27	22.00
20.78	18	15.30	18	15.30	30	24.40	18	15.30	21	17.00	30	24.40
22.00	18	15.30	18	15.30	30	24.40	18	15.30	21	17.00	30	24.40
22.86	18	15.30	21	17.00	—	—	18	15.30	24	19.50	36	29.00
23.00	18	15.30	21	17.00	—	—	18	15.30	24	19.50	36	29.00
24.94	21	17.00	24	19.50	—	—	21	17.00	24	19.50	36	29.00
25.80	21	17.00	24	19.50	—	—	21	17.00	24	19.50	36	29.00
26.40	21	17.00	24	19.50	—	—	21	17.00	27	22.00	39	31.50
33.00	27	22.00	30	24.40	—	—	27	22.00	36	29.00	45	36.50
34.50	30	24.40	30	24.40	—	—	30	24.40	36	29.00	48	39.00
38.00	30	24.40	—	—	—	—	30	24.40	36	29.00	—	—

Power Quality Terms Technical Overview

Introduction

Sensitive electronic loads deployed today by users require strict requirements for the quality of power delivered to loads.

For electronic equipment, power disturbances are defined in terms of amplitude and duration by the electronic equipment operating envelope. Electronic loads may be damaged and disrupted, with shortened life expectancy, by disturbances.

The proliferation of computers, variable frequency motor drives, UPS systems and other electronically controlled equipment is placing a greater demand on power producers for a disturbance-free source of power. Not only do these types of equipment require quality power for proper operation; many times, these types of equipment are also the sources of power disturbances that corrupt the quality of power in a given facility.

Power quality is defined according to IEEE Standard 1100 as the concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment. IEEE Standard 1159 notes that "within the industry, alternate definitions or interpretations of power quality have been used, reflecting different points of view."

In addressing power quality problems at an existing site, or in the design stages of a new building, engineers need to specify different services or mitigating technologies. The lowest cost and highest value solution is to selectively apply a combination of different products and services as follows:

Key services/technologies in the "power quality" industry:

- Power quality surveys, analysis and studies
- Power monitoring
- Grounding products and services
- Surge protection
- Voltage regulation
- Harmonic solutions
- Lightning protection (ground rods, hardware, etc.)
- Uninterruptible power supply (UPS) or motor-generator (M-G) set

Defining the Problem

Power quality problems can be resolved in three ways: by reducing the variations in the power supply (power disturbances), by improving the load equipment's tolerance to those variations, or by inserting some interface equipment (known as power conditioning equipment) between the electrical supply and the sensitive load(s) to improve the compatibility of the two. Practicality and cost usually determine the extent to which each option is used.

Many methods are used to define power quality problems. For example, one option is a thorough on-site investigation, which includes inspecting wiring and grounding for errors, monitoring the power supply for power disturbances, investigating equipment sensitivity to power disturbances, and determining the load disruption and consequential effects (costs), if any. In this way, the power quality problem can be defined, alternative solutions developed, and optimal solution chosen.

Before applying power-conditioning equipment to solve power quality problems, the site should be checked for wiring and grounding problems. Sometimes, correcting a relatively inexpensive wiring error, such as a loose connection or a reversed neutral and ground wire, can avoid a more expensive power conditioning solution.

Sometimes this approach is not practical because of limitations in time; expense is not justified for smaller installations; monitoring for power disturbances may be needed over an extended period of time to capture infrequent disturbances; the exact sensitivities of the load equipment may be unknown and difficult to determine; and finally, the investigative approach tends to solve only observed problems. Thus unobserved or potential problems may not be considered in the solution. For instance, when planning a new facility, there is no site to investigate. Therefore, power quality solutions are often implemented to solve potential or perceived problems on a preventive basis instead of a thorough on-site investigation.

Another option is to buy power conditioning equipment to correct any and all perceived power quality problems without any on-site investigation.

Power Quality Terms

Power disturbance: Any deviation from the nominal value (or from some selected thresholds based on load tolerance) of the input AC power characteristics.

Total harmonic distortion or distortion factor: The ratio of the root-mean-square of the harmonic content to the root-mean-square of the fundamental quantity, expressed as a percentage of the fundamental.

Crest factor: Ratio between the peak value (crest) and rms value of a periodic waveform.

Apparent (total) power factor: The ratio of the total power input in watts to the total volt-ampere input.

Sag: An rms reduction in the AC voltage, at the power frequency, for the duration from a half-cycle to a few seconds. An undervoltage would have a duration greater than several seconds.

Interruption: The complete loss of voltage for a time period.

Transient: A sub-cycle disturbance in the AC waveform that is evidenced by a sharp brief discontinuity of the waveform. May be of either polarity and may be additive to or subtractive from the nominal waveform.

Surge or impulse: See transient.

Noise: Unwanted electrical signals that produce undesirable effects in the circuits of control systems in which they occur.

Common-mode noise: The noise voltage that appears equally and in phase from each current-carrying conductor to ground.

Normal-mode noise: Noise signals measurable between or among active circuit conductors feeding the subject load, but not between the equipment grounding conductor or associated signal reference structure and the active circuit conductors.

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Methodology for Ensuring Effective Power Quality to Electronic Loads

The power quality pyramid is an effective guide for addressing power quality problems at an existing facility. The framework is also effective for specifying engineers who are designing a new facility. Power quality starts with grounding (the base of the pyramid) and then moves upward to address the potential issues. This simple, yet proven methodology, will provide the most cost-effective approach. As we move higher up the pyramid, the cost per kVA of mitigating potential problems increase and the quality of the power increases (refer to **Figure 1.4-11**).

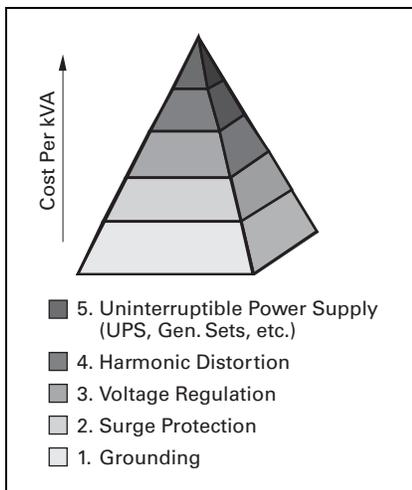


Figure 1.4-11. Power Quality Pyramid

1. Grounding

Grounding represents the foundation of a reliable power distribution system. Grounding and wiring problems can be the cause of up to 80% of all power quality problems. All other forms of power quality solutions are dependent upon good grounding procedures.

The proliferation of communication and computer network systems has increased the need for proper grounding and wiring of AC and data/communication lines. In addition to reviewing AC grounding and bonding practices, it is necessary to prevent ground loops from affecting the signal reference point.

2. Surge Protection

Surge protection devices (SPDs) are recommended as the next stage power quality solutions. NFPA, UL 96A, IEEE Emerald Book and equipment manufacturers recommend the use of surge protectors. The SPD shunt short duration voltage disturbances to ground, thereby preventing the surge from affecting electronic loads. When installed as part of the facility-wide design, SPDs are cost-effective compared to all other solutions (on a \$/kVA basis).

The IEEE Emerald Book recommends the use of a two-stage protection concept. For large surge currents, diversion is best accomplished in two stages: the first diversion should be performed at the service entrance to the building. Then, any residual voltage resulting from the action can be dealt with by a second protective device at the power panel of the computer room (or other critical loads).

The benefit of implementing cascaded network protection is shown in **Figure 1.4-12**. Combined, the two stages of protection at the service entrance and branch panel locations reduce the IEEE 62.41 recommended test wave (C3–20 kV, 10 kA) to less than 200 V voltage, a harmless disturbance level for 120 V rated sensitive loads.

If only building entrance feeder protection were provided, the let-through voltage will be approximately 950 V in a 277/480 V system exposed to induced lightning surges. This level of let-through voltage can cause degradation or physical damage of most electronic loads.

Wherever possible, consultants, specifiers and application engineers should ensure similar loads are fed from the same source. In this way, disturbance-generating loads are separated from electronic circuits affected by power disturbances. For example, motor loads, HVAC systems and other linear loads should be separated from the sensitive process control and computer systems.

The most effective and economic solution for protecting a large number of loads is to install parallel SPDs at the building service entrance feeder and panelboard locations. This reduces the cost of protection for multiple sensitive loads.

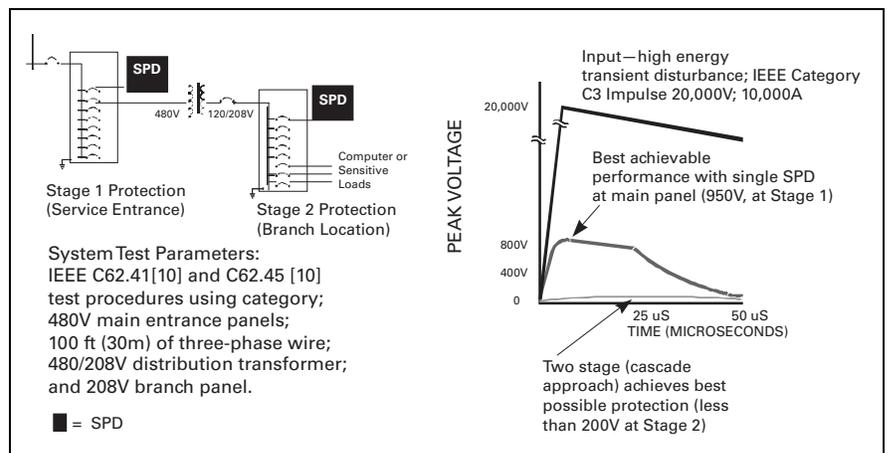


Figure 1.4-12. Cascaded Network Protection

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The recommended system approach for installing SPDs is summarized in **Figure 1.4-13**.

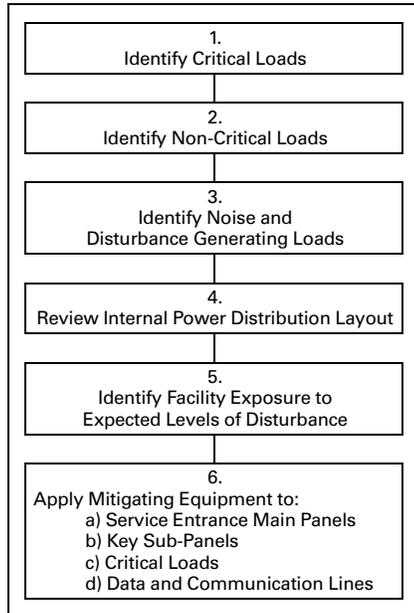


Figure 1.4-13. System Approach for Installing SPDs

There may be specific critical loads within a facility that require a higher level of protection. A series SPD is best suited for protecting such loads.

Advantages of the system approach are:

- The lowest possible investment in mitigating equipment to protect a facility

- Building entrance SPDs protect the facility against large external transients, including lightning
- SPDs are bi-directional and prevent transient and noise disturbances from feeding back within a system when installed at distribution or branch panels
- Two levels of protection safeguard sensitive loads from physical damage or operational upset

Side-Mounted SPD vs. Integral SPD

Directly connecting the surge suppressor to the busbar of electrical distribution equipment results in the best possible level of protection. Compared to side-mounted devices, connecting the SPD unit to the busbar eliminates the need for lead wires and reduces the let-through voltage up to 50% (see **Figure 1.4-14**).

Given that surges are high frequency disturbances, the inductance of the installation wiring increases the let-through voltage of the protective device. **Figure 1.4-15** shows that for every inch of lead length, the let-through voltage is increased by an additional 15–25 V above the manufacturer's stated suppression performance.

Lead length has the greatest effect on the actual level of protection realized. Twisting of the installation wires is the second most important installation consideration.

By twisting the installation wires, the area between wires is reduced and the mutual inductance affect minimized.

Increasing the diameter of the installation wires is of negligible benefit. Inductance is a "skin effect" phenomenon and a function of wire circumference. Since only a marginal reduction in inductance is achieved when the diameter of the installation conductors is increased, the use of large diameter wire results in only minimal improvement (see **Figure 1.4-15**).

Further benefits provided by integrated surge suppression designs are the elimination of field installation costs and the amount of expensive "outboard" wall space taken up by side-mounted SPD devices.

Building Entrance Feeder Installation Considerations

Installing an SPD device immediately after the switchgear or switchboard main breaker is the optimal location for protecting against external disturbances such as lightning. When placed in this location, the disturbance is "intercepted" by the SPD and reduced to a minimum before reaching the distribution and/or branch panel(s).

The use of a disconnect breaker eliminates the need to de-energize the building entrance feeder equipment should the SPD fail or require isolation for Megger testing.

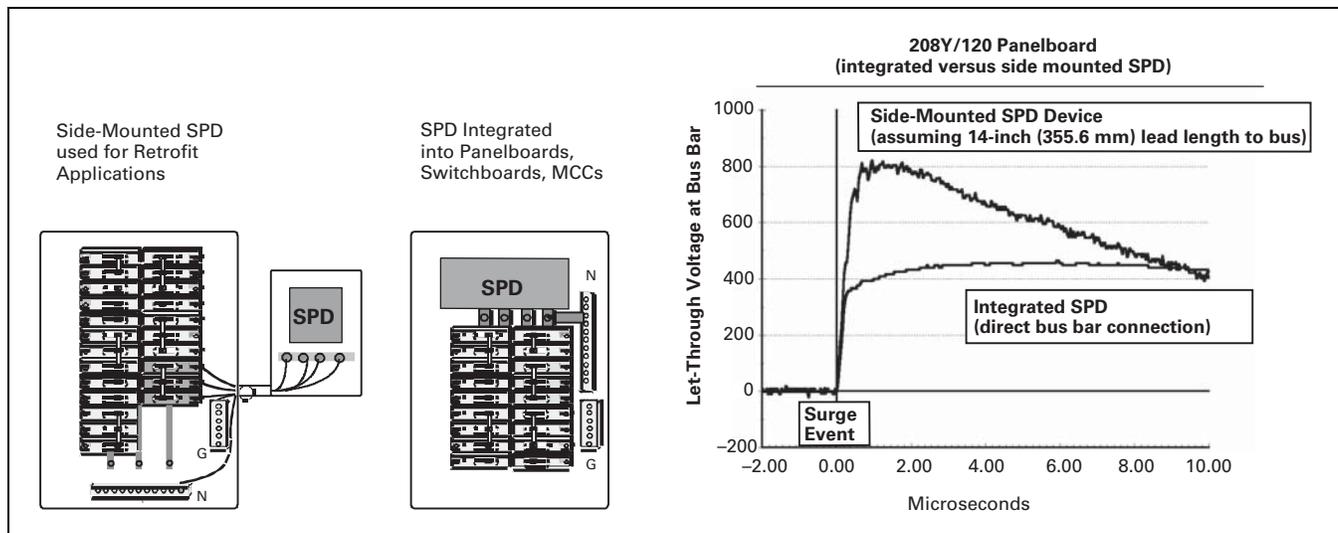


Figure 1.4-14. Performance Comparison of Side-Mounted vs. Integrated SPD

Power Quality

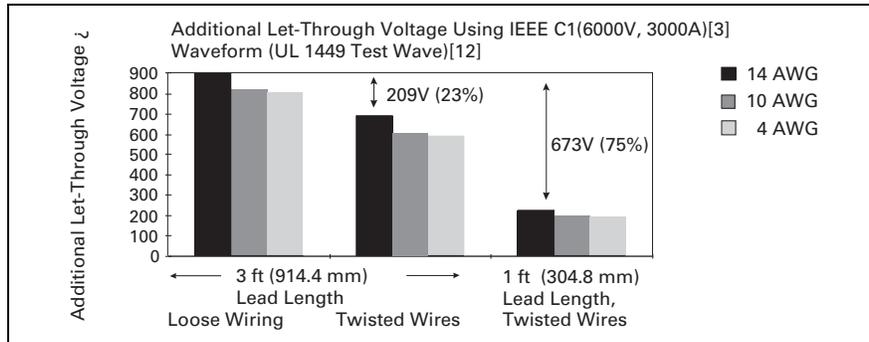


Figure 1.4-15. The Effect of Installation Lead Length on Let-Through Voltage

① Additional to UL 1449 ratings.

The size or capacity of a suppressor is measured in surge current per phase. Larger suppressors rated at approximately 250 kA per phase should be installed at the service entrance to survive high-energy surges associated with lightning.

A 250 kA per phase surge rating allows for over a 25-year life expectancy assuming an IEEE defined high exposure environment. Lower surge rating devices may be used; however, device reliability and long-term performance may be compromised.

For aerial structures, the 99.8 percentile recorded lightning stroke current is less than 220 kA. The magnitude of surges conducted or induced into a facility electrical distribution system is considerably lower given the presence of multiple paths for the surge to travel along. It is for this reason that IEEE C62.41 recommends the C3 (20 kV, 10 kA) test wave for testing SPDs installed at building entrance feeders.

SPDs with surge ratings greater than 250 kA are not required, however, higher ratings are available and may provide longer life.

Installing Panelboard Surge Protection Devices

Smaller surge capacity SPDs (120 kA per phase) are installed at branch panelboards where power disturbances are of lower energy, but occur much more frequently. This level of surge current rating should result in a greater than 25-year life expectancy.

When isolated ground systems are used, the SPD should be installed such that any common mode surges are shunted to the safety ground.

The use of a disconnect breaker is optional. The additional let-through voltage resulting from the increased inductance caused by the disconnect switch is about 50–60 V.

This increase in disturbance voltage can result in process disruption and downtime.

Installing Dataline Surge Protection

Most facilities also have communication lines that are potential sources for external surges. As identified by the power quality pyramid, proper grounding of communication lines is essential for dependable operation. NEC Article 800 states that all data, power and cable lines be grounded and bonded.

Power disturbances such as lightning can elevate the ground potential between two communicating pieces of electronic equipment with different ground references. The result is current flowing through the data cable, causing component failure, terminal lock-up, data corruption and interference.

NFPA 780 D–4.8 warns that “surge suppression devices should be installed on all wiring entering or leaving electronic equipment, usually power, data or communication wiring.”

Surge suppressors should be installed at both ends of a data or communication cable. In those situations where one end of the cable is not connected into an electronic circuit (e.g., contactor coil), protection on the electronic end only is required.

To prevent the coupling or inducing of power disturbances into communication lines, the following should be avoided:

- Data cables should not be run over fluorescent lighting fixtures
- Data cables should not be in the vicinity of electric motors
- The right category cable should be used to ensure transmission performance
- Data cables must be grounded at both ends when communicating between buildings

Reference **Tab 34** for detailed information on SPDs.

3. Voltage Regulation

Voltage regulation (i.e., sags or over-voltage) disturbances are generally site- or load-dependent. A variety of mitigating solutions are available depending upon the load sensitivity, fault duration/magnitude and the specific problems encountered. It is recommended to install monitoring equipment on the AC power lines to assess the degree and frequency of occurrences of voltage regulation problems. The captured data will allow for the proper solution selection.

4. Harmonics Distortion

Harmonics and Nonlinear Loads

Until recently, most electrical loads were linear. Linear loads draw the full sine wave of electric current at its 60 cycle (Hz) fundamental frequency—**Figure 1.4-16** shows balance single-phase, linear loads. As the figure shows, little or no current flows in the neutral conductor when the loads are nonlinear and balanced.

With the arrival of nonlinear electronic loads, where the AC voltage is converted to a DC voltage, harmonics are created because of the use of only part of the AC sine wave. In this conversion from AC to DC, the electronics are turned on in the 60 cycle wave at a given point in time to obtain the required DC level. The use of only part of the sign wave causes harmonics.

It is important to note that the current distortion caused by loads such as rectifiers or switch mode power supplies causes the voltage distortion. That voltage distortion is caused by distorted currents flowing through an impedance. The amount of voltage distortion depends on:

- System impedance
- Amount of distorted current

Devices that can cause harmonic disturbances include rectifiers, thrusters and switching power supplies, all of which are nonlinear. Further, the proliferation of electronic equipment such as computers, UPS systems, variable speed drives, programmable logic controllers, and the like: non-linear loads have become a significant part of many installations. Other types of harmonic-producing loads include arcing devices (arc furnaces, fluorescent lights) and iron core storable devices (transformers, especially during energization).

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Nonlinear load currents vary widely from a sinusoidal wave shape; often they are discontinuous pulses. This means that nonlinear loads are extremely high in harmonic content.

Triplen harmonics are the 3rd, 9th, 15th,...harmonics. Further, triplen harmonics are the most damaging to an electrical system because these harmonics on the A-phase, B-phase and C-phase are in sequence with each other. Meaning, the triplen harmonics

present on the three phases add together in the neutral, as shown in **Figure 1.4-17**, rather than cancel each other out, as shown in **Figure 1.4-16**. Odd non-triplen harmonics are classified as “positive sequence” or “negative sequence” and are the 1st, 5th, 7th, 11th, 13th, etc.

In general, as the order of a harmonic gets higher, its amplitude becomes smaller as a percentage of the fundamental frequency.

Harmonic Issues

Harmonic currents perform no work and result in wasted electrical energy that may over burden the distribution system. This electrical overloading may contribute to preventing an existing electrical distribution system from serving additional future loads.

In general, harmonics present on a distribution system can have the following detrimental effects:

1. Overheating of transformers and rotating equipment.
2. Increased hysteresis losses.
3. Decreased kVA capacity.
4. Overloading of neutral.
5. Unacceptable neutral-to-ground voltages.
6. Distorted voltage and current waveforms.
7. Failed capacitor banks.
8. Breakers and fuses tripping.
9. Double or even triple sized neutrals to defy the negative effects of triplen harmonics.

In transformers, generators and uninterruptible power supplies (UPS) systems, harmonics cause overheating and failure at loads below their ratings because the harmonic currents cause greater heating than standard 60 Hz current. This results from increased eddy current losses, hysteresis losses in the iron cores, and conductor skin effects of the windings. In addition, the harmonic currents acting on the impedance of the source cause harmonics in the source voltage, which is then applied to other loads such as motors, causing them to overheat.

The harmonics also complicate the application of capacitors for power factor correction. If, at a given harmonic frequency, the capacitive impedance equals the system reactive impedance, the harmonic voltage and current can reach dangerous magnitudes. At the same time, the harmonics create problems in the application of power factor correction capacitors, they lower the actual power factor. The rotating meters used by the utilities for watt-hour and various measurements do not detect the distortion component caused by the harmonics. Rectifiers with diode front ends and large DC side capacitor banks have displacement power factor of 90% to 95%. More recent electronic meters are capable of metering the true kVA hours taken by the circuit.

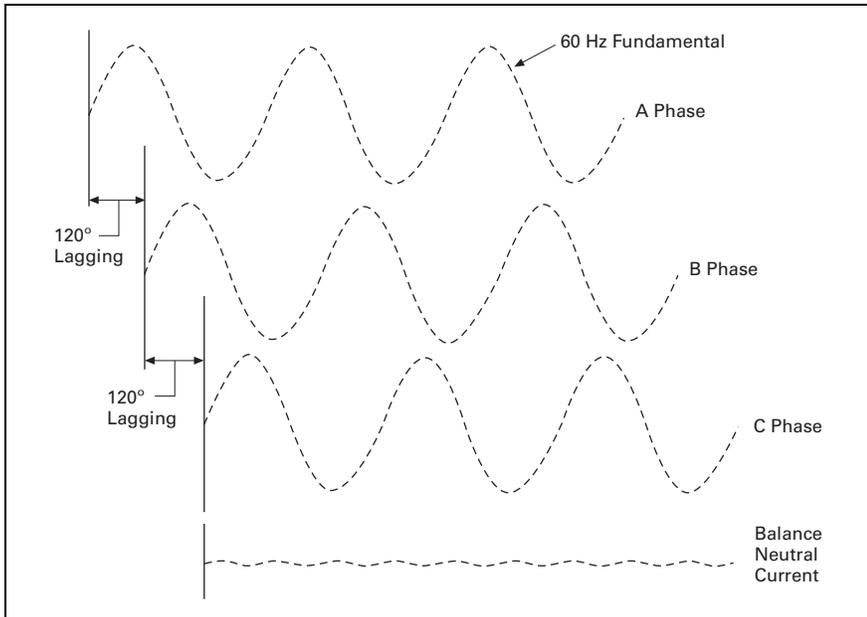


Figure 1.4-16. Balanced Neutral Current Equals Zero

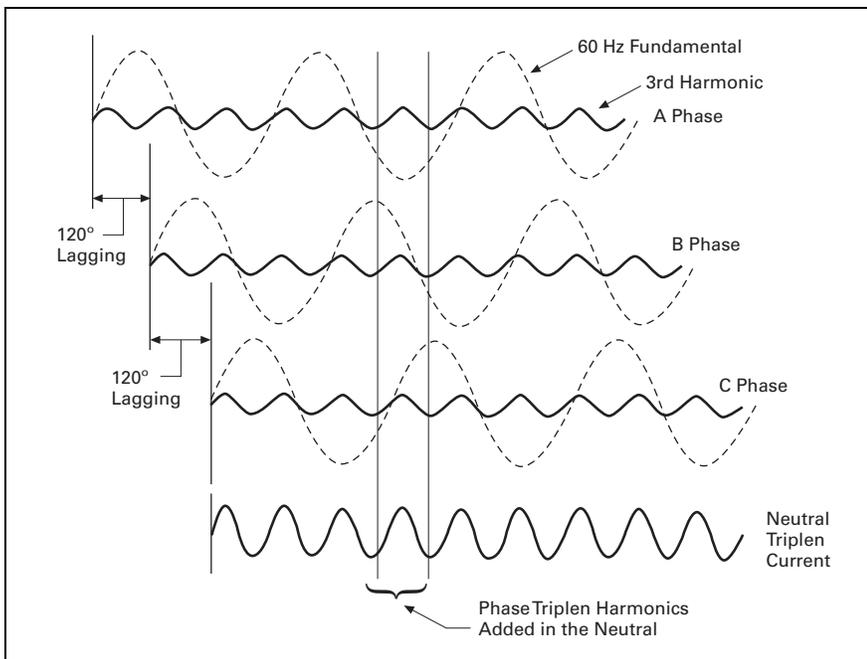


Figure 1.4-17. Unbalanced Single-Phase Loads with Triplen Harmonics

Single-phase power supplies for computer and fixture ballasts are rich in third harmonics and their odd multiples.

Even with the phase currents perfectly balanced, the harmonic currents in the neutral can total 173% of the phase current. This has resulted in overheated neutrals. The Information Technology Industry Council (ITIC) formerly known as CBEMA, recommends that neutrals in the supply to electronic equipment be oversized to at least 173% of the ampacity of the phase conductors to prevent problems. ITIC also recommends derating transformers, loading them to no more than 50% to 70% of their nameplate kVA, based on a rule-of-thumb calculation, to compensate for harmonic heating effects.

In spite of all the concerns they cause, nonlinear loads will continue to increase. Therefore, the design of nonlinear loads and the systems that supply them will have to be designed so that their adverse effects are greatly reduced. **Table 1.4-4** shows the typical harmonic orders from a variety of harmonic generating sources.

Table 1.4-4. Source and Typical Harmonics

Source	Typical Harmonics ①
6-pulse rectifier	5, 7, 11, 13, 17, 19...
12-pulse rectifier	11, 13, 23, 25...
18-pulse rectifier	17, 19, 35, 37...
Switch-mode power supply	3, 5, 7, 9, 11, 13...
Fluorescent lights	3, 5, 7, 9, 11, 13...
Arcing devices	2, 3, 4, 5, 7...
Transformer energization	2, 3, 4

① Generally, magnitude decreases as harmonic order increases.

Total Harmonic Distortion

Revised standard IEEE 519-1992 indicates the limits of current distortion allowed at the PCC (Point of Common Coupling) point on the system where the current distortion is calculated, usually the point of connection to the utility or the main supply bus of the system.

The standard also covers the harmonic limits of the supply voltage from the utility or cogenerators.

Table 1.4-5. Low Voltage System Classification and Distortion Limits for 480 V Systems

Class	C	A _N	DF
Special application ②	10	16,400	3%
General system	5	22,800	5%
Dedicated system	2	36,500	10%

② Special systems are those where the rate of change of voltage of the notch might mistrigger an event. A_N is a measurement of notch characteristics measured in volt-microseconds, C is the impedance ratio of total impedance to impedance at common point in system. DF is distortion factor.

Table 1.4-6. Utility or Cogenerator Supply Voltage Harmonic Limits

Voltage Range	2.3–69 kV	69–138 kV	>138 kV
Maximum individual harmonic	3.0%	1.5%	1.0%
Total harmonic distortion	5.0%	2.5%	1.5%

Percentages are $\frac{V_h}{V_1} \times 100$ for each harmonic

and

$$V_{thd} = \left\{ \begin{matrix} h = h_{max} \\ 2 \\ h = 2 \end{matrix} V_h^2 \right\}^{1/2}$$

It is important for the system designer to know the harmonic content of the utility's supply voltage because it will affect the harmonic distortion of the system.

Table 1.4-7. Current Distortion Limits for General Distribution Systems (120–69,000 V)

Maximum Harmonic Current Distortion in Percent of I _L						
Individual Harmonic Order (Odd Harmonics)						
I _{SC} /I _L	<11	11 ≤ h <17	17 ≤ h <23	23 ≤ h <35	35 ≤ h	TDD
<20 ③	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

③ All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L where:
I_{SC} = Maximum short-circuit current at PCC.
I_L = Maximum demand load current (fundamental frequency component) at PCC.

TDD = Total Demand Distortion. Even harmonics are limited to 25% of the odd harmonic limits above. Current distortions that result in a DC offset, e.g., half-wave converters, are not allowed.

Harmonic Solutions

In spite of all the concerns nonlinear loads cause, these loads will continue to increase. Therefore, the design of nonlinear loads and the systems that supply them will need design so adverse harmonic effects are greatly reduced. **Table 1.4-8** and depicts many harmonic solutions along with their advantages and disadvantages.

Eaton's Engineering Services & Systems Group (EESS) can perform harmonic studies and recommend solutions for harmonic problems.

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Table 1.4-8. Harmonic Solutions for Given Loads

Load Type	Solutions	Advantages	Disadvantages
Drives and rectifiers—includes three-phase UPS loads	Line reactors	<ul style="list-style-type: none"> ■ Inexpensive ■ For 6-pulse standard drive/rectifier, can reduce harmonic current distortion from 80% down to about 35–40% 	<ul style="list-style-type: none"> ■ May require additional compensation
	K-rated/drive isolation transformer	<ul style="list-style-type: none"> ■ Offers series reactance (similar to line reactors) and provides isolation for some transients 	<ul style="list-style-type: none"> ■ No advantage over reactors for reducing harmonics unless in pairs for shifting phases
	DC choke	<ul style="list-style-type: none"> ■ Slightly better than AC line reactors for 5th and 7th harmonics 	<ul style="list-style-type: none"> ■ Not always an option for drives ■ Less protection for input semiconductors
	12-pulse convertor	<ul style="list-style-type: none"> ■ 85% reduction versus standard 6-pulse drives 	<ul style="list-style-type: none"> ■ Cost difference approaches 18-pulse drive and blocking filters, which guarantee IEEE 519 compliance
	Harmonic mitigating transformers/phase shifting	<ul style="list-style-type: none"> ■ Substantial (50–80%) reduction in harmonics when used in tandem 	<ul style="list-style-type: none"> ■ Harmonic cancellation highly dependent on load balance ■ Must have even multiples of matched loads
	Tuned filters	<ul style="list-style-type: none"> ■ Bus connected—accommodates load diversity ■ Provides PF correction 	<ul style="list-style-type: none"> ■ Requires allocation analysis ■ Sized only to the requirements of that system; must be resized if system changes
	Broadband filters	<ul style="list-style-type: none"> ■ Makes 6-pulse into the equivalent of 18-pulse 	<ul style="list-style-type: none"> ■ Higher cost ■ Requires one filter per drive
	18-pulse converter	<ul style="list-style-type: none"> ■ Excellent harmonic control for drives above 100 hp ■ IEEE 519 compliant 	<ul style="list-style-type: none"> ■ High cost
	Active filters	<ul style="list-style-type: none"> ■ Handles load/harmonic diversity ■ Complete solution up to 50th harmonic 	<ul style="list-style-type: none"> ■ High cost
Computers/switch-mode power supplies	Neutral blocking filter	<ul style="list-style-type: none"> ■ Eliminates the 3rd harmonic from load ■ Relieves system capacity ■ Possible energy savings 	<ul style="list-style-type: none"> ■ High cost ■ May increase voltage distortion
	Harmonic mitigating transformers	<ul style="list-style-type: none"> ■ 3rd harmonic recalculated back to the load ■ When used as phase-shifted transformers, reduces other harmonics ■ Reduces voltage “flat-topping” 	<ul style="list-style-type: none"> ■ Requires fully rated circuits and oversized neutrals to the loads
	Oversized neutral/derated transformer	<ul style="list-style-type: none"> ■ Tolerate harmonics rather than correct ■ Typically least expensive 	<ul style="list-style-type: none"> ■ Upstream and downstream equipment fully rated for harmonics
	K-rated transformer	<ul style="list-style-type: none"> ■ Tolerate harmonics rather than correct 	<ul style="list-style-type: none"> ■ Does not reduce system harmonics
Fluorescent lighting	Harmonic mitigating transformers	<ul style="list-style-type: none"> ■ 3rd harmonic recalculated back to the load ■ When used as phase-shifted transformers, reduces other harmonics ■ Reduces voltage “flat-topping” 	<ul style="list-style-type: none"> ■ Requires fully rated circuits and oversized neutrals to the loads
	K-rated transformer	<ul style="list-style-type: none"> ■ Tolerate harmonics rather than correct them 	<ul style="list-style-type: none"> ■ Does not reduce system harmonics
	Low distortion ballasts	<ul style="list-style-type: none"> ■ Reduce harmonics at the source 	<ul style="list-style-type: none"> ■ Additional cost and typically more expensive than “system” solutions
Welding/arcing loads	Active filters	<ul style="list-style-type: none"> ■ Fast response and broadband harmonic correction ■ Reduces voltage flicker 	<ul style="list-style-type: none"> ■ High cost
	Tuned filters	<ul style="list-style-type: none"> ■ SCR controlled tuned filters simulates an active filter response 	<ul style="list-style-type: none"> ■ SCR controlled units are high cost but fixed filters are reasonable
System solutions	Tuned filters	<ul style="list-style-type: none"> ■ Provides PF correction ■ Lower cost compared to other systems 	<ul style="list-style-type: none"> ■ System analysis required to verify application. Must be resized if system changes
	Harmonic mitigating transformers	<ul style="list-style-type: none"> ■ Excellent choice for new design or upgrade 	<ul style="list-style-type: none"> ■ No PF correction benefit
	Active filters	<ul style="list-style-type: none"> ■ Ideal solution and handles system diversity 	<ul style="list-style-type: none"> ■ Highest cost

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5. Uninterruptible Power Systems (UPS)

The advent of solid-state semiconductors over 40 years ago, and their subsequent evolution to transistors, and the miniaturization of electronics into microprocessor over 25 years ago, has created numerous computation machines that assist us in every conceivable manner. These machines, and their clever configurations, whether they take the form of computers, appliance controls, fax machines, phone systems, computers of all sizes, server systems and server farms, emergency call centers, data processing at banks, credit companies, private company communication networks, government institutions and defense agencies, all rely on a narrow range of nominal AC power in order for these devices to work properly. Indeed, many other types of equipment also require that the AC electrical power source be at or close to nominal voltage and frequency. Disturbances of the power translate into failed processes, lost data, decreased efficiency and lost revenue.

The normal power source supplied by the local utility or provider is not stable enough over time to continuously serve these loads without interruption. It is possible that a facility outside a major metropolitan area served by the utility grid will experience outages of some nature 15–20 times in one year. Certain outages are caused by the weather, and others by the failure of the utility supply system due to equipment failures or construction interruptions. Some outages are only several cycles in duration, while others may be for hours at a time.

In a broader sense, other problems exist in the area of power quality, and many of those issues also contribute to the failure of the supply to provide that narrow range of power to the sensitive loads mentioned above. Power quality problems take the form of any of the following: power failure, power sag, power surge, undervoltage, overvoltage, line noise, frequency variations, switching transients and harmonic distortion. Regardless of the reason for outages and power quality problems, the sensitive loads can not function normally without a backup power source, and in many cases, the loads must be isolated from the instabilities of the utility supply and power quality problems and given clean reliable power on a continuous basis, or be able to switch over to reliable clean electrical power quickly.

Uninterruptible power supply (UPS) systems have evolved to serve the needs of sensitive equipment and can supply a stable source of electrical power, or switch to backup to allow for an orderly shutdown of the loads without appreciable loss of data or process. In the early days of main-frame computers, motor-generator sets provide isolation and clean power to the computers. They did not have deep reserves, but provided extensive ride-through capability while other sources of power (usually standby emergency engine generator sets) were brought to serve the motor-generator sets while the normal source of power was unstable or unavailable.

UPS systems have evolved along the lines of rotary types and static types of systems, and they come in many configurations, and even hybrid designs having characteristics of both types. The discussion that follows attempts to compare and contrast the two types of UPS systems, and give basic guidance on selection criteria. This discussion will focus on the medium, large and very large UPS systems required by users who need more than 10 kVA of clean reliable power.

Power Ratings of UPS Systems

- **Small UPS:** Typically 300 VA to 10 kVA, and sometimes as high as 18 kVA
- **Medium UPS:** 10–60 kVA
- **Large UPS:** 100–200 kVA units, and higher when units are paralleled
- **Very Large UPS:** 200–750 kVA units, and higher when units are paralleled

Each of these categories is arbitrary because manufacturers have many different UPS offerings for the same application. The choice of UPS type and the configuration of UPS modules for a given application depends upon many factors, including how many power quality problems the UPS is expected to solve; how much future capacity is to be purchased now for future loads; the nature of the sensitive loads and load wiring; which type of UPS system is favored, rotary or static; choices of battery or DC storage technology considered; and a host of other application issues.

Rotary UPS Systems

Typical Ratings

300–900 kVA/720 kW maximum.

Typical Rotary Configurations

Rotary UPS systems are among the oldest working systems developed to protect sensitive loads. Many of these systems are complicated engine-generator sets coupled with high inertial flywheels operated at relatively low rotational speeds. These legacy

types of hybrid UPS systems are not the focus of this discussion, because only one or two vendors offer these hybrid types of rotary UPS systems, although admittedly they continue to be used in very large-scale data center applications. See **Figure 1.4-18** for the modern high speed Rotary UPS systems discussed in this section of the guide. These types of modern rotary UPS systems are advanced, integrated designs using scalable configurations of high-speed flywheel, motor and generator in one compact UPS package. The new rotary technologies have the potential to replace battery backup systems, or at least reduce the battery content for certain applications. The appeal of rotary systems is the avoidance of the purchase, maintenance and facility space required by DC battery based backup systems.

High-Speed Rotary Concept of Operation

The modern rotary type of UPS operation is understood by reviewing the four topics below: startup mode, normal operation mode, discharge mode and recharge mode.

Startup Mode

The UPS output is energized on bypass as soon as power is applied from the source to the system input. The UPS continues the startup procedure automatically when the front panel controls are placed into the "Online" position. Internal UPS

system checks are performed then the input contactor is closed. The static disconnect switch is turned on and the conduction angle is rapidly increased from zero to an angle that causes the DC bus voltage between the utility converter and the flywheel converter to reach approximately 650 V through the rectifying action of the freewheeling diodes in the utility converter. As soon as this level of DC voltage is reached, the static disconnect turns on fully. The next steps involved the utility converter IGBTs to start firing, which allows the converter to act as a rectifier, a regulating voltage source and an active harmonic filter. As the IGBTs begin to operate, the DC bus is increased to a normal operating voltage of approximately 800 V, and the output bus is transferred from bypass to the output of the power electronics module. The transfer from bypass is completed when the output contactor is closed and the bypass contactor opened in a make-before-break manner.

The firing of the SCRs in the static disconnect switch is now changed so that each SCR in each phase is only turned on during the half-cycle, which permits real power to flow from the utility supply to the UPS. This firing pattern at the static disconnect switch prevents power from the flywheel from feeding backward into the utility supply and ensures that all of the flywheel energy is available to support the load.

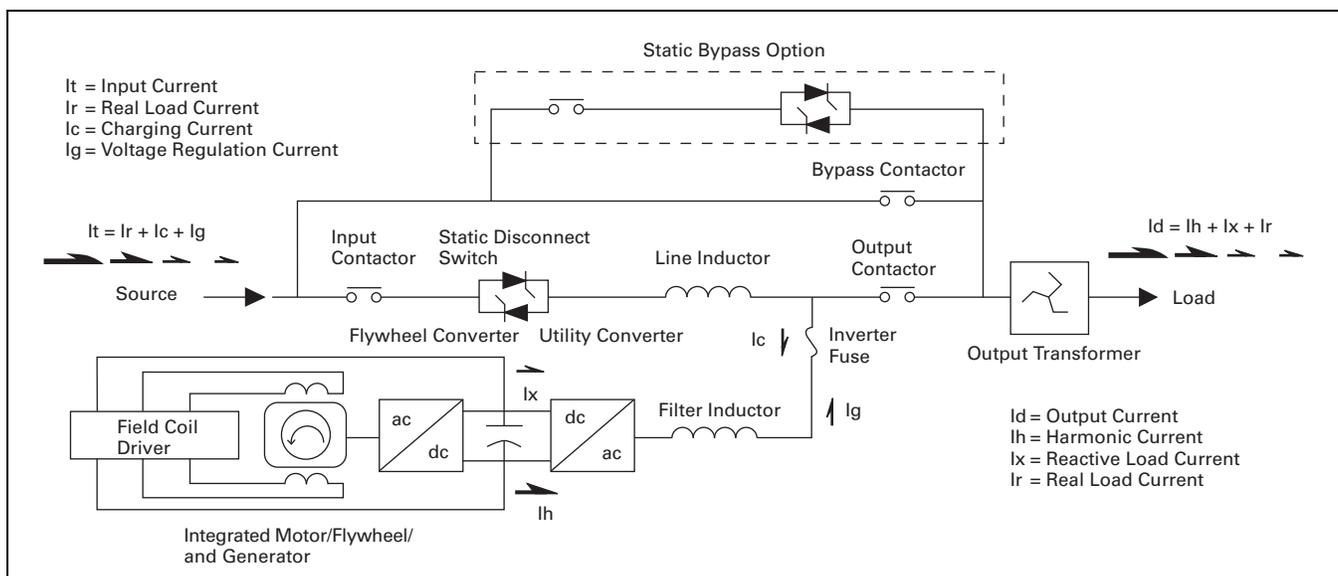


Figure 1.4-18. Typical-High Speed Modern Rotary UPS

Immediately after the output is transferred from bypass to the power electronic module, the flywheel field is excited, which also provides magnetic lift to unload the flywheel bearings. The flywheel inverter is turned on and gradually increases frequency at a constant rate to accelerate the flywheel to approximately 60 rpm. Once the flywheel reaches 60 rpm, the flywheel inverter controls the acceleration to keep currents below the maximum charging and the maximum input settings. Once the flywheel reaches 4000 rpm, the UPS is fully functional and capable of supporting the load during a power quality event. Flywheel acceleration continues until the flywheel reaches “full charge” at 7700 rpm. The total time to complete startup is less than 5 minutes.

Normal Operation Mode

Once the UPS is started and the flywheel is operating at greater than 4000 rpm, the UPS is in the normal operating mode where it is regulating output voltage and supplying reactive and harmonic currents required by the load. At the same time it cancels the effect of load current harmonics on the UPS output voltage.

Input current consists of three components: real load current, charging current, and voltage regulation current. Real current is current that is in phase with the supply voltage and supplies real power to the load. Real current flowing through the line inductor causes a slight phase shift of the current lagging the voltage by 10 degrees and ensures that the UPS can quickly transfer to bypass without causing unacceptable switching transients. The second component is charging current required by the flywheel to keep the rotating mass fully charged at rated rpm, or to recharge the rotating mass after a discharge. The power to maintain full charge is low at 2 kW and is accomplished by the IGBTs of the flywheel converter gating to provide small pulses of motoring current to the flywheel. This current can be much higher if fast recharge times are selected. The final component of input current is the voltage regulation current, which is usually a reactive current that circulates between the input and the utility converter to regulate the output voltage. Leading reactive current

causes a voltage boost across the line inductor, and a lagging current causes a bucking voltage. By controlling the utility converter to maintain nominal output voltage, just enough reactive current flows through the line inductor to make up the difference between the input voltage and the output voltage.

The load current consists of three components: the harmonic current required by the load, the reactive load current, and the real current, which does the work. The utility converter supplies both the harmonic and reactive currents. Because these currents supply no net power to the load, the flywheel supplies no energy for these currents. They circulate between the utility converter and the load. The power stage controls analyze the harmonic current requirements of the load and set the firing angle of the inverter IGBTs to make the utility converter a very low impedance source to any harmonic currents. Thus, nonlinear load currents are supplied almost entirely from the utility converter with little effect on the quality of the UPS output voltage waveform and with almost no transmission of load harmonics currents to the input of the UPS.

Discharge Mode

The UPS senses the deviation of the voltage or frequency beyond programmed tolerances and quickly disconnects the supply source by turning off the static disconnect switch and opening the input contactor. The disconnect occurs in less than one-half cycle. Then the utility converter starts delivering power from the DC bus to the load, and the flywheel converter changes the firing point of its IGBTs to deliver power to the DC bus. The UPS maintains a clean output voltage within 3% or nominal voltage to the load when input power is lost.

Recharge Mode

When input power is restored to acceptable limits, the UPS synchronizes the output and input voltages, closes the input contactor and turns on the static disconnect switch. The utility converter then transfers power from the flywheel to the input source by linearly increasing the real input current. The transfer time is programmable from 1 to 15 seconds. As soon

as the load power is completely transferred to the input source, the utility converter and flywheel converter start to recharge the flywheel and return to normal operation mode. The flywheel recharge power is programmable between a slow and fast rate, and using the fast rate results in an increase of UPS input current over nominal levels. Recharging the flywheel is accomplished by controlling the utility and flywheel converter in a similar manner as is used to maintain full charge in the normal operation mode, however the IGBT gating points are changed to increase current into the flywheel.

High-Speed Rotary Advantages

- Addresses all power quality problems
- Battery systems are not required or used
- No battery maintenance required
- Unlimited discharge cycles
- 150-second recharge time available
- Wide range of operating temperatures can be accommodated (-20 ° to 40 °C)
- Small compact size and less floor space required (500 kW systems takes 20 sq ft)
- N+1 reliability available up to 900 kVA maximum
- No disposal issues

High-Speed Rotary Disadvantages

- Flywheel does not have deep reserve capacity—rides through for up to 13 seconds at 100% load
- Some enhanced flywheel systems may extend the ride through to 30 seconds at 100% load
- Mechanical flywheel maintenance required every 2–3 years, and oil changes required every year
- Recharge fast rates require the input to be sized for 125% of nominal current
- Flywheels failures in field not understood
- Requires vacuum pumps for high-speed flywheels
- Limited number of vendors and experience

Static UPS Systems

Typical Ratings

40–750 kVA/600 kW, and higher when multiple units are paralleled.

Typical Static UPS Configurations

Static UPS systems modules are available in three basic types of configurations known as standby, line interactive and double conversion. See **Tab 33** in this guide for details on all the UPS configurations available from Eaton. The lighter power ratings are likely to be one of the first two types of configurations, e.g., standby or line interactive. Most medium or large static UPS installations use the double conversion technology in one or multiple module configurations, i.e., or multiple UPS units in parallel. **Figure 1.4-19** illustrates the one-line diagram of a simple single Double Conversion UPS module. Brief explanations appear for the standby and line interactive UPS systems after the text explaining the Double Conversion static UPS type of system.

A. **Double conversion concept of operation**—the basic operation of the Double Conversion UPS is:

1. Normal power is connected to the UPS input through the facility electrical distribution system. This usually involves two input circuits that must come from the same source.
2. The Rectifier/Charger function converts the normal AC power to DC power to charge the battery and power the inverter. The load is isolated from the normal input source.
3. The battery stores DC energy for use when input power to the UPS fails. The amount of power available from the DC battery system and time to discharge voltage is a function of the type of battery selected and the ampere-hour sized used. Battery systems should be sized for no less than 5 minutes of clean power usage from a fully charged state, and, in many cases, are sized to provide more time on battery power.
4. The DC link connects the output of the rectifier/charger to the input of the inverter and to the battery. Typically the rectifier/charger is sized slightly higher than 100% of UPS output because it must power the inverter and supply charger power to the battery.
5. The bypass circuit provides a path for unregulated normal power to be routed around the major electronic sub-assemblies of the UPS to the load so that the load can continue to operate during maintenance, or when the UPS electronics fails. The bypass static switch can switch to conducting

mode in 150–120 milliseconds. When the UPS recognizes a requirement to transfer to the bypass mode, it simultaneously turns the static switch ON, the output breaker to OPEN, and the bypass breaker to CLOSE. The output breaker opens and the bypass breaker closes in about 50 milliseconds. The restoration of normal conditions at the UPS results in the automatic restoration of the UPS module powering the load through the rectifier/charger and inverter with load isolation from power quality problems, and the opening of the bypass circuit.

Static Double Conversion Advantages

- Addresses all power quality problems
- Suitable for applications from 5 kVA to over 2500 kVA
- Simple battery systems are sized for application
- Long battery backup times and long life batteries are available
- Higher reliability is available using redundant UPS modules

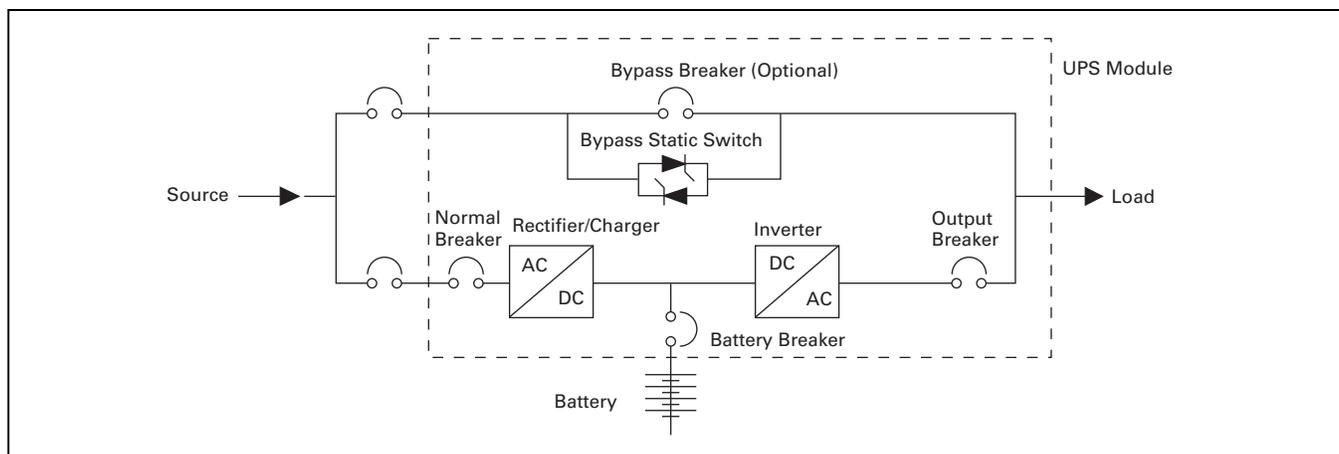


Figure 1.4-19. Typical Static UPS, Double Conversion Type with Battery Backup

Static Double Conversion Disadvantages

- Battery systems, battery maintenance and battery replacement are required
- Large space requirement for battery systems (higher life takes more space, e.g., 500 kW takes 80–200 sq ft depending upon the type of battery used, VRLA 10 year, VRLA 20 year or flooded)
- Limited discharge cycles of battery system
- Narrow temperature range for application
- Efficiencies are in the 90–94% range, which is lower than some line interactive configurations
- Bypass mode places load at risk unless bypass has UPS backup
- Redundancy of UPS modules results in higher costs
- Output faults are cleared by the bypass circuit
- Output rating of the UPS is 150% for 30 seconds
- Battery disposal and safety issues exist

B. Standby UPS concept of

operation—The basic operation of the Standby UPS is:

1. The Standby UPS topology is similar to the double conversion type, but the operation of the UPS is different in significant ways. Normal power is connected to the UPS input through the facility electrical distribution system. This usually involves two input circuits that must come from the same source. See **Figure 1.4-20** for details.
2. The rectifier/charger function converts the normal AC power to DC power to charge the battery only, and does not simultaneously power the inverter. The load is connected to the input source through the bypass static switch. The inverter is in the standby mode ready to serve the load from battery power if the input power source fails.

3. The battery stores DC energy for use by the inverter when input power to the UPS fails. The amount of power available from the DC battery system and time to discharge voltage is a function of the type of battery selected and the ampere-hour sized used. Battery systems should be sized for the anticipated outage.
4. The DC link connects the output of the rectifier/charger to the input of the inverter and to the battery. Typically the rectifier/charger is sized only to supply charger power to the battery, and is rated far lower than in the double conversion UPS.
5. The bypass circuit provides a direct connection of input source to the load. The load operates from unregulated power. The bypass static switch can switch to non-conducting mode in 150–120 milliseconds. When the UPS recognizes the loss of normal input power, it transfers to battery/inverter mode by simultaneously turning the Inverter ON and the static switch OFF.

Static Standby UPS Advantages

- Lower costs than double conversion
- Rectifier and charger are economically sized
- Efficient design
- Batteries are sized for the application

Static Standby UPS Disadvantages

- Impractical over 2 kVA
- Little to no isolation of load from power quality disturbances
- Standby power is from battery alone
- Battery systems, battery maintenance and battery replacement are required
- Limited discharge cycles of battery system
- Narrow temperature range for application
- Output faults are cleared by the bypass circuit
- Battery disposal and safety issues exist

C. Static line interactive UPS

concept of operation—the basic operation of the Line Interactive UPS is:

1. The Line Interactive type of UPS has a different topology than the static double conversion and standby systems. The normal input power is connected to the load in parallel with a battery and bi-directional inverter/charger assembly. The input source usually terminates at a line inductor and the output of the inductor is connected to the load in parallel with the battery and inverter/charger circuit. See **Figure 1.4-21** for more details.
2. The traditional rectifier circuit is eliminated and this results in a smaller footprint and weight reduction. However, line conditioning is compromised.
3. When the input power fails, the battery/inverter charger circuit reverses power and supplies the load with regulated power.

Static Line Interactive UPS Advantages

- Slight improvement of power conditioning over standby UPS systems
- Small footprints and weights
- Efficient design
- Batteries are sized for the application

Static Line Interactive UPS Disadvantages

- Impractical over 5 kVA
- Not as good conditioning as double conversion
- Standby power is from battery alone
- Battery systems, battery maintenance and battery replacement are required
- Limited discharge cycles for the battery system
- Narrow temperature range for application
- Battery disposal and safety issues exist

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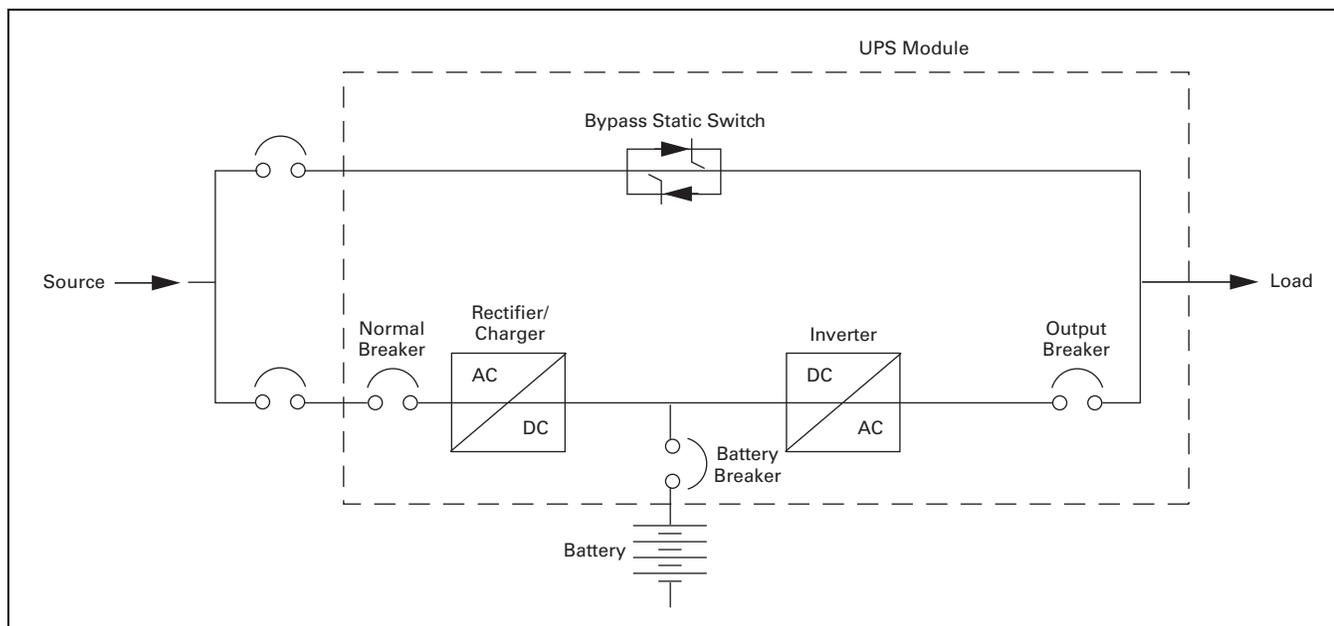


Figure 1.4-20. Typical Static UPS, Standby Type with Battery Backup

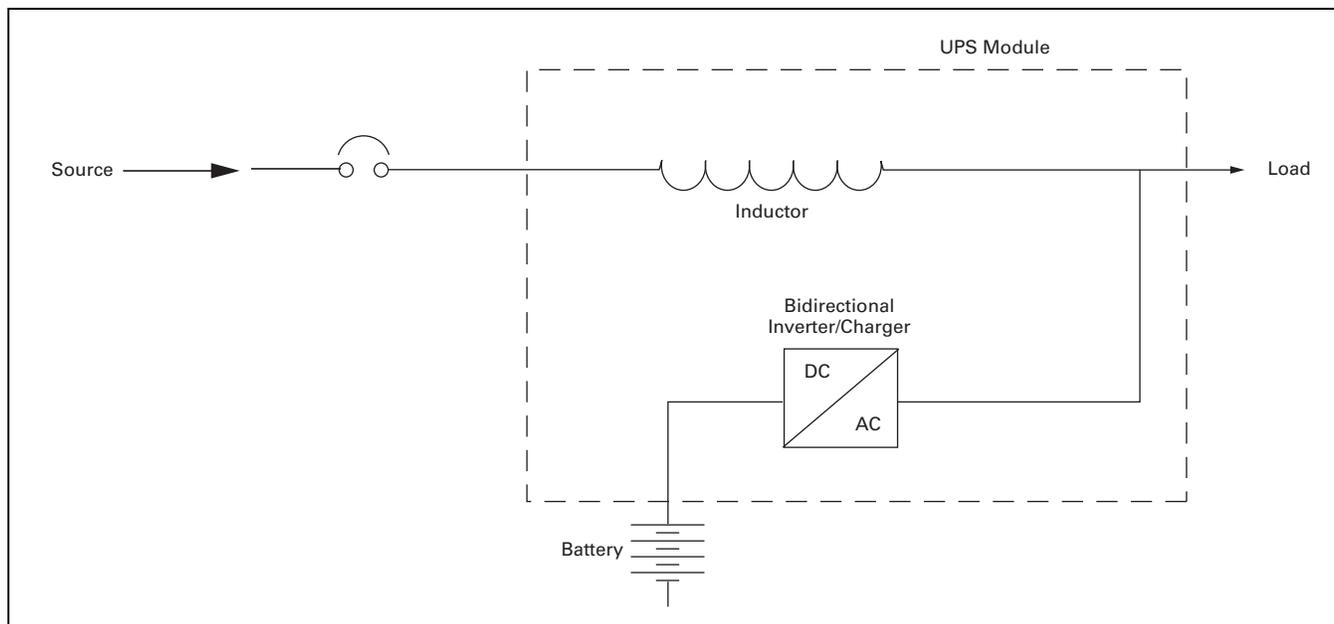


Figure 1.4-21. Typical Static UPS, Line Interactive Type with Battery Backup

Secondary Voltage Selection

The choice between 208Y/120 V and 480Y/277 V secondary distribution for commercial and institutional buildings depends on several factors. The most important of these are size and types of loads (motors, fluorescent lighting, incandescent lighting, receptacles) and length of feeders. In general, large motor and fluorescent lighting loads, and long feeders, will tend to make the higher voltages, such as 480Y/277 V, more economical. Very large loads and long runs would indicate the use of medium voltage distribution and loadcenter unit substations close to the loads. Conversely, small loads, short runs and a high percentage of incandescent lighting would favor lower utilization voltages such as 208Y/120 V.

Industrial installations, with large motor loads, are almost always 480 V, often ungrounded delta or resistance grounded delta or wye systems (see section on ground fault protection).

Practical Factors

Because most low voltage distribution equipment available is rated for up to 600 V, and conductors are insulated for 600 V, the installation of 480 V systems uses the same techniques and is essentially no more difficult, costly, or hazardous than for 208 V systems. The major difference is that an arc of 120 V to ground tends to be self-extinguishing, while an arc of 277 V to ground tends to be self-sustaining and likely to cause severe damage. For this reason, the National Electrical Code requires ground fault protection of equipment on grounded wye services of more than 150 V to ground, but not exceeding 600 V phase-to-phase (for practical purpose, 480Y/277 V services), for any service disconnecting means rated 1000 A or more. The National Electrical Code permits voltage up to 300 V to ground on circuits supplying permanently installed electric discharge lamp fixtures, provided the luminaires do not have an integral manual switch and are mounted at least 8 ft (2.4 m) above the floor. This permits a three-phase, four-wire, solidly grounded 480Y/277 V system to supply directly all of the fluorescent and high-intensity discharge (HID) lighting in a building at 277 V, as well as motors at 480 V.

Technical Factors

The principal advantage of the use of higher secondary voltages in buildings is that for a given load, less current means smaller conductors and lower voltage drop. Also, a given conductor size can supply a large load at the same voltage drop in volts, but a lower *percentage* voltage drop because of the higher supply voltage. Fewer or smaller circuits can be used to transmit the power from the service entrance point to the final distribution points. Smaller conductors can be used in many branch circuits supplying power loads, and a reduction in the number of lighting branch circuits is usually possible.

It is easier to keep voltage drops within acceptable limits on 480 V circuits than on 208 V circuits. When 120 V loads are

supplied from a 480 V system through step-down transformers, voltage drop in the 480 V supply conductors can be compensated for by the tap adjustments on the transformer, resulting in full 120 V output. Because these transformers are usually located close to the 120 V loads, secondary voltage drop should not be a problem. If it is, taps may be used to compensate by raising the voltage at the transformer.

The interrupting ratings of circuit breakers and fuses at 480 V have increased considerably in recent years, and protective devices are now available for any required fault duty at 480 V. In addition, many of these protective devices are current limiting, and can be used to protect downstream equipment against these high fault currents.

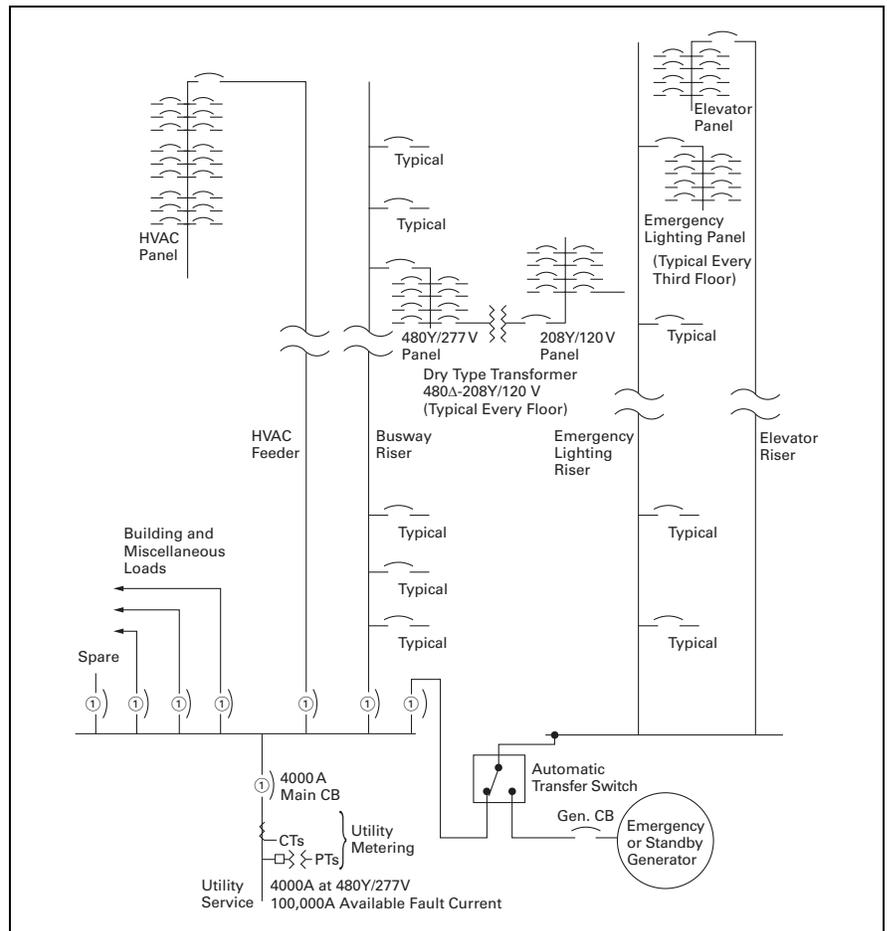


Figure 1.4-22. Typical Power Distribution and Riser Diagram for a Commercial Office Building

Ⓢ Include ground fault trip.

Other Application Considerations

Economic Factors

Utilization equipment suitable for principal loads in most buildings is available for either 480 V or 208 V systems. Three-phase motors and their controls can be obtained for either voltage, and for a given horsepower are less costly at 480 V. Fluorescent and HID lamps can be used with either 277 V or 120 V ballasts. However, in almost all cases, the installed equipment will have a lower total cost at the higher voltage.

Energy Conservation

Because of the greatly increased cost of electrical power, designers must consider the efficiency of electrical distribution systems, and design for energy conservation. In the past, especially in commercial buildings, design was for lowest first cost, because energy was inexpensive. Today, even in the speculative office building, operating costs are so high that energy-conserving designs can justify their higher initial cost with a rapid payback and continuing savings. Buildings that must meet LEED certifications may require energy-saving designs. There are four major sources of energy conservation in a commercial building—the lighting system, the motors and controls, the transformers and the HVAC system.

The lighting system must take advantage of the newest equipment and techniques. New light sources, familiar light sources with higher efficiencies, solid-state ballasts with dimming controls, use of daylight, environmental design, efficient luminaires, computerized or programmed control, and the like, are some of the methods that can increase the efficiency of lighting systems. They add up to providing the necessary amount of light, with the desired color rendition, from the most efficient sources, where and when it is needed, and not providing light where or when it is not necessary. Using the best of techniques, office spaces that originally required as much as 3.5W per square foot have been given improved lighting, with less glare and higher visual comfort, using as little as 1.0 to 2.0W per square foot. In an office building of 200,000 square feet (60,960 m), this could mean a saving of 400 kW, which, at \$0.05 per kWh, 250 days per year, 10 hours per day, could save \$50,000 per year in energy costs. Obviously, efficient lighting is a necessity.

Motors and controls are another cause of wasted energy that can be reduced. New, energy-efficient motor designs are available using more and better core steel, and larger windings.

For any motor operating 10 or more hours per day, it is recommended to use the energy-efficient types. These motors have a premium cost of about 20% more than standard motors. Depending on loading, hours of use and the cost of energy, the additional initial cost could be repaid in energy saved within a few months, and it rarely takes more than two years. Because, over the life of a motor, the cost of energy to operate it is many times the cost of the motor itself, any motor with many hours of use should be of the energy-efficient type.

Where a motor drives a load with variable output requirements such as a centrifugal pump or a large fan, customary practice has been to run the motor at constant speed, and to throttle the pump output or use inlet vanes or outlet dampers on the fan. This is highly inefficient and wasteful of energy. In recent years, solid-state variable-frequency, variable-speed drives for ordinary induction motors have been available, reliable and relatively inexpensive. Using a variable-speed drive, the throttling valves, inlet vanes or output dampers can be eliminated, saving their initial cost and energy over the life of the system. An additional benefit of both energy-efficient motors and variable-speed drives (when operated at less than full speed) is that the motors operate at reduced temperatures, resulting in increased motor life.

Transformers have inherent losses. Transformers, like motors, are designed for lower losses by using more and better core materials, larger conductors, etc., and this results in increased initial cost. Because the 480 V to 208Y/120 V stepdown transformers in an office building are usually energized 24 hours a day, savings from lower losses can be substantial, and should be considered in all transformer specifications. One method of obtaining reduced losses is to specify transformers with 220 °C insulation systems designed for 150 °C average winding temperature rise, with no more than 80 °C (or sometimes 115 °C) average winding temperature rise at full load. A better method would be to evaluate transformer losses, based on actual loading cycles throughout the day, and consider the cost of losses as well as the initial cost of the transformers in purchasing.

NEMA standard TP-1 is being adopted by many states and is another method of energy-efficient design. NEMA TP-1 establishes minimum operating efficiencies for each distribution transformer size at a loading equal to 35% of the transformer full load kVA. The 35% loading value in the NEMA standard reflects field studies conducted by the U.S. Department of Energy, which showed that dry-type transformers installed in commercial facilities are typically loaded at an average of 35% of their full load capacity over a 24-hour time period. **Table 1.4-9** compares losses for both low temperature rise and TP-1 transformers using a 75 kVA design.

Table 1.4-9. Load Losses

Temp. Rise °C	Load Losses in Watts					
	No Loss	25% Load	35% Load	50% Load	75% Load	Full Load
150	360	490	620	885	1535	2450
115	420	480	610	805	1170	1950
80	500	535	615	730	945	1410
TP-1 150	230	310	480	745	1235	2280

Efficiencies above TP-1. Candidates Standard Level (CSL) is a DOE efficiency evaluation for transformers. CSL-1 is equivalent to TP-1. Levels are from CSL-1 to CSL-5. CSL-3 is being promoted for higher efficiency applications. A NEMA white paper *Clarifications on the Use of DOE Design—Lines 6, 7 and 8* is available from NEMA that elaborates on the matter.

HVAC systems have traditionally been very wasteful of energy, often being designed for lowest first cost. This, too, is changing. For example, reheat systems are being replaced by variable air volume systems, resulting in equal comfort with substantial increases in efficiency. While the electrical engineer has little influence on the design of the HVAC system, he/she can specify that all motors with continuous or long duty cycles are specified as energy-efficient types, and that the variable-air-volume fans do not use inlet vanes or outlet dampers, but are driven by variable-speed drives. Variable-speed drives can often be desirable on centrifugal compressor units as well. Since some of these requirements will be in HVAC specifications, it is important for the energy-conscious electrical engineer to work closely with the HVAC engineer at the design stage.

Building Control Systems

In order to obtain the maximum benefit from these energy-saving lighting, power and HVAC systems, they must be controlled to perform their functions most efficiently. Constant monitoring would be required for manual operation, so some form of automatic control is required. The simplest of these energy-saving controls, often very effective, is a time clock to turn various systems on and off. Where flexible control is required, programmable controllers may be used. These range from simple devices, similar to multi-function time clocks, up to full micro-processor-based, fully programmable devices, really small computers. For complete control of all building systems, computers with specialized software can be used. Computers can not only control lighting and HVAC systems, and provide peak demand control, to minimize the cost of energy, but they can perform many other functions. Fire detection and alarm systems can operate through the computer, which can also perform auxiliary functions such as elevator control and building communication in case of fire. Building security systems, such as closed-circuit television monitoring, door alarms and intruder sensing, can be performed by the same building computer system.

The time clocks, programmable controllers and computers can obtain data from external sensors and control the lighting, motors and other equipment by means of hard wiring—separate wires to and from each piece of equipment. In the more complex systems, this would result in a tremendous number of control wires, so other methods are frequently used. A single pair of wires, with electronic digital multiplexing, can control or obtain data from many different points. Sometimes, coaxial cable is used with advanced signaling equipment. Some systems dispense with control wiring completely, sending and receiving digital signals over the power wiring. The newest systems may use fiber-optic cables to carry tremendous quantities of data, free from electromagnetic interference. The method used will depend on the type, number and complexity of functions to be performed.

Because building design and control for maximum energy saving is important and complex, and frequently involves many functions and several systems, it is necessary for the design engineer to make a thorough building and environmental study, and to weigh the costs and advantages of many systems. The result of good design can be economical, efficient operation. Poor design can be wasteful and extremely costly.

Distributed Energy Resources

Distributed energy resources (DER) are increasingly becoming prominent sources of electric power. Distributed energy resources are usually small-to-medium sources of electric generation, either from renewable or non-renewable sources. Sources include:

- Photovoltaic (PV) systems (solar systems)
- Wind
- Fossil-fueled (diesel, natural gas, landfill gas, coal-bed methane) generators (reciprocating engines)
- Gas-fired turbines (natural gas, landfill gas, coal-bed methane)
- Water-powered (hydro)
- Fuel cells
- Microturbines
- Wave power
- Coal-fired boilers

Distributed energy resources may also be termed alternative energy resources.

Prime Power

DER can be used for generating prime power or for cogeneration. Prime power concerns a system that is electrically separated from the electrical grid. Prime power is generated at remote sites where commercial electrical power is not available.

Cogeneration

Cogeneration is another outgrowth of the high cost of energy. Cogeneration is the production of electric power concurrently with the production of steam, hot water and similar energy uses. The electric power can be the main product, and steam or hot water the byproduct, as in most commercial installations, or the steam or hot water can be the most required product, and electric power a byproduct, as in many industrial installations. In some industries, cogeneration has been common practice for many years, but until recently it has not been economically feasible for most commercial installations.

This has been changed by the high cost of purchased energy, plus a federal law (Public Utility Regulatory Policies Act, known as PURPA) that requires public utilities to purchase any excess power generated by the cogeneration plant. In many cases, practical commercial cogeneration systems have been built that provide some or all of the electric power required, plus hot water, steam, and sometimes steam absorption-type air conditioning. Such cogeneration systems are now operating successfully in hospitals, shopping centers, high-rise apartment buildings and even commercial office buildings.

Where a cogeneration system is being considered, the electrical distribution system becomes more complex. The interface with the utility company is critical, requiring careful relaying to protect both the utility and the cogeneration system. Many utilities have stringent requirements that must be incorporated into the system. Proper generator control and protection is necessary, as well. An on-site electrical generating plant tied to an electrical utility, is a sophisticated engineering design.

Utilities require that when the protective device at their substation opens that the device connecting a cogenerator to the utility open also.

One reason is that most cogenerators are connected to feeders serving other customers. Utilities desire to reclose the feeder after a transient fault is cleared. Reclosing in most cases will damage the cogenerator if it had remained connected to their system.

Islanding is another reason why the utility insists on the disconnection of the cogenerator. Islanding is the event that after a fault in the utility's system is cleared by the operation of the protective devices, a part of the system may continue to be supplied by cogeneration. Such a condition is dangerous to the utility's operation during restoration work.

Major cogenerators are connected to the subtransmission or the transmission system of a utility. Major cogenerators have buy-sell agreements. In such cases, utilities use a trip transfer scheme to trip the cogenerator breaker.

Guidelines that are given in ANSI Guide Standard 1001 are a good starting point, but the entire design should be coordinated with the utility.

Other Application Considerations

1

PV System Design Considerations

Successful photovoltaic (PV) design and construction is a complex multi-discipline endeavor. Proper planning includes the site-layout study for maximizing the sun's energy harvesting for solar module selection, and for updating the electrical/mechanical design and construction to the latest code and local constraints, including fire marshal and seismic regulations. Professionally prepared bid, permit, construction and as-built drawings shall be required and maintained. For installation in/on/for existing structures and sites, it is advised that, at the minimum, pre-design and construction tests be performed for existing power-quality issues, water drainage and the utility feeder/transformer, and that electrical distribution panel ratings are verified sufficient for the planned solar system, and the necessary arc flash studies be performed. Connection to the utility is always a utility interconnect agreement (application) process, and is typically required for the available solar incentives and programs offered by the utility, municipality, state, and various federal agencies and departments. State, and IRS tax incentives require well-documented records.

Solar systems, while low maintenance, do require periodic service. The solar modules need to be washed-clean on a regular basis and electrical terminations require initial and annual checks. Cooling system filters are periodic maintenance items, with the re-fresh rate dependent upon typical and unusual circumstances.

Solar systems installed near other new construction where dust is generated (e.g., grading, paving) or agricultural environments may require additional solar-system checks and services. Planning for such contingencies is the business of solar-system design, construction and on-going operation. Performance-based incentives require verifiable metering, often by registered/approved independent third parties. Such monitoring periods are typically for 60 or more months.

The S-Max inverter offers a wide range of features and options to enable a successful and long-lived solar-energy harvesting solution. The isolation step-up transformer, coupled to either a negative or a positive grounded solar array, ensures that the S-Max can match to all (known) solar module technologies.

The S-Max follows standard industry and code practices in determining the maximum number of solar modules per string for the open-circuit photovoltaic (PV) voltage rise in cold weather ($V_{oc} < 600$ V as per NEC). Its low 300 V MPPT lower-limit ensures that multiple configurations are possible for solar systems hot weather voltage drop (i.e., V_{mp} as a function of temperature, solar irradiance and array-conductor voltage drop). The following equations are the basis of all solar system layout and design. Consult professional engineering to help when planning any solar system. Engineering design firms offering complete solar systems "turn-key" calculations, drawings, construction management and procurement are a good place to start. Eaton offers professional S-Max inverter application assistance, on-site commissioning and maintenance services. Eaton maintains a working relationship with the best engineering services firms across the country, and helps arrange the successful implantation of your solar system. The S-Max 250 kW inverter and up-fit solutions easily perform well in Mega-Watt and Utility-Scale systems. Eaton also offers a wide range of balance-of-system (BOS) products, ranging from solar module source and array combiners, to DC and AC breakers, electrical and distribution panels and switchgear.

Low Temperature Equation

$$V_{oc_max} = V_{oc} + (\text{temp-differential} \times \text{temp-coefficient-of-}V_{oc})$$

The temp-differential is the difference between the standard module rating at 25 °C and the low temperature. The voltage (V_{oc}) will rise with temperatures under 25 °C.

Seek the solar module data sheet for a list of standard test condition (STC) data, temperature coefficients, and any special module-related information to determine the low-temperature open circuit voltage. The NEC 2011, and industry practice, requires the use of the site's Extreme Annual Mean Minimum Design Dry Bulb Temperature data, available in the ASHRAE Handbook. Code requires that the resulting maximum voltage (V_{oc}) when added in the "string of modules" be under 600 V. Record low temperatures provide an indication of system performance when temperatures drop to these levels. The S-Max inverter is designed to standards higher than 600 Vdc.

High Temperature Equation

Once the maximum number of modules per string is established, the minimum number of modules per string needs to be calculated. Here, more site-related aspects come into play, as the voltage of solar modules decreases with increasing temperature. The modules' (photovoltaic cell) temperature is influenced by the ambient temperature, reflected sun-loads from nearby structures, parapet walls, roof-coatings, etc. Air-flow above and behind the solar modules affect the cell temperature. The accepted industry standards to add to the module heating is listed below. Unusual mounting systems may adjust these figures, and it is best to seek assistance in establishing and planning such installations.

- 20 °C for ground or pole mounted solar systems
- 25 °C for roof-top solar systems mounted at inclined angles (offers improved air-flow behind the modules)
- 30 °C for roof-top solar systems mounted flat, yet at least 6.00 inches (152.4 mm) above the roof surface

$$V_{mp_min} = V_{mp} + (\text{temp-differential} \times \text{temp-coefficient-of-}V_{mp})$$

The temp-differential in this case includes the above temperature "adders." The V_{mp} and related temperature coefficients are listed on the solar module's data sheets.

While the code doesn't indicate the high temperature to use (i.e., because it is an equipment application issue), the industry standard is to evaluate the ASHRAE 2% and 4% high temperature figures, coupled to known location differences. Record high temperatures provide an indication of system performance when climatic condition reaches these levels.

Beyond the damaging temperature effects on photovoltaic module V_{mp} voltage levels, voltage drop in PV conductors under such conditions also need to be calculated and evaluated, beyond normal temperatures. The inverter only uses (knows) the V_{mp} voltage at the inverter, not at the PV modules.

Increasing grid voltages also puts a constraint on the minimum V_{mp} voltage at the DC input stage.

Other Application Considerations

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To ensure the full MPPT range without power-clipping (reduced power output), prudent PV system designs shall consider the PV array's Vmp voltage drop to the point of the inverter connection, ambient temperatures and the PV system installation type's effects on Vmp, solar module miss-match and tolerance variations, degradation of solar modules over time (solar system life), etc. Typical Vmp design values, based upon known and expected conditions are 5–10% over the minimum MPPT tracking voltage. Reference NEC 2011 Section 690, Solar Photovoltaic Systems.

Emergency Power

Most areas have requirements for emergency and standby power systems. The National Electrical Code does not specifically call for any emergency or standby power, but does have requirements for those systems when they are legally mandated and classed as emergency (Article 700), legally required standby (Article 701) by municipal, state, federal or other codes, or by any

governmental agency having jurisdiction. Optional standby systems, not legally required, are also covered in the NEC (Article 702).

Emergency systems are intended to supply power and illumination essential for safety to human life, when the normal supply fails. NEC requirements are stringent, requiring periodic testing under load and automatic transfer to emergency power supply on loss of normal supply. See **Figure 1.4-23**. All wiring from emergency source to emergency loads must be kept separate from all other wiring and equipment, in its own distribution and raceway system, except in transfer equipment enclosures and similar locations. The most common power source for large emergency loads is an engine-generator set, but the NEC also permits the emergency supply (subject to local code requirements) to be storage batteries, uninterruptible power supplies, a separate emergency service, or a connection to the service ahead of the normal service disconnecting means. Unit equipment for emergency illumination, with a rechargeable battery,

a charger to keep it at full capacity when normal power is on, one or more lamps, and a relay to connect the battery to the lamps on loss of normal power, is also permitted. Because of the critical nature of emergency power, ground fault protection is not required. It is considered preferable to risk arcing damage, rather than to disconnect the emergency supply completely. For emergency power, ground fault alarm is required by NEC 700.7(D) to indicate a ground fault in solidly grounded wye emergency systems of more than 150 V to ground and circuit-protective devices rated 1000 A or more.

Legally required standby systems, as required by the governmental agency having jurisdiction, are intended to supply power to selected loads, other than those classed as emergency systems, on loss of normal power. These are usually loads not essential to human safety, but loss of which could create hazards or hamper rescue or fire-fighting operations.

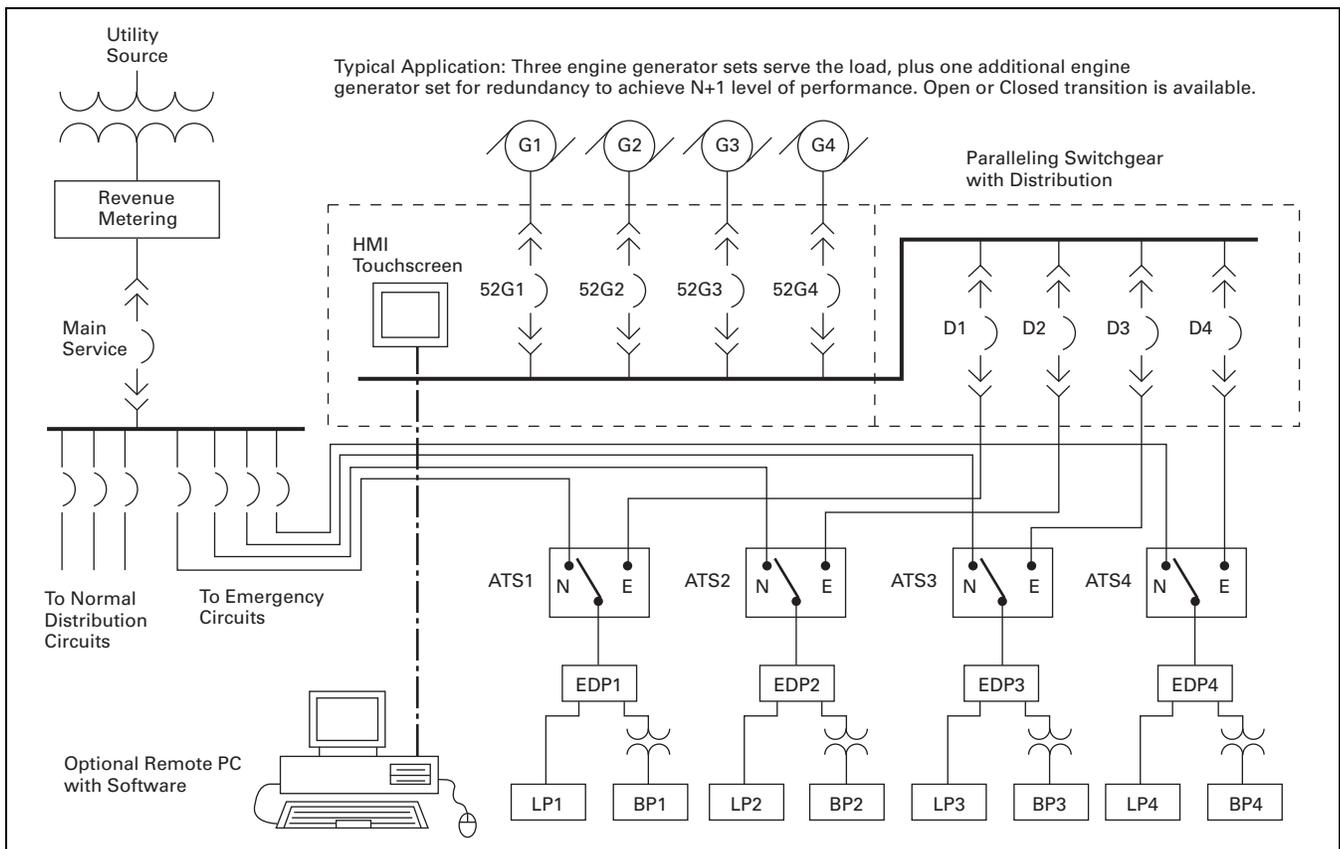


Figure 1.4-23. Typical Emergency Power System

Other Application Considerations

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NEC requirements are similar to those for emergency systems, except that wiring may occupy the same distribution and raceway system as the normal wiring if desired. Optional standby systems are those not legally required, and are intended to protect private business or property where life safety does not depend on performance of the system. Optional systems can be treated as part of the normal building wiring system. Both legally required and optional standby systems should be installed in such a manner that they will be fully available on loss of normal power. It is preferable to isolate these systems as much as possible, even though not required by code.

Where the emergency or standby source, such as an engine generator or separate service, has capacity to supply the entire system, the transfer scheme can be either a full-capacity automatic transfer switch, or, less costly but equally effective, normal and emergency main circuit breakers, electrically interlocked such that on failure of the normal supply the emergency supply is connected to the load. However, if the emergency or standby source does not have capacity for the full load, as is usually the case, such a scheme would require automatic disconnection of the nonessential loads before transfer. Simpler and more economical in such a case is a separate emergency bus, supplied through an automatic transfer switch, to feed all critical loads. The transfer switch connects this bus to the normal supply, in normal operation. On failure of the normal supply, the engine-generator is started, and when it is up to speed the automatic switch transfers the emergency loads to this source. On return of the normal source, manual or automatic retransfer of the emergency loads can take place.

Peak Shaving

Many installations now have emergency or standby generators. In the past, they were required for hospitals and similar locations, but not common in office buildings or shopping centers. However, many costly and unfortunate experiences during utility blackouts in recent years have led to the more frequent installation of engine generators in commercial and institutional systems for safety and for supplying important loads.

Industrial plants, especially in process industries, usually have some form of alternate power source to prevent extremely costly shutdowns. These standby generating systems are critical when needed, but they are needed only infrequently. They represent a large capital investment. To be sure that their power will be available when required, they should be tested periodically under load.

The cost of electric energy has risen to new high levels in recent years, and utilities bill on the basis not only of power consumed, but also on the basis of peak demand over a small interval. As a result, a new use for in-house generating capacity has developed. Utilities measure demand charges on the basis of the maximum demand for electricity in any given specific period (typically 15 or 30 minutes) during the month. Some utilities have a demand "ratchet clause" that will continue demand charges on a given peak demand for a full year, unless a higher peak results in even higher charges. One large load, coming on at a peak time, can create higher electric demand charges for a year.

Obviously, reducing the peak demand can result in considerable savings in the cost of electrical energy. For those installations with engine generators for emergency use, modern control systems (computers or programmable controllers) can monitor the peak demand, and start the engine-generator to supply part of the demand as it approaches a preset peak value. The engine-generator must be selected to withstand the required duty cycle. The simplest of these schemes transfer specific loads to the generator. More complex schemes operate the generator in parallel with the normal utility supply. The savings in demand charges can reduce the cost of owning the emergency generator equipment.

In some instances, utilities with little reserve capacity have helped finance the cost of some larger customer-owned generating equipment. In return, the customer agrees to take some or all of his load off the utility system and on to his own generator at the request of the utility (with varying limitations) when the utility load approaches capacity. In some cases, the customer's generator is paralleled with the utility to help supply the peak utility loads, with the utility buying the supplied power. Some utilities have been able to delay large capital expenditures for additional generating capacity by such arrangements.

It is important that the electrical system designer providing a substantial source of emergency and standby power investigate the possibility of using it for peak shaving, and even of partial utility company financing. Frequently, substantial savings in power costs can be realized for a small additional outlay in distribution and control equipment.

Peak shaving equipment operating in parallel with the utility are subject to the comments made under *cogeneration* as to separation from the utility under fault conditions.

Sound Levels

Sound Levels of Electrical Equipment for Offices, Hospitals, Schools and Similar Buildings

Insurance underwriters and building owners desire and require that the electrical apparatus be installed for maximum safety and the least interference with the normal use of the property. Architects should take particular care with the designs for hospitals, schools and similar buildings to keep the sound perception of such equipment as motors, blowers and transformers to a minimum.

Even though transformers are relatively quiet, resonant conditions may exist near the equipment, which will amplify their normal 120 Hz hum. Therefore, it is important that consideration be given to the reduction of amplitude and to the absorption of energy at this frequency. This problem begins in the designing stages of the equipment and the building. There are two points worthy of consideration: 1) What sound levels are desired in the normally occupied rooms of this building? 2) To effect this, what sound level in the equipment room and what type of associated acoustical treatment will give the most economical installation overall?

A relatively high sound level in the equipment room does not indicate an abnormal condition within the apparatus. However, absorption may be necessary if sound originating in an unoccupied equipment room is objectionable outside the room. Furthermore, added absorption material usually is desirable if there is a "build-up" of sound due to reflections.

Other Application Considerations

Some reduction or attenuation takes place through building walls, the remainder may be reflected in various directions, resulting in a build-up or apparent higher levels, especially if resonance occurs because of room dimensions or material characteristics.

Area Consideration

In determining permissible sound levels within a building, it is necessary to consider how the rooms are to be used and what levels may be objectionable to occupants of the building. The ambient sound level values given in **Table 1.4-10** are representative average values and may be used as a guide in determining suitable building levels.

Decrease in sound level varies at an approximate rate of 6 dB for each doubling of the distance from the source of sound to the listener. For example, if the level 6 ft (1.8 m) from a transformer is 50 dB, the level at a distance of 12 ft (3.7 m) would be 44 dB and at 24 ft (7.3 m) the level decreases to 38 dB, etc. However, this rule applies only to equipment in large areas equivalent to an out-of-door installation, with no nearby reflecting surfaces.

Table 1.4-10. Typical Sound Levels

Description	Average Decibel Level (dB)
Radio, recording and TV studios	25-30
Theatres and music rooms	30-35
Hospitals, auditoriums and churches	35-40
Classrooms and lecture rooms	35-40
Apartments and hotels	35-45
Private offices and conference rooms	40-45
Stores	45-55
Residence (radio, TV off) and small offices	53
Medium office (3 to 10 desks)	58
Residence (radio, TV on)	60
Large store (5 or more clerks)	61
Factory office	61
Large office	64
Average factory	70
Average street	80

Transformer Sound Levels

Transformers emit a continuous 120 Hz hum with harmonics when connected to 60 Hz circuits. The fundamental frequency is the “hum” that annoys people primarily because of its continuous nature. For purposes of reference, sound measuring instruments convert the different frequencies to 1000 Hz and a 40 dB level. Transformer sound levels based on NEMA publication TR-1 are listed in **Table 1.4-11**.

Table 1.4-11. Maximum Average Sound Levels for Medium Voltage Transformers—Decibels

kVA	Liquid-Filled Transformers		Dry-Type Transformers	
	Self-Cooled Rating (OA)	Forced-Air Cooled Rating (FA)	Self-Cooled Rating (AA)	Forced-Air Cooled Rating (FA)
300	55	—	58	67
500	56	—	60	67
750	57	67	64	67
1000	58	67	64	67
1500	60	67	65	68
2000	61	67	66	69
2500	62	67	68	71
3000	63	67	68	71
3750	64	67	70	73
5000	65	67	71	73
6000	66	68	72	74
7500	67	69	73	75
10,000	68	70	—	76

Because values given in **Table 1.4-11** are in general higher than those given in **Table 1.4-10**, the difference must be attenuated by distance and by proper use of materials in the design of the building. An observer may believe that a transformer is noisy because the level in the room where it is located is high. Two transformers of the same sound output in the same room increase the sound level in the room approximately 3 dB, and three transformers by about 5 dB, etc.

Sounds due to structure-transmitted vibrations originating from the transformer are lowered by mounting the transformers on vibration dampeners or isolators. There are a number of different sound vibration isolating materials that may be used with good results. Dry-type power transformers are often built with an isolator mounted between the transformer support and case members. The natural period of the core and coil structure when mounted on vibration dampeners is about 10% of the fundamental frequency. The reduction in the

transmitted vibration is approximately 98%. If the floor or beams beneath the transformer are light and flexible, the isolator must be softer or have improved characteristics in order to keep the transmitted vibrations to a minimum. (Enclosure covers and ventilating louvers are often improperly tightened or gasketed and produce unnecessary noise.) The building structure will assist the dampeners if the transformer is mounted above heavy floor members or if mounted on a heavy floor slab. Positioning of the transformer in relation to walls and other reflecting surfaces has a great effect on reflected noise and resonances. Often, placing the transformer at an angle to the wall, rather than parallel to it, will reduce noise. Electrical connections to a substation transformer should be made with flexible braid or conductors; connections to an individually mounted transformer should be in flexible conduit.

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IEEE Protective Relay Numbers

Table 1.5-1. Selected IEEE Device Numbers for Switchgear Apparatus

Device Number	Function	Definition	Typical Uses
2	Time-delay starting or closing relay	A device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62 and 79 described later.	Used for providing a time-delay for re-transfer back to the normal source in an automatic transfer scheme.
6	Starting circuit breaker	A device whose principal function is to connect a machine to its source of starting voltage.	—
19	Starting to running transition timer	A device that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.	Used to transfer a reduced voltage starter from starting to running.
21	Distance relay	A device that functions when the circuit admittance, impedance or reactance increases or decreases beyond predetermined limits.	—
23	Temperature control device	A device that functions to raise or to lower the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above, a predetermined level.	Used as a thermostat to control space heaters in outdoor equipment.
24	Volts per hertz relay	A device that operates when the ratio of voltage to frequency is above a preset value or is below a different preset value. The relay may have any combination of instantaneous or time delayed characteristics.	—
25	Synchronizing or synchronism check device	A device that operates when two AC circuits are within the desired limits of frequency, phase angle or voltage, to permit or cause the paralleling of these two circuits.	In a closed transition breaker transfer, a 25 relay is used to ensure two-sources are synchronized before paralleling. Eaton FP-5000/EDR-5000 feeder protective relays.
27	Undervoltage relay	A device which functions on a given value of undervoltage.	Used to initiate an automatic transfer when a primary source of power is lost. Eaton FP-5000/FP-4000/MP-4000/EDR-5000/EDR-4000 protective relays.
30	Annunciator relay	A non-automatically reset device that gives a number of separate visual indications upon the functioning of protective devices, and which may also be arranged to perform a lockout function.	Used to remotely indicate that a protective relay has functioned, or that a circuit breaker has tripped. Typically, a mechanical "drop" type annunciator panel is used.
32	Directional power relay	A relay that functions on a desired value of power flow in a given direction, or upon reverse power resulting from arc back in the anode or cathode circuits of a power rectifier.	Used to prevent reverse power from feeding an upstream fault. Often used when primary backup generation is used in a facility. Eaton FP-5000/EDR-5000 protective relays.
33	Position switch	A device that makes or breaks contact when the main device or piece of apparatus, which has no device function number, reaches a given point.	Used to indicate the position of a drawout circuit breaker (TOC switch).
34	Master sequence device	A device such as a motor-operated multi-contact switch, or the equivalent, or a programmable device, that establishes or determines the operating sequence of the major devices in equipment during starting and stopping, or during sequential switching operations.	—
37	Undercurrent or underpower relay	A relay that functions when the current or power flow decreases below a predetermined value.	Eaton MP-3000/MP-4000/EMR-3000 motor protective relays.
38	Bearing protective device	A device that functions on excessive bearing temperature, or on other abnormal mechanical conditions, such as undue wear, which may eventually result in excessive bearing temperature.	Eaton MP-3000/MP-4000 motor protective relays.
40	Field relay	A device that functions on a given or abnormally high or low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an AC machine indicating abnormally high or low field excitation.	—
41	Field circuit breaker	A device that functions to apply, or to remove, the field excitation of a machine.	—
42	Running circuit breaker	A device whose function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault-protecting means, primarily for frequent opening and closing of the circuit.	—

IEEE Protective Relay Numbers

Table 1.5-1. Selected IEEE Device Numbers for Switchgear Apparatus (Continued)

Device Number	Function	Definition	Typical Uses
43	Manual transfer or selector device	A manually operated device that transfers control or potential circuits in order to modify the plan of operation of the associated equipment or of some of the associated devices.	—
44	Unit sequence starting relay	A device that functions to start the next available unit in multiple-unit equipment upon the failure or non-availability of the normally preceding unit.	—
46	Reverse-phase, or phase balance, current relay	A relay that functions when the polyphase currents are of reverse-phase sequence, or when the polyphase currents are unbalanced or contain the negative phase-sequence components above a given amount.	Eaton FP-5000/FP-4000/EDR-5000/EDR-4000 feeder protective relays and MP-3000/MP-4000/EMR-3000 motor protective relays.
47	Phase-sequence voltage relay	A relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence.	Eaton FP-5000/FP-4000/EDR-5000/EDR-4000 feeder protective relays and MP-3000/MP-4000 motor protective relays.
48	Incomplete sequence relay	A relay that generally returns the equipment to the normal, or off, position and locks it out of the normal starting, or operating or stopping sequence is not properly completed within a predetermined amount of time. If the device is used for alarm purposes only, it should preferably be designated as 48 A (alarm).	—
49	Machine, or transformer, thermal relay	A relay that functions when the temperature of a machine armature, or other load carrying winding or element of a machine, or the temperature of a power rectifier or power transformer (including a power rectifier transformer) exceeds a predetermined value.	Eaton MP-3000/MP-4000/EMR-3000/ETR-4000 motor protective relays.
50	Instantaneous overcurrent, or rate-of-rise relay	A relay that functions instantaneously on an excessive value of current, or an excessive rate of current rise, thus indicating a fault in the apparatus of the circuit being protected.	Used for tripping a circuit breaker instantaneously during a high-level short circuit. Can trip on phase-phase (50), phase-neutral (50N), phase-ground (50G) faults. Eaton Digitrip 3000, FP-5000/FP-4000/EDR-5000/EDR-4000/EDR-3000 protective relays, MP-3000/MP-4000/EMR-3000/ETR-4000 motor protective relays.
51	AC time overcurrent relay	A relay with either a definite or inverse time characteristic that functions when the current in an AC circuit exceeds a predetermined value.	Used for tripping a circuit breaker after a time delay during a sustained overcurrent. Used for tripping a circuit breaker instantaneously during a high-level short circuit. Can trip on phase (51), neutral (51N) or ground (51G) overcurrents. Eaton Digitrip 3000, FP-5000/FP-4000/EDR-5000/EDR-4000/EDR-3000 protective relays, MP-3000/MP-4000/EMR-3000/ETR-4000 motor protective relays.
52	AC circuit breaker	A device that is used to close and interrupt an AC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.	A term applied typically to medium voltage circuit breakers, or low voltage power circuit breakers. Eaton VCP-W vacuum circuit breaker, magnum DS low voltage power circuit breaker
53	Exciter or DC generator relay	A device that forces the DC machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.	—
55	Power factor relay	A relay that operates when the power factor in an AC circuit rises above or below a predetermined value.	Eaton FP-5000/FP-4000/EDR-5000 feeder protective relays and MP-4000 motor protective relay.
56	Field application relay	A device that automatically controls the application of the field excitation to an AC motor at some predetermined point in the slip cycle.	—
59	Overvoltage relay	A relay that functions on a given value of overvoltage.	Used to trip a circuit breaker, protecting downstream equipment from sustained overvoltages. Eaton FP-5000/FP-4000/EDR-5000 feeder protective relays and MP-4000 motor protective relay.

IEEE Protective Relay Numbers

Table 1.5-1. Selected IEEE Device Numbers for Switchgear Apparatus (Continued)

Device Number	Function	Definition	Typical Uses
60	Voltage or current balance relay	A relay that operates on a given difference in voltage, or current input or output of two circuits.	—
62	Time-delay stopping or opening relay	A time-delay relay that serves in conjunction with the device that initiates the shutdown, stopping or opening operation in an automatic sequence.	Used in conjunction with a 27 device to delay tripping of a circuit breaker during a brief loss of primary voltage, to prevent nuisance tripping.
63	Pressure switch	A switch that operates on given values or on a given rate of change of pressure.	Used to protect a transformer during a rapid pressure rise during a short circuit. This device will typically act to open the protective devices above and below the transformer. Typically used with a 63-X auxiliary relay to trip the circuit breaker.
64	Ground protective relay	A relay that functions on a failure of the insulation of a machine, transformer or of other apparatus to ground, or on flashover of a DC machine to ground.	Used to detect and act on a ground-fault condition. In a pulsing high resistance grounding system, a 64 device will initiate the alarm.
65	Governor	A device consisting of an assembly of fluid, electrical or mechanical control equipment used for regulating the flow of water, steam or other media to the prime mover for such purposes as starting, holding speed or load, or stopping.	—
66	Notching or jogging device	A device that functions to allow only a specified number of operations of a given device, or equipment, or a specified number of successive operations within a given time of each other. It also functions to energize a circuit periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.	Eaton MP-3000/MP-4000/EMR-3000 motor protective relays.
67	AC directional overcurrent relay	A relay that functions on a desired value of AC overcurrent flowing in a predetermined direction.	Eaton FP-5000/EDR-5000 feeder protective relays.
69	Permissive control device	A device that is generally a two-position manually operated switch that in one position permits the closing of a circuit breaker, or the placing of equipment into operation, and in the other position prevents the circuit breaker to the equipment from being operated.	Used as a remote-local switch for circuit breaker control.
71	Level switch	A switch that operates on given values, or on a given rate of change of level.	Used to indicate a low liquid level within a transformer tank in order to save transformers from loss-of-insulation failure. An alarm contact is available as a standard option on a liquid level gauge. It is set to close before an unsafe condition actually occurs.
72	DC circuit breaker	A device that is used to close and interrupt a DC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.	—
73	Load-resistor contactor	A device that is used to shunt or insert a step of load limiting, shifting or indicating resistance in a power circuit; to switch a space heater in circuit; or to switch a light or regenerative load resistor of a power rectifier or other machine in and out of circuit.	—
74	Alarm relay	A device other than an annunciator, as covered under device number 30, which is used to operate, or to operate in connection with, a visible or audible alarm.	—
78	Phase-angle measuring relay	A device that functions at a predetermined phase angle between two voltages, between two currents, or between voltage and current.	—
79	AC reclosing relay	A relay that controls the automatic closing and locking out of an AC circuit interrupter.	Used to automatically reclose a circuit breaker after a trip, assuming the fault has been cleared after the power was removed from the circuit. The recloser will lock-out after a predetermined amount of failed attempts to reclose.

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IEEE Protective Relay Numbers

Table 1.5-1. Selected IEEE Device Numbers for Switchgear Apparatus (Continued)

Device Number	Function	Definition	Typical Uses
81	Frequency relay	A relay that functions on a predetermined value of frequency—either under or over, or on normal system frequency—or rate of change frequency.	Used to trip a generator circuit breaker in the event the frequency drifts above or below a given value. Eaton FP-5000/FP-4000/EDR-5000/EDR-4000 feeder protective relays and MP-4000 motor protective relay.
83	Automatic selective control or transfer relay	A relay that operates to select automatically between certain sources or conditions in equipment, or performs a transfer operation automatically.	Used to transfer control power sources in a double-ended switchgear lineup.
85	Carrier or pilot-wire relay	A device that is operated or restrained by a signal transmitted or received via any communications media used for relaying.	—
86	Locking-out relay	An electrically operated hand, or electrically, reset relay that functions to shut down and hold an equipment out of service on the occurrence of abnormal conditions.	Used in conjunction with protective relays to lock-out a circuit breaker (or multiple circuit breakers) after a trip. Typically required to be manually reset by an operator before the breaker can be reclosed.
87	Differential protective relay	A protective relay that functions on a percentage or phase angle or other quantitative difference of two currents or of some other electrical quantities.	Used to protect static equipment, such as cable, bus or transformers, by measuring the current differential between two points. Typically the upstream and/or downstream circuit breaker will be incorporated into the “zone of protection.” Eaton FP-5000 feeder protective relay (87B) and MD-3000 protective relay.
90	Regulating device	A device that functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature and load, at a certain value or between certain (generally close) limits for machines, tie lines or other apparatus.	—
91	Voltage directional relay	A device that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.	—
94	Tripping or trip-free relay	A relay that functions to trip a circuit breaker, contactor or equipment, or to permit immediate tripping by other devices, or to prevent immediate reclosure of a circuit interrupter, in case it should open automatically even though its closing circuit is maintained closed.	—

Suggested IEEE Designations for Suffix Letters

Suggested IEEE Designations
for Suffix Letters

Auxiliary Devices

These letters denote separate auxiliary devices, such as the following:

C	Closing relay/contactor
CL	Auxiliary relay, closed (energized when main device is in closed position)
CS	Control switch
D	"Down" position switch relay
L	Lowering relay
O	Opening relay/contactor
OP	Auxiliary relay, open (energized when main device is in open position)
PB	Push button
R	Raising relay
U	"UP" position switch relay
X	Auxiliary relay
Y	Auxiliary relay
Z	Auxiliary relay

Actuating Quantities

These letters indicate the condition or electrical quantity to which the device responds, or the medium in which it is located, such as the following:

A	Amperes/alternating
C	Current
F	Frequency/fault
I0	Zero sequence current
I-, I2	Negative sequence current
I+, I1	Positive sequence current
P	Power/pressure
PF	Power factor
S	Speed
T	Temperature
V	Voltage/volts/vacuum
VAR	Reactive power
VB	Vibration
W	Watts

Main Device

The following letters denote the main device to which the numbered device is applied or is related:

A	Alarm/auxiliary power
AC	Alternating current
BP	Bypass
BT	Bus tie
C	Capacitor
DC	Direct current
E	Exciter
F	Feeder/field
G	Generator/ground
M	Motor/metering
MOC	Mechanism operated contact
S	Synchronizing/secondary
T	Transformer
TOC	Truck-operated contacts

Main Device Parts

These letters denote parts of the main device, except auxiliary contacts, position switches, limit switches and torque limit switches:

C	Coil/condenser/capacitor
CC	Closing coil/closing contactor
HC	Holding coil
M	Operating motor
OC	Opening contactor
S	Solenoid
SI	Seal-in
T	Target
TC	Trip coil

Other Suffix Letters

The following letters cover all other distinguishing features, characteristics or conditions not specifically described in **Auxiliary Devices** through **Main Device Parts**, which serve to describe the use of the device in the equipment, such as:

A	Automatic
BF	Breaker failure
C	Close
D	Decelerating/down
E	Emergency
F	Failure/forward
HS	High speed
L	Local/lower
M	Manual
O	Open
OFF	Off
ON	On
R	Raise/reclosing/remote/reverse
T	Test/trip
TDC	Time-delay closing contact
TDDO	Time delayed relay coil drop-out
TDO	Time-delay opening contact
TDPU	Time delayed relay coil pickup
THD	Total harmonic distortion

Codes and Standards

Codes and Standards

The National Electrical Code (NEC), NFPA Standard No. 70, is the most prevalent electrical code in the United States. The NEC, which is revised every three years, has no legal standing of its own, until it is adopted as law by a jurisdiction, which may be a city, county or state. Most jurisdictions adopt the NEC in its entirety; some adopt it with variations, usually more rigid, to suit local conditions and requirements. A few large cities, such as New York and Chicago, have their own electrical codes, basically similar to the NEC. The designer must determine which code applies in the area of a specific project.

The Occupational Safety and Health Act (OSHA) of 1970 sets uniform national requirements for safety in the workplace—anywhere that people are employed. Originally OSHA adopted the 1971 NEC as rules for electrical safety. As the NEC was amended every three years, the involved process for modifying a federal law such as OSHA made it impossible for the act to adopt each new code revision. To avoid this problem, the OSHA administration in 1981 adopted its own code, a condensed version of the NEC containing only those provisions considered related to occupational safety. OSHA was amended to adopt this code, based on NFPA Standard 70E, Part 1, which is now federal law.

The NEC is a minimum safety standard. Efficient and adequate design usually requires not just meeting, but often exceeding NEC requirements to provide an effective, reliable, economical electrical system.

Many equipment standards have been established by the National Electrical Manufacturers' Association (NEMA) and the American National Standards Institute (ANSI). Underwriters Laboratories (UL) has standards that equipment must meet before UL will list or label it. Most jurisdictions and OSHA require that where equipment listed as safe by a recognized laboratory is available, unlisted equipment may not be used. UL is by far the most widely accepted national laboratory, although Factory Mutual Insurance Company lists some equipment, and

a number of other testing laboratories have been recognized and accepted. The Institute of Electrical and Electronic Engineers (IEEE) publishes a number of books (the "color book" series) on recommended practices for the design of industrial buildings, commercial buildings, emergency power systems, grounding, and the like. Most of these IEEE standards have been adopted as ANSI standards. They are excellent guides, although they are not in any way mandatory.

Professional Organizations**American National Standards Institute (ANSI)****Headquarters:**

1819 L Street, NW
6th Floor
Washington, DC 20036
202-293-8020

Operations:

25 West 43rd Street
4th Floor
New York, NY 10036
212-642-4900

www.ansi.org

Institute of Electrical and Electronic Engineers (IEEE)**Headquarters:**

3 Park Avenue
17th Floor
New York, NY 10016-5997
212-419-7900

Operations:

445 Hoes Lane
Piscataway, NJ 08854-1331
732-981-0060

www.ieee.org

International Association of Electrical Inspectors (IAEI)

901 Waterfall Way
Suite 602
Richardson, TX 75080-7702
972-235-1455

www.iaei.org

A design engineer should conform to all applicable codes, and require equipment to be listed by UL or another recognized testing laboratory wherever possible, and to meet ANSI or NEMA standards. ANSI/IEEE recommended practices should be followed to a great extent. In many cases, standards should be exceeded to get a system of the quality required. The design goal should be a safe, efficient, long-lasting, flexible and economical electrical distribution system.

National Electrical Manufacturers Association (NEMA)

1300 North 17th Street
Suite 1847
Rosslyn, VA 22209
703-841-3200

www.nema.org

National Fire Protection Association (NFPA)

1 Battery March Park
Quincy, MA 02169-7471
617-770-3000

www.nfpa.org

Underwriters Laboratories (UL)

333 Pfingsten Road
Northbrook, IL 60062-2096
847-272-8800

www.ul.com

International Code Council (ICC)

5203 Leesburg Pike
Suite 600
Falls Church, VA 22041
1-888-422-7233

www.iccsafe.org

The American Institute of Architects (AIA)

1735 New York Avenue, NW
Washington, DC 20006-5292
202-626-7300

www.aia.org

Motor Protective Device Data

Motor Protection

Consistent with the 2011 NEC 430.6(A)(1) circuit breaker, HMCP and fuse rating selections are based on full load currents for induction motors running at speeds normal for belted motors and motors with normal torque characteristics using data taken from NEC Table 430.250 (three-phase). Actual motor nameplate ratings shall be used for selecting motor running overload protection. Motors built special for low speeds, high torque characteristics, special starting conditions and applications will require other considerations as defined in the application section of the NEC.

These additional considerations may require the use of a higher rated HMCP, or at least one with higher magnetic pickup settings.

Circuit breaker, HMCP and fuse ampere rating selections are in line with maximum rules given in NEC 430.52 and Table 430.250. Based on known characteristics of Eaton type breakers, specific units are recommended. The current ratings are no more than the maximum limits set by the NEC rules for motors with code letters F to V or without code letters. Motors with lower code letters will require further considerations.

In general, these selections were based on:

1. Ambient—outside enclosure not more than 40 °C (104 °F).
2. Motor starting—infrequent starting, stopping or reversing.
3. Motor accelerating time—10 seconds or less.
4. Locked rotor—maximum 6 times motor FLA.

Type HMCP motor circuit protector may not set at more than 1300% of the motor full-load current to comply with NEC 430.52. (Except for NEMA Design B energy high-efficiency motors that can be set up to 1700%.)

Circuit breaker selections are based on types with standard interrupting ratings. Higher interrupting rating types may be required to satisfy specific system application requirements.

For motor full load currents of 208 V and 200 V, increase the corresponding 230 V motor values by 10 and 15% respectively.

Table 1.5-2. Motor Circuit Protector (MCP), Circuit Breaker and Fusible Switch Selection Guide

Horsepower	Full Load Amperes (NEC) FLA	Fuse Size NEC 430.52 Maximum Amperes		Recommended Eaton		
		Time Delay	Non-Time Delay	Circuit Breaker Amperes	Motor Circuit Protector Type HMCP	
					Amperes	Amperes
230 V, Three-Phase						
1	3.6	10	15	15	7	21–70
1-1/2	5.2	10	20	15	15	45–150
2	6.8	15	25	15	15	45–150
3	9.6	20	30	20	30	90–300
5	15.2	30	50	30	30	90–300
7-1/2	22	40	70	50	50	150–500
10	28	50	90	60	50	150–500
15	42	80	150	90	70	210–700
20	54	100	175	100	100	300–1000
25	68	125	225	125	150	450–1500
30	80	150	250	150	150	450–1500
40	104	200	350	150	150	750–2500
50	130	250	400	200	150	750–2500
60	154	300	500	225	250	1250–2500
75	192	350	600	300	400	2000–4000
100	248	450	800	400	400	2000–4000
125	312	600	1000	500	600	1800–6000
150	360	700	1200	600	600	1800–6000
200	480	1000	1600	700	600	1800–6000
460 V, Three-Phase						
1	1.8	6	6	15	7	21–70
1-1/2	2.6	6	10	15	7	21–70
2	3.4	6	15	15	7	21–70
3	4.8	10	15	15	15	45–150
5	7.6	15	25	15	15	45–150
7-1/2	11	20	35	25	30	90–300
10	14	25	45	35	30	90–300
15	21	40	70	45	50	150–500
20	27	50	90	50	50	150–500
25	34	60	110	70	70	210–700
30	40	70	125	70	100	300–1000
40	52	100	175	100	100	300–1000
50	65	125	200	110	150	450–1500
60	77	150	150	125	150	750–2500
75	96	175	300	150	150	750–2500
100	124	225	400	175	150	750–2500
125	156	300	500	225	250	1250–2500
150	180	350	600	250	400	2000–4000
200	240	450	800	350	400	2000–4000
575 V, Three-Phase						
1	1.4	3	6	15	3	9–30
1-1/2	2.1	6	10	15	7	21–70
2	2.7	6	10	15	7	21–70
3	3.9	10	15	15	7	21–70
5	6.1	15	20	15	15	45–150
7-1/2	9	20	30	20	15	45–150
10	11	20	35	25	30	90–300
15	17	30	60	40	30	90–300
20	22	40	70	50	50	150–500
25	27	50	90	60	50	150–500
30	32	60	100	60	50	150–500
40	41	80	125	80	100	300–1000
50	52	100	175	100	100	300–1000
60	62	110	200	125	150	750–2500
75	77	150	250	150	150	750–2500
100	99	175	300	175	150	750–2500
125	125	225	400	200	250	1250–2500
150	144	300	450	225	250	1250–2500
200	192	350	600	300	400	2000–4000

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Motor Protective Device Data

Table 1.5-3. 60 Hz, Recommended Protective Setting for Induction Motors

hp	Full Load Amperes (NEC) FLA	Minimum Wire Size 75 °C Copper Ampacity at 125% FLA		Minimum Conduit Size, Inches (mm)		Fuse Size NEC 430.52 Maximum Amperes ①		Recommended Eaton:		
								Circuit Breaker ② Amperes	Motor Circuit Protector	
		Size	Amperes	THW	THWN XHHN	Time Delay	Non-Time Delay		Amperes	Amperes
115 V, Single-Phase										
3/4	13.8	14	20	0.50 (12.7)	0.50 (12.7)	25	45	30	Two-pole device not available	
1	16	14	20	0.50 (12.7)	0.50 (12.7)	30	50	35		
1-1/2	20	12	30	0.50 (12.7)	0.50 (12.7)	35	60	40		
2	24	10	30	0.50 (12.7)	0.50 (12.7)	45	80	50		
3	34	8	50	0.75 (19.1)	0.50 (12.7)	60	110	70		
5	56	4	85	1.00 (25.4)	0.75 (19.1)	100	175	100		
7-1/2	80	3	100	1.00 (25.4)	1.00 (25.4)	150	250	150		
230 V, Single-Phase										
3/4	6.9	14	20	0.50 (12.7)	0.50 (12.7)	15	25	15	Two-pole device not available	
1	8	14	20	0.50 (12.7)	0.50 (12.7)	15	25	20		
1-1/2	10	14	20	0.50 (12.7)	0.50 (12.7)	20	30	25		
2	12	14	20	0.50 (12.7)	0.50 (12.7)	25	40	30		
3	17	12	30	0.50 (12.7)	0.50 (12.7)	30	60	40		
5	28	10	50	0.50 (12.7)	0.50 (12.7)	50	90	60		
7-1/2	40	8	50	0.75 (19.1)	0.50 (12.7)	70	125	80		

① Consult fuse manufacturer's catalog for smaller fuse ratings.

② Types are for minimum interrupting capacity breakers. Ensure that the fault duty does not exceed breaker's I.C.

Chart of Short Circuit Currents for Transformers

Table 1.5-4. Secondary Short-Circuit Current of Typical Power Transformers

Trans- former Rating Three- Phase kVA and Impedance Percent	Maximum Short- Circuit kVA Available from Primary System	208 V, Three-Phase					240 V, Three-Phase					480 V, Three-Phase					600 V, Three-Phase				
		Rated Load Contin- uous Current, Amps	Short-Circuit Current rms Symmetrical Amps			Rated Load Contin- uous Current, Amps	Short-Circuit Current rms Symmetrical Amps			Rated Load Contin- uous Current, Amps	Short-Circuit Current rms Symmetrical Amps			Rated Load Contin- uous Current, Amps	Short-Circuit Current rms Symmetrical Amps						
			Trans- former Alone ①	50% Motor Load ②	Com- bined		Trans- former Alone ①	100% Motor Load ②	Com- bined		Trans- former Alone ①	100% Motor Load ②	Com- bined		Trans- former Alone ①	100% Motor Load ②	Com- bined				
300 5%	50,000	834	14,900	1700	16,600	722	12,900	2900	15,800	361	6400	1400	7800	289	5200	1200	6400				
	100,000	834	15,700	1700	17,400	722	13,600	2900	16,500	361	6800	1400	8200	289	5500	1200	6700				
	150,000	834	16,000	1700	17,700	722	13,900	2900	16,800	361	6900	1400	8300	289	5600	1200	6800				
	250,000	834	16,300	1700	18,000	722	14,100	2900	17,000	361	7000	1400	8400	289	5600	1200	6800				
500 5%	50,000	1388	21,300	2800	25,900	1203	20,000	4800	24,800	601	10,000	2400	12,400	481	8000	1900	9900				
	100,000	1388	25,200	2800	28,000	1203	21,900	4800	26,700	601	10,900	2400	13,300	481	8700	1900	10,600				
	150,000	1388	26,000	2800	28,800	1203	22,500	4800	27,300	601	11,300	2400	13,700	481	9000	1900	10,900				
	250,000	1388	26,700	2800	29,500	1203	23,100	4800	27,900	601	11,600	2400	14,000	481	9300	1900	11,200				
750 5.75%	50,000	2080	28,700	4200	32,900	1804	24,900	7200	32,100	902	12,400	3600	16,000	722	10,000	2900	12,900				
	100,000	2080	32,000	4200	36,200	1804	27,800	7200	35,000	902	13,900	3600	17,500	722	11,100	2900	14,000				
	150,000	2080	33,300	4200	37,500	1804	28,900	7200	36,100	902	14,400	3600	18,000	722	11,600	2900	14,500				
	250,000	2080	34,400	4200	38,600	1804	29,800	7200	37,000	902	14,900	3600	18,500	722	11,900	2900	14,800				
1000 5.75%	50,000	2776	35,900	5600	41,500	2406	31,000	9800	40,600	1203	15,500	4800	20,300	962	12,400	3900	16,300				
	100,000	2776	41,200	5600	46,800	2406	35,600	9800	45,200	1203	17,800	4800	22,600	962	14,300	3900	18,200				
	150,000	2776	43,300	5600	48,900	2406	37,500	9800	47,100	1203	18,700	4800	23,500	962	15,000	3900	18,900				
	250,000	2776	45,200	5600	50,800	2406	39,100	9800	48,700	1203	19,600	4800	24,400	962	15,600	3900	19,500				
1500 5.75%	50,000	4164	47,600	8300	55,900	3609	41,200	14,400	55,600	1804	20,600	7200	27,800	1444	16,500	5800	22,300				
	100,000	4164	57,500	8300	65,800	3609	49,800	14,400	64,200	1804	24,900	7200	32,100	1444	20,000	5800	25,800				
	150,000	4164	61,800	8300	70,100	3609	53,500	14,400	67,900	1804	26,700	7200	33,900	1444	21,400	5800	27,200				
	250,000	4164	65,600	8300	73,900	3609	56,800	14,400	71,200	1804	28,400	7200	35,600	1444	22,700	5800	28,500				
2000 5.75%	50,000	—	—	—	—	—	—	—	—	2406	24,700	9600	34,300	1924	19,700	7800	27,500				
	100,000	—	—	—	—	—	—	—	—	2406	31,000	9600	40,600	1924	24,800	7800	32,600				
	150,000	—	—	—	—	—	—	—	—	2406	34,000	9600	43,600	1924	27,200	7800	35,000				
	250,000	—	—	—	—	—	—	—	—	2406	36,700	9600	46,300	1924	29,400	7800	37,200				
2500 5.75%	50,000	—	—	—	—	—	—	—	—	3008	28,000	12,000	40,000	2405	22,400	9600	32,000				
	100,000	—	—	—	—	—	—	—	—	3008	36,500	12,000	48,500	2405	29,200	9600	38,800				
	150,000	—	—	—	—	—	—	—	—	3008	40,500	12,000	52,500	2405	32,400	9600	42,000				
	250,000	—	—	—	—	—	—	—	—	3008	44,600	12,000	56,600	2405	35,600	9600	45,200				
3000 5.75%	50,000	—	—	—	—	—	—	—	—	3609	30,700	14,000	44,700	2886	24,600	11,500	36,100				
	100,000	—	—	—	—	—	—	—	—	3609	41,200	14,000	55,200	2886	33,000	11,500	44,500				
	150,000	—	—	—	—	—	—	—	—	3609	46,600	14,000	60,600	2886	37,300	11,500	48,800				
	250,000	—	—	—	—	—	—	—	—	3609	51,900	14,000	65,900	2886	41,500	11,500	53,000				
3750 5.75%	50,000	—	—	—	—	—	—	—	—	4511	34,000	18,000	52,000	3608	27,200	14,400	41,600				
	100,000	—	—	—	—	—	—	—	—	4511	47,500	18,000	65,500	3608	38,000	14,400	52,400				
	150,000	—	—	—	—	—	—	—	—	4511	54,700	18,000	72,700	3608	43,700	14,400	58,100				
	250,000	—	—	—	—	—	—	—	—	4511	62,200	18,000	80,200	3608	49,800	14,400	64,200				
Unlimited	500,000	—	—	—	—	—	—	—	—	4511	69,400	18,000	87,400	3608	55,500	14,400	69,900				
	Unlimited	—	—	—	—	—	—	—	—	4511	78,500	18,000	96,500	3608	62,800	14,400	77,200				

① Short-circuit capacity values shown correspond to kVA and impedances shown in this table. For impedances other than these, short-circuit currents are inversely proportional to impedance.

② The motor's short-circuit current contributions are computed on the basis of motor characteristics that will give four times normal current. For 208 V, 50% motor load is assumed while for other voltages 100% motor load is assumed. For other percentages, the motor short-circuit current will be in direct proportion.

Transformer Full Load Amperes

Table 1.5-5. Transformer Full-Load Current, Three-Phase, Self-Cooled Ratings

Voltage, Line-to-Line													
kVA	208	240	480	600	2400	4160	7200	12,000	12,470	13,200	13,800	22,900	34,400
30	83.3	72.2	36.1	28.9	7.22	4.16	2.41	1.44	1.39	1.31	1.26	0.75	0.50
45	125	108	54.1	43.3	10.8	6.25	3.61	2.17	2.08	1.97	1.88	1.13	0.76
75	208	180	90.2	72.2	18.0	10.4	6.01	3.61	3.47	3.28	3.14	1.89	1.26
112-1/2	312	271	135	108	27.1	15.6	9.02	5.41	5.21	4.92	4.71	2.84	1.89
150	416	361	180	144	36.1	20.8	12.0	7.22	6.94	6.56	6.28	3.78	2.52
225	625	541	271	217	54.1	31.2	18.0	10.8	10.4	9.84	9.41	5.67	3.78
300	833	722	361	289	72.2	41.6	24.1	14.4	13.9	13.1	12.6	7.56	5.04
500	1388	1203	601	481	120	69.4	40.1	24.1	23.1	21.9	20.9	12.6	8.39
750	2082	1804	902	722	180	104	60.1	36.1	34.7	32.8	31.4	18.9	12.6
1000	2776	2406	1203	962	241	139	80.2	48.1	46.3	43.7	41.8	25.2	16.8
1500	4164	3608	1804	1443	361	208	120	72.2	69.4	65.6	62.8	37.8	25.2
2000	—	4811	2406	1925	481	278	160	96.2	92.6	87.5	83.7	50.4	33.6
2500	—	—	3007	2406	601	347	200	120	116	109	105	63.0	42.0
3000	—	—	3609	2887	722	416	241	144	139	131	126	75.6	50.4
3750	—	—	4511	3608	902	520	301	180	174	164	157	94.5	62.9
5000	—	—	—	4811	1203	694	401	241	231	219	209	126	83.9
7500	—	—	—	—	1804	1041	601	361	347	328	314	189	126
10,000	—	—	—	—	2406	1388	802	481	463	437	418	252	168

Impedances Data

Approximate Impedance Data

**Table 1.5-6. Typical Impedances—
Three-Phase Transformers Liquid-Filled ①**

kVA	Liquid-Filled	
	Network	Padmount
37.5	—	—
45	—	—
50	—	—
75	—	3.4
112.5	—	3.4
150	—	3.4
225	—	3.4
300	5.00	3.4
500	5.00	4.6
750	5.00	5.75
1000	5.00	5.75
1500	7.00	5.75
2000	7.00	5.75
2500	7.00	5.75
3000	—	5.75
3750	—	6.00
5000	—	6.50

① Values are typical. For guaranteed values, refer to transformer manufacturer.

**Table 1.5-7. 15 kV Class Primary—
Oil Liquid-Filled Substation Transformers**

kVA	%Z	%R	%X	X/R
65 °C Rise				
112.5	5.00	1.71	4.70	2.75
150	5.00	1.88	4.63	2.47
225	5.00	1.84	4.65	2.52
300	5.00	1.35	4.81	3.57
500	5.00	1.50	4.77	3.18
750	5.75	1.41	5.57	3.96
1000	5.75	1.33	5.59	4.21
1500	5.75	1.12	5.64	5.04
2000	5.75	0.93	5.67	6.10
2500	5.75	0.86	5.69	6.61

**Table 1.5-8. DOE 2016 Transformer
Efficiencies—Medium Voltage Three-Phase
Distribution Transformers ①**

kVA	% Efficiency			
	Liquid-Filled	Dry Transformers		
		All BILs	25–45 kV BIL	46–95 kV BIL
15	98.65	97.5	97.18	—
30	98.83	97.9	97.63	—
45	98.92	98.1	97.86	—
75	99.03	98.33	98.13	—
112.5	99.11	98.52	98.36	—
150	99.16	98.65	98.51	—
225	99.23	98.82	98.69	98.57
300	99.27	98.93	98.81	98.69
500	99.35	99.09	98.99	98.89
750	99.40	99.21	99.12	99.02
1000	99.43	99.28	99.2	99.11
1500	99.48	99.37	99.3	99.21
2000	99.51	99.43	99.36	99.28
2500	99.53	99.47	99.41	99.33

① Based on transformer operating at 50% of nameplate base kVA.

**Table 1.5-9. 15 kV Class Primary—
Dry-Type Substation Transformers**

kVA	%Z	%R	%X	X/R
150 °C Rise				
300	4.50	2.87	3.47	1.21
500	5.75	2.66	5.10	1.92
750	5.75	2.47	5.19	2.11
1000	5.75	2.16	5.33	2.47
1500	5.75	1.87	5.44	2.90
2000	5.75	1.93	5.42	2.81
2500	5.75	1.74	5.48	3.15
80 °C Rise				
300	4.50	1.93	4.06	2.10
500	5.75	1.44	5.57	3.87
750	5.75	1.28	5.61	4.38
1000	5.75	0.93	5.67	6.10
1500	5.75	0.87	5.68	6.51
2000	5.75	0.66	5.71	8.72
2500	5.75	0.56	5.72	10.22

**Table 1.5-10. 600 V Primary Class Three-
Phase DOE 2016 Energy-Efficient Dry-Type
Distribution Transformers, Aluminum Wound**

kVA	%Z	%X	%R	X/R
150 °C Rise Aluminum				
15	4.04	2.08	3.46	0.60
30	2.52	1.13	2.25	0.50
45	3.75	2.64	2.67	0.99
75	4.05	3.34	2.29	1.46
112.5	4.66	4.22	1.99	2.12
150	3.48	3.09	1.61	1.92
225	4.20	3.96	1.39	2.85
300	4.46	4.26	1.32	3.23
115 °C Rise Aluminum				
15	3.77	2.08	3.14	0.66
30	2.34	1.37	1.90	0.72
45	4.26	3.44	2.52	1.37
75	4.45	3.90	2.14	1.83
112.5	5.17	4.81	1.89	2.54
150	3.89	3.59	1.49	2.41
225	4.90	4.73	1.28	3.69
300	4.80	4.65	1.21	3.85
80 °C Rise Aluminum				
15	4.19	2.94	2.98	0.99
30	2.50	1.76	1.78	0.99
45	2.43	2.01	1.37	1.46
75	3.11	2.81	1.32	2.12
112.5	2.61	2.31	1.21	1.92
150	2.80	2.64	0.93	2.85
225	3.35	3.20	0.99	3.23

**Table 1.5-11. 600V Primary Class Three-Phase
DOE 2016 Energy-Efficient Dry-Type
Distribution Transformers, Copper Wound**

kVA	%Z	%X	%R	X/R
150 °C Rise Copper				
15	3.10	1.59	2.66	0.60
30	2.52	0.79	2.39	0.33
45	3.80	2.60	2.77	0.94
75	2.84	1.94	2.08	0.93
112.5	3.63	3.11	1.88	1.66
150	3.02	2.64	1.46	1.81
225	4.34	3.98	1.73	2.31
300	3.48	3.19	1.38	2.31
115 °C Rise Copper				
15	2.90	1.59	2.43	0.66
30	2.35	0.97	2.14	0.45
45	3.85	2.87	2.57	1.12
75	2.86	2.12	1.92	1.10
112.5	4.02	3.59	1.82	1.97
150	3.34	3.05	1.37	2.23
225	5.03	4.78	1.58	3.02
300	4.14	3.94	1.29	3.06
80 °C Rise Copper				
15	3.09	2.04	2.32	0.88
30	2.53	1.73	1.85	0.94
45	1.70	1.16	1.25	0.93
75	2.42	2.07	1.25	1.66
112.5	2.27	1.98	1.09	1.81
150	2.89	2.65	1.15	2.31
225	3.11	2.95	0.96	3.06

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Transformer Losses

Transformer Loss Data

See product sections for data.

Transformer Losses at Reduced Loads

Information on losses based on actual transformer test data can be obtained from the manufacturer. Transformer manufacturers provide no load watt losses and total watt losses in accordance with ANSI standards. The calculated difference between the no load losses and the total losses are typically described as the load losses. Although transformer coils are manufactured with either aluminum or copper conductors, the industry has sometimes referred to these load losses as the "copper losses."

Transformer losses for various loading can be estimated in the following manner. The no load watt losses of the transformer are due to magnetization and are present whenever the transformer is energized. The load watt losses are the difference between the no load watt losses and the full load watt losses. The load watt losses are proportional to I^2R and can be estimated to vary with the transformer load by the square of the load current.

For example, the approximate watts loss data for a 1000 kVA oil-filled substation transformer is shown in the table as having 1800 watts no load losses and 15,100 watts full load losses, so the load losses are approximately 13,300 watts (15,100–1800). The transformer losses can be calculated for various loads as follows.

At 0% load:
1800 watts

At 50% load:
 $1800 \text{ watts} + (13,300)(0.5)^2 =$
 $1800 \text{ watts} + 3325 \text{ watts} = 5125 \text{ watts}$

At 100% load:
 $1800 \text{ watts} + 13,300 \text{ watts} = 15,100 \text{ watts}$

At 110% load:
 $1800 \text{ watts} + (13,300)(1.1)^2 =$
 $1800 \text{ watts} + 16,093 \text{ watts} = 17,893 \text{ watts}$

Because transformer losses vary between designs and manufacturers, additional losses such as from cooling fans can be ignored for these approximations.

Note: 1 watthour = 3.413 Btu.

Power Equipment Losses and Enclosures/Knockout Dimensions

Power Equipment Losses

Table 1.5-12. Power Equipment Losses

Equipment	Watts Loss
Medium Voltage Switchgear (Indoor, 5 and 15 kV)	
1200 A breaker	600
2000 A breaker	1400
3000 A breaker	2100
4000 A breaker	3700
Medium Voltage Switchgear (Indoor, 5 and 15 kV)	
600 A unfused switch	500
1200 A unfused switch	750
100 A CL fuses	840
Medium Voltage Starters (Indoor, 5 kV)	
400 A starter FVNR	600
800 A starter FVNR	1000
600 A fused switch	500
1200 A fused switch	800
Low Voltage Switchgear (Indoor, 480 V)	
800 A breaker	400
1600 A breaker	1000
2000 A breaker	1500
3200 A breaker	2400
4000 A breaker	3000
5000 A breaker	4700
Fuse limiters—800 A CB	200
Fuse limiters—1600 A CB	500
Fuse limiters—2000 A CB	750
Fuse truck—3200 A CB	3600
Fuse truck—4000 A CB	4500
Structures—3200 A	4000
Structures—4000 A	5000
Structures—5000 A	7000
High resistance grounding	1200
Panelboards (Indoor, 480 V)	
225 A, 42 circuit	300
Low Voltage Busway (Indoor, Copper, 480 V)	
800 A	44 per foot
1200 A	60 per foot
1350 A	66 per foot
1600 A	72 per foot
2000 A	91 per foot
2500 A	103 per foot
3200 A	144 per foot
4000 A	182 per foot
5000 A	203 per foot
Motor Control Centers (Indoor, 480 V)	
NEMA Size 1 starter	39
NEMA Size 2 starter	56
NEMA Size 3 starter	92
NEMA Size 4 starter	124
NEMA Size 5 starter	244
Structures	200
Adjustable Frequency Drives (Indoor, 480 V)	
Adjustable frequency drives	> 96% efficiency

Note: The information provided on power equipment losses is generic data intended to be used for sizing of HVAC equipment.

Enclosures

The following are reproduced from NEMA 250.

Table 1.5-13. Comparison of Specific Applications of Enclosures for Indoor Nonhazardous Locations

Provides a Degree of Protection Against the Following Environmental Conditions	Enclosure Type									
	1 ①	2 ①	4	4X	5	6	6P	12	12K	13
Incidental contact with the enclosed equipment	■	■	■	■	■	■	■	■	■	■
Falling dirt	■	■	■	■	■	■	■	■	■	■
Falling liquids and light splashing	■	■	■	■	■	■	■	■	■	■
Circulating dust, lint, fibers and flyings ②			■	■	■	■	■	■	■	■
Settling airborne dust, lint, fibers and flyings ②			■	■	■	■	■	■	■	■
Hosedown and splashing water			■	■	■	■	■	■	■	■
Oil and coolant seepage							■	■	■	■
Oil or coolant spraying and splashing							■	■	■	■
Corrosive agents				■			■	■	■	■
Occasional temporary submersion						■	■	■	■	■
Occasional prolonged submersion						■	■	■	■	■

- ① These enclosures may be ventilated.
- ② These fibers and flying are nonhazardous materials and are not considered the Class III type ignitable fibers or combustible flyings. For Class III type ignitable fibers or combustible flyings, see the National Electrical Code, Article 500.

Table 1.5-14. Comparison of Specific Applications of Enclosures for Outdoor Nonhazardous Locations

Provides a Degree of Protection Against the Following Environmental Conditions	Enclosure Type						
	3	3R ③	3S	4	4X	6	6P
Incidental contact with the enclosed equipment	■	■	■	■	■	■	■
Rain, snow and sleet ④	■	■	■	■	■	■	■
Sleet ⑤			■				
Windblown dust	■		■	■	■	■	■
Hosedown				■	■	■	■
Corrosive agents					■	■	■
Occasional temporary submersion						■	■
Occasional prolonged submersion						■	■

- ③ These enclosures may be ventilated.
- ④ External operating mechanisms are not required to be operable when the enclosure is ice covered.
- ⑤ External operating mechanisms are operable when the enclosure is ice covered.

Table 1.5-15. Comparison of Specific Applications of Enclosures for Indoor Hazardous Locations

Provides a Degree of Protection Against Atmospheres Typically Containing (For Complete Listing, See NFPA 497M)	Class	Enclosure Types 7 and 8, Class I Groups ⑥				Enclosure Type 9, Class II Groups ⑥			
		A	B	C	D	E	F	G	10
Acetylene	I		■						
Hydrogen, manufactured gas	I		■						
diethyl ether, ethylene, cyclopropane	I			■					
Gasoline, hexane, butane, naphtha, propane, acetone, toluene, isoprene	I				■				
Metal dust	II					■			
Carbon black, coal dust, coke dust	II						■		
Flour, starch, grain dust	II							■	
Fibers, flyings ⑦	III							■	
Methane with or without coal dust	MSHA								■

- ⑥ For Class III type ignitable fibers or combustible flyings, see the National Electrical Code, Article 500.
- ⑦ Due to the characteristics of the gas, vapor or dust, a product suitable for one class or group may not be suitable for another class or group unless so marked on the product.

Note: If the installation is outdoors and/or additional protection is required by Tables 1.5-13 and 1.5-14, a combination-type enclosure is required.

Power Equipment Losses and Enclosures/Knockout Dimensions

Table 1.5-16. Conversion of NEMA Enclosure Type Ratings to IEC 60529 Enclosure Classification Designations (IP) (Cannot be Used to Convert IEC Classification Designations to NEMA Type Ratings)

IP First Character	NEMA Enclosure Type												IP Second Character				
	1	2	3	3R	3S	4	4X	5	6	6P	12	12K		13			
IP0	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	IP_0
IP1																	IP_1
IP2																	IP_2
IP3																	IP_3
IP4																	IP_4
IP5																	IP_5
IP6																	IP_6
																	IP_7
																	IP_8
	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	

A = A shaded block in the "A" column indicates that the NEMA Enclosure Type exceeds the requirements for the respective IEC 60529 IP First Character Designation. The IP First Character Designation is the protection against access to hazardous parts and solid foreign objects.
 B = A shaded block in the "B" column indicates that the NEMA Enclosure Type exceeds the requirements for the respective IEC 60529 IP Second Character Designation. The IP Second Character Designation is the protection against the ingress of water.

EXAMPLE OF TABLE USE

An IEC IP 45 Enclosure Rating is specified. What NEMA Type Enclosures meet and exceed the IP 45 rating?

Referencing the first character, 4, in the IP rating and the row designated "IP4_" in the leftmost column in the table; the blocks in Column "A" for NEMA Types 3, 3S, 4, 4X, 5, 6, 6P, 12, 12K and 13 are shaded. These NEMA ratings meet and exceed the IEC protection requirements against access to hazardous parts and solid foreign objects. Referencing the second character, 5, in the IP rating and the row designated "IP_5" in the rightmost column in the table; the blocks in Column "B" for NEMA Types 3, 3S, 4, 4X, 6 and 6P are shaded. These NEMA ratings meet and exceed the IEC requirements for protection against the ingress of water. The absence of shading in Column "B" beneath the "NEMA Enclosure Type 5" indicates that Type 5 does not meet the IP 45 protection requirements against the ingress of water. Likewise the absence of shading in Column "B" for NEMA Type 12, 12K and 13 enclosures indicates that these enclosures do not meet the IP 45 requirements for protection against the ingress of water. Only Types 3, 3S, 4, 4X, 6 and 6P have both Column "A" in the "IP4_" row and Column "B" in the "IP_5" row shaded and could be used in an IP45 application.

The NEMA Enclosure Type 3 not only meets the IP 45 Enclosure Rating, but also exceeds the IEC requirements because the NEMA Type requires an outdoor corrosion test; a gasket aging test; a dust test; an external icing test; and no water penetration in the rain test. Slight differences exist between the IEC and NEMA test methods, but the IEC rating permits the penetration of water if "it does not deposit on insulation parts, or reach live parts." The IEC rating does not require a corrosion test; gasket aging test; dust test or external icing test. Because the NEMA ratings include additional test requirements, this table cannot be used to select IP Designations for NEMA rated enclosure specifications.

IEC 60529 specifies that an enclosure shall only be designated with a stated degree of protection indicated by the first characteristic numeral if it also complies with all lower degrees of protection. Furthermore IEC 60529 states that an enclosure shall only be designated with a degree of protection indicated by the second characteristic numeral if it also complies with all lower degrees of protection up to and including the second characteristic numeral 0. An enclosure designated with a second characteristic numeral 7 or 8 only is considered unsuitable for exposure to water jets (designated by second characteristic numeral 5 or 6) and need not comply with requirements for numeral 5 or 6 unless it is dual coded. Since the IEC protection requirements become more stringent with increasing IP character value up through 6, once a NEMA Type rating meets the requirements for an IP designation up through 6, it will also meet the requirements for all lower IP designations. This is apparent from the shaded areas shown in the table.

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Conductor Resistance, Reactance, Impedance

**Average Characteristics of
600 V Conductors—
Ohms per 1000 ft (305 m)**

The tables below are average characteristics based on data from IEEE Standard 141-1993. Values from different sources vary because of operating temperatures, wire stranding, insulation materials and thicknesses, overall diameters, random lay of multiple conductors in conduit, conductor spacing, and other divergences in materials, test conditions and calculation methods. These tables are for 600 V 5 kV and 15 kV conductors, at an average temperature of 75 °C. Other parameters are listed in the notes. For medium voltage cables, differences among manufacturers are considerably greater because of the wider variations in insulation materials and thicknesses, shielding, jacketing, overall diameters, and the like. Therefore, data for medium voltage cables should be obtained from the manufacturer of the cable to be used.

Application Notes

- Resistance and reactance are phase-to-neutral values, based on 60 Hz AC, three-phase, four-wire distribution, in ohms per 100 ft (30 m) of circuit length (not total conductor lengths)
- Based upon conductivity of 100% for copper, 61% for aluminum
- Based on conductor temperatures of 75 °C. Reactance values will have negligible variation with temperature. Resistance of both copper and aluminum conductors will be approximately 5% lower at 60 °C or 5% higher at 90 °C. Data shown in tables may be used without significant error between 60 ° and 90 °C
- For interlocked armored cable, use magnetic conduit data for steel armor and non-magnetic conduit data for aluminum armor

- $Z = \sqrt{X^2 + R^2}$
- For busway impedance data, see **Tab 21** of this catalog
- For PF (power factor) values less than 1.0, the effective impedance Z_e is calculated from
 $Z_e = R \times PF + X \sin(\text{arc cos PF})$
- For copper cable data, resistance based on tinned copper at 60 Hz; 600 V and 5 kV nonshielded cable based on varnished cambric insulation; 5 kV shielded and 15 kV cable based on neoprene insulation
- For aluminum cable data, cable is cross-linked polyethylene insulated

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Table 1.5-17. 60 Hz Impedance Data for Three-Phase Copper Cable Circuits, in Approximate Ohms per 1000 ft (305 m) at 75 °C (a) Three Single Conductors

Wire Size, AWG or kcmil	In Magnetic Duct						In Non-Magnetic Duct					
	600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV			600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV		
	R	X	Z	R	X	Z	R	X	Z	R	X	Z
8	0.811	0.0754	0.814	0.811	0.0860	0.816	0.811	0.0603	0.813	0.811	0.0688	0.814
8 (solid)	0.786	0.0754	0.790	0.786	0.0860	0.791	0.786	0.0603	0.788	0.786	0.0688	0.789
6	0.510	0.0685	0.515	0.510	0.0796	0.516	0.510	0.0548	0.513	0.510	0.0636	0.514
6 (solid)	0.496	0.0685	0.501	0.496	0.0796	0.502	0.496	0.0548	0.499	0.496	0.0636	0.500
4	0.321	0.0632	0.327	0.321	0.0742	0.329	0.321	0.0506	0.325	0.321	0.0594	0.326
4 (solid)	0.312	0.0632	0.318	0.312	0.0742	0.321	0.312	0.0506	0.316	0.312	0.0594	0.318
2	0.202	0.0585	0.210	0.202	0.0685	0.214	0.202	0.0467	0.207	0.202	0.0547	0.209
1	0.160	0.0570	0.170	0.160	0.0675	0.174	0.160	0.0456	0.166	0.160	0.0540	0.169
1/0	0.128	0.0540	0.139	0.128	0.0635	0.143	0.127	0.0432	0.134	0.128	0.0507	0.138
2/0	0.102	0.0533	0.115	0.103	0.0630	0.121	0.101	0.0426	0.110	0.102	0.0504	0.114
3/0	0.0805	0.0519	0.0958	0.0814	0.0605	0.101	0.0766	0.0415	0.0871	0.0805	0.0484	0.0939
4/0	0.0640	0.0497	0.0810	0.0650	0.0583	0.0929	0.0633	0.0398	0.0748	0.0640	0.0466	0.0792
250	0.0552	0.0495	0.0742	0.0557	0.0570	0.0797	0.0541	0.0396	0.0670	0.0547	0.0456	0.0712
300	0.0464	0.0493	0.0677	0.0473	0.0564	0.0736	0.0451	0.0394	0.0599	0.0460	0.0451	0.0644
350	0.0378	0.0491	0.0617	0.0386	0.0562	0.0681	0.0368	0.0393	0.0536	0.0375	0.0450	0.0586
400	0.0356	0.0490	0.0606	0.0362	0.0548	0.0657	0.0342	0.0392	0.0520	0.0348	0.0438	0.0559
450	0.0322	0.0480	0.0578	0.0328	0.0538	0.0630	0.0304	0.0384	0.0490	0.0312	0.0430	0.0531
500	0.0294	0.0466	0.0551	0.0300	0.0526	0.0505	0.0276	0.0373	0.0464	0.0284	0.0421	0.0508
600	0.0257	0.0463	0.0530	0.0264	0.0516	0.0580	0.0237	0.0371	0.0440	0.0246	0.0412	0.0479
750	0.0216	0.0495	0.0495	0.0223	0.0497	0.0545	0.0194	0.0356	0.0405	0.0203	0.0396	0.0445

Note: More tables on **Page 1.5-16**.

Conductor Resistance, Reactance, Impedance

Table 1.5-18. 60 Hz Impedance Data for Three-Phase Copper Cable Circuits, in Approximate Ohms per 1000 ft (305 m) at 75 °C (b) Three Conductor Cable

Wire Size, AWG or kcmil	In Magnetic Duct and Steel Interlocked Armor						In Non-Magnetic Duct and Aluminum Interlocked Armor					
	600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV			600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV		
	R	X	Z	R	X	Z	R	X	Z	R	X	Z
8	0.811	0.0577	0.813	0.811	0.0658	0.814	0.811	0.0503	0.812	0.811	0.0574	0.813
8 (solid)	0.786	0.0577	0.788	0.786	0.0658	0.789	0.786	0.0503	0.787	0.786	0.0574	0.788
6	0.510	0.0525	0.513	0.510	0.0610	0.514	0.510	0.0457	0.512	0.510	0.0531	0.513
6 (solid)	0.496	0.0525	0.499	0.496	0.0610	0.500	0.496	0.0457	0.498	0.496	0.0531	0.499
4	0.321	0.0483	0.325	0.321	0.0568	0.326	0.321	0.0422	0.324	0.321	0.0495	0.325
4 (solid)	0.312	0.0483	0.316	0.312	0.0508	0.317	0.312	0.0422	0.315	0.312	0.0495	0.316
2	0.202	0.0448	0.207	0.202	0.0524	0.209	0.202	0.0390	0.206	0.202	0.0457	0.207
1	0.160	0.0436	0.166	0.160	0.0516	0.168	0.160	0.0380	0.164	0.160	0.0450	0.166
1/0	0.128	0.0414	0.135	0.128	0.0486	0.137	0.127	0.0360	0.132	0.128	0.0423	0.135
2/0	0.102	0.0407	0.110	0.103	0.0482	0.114	0.101	0.0355	0.107	0.102	0.0420	0.110
3/0	0.0805	0.0397	0.0898	0.0814	0.0463	0.0936	0.0766	0.0346	0.0841	0.0805	0.0403	0.090
4/0	0.0640	0.0381	0.0745	0.0650	0.0446	0.0788	0.0633	0.0332	0.0715	0.0640	0.0389	0.0749
250	0.0552	0.0379	0.0670	0.0557	0.0436	0.0707	0.0541	0.0330	0.0634	0.0547	0.0380	0.0666
300	0.0464	0.0377	0.0598	0.0473	0.0431	0.0640	0.0451	0.0329	0.0559	0.0460	0.0376	0.0596
350	0.0378	0.0373	0.0539	0.0386	0.0427	0.0576	0.0368	0.0328	0.0492	0.0375	0.0375	0.0530
400	0.0356	0.0371	0.0514	0.0362	0.0415	0.0551	0.0342	0.0327	0.0475	0.0348	0.0366	0.0505
450	0.0322	0.0361	0.0484	0.0328	0.0404	0.0520	0.0304	0.0320	0.0441	0.0312	0.0359	0.0476
500	0.0294	0.0349	0.0456	0.0300	0.0394	0.0495	0.0276	0.0311	0.0416	0.0284	0.0351	0.0453
600	0.0257	0.0343	0.0429	0.0264	0.0382	0.0464	0.0237	0.0309	0.0389	0.0246	0.0344	0.0422
750	0.0216	0.0326	0.0391	0.0223	0.0364	0.0427	0.0197	0.0297	0.0355	0.0203	0.0332	0.0389

Table 1.5-19. 60 Hz Impedance Data for Three-Phase Aluminum Cable Circuits, in Approximate Ohms per 1000 Ft (305 m) at 90 °C (a) Three Single Conductors

Wire Size, AWG or kcmil	In Magnetic Duct						In Non-Magnetic Duct					
	600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV			600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV		
	R	X	Z	R	X	Z	R	X	Z	R	X	Z
6	0.847	0.053	0.849	—	—	—	0.847	0.042	0.848	—	—	—
4	0.532	0.050	0.534	0.532	0.068	0.536	0.532	0.040	0.534	0.532	0.054	0.535
2	0.335	0.046	0.338	0.335	0.063	0.341	0.335	0.037	0.337	0.335	0.050	0.339
1	0.265	0.048	0.269	0.265	0.059	0.271	0.265	0.035	0.267	0.265	0.047	0.269
1/0	0.210	0.043	0.214	0.210	0.056	0.217	0.210	0.034	0.213	0.210	0.045	0.215
2/0	0.167	0.041	0.172	0.167	0.055	0.176	0.167	0.033	0.170	0.167	0.044	0.173
3/0	0.133	0.040	0.139	0.132	0.053	0.142	0.133	0.037	0.137	0.132	0.042	0.139
4/0	0.106	0.039	0.113	0.105	0.051	0.117	0.105	0.031	0.109	0.105	0.041	0.113
250	0.0896	0.0384	0.0975	0.0892	0.0495	0.102	0.0894	0.0307	0.0945	0.0891	0.0396	0.0975
300	0.0750	0.0375	0.0839	0.0746	0.0479	0.0887	0.0746	0.0300	0.0804	0.0744	0.0383	0.0837
350	0.0644	0.0369	0.0742	0.0640	0.0468	0.0793	0.0640	0.0245	0.0705	0.0638	0.0374	0.0740
400	0.0568	0.0364	0.0675	0.0563	0.0459	0.0726	0.0563	0.0291	0.0634	0.0560	0.0367	0.0700
500	0.0459	0.0355	0.0580	0.0453	0.0444	0.0634	0.0453	0.0284	0.0535	0.0450	0.0355	0.0573
600	0.0388	0.0359	0.0529	0.0381	0.0431	0.0575	0.0381	0.0287	0.0477	0.0377	0.0345	0.0511
700	0.0338	0.0350	0.0487	0.0332	0.0423	0.0538	0.0330	0.0280	0.0433	0.0326	0.0338	0.0470
750	0.0318	0.0341	0.0466	0.0310	0.0419	0.0521	0.0309	0.0273	0.0412	0.0304	0.0335	0.0452
1000	0.0252	0.0341	0.0424	0.0243	0.0414	0.0480	0.0239	0.0273	0.0363	0.0234	0.0331	0.0405

Table 1.5-20. 60 Hz Impedance Data for Three-Phase Aluminum Cable Circuits, in Approximate Ohms per 1000 ft (30 m) at 90 °C (b) Three Conductor Cable

Wire Size, AWG or kcmil	In Magnetic Duct and Steel Interlocked Armor						In Non-Magnetic Duct and Aluminum Interlocked Armor					
	600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV			600 V and 5 kV Non-Shielded			5 kV Shielded and 15 kV		
	R	X	Z	R	X	Z	R	X	Z	R	X	Z
6	0.847	0.053	0.849	—	—	—	0.847	0.042	0.848	—	—	—
4	0.532	0.050	0.534	—	—	—	0.532	0.040	0.534	—	—	—
2	0.335	0.046	0.338	0.335	0.056	0.340	0.335	0.037	0.337	0.335	0.045	0.338
1	0.265	0.048	0.269	0.265	0.053	0.270	0.265	0.035	0.267	0.265	0.042	0.268
1/0	0.210	0.043	0.214	0.210	0.050	0.216	0.210	0.034	0.213	0.210	0.040	0.214
2/0	0.167	0.041	0.172	0.167	0.049	0.174	0.167	0.033	0.170	0.167	0.039	0.171
3/0	0.133	0.040	0.139	0.133	0.048	0.141	0.133	0.037	0.137	0.132	0.038	0.138
4/0	0.106	0.039	0.113	0.105	0.045	0.114	0.105	0.031	0.109	0.105	0.036	0.111
250	0.0896	0.0384	0.0975	0.0895	0.0436	0.100	0.0894	0.0307	0.0945	0.0893	0.0349	0.0959
300	0.0750	0.0375	0.0839	0.0748	0.0424	0.0860	0.0746	0.0300	0.0804	0.0745	0.0340	0.0819
350	0.0644	0.0369	0.0742	0.0643	0.0418	0.0767	0.0640	0.0245	0.0705	0.0640	0.0334	0.0722
400	0.0568	0.0364	0.0675	0.0564	0.0411	0.0700	0.0563	0.0291	0.0634	0.0561	0.0329	0.0650
500	0.0459	0.0355	0.0580	0.0457	0.0399	0.0607	0.0453	0.0284	0.0535	0.0452	0.0319	0.0553
600	0.0388	0.0359	0.0529	0.0386	0.0390	0.0549	0.0381	0.0287	0.0477	0.0380	0.0312	0.0492
700	0.0338	0.0350	0.0487	0.0335	0.0381	0.0507	0.0330	0.0280	0.0433	0.0328	0.0305	0.0448
750	0.0318	0.0341	0.0466	0.0315	0.0379	0.0493	0.0309	0.0273	0.0412	0.0307	0.0303	0.0431
1000	0.0252	0.0341	0.0424	0.0248	0.0368	0.0444	0.0239	0.0273	0.0363	0.0237	0.0294	0.0378

Conductor Ampacities

Current Carrying Capacities of Copper and Aluminum and Copper-Clad Aluminum Conductors From National Electrical Code (NEC), 2011 Edition (NFPA 70-2011)

Table 1.5-21. Allowable Ampacities of Insulated Conductors Rated 0–2000 V, 60 ° to 90 °C (140° to 194 °F).

Not more than three current-carrying conductors in raceway, cable or earth (directly buried), based on ambient temperature of 30 °C (86 °F).

Size AWG or kcmil	Temperature Rating of Conductor (See Table 310.15 [B][16])						Size AWG or kcmil
	60 °C (140 °F)			90 °C (194 °F)			
	Types			Types			
	TW, UF	RHW, THHW, THW, THWN, XHHW, USE, ZW	TBS, SA, SIS, FEP, FEPB, MI, RHH, RHW-2, THHN, THHW, THW-2, THWN-2, USE-2, XHH, XHHW, XHHW-2, ZW-2	TW, UF	RHW, THHW, THW, THWN, XHHW, USE	TBS, SA, SIS, THHN, THHW, THW-2, THWN-2, RHH, RHW-2, USE-2, XHH, XHHW, XHHW-2, ZW-2	
	Copper			Aluminum or Copper-Clad Aluminum			
18	—	—	14	—	—	—	—
16	—	—	18	—	—	—	—
14 ①	15	20	25	—	—	—	—
12 ①	20	25	30	20	20	25	12 ①
10 ①	30	35	40	25	30	35	10 ①
8	40	50	55	30	40	45	8
6	55	65	75	40	50	60	6
4	70	85	95	55	65	75	4
3	85	100	110	65	75	85	3
2	95	115	130	75	90	100	2
1	110	130	150	85	100	115	1
1/0	125	150	170	100	120	135	1/0
2/0	145	175	195	115	135	150	2/0
3/0	165	200	225	130	155	175	3/0
4/0	195	230	260	150	180	205	4/0
250	215	255	290	170	205	230	250
300	240	285	320	190	230	255	300
350	260	310	350	210	250	280	350
400	280	335	380	225	270	305	400
500	320	380	430	260	310	350	500
600	355	420	475	285	340	385	600
700	385	460	520	310	375	420	700
750	400	475	535	320	385	435	750
800	410	490	555	330	395	450	800
900	435	520	585	355	425	480	900
1000	455	545	615	375	445	500	1000
1250	495	590	665	405	485	545	1250
1500	520	625	705	435	520	585	1500
1750	545	650	735	455	545	615	1750
2000	560	665	750	470	560	630	2000

① See NEC Section 240.4 (D).

Note: For complete details of using Table 1.5-21, see NEC Article 310 in its entirety.

Table 1.5-22. Correction Factors From NFPA 70-2011 (See Table 310.15 [B][2][a])

Ambient Temperature °C	For ambient temperatures other than 30 °C (86 °F), multiply the allowable ampacities shown above by the appropriate factor shown below.						Ambient Temperature °F
21–25	1.08	1.05	1.04	1.08	1.05	1.04	070–77
26–30	1.00	1.00	1.00	1.00	1.00	1.00	078–86
31–35	0.91	0.94	0.96	0.91	0.94	0.96	087–95
36–40	0.82	0.88	0.91	0.82	0.88	0.91	096–104
41–45	0.71	0.82	0.87	0.71	0.82	0.87	105–113
46–50	0.58	0.75	0.82	0.58	0.75	0.82	114–122
51–55	0.41	0.67	0.76	0.41	0.67	0.76	123–131
56–60	—	0.58	0.71	—	0.58	0.71	132–140
61–70	—	0.33	0.58	—	0.33	0.58	141–158
71–80	—	—	0.41	—	—	0.41	159–176

Conductor Ampacities

**Ampacities for Conductors
Rated 0–2000 V (Excerpted
from NFPA 70-2011, 310.15)**

Note: Fine Print Note (FPN) was changed to Informational Note in the 2011 NEC.

(A) General.**(1) Tables or Engineering Supervision.**

Ampacities for conductors shall be permitted to be determined by tables as provided in 310.15(B) or under engineering supervision, as provided in 310.15(C).

Note: Informational Note No. 1: Ampacities provided by this section do not take voltage drop into consideration. See 210.19(A), Informational Note No. 4, for branch circuits and 215.2(A), Informational Note No. 2, for feeders.

Note: Informational Note No. 2: For the allowable ampacities of Type MTW wire, see Table 13.5.1 in NFPA 79-2007, *Electrical Standard for Industrial Machinery*.

(2) Selection of Ampacity. Where more than one ampacity applies for a given circuit length, the lowest value shall be used.

Exception: Where two different ampacities apply to adjacent portions of a circuit, the higher ampacity shall be permitted to be used beyond the point of transition, a distance equal to 10 ft (3.0 m) or 10 percent of the circuit length figured at the higher ampacity, whichever is less.

Note: Informational Note: See 110.14(C) for conductor temperature limitations due to termination provisions.

(B) Tables. Ampacities for conductors rated 0–2000 V shall be as specified in the Allowable Ampacity Table 310.15(B)(16) through Table 310.15(B)(19), and Ampacity Table 310.15(B)(20) and Table 310.15(B)(21) as modified by 310.15(B)(1) through (B)(7).

Note: Informational Note: Table 310.15(B)(16) through Table 310.15(B)(19) are application tables for use in determining conductor sizes on loads calculated in accordance with Article 220. Allowable ampacities result from consideration of one or more of the following:

- (1) Temperature compatibility with connected equipment, especially the connection points.
- (2) Coordination with circuit and system overcurrent protection.
- (3) Compliance with the requirements of product listings or certifications. See 110.3(B).

(4) Preservation of the safety benefits of established industry practices and standardized procedures.

(1) General. For explanation of type letters used in tables and for recognized sizes of conductors for the various conductor insulations, see Table 310.104(A) and Table 310.104(B). For installation requirements, see 310.1 through 310.15(A)(3) and the various articles of this Code. For flexible cords, see Table 400.4, Table 400.5(A)(1) and Table 400.5(A)(2).

(3) Adjustment Factors.

(a) *More Than Three Current-Carrying Conductors in a Raceway or Cable.* Where the number of current-carrying conductors in a raceway or cable exceeds three, or where single conductors or multi-conductor cables are installed without maintaining spacing for a continuous length longer than 24.00-inch (600 mm) and are not installed in raceways, the allowable ampacity of each conductor shall be reduced as shown in Table 310.15(B)(3)(a). Each current-carrying conductor of a paralleled set of conductors shall be counted as a current-carrying conductor.

Note: Informational Note No. 1: See Annex B, Table B.310.15(B)(2)(11), for adjustment factors for more than three current-carrying conductors in a raceway or cable with load diversity.

Note: Informational Note No. 2: See 366.23(A) for adjustment factors for conductors in sheet metal auxiliary gutters and 376.22(B) for adjustment factors for conductors in metal wireways.

- (1) Where conductors are installed in cable trays, the provisions of 392.80 shall apply.
- (2) Adjustment factors shall not apply to conductors in raceways having a length not exceeding 24.00-inch (600 mm).
- (3) Adjustment factors shall not apply to underground conductors entering or leaving an outdoor trench if those conductors have physical protection in the form of rigid metal conduit, intermediate metal conduit, rigid polyvinyl chloride conduit (PVC), or reinforced thermosetting resin conduit (RTRC) having a length not exceeding 10 ft (3.05 m), and if the number of conductors does not exceed four.

(4) Adjustment factors shall not apply to Type AC cable or to Type MC cable under the following conditions:

- a. The cables do not have an overall outer jacket.
- b. Each cable has not more than three current-carrying conductors.
- c. The conductors are 12 AWG copper.
- d. Not more than 20 current-carrying conductors are installed without maintaining spacing, are stacked, or are supported on "bridle rings."

(5) An adjustment factor of 60 percent shall be applied to Type AC cable or Type MC cable under the following conditions:

- a. The cables do not have an overall outer jacket.
- b. The number of current carrying conductors exceeds 20.
- c. The cables are stacked or bundled longer than 24.00-inch (600 mm) without spacing being maintained.

(b) *More Than One Conduit, Tube, or Raceway.* Spacing between conduits, tubing, or raceways shall be maintained.

(c) *Circular Raceways Exposed to Sunlight on Rooftops.*

Where conductors or cables are installed in circular raceways exposed to direct sunlight on or above rooftops, the adjustments shown in **Table 1.5-23** shall be added to the outdoor temperature to determine the applicable ambient temperature for application of the correction factors in Table 310.15(B)(2)(a) or Table 310.15(B)(2)(b).

Note: Informational Note: One source for the average ambient temperatures in various locations is the ASHRAE Handbook —Fundamentals.

Table 1.5-23. NEC (2011) Table 310.15(B)(3)(c) Ambient Temperature Adjustment for Circular Raceways Exposed to Sunlight On or Above Rooftops

Distance Above Roof to Bottom of Conduit	Temperature Adder °F (°C)
0–0.51-inch (0–13.0 mm)	60 (33)
Above 0.51-inch (13.0 mm)–3.54-inch (90.0 mm)	40 (22)
Above 3.54-inch (90.0 mm)–11.81-inch (300.0 mm)	30 (17)
Above 12.00-inch (300.0 mm)–36.00-inch (900.0 mm)	25 (14)

Conductor Ampacities

(4) Bare or Covered Conductors.

Where bare or covered conductors are installed with insulated conductors, the temperature rating of the bare or covered conductor shall be equal to the lowest temperature rating of the insulated conductors for the purpose of determining ampacity.

(5) Neutral Conductor.

(a) A neutral conductor that carries only the unbalanced current from other conductors of the same circuit shall not be required to be counted when applying the provisions of 310.15(B)(3)(a).

(b) In a three-wire circuit consisting of two phase conductors and the neutral conductor of a four-wire, three-phase, wye-connected system, a common conductor carries approximately the same current as the line-to-neutral load currents of the other conductors and shall be counted when applying the provisions of 310.15(B)(3)(a).

(c) On a four-wire, three-phase wye circuit where the major portion of the load consists of nonlinear loads, harmonic currents are present in the neutral conductor; the neutral conductor shall therefore be considered a current-carrying conductor.

(6) Grounding or Bonding Conductor.

A grounding or bonding conductor shall not be counted when applying the provisions of 310.15(B)(3)(a).

Formulas and Terms

Table 1.5-24. Formulas for Determining Amperes, hp, kW and kVA

To Find	Direct Current	Alternating Current		
		Single-Phase	Two-Phase—Four-Wire ①	Three-Phase
Amperes (I) when horsepower is known	$\frac{hp \times 746}{E \times \% \text{ eff}}$	$\frac{hp \times 746}{E \times \% \text{ eff} \times pf}$	$\frac{hp \times 746}{2 \times E \times \% \text{ eff} \times pf}$	$\frac{hp \times 746}{\sqrt{3} \times E \times \% \text{ eff} \times pf}$
Amperes (I) when kilowatts is known	$\frac{kW \times 1000}{E}$	$\frac{kW \times 1000}{E \times pf}$	$\frac{kW \times 1000}{2 \times E \times pf}$	$\frac{kW \times 1000}{\sqrt{3} \times E \times \% pf}$
Amperes (I) when kva is known	—	$\frac{kVA \times 1000}{E}$	$\frac{kVA \times 1000}{2 \times E}$	$\frac{kVA \times 1000}{\sqrt{3} \times E}$
Kilowatts	$\frac{I \times E}{1000}$	$\frac{I \times E \times pf}{1000}$	$\frac{I \times E \times 2 \times pf}{1000}$	$\frac{I \times E \times \sqrt{3} \times pf}{1000}$
kVA	—	$\frac{I \times E}{1000}$	$\frac{I \times E \times 2}{1000}$	$\frac{I \times E \times \sqrt{3}}{1000}$
Horsepower (output)	$\frac{I \times E \times \% \text{ eff}}{746}$	$\frac{I \times E \times \% \text{ eff} \times pf}{746}$	$\frac{I \times E \times 2 \times \% \text{ eff} \times pf}{746}$	$\frac{I \times E \times \sqrt{3} \times \% \text{ eff} \times pf}{746}$

① For two-phase, three-wire circuits, the current in the common conductor is $\sqrt{2}$ times that in either of the two other conductors.

Note: Units of measurement and definitions for E (volts), I (amperes), and other abbreviations are given below under Common Electrical Terms.

Common Electrical Terms

Ampere (I)	= unit of current or rate of flow of electricity
Volt (E)	= unit of electromotive force
Ohm (R)	= unit of resistance
	Ohm's law: $I = \frac{E}{R}$ (DC or 100% pf)
Megohm	= 1,000,000 ohms
Volt Amperes (VA)	= unit of apparent power
	= $E \times I$ (single-phase)
	= $E \times I \times \sqrt{3}$
Kilovolt Amperes (kVA)	= 1000 volt-amperes
Watt (W)	= unit of true power
	= $VA \times pf$
	= 0.00134 hp
Kilowatt (kW)	= 1000 watts
Power Factor (pf)	= ratio of true to apparent power
	= $\frac{W}{VA} = \frac{kW}{kVA}$
Watt-hour (Wh)	= unit of electrical work
	= 1 watt for 1 hour
	= 3.413 Btu
	= 2655 ft-lbs
Kilowatt-hour (kWh)	= 1000 watt-hours
Horsepower (hp)	= measure of time rate of doing work
	= equivalent of raising 33,000 lbs 1 ft in 1 minute
	= 746 watts
Demand Factor	= ratio of maximum demand to the total connected load
Diversity Factor	= ratio of the sum of individual maximum demands of the various subdivisions of a system to the maximum demand of the whole system
Load Factor	= ratio of the average load over a designated period of time to the peak load occurring in that period

How to Compute Power Factor

$$\text{Determining Watts pf} = \frac{\text{Watts}}{\text{Volts} \times \text{Amperes}}$$

1. From watt-hour meter.
Watts = rpm of disc \times 60 \times Kh

Where Kh is meter constant printed on face or nameplate of meter.

If metering transformers are used, above must be multiplied by the transformer ratios.

2. Directly from wattmeter reading.
Where:

Volts = line-to-line voltage as measured by voltmeter.

Amperes = current measured in line wire (not neutral) by ammeter.

Table 1.5-25. Temperature Conversion

(F° to C°)	C° = 5/9 (F° - 32°)							
(C° to F°)	F° = 9/5(C°) + 32°							
C°	-15	-10	-5	0	5	10	15	20
F°	5	14	23	32	41	50	59	68
C°	25	30	35	40	45	50	55	60
F°	77	86	95	104	113	122	131	140
C°	65	70	75	80	85	90	95	100
F°	149	158	167	176	185	194	203	212

1 Inch	= 2.54 centimeters
1 Kilogram	= 2.20 lbs
1 Square Inch	= 1,273,200 circular mills
1 Circular Mill	= 0.785 square mil
1 Btu	= 778 ft lbs
	= 252 calories
1 Year	= 8760 hours

Seismic Requirements

Seismic Requirements



General

In the 1980s, Eaton embarked on a comprehensive program centered around designing and building electrical distribution and control equipment capable of meeting and exceeding the seismic load requirements of the Uniform Building Code (UBC) and California Building Code (CBC). These codes emphasize building design requirements. Electrical equipment and distribution system components are considered attachments to the building. The entire program has been updated to show compliance with the 2009 International Building Code (IBC) and the 2010 CBC seismic requirements. A cooperative effort with the equipment user, the building designer and the equipment installer ensures that the equipment is correctly anchored such that it can withstand the effects of an earthquake. Eaton's electrical distribution and control equipment has been tested and seismically proven for requirements exceeding the IBC and CBC. Over 100 different assemblies representing essentially all product lines have been successfully tested and verified to seismic levels higher than the maximum seismic requirements specified in the IBC and CBC. The equipment maintained structural integrity and demonstrated the ability to function immediately after the seismic tests. A technical paper, *Earthquake Requirements and Eaton Distribution and Control Equipment Seismic Capabilities* (SA12501SE), provides a detailed explanation of the applicable seismic codes and Eaton's equipment qualification program. The paper may be found at www.eaton.com/seismic. Type in SA12501SE in the document search field.

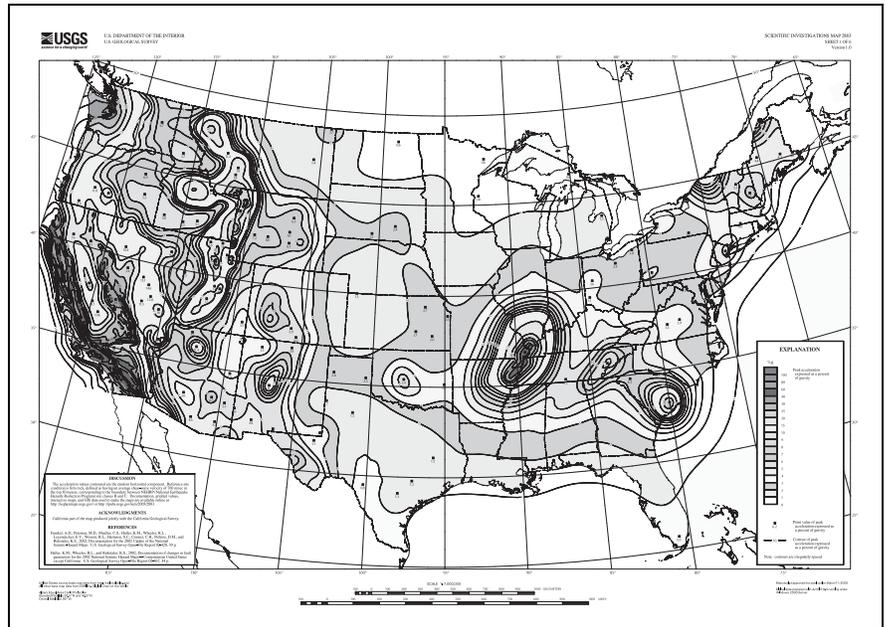


Figure 1.5-1. Typical Earthquake Ground Motion Map for the United States

International Building Code (IBC)

On December 9, 1994, the International Code Council (ICC) was established as a nonprofit organization dedicated to developing a single set of comprehensive and coordinated codes. The ICC founders—the Building Officials and Code Administrators (BOCA), the International Conference of Building Officials (ICBO), and the Southern Building Code Congress International (SBCCI)—created the ICC in response to technical disparities among the three nationally recognized model codes now in use in the U.S. The ICC offers a single, complete set of construction codes without regional limitations—the International Building Code.

Uniform Building Code (UBC)

1997 was the final year in which the UBC was published. It has since been replaced by the IBC.

California Building Code

The 2001 CBC was based upon the 1997 UBC. In August of 2006, it was repealed by the California Building Standards Commission (CBSC) and replaced by the 2007 CBC, California Code of Regulations (CCR), Title 24, Part 2 and used the 2006 IBC as the basis for the code. The 2010 CBC is based upon the 2009 IBC, with amendments as deemed appropriate by the CBSC. Eaton's seismic qualification program fully envelopes the requirements of the 2010 CBC.

Process

According to Chapter 16 of the 2009 IBC, structure design, the seismic requirements of electrical equipment in buildings may be computed in two steps. The first step is to determine the maximum ground motion to be considered at the site. The second step is to evaluate the equipment mounting and attachments inside the building or structure. These are then evaluated to determine appropriate seismic test requirements. The ground motion, seismic requirements of the equipment, and the seismic response spectrum requirements are discussed on **Page 1.5-23**, see **Figure 1.5-3**.

Seismic Requirements

Ground Motion

According to the code, the first and most important step in the process is to determine the maximum considered earthquake spectral response acceleration at short periods of 0.2 seconds (S_S) and at a period of 1.0 second (S_1). These values are determined from a set of 24 spectral acceleration maps (Figure 1.5-1) and include numerous contour lines indicating the severity of the earthquake requirements at a particular location in the country.

The spectral acceleration maps indicate low to moderate seismic requirements for the entire country, with the exception of two particular areas; the West Coast and the Midwest (the New Madrid area). The seismic requirements at the New Madrid area are approximately 30% higher than the maximum requirements of the West Coast. The maps also suggest that the high seismic requirements in both regions, West Coast and Midwest, quickly decrease as one moves away from the fault area. Therefore, the high requirements are only limited to a relatively narrow strip along the fault lines. Just a few miles away from this strip, only a small percentage of the maximum requirements are indicated.

Assuming the worse condition, which is a site directly located near a fault, the maximum considered earthquake spectral response acceleration at short periods of 0.2 seconds (S_S) is equal to 285% gravity and at 1.0 second period (S_1) is 124% gravity. These numbers are the maximum numbers for the entire country except for the New Madrid area. These particular sites are on the border of California and Mexico (S_1) and in Northern California (S_S).

To help understand the 2009 IBC (and 2010 CBC) seismic parameters for a specific building location, the link to the US Geological Society is extremely helpful: <http://earthquake.usgs.gov/research/hazmaps/design/>

Download the file "Java Ground Motion Parameter Calculator" — and save it to your hard drive, then run the executable that was downloaded.

The program will allow one to enter the latitude and longitude of a location. (One must be connected to the Internet to run this application, even after downloading the program.) The IBC (CBC) seismic parameters for that location will then be displayed.

If the latitude and longitude of the building location is not known, another convenient Web site is available that will provide this information based upon a street address: <http://geocoder.us/>

To determine the maximum considered earthquake ground motion for most site classes (A through D), the code introduces site coefficients, which when applied against the location-specific site class, produces the adjusted maximum considered earthquake spectral response acceleration for the required site. The site coefficients are defined as F_a at 0.2 seconds short period and F_v at 1.0 second period. From the tables in the code, the highest adjusting factor for S_S is equal to 1.0 and the highest adjusting factor for S_1 is 1.50.

As a result, the adjusted maximum considered earthquake spectral response for 0.2 second short period (S_{MS}) and at 1.0 second (S_{M1}), adjusted for site class effects, are determined from the following equations:

$$S_{MS} = F_a S_S = 1.0 \times 2.85 \text{ g} = 2.85 \text{ g}$$

$$S_{M1} = F_v S_1 = 1.5 \times 1.24 \text{ g} = 1.86 \text{ g}$$

ASCE 7 (American Society of Civil Engineers), Section 11.4, provides a plot of the final shape of the design response spectra of the seismic ground motion. The plot is shown in Figure 1.5-2. ASCE 7 is referenced throughout the IBC as the source for numerous structural design criteria.

The design spectral acceleration curve can now be computed. The peak spectral acceleration (S_{DS}) and the spectral acceleration at 1.0 second (S_{D1}) may now be computed from the following formulas in the code:

$$S_{DS} = 2/3 \times S_{MS} = 2/3 \times 2.85 \text{ g} = 1.90 \text{ g}$$

$$S_{D1} = 2/3 \times S_{M1} = 2/3 \times 1.8 \text{ g} = 1.24 \text{ g}$$

S_{DS} , the peak spectral acceleration, extends between the values of T_0 and T_S . T_0 and T_S are defined in the codes as follows:

$$T_0 = 0.2 S_{D1}/S_{DS} = 0.2 \times 1.24/1.90 = 0.131 \text{ seconds (7.63 Hz)}$$

$$T_S = S_{D1}/S_{DS} = 1.24/1.90 = 0.653 \text{ seconds (1.53 Hz)}$$

According to the IBC and ASCE 7, the spectral acceleration (S_a) at periods less than 1.45 seconds may be computed by using the following formula:

$$S_a = S_{DS} (0.6 T/T_0 + 0.4)$$

Where T is the period where S_a is being calculated:

Therefore, the acceleration at 0.0417 seconds (24 Hz), for example, is equal to:

$$S_a = 1.90 (0.6 (0.0417/0.131) + 0.4) = 1.12 \text{ g}$$

The acceleration at 0.03 seconds (33 Hz) is equal to:

$$S_a = 1.90 (0.6 (0.03/0.131) + 0.4) = 1.02 \text{ g}$$

At zero period (infinite frequency), $T = 0.0$, the acceleration (ZPA) is equal to:

$$S_a = 1.90 (0.6 (0.0/0.131) + 0.4) = 0.76 \text{ g (ZPA)}$$

The acceleration to frequency relationship in the frequency range of 1.0 Hz to T_S is stated equal to:

$$S_a = S_{D1}/T$$

Where S_a is the acceleration at the T period.

At 1.0 Hz ($T=1.0$) this equation yields the following acceleration:

$$S_a = 1.24/1 = 1.24 \text{ g}$$

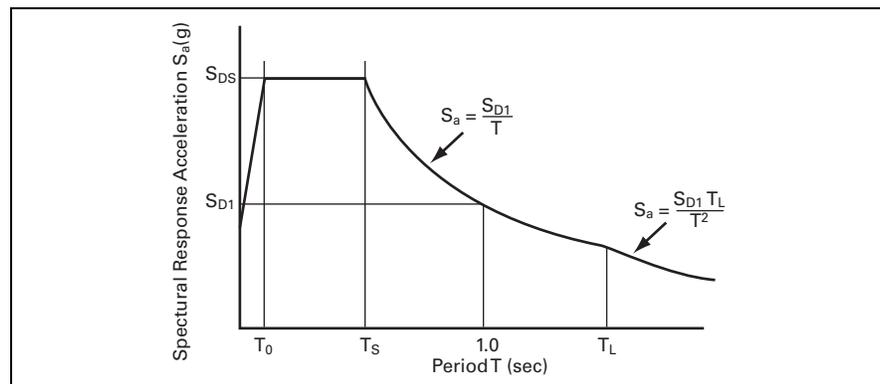


Figure 1.5-2. Design Response Spectrum

Seismic Requirements

1

Testing has demonstrated that the lowest dominant natural frequency of Eaton's electrical equipment is above 3.2 Hz. This indicates that testing at 1.24g at 1 Hz is not necessary. In addition, having the low end of the spectra higher than realistically required forces the shake table to move at extremely high displacements to meet the spectral acceleration at the low frequencies.

Testing to accommodate the low end of the spectra using this acceleration component can result in testing to a factor 2 to 3 times greater than that realistically required.

Through testing experience and data analysis, the seismic acceleration at 1.0 Hz is taken equal to 0.7 g, which will ensure that the seismic levels are achieved well below 3.2 Hz. This yields a more vigorous test over a wider range of seismic intensities.

In developing the seismic requirements above, it is important to recognize the following:

T_0 and T_S are dependent on S_{MS} and S_{D1} . If S_{D1} is small relative to S_{MS} then T_0 and T_S will be smaller and the associated frequencies will shift higher. The opposite is also true. This must be realized in developing the complete required response spectrum (RRS). Therefore, it is not adequate to stop the peak spectral acceleration at 7.63 Hz. There are other contour line combinations that will produce higher T_0 . To account for this variation it is almost impossible to consider all combinations. However, a study of the spectral acceleration maps indicates that all variations with high magnitude of contour lines could very well be enveloped by a factor of 1.5. Therefore, T_0 is recomputed as follows:

$$T_0 = 0.2 S_{D1} / (S_{DS} \times 1.5) = 0.2 \times 1.24 / (1.90 \times 1.5) = 0.087 \text{ seconds (11.49 Hz)}$$

Eaton ensures maximum certification by requiring peak acceleration during testing to extend to 12 Hz.

It can be seen that Eaton has elected to develop generic seismic requirements that envelop two criteria:

- The highest possible spectral peak accelerations and ZPA
- The maximum frequency range required for many different sites

This completes the ground motion design response spectrum. The spectral accelerations are equal to 0.76 g at ZPA, or 33 Hz, and increases linearly to a peak acceleration of 1.90 g at 0.09 seconds (or 11.49 Hz) and stays constant to 0.653 seconds (1.53 Hz), then gradually decreases to 1.24 g at 1 second (or 1.0 Hz). This curve is shown in **Figure 1.5-3**.

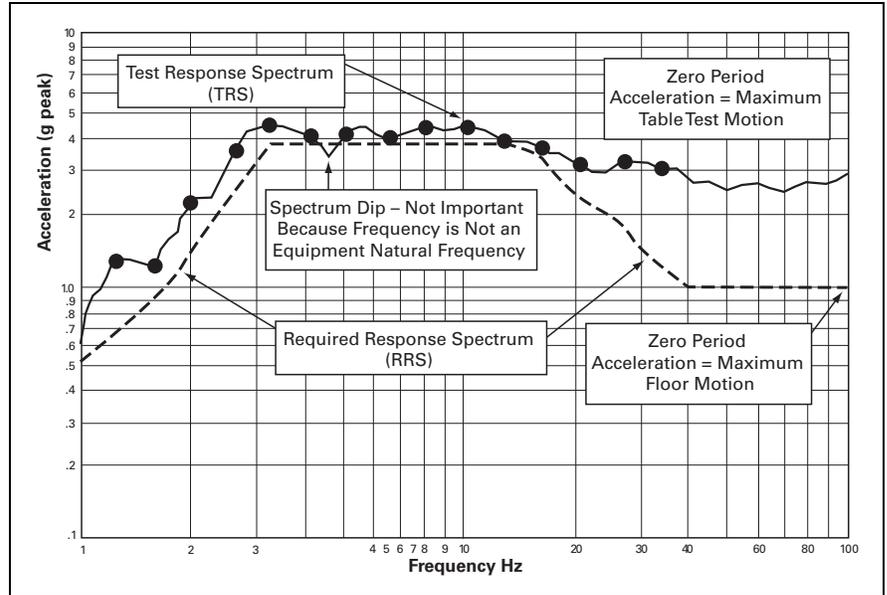


Figure 1.5-3. Design Response Spectrum

ASCE 7 Section 13.3—Seismic Demands on Non-Structural Components

ASCE 7 Paragraph 13.3.1 (IBC Section 1621.1.4) provides a formula for computing the seismic requirements of electrical and mechanical equipment inside a building or a structure. The formula is designed for evaluating the equipment attachment to the equipment foundations. The seismic loads are defined as:

$$F_p = 0.4 a_p S_{DS} W_p (1 + 2 Z/h) / (R_p / I_p)$$

Where:

F_p = Seismic design force imposed at the component's center of gravity (C.G.) and distributed relative to component mass distribution.

a_p = Component amplification factor that varies from 1.00 to 2.50.

S_{DS} = Ground level spectral acceleration, short period.

W_p = Component operating weight.

R_p = Component response modification factor that for electrical equipment varies from 2.5 to 6.0.

I_p = Component importance factor that is either 1.0 or 1.5.

Z = Highest point of equipment in a building relative to grade elevation.

h = Average roof height of building relative to grade elevation.

The following parameters produce the maximum required force:

- Z is taken equal to h (equipment on roof)
- I_p is taken equal to 1.5
- a_p is taken equal to 2.5
- R_p is taken equal to 2.5
- S_{DS} is equal to 1.90 g as indicated in the previous section

The acceleration (F_p/W_p) at the C.G. of the equipment is then computed equal to:

$$\text{Acceleration} = F_p/W_p = 0.4 \times 2.5 \times 1.90 \text{ g} (1 + 2) / (2.5/1.5) = 3.42 \text{ g}$$

Seismic Requirements

For equipment on (or below) grade, the acceleration at the equipment C.G. is then computed equal to:

$$\text{Acceleration} = F_p/W_p = 0.4 \times 2.5 \times 1.90 \text{ g} (1 + 0) / (2.5 / 1.5) = 1.14 \text{ g}$$

1

It is impractical to attempt to measure the actual acceleration of the C.G. of a piece of equipment under seismic test. The seismic response at the middle of base mounted equipment close to its C.G. is at least 50% higher than the floor input at the equipment natural frequency. The base accelerations associated with the accelerations of F_p/W_p at the C.G. of the equipment could then be computed as $3.42 / 1.5 = 2.28 \text{ g}$. It is the equipment base input acceleration that is measured and documented during seismic testing and is the acceleration value shown on Eaton's seismic certificates.

Final Combined Requirements

To better compare all seismic levels and determine the final envelope seismic requirements, the 2010 CBC, 2009 IBC for California, and 2009 IBC for New Madrid area seismic requirements are plotted in Figure 1.5-4. All curves are plotted at 5% damping. An envelopment of the seismic levels in the frequency range of 3.2 Hz to 100 Hz is also shown. This level is taken as Eaton's generic seismic test requirements for all certifications. Eaton performed additional seismic test runs on the equipment at approximately 120% of the generic enveloping seismic requirements (see Figure 1.5-5). Eaton has established this methodology to provide additional margin to accommodate potential changes with the spectral maps, thus eliminating the need for additional testing.

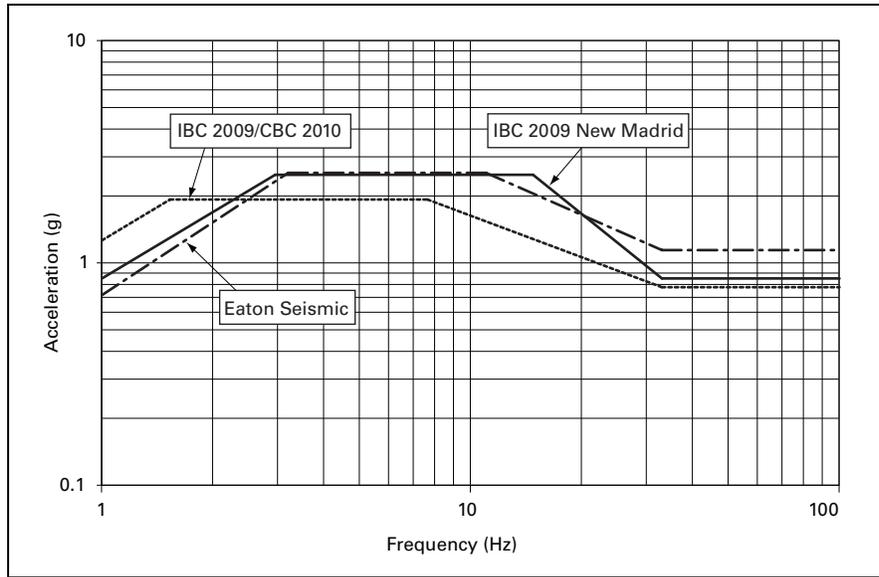


Figure 1.5-4. Required Response Spectrum Curve

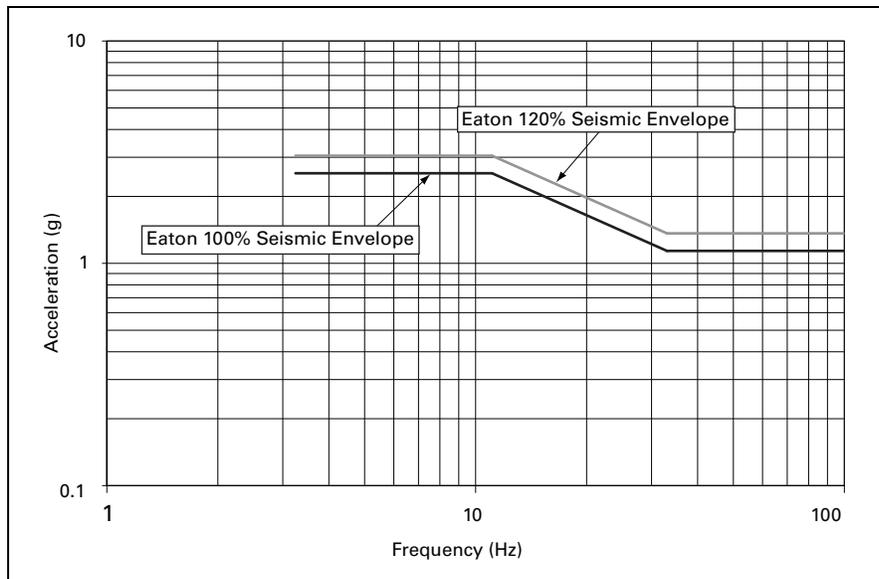


Figure 1.5-5. Eaton Test Required Response Spectrum Curve

Seismic Requirements

Product Specific Test Summaries

Table 1.5-26. Distribution Equipment Tested and Seismically Proven Against Requirements within IBC 2009

Eaton Equipment		
Low voltage metal-enclosed switchgear DS II Magnum DS High resistance ground		
Panelboards Pow-R-Line C 1a, 1a-LX, 2a, 2a-LX, 3a, 3E, 4, 5P, F-16 and Pow-R-Command™		
Switchboards Instant Integrated facilities Multimeter	Pow-R-Line 5P Pow-R-Line C Pow-R-Line i	
MCC Advantage® FlashGard® Freedom 2100	IT Series 2100	
Low voltage busway Pow-R-Way® and associated fittings Pow-R-Way III® and associated fittings		
Dry type transformers Mini powercenters EP, EPT, DS-3, DT-3		
Transfer switches Automatic transfer switch equipment		
Uninterruptible power supplies (UPS) Battery modules UPSs		
Enclosed control safety switches General-duty Heavy-duty Elevator control module		
Medium voltage switchgear Type VacClad-W MEF		Type MMVS Type MVS/MEB
MV bus Metal-enclosed non-segregated phase bus		
Network protectors Type CM-22 Type CMD		
Medium voltage control AMPGARD® SC9000 drives		
Substation transformers Dry-type Liquid type Unitized dry-type power centers		

Note: See www.eaton.com/seismic for current seismic certificates.

Test certificate of seismic withstand capability

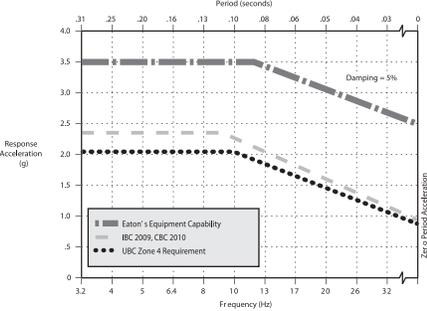
Seismic qualified

Eaton Corporation's equipment identified below was tested for seismic withstand capability and tested in accordance with the combined requirements specified in the International Building Code, the California Building Code, and the Uniform Building Code.



As required by the codes, the equipment demonstrated its ability to function after the seismic tests. The seismic capability of the equipment exceeds the worst-case required levels, as illustrated in the figure below.

Metal-Enclosed Low Voltage Switchgear—Magnum™ DS Front Accessible with Type MDS Circuit Breakers or CM-52 Network Protectors



The frequency sweep tests revealed that the lowest equipment natural frequency is:

7.1 Hz

Drawing Number
SA01901003E

Nathan Glenn, PE
Westinghouse Electric Company, LLC

TESTED BY
Wyle Laboratories
September 2008



3RD PARTY TEST ENGINEER IN CHARGE

For interpretation of testing data,
refer to Eaton
Publication SA12501SE



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Figure 1.5-6. Sample Seismic Certificate

Seismic Requirements

**Additional Design and
Installation Considerations**

When installing electrical distribution and control equipment, consideration must be given as to how the methods employed will affect seismic forces imposed on the equipment, equipment mounting surface, and conduits entering the equipment.

Eaton recommends that when specifying a brand of electrical distribution and control equipment, the designer references the installation manuals of that manufacturer to ascertain that the requirements can be met through the design and construction process.

For Eaton electrical distribution and control products, the seismic installation guides for essentially all product lines can be found at our Web site: <http://www.eaton.com/seismic>.

Electrical designers must work closely with the structural or civil engineers for a seismic qualified installation.

Consideration must be given to the type of material providing anchorage for the electrical equipment.

If steel, factors such as thickness or gauge, attachment via bolts or welding, and the size and type of hardware must be considered.

If concrete, the depth, the PSI, the type of re-enforcing bars used, as well as the diameter and embedment of anchorage all must be considered.

The designer must also give consideration if the equipment will be secured to the wall, versus stand-alone or free-standing, which requires the equipment to withstand the highest level of seismic forces. Top cable entry should be avoided for large enclosures, as accommodation for cable/conduit flexibility will need to be designed into the system.

For a manufacturer to simply state "Seismic Certified" or "Seismic Qualified" does not tell the designer if the equipment is appropriate for the intended installation.

Note: Eaton recommends that designers confirm with the manufacturer if the seismic certification supplied with the equipment is based on:

1. ACTUAL shaker table test as required by the IBC and CBC.
2. The seismic certificate and test data clearly state if the equipment was tested as free-standing—anchored at the bottom of the equipment to the shaker table.
3. Structure attached, that is, anchored at the center of gravity (C.G.) or at the TOP of the equipment to a simulated wall on the shaker table.

Stand-Alone or Free-Standing Equipment

If stand-alone or free-standing, then this may require that additional width space be allowed at each end of the equipment for additional seismic bracing supplied by the manufacturer.

Additional thought must be given to the clearances around the equipment to rigid structural edifices. Space must be allowed for the differing motions of the equipment and the structure, so that they do not collide during a seismic event and damage one another.

Note: If the equipment is installed as stand-alone or free-standing, with additional seismic bracing at each end and not attached to the structure as tested, and yet, it is fitted tightly against a structural wall, then this would be an incorrect installation for the application of the seismic certificate.

Furthermore, if conduits are to be installed overhead into the equipment, does the design call for flexible conduits of sufficient length to allow for the conflicting motion of the equipment and the structure during a seismic event so as to not damage the conductors contained therein, and the terminations points within the equipment.

Structure Attached Equipment

The designer must work closely with the structural engineer if the equipment is to be attached to the structure to ascertain that the internal wall re-enforcement of the structure, type of anchor, and depth of embedment is sufficient to secure the equipment so that the equipment, conduits and structure move at or near the same frequency.